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December 9, 2019

(Via Email to Secretary@dps.ny.gov)
Honorable Michelle L. Phillips
Secretary to the Commission
New York State Public Service Commission
Three Empire State Plaza
Albany, NY 12223-1350

Re: 15-E-0751 – In the Matter of the Value of Distributed Energy Resources

17-01277 – In the Matter of the Value of Distributed Energy Resources Working Group
Regarding Rate Design.

Dear Secretary Phillips:

In its March 9, 2017 Order on Net Energy Metering Transition, Phase One Value of Distributed Energy Resources, and Related Matters (VDER Transition Order), the Commission directed the immediate transition of certain distributed generation projects to Value Stack compensation but stated that mass market, on-site projects interconnected before January 1, 2020 would continue to receive net metering compensation, under the Phase One NEM policy. The Commission explained that a proposed successor tariff to take effect for projects interconnected after January 1, 2020 should be developed through the Phase Two process convened by Staff.

Subsequently, Staff conducted an extensive stakeholder process through the VDER Rate Design Working Group, which included opportunities for submission of proposals and multi-stage evaluation of various options. The attached *Staff Whitepaper on Rate Design for Mass Market Net Metering Successor Tariff* presents a detailed summary of that process and Staff's recommendations going forward. This whitepaper

will be subject to stakeholder comment, followed by Commission consideration.

Sincerely,

Marco L. Padula
Director, Office of Markets &
Innovation

STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

CASE 15-E-0751 – In the Matter of the Value of Distributed Energy Resources
MATTER 17-01277 – In the Matter of the Value of Distributed Energy Resources
Working Group Regarding Rate Design

STAFF WHITEPAPER ON RATE DESIGN FOR
MASS MARKET NET METERING SUCCESSOR TARIFF

December 2019

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EXECUTIVE SUMMARY

The Department of Public Service Staff (Staff) recommends the continuation of net energy metering (NEM) as a compensation mechanism for all eligible mass market and commercial projects under 750 kW. NEM provides a simple and convenient way for adopters of onsite distributed energy resources (DER) to be compensated for the benefits provided to the grid. Staff also proposes that these projects should be eligible for the range of options currently provided in delivery rates. For projects with load profiles or expertise that may benefit from time-varying price signals, projects would have the option to forego the use of standard delivery rates and instead utilize more sophisticated time-of-use (TOU) or new mass market standby rates. Coupled with a modest charge to collect public benefit funds that are otherwise avoided by using NEM, Staff's proposal would serve the State well by beginning to move the market gradually towards more cost-reflective rates while simultaneously preserving a simple and well-known compensation option.

Such an approach achieves a key goal to strengthen the relationship between the compensation level of NEM-eligible DER and its system contributions, while at the same time reflecting the rate design principles articulated by the Public Service Commission in the REV Track Two Order, including gradualism and customer orientation (i.e., that the customer experience be practical, understandable, and promote customer choice). At the same time, Staff's proposal begins to reduce the cost shift to non-adopters. Analysis performed in the VDER Working Group Regarding Rate Design identified cost shifts from onsite solar adopters using NEM to non-adopters of between \$3.00/kW per month to \$7.00/kW per month depending on utility and customer class. For a typical 6 kW (based on DC nameplate capacity) solar project, completely eliminating this cost shift would require \$19 to \$44 per month from a participating residential customer or \$19 to \$41 per month from a participating commercial customer. Included in those amounts are the costs of key policy programs that aid low income customers as well as fund energy efficiency and clean energy programs that NEM customers otherwise avoid paying for, but from which solar customers directly and indirectly derive benefits.

Staff's proposal would begin to reduce this cost shift in conjunction with the REV Track Two Order's emphasis on gradualism and the importance of mitigating adverse market reactions. Onsite solar adopters would continue to have the option to choose VDER Phase One NEM compensation along with existing delivery rates for all new projects, but would be required to continue contributing to public benefit programs by the application of a monthly Customer Benefit Contribution (CBC) charge of between \$0.69/kW to \$1.09/kW depending on utility and customer class. A utility specific CBC charge linked to the size of the system would be a fair and simple way to continue to recover public benefit funds and reduce the identified cost shifts from participants to non-participants. These CBC charges are relatively minor amounts compared to the cost shifts identified, and the impact on the economics of solar is also small, ranging from a 3.6% to 7.8% impact on the simple payback of a solar system and averaging 5.8% across all utilities and customer classes.

Staff's proposal will not only provide flexibility for customers and developers to choose delivery rates that are best suited to the needs of the project, they also provide important incentives to increase adoption of more value-oriented and sustainable compensation methodologies like the Value Stack. Mass market onsite solar adopters could choose to receive compensation under the Value Stack, rather than Phase One NEM, and would be eligible for a discount on the CBC based on their customer classification. The CBC charge would only be applied to self-consumed energy for these customers because the Value Stack already compensates injections based on value, whereas the compensation for self-consumed energy is based on the volumetric kWh retail rate. Self-consumed energy is assumed to be approximately 50% for a typical residential solar project and 70% for a small commercial project. Therefore, the CBC contribution for residential customers who choose the Value Stack compensation would be approximately half the amount compared to residential customers using NEM, and about two-thirds of the amount compared to small commercial customers using NEM.

Currently, mass market on-site projects using NEM-eligible technologies interconnected before January 1, 2020, are eligible for Phase One NEM. Staff recommends that the Commission modify the existing eligibility deadline for Phase One NEM without a CBC from January 1, 2020 to January 1, 2021, to allow the industry

adequate time to prepare for any new rate options adopted by the Commission. Maintaining a close variation of today's structure would give customers and vendors an option with which they are familiar, while mass market rate designs and a more sophisticated VDER mass market NEM successor tariff is developed. While an underlying rate design with more sophisticated rate elements and demand-based price signals is preferred from system benefit and technology-enabling perspectives, the lack of existing customer interval data presents a barrier to sizing DER solutions and estimating adopting customer economics. Given the pending implementation of advanced metering infrastructure in some utility service territories and the current lack of historical interval data for residential and small commercial customers, more time is needed to unlock the full suite of rate designs envisioned by the REV Track Two Order.

Below is a summary of Staff's proposal on rate and compensation options for new onsite solar projects. For other projects using NEM-eligible technologies besides solar, for mass market solar customers choosing new optional standby rates, and for commercial solar customers up to 750 kW, the CBC applicability has not yet been determined although the other components of Staff's proposal would still apply. For all remote metered solar projects, including those using the community distributed generation program, compensation would continue to be provided through the Value Stack only.

STAFF'S PROPOSAL ON COMPENSATION FOR NEW ONSITE SOLAR PROJECTS			
Customer Class	Delivery Rate	Compensation	CBC Applicability (% of Total Charge)
Mass Market	Standard or TOU	Phase One NEM	100%
		Value Stack	50% residential 70% small commercial
	Optional Standby	Value Stack	TBD
Commercial (<750 kW)	Standard, TOU, Legacy Standby	Phase One NEM	TBD
		Value Stack	

I. INTRODUCTION AND BACKGROUND

A. Introduction

This Whitepaper presents the work conducted in the Value of Distributed Energy Resources (VDER) Working Group Regarding Rate Design (the Rate Design Working Group) and presents the recommendations of Department of Public Service Staff (Staff) based on those efforts. Included are Staff's recommendations for a successor tariff for mass market Phase One Net Energy Metering (NEM) customers and for demand customers with projects under 750 kilowatts (kW). The recommendations, if adopted by the Public Service Commission (Commission), would replace current VDER NEM compensation for mass market customers who interconnect new on-site generation after December 31, 2020. Currently, mass market on-site projects using NEM-eligible technologies interconnected before January 1, 2020, are eligible for Phase One NEM as defined in the Commission Order on Net Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters.¹ Staff recommends that the Commission modify the existing eligibility deadline from January 1, 2020 to January 1, 2021, to allow the industry adequate time to prepare for any new rate options adopted by the Commission. While this Whitepaper does not modify the tariff or rate design applicable to mass market customers without on-site generation, the information discussed in this Whitepaper will be relevant to future rate design activities that may include such customers.

B. REV Track Two Order

In its Reforming the Energy Vision (REV) proceeding, the Commission articulated the essential elements of the utility revenue model and found that a more refined rate design, with improved price signals and opportunities for participation in distributed energy resource (DER) markets, would benefit consumers and facilitate the

¹ Case 15-E-0751, Value of Distributed Energy Resources, Order on Net Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017) (VDER Transition Order).

accomplishment of REV objectives.² The Commission noted in the REV Track Two Order that improvements in rate design are essential to a modern electric system and the efficient operation of customer-oriented markets. The Commission found that existing rate design practices contain implicit price signals that discourage customers from engaging with DER in a manner that optimizes both customer and system benefits. At the same time, the Commission made it clear that efficient cost recovery is only the beginning of rate design and that rates must also be designed to encourage price-responsive behavior to advance policy objectives, including achievement of environmental policies with managed impacts on customer bills. The Commission explained that it would undertake the rate design reforms necessary to drive maximally beneficial DER investment on a large scale by customers and third-party developers.

With that guidance, the REV Track Two Order directed Staff to examine a range of mass market customer³ rate reform scenarios, including consideration of wider use of time-of-use (TOU) rates.⁴ These rates can encourage customers to move their peak demands to a time that is off-peak for the system (or for the local distribution circuit), when the system savings exceed the cost of shifting. The Commission directed that TOU rates be considered for both commodity and delivery rates, and directed evaluation of demand charges and peak-coincident demand charges within mass market rate designs. The Commission identified a range of determinant factors for consideration as part of the evaluation of various rate designs, including (a) type of costs recovered within particular rate elements or time periods, (b) ratio of peak to off-peak prices, (c) duration of peak or demand intervals, (d) number of peak periods included, (e) seasonal differentials, and

² Case 14-M-0101, Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016) (REV Track Two Order), p. 118.

³ In this Whitepaper, “mass market customers” are the customers of New York’s large investor-owned electric utilities who are billed on a wholly volumetric basis, rather than partially based on demand. This includes all residential customers and some small non-residential customers.

⁴ REV Track Two Order, p. 120.

(f) implementation factors including types of monetary signal, enrollment mechanisms, and enabling technologies.⁵

The REV Track Two Order also articulated and adopted rate design principles to guide the process. The principles adopted by the Commission are the following:⁶

- **Cost causation:** Rates should reflect cost causation, including embedded costs as well as long-run marginal and future costs. Fixed charges should only be used to recover costs that do not vary with demand or energy usage.
- **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 dynamic and sophisticated price signals.
- **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 or delivery rate impacts.
- **Economic sustainability:** Rate design should reflect a long-term approach to price signals and the ability to build markets independent of any particular technology or investment cycle.

The Commission directed Staff to consult with stakeholders to define the scope of a study to analyze the potential impacts of a range of mass-market rate reform scenarios, including time-of-use and demand charges, for opt-out delivery and/or default

⁵ REV Track Two Order, p. 124.

⁶ REV Track Two Order, Appendix A.

commodity service. The study should model impacts using New York-specific data, and should consider experience from other jurisdictions. The Commission also directed the study to include the following:

- Integrating REV objectives with rate design principles (e.g., a time-variable rate should support customer response as well as representing efficient cost recovery);
- Potential consequences for customers using DER (both “active” and “prosumer”), non-participants (“traditional” customers), low-income customers, and utility financial risk as it relates to cost recovery; and
- Prerequisites to implementation, including advanced metering, valuation of DER, outreach and education, and enabling technologies.⁷

C. VDER Transition Order and Rate Design Working Group

The Commission’s adoption of the VDER Transition Order began the transition of compensation for DER to methodologies that reflect the actual value provided by those resources to the grid and to society, and that enable a distributed, transactive, and integrated electric system. The VDER Transition Order also contemplated the development of methodologies to more accurately reflect the costs that DERs impose on the grid. The Commission was motivated by the need to align compensation with actual benefits in order to incentivize behavior that maximizes overall value, as well as by the concern that continuation of previous compensation mechanisms could shift costs onto non-participants at unreasonable and unsustainable levels.

Specifically, the Commission directed in the VDER Transition Order the immediate sunseting of NEM rates under Public Service Law (PSL) 66-j and 66-l, so that new DER projects using technologies that that would have been NEM-eligible would instead receive Phase One NEM or Value Stack compensation. Phase One NEM applies to all on-site mass market projects⁸ interconnected before January 1, 2020, as well as certain projects in other categories that were far along in development at the time of the VDER Transition Order’s issuance. Phase One NEM provides compensation equivalent

⁷ REV Track Two Order, pp. 123-124.

⁸ That is, projects connected to the meter of a mass market customer, as described above, such as solar photovoltaic (PV) generation installed on the rooftop or in the yard of a residential customer or non-demand commercial customer.

to and under the same rules as NEM, except that projects are only eligible to receive Phase One NEM for a term of 20 years from their date of interconnection and are not entitled under any circumstance to a cash out of any excess bill credits.

All other new projects including Community Distributed Generation (CDG) projects, remote crediting projects (RNM), and large on-site projects, receive Value Stack compensation. The Value Stack provides monetary crediting for net hourly injections based on the actual values created, including the energy, capacity, environmental, and distribution system values. In addition, certain mass market customers participating in these projects were eligible for an additional transitional element, the Market Transition Credit (MTC). Projects receiving NEM or Phase One NEM compensation may opt into the Value Stack, though in some cases it may require the installation of more advanced meters and concomitant fees. Mass market on-site projects opting into the Value Stack are also eligible for the MTC, and its successor the “Community Credit” in some utility service territories.

The VDER Transition Order anticipated further stakeholder outreach to be initiated by Staff to develop new compensation rules for NEM-eligible mass market on-site projects. As with the overall transition, the Commission directed that these new compensation rules should improve the alignment of compensation with the values they provide and the costs that they incur. Staff subsequently formed a number of working groups, including the Rate Design Working Group.⁹ In recognition of the alignment between the issues identified in the VDER Transition Order regarding mass market on-site projects and the issues raised in the REV Track Two Order regarding mass market rate design, Staff explained that the study of mass market rate design reforms directed in the REV Track Two Order would be conducted as part of the Rate Design Working Group’s activities.¹⁰ As described below, that process and related studies and evaluations to date culminated in this Whitepaper.

⁹ Case 15-E-0751, supra, Notice of Formation of Working Groups and Protocols for Participation in VDER Phase Two (issued July 13, 2017).

¹⁰ Matter 17-01277, Value of Distributed Energy Resources Working Group Regarding Rate Design, Notice of Rate Design Issues To Be Addressed in VDER Proceeding (issued July 21, 2017).

II. VDER RATE DESIGN WORKING GROUP PROCESS

A. Overview of Process

On January 30, 2018, Staff issued its Guiding Instructions to Utilities and Stakeholders on the Approach/Implementation of Mass Market Rate Reform and Bill Impact Analysis, which outlined the process to be followed by the Rate Design Working Group in developing the mass market NEM successor tariffs. As noted in that document, there were three perspectives from which to perform the impact analysis; the existing mass market PV customers, new mass market PV adopters, and all non-participants, as detailed below:

- **Bill impact analysis.** The bill impact study is designed to inform the Commission regarding the pace of implementation and the effects of specific rate design modifications compared to existing NEM rates.
- **Project economics.** The study measures the impact of the proposed rate designs on the project economics for new mass-market customers that install rooftop solar and considers its effect on New York’s solar market and clean energy goals.
- **Impact of proposed rates on non-participants.** This is the “cost-shift” portion of the analysis, which measures the change in costs that would be shifted to non-participants as a result of the proposed new rates.

The document also described the process for developing and analyzing the rate design options, starting with the rate structure (e.g., customer charge, demand charge, energy charge, time periods for TOU rates), followed by calculation of billing determinants (e.g., number of billed kWh or kW by time period) for customers in the sample, using available interval data from each utility’s load research sample. Using these billing determinants and other rate design parameters (e.g., peak to off-peak differentials, summer to winter differentials, costs to be recovered through each rate component), revenue neutral rates would be calculated for each rate design to be considered.

