Control Number: 46831

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SOAH DOCKET NO. 473-17-2686
PUC DOCKET NO. 46831

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FILING CLERK

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	**§ § §**	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

WORKPAPERS

TO THE

DIRECT TESTIMONY

OF

WILLIAM PEREA MARCUS

ON BEHALF OF THE

OFFICE OF PUBLIC UTILITY COUNSEL

JUNE 26, 2017

549

SOAH DOCKET NO. 473-17-2686
PUC DOCKET NO. 46831

APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO	§	OF
CHANGE RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
OFFICE OF PUBLIC UTILITY COUNSEL'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. OPUC 1-1 THROUGH OPUC 1-17

OPUC 1-2:

Please identify each time that industrial interruptible load was interrupted between January 1, 2014 and the present. Identify (a) the system load immediately preceding the interruption; (b) the amount of load interrupted (divide between Texas and New Mexico if possible); (c) the number of customers interrupted (divide between Texas and New Mexico if possible); (d) the number of customers and amount of load that did not comply with the interruption (divide between Texas and New Mexico if possible); (e) the reason for the interruption, and specifically as to whether interruption was caused by loss of generation, loss of bulk transmission (higher voltage than 200 kV), or loss of other transmission.

RESPONSE:

Please see OPUC 1-2 Attachment 1 Highly Sensitive Protected Materials.

Preparer:	Mike Graniczny Abel Bustillos	Title:	Manager-Commercial Services Outage Coordinator - Staff
Sponsor:	David C. Hawkins	Title:	Vice President-System Operations, Resource Planning and Management

SOAH DOCKET NO. 473-17-2686
PUC DOCKET NO. 46831

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S FIRST REQUEST FOR INFORMATION QUESTION NOS. OPUC 1-1 THROUGH OPUC 1-17

OPUC 1-3:

Please provide a calculation of the revenues that interruptible customers would pay in the test year (adjusted to annualize the rates resulting from the order in Docket No. 44941) showing billing determinants and applicable rates. Divide by rate schedule and voltage level if applicable.

RESPONSE:

Please refer to OPUC 1-3 Attachment 1, pages 1 through 6, electronic worksheet tab labeled "Interruptible (OPUC 1-3)."

Preparer: Manuel Carrasco Title: Supervisor-Rates & Regulatory Affairs

Sponsor: Manuel Carrasco Title: Supervisor-Rates & Regulatory Affairs the gandalf group

Ontario Energy Board

Distribution Charge Focus Groups

Final Report

October 9, 2013

420 Wellington Street West, Toronto, ON, M5V 1E3 | T 416.644.4120
info@gandalfgroup.ca | gandalfgroup.ca

Table of Contents

I. Introduction & Methodology

On behalf of the Ontario Energy Board, the Gandalf Group was pleased to conduct four focus groups with residential electricity consumers about proposed changes to distribution charges.

Groups were 2 hours in duration, with nine to ten participants in each of the four groups. Two groups were held with seniors and representatives of middle and lower income households, and two were held with representatives of middle to upper income households and parents with children in the home. Participants were a mix of Toronto and 905 community residents. All participants were homeowners, condo-owners or renters that pay their own electricity costs. Participants were all customers of Powerstream, Hydro One, Enersource, Veridian, or Toronto Hydro (see Appendix B).

These groups were conducted on September 25th and 26th 2013 in North York.

The moderator's guide for the focus groups (see Appendix A) begins with a warm-up and an introduction to the focus group format. Then basic ideas around electricity use and pricing are discussed including familiarity with time of use pricing and delivery charges. The moderator begins a discussion of distribution costs and pricing. The guide then introduces the new distribution pricing scheme. The current and proposed pricing systems are compared, as well as the introduction of fixed 12-month charges and tiered pricing. Later a rationale document is shared and discussed to see where it is helpful at explaining if not arguing for the changes.

To discuss this report and address any questions or concerns, please contact Alex Swann at 416.644.4125 or swann@gandalfgroup.ca.

II. Executive Summary

Engagement in "time of use" (TOU) pricing among participants is high. Understanding the need to avoid or reduce consumption during peak times is something most were prepared to manage, although with varying degrees of difficulty.

While many understand how TOU and electricity charges are calculated, many do not understand why the electricity system benefits from peak-time pricing. More information about the actual and potential costs of delivery during peak times (and how the system has to be built to handle peak loads) was interesting to participants. It helped build understanding more about the service they get and as rationale for proposed distribution charges that reflect consumption during peak hours.

There was concern among some that bills would likely increase significantly under the proposal. A relationship to TOU specifically will be important – i.e. implying a range of rates rather than a focus on consumption during peak hours. But many people will be anxious to know specifically what will happen to their bills, either in transition or in the long run – will they jump up because of peak time usage or be introduced at a rate similar to what they pay now, given how tiers track consumption?

Consumers want tools not only to understand the calculation but manage their costs by offering evidence of past and present or projected usage with respect to what each mean for bills.

An explanation of how proposed "tiered" charges would track current variable costs was reassuring to some in the sense that they felt the new charges align with what they presently pay. Some could see the opportunity for bill decreases. But in the absence of certainty about their bill others were concerned about the potential increases of several dollars monthly. Citizens of modest means could be very vocal about bill increases amounting to $4 or $5 a month or more.

A more widely shared concern was the proposal to move to 12 months of fixed charges. It helped modestly to explain that system costs are relatively fixed month to month as a justification for fixed charges. That argument was somewhat undermined by the proposal to peg charges at different levels leaving people confused as to whether costs are variable or fixed and whether charges should be too.

Fundamentally there is a concern about cost of living pressures here and an engrained acceptance that a substantial portion of costs or bills should be variable (perhaps more since the introduction of TOU). This specific proposal appears to preclude savings they believe they are working to achieve with steady reductions in use under TOU. Finally, a fixed charge approach over 12 months seems like a higher burden.

III. Detailed Findings

Context: What Consumers Know About Delivery Charges and "Time of Use"
Most in the groups said they had embraced "time of use" (TOU) pricing habits. They were aware of whether peak pricing impacted or benefited them or how they had changed their habits to conserve.

Despite this level of engagement, many do not understand why peak pricing is in place. Some assumed that when energy is in demand it will cost more to generate or import. But others assumed the price is merely raised when it can fetch more on the market. Only a few went so far as to articulate the goal of TOU pricing (to spread out demand) and if they did they would be far more likely to say this was to avoid brownouts than manage investments in system capacity.

Participants believe they get comparatively little information on their bills about delivery charges, compared to the electricity line where both the calculation or rate is evident. As well they are more likely to understand intuitively what they receive for the cost of "electricity." Few could articulate what they get for delivery. The infrastructure behind the system is simply not top of mind. It is not easy to visualize let alone value. This helps to explain why some participants told us they are displeased that the delivery portion could sometimes cost the same or more than the electricity portion of their bill. Some questioned how such a charge could exceed the value of what they believe they are buying.

We provided some detailed information to group participants about the costs entailed in the delivery line of bills. Little of the information about distribution or transmission (poles, high voltage transmission lines etc.) was surprising to them; it served as a reminder of information that is not top of mind. It is somewhat helpful to getting people to visualize the true costs of their electricity consumption.

Showing how the line was calculated seemed more important. The lack of transparency around this charge now was noted in comparison to the detail around how TOU is applied and what drives the electricity charge or line.

