Solar Program Design Study

EXECUTIVE SUMMARY

Prepared for: Colorado Springs Utilities

It's how we're all connected

Prepared by: General Electric International, Inc. and Concentric Energy Advisors

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Foreword

This report was prepared by General Electric International, Inc. (GEII), acting through its Energy Consulting Group, based in Schenectady, New York. Questions and any correspondence concerning this document should be referred to:

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Falling photovoltaic (PV) prices have led Colorado Springs Utilities (CSU) to consider significant PV additions in CSU's 2016 Electric Integrated Resource Plan (EIRP)[1]. The EIRP called for a solar rollout plan to determine how to increase PV capacity, such as rooftop solar, community solar or utility-scale solar. CSU retained GE Energy Consulting and Concentric Energy Advisors (together the "Team") to undertake this Solar Program Design Study to investigate distributed PV (DPV), and specifically, to assess the impacts of retaining the current net energy metering (NEM) tariff versus other rate alternatives.

This Study finds:

1. CSU does not fully recover costs from net-metered solar customers today, resulting in a greater cost burden on non-solar customers, and
2. Alternative rate designs could more adequately recover the costs of serving solar customers, enabling CSU to more sustainably scale DPV and other distributed energy resources.

Today's rate structures do not reflect cost structures

Rate reform and NEM alternatives are widely debated around the country, especially in regions that have had high solar growth. NEM highlights a mismatch between utility cost and rate structures, particularly for residential and small commercial customers, namely that fixed costs tend to comprise a large majority of the utility cost of service while variable charges are used to collect the vast majority of costs from customers (see Figure 1).

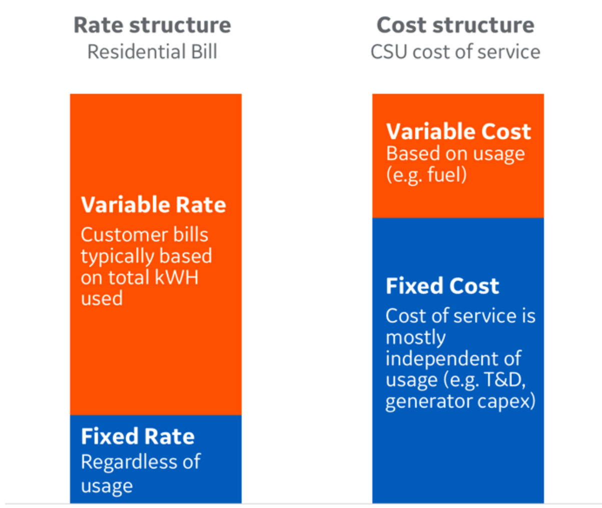

Figure 1 Residential (E1R) rates are mostly based on usage (variable) while cost of service is mostly independent of usage (fixed).

A NEM tariff compensates solar generation at the variable rate. Therefore, CSU may not recover its cost of service from solar customers. Any revenue shortfall must ultimately be recovered from the customer base, resulting in a greater share of costs being recovered from non-solar customers. CSU's goal is to

[1] Colorado Springs Utilities, *2016 Electric Integrated Resource Plan*, July 12, 2016, https://www.csu.org/CSUDocuments/2016eirp.pdf

find solutions that ensure fair and equitable rates that are non-discriminatory, align with customers' cost of service and do not discourage solar development.

NEM at current rates essentially combines a DPV compensation mechanism with an incentive. As CSU looks to the future and growth of other distributed energy resources (DERs), it may want to consider rate alternatives that reflect value to the grid or that incentivize grid-friendly behavior.

Alternative rate designs can more adequately recover costs of service

Rate alternatives analyzed in this Study are listed in Table 1. Specific rates were designed for the first four alternatives to mitigate cost-shifting[2] and recover costs from solar customers, while remaining revenue-neutral (i.e., overall revenues within a rate class remained constant) and limiting bill impacts for non-solar customers[3] (see Table 2).

Table 1 Alternative Rate Options Evaluated

Alternative	Description
Increased Fixed or Standby Charge	Customers pay an increased fixed charge each billing period. Better reflects actual fixed portion of cost of service.
Demand Charge	Customers pay a demand charge based on their maximum demand (measured in kW) during that month. Incentivizes customers to reduce demand.
Time-of-Use (TOU) Rates	Customers pay different rates for usage during different time periods (e.g., peak and off-peak). Reflecting actual costs incurred by the utility and incentivizes customers to reduce peak usage and/or shift usage to off-peak periods[4].
Demand-block/TOU	Combination of TOU rate and a *peak* demand charge that is only applicable to customers whose demand exceeds a threshold during peak periods[5].
Buy All, Sell All Value of Solar Tariff (VOST)	CSU buys all DPV generation at a VOS rate, which reflects the value stream of net benefits from DPV. All consumption is purchased at normal retail rates.
Hybrid VOST	Solar generation first offsets onsite consumption, and excess generation is exported to the grid at the VOS rate. There is no carryover of excess kWh from month to month.
Utility-owned Solar (UOS) Rooftop Program	CSU would run a DPV leasing program for customers who want DPV. Customers would receive bill credits based on DPV production. CSU would partner with a developer who owns and maintains the system.