At the April 6, 2018 Rate Design Working Group meeting, the Joint Utilities outlined the process to be used in performing the bill impact analysis. Parties were then given an opportunity to submit their suggested rate design proposals to be considered by Staff for selection to be run by the Joint Utilities through their bill impact models and

further analyzed by Staff's consultant, Energy and Environmental Economics, Inc. (E3),¹¹ with respect to cost shift and project economics. These proposals were submitted by the parties on May 29, 2018. On June 29, 2018, Staff identified the rate design proposals that it selected for further analysis. The four rate design proposals and three sensitivity rate designs selected by Staff for further analysis were the following:¹²

1. Joint Utilities time-of-use with demand charge (as filed) ("JU TOU Demand")
2. Joint Utilities with 2 demand charges (as filed) ("JU 2 Demand")
3. Clean Energy Parties TOU (as modified by Staff)¹³ ("CEP TOU Vol")
4. Alternative TOU (as requested by Staff) without demand charges (based on Joint Utilities' demand rate proposals)¹⁴ ("Alt TOU Vol")
5. Sensitivity: Alternative TOU with reduced customer charge¹⁵ ("Alt TOU Vol (Alt CC)")
6. Sensitivity: Joint Utilities with reduced demand charges ("TOU Demand & Vol")
7. Sensitivity: Clean Energy Parties' TOU with reduced customer charge¹⁶ ("CEP TOU Vol (Alt CC)")

¹¹ Information regarding E3 is available at <https://www.ethree.com>.

¹² Detailed descriptions of the proposed rates are available in several filings in the Working Group matter, including the Joint Utility filing of May 29, 2018 and the Staff filing of June 29, 2018. See Matter 17-01277.

¹³ Staff modified the seasonal TOU rates to include a 3:1 seasonal price ratio (summer peak to non-summer peak), a 3:1 summer peak to off-peak TOU price ratio, a 2:1 winter peak to off-peak TOU price ratio, with a 4-hour peak period used for summer and a 6-hour peak period used for winter.

¹⁴ For distribution rates, peak charges are designed to recover a portion of the local distribution costs (i.e., customer-related costs that are not recovered in the customer charge, secondary distribution costs, and a portion of primary distribution costs) and upstream delivery costs (the portion of primary distribution costs that are not local distribution costs and transmission costs). Off-peak charges are designed to recover a portion of the local distribution costs.

¹⁵ The customer charge was defined to include only the embedded cost of meters, customer service, billing and service drop.

¹⁶ The customer charge was defined to include only the embedded cost of meters, customer service, billing and service drop.

B. Presentation by Joint Utilities of Bill Impact Analysis

The Joint Utilities submitted the rate structure for rate designs specified in the June 29 letter on August 17, 2018, and filed their full bill impact analysis results on September 28, 2018. The bill impact analysis results were presented to the Rate Design Working Group on October 10, 2018. The Joint Utilities' bill impact analyses were based on a sample of residential and small non-residential customers by stratum (usage range) and load factor.¹⁷ Con Edison, Central Hudson, National Grid, and Orange and Rockland selected the bill impact customers from their load research samples, while NYSEG and RG&E determined bill impact profiles using load data from third-party vendors, modified to match stratum limits and to produce target low, medium and high load factors.

The hourly generation for solar scenarios was developed using the NYSERDA Value Stack Calculator, which contains solar output data (8760 hourly kWh produced by a 1 kW Direct Current (DC) system) for 2015 and 2016 (averaged) for Albany, Brookhaven, Buffalo, Ithaca, New York City, Plattsburgh, Rochester, and Syracuse.¹⁸ The Joint Utilities used data for a south-facing roof mount solar system. For each customer, the annual kWh offset by solar (i.e., 70% and 100% of annual usage) was divided by the kWh produced by a 1 kW system to determine the solar DC kW installed. The solar DC kW installed was then multiplied by the applicable averaged hourly kWh produced by a 1 kW system to create an hourly solar output profile that was netted against the customer's hourly usage.

The bill impact summary presented by the Joint Utilities showed the change in monthly bills for each analyzed customer, in dollars and by percentage. The "base" monthly bill for an analyzed customer was calculated as the annual bill for that customer based on current rates and the load profile for that customer with no solar production. The "Proposed" monthly bills for a bill impact customer were calculated as the monthly bills for that customer at current rates and each of the six proposed rate designs with (1) no

¹⁷ For low load factor, the 25th stratum percentile was used; for medium, the 50th stratum percentile; and for high, the 75th percentile.

¹⁸ Available at <https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Solar-Value-Stack-Calculator>

solar production, (2) solar production at 70% of the base annual kWh usage for that customer, and (3) solar production at 100% of the base annual kWh usage for that customer. The Joint Utilities also provided a Bill Impact Data Repository that provided bill totals and subtotals plus billing determinant totals and subtotals that stakeholders could use to develop their own bill impact analyses. Finally, the Joint Utilities presented charts that provided summary statistics based on mass market customer bill impacts for Con Edison, National Grid, NYSEG, Orange and Rockland, and RG&E for the six proposed rate designs.

C. Presentation by E3 of Rate Design Analysis

E3 performed further analysis of the rate design proposals to examine the cost shift issue and the impacts on project economics. This analysis consisted of three components (1) customer bill savings, (2) avoided costs and cost shift, and (3) project economics. E3's analysis relied on inputs and assumptions consistent with the JU analysis to the extent possible. The summary presentation for E3 has been filed along with this Whitepaper.

Bill Savings Calculation: The bill savings calculation estimated the savings from a customer bill under the new rate design after installing solar, compared to a counterfactual customer bill under existing rates before installing solar. The bill savings were analyzed by component (e.g., fixed charges, supply charges, delivery charges, and other surcharges). For each utility and customer class, bill savings were calculated as the load-weighted average of the savings in each stratum (with equal weight given to each load factor and each PV size). Load profiles with less than 150 kWh/month were excluded as unlikely candidates for solar adoption (e.g. studio apartments, commercial meters for single end uses). Bill savings were averaged (50/50) between customers who install solar to meet 70% of load and 100% of load, respectively. E3 also examined bill savings assuming solar plus storage, with storage sized to 25% of PV capacity, for Con Edison and National Grid. E3 also examined illustrative bill savings for illustrative customers adopting standalone storage, electric heat pumps, and electric vehicles.

Cost Shift Analysis: Avoided costs were used to estimate the “cost shift” (or “revenue shift,” i.e. the impact on non-participant bills), calculated as the difference between customer bill savings from adopting solar vs. the utility avoided costs. This

analysis focused on monetized avoided costs that would be directly realized in customer rates. The monetized avoided costs include wholesale energy, Installed Capacity (ICAP), carbon compliance (monetized via Regional Greenhouse Gas Initiative and avoided Renewable Energy Credit purchases),¹⁹ and a 'D' value calculated using each utility's Demand Reduction Value (DRV) rates under the Value Stack. E3's analysis compares calculated bill savings and forecast avoided costs for a single snapshot year, 2020, to estimate impacts on non-participants and rates for each utility. The rate impacts were calculated per 10 MW of solar installed to normalize the results across utilities (i.e., the rate impact estimates do not rely on a solar adoption forecast).

Project Economics: This portion of E3's analysis estimated the payback period of upfront solar investment as a function of the average bill savings under each rate proposal, summed by utility and then for the entire state. Upfront solar costs for each utility were derived from NYSERDA's historical installation data. The estimate accounts for the federal Investment Tax Credit (ITC), but does not account for any state or local incentives as the analytical focus was on the relative project economic impacts²⁰ across the different rate designs. Over the forecast period, supply charges were escalated using a blended average growth rate of New York Independent System Operator (NYISO) energy prices and ICAP prices, while delivery charges and other surcharges were escalated at 2% per year. Solar output was assumed to decline by 0.5%/year as a result of degradation.

D. Staff's Observations

1. Cost Shift

The avoided cost analysis performed by E3 shows a considerable cost shift between the first year avoided cost and the compensation received by the passive, non-

¹⁹ This represents the Renewable Energy Credit (REC) purchases that are avoided by the utility when the solar customer's reduced load translates to a lower utility REC compliance obligation.

²⁰ Individual project economics are expected to vary considerably based on local incentives, specific financing structures, and other factors. This level of granularity was not necessary and would likely have been potentially confusing for this relative rate design impact analysis.

tracking, solar PV adopting customer under current NEM rules. Avoided costs for residential and small commercial market segments ranged from around 4.5 cents/kWh to 7.7 cents/kWh, while bill savings for the solar adopter ranged from around 9 cents/kWh to 21 cents/kWh. Including estimated DRV values as an avoided cost does not meaningfully narrow the cost shift for some utilities while other utilities may see 2 cents/kWh to 6 cents/kWh of benefit. For a typical 6 kW PV system, completely closing this gap to eliminate the cost shift would require \$19 to \$44 per month from a participating residential customer or \$19 to \$41 per month from a participating commercial customer, as indicated in tables 1A and 1B below. Moreover, this gap can be expected to widen further in the future as fully volumetric rates can increase more than avoided costs over time as a result of the inclusion of non-market related costs (e.g. cyber security, emergency services, safety initiatives, etc.), in contrast to the declining cost trends of solar technology.

	National Grid	NYSEG	RGE	Central Hudson	O&R	Con Ed
Cost-Shift: Cents/kWh	4.1	3.5	4.2	8.1	7.5	7.1
\$/year (6 kW PV)	\$262	\$227	\$270	\$524	\$480	\$459
\$/month (6 kW PV)	\$22	\$19	\$23	\$44	\$40	\$38
\$/kW DC	\$ 3.63	\$ 3.16	\$ 3.75	\$ 7.28	\$ 6.68	\$ 6.38

Table 1A: Residential Cost Shift with Phase One NEM

	National Grid	NYSEG	RGE	Central Hudson	O&R	Con Ed
Cost-Shift: Cents/kWh	4.8	4.2	3.6	4.8	3.5	7.6
\$/year (6 kW PV)	\$311	\$268	\$233	\$310	\$225	\$489
\$/month (6 kW PV)	\$26	\$22	\$19	\$26	\$19	\$41
\$/kW DC	\$ 4.32	\$ 3.72	\$ 3.23	\$ 4.30	\$ 3.13	\$ 6.80

Table 1B: Small Commercial Cost Shift with Phase One NEM²¹

²¹ ConEd and O&R values differ from the April 15, 2019 and May 31, 2019 Rate Design Working Group presentations due to an adjustment made to the supply

There are three important considerations when evaluating these cost shift figures. First, the calculations do not include the social cost of carbon or any other proxy for emission reductions, in contrast to its inclusion in the Value Stack. Second, DRV value is not an immediate or precise avoided cost, but rather a proxy for the marginal system wide distribution value *expected to be avoided in the future* if a resource can produce during the most constrained hours on the delivery system. This value is highly generalized and continues to be refined through the ongoing Case 19-E-0283, Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies.²² Third, included in the gap between compensation and system value are the cost of public benefit programs. The costs of these programs are recovered from all ratepayers on a volumetric basis; therefore, the adoption of solar PV by a customer has the potential to dramatically reduce that customer's contribution.

These programs support low-income ratepayers as well as programs from which DER adopters benefit, such as energy efficiency and clean energy programs. Most, if not all, of the mass market customers installing on-site generation received an incentive from NY-Sun or a similar program paid for through these charges. Public benefit programs funded through volumetric charges include the following:

1. Utility Low Income Program
2. Utility Energy Efficiency Program
3. NY-Sun
4. New York Green Bank
5. Other Clean Energy Fund Programs
6. Clean Energy Standard (CES)

Table 2 summarizes the avoided contributions to public benefit program costs by a customer with a 6 kW solar PV system each month.

charges. The original tables used 2013 and 2015 supply charge data that has since been scaled to 2018 to represents more normal weather and recent market trends. Both charts assume a 6 kW system with a 12.27% capacity factor.

²² The DRV values used reflect the Marginal Cost Studies filed by each utility in March 2017. While the utilities have filed updated studies, some with lower DRV estimates, these have not been approved by the Commission at this time.

	National Grid	NYSEG	RG&E	Central Hudson	O&R	Con Edison
Residential (\$/month)	\$5.72	\$4.15	\$5.05	\$5.53	\$5.56	\$6.54
Small Commercial (\$/month)	\$6.07	\$4.34	\$5.00	\$5.03	\$5.54	\$6.60

Table 2: Avoided Contributions to Public Benefit Programs²³ with a 6 kW Solar PV System

Regarding commercial projects under 750 kW that are presently eligible for Phase One NEM, Staff maintains that any resulting cost shifts will be minimal as these demand-metered customers have volumetric rates that are much more aligned with utility costs than volumetrically-metered mass market customers and in most cases would not be able to avoid delivery costs using Phase One NEM. At this time, Staff has not performed an assessment to determine if there may be a small cost shift or even a net benefit from these larger demand-metered customers by technology. Given that the existence of the kW-based charge *reduces* kWh-based cost shifts, Staff believes that this analysis is presently not a high priority. Nevertheless, while the existence of the kW charge reduces kWh-based cost shifts, it does not preclude the avoidance of public benefit charges directly. Staff therefore will continue to examine this segment and provide opportunity for additional stakeholder input through future Rate Design Working Group activities.

2. Rate Design Proposals

After reviewing these cost shift issues, Staff examined the impact of the rate design proposals on customer bills for both participant savings and avoided costs. Staff created a common comparison method to determine the individual customer savings and avoided costs of rooftop solar by recovery component (e.g. supply and delivery) on existing and proposed rates.²⁴ Staff's rate design consultant, Navigant, presented these findings and discussed rate options with the Rate Design Working Group on April 15, 2019 and May 31, 2019.

²³ Excludes supply-related social benefit costs (i.e., CES).

²⁴ The JU 2 Demand rate design was excluded for simplicity since it was nearly identical to the JU TOU Demand rate design in terms of impacts.

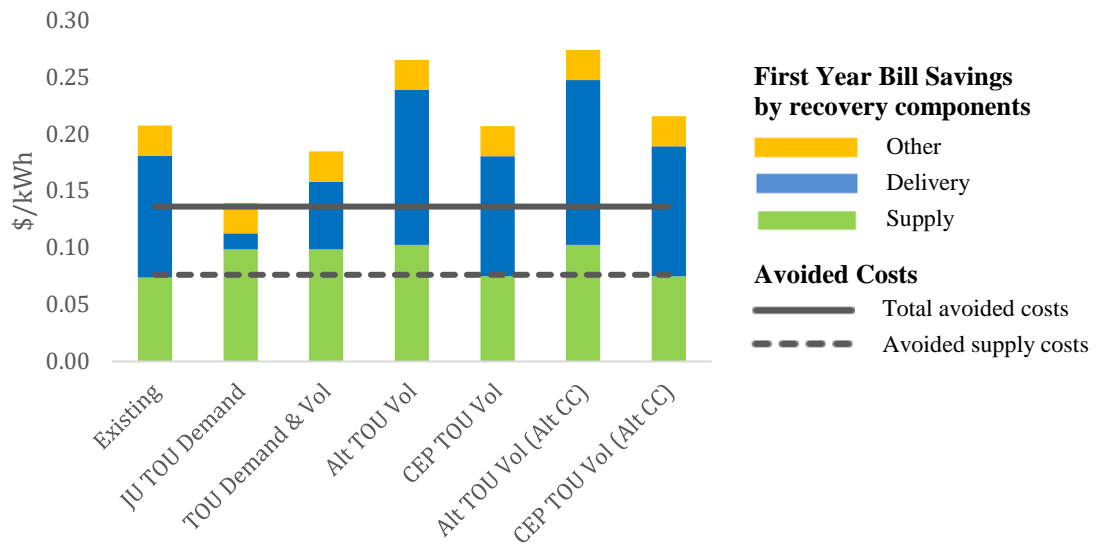


Figure 1A: Bill Impact Analysis – Con Edison Residential Service Class

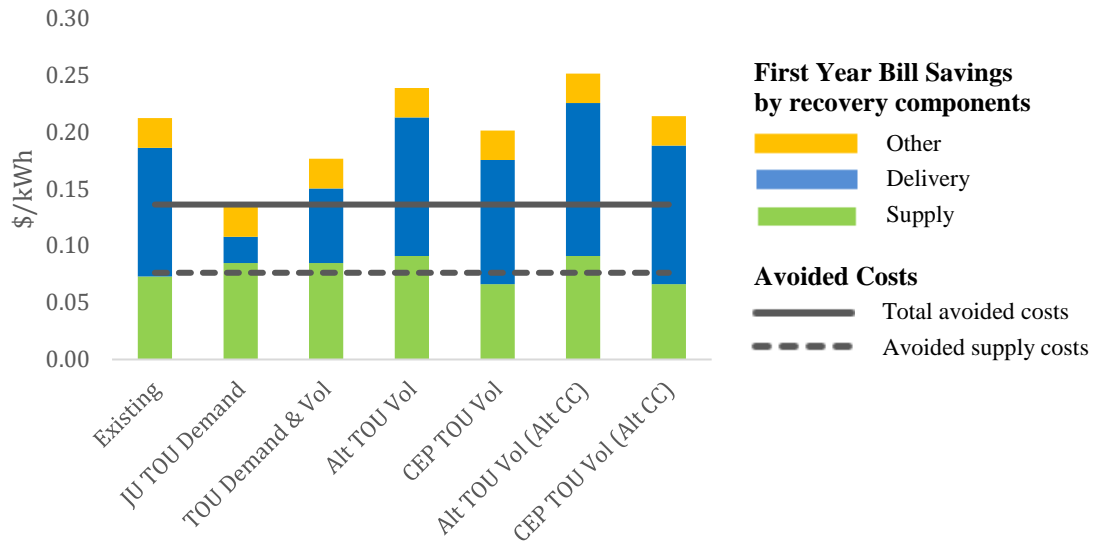


Figure 1B: Bill Impact Analysis – Con Edison Small Commercial Service Class

The Bill Impact Analysis for Con Edison, presented in Figures 1A and 1B, compares the first-year bill savings to the avoided system costs for each rate proposal as well as the existing rate with Phase One NEM compensation, for a customer who installs rooftop solar. These results isolate the impacts of solar generation and do not account for

the non-solar impacts to customer bills or avoided costs for the rate design in question. The Bill Impact Analysis for all six of the investor-owned utilities, along with a more detailed description of the Bill Impact Analysis methodology and assumptions, can be found in Appendix A.