A New Approach To Distribution Charges

When a proposal for pricing delivery based on demand during "peak hours" was presented we saw immediate concern from some in the groups. Those consumers appeared to believe they would be charged a higher rate per kwh for all their electricity use in relation to delivery – i.e. a "peak" rate. Others understood that this system would not impact them much if they felt they had reduced or could avoid consumption during peak times already.

A more widely held concern is that their bills give them no tools to manage this going forward. Participants wanted tools or metrics on their bills to better understand how charges are calculated in the new system, and to so see if they what targets they are meeting.

A Rationale for Peak Time Pricing

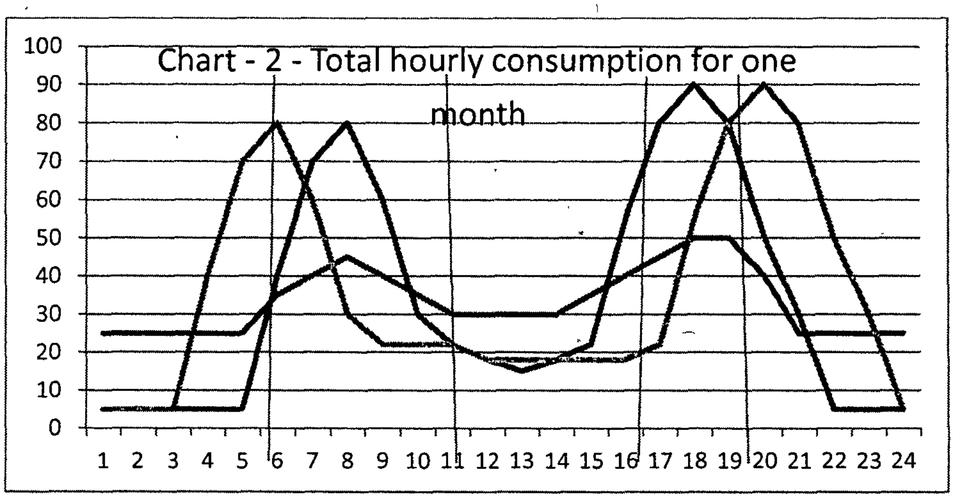
We found that the presentation of a rationale for these changes was somewhat interesting for participants and somewhat helpful to increasing acceptance of the changes. At least it helped break down the cynicism or concern about lack of transparency, which is a separate or additional concern that accompanies electricity charges and rate increases.

A "water pipe" analogy was helpful at building understanding of costs to the system that result from peak demand. This analogy effectively conveyed the idea that we need a bigger system to deliver more power at once.

If we have used language to tell consumers that infrastructure costs are static and don't fluctuate with monthly usage, some will not grasp the water pipe analogy or what costs to the system we could possibly be talking about. Indeed those who questioned whether the system needs to be build out to manage peak capacity assume that poles and wires are cannot be expanded and do not need to be.

It will be important to talk about tangible investments that will have to be made or have been made to handle higher net peak demand. As well we should illustrate the problem in a way that people can grasp – e.g. the hottest days of summer and the concern that utilities must take in planning for the future. This would be a more graphic depiction of the costs and the risks and the need for pricing signals to forestall this.

There was a tension between an argument for less fluctuation month to month in terms of what the customer pays on the one hand and the need to talk about future costs or expanding the system to handle peak consumption. It is difficult to try convey that costs do not fluctuate as much as charges do (as the communications materials we tested did) and then speak to reduce peak consumption. It seems that a discussion of fixed costs should not be discussed outside of the larger argument or context. In our communications, the sooner we explain the big picture, and get at the total costs to the system of peak days (the "water pipe" analogy and planning for peak days) the better our argument. Our argument would emphasize that the system has to have a maximum capacity, one that might vary over time (i.e. some variability) but in essence only grow with increases in maximum demand, and not contract if average demand decreases.



A presentation of how peak time users' consumption could vary substantially from a consumer who either shifts or reduces peak consumption helped to illustrate to group participants the range of demand that homes have and what this can entail for the system during peak hours (shown in red in chart 2 above).

The idea that different utilities calculate the charge differently now (with some offering a very low flat rate) raised an issue of fairness that people agreed should be fixed. It might be considered as a talking point in communications; but if different utilities continue to have different costs (or if rural customers continue to pay more) it would negate the overall credibility of this argument. (Yes, there would likely be more fairness between consumers with similar consumption patterns with some of the various utilities but not overall.)

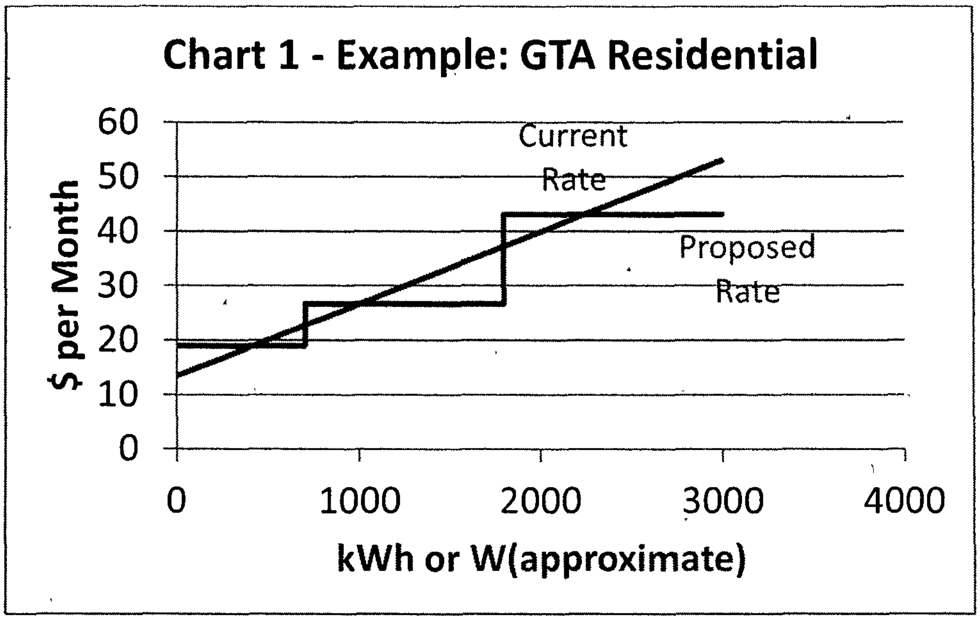
Tiered Pricing
Moving to tiered pricing drew mixed reactions.

Some in the groups were not concerned about new charge system because they believed they had shifted or could move their power consumption away from peak times. Some believed they would benefit with a lower charge. How many will be able to do so in transition, and over time, will impact the long-term communications around this issue.

Others felt that since they are likely to adopt some energy efficiency measures, but are limited from adopting substantial conservation efforts, this system prevents them from seeing small reductions in costs and therefore any reductions which they would see otherwise.

A few questioned any suggestion that this was revenue neutral – either to consumers overall or to them in particular. This fact will not be assumed. Some will assume the tiers have been selected in a way that means a net revenue increase.

The key concern here is the possibility that some would see increases. In the short run, many will be concerned about this possibility. And in the long run, a few may determine their charges increased even if they haven't switched tiers that they are in the lower-end of the scale within a tier (see chart 1: differential can be deduced from the pricing graph with tiers and current charges or rates, e.g. at about 900 kwh or 1900kwh where the red tiered line exceeds the blue straight line of current rates).