The 5th and 6th alternatives in Table 1 are value of solar (VOS) options, which are compensation mechanisms specifically for solar customers (as opposed to the fixed, demand and TOU options which apply to all customers in a rate class). The VOS is the aggregate value stream of net benefits that DPV provides to the grid, and includes avoided energy costs such as fuel and operations and maintenance costs, the avoided need to build new capacity to meet peak demand, avoided distribution losses as power is generated at the point of use, and other avoided costs. The Team modeled CSU's operations and resource adequacy to calculate the VOS under four levels of increasing solar penetration (from 2017 DPV levels of 7.1 MW to a High Scenario with 100 MW DPV) to quantify the net benefits to CSU.

[2] The Team recognizes that the term "cost-shifting" is a complex subject in the industry-wide NEM discussion. For the purposes of this Study, the Team defined "cost-shifting" as the shortfall in the revenue collected from NEM customers in meeting their cost of service revenue requirement.

[3] Bill impacts were generally limited to less than 25% for non-solar customers.

[4] Under the TOU rates designed in the Study, solar generation during peak hours can offset (or generate credits for) peak consumption and off-peak generation can offset (or generate credits for) off-peak consumption. Annual excess kWh credits are compensated at a blended Small Power Producers and Cogeneration Service rate of $0.0228/kWh.

[5] The inclining block structure for CSU divides the demand price into two blocks with only the second block of demand being charged.

The VOS decreases with increasing DPV penetrations, because the avoided energy and capacity values decrease as more resources with the same generation profile are added. The VOS for 2017 levels of DPV was estimated at $0.0565/kWh, which is lower than CSU's variable charges for residential and commercial customers. This reflects the fact that CSU currently has excess capacity, that gas prices are low, that CSU's transmission and distribution systems are already robust so that DPV does not avoid upgrades, and that avoided emissions had zero monetary value[6].

Table 2 Summary of Rate Design Alternatives

Alternative	Residential (E1R)	Small Commercial (E1C)	General Commercial (E2C)	Industrial (ETL)
Increased Fixed or Standby Charge*	$0.7515/day	$0.7515/day	$0.9270/day	
Demand Charge	$0.0540/kW/day	$0.0810/kW/day	$0.0837/kW/day	
TOU Rates	$0.1297/kWh peak $0.0648/kWh off-peak	$0.1297/kWh peak $0.0648/kWh off-peak	$0.1372/kWh peak $0.0398/kWh off-peak	
Demand-block/TOU	≤ 3kW demand during peak period: $0/kW/day > 3 kW demand during peak period: $0.2359/kW/day $0.1264/kWh peak $0.0632/kWh off-peak			
Buy All, Sell All VOST	$0.0565/kWh	$0.0565/kWh	$0.0565/kWh	$0.0565/kWh
Hybrid VOST	$0.0565/kWh	$0.0565/kWh	$0.0565/kWh	$0.0565/kWh
Utility-owned Solar (UOS) Rooftop Program	Rates were not designed for this option.			

*This shows only the new rates; it does not show the corresponding change to other elements of the rate (e.g., an increase in fixed charge is accompanied by a decrease in variable charge) to maintain revenue-neutrality.

The final option was the possibility of CSU implementing a UOS program, and recommendations were made for potential suitable models. However, such a program was difficult to justify from an economic perspective, given that electricity from utility-scale PV costs half of what it would cost from DPV, due to economies of scale, increased capacity factors, and extremely low land costs. Given CSU priorities, potential risks, and relatively low rewards, the UOS program was not pursued further.