For each utility, the bill savings under existing rates coupled with Phase One NEM, are higher than the utility's avoided costs, driven in part by a large disparity between delivery bill savings and avoided distribution costs. The savings on the supply portion of the bill are generally slightly lower than the avoided supply costs. The market supply charges represent an average supply cost spread evenly over all hours in a given month, whereas solar generation is generally well-aligned with peak energy and capacity prices in New York, leading to lower supply charge savings than avoided supply costs. However, the impacts on the delivery portion of the bill under existing rates are much higher than avoided distribution costs, and outweigh the modest difference between supply charge bill savings and avoided supply costs. As a result, total bill savings are higher than total avoided costs across all utilities and both customer classes. Figure 2 demonstrates how the cost shift for the delivery component of the bill outweigh the inverse effect of supply, resulting in a net cost shift for Niagara Mohawk's residential service class for not only the existing rates coupled with Phase One NEM but all rate designs examined in this Whitepaper.

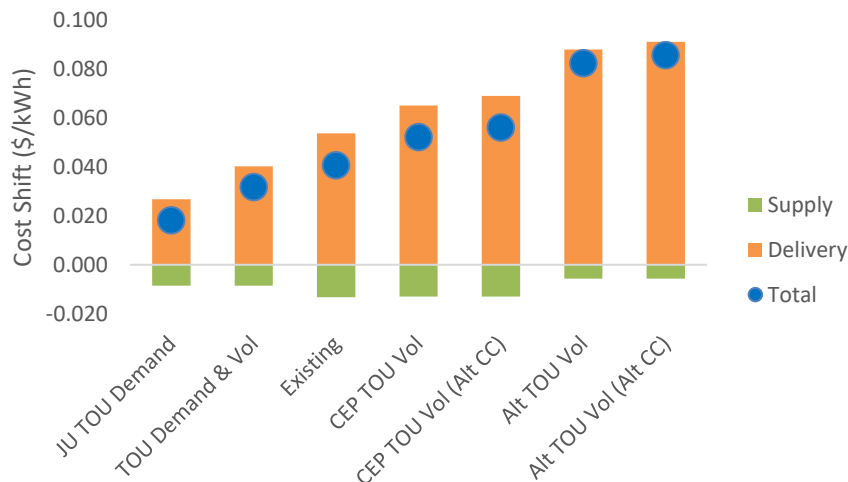


Figure 2: Cost Shift Analysis²⁵ - Niagara Mohawk Residential Service Class

²⁵ Derived from the Bill Impact Analysis by subtracting the avoided costs from the bill savings. The delivery value includes the Delivery & Other recovery components.

The JU TOU Demand and JU 2 Demand rates rely solely on a demand-based (\$/kW) charge for the delivery portion of a customer's bill. This results in significantly lower delivery bill savings compared to a volumetric delivery charge, because hourly and daily fluctuations in solar output can lead to limited reductions in a customer's demand-based billing determinants. The steep reduction in delivery bill savings drives overall solar offset bill savings below those of existing rates, across both residential and small commercial customer classes. While the timing and the level of the demand charges differ somewhat between the JU TOU Demand and JU 2 Demand, they have very similar solar offset results, with both providing the highest alignment between avoided costs and rooftop solar compensation. The Staff-directed TOU Demand & Vol rate reduces the demand charges of the JU TOU Demand rate by 50%, allocating the remaining costs on a flat volumetric basis. This rate yields results in between the pure demand rates and the full volumetric rates.

The Alt TOU Vol rate maintains the same TOU period definitions as the JU demand rates but relies on a volumetric delivery charge. For residential customers in some utility service territories, the Alt TOU Vol rate increases compensation to passive solar PV systems compared to existing rates, thereby further increasing the cost shift. This demonstrates that the ability of TOU rates to better reflect cost-causation relies heavily on the specific time periods chosen to approximate cost periods, the allocation of cost recovery between fixed and variable charges, and the load shapes of the alternative generator. For example, for some customer load shapes this higher compensation may be mitigated. Moving cost recovery from the fixed customer charge into volumetric rate components (Alt TOU Vol (Alt CC)) would increase compensation for both residential and commercial customer classes.

The CEP TOU Vol rate differs from the Alt TOU Vol rate in its peak period definitions, with the CEP TOU Vol rate relying on a narrower peak during the late afternoon/evenings. Solar production is less coincident with the CEP-defined peak periods, and as a result bill savings are lower than both Alt TOU Vol rates and existing rates. As with the Alt TOU Vol, moving costs from the fixed customer charge into volumetric rate components (CEP TOU Vol (Alt CC)) increases the solar offset value incrementally for both residential and commercial rates. Most crucially, the supply rate

structure envisioned in the CEP TOU Vol leads to a drop in supply savings in comparison to supply savings under default rates. As discussed above in Figure 2, the existing Phase One NEM default rates over-collect the supply costs. A more accurate mass market NEM replacement rate design would hold steady or even slightly increase supply compensation compared to existing rates while decreasing unjustified delivery rate offsets. In some cases, the CEP TOU Vol rate actually increases delivery compensation while lowering supply compensation.

To summarize the results of the Bill Impact Analysis, Figures 3A and 3B below compare the cost shift of the rates examined by the working group to the cost shift of existing rates with Phase One NEM compensation for the residential and small commercial service classes, respectively. Values above zero on the y-axis indicate rate designs that increase the cost shift, and values below zero indicate rate designs that reduce the cost shift when compared to the existing rate with Phase One NEM rate. The JU TOU Demand and TOU Demand & Vol rate designs reduced the overall cost shift for both the residential and small commercial service classes. Of the fully volumetric TOU rates, the CEP TOU Vol rate presented the lowest cost shift, with a similar performance as the existing flat volumetric rates.

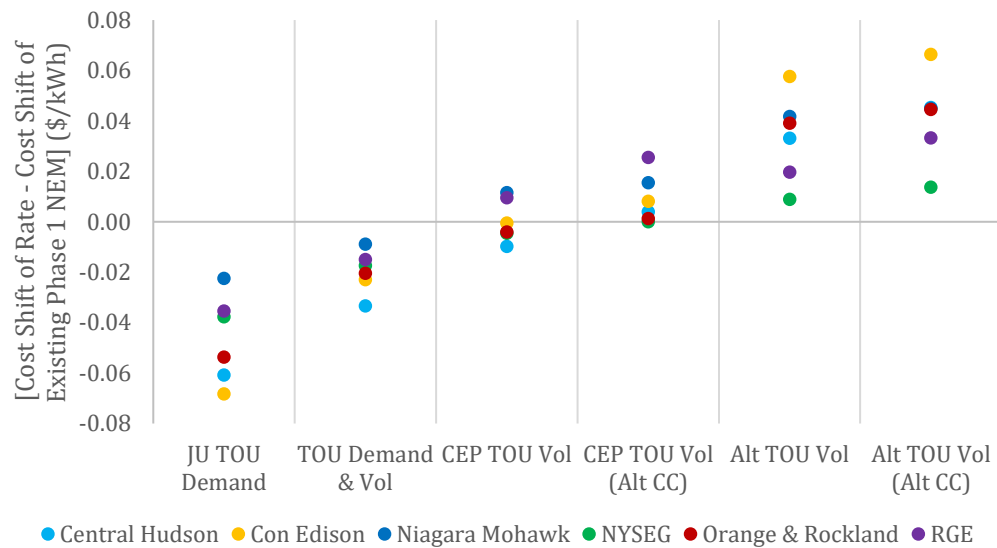


Figure 3A: Change in Cost Shift vs. Existing Phase One NEM rates – Residential

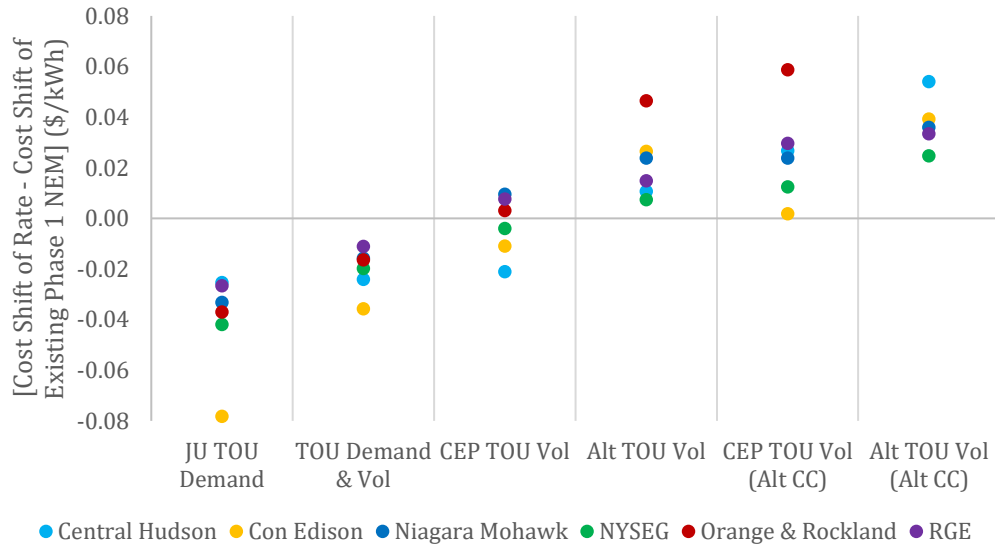


Figure 3B: Change in Cost Shift vs. Existing Phase One NEM – Small Commercial

III. STAFF RECOMMENDATIONS

A key goal of the mass market Phase One NEM successor tariff moving forward is to strengthen the relationship between the compensation level of NEM-eligible DER and its system contribution. In addition to reflecting the cost of remaining connected to the distribution grid, Staff is also mindful of the rate design principles articulated by the Commission in the REV Track Two Order, including gradualism and customer orientation (i.e., that the customer experience be practical, understandable, and promote customer choice). The progression to cost reflective rates and economic sustainability must therefore be measured. At the same time, REV principles call for customer choice and technology-neutral rates. Meeting these principles requires access to data to enable customers and vendors to make economically efficient choices.

While an underlying rate design with more sophisticated rate elements and demand-based price signals is preferred from system benefit and technology-enabling perspectives, the lack of existing customer interval data presents a barrier to sizing DER

solutions and estimating adopting customer economics. Given the pending implementation of Advanced Metering Infrastructure (AMI) in some utility service territories and the current lack of historical interval data for residential and small commercial customers, more time is needed to unlock the full suite of rate designs envisioned by the REV Track Two Order. In the near-term, a mass market Phase One NEM successor bridge tariff is needed to be implemented prior to a more permanent successor tariff. The bridge tariff should be customer-oriented while containing features that bring the economics more in line with system value than present rates.

Staff believes that the current package of rate plan options available to customers plus a bridge tariff can serve the State well and start to move the market gradually toward economic sustainability across technologies. Fortunately, the past efforts of the Rate Design Working Group can be used to inform the bridge tariff rates that will remain in effect pending mass market AMI deployment and further development of the mass market Phase One NEM successor tariff. The bridge tariff recommended by Staff would use the existing Phase One NEM compensation methodology, coupled with existing delivery rates and a monthly Customer Benefit Contribution (CBC) charge, to continue to recover public benefit funds and other costs not avoided by the installation of NEM-eligible DER. A utility specific CBC charge linked to the size of the system would be a fair and simple way to continue recovery of public benefit funds and start to close the value gap.

The simplicity of using existing delivery and compensation methodologies, plus a modest charge to collect public benefits funds, is an effective way to achieve more cost reflective rates in light of the goals of REV. Existing methodologies, however, have certain tradeoffs that Staff's recommendations attempt to mitigate to the extent possible. First, mass market standard rates fall short of reflecting the time-varying and demand-based nature of electric system costs. Second, and as a result, standard rates would not encourage new technology coupling such as solar and storage. As a bridge tariff, however, maintaining a close variation of today's structure would give customers and vendors an option with which they are familiar while mass market rate designs and a more sophisticated VDER mass market NEM successor tariff is developed and AMI continues to be deployed. To allow mass market customers using NEM-eligible

technologies that have load profiles or expertise that may benefit from time-varying price signals, projects would have the option to utilize existing TOU rates or new standby rates currently under review by the Commission. Since volumetric TOU rates with NEM do not rely on the availability of historic interval data for successful implementation, as generation value can be simply determined based on a solar load curve, the existing TOU rates can be viewed as a transitional offering, attractive to certain customers not yet ready for the complexity featured in standby rates.

To summarize, Staff is proposing that mass market customers with onsite NEM-eligible DER be required to choose among the following rate and compensation options for new installations as of January 1, 2021. In addition, those projects would have grandfathered rights to remain on either the Standard Rate with CBC or the TOU Rate with CBC for a period of twenty years.²⁶

A. Delivery Rate Options

Standard Rates – Mass market on-site DER customers would have the option to remain on standard delivery rates of each utility and receive either VDER Phase One NEM or Value Stack as compensation for net injections. In either case, the cost of public benefit funds would now be largely recovered, however, through a new CBC charge. Under this option, Staff proposes a modest \$/kW DC per month charge tied to PV system size (based on DC nameplate capacity) specific to all utilities starting January 1, 2021. Staff initially calculates the CBC charge at the levels shown in Figure 4 below.

²⁶ Staff also proposes that customers be allowed to switch among the currently available options once per year at their selected anniversary date but if the switch is to Standby Rates, the grandfathering rights are revoked.



Figure 4: CBC Charge by Utility

These are relatively minor amounts compared to the cost shift identified in E3 modeling, which ranges from \$3.00/kW per month to \$7.00/kW per month depending on utility and customer class as shown in Tables 1A and 1B. Consequently, the impact on the economics of adopting solar customers is also small, ranging from a 3.6% to 7.8% impact on the simple payback of a PV system, and averaging 5.8% across all utilities and customer classes. Rooftop solar adopters should contribute to the costs of key policy programs that aid LMI customers as well as programs from which solar customers directly and indirectly derive benefits, such as energy efficiency and clean energy programs. Because public benefit program costs are likely to increase in the future, Staff seeks comment on whether the CBC charge should increase over time, to ensure continued cost recovery of public benefit program costs.

Many utility costs, such as cyber security, emergency services, and safety programs are still being avoided by rooftop solar adopters using standard delivery rates combined with Phase One NEM compensation. In addition, rooftop solar exports likely rely on the secondary distribution system to be successfully delivered to neighboring load sources. The net metering transaction on fully volumetric rates results in an inequitable contribution to the cost of providing these services.

However, consistent with the principle of gradualism, Staff is reluctant to address changes to the cost recovery for the service categories described above at this time. Subjecting the CBC to potential adjustments to reflect future, unavoided cost increases is an equitable way to account for these expenses since the adjustments will not impact the original project economics, rather it minimizes windfalls that can accumulate from volumetric rate increases in the future. For example, if today's delivery rate in a utility territory is 4 cents/kWh, barring rate decreases, the solar adopter in that territory will be offsetting at least that amount for years to come. This approach provides certainty to the project economics for new solar installations while helping cover incremental costs for services which clearly rooftop solar does not offset, such as cyber security. To further inform the Commission on this issue, Staff seeks comment on whether and how the CBC charge should be adjusted to account for cost categories outside of direct public benefit program collections in future rate cases.

Staff also recommends that customers with eligible projects should be treated similarly to other customers without DER, so that as standard delivery rates change the rates for all customers would correspondingly change. That is, any changes in the default rate design that affect customers in the same service class without DERs would similarly affect these customers.²⁷ To the extent that the default rate changes, such that all customers including mass market on-site customers are placed on time-varying or other modified rates, the Commission should evaluate whether the impacts of that change justify a change in or elimination of the CBC charge. If the underlying economics of the bridge tariffs change substantially, special consideration should be given to DER adopters to mitigate the impact. Finally, to the extent that new NEM customers require new

²⁷ The fact that the CBC charge may fluctuate, and delivery rate structures and levels may change, should be added to the disclosure form that customers must be provided pursuant to the Commission's DER oversight decisions. The form will also need to be updated to reflect the other rate and compensation changes resulting from the recommendations in this Whitepaper.

meters, those costs should be charged to NEM customers rather than socialized to non-participants.