An approximate increase of close to $5 monthly will be an irritant for those who believe their bills have increased of late with no change in consumption. They will be a serious concern for those of modest means. Based on what we heard, citizens of modest means who already feel stretched could be very concerned and very vocal about bill increases amounting to $4 or $5 a month or more. We heard suggestions about increasing the number of tiers to make such cost differentials lower.

Maximum Usage Pricing

The concept of maximum use during peak times is difficult for people to understand and raised concern among a few. There is no template for measuring maximum use that people are used to in the way they understand TOU. It was not obvious how this would be calculated.

Without precise details of this there was concern expressed by some that small lapses in their conservation efforts will mean they will have to pay a high price for that (even if they conserve diligently on the vast majority of days during peak times). So there will be questions of fairness if they have conserved on the vast majority of days during peak demand times and essentially helped to reduce peak consumption.

Fixed Monthly Charges

Moving to a fixed monthly charge every month for 12 month periods was problematic for participants in our groups. Concerns included:

- The fact that many assume they will seek efficiencies in the course of each year and that this will forestall the benefit or reduce the payback of those.
- Others believed that if we were encouraging reductions in peak consumption, along the lines of TOU pricing that they should be incentivized either to the full extent or in the way they are accustomed to.
- Some worried that in order for them to qualify for lower charges due to decreased consumption, that decrease in consumption would have to be sustained for 12 months and with less forgiveness than exists now for lapses. It seems like a higher burden, with a chance of no reward if they fall short.
- Two groups' participants were particularly cynical and felt that utilities might simply change the rules or conditions at the end of each year, and that the promise of lower rates based on a reassessment of usage would essentially disappear with a rate increase.
- This helps explain why several respondents immediately asked if they would see credits retroactively if use was lower than assumed in the rate they were charged.

The responses we heard suggest people believe their bills and distribution charges vary substantially month to month.

Variability is a deeply engrained principle – from home to home and month to month. While most cannot explain how the charge is calculated now they apply the perspective that charges should not be the same for each household and should be affordable for those who are both of modest means and consuming less. Individually, for themselves, consumers expect to be able to decrease each bill amounts as their consumption comes down.

We found a few individuals supported the idea of fixed charges in that costs to them do not fluctuate month to month given the constant costs of delivery infrastructure. But, if they accepted that, they might then have trouble understanding why delivery charges could be pegged higher or lower based on peak demand. This issue is complex and confusing until we introduce the need for the system to be built to handle peak demand (using a "water pipe" analogy, which we discuss below).

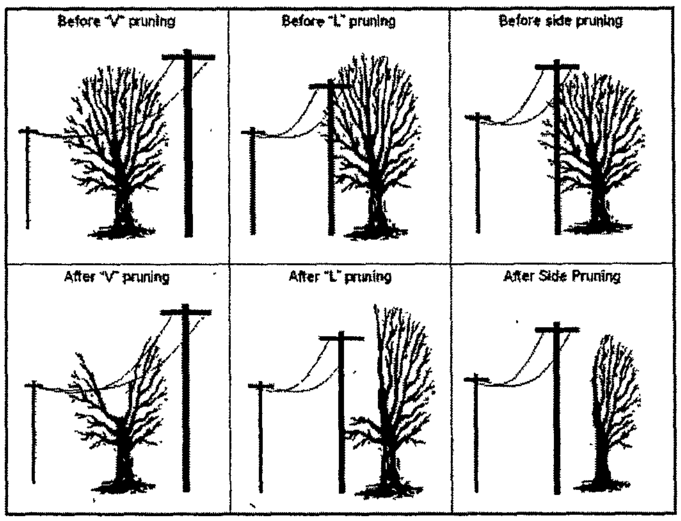
Residential Main Page
Tree Trimming
Safety
Reliability
Storm Restoration
Tree Health
Tree Pruning and Trimming
Door Hangers
Tree Trimming Crews
Customer Requests
Landscaping with Trees
Free Wood Chips
Transmission Line Right of Way

Tree Trimming

How We Trim

Prior to tree trimming in your area, we place an automated call to the telephone number provided on your account. This courtesy message lets you know we will begin tree trimming work in your area within the next few weeks. It is not necessary that you be home on the day of the trimming; contractors will proceed with trimming and cleanup.

The three most common methods of pruning are:



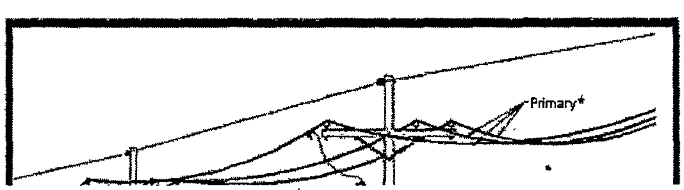
What We Trim

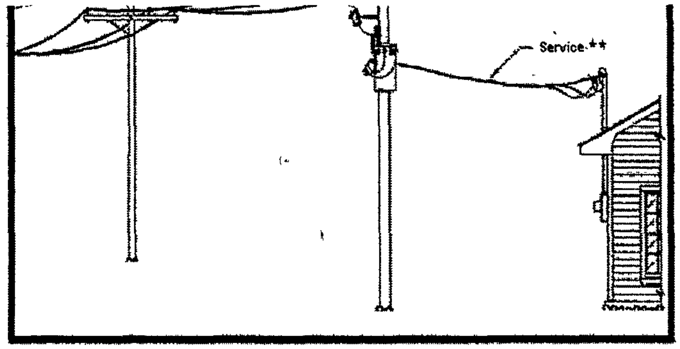
Primary Lines: Entergy routinely maintains the vegetation along our power lines (pole-to-pole) ensuring appropriate clearance on the power lines for safety, reliability and tree health.

What We Do Not Trim

Services (Secondary) and Security Lighting ("Night Watchers"): We do not prune or remove trees that appear to threaten individual service lines (pole-to-home) or security lighting ("night watchers"). These service lines are the responsibility of the customer. If you have trees that need pruning or removal near your service lines, please hire a professional tree-trimming contractor to perform the work. If requested, we can temporarily disconnect the service to your home, at no charge to you, so the contractor can work safely.

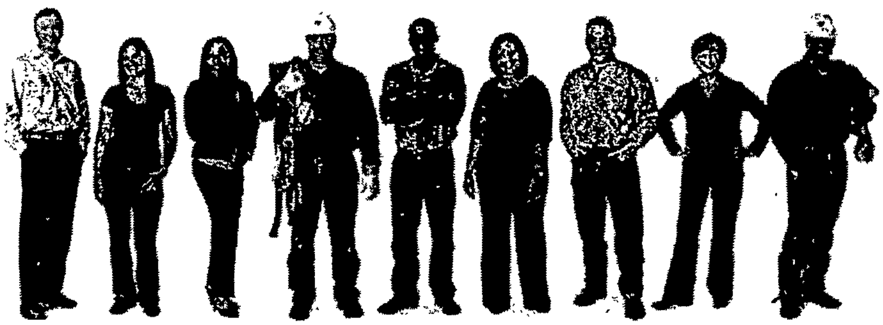
Cable and Telephone Lines: We do not trim around cable or telephone lines. Please contact your cable or telephone company if you are concerned about trees contacting these lines.





* Entergy trims around primary power lines.