Rate alternatives have different impacts on customer bills

Bill impacts were examined separately for non-solar and solar customers, for the four rate classes which comprise the vast majority of CSU's customers. For the E1R rate class, bill impacts for the non-

[6] CSU does not place a monetary value on CO_2 in their EIRP. CSU has excess SO_2 allowances, so avoided SO_2 was also valued at zero.

solar customers are greatest for the demand-block/TOU rate.[7] Conversely, the fixed charge option shows a slight bill decrease for the average-use non-solar customer.[8] The bill impacts of the TOU rate were moderate, because the higher-cost peak period represents a small number of hours, and most consumption occurs during off peak hours. The positive bill impacts from the demand charge reflect that the customers had low load factors, meaning that their consumption over time was quite variable.[9]

The bill impacts for residential solar customers were similar to the non-solar customers, with a few notable variations. For example, the bill impacts for the TOU rate were higher for solar customers, which is primarily due to the fact that most solar generation occurs during non-peak times, as defined by CSU. The larger Buy All Sell All VOST bill impacts occur because the value of the solar generation exported to the grid is valued at the VOS rate, which is lower than the retail rate.

The analyses for the other rate classes yield several key results. First, the bill impact analyses for E1C and E1R are generally similar because E1R and E1C have historically been billed using the same rates. Bills impacts from the demand charge were different for Rates E1C and E2C because more of the latter customers have higher load factors, and thus would experience lesser impacts with this rate alternative, as compared to E1R. The analysis of E2C and ETL customers included the impacts of allowing these customers to install PV systems above the NEM size limits as detailed in the Colorado Statute (i.e., which applies absent permission from CSU) under a Buy All Sell All VOST; this may be an appealing option for these customers.

The bill impacts in Rate ETL contrast with those of the other three rate classes evaluated. This is the case because Rate ETL includes only a customer charge and a TOU demand charge, but not a volumetric charge. Because NEM offsets volumetric (i.e., kWh) usage, ETL customers do not realize significant value through NEM.[10]

Increasing revenue and reducing costs can help recover costs

Analysis was undertaken to determine whether the cost of serving a customer was recovered through a combination of revenue from that customer and the value that their DPV provided to the grid. Figure 2 illustrates this analysis, showing this dynamic for several of the rate design alternatives reviewed for E1R customers.

The left-most bar in Figure 2 shows the revenue from a typical non-solar customer[11]. Assuming that the revenues from this non-solar customer reflect CSU's cost of service (i.e., CSU achieves 100% cost recovery on this non-solar customer), the second bar shows how cost recovery would change if this customer were a solar customer under NEM[12]. The customer would pay the same fixed charges (orange

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[7] For the demand-block/TOU rate, we separately examined how the rate design impacted air conditioning customers (i.e., high demand) and non-air conditioning customers (i.e., low demand). The resulting bill impacts are slightly higher for air conditioning customers than non-air conditioning customers. We believe a greater discrepancy is not seen between these two groups due to the high peak demand for a number of the non-air-conditioning customers, which is likely due to other high-demand end-uses such as electric space-heating, hot-tubs, etc.

[8] The large *percentage* bill impact on a few customers from the fixed charge is actually a result of those customers having very low (near zero) monthly kwh usage, and therefore low total bills.

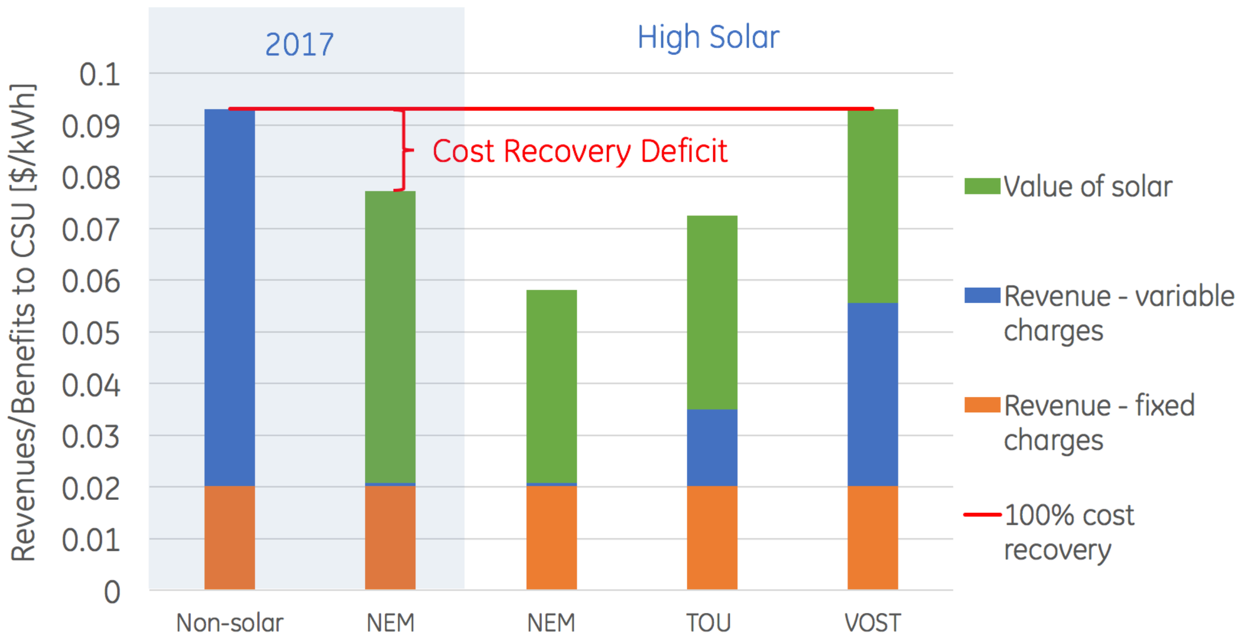
[9] Customers that have the lowest load factors have the largest bill impacts and customers with the highest annual load factors had the lowest bill impacts.