The CBC charge calculations in this whitepaper assume passive, non-tracking, solar PV as a proxy for eligible DER projects. Additional NEM-eligible DER technologies include residential micro-combined heat and power, fuel cells, micro-hydroelectric and farm waste digesters. Staff seeks comments on how the CBC charge for these other NEM eligible DER technologies, including eligible resources paired with storage, should be calculated and applied to the various delivery rate and compensation options proposed.

TOU Rates – Staff recommends allowing mass market NEM-eligible DER adopters the option to choose amongst delivery rates, including TOU. These existing TOU rate options, coupled with Phase One NEM or Value Stack compensation for net injections, are relatively straightforward for customers and installers to both understand and model economic savings, and the gradualism will ease the industry’s transition to more complex time-varying rates. Time-varying rates that accurately capture seasonal and intraday cost fluctuations will play an important role in an electric system with significant amounts of variable renewable energy. The CEP TOU Vol rate with the existing customer charge starts to provide improved price signals to DER adopters, but more refinement must be done before putting it into effect.

Because the existing TOU rates are fully volumetric, the CBC charge applicable under the standard rate, and any future changes to such charge, would also be applied to this option. Additionally, staff recommends that under this TOU option the utilities shift to monetary crediting to properly capture the seasonal differentials in pricing while maintaining the credit rollover processes laid out in the VDER Transition Order for Phase One NEM.

Standby Rates – Another option available to mass market customers installing eligible DER technologies would be to opt in to the new standby rates. The rate components for Standby Service include a Customer Charge, Contract Demand Charge, and Daily As-Used Demand Charge. These rates are for more sophisticated customers, likely with multiple technologies such as energy storage and electric

vehicle charging. The utilities have been directed by the Commission to develop optional standby rates for mass market customers (see Case 15-E-0751), and it is anticipated these rates will go into effect in the second or third quarter of 2020. Staff's proposal would require customers opting in to the new standby rates to be eligible for Value Stack compensation only for net injections. Staff has not performed an assessment to determine if there is a cost shift with this option because the rates are still being developed, so the potential size of the CBC, if any, has not been determined. The mass market standby rates were filed by the utilities on September 23, 2019. Staff requests comments on the need for applying and the methodology for determining a CBC for customers using the optional standby rates.

B. Compensation Options for Net Injections

Phase One NEM – The existing Phase One NEM compensation methodology is an effective option for many mass market customers and should remain available for any onsite NEM-eligible projects. The CBC would be included to start to recover public benefit funds and other costs not avoided by the installation of these technologies. Customers electing Phase One NEM compensation would be permitted to assume any underlying delivery rate design of their choosing, and would also be allowed to switch underlying rate plans as new options become available.

Value Stack – Mass market DER adopters could also choose to receive compensation under the Value Stack, rather than Phase One NEM, and would be eligible for a discount on the CBC based on their customer classification.²⁸ Customers electing Value Stack compensation would be permitted to assume any underlying delivery rate design of their choosing, and would be allowed to switch underlying rate plans as new options become available.

At this time, Staff does not believe it necessary to assess the full CBC charge on this option because the Value Stack compensation for net injections has been

²⁸ For mass market customers who opt in to the Value Stack compensation methodology, the Community Credit is available in some service territories.

fully decoupled from the retail rate. Instead, the CBC charge would only be applied to self-consumed energy generated on-site, which is assumed to be on average 50% of a residential PV system's production, and 70% of a small commercial PV system's production.²⁹ Therefore, the CBC contribution for residential customers who choose the Value Stack compensation should be approximately half the amount compared to residential customers using Phase one NEM, and about two-thirds of the amount compared to small commercial customers using Phase One NEM. Staff requests comments on these percentages and their accuracy.

This option would be open to eligible DER coupled with storage, as is now presently the case, although stand-alone storage configurations would continue to be subject to Mandatory Hourly Pricing and standby rates in most cases.

Below in Table 3 is a summary of the Staff proposals on rate and compensation options for certain NEM-eligible onsite solar projects applicable to installations after December 31, 2020.

Project Type	Delivery Rate	Compensation	CBC Applicability (% of Total Charge)	Other
Mass Market	Standard	Phase One NEM	100%	
		Value Stack	50% residential 70% small commercial	
	TOU	Phase One NEM	100%	Monetary crediting
		Value Stack	50% residential 70% small commercial	
	Optional Standby	Value Stack	TBD	
Commercial (<750 kW)	Standard, TOU, Legacy Standby	Phase One NEM	TBD	
		Value Stack		

Table 3: Staff Proposals on Rate and Compensation Options

Regarding demand-metered, commercial projects below 750 kW, Staff continues to believe it is appropriate to extend Phase One NEM to these customers in order to

²⁹ Case 15-E-0751, Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding (issued October 27, 2016).

encourage greater participation and investment in DER across all customer segments. Phase One NEM is already an option for these types of projects that qualify before January 1, 2020, for a 20-year term from each project's in-service date.³⁰ As these customers are, by definition, already subject to demand rates, this modification will cause no meaningful cost impacts in most cases as most eligible customers would not be able to avoid delivery costs. These commercial customers, who may also want an option for more fixed compensation alternatives for DER projects, would receive compensation from NEM that are much more aligned with utility costs than non-demand-metered customers since the volumetric component of their rates are lower due to the applicability of demand charges. Staff requests comment from stakeholders on potential cost shifts for this customer segment, and whether the CBC charge, or some variant, should be applied.

C. Application of REV Track Two Order Principles

A key goal of Staff's proposal is to strengthen the relationship between the compensation level of NEM-eligible DER and its system contributions, while at the same time reflecting the rate design principles articulated by the Commission in the REV Track Two Order. For a typical 6 kW solar project, eliminating the cost shift from participants to non-participants would require \$3/kW-month to \$7/kW-month from a participating customer. Eliminating these cost shifts through fixed or demand charges would address the Cost Causation principle of rate design, but at the expense of several other equally important principles that include Customer Orientation, Stability, Gradualism and Encouragement of Outcomes.

Staff's proposal of a modest CBC charge that varies between \$0.69/kW-month and \$1.09/kW-month would begin to reduce the cost shift in an economically justifiable

³⁰ For Phase One NEM to be available, the project must have the following characteristics: (a) a rated capacity of 750 kW AC or lower; (b) the same location and behind the same meter as the electric customer whose usage they are designed to offset; and (c) an estimated annual output less than or equal to that customer's historic annual usage in kWh. Staff had noted previously that it would consider whether Phase One NEM should continue for new projects only or should be modified as part of making its recommendations regarding a post-January 1, 2020 successor tariff for on-site mass market customers.

way by recovering the costs that fund low income and clean energy programs that are not avoided by the utility as a result of rooftop solar installations. The proposed CBC balances the need for more cost reflective rates with the other principles in the REV Track Two Order.

Leaving the volumetric NEM compensation structure in place supports the Customer-Orientation principle by providing customers with an easy to understand option that they are already familiar with. The Gradualism and Stability principles of rate design dictate that changes to rate designs should not cause large abrupt delivery rate impacts and should ensure relatively stable customer bills. Staff examined the impact of the CBC on the economics for rooftop solar adopters, examining simple payback and the internal rate of return (IRR). Figure 4A shows that the proposed CBC charge would have a relatively subtle effect on the economics of solar, with expected increases to simple payback ranging from 0.2 years in Con Edison to 1.4 years in NYSEG, and averaging 0.7 years across all service territories.

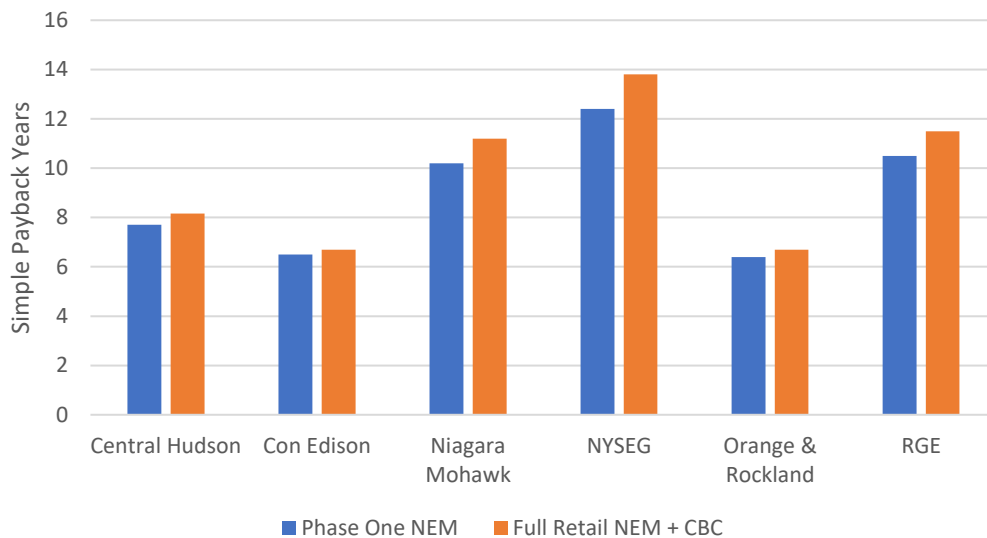


Figure 4A: Simple Payback Analysis – Residential Service Class

Similarly, Figure 4B shows that a monthly CBC charge of between \$0.69/kW-month to \$1.09/kW-month would reduce the internal rate of return (IRR) by less than 1% in all service territories.

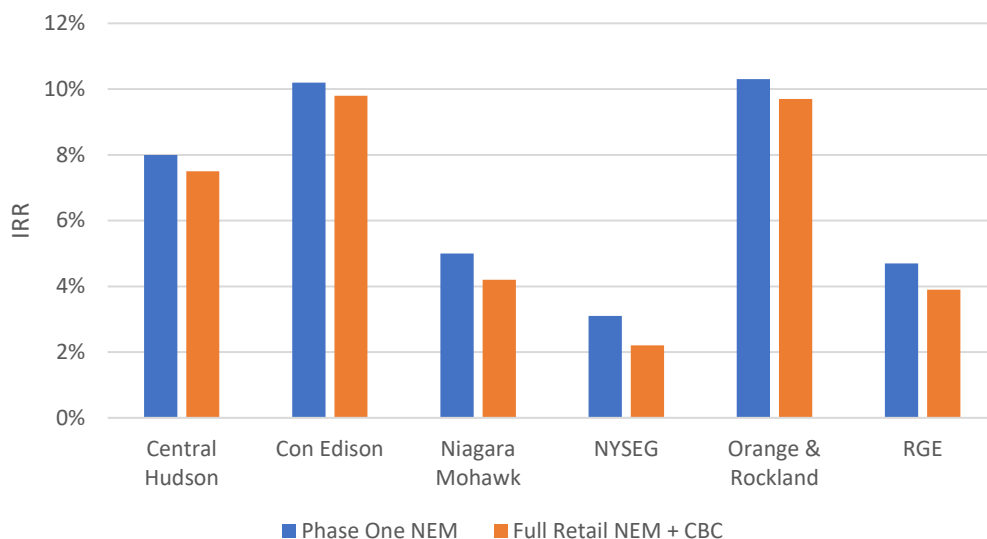


Figure 4B: Internal Rate of Return Analysis – Residential³¹ Service Class

Staff believes that the CBC charge strikes an appropriate balance between the Cost Causation principle of rate design by continuing recovery of the non by-passable public benefit funds, with the Gradualism and Stability principles by limiting the financial impacts on new solar projects to less than 1 year for simple payback and less than 1% for the IRR, as presented in Figures 4A and 4B.

To the extent that the transition to more cost reflective rate designs has a negative effect on the distributed solar market and threatens the achievement of New York’s 6 GW distributed solar goal, Staff recommends the Commission address the market gap more explicitly, through modifications to the incentive levels in the NY-Sun program. This approach has the added benefit of supporting yet another principle of rate design, Policy Transparency.

Staff also notes that while Table 5 shows that the rooftop solar market has seen an 18% decrease in MWs installed over the last 4 years, the distributed solar market has enjoyed a 46% increase in MWs installed per year over the same time period, thanks to the success of the community solar market. Because community solar has been popular

³¹ The Simple Payback and IRR analysis was presented during the May 31st, 2019 Rate Design Working Group meeting and was conducted for Residential and Small Commercial service classes.

with residential customers, providing bill savings benefits to customers who previously were unable to access rooftop solar, or simply prefer a solar product that does not require modifications to their home, Staff will consider the distributed solar market as a whole, including the transfer of potential NEM customers to the community solar market, when evaluating the effects of future NEM policy.

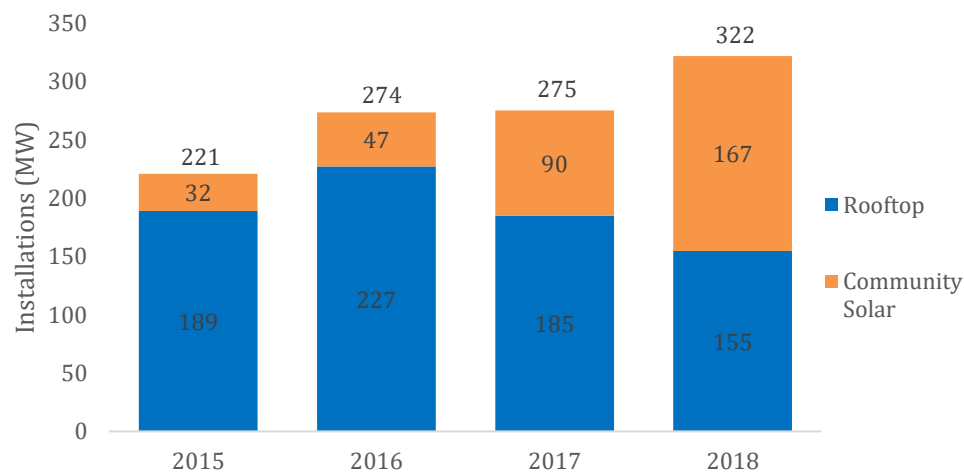


Figure 5: Distributed Solar PV Installations³²

IV. ADDITIONAL ANALYSIS

While the rate designs for mass market NEM successor tariffs can more closely balance economic sustainability and customer suitability in the case of DER customers, the rate designs must also be compatible with achieving other State policy objectives, such as encouraging energy efficiency and achieving greenhouse gas (GHG) reduction goals through beneficial electrification. The mass market NEM successor tariff rates, for example, should not discourage economic heat pumps or transportation electrification by sending price signals that are confusing or that discourage energy use during times of the day that do not drive up system costs. The mass market NEM successor tariff rates also need to properly align demand and volumetric price signals to enable demand response and energy storage.

³² NYSERDA reported distributed solar installations, including projects with and without NYSERDA incentives

The Commission is currently examining the pursuit of these policy objectives in other proceedings. In November 2018, the Commission issued an order regarding electric vehicle (EV) charging tariffs, and required tariff revisions to encourage broader use of TOU rates for EV charging by, among other things, equalizing the customer charge between residential TOU rates and the traditional residential customer charge.³³ Although the Commission left in place the existing periods for peak and off-peak pricing, it noted that wider deployment of AMI will ultimately allow greater flexibility in designing TOU rates with super-peak periods. The Commission is also considering a voluntary residential beneficial electrification rate structure in connection with National Grid's recently concluded general rate case for electric service.³⁴ As part of the Joint Proposal adopted by the Commission in that proceeding, National Grid submitted a proposed rate design to promote further adoption of beneficial electrification technologies such as EVs and heat pumps.³⁵ Finally, the Commission issued an Order adopting new standby and buyback service rate designs on May 16, 2019.³⁶

The rate objectives for the mass market NEM successor tariff must be considered alongside the pursuit of these other policy objectives. The REV Track Two Order for its part, strongly encouraged introducing time-sensitive rates for mass market customers, noting that “a time-variable rate should support customer response as well as representing efficient cost recovery.”³⁷ Recognizing that design choices within the general category of time-variable rates can have a large impact on the effect both for achieving REV

³³ Case 18-E-0206, Tariff Filings to Effectuate the Provisions of Public Service Law Section 66-o (Residential Electric Vehicle Charging Tariff, Order Rejecting Tariff Filings and Directing Tariff Provisions (issued November 15, 2018).

³⁴ Case 17-E-0238, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service.