** Entergy does not trim around service lines.



SOAH DOCKET NO. 473-15-5257
PUC DOCKET NO. 44941

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
OFFICE OF PUBLIC UTILITY COUNSEL'S ELEVENTH
REQUEST FOR INFORMATION
QUESTION NOS. OPUC 11-1 THROUGH OPUC 11-8

OPUC 11-6:

Provide estimates of the percentage of costs spent to manage vegetation around primary lines, secondary lines, and service drops.

RESPONSE:

EPE does not separate vegetation management costs by primary lines, secondary lines and service drops. Vegetation management is performed concurrently on all three and invoiced as one amount without a breakout between those three items. We are unable to estimate the percentage between those three breakouts.

Preparer: Omar Gallegos — Title: Manager-Asset Management Services

Sponsor: R. Clay Doyle — Title: Vice President-T&D and System Planning

SOAH DOCKET NO. 473-15-5257
PUC DOCKET NO. 44941

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

REBUTTAL TESTIMONY

OF

MANUEL CARRASCO

ON BEHALF OF

EL PASO ELECTRIC COMPANY

JANUARY 15, 2016

that the output should be "grossed up" for losses. Adjusting this output upward makes the treatment of these facilities consistent with the treatment of all other EPE generation resources.

IV. PRODUCTION-RELATED COST ALLOCATION METHODOLOGY

Q. CEP WITNESS JOHNSON CONTENDS THAT THE COMPANY'S CLASSIFICATION OF GENERATION NON-FUEL OPERATIONS AND MAINTENANCE (O&M) EXPENSE IN THE CLASS COST OF SERVICE STUDY (CCOS) STUDY DOES NOT ASSIGN AN APPROPRIATE PERCENTAGE OF EXPENSE AS ENERGY-RELATED. HE ALSO CONTENDS THAT THE COMPANY DID NOT FULLY APPLY THE CLASSIFICATION METHOD SET OUT IN THE NARUC ELECTRIC UTILITY COST ALLOCATION MANUAL. DO YOU HAVE ANY COMMENT?

A. Yes, I do. Mr. Johnson suggests that Maintenance of Miscellaneous Steam Expense [sic] (Account 514) and Maintenance of Miscellaneous Nuclear Plant (Account 532) are energy-related. EPE's cost of service studies use the 4CP-A&E allocator for these accounts, which is consistent with cost of service studies filed in EPE's prior rate case filing. However, the often-referenced NARUC Electric Utility Cost Allocation Manual[1] (NARUC Manual), classifies these accounts as all energy-related. It is my preference to remain consistent with the NARUC Manual's recommendations as much as possible. Accordingly, Mr. Johnson's suggestion regarding Accounts 514 and 532 should be accepted. The jurisdictional allocation for these accounts will also be set to classify them as all energy-related in the JCOS.

[1] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992

Q. OPUC WITNESS MARCUS CRITICIZES THE COMPANY FOR USING AN ALLOCATION FACTOR FOR ENERGY-RELATED O&M EXPENSES IN ACCOUNTS 510, 512, 513, 528, 530 AND 531 THAT EXCLUDES INTERRUPTIBLE CUSTOMERS. HE RECOMMENDS USING AN ALLOCATION FACTOR THAT INCLUDES INTERRUPTIBLES. DO YOU HAVE ANY COMMENT?

A. Yes, I do. At EPE, "interruptible service" is not considered a stand-alone rate class, since more than one rate class can take interruptible service, and as such, it is not subject to cost of service allocations. For proper allocation of costs, the energy allocator applied to Accounts 510, 512, 513, 528, 530, and 531 must not include energy related to interruptible service. As such, Mr. Marcus' recommendation of using the E2ENERGY allocation factor (including interruptibles) instead of the E1ENERGY allocation factor (excluding interruptibles) should be rejected.

Q. OPUC WITNESS MARCUS ALSO ARGUES THAT LOAD DISPATCHING COSTS (ACCOUNTS 556 AND 561) SHOULD NOT BE ALLOCATED BASED ON PEAK DEMAND. HE RECOMMENDS USING A 12CP AVERAGE TO ALLOCATE ACCOUNT 556 AND AN AVERAGE DEMAND ALLOCATOR FOR ACCOUNT 561 AND JUSTIFIES HIS PROPOSAL BASED ON THE RECENT SPS CASE. HOW DO YOU RESPOND?

A. At pages 8 through 10 of his Direct Testimony, Mr. Marcus makes a persuasive argument regarding load dispatching (Accounts 556 and 561) and how this function is not simply a function of peak demand. EPE's cost of service studies use a 4CP allocator for these accounts, which is consistent with cost of service studies filed in EPE's prior rate case filing. However, the NARUC Manual simply classifies these accounts as all demand-related but without a specific demand methodology. Therefore, the use of a 12 coincident peak demand average (12CP) is an acceptable method of allocating the costs in both of these accounts. Mr. Marcus' suggestion of a broader, 12 CP allocation basis regarding Accounts 556 and 561 should be accepted because load dispatching is a function that operates 24 hours of each day in a year to ensure loads meet peak demands, regardless of which month it is. The jurisdictional allocation for these accounts will also be set to allocate them under a 12CP method in the JCOS.

V. DISTRIBUTION-RELATED COST ALLOCATION METHODOLOGY

Q. A FEW PARTIES HAVE EXPRESSED CONCERN OVER THE METHODOLOGY THE COMPANY'S CLASS COST OF SERVICE STUDY APPLIES IN ALLOCATION OF DISTRIBUTION-RELATED COSTS. IS EPE'S ALLOCATION METHOD REASONABLE?

A. Yes, it is. The distribution-related cost allocation methodology used in the Company's CCOS is consistent with the recommendation found in the NARUC Manual. According to page 97 of the manual:

> *The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities.. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands.*[2]

Q. ARE THE DISTRIBUTION-RELATED COST ALLOCATION METHODOLOGIES RECOMMENDED BY THE PARTIES UNREASONABLE?

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[2] "Customer-class peaks" is synonymous to maximum class demand (MCD). "Customer's maximum demands" is synonymous to non-coincident peak demand (NCP).

Settlement Allocation of $37M Base Rate Increase by Class

Rate Schedule No.	Description	Present Revenues	Settlement Increase	% Settlement Increase
	Firm Service Rates			
1	Residential Service	$ 180,425,877	$ 23,969,367	13.3%
2	Small General Service	29,056,037	1,263,912	4.3%
7	Outdoor Recreational Lighting	428,233	73,470	17.2%
8	Government Street Lighting	3,432,085	500,059	14.6%
9	Traffic Signals	71,791	19,977	27.8%
11	Municipal Pumping	2,636,686	94,675	3.6%
11-TOU	Municipal Pumping TOU	6,780,227	296,670	4.4%
15	Electrolytic Refining Service	2,401,515	4,950	0.2%
WH	Water Heating Service	583,702	148,496	25.4%
22	Irrigation Service	551,525	66,028	12.0%
24	General Service	112,602,803	4,107,996	3.6%
25	Large Power Service	40,303,531	531,531	1.3%
26	Petroleum Refinery Service	11,855,919	120,665	1.0%
28	Area Lighting Service	2,667,061	99,039	3.7%
30	Electric Furnace Rate	1,128,166	154,890	13.7%
31	Military Reservation Service	12,390,022	549,617	4.4%
34	Cotton Gin Service	77,015	19,980	25.9%
41	City & County Service	22,708,541	3,191,357	14.1%
	Total Firm Service	$ 430,100,736	$ 35,212,679	8.2%
	Non-Firm Service	3,537,114	310,000	8.8%
	Other Operating Revenue	29,005,685	1,477,321	5.1%
	Total Firm, Non-Firm Service, and Other Operating Revenue	$ 462,643,535	$ 37,000,000	8.0%

ELECTRIC TARIFF

INTERRUPTIBLE CREDIT OPTION

AVAILABILITY: Available as an optional, interruptible service for Customers who receive electric service under Company's Large General Service Transmission rate schedules at voltages of 69 kV and above, when the total Contract Interruptible Load (CIL) for all existing Customers taking service under this tariff is less than 85 MW, and the addition of the new Customer's CIL does not cause the total CIL of all existing Customers to exceed 85 MW. Not available to Customers who receive electric service under Company's standby service rate schedules.