[10] Because of this dynamic, the Team only examined for ETL the impact of a Buy All Sell All VOST, under the scenario that customers were permitted by CSU to size above the otherwise applicable NEM system size limit of 25 kW.

[11] Revenues and benefits are 25-year levelized values to reflect the lifetime of PV and the 25-year impact it has on value to the grid and impacts on revenue.

[12] PV systems were sized so that the generation over the DPV lifetime equaled customer load over the DPV lifetime. Because PV output degrades slightly over time, PV systems slightly overproduced in early years and slightly under-produced in later years.

segment) over the lifetime of the system, but the costs recovered through variable charges would be minimal. Additionally, the solar provides net benefits, shown in green. The difference between the red line (100% cost recovery) and the second bar is the deficit in cost recovery from this customer. The estimated deficit from NEM across the 2017 DPV fleet is $184k in 2017 with a net present value (NPV) of $3.5M over the 25-year lifetime of these systems.



	Non-solar	NEM	NEM	TOU	VOST
First year CSU deficit	0	$0.2M	$7M	$4M	0
25-year NPV of CSU deficit	0	$3M	$127M	$70M	0

Figure 2 25-year levelized cost recovery from solar and non-solar customers under different solar scenarios (2017 and High Scenario) and for rate alternatives (NEM, TOU, and Buy All Sell All VOST)

The three right-hand bars show cost recovery in the High Solar Scenario which includes 50 MW residential and 50 MW commercial DPV. The High Solar Scenario has a lower VOS than the 2017 Scenario, as shown by the shorter green segments. The third bar shows that the lower VOS increases the deficit. The deficit in this High Scenario is $7M in the first year with a NPV of $126M over the DPV lifetime. Moving to a TOU rate increases CSU's cost recovery (fourth bar is higher than third bar), as the solar customer modeled here is unable to offset all his/her peak energy usage with peak DPV production. Under this rate, a deficit is still shown in CSU's cost recovery. However, a TOU rate also incentivizes grid-friendly customer behavior that can reduce the cost of service (lowers the red line) which can reduce this deficit further[13].

Moving to a Buy All Sell All VOST (fifth bar) fully recovers costs from the solar customer[14] because solar customers pay the normal retail rate for their consumption, and are compensated for their generation at the VOS rate. However, it is noted that unlike the demand charge and TOU rate, the VOST does nothing to incentivize customers to reduce their cost of service (lower the red line). In short, this TOU rate and this Buy All Sell All VOST both have the potential to mitigate the revenue shortfall. However,

[13] The degree to which customers change their behavior, and the resulting reduction in their cost of service, was not part of the scope of this Study. This is an area for further research.

[14] Note that this is a consequence of how cost recovery is defined and calculated in this Study.

the TOU rate does so with a combination of increasing revenue and lowering the cost of service, while the VOST only increases revenues without impacting the cost of service.

While DPV is growing steadily in CSU, it has not taken off at the same levels seen in regions such as Hawaii or California. Some of these rate alternatives reduce the economic attractiveness of "going solar". From the customer perspective, the Team examined how low DPV costs need to fall to enable potential solar customers to break-even. The Team found that customers should be able to break-even at current and near-term DPV cost projections for the fixed charge, demand charge and TOU rates in Table 2[15].

If CSU revises its rates and reduces the incentive inherent in current rates, it may want to fine-tune specific financial incentives, such as the Renewable Energy Rebates Program, to encourage DPV growth or to internalize external benefits such as emissions reductions or job creation[16]. Break-even costs and DPV cost projections discussed in the Study could help CSU determine these levels. Separating the incentive from the rate structure also allows CSU to not incentivize a distributed energy resource that does not provide green or other attributes desired by CSU.