³⁵ Case 17-E-0238, Proposal of Niagara Mohawk Power Corporation d/b/a National Grid for Voluntary Residential Rate Structure to Further Adoption of Beneficial Electrification Technologies (submitted September 17, 2018).

³⁶ Case 15-E-0751, supra, Order on Standby and Buyback Service Rate Design and Establishing Optional Demand-Based Rates (issued May 16, 2019).

³⁷ REV Track Two Order, pp. 123-24.

objectives and on bill impacts for customers at all levels of participation, the Commission in the REV Track Two Order encouraged Staff to consider a range of determinant factors in the process of developing possible rate designs, including the ratio of peak to off-peak prices, the duration of peak demand intervals, the number of peak periods included, and seasonal differentials.³⁸

Being mindful of New York's other public policy objectives, the ultimate goal for the mass market NEM successor rate(s) is to retain the positive aspect of today's rates while moving to overall economic sustainability across technologies. Rate design structures and options must be analyzed to identify the structures that align with the key considerations and principles envisioned in REV. Achieving overall economic sustainability through improved cost causation and efficient, market-enabled, decision-making is not an easy task. This analysis will likely require consideration of additional rate design proposals beyond those developed and analyzed in the Rate Design Working Group.

To aid in this task, Staff recommends development of a prioritization framework that ranks rate options based on how several key criteria are met. Initial criteria considered by Staff include:

1. **Technology Applicability** - Applicability of the rate to enable future technology such as EVs, advanced heat pumps, energy storage, etc.
2. **Economic Sustainability** - Level of linkage between system costs and pricing so high levels of technology adoption can occur without negative economic impacts to nonparticipants.
3. **Speed to Implement** - Estimated time frame that New York could design, plan, and launch the NEM successor rate(s).
4. **Gradualism** - Degree of value change for rooftop solar and major categories of cost-effective energy efficiency measures compared to current rates.
5. **Simplicity** - Level of effort and education needed for the customer to fully engage with rate.
6. **Ability to Save** - Number of ways customers can save on their bill such as shifting or staggering usage.

The first three considerations are system and non-participant related, while the last three are more focused on future participant customer acceptance. Staff also

³⁸ REV Track Two Order, p. 124.

acknowledges that there is inherent tension between some of the criteria, and suggests adding policy-related criteria of lesser weight that can cover such topics as GHG savings per dollar invested, technology enablement, equitable funding, efficient use of the system, and cleaner DER deployment. The objective would be to use these considerations to rank and evaluate mass market NEM successor rates and the tradeoffs among them with respect to these criteria, in an open and transparent manner. Extending the time period for mass market NEM successor rates analysis would also allow stakeholders additional time to become familiar with data sets and methodologies.

A. Future Work of the Rate Design Working Group

Going forward, the Rate Design Working Group will continue to develop additional rate design recommendations for further study or implementation on a voluntary basis. To approach rate design in a comprehensive and strategic manner – with respect to both State goals and to reduce customer confusion – the work of the Rate Design Working Group would be informed by the outcome of the proceedings summarized above regarding EV charging tariffs, National Grid’s voluntary residential beneficial electrification rate proposal, standby and buyback service rate design, residential voluntary demand rates, and the implementation of AMI by various utilities. Staff recommends that the Rate Design Working Group use the prioritization framework identified above to rank options and narrow down top mass market NEM successor rates that can also serve as broader technology-agnostic rates able to meet State goals. Through the continuation of the Rate Design Working Group, stakeholders should craft rate options that enable new technology adoption and meet State policy goals in an economically efficient manner. Staff also recommends that future working group meetings include discussion of the necessary outreach and education approaches and tools that will enable customers to increase uptake of the new rate design options. While widespread implementation of these rates may have to wait until no later than when a full year of interval data is available, these new rate designs can be offered as additional

customer options much earlier.³⁹ Staff anticipates performing these analyses and discussions as the Rate Design Working Group continues to meet through 2020.

V. QUESTIONS FOR STAKEHOLDER COMMENT

While Staff welcomes comments on any part of this Whitepaper, there are specific issues where stakeholder input is specifically requested throughout the paper. For convenience, listed below are those questions as well as other topics needing stakeholder input. In responding to questions, please be consistent with this format and provide comments as listed below.

A. Principles of Rate Design

Are there recommended alternative ways to apply the Principles of Rate Design detailed on page 3 of the Whitepaper in establishing the successor tariff?

B. Delivery Rate and Compensation Options

Collectively, are the proposed Delivery Rate and Compensation Options sufficient to allow projects to be economically viable?

C. Additional Questions

1. Grandfathering

Should customers choosing standard or TOU delivery rates be allowed to remain on those options for some period of time (e.g. 20 years)?

2. Optional Standby Rates

Should the CBC be applied to customers choosing the optional standby rates and, if so, what is the calculation methodology?

³⁹ In the case of an Alt TOU Vol variant rate, for example, Staff would closely track adoption statistics and related economic impacts in order to make any adjustments necessary to improve the rate.

3. Reduced CBC for Value Stack

The Staff proposal recommends that the CBC contribution for on-site PV customers who choose the Value Stack compensation be approximately half the amount compared to residential customers using Phase One NEM, and about a third of the amount compared to small commercial customers using Phase One NEM. Are higher or lower levels appropriate and if so, what levels, based on what methodology, and according to what principles of rate design?

4. Demand-Metered Customers

Should demand-metered customers under 750 kW who opt in to Phase One NEM pay the full CBC, or some decrement? If so, what decrements and based on what methodology, and according to what principles of rate design?

5. Non-Solar Technologies

How should the CBC be applied and calculated for non-solar NEM-eligible technologies? Identify the specific methodology and according to what principles of rate design.

6. How should the CBC change in the future? Identify the specific methodology and timeframe, and according to what principles of rate design.

7. How should New York transition to more cost reflective electric delivery and supply rates, both as a default and as an option?

8. What specific outreach and education approaches and tools (e.g. online rate calculators) would enable customers to increase uptake of the new rate design options?

VI. CONCLUSION

The recommendations in this Whitepaper are designed to ensure the continued growth of New York's robust solar industry while bringing the compensation of NEM eligible DER into closer alignment with the benefits it provides. At the same time, the proposal ensures that cost shifts to non-participants are reduced. The proposed rates reflect extensive evaluation and stakeholder input. They are intended to enable new DER adoption and meet State policy goals in the most economically efficient manner available considering existing data and other technological limitations.

Appendix A: Bill Impact Analysis

The Bill Impact Analysis compares the First Year Bill Savings to the system costs avoided by a customer that adopts rooftop solar for each rate design proposal as well as the existing Phase One NEM rate. These results isolate the impacts of solar generation and do not account for the non-solar impacts to customer bills or avoided costs for the rate design in question.

The calculation uses a monetary crediting methodology in which all solar is credited at the applicable supply and delivery charges in the hour in which it is generated. For non-demand rates, the bill impacts from solar offsets are independent of customer load. For demand-based rates, the bill savings from solar offsets are dependent on customer load and reductions in monthly peak demand. The results presented here represent a load-weighted average of the impacts across each of the customer profiles provided by the utilities, after removing customers deemed to be unlikely solar candidates.

Hourly solar generation profiles from the NYSERDA Value Stack Calculator were used for this analysis, assuming a roof-mounted system and an average of south, southwest, and southeast-facing installations.

The rates were analyzed as submitted by the utilities, except for Con Edison and Orange and Rockland whose rates included market supply charges (MSCs) from 2013 and 2015, respectively. A scaling factor, based on an analysis of historical and current MSCs, was applied to more closely align the rates submitted by Con Edison and Orange and Rockland to their current rates. For all other utilities, 2017 MSCs were provided and no further adjustments to the rates were applied.

The avoided costs represent the total supply and distribution costs that would be avoided by each utility as a result of solar generation being added to its system. Avoided costs are calculated on an hourly generation-weighted basis over the course of a year. The avoided supply costs represent the sum of energy and ICAP costs, as well as avoided

Regional Greenhouse Gas Initiative (RGGI) costs and avoided CES purchases (as the customer load reduction from solar reduces a utility's CES obligations).⁴⁰

The avoided energy value is calculated using a projection of 2020 energy prices from NYISO's 2017 CARIS Report. The annual energy prices by zone are shaped into hourly energy price profiles using a 3-year average of NYISO day ahead prices, and zonal hourly prices are applied to each utility on a load-weighted basis. The avoided capacity value is calculated using a projection of the avoided capacity value at the distribution level from the DPS Staff ICAP Model (May 2018 version). The avoided capacity value is allocated on an hourly basis to summer weekday afternoons from 2 to 7 PM between June 24 and August 31, consistent with the updated Value Stack Capacity Value methodology.⁴¹ Due to a number of factors, the ICAP model projected a sharp decrease in capacity value in 2020 followed by a rebound in 2021; therefore, a three-year average of the projected 2019-2021 avoided capacity value is used to ensure that the 2020 projection does not have an outsized influence on the results. The avoided distribution value is calculated using each utility's current DRV rates, allocated to the hours set forth for each utility in the Value Stack methodology.⁴²

The results of the Bill Impact Analysis for the residential and small commercial services classes are summarized below, in Figures A1-A12, and tables A1-A2.

⁴⁰ As noted above, this does not include the social cost of carbon or another proxy for reduced emissions.

⁴¹ Case 15-E-0751, Order Regarding Value Stack Compensation (issued April 18, 2019).

⁴² For ConEd, the DRV window is consistent with its CSRP windows and zones. For Central Hudson, National Grid, Orange & Rockland, and RG&E, the DRV hours occur on non-holiday weekdays from 2 to 7 PM between June 24 and September 15. For NYSEG, DRV credits are allocated to the same hours as above as well as non-holiday weekdays from 5-7 PM in January. For more detail, *see* Case 15-E-0751, Order Regarding Value Stack Compensation (issued April 18, 2019).

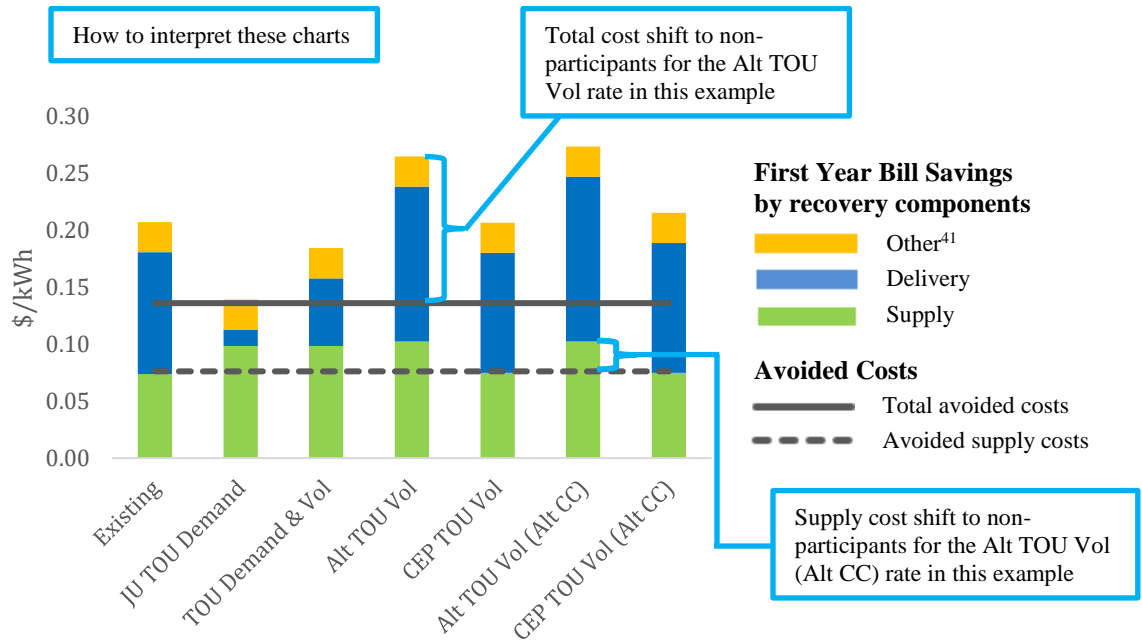


Figure A1: Bill Impact Analysis – Con Edison Residential Service Class

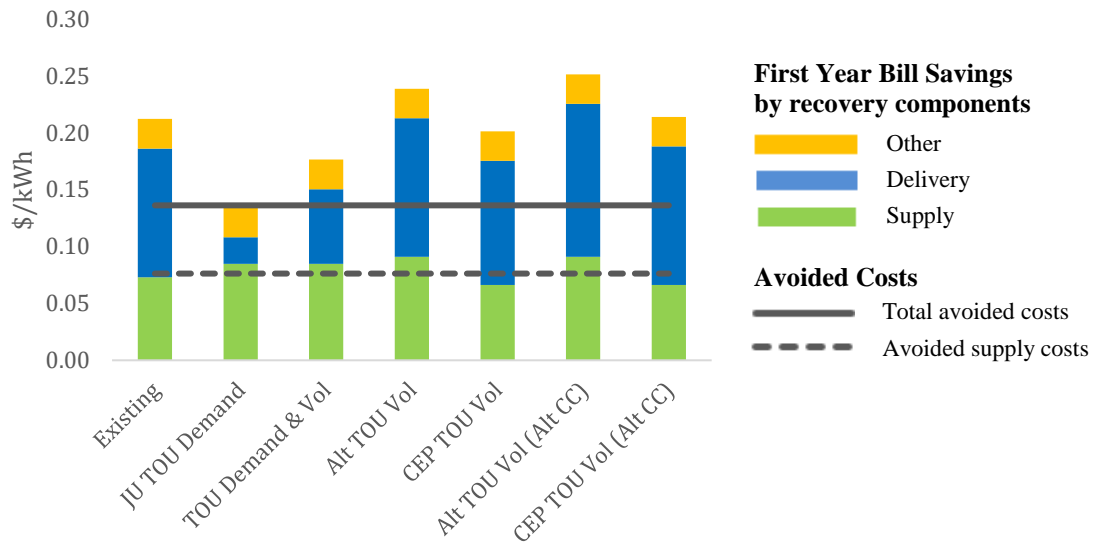


Figure A2: Bill Impact Analysis – Con Edison Small Commercial Service Class

⁴³ The “Other” category includes components of existing retail rates in addition to supply and delivery charges, such as system benefits charges (SBCs), dynamic load management (DLM) charges, merchant function charges (MFCs) and others. These charges were assumed to stay constant across all rate design proposals.