APPLICABILITY:
Optional service under this tariff is applicable to a Customer under the following conditions:

(1) Customer's CIL to be used in calculating the Monthly Credit is 500 kilowatts (kW) or greater; and

(2) Customer achieved an Interruptible Demand of at least 500 kW during each of the most recent four summer peak season months of June, July, August, and September; or, Company estimates that Customer will achieve an Interruptible Demand of at least 500 kW during each of the four summer peak season months of June, July, August, and September in the coming season; and

(3) Customer and Company have executed an Interruptible Credit Option Agreement (Agreement) that specifies the Contract Firm Demand, Number of Interruptible Hours, the Service Options elected by Customer, as described under CUSTOMER SPECIFIED TERMS AND CONDITIONS in this tariff, and Customer specific data necessary for Company to calculate Customer's Monthly Credit Rate (MCR).

TARIFF TERMINATION AND CHANGE:
This tariff and the Agreement shall be deemed to be modified to conform to any changes or revisions approved by the Public Utility Commission of Texas, as of the date of the effectiveness of such change, including cancellation or termination of this option. Changes in the Customer's MCR will take effect in the billing month following the effective date of a change in this tariff. Company reserves the right to request approval by the Public Utility Commission of Texas for changes to or termination of this tariff at any time.

Effective Date: June 1, 2014

PUBLIC UTILITY COMMISSION OF TEXAS
APPROVED

DEC 19 '14 DOCKET 42004

CONTROL #

REGIONAL VICE PRESIDENT RATES AND REGULATORY AFFAIRS

ELECTRIC TARIFF

INTERRUPTIBLE CREDIT OPTION

TERM OF AGREEMENT, SERVICE PERIODS, AND TERMINATION OF AGREEMENT BY CUSTOMER:

Service Periods under this tariff normally will begin on January 1 and continue for one calendar year. Customer may enter into an Agreement at any time during the calendar year; however, if Customer enters into the Agreement after March 1 of any year, the first Service Period under this tariff will begin at the start of the following calendar year. If Customer enters into the Agreement prior to March 1 of any year, the first Service Period will begin on the first day of the following month and will consist of the remainder of that calendar year. Customer's Number of Interruptible Hours (Ha) for the first Service Period will be reduced to a level that is reasonably representative of the Number of Interruptible Hours remaining for that calendar year, determined at the discretion of the Company.

At any time during the first Service Period under this rate schedule, Customer may opt to cancel the Agreement by returning all Monthly Credits paid by Company up until the date of cancellation. No additional payment will be assessed. Economic buy-through payments made by Customer and Economic buy-through penalty charges shall not be refunded by Company. Capacity Interruption penalties shall be refunded.

Any Customer who otherwise terminates the Agreement prior to the end of its term shall be required to pay the Company, as a penalty, an amount equal to the product of one hundred and ten percent (110%) times Customer's CIL, times Customer's MCR for each of the remaining months of the unexpired contract term. In addition, Customer shall reimburse the Company for the direct cost incurred by the Company for equipment (including its installation cost, less salvage value) to measure Customer's Interruptible Demand and to interrupt Customer.

OBLIGATION TO INTERRUPT:

A Customer taking service under this tariff is required to reduce its load to the level of the Contract Firm Demand specified in the Agreement when Company schedules an interruption pursuant to the terms and conditions specified herein. Company shall have the right to interrupt Customer's available interruptible load for the total Number of Interruptible Hours (Ha) specified in the Agreement.

Effective Date: June 1, 2014

PUBLIC UTILITY COMMISSION OF TEXAS
APPROVED

DEC 19 '14 DOCKET 42004

CONTROL #

REGIONAL VICE PRESIDENT RATES AND REGULATORY AFFAIRS

ELECTRIC TARIFF

INTERRUPTIBLE CREDIT OPTION

CUSTOMER SPECIFIED TERMS, CONDITIONS, AND SERVICE OPTIONS :

Contract Firm Demand - the Contract Firm Demand shall be specified by Customer in the Agreement. The Contract Firm Demand of an existing Customer taking service under this tariff may not be changed unless approved by Company.

Number of Interruptible Hours (Ha) – the Number of Interruptible Hours (Ha) shall be specified by Customer in the Agreement. The options are: 40 hours, 80 hours, or 160 hours annually.

Four (4) Hour Minimum / Waiver of Four (4) Hour Minimum - an interruption shall be a minimum of four (4) hours in duration. In the Agreement, however, Customer may elect to waive the 4 hour minimum, in which case, the interruption may be less than 4 hours in duration. The duration of any interruption shall not be less than one hour.

One Hour Notice / No Notice Option - Company shall provide notice a minimum of one hour prior to the start of the interruption. In the Agreement, however, Customer may allow Company to interrupt Customer's load without providing prior notice of the interruption.

ECONOMIC INTERRUPTION:

Company shall have the right to call an Economic Interruption for one or more Customers once per day when Company determines, in its sole discretion, that calling an interruption will lower its overall system costs when compared to what the overall system cost would be in the absence of the interruption. The duration of any Economic Interruption shall not be less than four hours, unless Customer has opted to waive the four-hour minimum and, in such case, the duration shall not be less than one hour. Company will provide notice at least one hour prior to an Economic Interruption.

BUY-THROUGH - ECONOMIC INTERRUPTION:

Once Company has called an Economic Interruption, Company will provide Customer, via the contact methods identified on the Contact Information Sheet of the Agreement, with the estimated buy-through price for each hour of the interruption period. Such notice shall advise Customer of Company's best estimate of the buy-through price. Customers must notify Company forty-five (45) minutes prior to the start of an Economic Interruption if they elect to buy-through all or a portion of their available interruptible load by logging into the ICO Web Site at the address provided in the Agreement and indicating their buy-through request for each hour of the Economic Interruption period. The ICO Web Site shall advise Customer of

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BUY-THROUGH - ECONOMIC INTERRUPTION: (cont.)

Company's best estimate of the buy-through price for each hour of the Economic Interruption period.

The buy-through price shall be calculated by taking the weighted average cost, as determined by the Company's Cost Calculator or its successor, plus three mils per kWh, for the block of electricity used to serve Customer(s) who elected to buy-through. For purposes of this calculation, Company shall assume that the block of electricity used is the highest cost block of electricity consumed in each buy-through hour.

If Customer elects to buy-through the Economic Interruption, it must continue to buy-through all hours of the interruption period unless Company provides notice to Customer of an updated buy-through price for any hour of the interruption that exceeds the original estimated buy-through price for the hour in question, whereupon Customer that elected initially to buy-through the Economic Interruption will have 15 minutes after being provided notice of the updated estimated price to advise the Company that such Customer desires to be interrupted at the start of the next hour. Once Customer chooses to interrupt, Customer will be interrupted for the remainder of the interruption period, as determined by the Company.