Reforming rates can enable sustainable solar growth

Rooftop solar provides many benefits to CSU's system. This Study quantifies those net benefits and finds a 25-year levelized value of $0.0374/kWh to $0.0565/kWh, depending on DPV penetration levels. This value is lower than CSU's 2017 variable rates. While CSU has higher fixed than variable costs, they, like most utilities, recover those costs mainly through fixed rather than variable charges for their residential and commercial classes. That, combined with NEM, means that CSU is not fully recovering costs from solar customers today. This leads to cost-shifting in that rates must be increased on all customers. While the cost-shifting may be manageable today, cost recovery will worsen with increased DPV levels. DPV may be the first DER to impact CSU's system, but it may be followed quickly by storage and electric vehicles as seen in other regions. Options that reflect value to the utility or that incentivize grid-friendly behavior will help to set up CSU for the longer term. CSU is therefore advised to consider reforming rates.

This Study designed several rate options and evaluated their impact on customer bills and CSU cost recovery. Recommended rate options are shown in Table 3. For residential and commercial rates, an optimal long-term solution is a volumetric TOU rate with a demand charge. This was the most robust option in terms of reasonable bill impacts to non-solar customers and CSU cost recovery. Moreover, it incentivizes customers to shift usage from peak to off-peak periods, and sends correct price signals regarding future deployment of other distributed energy resource such as storage and electric vehicles. A short-term option is an increase in the fixed charge. This would capture more customer and demand costs and help reduce the cost-shift due to solar. However, a fixed charge does not incentivize grid-friendly behavior, and CSU may want to study impacts on customer groups such as low-income customers prior to implementation.

For larger commercial and industrial customers, the Buy All Sell All VOST could potentially be a win-win alternative, as it would both address utility cost recovery issues and provide an appealing option to customers. The VOST could also involve allowing larger PV system sizing for these larger energy users.

15 National Renewable Energy Laboratory, *Annual Technology Baseline 2016,* Golden, CO. http://www.nrel.gov/analysis/data_tech_baseline.html

16 For example, economic and jobs impacts from DPV were investigated using an input-output economic model (National Renewable Energy Laboratory Jobs and Economic Development Impact model). Depending on whether small, local installers or large, national installers conducted the installations, the model predicted that each MW_{AC} would create 7.8 to 27.1 jobs in Colorado.

Table 3 Summary of Recommendations and Implementation Considerations

Rate Class	Summary of Recommendations	Key Implementation Considerations
Residential, Small Commercial, General Commercial	• Fixed charge increase can mitigate NEM revenue erosion in the short-run	• Easy implementation for all rate classes, but inequitable impacts and an inefficient price signal to customers
	• TOU volumetric rates encourage grid-friendly behavior, offer customers another choice, • TOU rates have a lower bill impact on non-solar customers and alleviate NEM-related revenue erosion	• Requires new metering infrastructure • Large bill impacts for solar customers if TOU periods are not aligned with solar output • Long-term "Duck Curve" and shifting peak issues with increased DER penetration
	• A combination of a demand charge with a TOU rate may provide the most robust option in terms of the right price signals and fair compensation in anticipation of other DER	• Requires new metering infrastructure • Can be structured to charge customer based on higher peak usage (e.g., a block demand rate) • Potentially confusing and difficult to customers
General Commercial, Industrial	• Current ETL tariff is well-structured to recover cost of service and mitigate NEM-related revenue erosion • An optional Value of Solar "Buy All, Sell All" program may encourage more solar in this class by allowing them more attractive compensation for the value that DPV brings	• Would need a new program design for a C&I VOST to set eligibility, compensation, etc. • Interconnection policies would need to be re-examined • Removes ability for customers to offset onsite • Different tax ramifications than NEM

Details of rate design would need to be further evaluated and determined (e.g., for TOU with NEM, whether peak production only would offset peak usage). CSU would need to consider a number of important program characteristics prior to the implementation of a new VOST program. For example, because both the VOS and the cost of PV change quickly as more PV is installed, CSU would need to consider calculating the customer compensation (e.g., VOS) on an annual basis.

Several rates require investment in advanced metering infrastructure, which is part of CSU's long-term plan. The implementation of a long term strategy and rate design changes may be optimally integrated in phases, to mitigate bill increases, allow customers to adjust to changes, and enable the adoption of energy management tools by customers. CSU could conduct pilot programs to test rate design changes. This could give customers experience with new rate designs, foster the development of effective education and outreach to explain new rates or programs, and test energy management tools for customers.