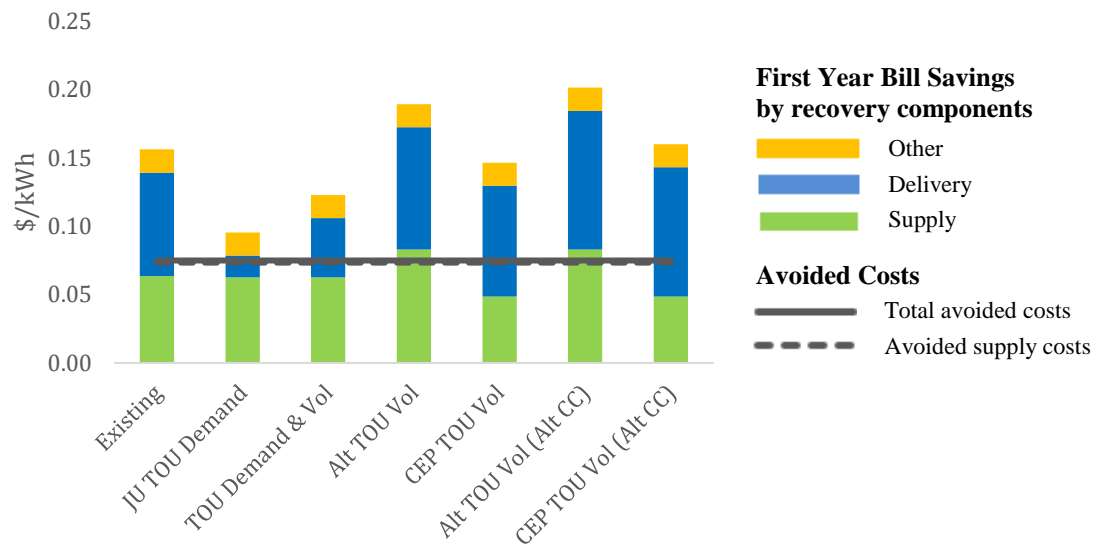


Figure A3: Bill Impact Analysis – Central Hudson Residential Service Class

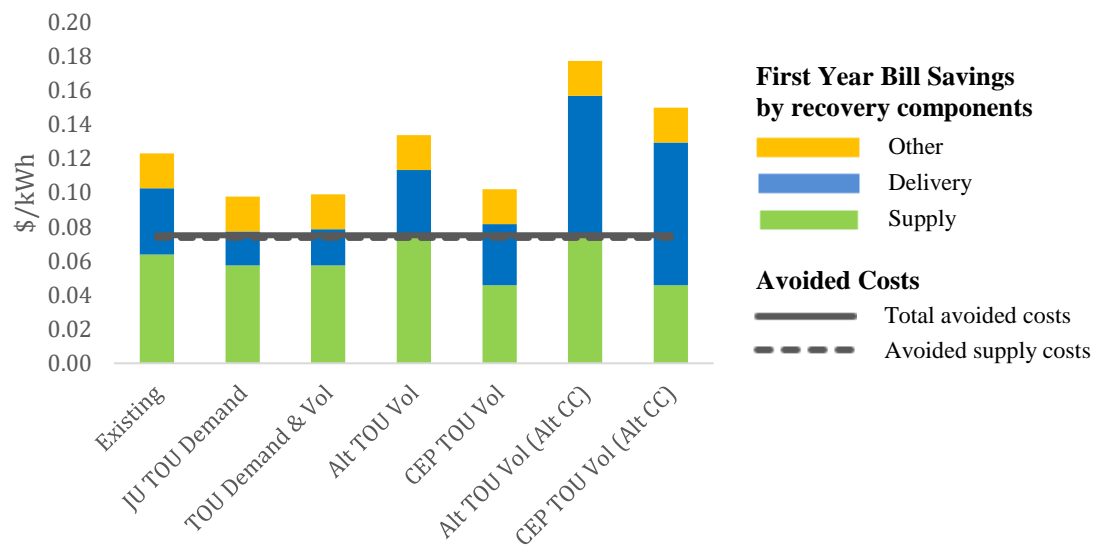


Figure A4: Bill Impact Analysis – Central Hudson Small Commercial Service Class

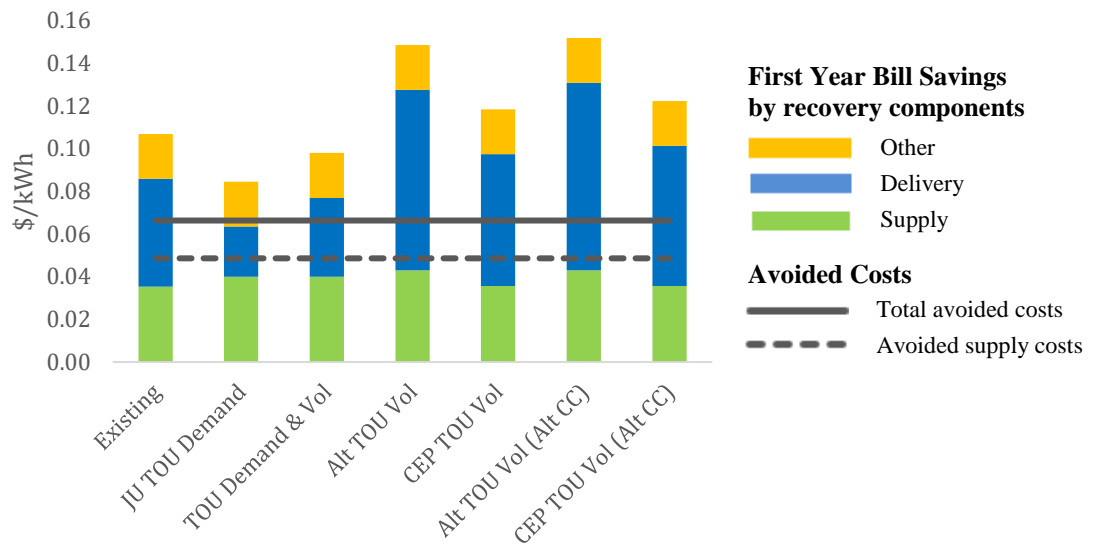


Figure A5: Bill Impact Analysis – Niagara Mohawk Residential Service Class

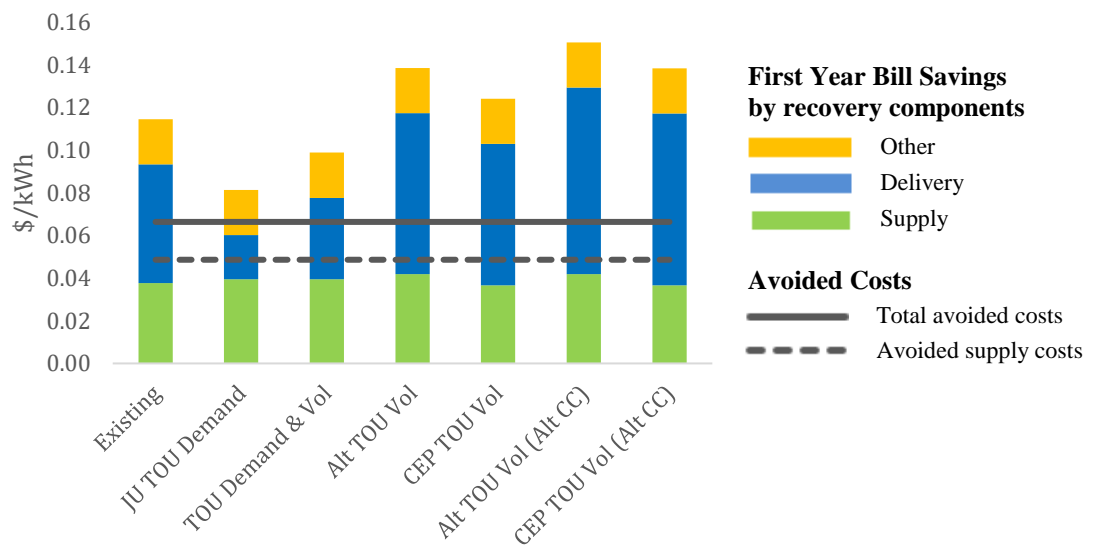


Figure A6: Bill Impact Analysis – Niagara Mohawk Small Commercial Service Class

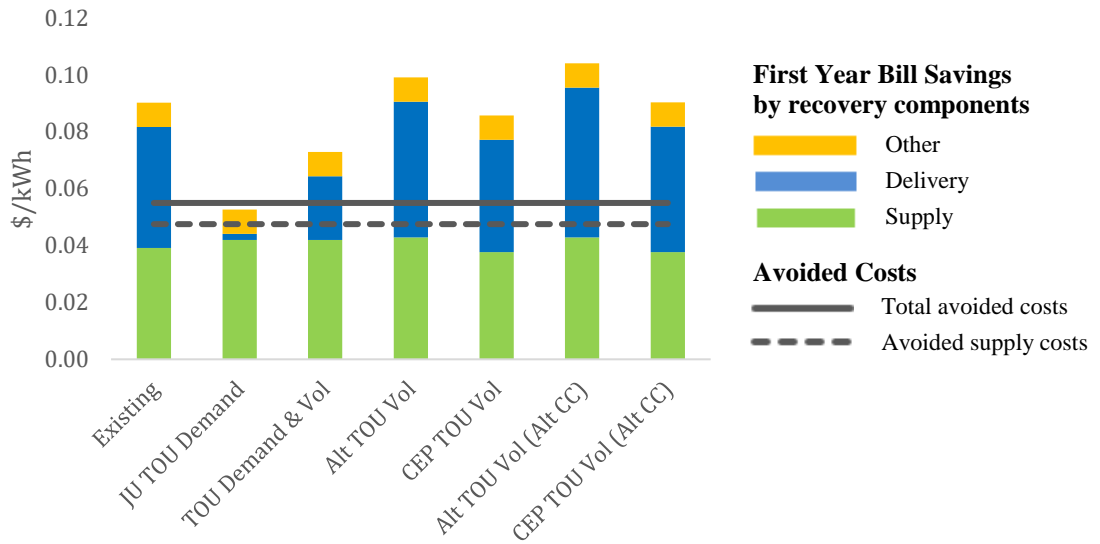


Figure A7: Bill Impact Analysis – NYSEG Residential Service Class

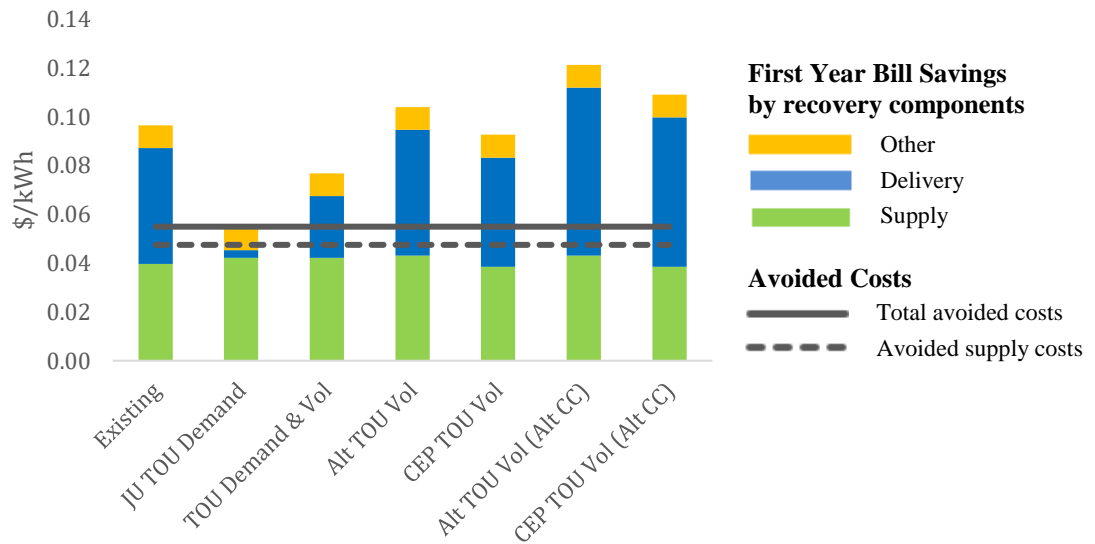


Figure A8: Bill Impact Analysis – NYSEG Small Commercial Service Class

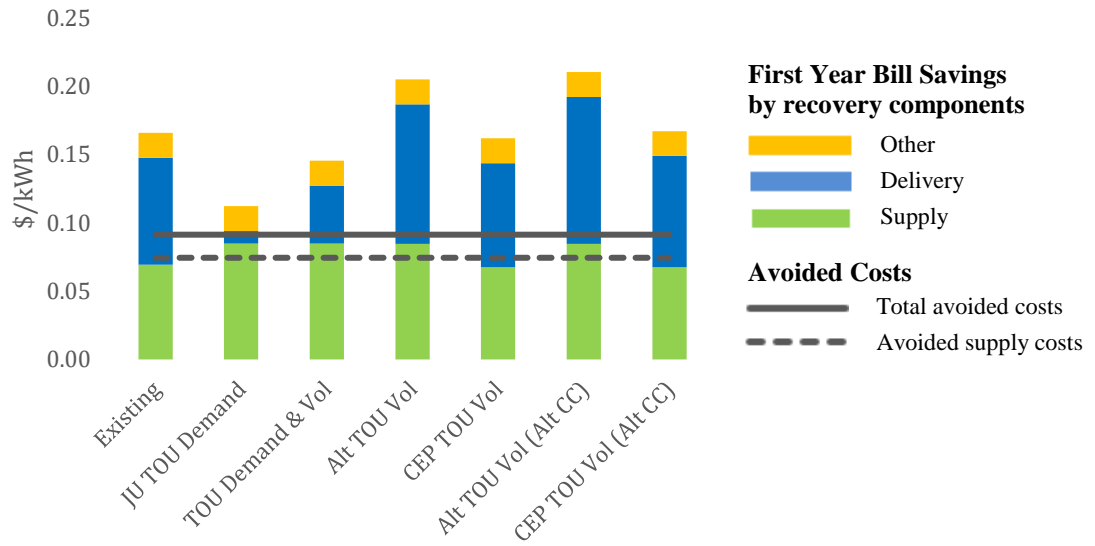


Figure A9: Bill Impact Analysis – Orange & Rockland Residential Service Class

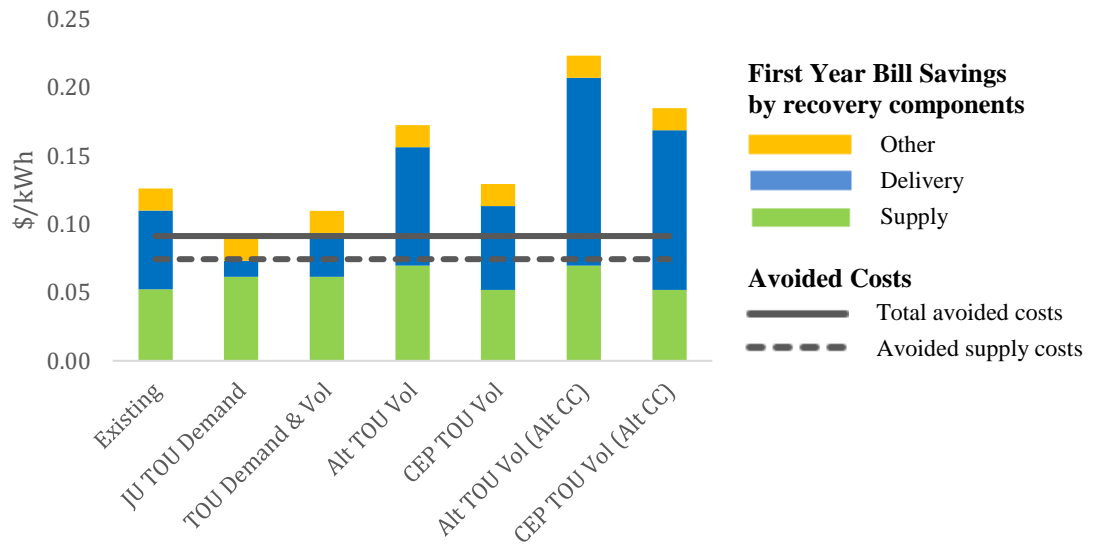


Figure A10: Bill Impact Analysis – Orange & Rockland Small Commercial Service Class