If Company chooses to extend an Economic Interruption from the original notification, all ICO Customers affected by the Economic Interruption will be provided notice of the opportunity to buy-through or interrupt for the duration of the Economic Interruption extension period. Economic Interruption extensions may be less than four hours in duration.

Customer may provide advance election to buy-though up to a specified price. Such election shall be made no later than the last business day prior to the first day of the month to which the election will apply, and shall be delivered to Customer's service representative by electronic mail as provided in Customer's Agreement. Any Customer with a standing buy-though order shall have the option, up to 45 minutes before the start of an event, to advise Company that it desires to be interrupted. Further, in the event that the buy-though price exceeds the Customer-specified price, Customer may nevertheless elect to buy though the interruption by providing the Company with the required notice within 45 minutes.

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CAPACITY INTERRUPTION:

Company shall have the right to call a Capacity Interruption for one or more Customers at any time when Company believes, in its sole discretion, that generation or transmission capacity is not sufficiently available to serve its firm load obligations, other than obligations to make intra-day energy sales. Capacity Interruptions will typically be called when the Company forecasts or, on shorter notice, has presently scheduled all available energy resources that are not held back for other contingency or reserve purposes, to be online generating to serve obligation loads. The Capacity Interruption may be activated to enable the Company to maintain Operating Reserves, consisting of spinning and non-spinning reserves, ensuring adequate capability above firm system demand to provide for such things as regulation, load forecasting error, equipment forced outages and local area protection. A Capacity Interruption may be called to relieve transmission facility overloads, relieve transmission under voltage conditions, prevent system instability, relieve a system under frequency condition, shed load if SPS is directed to shed load by the Southwest Power Pool (or subsequent regional reliability organization) Reliability Coordinator, and respond to other transmission system emergencies.

The duration of any Capacity Interruption shall not be less than four hours, unless Customer has opted to waive the four-hour minimum duration and, in such case, the duration shall not be less than one hour. In addition, a single interruption of less than four hours is permitted for any Customer, if the Customer has less than four hours remaining of its Number of Interruptible Hours.

CONTINGENCY INTERRUPTION: Company shall have the right to call a Contingency Interruption for one or more Customers receiving service under the No Notice Option at any time when the Company believes, in its sole discretion, that interruption is necessary for the Company to be able to meet its Disturbance Control Standard (DCS) criteria. Contingency Interruptions will typically be called by the Company following the unexpected failure or outage of a system component, such as a generator, transmission line or other element. Interruptible loads that are qualified as Contingency Reserve may be deployed by the Company to meet current or future North American Electric Reliability Corporation (NERC) and other Regional Reliability Organization contingency or reliability standards. The current standard is the DCS, which sets the time limit following a disturbance within which a Balancing Authority (BA) must return its Area Control Error (ACE) to within a specified range. In other words, a Contingency Interruption will be activated to help restore resources and load balance after an unexpected resource outage.

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The duration of any Contingency Interruption shall not be less than four hours, unless Customer has opted to waive the four-hour minimum duration and, in such case, the duration shall not be less than one hour. In addition, a single interruption of less than four hours is permitted if Customer has less than four hours of interruption available to use the remaining hours.

FAILURE TO INTERRUPT

Economic Interruption - In the event that Customer fails to interrupt during an Economic Interruption, Customer will be deemed by the Company to have failed to interrupt for all demand that Customer was obligated to interrupt, but did not. The failure-to-interrupt charge shall be equal to the highest incremental price for power during the Economic Interruption plus three mils per kWh, as determined by the Company after the fact, including market costs, unit start-up costs, spinning reserve costs and reserve penalty costs, if any. The charge will only apply to the portion of the load Customer fails to interrupt.

Capacity or Contingency Interruption - In the event Customer is directed to interrupt and fails to comply during a Capacity or Contingency Interruption, Customer shall pay the Company fifty percent (50%) of Customer's expected annual credit rate times the maximum 30 minute demand recorded during the event for all demand that Customer was obligated to interrupt, but did not. The penalty will apply only to the portion of the load that Customer fails to interrupt. After Customer fails to interrupt twice, the Company shall have the option to cancel the Agreement. If the Agreement is cancelled by the Company, Customer shall not be eligible for service under this tariff for a minimum of one year, and Customer will not be liable for the payment of 110% times the Customer's CIL, times Customer's MCR for each of the remaining months of the unexpired contract term, as previously specified under term of agreement, service periods, and termination of agreement by customer. For determining compliance during a Capacity or Contingency Interruption, the first and last fifteen-minute interval of each event shall not be considered. If Customer's violation is less than 60 minutes in duration, not including the first and last control period intervals, then Customer's penalty shall be: (1) be reduced by 75% if the violation is 15 minutes or shorter; (2) reduced by 50% if the violation is 16 to 30 minutes in duration; and (3) reduced by 25% if the violation is 31 to 59 minutes in duration. This provision does not apply to Economic Interruptions.

If Customer is a No Notice Option Customer and Company controls Customer's load through the operation of a Company installed, operated, and owned disconnect switch, in the event that Customer violates a Capacity or Contingency Interruption, Customer shall not be penalized unless evidence of tampering or bypassing the direct load control of Company is shown.

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Capacity or Contingency Interruption (cont.) -In the event that Company issues a Capacity or Contingency Interruption during a time in which the Customer's phone line is not working, the above described penalties shall apply if Customer fails to comply with the interruption.

BILLING AND MONTHLY CREDIT:

A Customer electing to take service under this tariff shall be billed on a calendar month basis, such that the first day of each month shall be the beginning and the last day of each month shall be the end of the monthly billing period. Company shall apply a Monthly Credit to Customer's monthly bill, pursuant to the terms and conditions specified herein.

The Customer's Monthly Credit shall be calculated by multiplying the applicable Monthly Credit Rate (MCR), as shown on the following table, by the lesser of the Customer's CIL, or the actual Interruptible Demand, during the billing month. The applicable MCR is determined by how the Customer is connected to the grid, the Number of Interruptible Hours (Ha) selected by the Customer in the Agreement, and the season of the year.

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Monthly Credit Rate (MCR)

		ONE HOUR NOTICE OPTION		NO NOTICE OPTION	
Ha	GRID CONNECTION	WINTER PER kW MONTH CREDIT	SUMMER PER kW MONTH CREDIT	WINTER PER kW MONTH CREDIT	SUMMER PER kW MONTH CREDIT
40	SUB-TRANSMISSION	$1.58	$2.25	$1.84	$2.62
	BACKBONE-TRANSMISSION	$1.57	$2.23	$1.83	$2.59
80	SUB-TRANSMISSION	$2.63	$3.74	$3.06	$4.34
	BACKBONE-TRANSMISSION	$2.61	$3.70	$3.03	$4.30
160	SUB-TRANSMISSION	$4.03	$5.73	$4.68	$6.65
	BACKBONE-TRANSMISSION	$3.99	$5.67	$4.64	$6.58

Contract Interruptible Load (CIL) - Customer's CIL is the median of Customer's maximum daily thirty (30) minute integrated kW demands occurring between the hours of 12:00 noon and 8:00 p.m. Monday through Friday, excluding federal holidays, during the period June 1 through September 30 of the prior year, less the Contract Firm Demand, if any. If Customer has no history in the prior year or Customer anticipates that its CIL for the upcoming year will exceed the prior year's CIL by one hundred (100) kW or more, at Customer's request, Company may, in its sole discretion, estimate the CIL. In extraordinary circumstances, Company may calculate CIL using load data from the year prior to the year normally used to calculate the CIL, if Customer has shown that, due to extraordinary circumstances, the load data that would normally be used to calculate its CIL is less representative of what Customer's load is likely to

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Contract Interruptible Load (CIL) (cont.) –
be in the upcoming year. For existing Customers, Company shall calculate Customer's CIL to be used in the upcoming year by December 31st of the current year. If the Company determines that Customer's CIL to be used in the upcoming year is less than 500 kW, then the Agreement shall terminate at the end of the current year. If the Company determines that the combined CIL of all existing Customers to be used in the upcoming year exceeds 85MW, then those existing Customers whose CIL is greater than the prior year's CIL may be required to reduce their CIL (by increasing their Contract Firm Demand) proportionally, so that total CIL does not exceed 85MW.