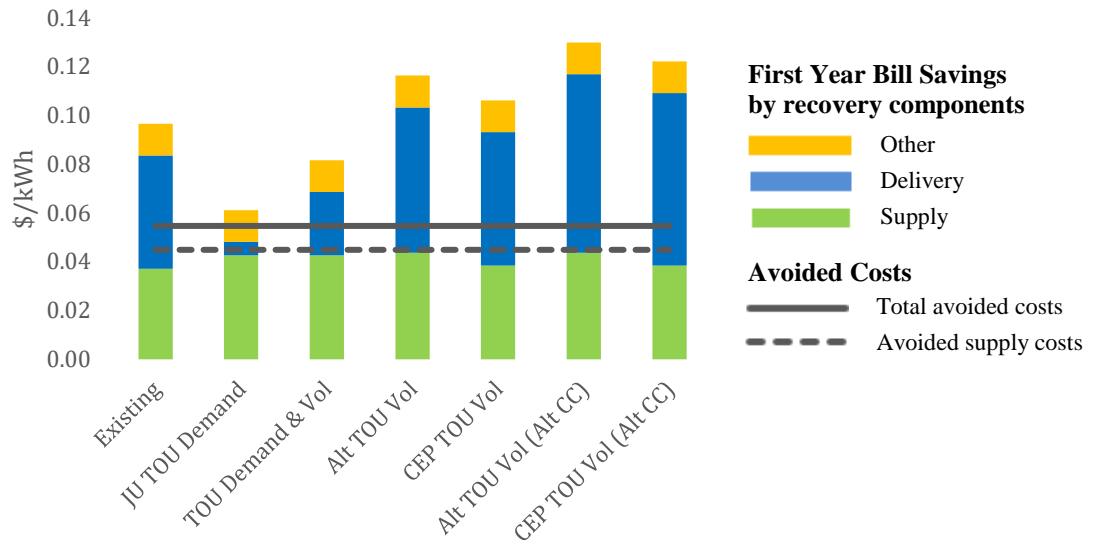


Figure A11: Bill Impact Analysis – RGE Residential Service Class

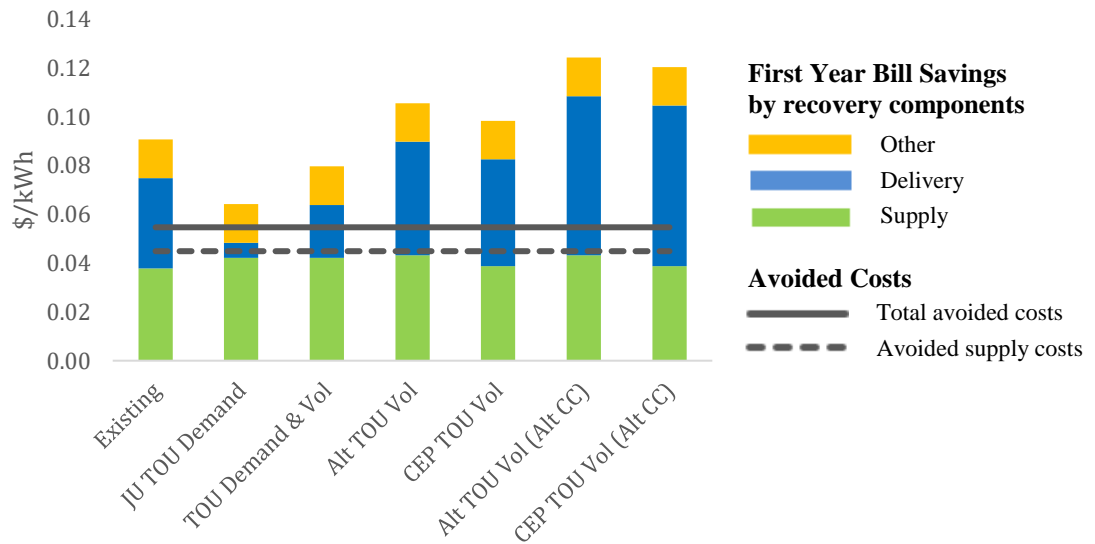


Figure A12: Bill Impact Analysis – RGE Small Commercial Service Class

Table A1: Bill Impact Analysis for the Residential Service Class

		Bill Savings (\$/kWh)				Avoided Cost (\$/kWh)	
Utility	Rate Design	Supply	Delivery	Other	Total Savings	Supply	Total
Central Hudson	Existing	0.064	0.076	0.017	0.156	0.07	0.0750
	JU TOU Demand	0.063	0.016	0.017	0.096	0.07	0.0750
	TOU Demand & Vol	0.063	0.043	0.017	0.123	0.07	0.0750
	Alt TOU Vol	0.083	0.089	0.017	0.190	0.07	0.0750
	CEP TOU Vol	0.049	0.081	0.017	0.147	0.07	0.0750
	Alt TOU Vol (Alt CC)	0.083	0.101	0.017	0.202	0.07	0.0750
	CEP TOU Vol (Alt CC)	0.049	0.095	0.017	0.160	0.07	0.0750
Con Edison	Existing	0.074	0.107	0.027	0.207	0.08	0.1362
	JU TOU Demand	0.099	0.014	0.027	0.139	0.08	0.1362
	TOU Demand & Vol	0.099	0.059	0.027	0.185	0.08	0.1362
	Alt TOU Vol	0.103	0.136	0.027	0.265	0.08	0.1362
	CEP TOU Vol	0.075	0.105	0.027	0.207	0.08	0.1362
	Alt TOU Vol (Alt CC)	0.103	0.145	0.027	0.274	0.08	0.1362
	CEP TOU Vol (Alt CC)	0.075	0.114	0.027	0.216	0.08	0.1362
Niagara Mohawk	Existing	0.035	0.050	0.021	0.107	0.05	0.0663
	JU TOU Demand	0.040	0.023	0.021	0.085	0.05	0.0663
	TOU Demand & Vol	0.040	0.037	0.021	0.098	0.05	0.0663
	Alt TOU Vol	0.043	0.085	0.021	0.149	0.05	0.0663
	CEP TOU Vol	0.036	0.062	0.021	0.118	0.05	0.0663
	Alt TOU Vol (Alt CC)	0.043	0.088	0.021	0.152	0.05	0.0663
	CEP TOU Vol (Alt CC)	0.036	0.066	0.021	0.122	0.05	0.0663
NYSEG	Existing	0.039	0.043	0.009	0.090	0.05	0.0550
	JU TOU Demand	0.042	0.002	0.009	0.053	0.05	0.0550
	TOU Demand & Vol	0.042	0.022	0.009	0.073	0.05	0.0550
	Alt TOU Vol	0.043	0.048	0.009	0.099	0.05	0.0550
	CEP TOU Vol	0.038	0.040	0.009	0.086	0.05	0.0550
	Alt TOU Vol (Alt CC)	0.043	0.053	0.009	0.104	0.05	0.0550
	CEP TOU Vol (Alt CC)	0.038	0.044	0.009	0.090	0.05	0.0550
Orange & Rockland	Existing	0.069	0.078	0.018	0.166	0.07	0.0914
	JU TOU Demand	0.085	0.009	0.018	0.112	0.07	0.0914
	TOU Demand & Vol	0.085	0.042	0.018	0.146	0.07	0.0914
	Alt TOU Vol	0.085	0.102	0.018	0.205	0.07	0.0914
	CEP TOU Vol	0.067	0.076	0.018	0.162	0.07	0.0914
	Alt TOU Vol (Alt CC)	0.085	0.108	0.018	0.210	0.07	0.0914
	CEP TOU Vol (Alt CC)	0.067	0.081	0.018	0.167	0.07	0.0914
RGE	Existing	0.037	0.046	0.013	0.097	0.04	0.0547
	JU TOU Demand	0.043	0.005	0.013	0.061	0.04	0.0547
	TOU Demand & Vol	0.043	0.026	0.013	0.082	0.04	0.0547
	Alt TOU Vol	0.044	0.060	0.013	0.116	0.04	0.0547
	CEP TOU Vol	0.038	0.055	0.013	0.106	0.04	0.0547
	Alt TOU Vol (Alt CC)	0.044	0.073	0.013	0.130	0.04	0.0547
	CEP TOU Vol (Alt CC)	0.038	0.071	0.013	0.122	0.04	0.0547

Table A2: Bill Impact Analysis for the Small Commercial Service Class

		Bill Savings (\$/kWh)				Avoided Cost (\$/kWh)	
Utility	Rate Design	Supply	Delivery	Other	Total	Supply	Total
Central Hudson	Existing	0.064	0.039	0.020	0.123	0.07	0.0750
	JU TOU Demand	0.057	0.020	0.020	0.098	0.07	0.0750
	TOU Demand & Vol	0.057	0.021	0.020	0.099	0.07	0.0750
	Alt TOU Vol	0.074	0.039	0.020	0.134	0.07	0.0750
	CEP TOU Vol	0.046	0.036	0.020	0.102	0.07	0.0750
	Alt TOU Vol (Alt CC)	0.074	0.083	0.020	0.177	0.07	0.0750
	CEP TOU Vol (Alt CC)	0.046	0.084	0.020	0.150	0.07	0.0750
Con Edison	Existing	0.073	0.113	0.026	0.212	0.08	0.1362
	JU TOU Demand	0.085	0.023	0.026	0.134	0.08	0.1362
	TOU Demand & Vol	0.085	0.066	0.026	0.176	0.08	0.1362
	Alt TOU Vol	0.091	0.122	0.026	0.239	0.08	0.1362
	CEP TOU Vol	0.066	0.109	0.026	0.201	0.08	0.1362
	Alt TOU Vol (Alt CC)	0.091	0.135	0.026	0.251	0.08	0.1362
	CEP TOU Vol (Alt CC)	0.066	0.122	0.026	0.214	0.08	0.1362
Niagara Mohawk	Existing	0.038	0.056	0.021	0.114	0.05	0.0663
	JU TOU Demand	0.039	0.021	0.021	0.081	0.05	0.0663
	TOU Demand & Vol	0.039	0.038	0.021	0.099	0.05	0.0663
	Alt TOU Vol	0.042	0.075	0.021	0.138	0.05	0.0663
	CEP TOU Vol	0.037	0.066	0.021	0.124	0.05	0.0663
	Alt TOU Vol (Alt CC)	0.042	0.087	0.021	0.150	0.05	0.0663
	CEP TOU Vol (Alt CC)	0.037	0.081	0.021	0.138	0.05	0.0663
NYSEG	Existing	0.040	0.047	0.009	0.097	0.05	0.0550
	JU TOU Demand	0.042	0.003	0.009	0.055	0.05	0.0550
	TOU Demand & Vol	0.042	0.025	0.009	0.077	0.05	0.0550
	Alt TOU Vol	0.043	0.052	0.009	0.104	0.05	0.0550
	CEP TOU Vol	0.038	0.045	0.009	0.093	0.05	0.0550
	Alt TOU Vol (Alt CC)	0.043	0.069	0.009	0.121	0.05	0.0550
	CEP TOU Vol (Alt CC)	0.038	0.061	0.009	0.109	0.05	0.0550
Orange & Rockland	Existing	0.052	0.058	0.016	0.126	0.07	0.0914
	JU TOU Demand	0.061	0.012	0.016	0.089	0.07	0.0914
	TOU Demand & Vol	0.061	0.032	0.016	0.110	0.07	0.0914
	Alt TOU Vol	0.070	0.087	0.016	0.173	0.07	0.0914
	CEP TOU Vol	0.052	0.061	0.016	0.129	0.07	0.0914
	Alt TOU Vol (Alt CC)	0.070	0.137	0.016	0.223	0.07	0.0914
	CEP TOU Vol (Alt CC)	0.052	0.117	0.016	0.185	0.07	0.0914
RGE	Existing	0.038	0.037	0.016	0.091	0.04	0.0547
	JU TOU Demand	0.042	0.006	0.016	0.064	0.04	0.0547
	TOU Demand & Vol	0.042	0.022	0.016	0.080	0.04	0.0547
	Alt TOU Vol	0.043	0.047	0.016	0.106	0.04	0.0547
	CEP TOU Vol	0.039	0.044	0.016	0.098	0.04	0.0547
	Alt TOU Vol (Alt CC)	0.043	0.065	0.016	0.124	0.04	0.0547
	CEP TOU Vol (Alt CC)	0.039	0.066	0.016	0.120	0.04	0.0547