Interruptible Demand –Customer's Interruptible Demand is the maximum thirty (30) minute integrated kW demand, determined by meter measurement, that is used during the month, less the Contract Firm Demand, if any, but not less than zero. Interruptible Demand is measured between the hours of 12:00 noon to 8:00 p.m. Monday through Friday, excluding federal holidays.

Application of Monthly Credit - the Monthly Credit shall be applied to Customer's monthly bill beginning in January if the Agreement was executed prior to that January. If the Agreement is executed between January 1 and May 1, to be effective in that year, the Monthly Credit will begin in the month following the month in which service begins. If the Agreement is executed after May 1, the Monthly Credit will begin in January of the following year. In the event that Customer's CIL is estimated, the Monthly Credit applicable to the estimated CIL will be applied to Customer's December bill, after the CIL calculation is completed for that year. For Customers with no history, the entire accumulated Monthly Credit will be credited to the December bill. For Customers with history, but who estimate an increase, accumulated credits attributable to the estimated increase in the CIL will be credited to the December bill and credits attributable to the actual CIL will be credited monthly.

PHONE LINE REQUIREMENTS:

Customer is responsible for the cost of installing and maintaining a properly working communication path between Customer and Company. The communication path must be dedicated. Options for the communication path include, but are not limited to, a dedicated analog phone line to the meter location. The communication path must be installed and working before Customer may begin taking service under this rate schedule.

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PHONE LINE REQUIREMENTS (Cont.):

In the event that the Company issues a Capacity or Contingency interruption during a time in which Customer's phone line is not working, the penalties detailed in the section of this tariff titled FAILURE TO INTERRUPT – Capacity and Contingency Interruptions, shall apply if Customer fails to comply with the interruption.

COMMUNICATION AND PHYSICAL CONTROL REQUIREMENTS FOR NO NOTICE OPTION CUSTOMERS:

A No Notice Option Customer must install and maintain a Company specified dedicated phone line to the meter location. In addition a No Notice Option Customer must also pay for the communication charges associated with the Company specified communication equipment installed in the Remote Terminal Unit (RTU) used to receive and transmit interruption signals and real time usage information.

A No Notice Option Customer shall either:

(i) utilize its own Energy Management System (EMS) automated intelligent equipment to reduce load down to the Contract Firm Demand level when requested by Company. Customer will pay for the cost of an RTU that will receive the interruption and restore signals via phone or cellular communication. The RTU shall be designed, purchased, installed, and tested by Company or Company contractor at Customer's expense. Customer must demonstrate that its automated intelligent device or equipment will receive Company's signal and automatically act upon that signal to remove load down to the Contract Firm Demand level within a time period to be specified in the Agreement. A $1,000 non-refundable contribution is required to perform the engineering and design work required to determine the costs associated with purchasing and installing the RTU;

or

(ii) utilize a Company owned and operated switch to remove Customer's entire load during a Capacity or Contingency Interruption. Use of a Company switch requires that Customer have no Contract Firm Demand. Customer must pay for the cost of Company-owned switch and an RTU that will receive the interruption and restore

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COMMUNICATION AND PHYSICAL CONTROL REQUIREMENTS FOR NO NOTICE OPTION CUSTOMERS (cont.): signals via phone or cellular communication, and lock Customer's load out during a Capacity or Contingency Interruption. The RTU shall be designed, purchased, installed, and tested by Company at Customer's expense. A $1,000 non-refundable contribution is required to perform the engineering and design work needed to determine the costs associated with providing Company physical control over Customer's load. A minimum of six (6) months is required to design, order, install and test the required equipment to give the Company control over Customer's load. During a Capacity or Contingency Interruption, the Company shall lock out Customer's load to prevent Customer from terminating the interruption before release. This option is not available if Customer receives secondary service from the Company.

A No Notice Option Customer shall submit to equipment testing at least once per year at Company's discretion, provided no other Capacity or Contingency events occurred in the past 12 months that could be used to verify the correct operation of the disconnect equipment and RTU. Equipment testing may last less than the four-hour duration and may not count toward Customer's Number of Interruptible Hours.

TAMPERING:

If Company determines that its load management or load control equipment on Customer's premises has been rendered ineffective due to tampering by use of mechanical, electrical, or other devices or actions, then Company may terminate Customer's Agreement, or remove Customer from the No Notice Option and place Customer on the One Hour Notice Option rate for a minimum one-year period. The Customer's credits will be adjusted accordingly. In addition, Customer may be billed for all expenses involved with the removal, replacement or repair of the load management equipment or load control equipment and any charges resulting from the investigation of the device tampering. Customer shall also pay 50% of the expected annual credit rate, times the maximum 30 minute demand recorded during the interruption event for all demand Customer was obligated to interrupt, but did not. The penalty will apply only to the portion of the load that Customer fails to interrupt. A Customer that is removed from the program is only eligible to participate again at the discretion of Company. Company will verify installation has been corrected before Customer is permitted to participate in the program again.

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INTERRUPTIBLE CREDIT OPTION

LIMITATION OF LIABILITY:

Customers who elect to take service under this tariff agree to indemnify and save harmless Company from all claims or losses of any sort due to death or injury to person or property resulting from interruption of electric service under this tariff or from the operation of the interruption signal and switching equipment.

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REGIONAL VICE PRESIDENT RATES AND REGULATORY AFFAIRS

DOCKET NO. 44941

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

JAMES SCHICHTL

FOR

EL PASO ELECTRIC COMPANY

AUGUST 2015

The "operating season" is defined as beginning September 1st of each year (or such date later that a new customer begins service) and extending for at least three (3) months and until April 30 of the following year (eight (8) months maximum).

Q. WHAT CHANGES ARE PROPOSED FOR RATE NO. 34 – COTTON GIN SERVICE RATE?

A. EPE currently has two customers remaining on Rate No. 34. EPE is not proposing any changes in the rate structure as it currently exists, except to adjust the customer charge to full cost and revise rate levels for the revenue increase assigned the rate class. EPE plans to work with the existing customers to evaluate the long term necessity for this rate class and whether the customers may instead be served on a standard commercial rate.