Appendix B: Cost Shift Analysis

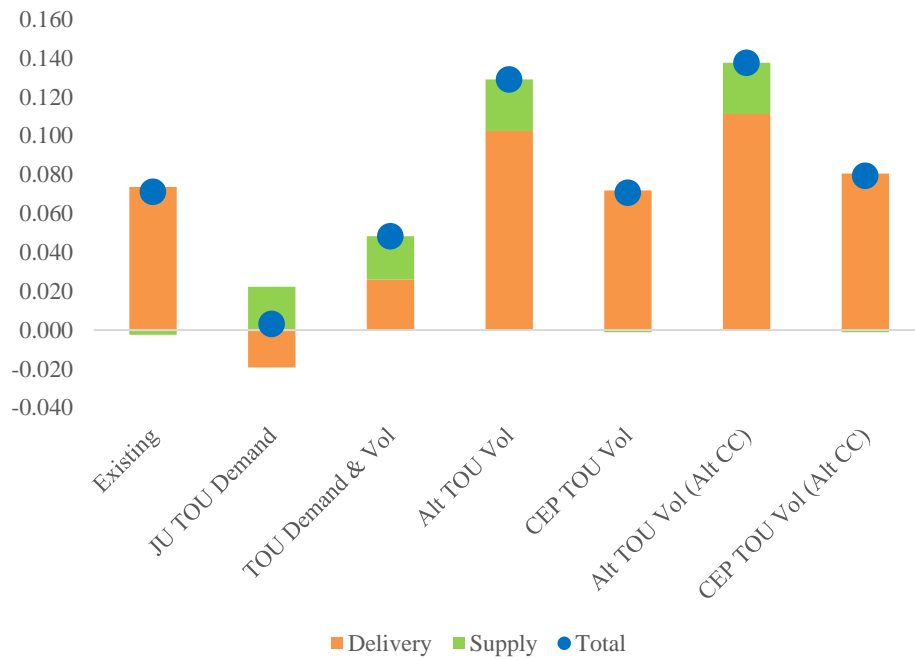


Figure B1: Cost Shift Analysis – Con Edison Residential Service Class

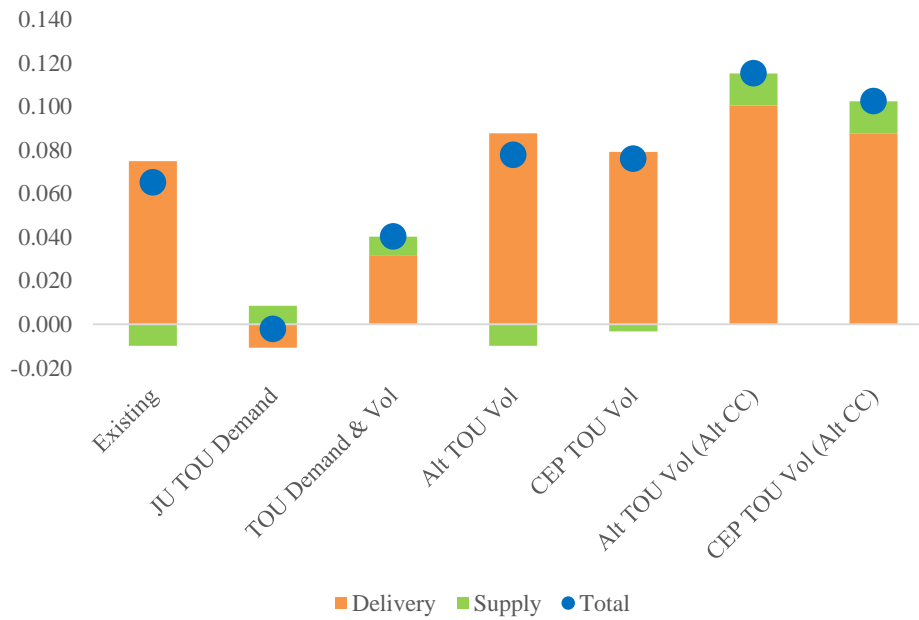


Figure B2: Cost Shift Analysis – Con Edison Small Commercial Service Class

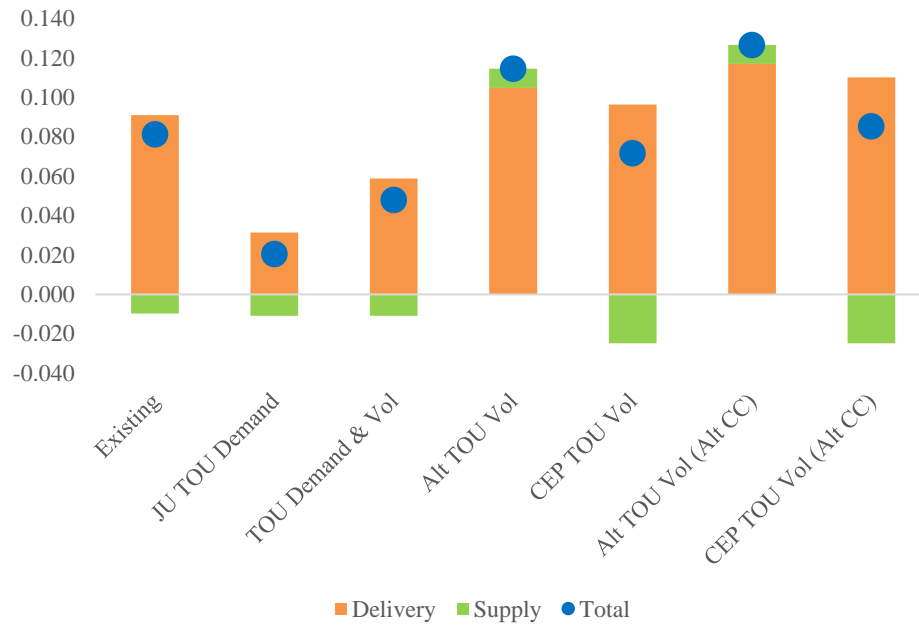


Figure B3: Cost Shift Analysis – Central Hudson Residential Service Class

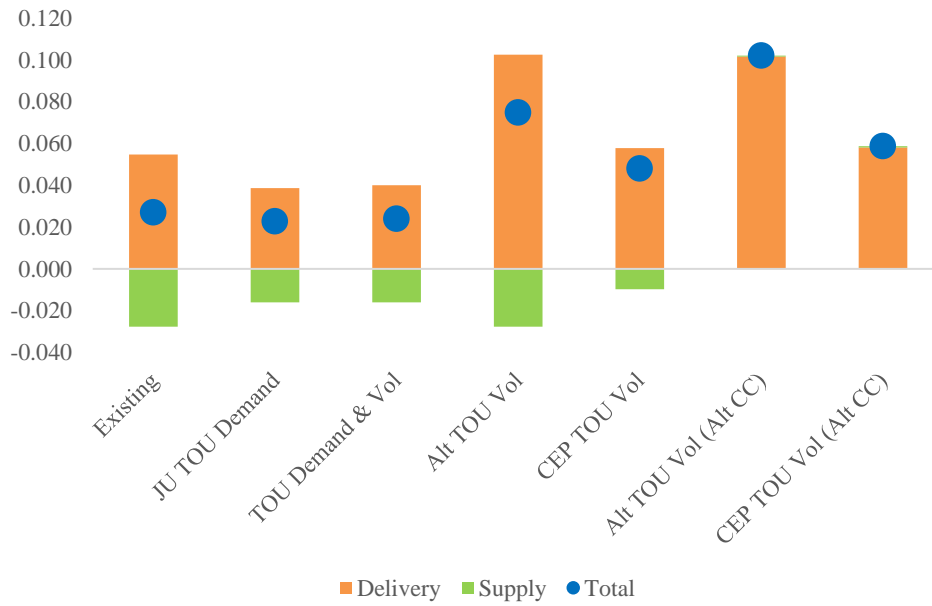


Figure B4: Cost Shift Analysis – Central Hudson Small Commercial Service Class



Figure B5: Cost Shift Analysis – Niagara Mohawk Residential Service Class

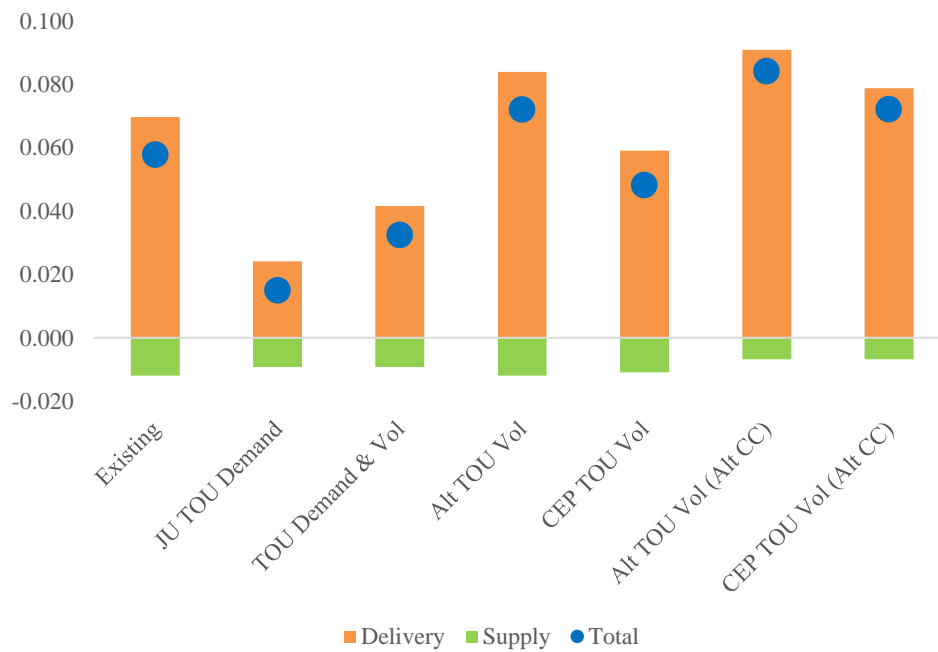


Figure B6: Cost Shift Analysis – Niagara Mohawk Small Commercial Service Class

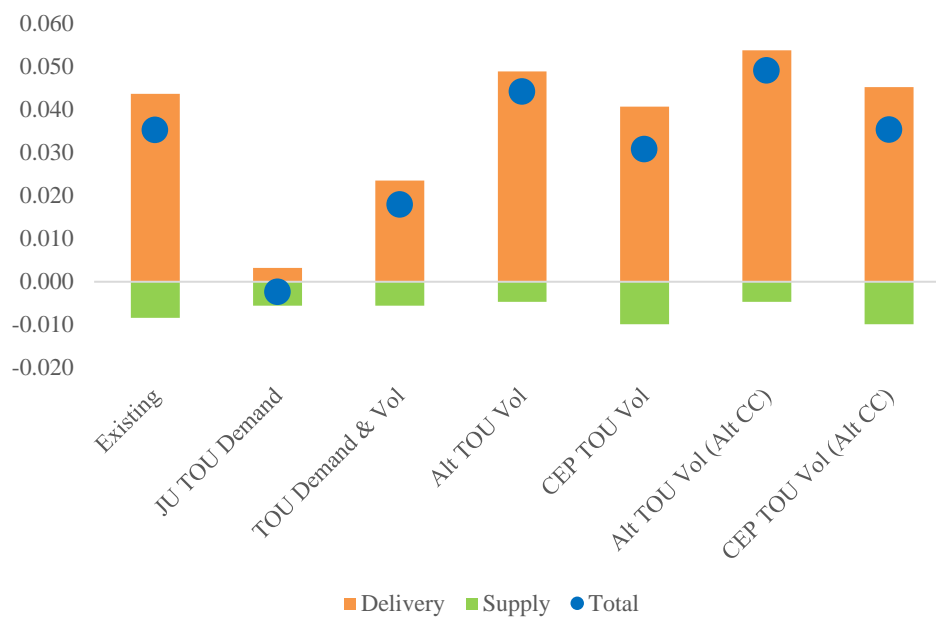


Figure B7: Cost Shift Analysis – NYSEG Residential Service Class

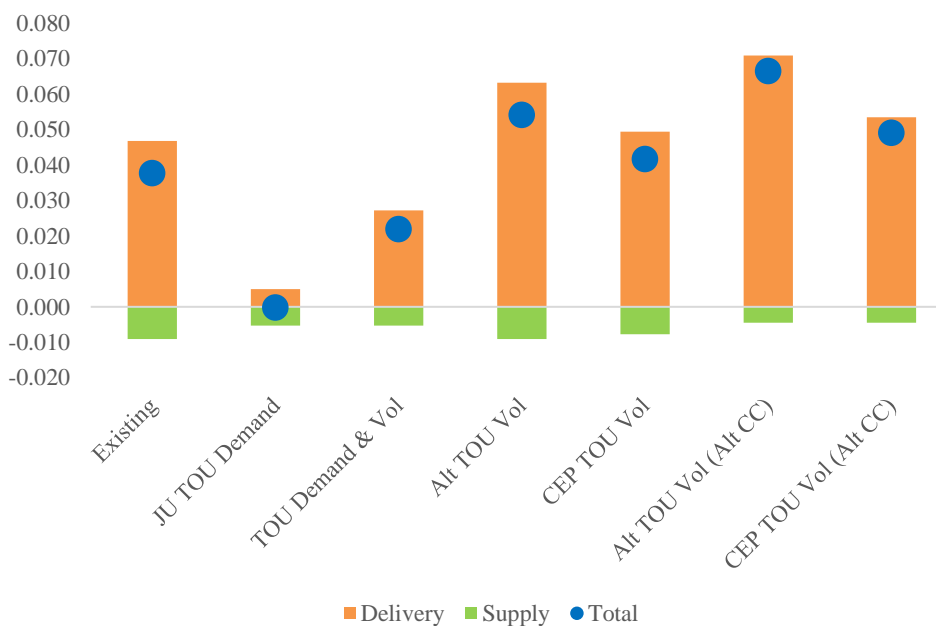


Figure B8: Cost Shift Analysis – NYSEG Small Commercial Service Class

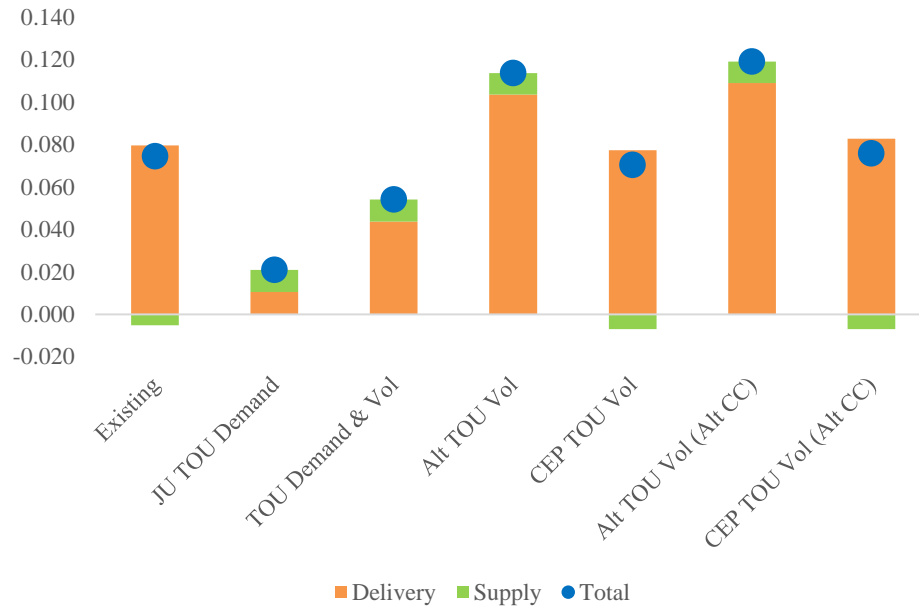


Figure B9: Cost Shift Analysis – Orange & Rockland Residential Service Class

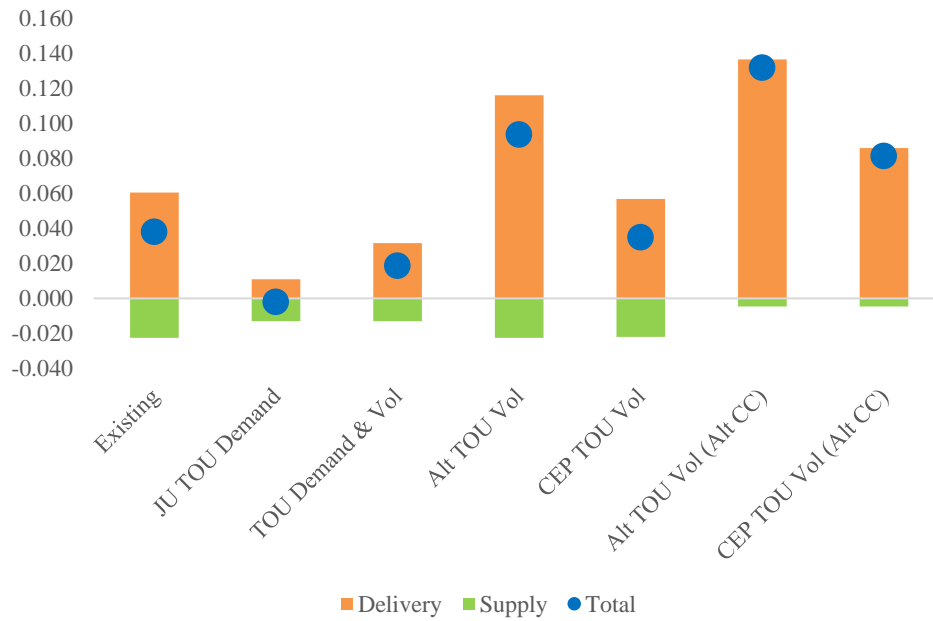


Figure B10: Cost Shift Analysis – Orange & Rockland Small Commercial Service Class



Figure B11: Cost Shift Analysis – RGE Residential Service Class

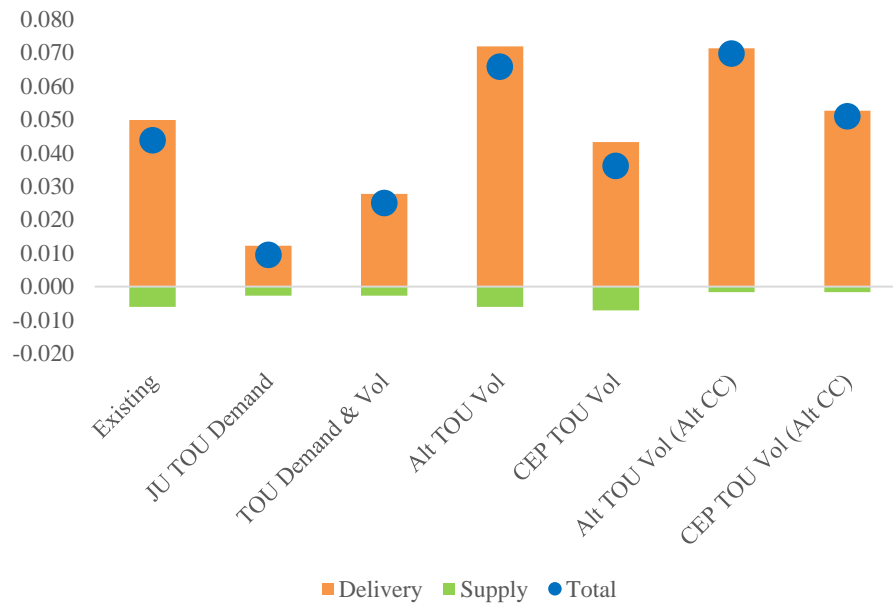


Figure B12: Cost Shift Analysis – RGE Small Commercial Service Class

Table B1: Cost Shift Analysis for the Residential Service Class

Utility		Existing	JU TOU Demand	TOU Demand & Vol	Alt TOU Vol	CEP TOU Vol	Alt TOU Vol (Alt CC)	CEP TOU Vol (Alt CC)
Con Edison	Total	0.071	0.003	0.048	0.129	0.071	0.138	0.079
	Delivery	0.074	-0.019	0.026	0.103	0.072	0.111	0.081
	Supply	-0.002	0.022	0.022	0.026	-0.001	0.026	-0.001
Central Hudson	Total	0.081	0.021	0.048	0.115	0.072	0.127	0.085
	Delivery	0.091	0.031	0.059	0.105	0.096	0.117	0.110
	Supply	-0.010	-0.011	-0.011	0.010	-0.025	0.010	-0.025
Niagara Mohawk	Total	0.041	0.018	0.032	0.082	0.052	0.086	0.056
	Delivery	0.054	0.027	0.040	0.088	0.065	0.091	0.069
	Supply	-0.013	-0.009	-0.009	-0.006	-0.013	-0.006	-0.013
NYSEG	Total	0.035	-0.002	0.018	0.044	0.031	0.049	0.035
	Delivery	0.044	0.003	0.023	0.049	0.041	0.054	0.045
	Supply	-0.008	-0.006	-0.006	-0.005	-0.010	-0.005	-0.010
Orange & Rockland	Total	0.075	0.021	0.054	0.114	0.070	0.119	0.076
	Delivery	0.080	0.010	0.044	0.104	0.077	0.109	0.083
	Supply	-0.005	0.010	0.010	0.010	-0.007	0.010	-0.007
RGE	Total	0.042	0.006	0.027	0.062	0.052	0.075	0.067
	Delivery	0.050	0.009	0.029	0.063	0.058	0.076	0.074
	Supply	-0.008	-0.002	-0.002	-0.001	-0.006	-0.001	-0.006

Table B2: Cost Shift Analysis for the Small Commercial Service Class

Utility		Existing	JU TOU Demand	TOU Demand & Vol	Alt TOU Vol	CEP TOU Vol	Alt TOU Vol (Alt CC)	CEP TOU Vol (Alt CC)
Con Edison	Total	0.065	-0.002	0.040	0.078	0.076	0.115	0.102
	Delivery	0.075	-0.011	0.032	0.088	0.079	0.101	0.088
	Supply	-0.010	0.008	0.008	-0.010	-0.003	0.015	0.015
Central Hudson	Total	0.027	0.023	0.024	0.075	0.048	0.102	0.059
	Delivery	0.055	0.039	0.040	0.102	0.058	0.101	0.058
	Supply	-0.028	-0.016	-0.016	-0.028	-0.010	0.001	0.001
Niagara Mohawk	Total	0.058	0.015	0.032	0.072	0.048	0.084	0.072
	Delivery	0.070	0.024	0.042	0.084	0.059	0.091	0.079
	Supply	-0.012	-0.009	-0.009	-0.012	-0.011	-0.007	-0.007
NYSEG	Total	0.038	0.000	0.022	0.054	0.042	0.066	0.049
	Delivery	0.047	0.005	0.027	0.063	0.049	0.071	0.053
	Supply	-0.009	-0.005	-0.005	-0.009	-0.008	-0.004	-0.004
Orange & Rockland	Total	0.038	-0.002	0.019	0.094	0.035	0.132	0.081
	Delivery	0.061	0.011	0.032	0.116	0.057	0.137	0.086
	Supply	-0.022	-0.013	-0.013	-0.022	-0.022	-0.005	-0.005
RGE	Total	0.044	0.009	0.025	0.066	0.036	0.070	0.051
	Delivery	0.050	0.012	0.028	0.072	0.043	0.071	0.053
	Supply	-0.006	-0.003	-0.003	-0.006	-0.007	-0.002	-0.002