T. <u>Interruptible Power Service</u>

Q. PLEASE DESCRIBE THE EXISTING STRUCTURE OF RATES OFFERED UNDER RATE NO. 38 – NOTICED INTERRUPTIBLE POWER SERVICE.

A. Noticed Interruptible Service is available to current customers with total connected capacity requirements of at least 1,000 kW and not served at a transmission voltage level, and at the sole discretion of EPE. Currently, there are 8 customers taking service under this rate. The minimum level of firm demand required from qualifying customers is 500 kW. Customers can take service on a calendar year basis only, and 60 to 90 days notice is required for termination of service without invoking penalty provisions. Service is available under this schedule only if such service is capable of being interrupted at any time upon request without damage to property or persons and without adversely affecting the public health, safety, and welfare. This schedule is available only in conjunction with firm service under other applicable rate schedules.

The current rate structure provides reduced seasonal demand and energy charges applicable to the interruptible portion of the customers load. The remaining portion, the "firm service" load, is billed under the otherwise applicable retail rate determined based on the customers total load requirements.

Interruptible customers effectively provide a capacity resource equal to the difference between their contracted firm service level and their full load requirement. Within 30 minutes of a notice by EPE to interrupt, the customer is required to reduce their demand to their firm service level, subject to penalties provided for in the tariff.

Q. WHAT CHANGES ARE PROPOSED FOR RATE NO. 38 – NOTICED INTERRUPTIBLE POWER SERVICE?

A. EPE is proposing to close Rate No. 38 to new customers and modify existing charges as described below.

EPE is proposing to modify the interruptible demand charge based upon EPE's calculated current avoided capacity costs, and maintain the energy charge at the level currently in effect. These changes are designed: (1) to more accurately reflect the avoided cost benefits for this service; (2) to ensure that loads served under this rate support the allocated cost of transmission and distribution facilities serving them; and (3) to ensure that loads served under this rate provide a reasonable contribution to system production costs.

Q. WHY IS EPE CLOSING INTERRUPTIBLE SERVICE TO NEW CUSTOMERS?

A. Interruptible or non-firm service is intended to provide a capacity resource during a system emergency. Under certain conditions, as defined in the tariff, EPE may interrupt service to participating customers, thereby freeing up additional generation capacity to serve firm service customers and potentially avoid service interruptions or more serious system emergencies. In its current Loads and Resources planning document, EPE assumes 52 MW of interruptible capacity is available from participating customers in Texas and New Mexico. This amount is judged to be sufficient at present, given the availability of generation and other resources and EPE's load requirements. In addition, interruptible service is closed in EPE's New Mexico service territory and, because it represents a system resource, it is reasonable to be consistent in treatment across jurisdictions. Finally, until such time that interruptible rates reflect a discount equal to the avoided cost of peaking capacity that the resource is used to replace, it would be unfair to firm service customers to expand the amount of interruptible load on EPE's system.

Q. HOW DOES INTERRUPTIBLE CAPACITY COMPARE WITH OTHER RESOURCES IN TERMS OF PRICE AND AVAILABILITY?

A. Generally speaking, interruptible capacity is beneficial because it is available on relatively short notice. Participating customers are required to respond to a request for interruption within 30 minutes, otherwise subject to penalty. This is a shorter response time than much of EPE's older local generation, but significantly slower than the new gas-fired combustion turbines located at the Rio Grande Power Plant and Montana Power Station. Because they are comparable in this respect, the avoided cost of these gas-fired units approximates the appropriate price discount for interruptible service. Although EPE is proposing to increase interruptible rates, as discussed below, the rate discount will continue to exceed the cost of the generating unit "avoided" through use of the interruptible program.

Q. PLEASE EXPLAIN HOW EPE CALCULATED THE PROPOSED INTERRUPTIBLE DEMAND CHARGE.

A. Noticed Interruptible Power Service rates were designed to provide an increase in the base revenue recovered from non-firm service equivalent to EPE's requested base rate increase.

A full cost based interruptible demand charge would be produced by subtracting avoided production capacity cost from the full-cost demand charge for firm service. EPE uses the Large Power rate group as the firm service rate class upon which interruptible charges are based. The avoided production capacity cost estimate utilizes Rio Grande Power Plant Unit 9 costs as a real-world proxy for capacity most closely approximating the characteristics of interruptible load. By determining demand charges in this way, energy charges reflect only variable costs allocated to the Large Power rate class, including fuel in base and variable O&M costs. Development of the avoided capacity credit for production and interruptible credit is shown in Workpaper Q-7.

EPE proposes to move existing interruptible demand charges towards the full cost level by scaling the existing voltage differentiated demand charges by 16.6 percent, which is EPE's requested increase in base revenues in this case. This reduces the amount of credit implicit in demand charges towards the true avoided cost level. The revised rates provide Noticed Interruptible customers with a level of credit that reflects the capacity benefit these customers provide by allowing their service to be interrupted. This interruptible capacity allows service to be maintained to firm loads during periods of generation or transmission capacity constraints.

Q. WHAT IS THE IMPACT ON EXISTING NOTICED INTERRUPTIBLE CUSTOMERS OF THE CHANGES EPE IS PROPOSING?

A. The combination of the increase in base revenues allocated to the Large Power rate group, which determines the firm service charges paid by interruptible customers, and the proposed interruptible rate design change determines the increase for interruptible service customers. The net impact of the changes in interruptible rates is a function of the customer's firm service level and changes in the Large Power rate structure. Mitigating these increases is the reduction in hours of possible interruption to which the customer is exposed.

Q. WHY IS IT REASONABLE TO PROPOSE A LARGE INCREASE FOR THE NOTICED INTERRUPTIBLE POWER SERVICE RATE?

A. Interruptible service provides an optional rate that presents an opportunity for larger customers to reduce costs by electing non-firm service for a portion of their total requirements. However, due to the fact that this is an optional service, firm customers should not be required to unduly subsidize these customers (beyond avoided capacity cost savings). The proposed rate for interruptible service reflects the value of interruptible loads to the firm customers on EPE's system and reflects the same gradual approach to full cost rates that EPE is exercising with firm service customers.

Q. PLEASE DESCRIBE THE NON-COMPLIANCE PROVISIONS.

A. The Company relies on Noticed Interruptible customers to reduce their load to their firm level during the times when it is necessary to invoke interruptions and compensates customers based on that understanding. Interruptible customers are essentially billed a lower rate for "non-firm" service, or service not subject to the expected availability of firm service.

The non-compliance provision states that if a customer does not fully comply with an interruption request, the non-complying customer's total load will be billed under the standard, firm rate for the month in which a first non-compliance occurs. This provision essentially rebills the customer for the month as if they were a firm service customer. If a second non-compliance occurs during a calendar year, the customer's total load for all months through the second non-compliance of the calendar year will be billed or rebilled under the standard firm rates. If a third non-compliance event occurs in a calendar year, the customer's total load would be billed under the standard, firm rate for all remaining months of the calendar year and the customer will not be permitted to take service under the Noticed Interruptible Service tariff for a minimum of 12 months.

EPE does not propose to change the terms of the non-compliance provision. However, EPE has proposed language changes to more clearly state the applicable penalties set forth within the non-compliance provision.

Q. DOES EPE EXPECT THAT THESE PROPOSED CHANGES WILL RESULT IN CUSTOMERS DECIDING TO LEAVE NOTICED INTERRUPTIBLE SERVICE?

A. No. While the percentage increase for the class of interruptible customers as a whole is greater than that for firm service load, the average rate paid by these customers is still lower than what they would pay, on average, for full firm service. The demand charge discounts provided are based on the value of capacity on EPE's system, which ensures that other ratepayers are not significantly disadvantaged by provision of capacity by interruptible customers versus purchases by EPE. Thus the rates are fair to both interruptible customers and the other customers who pay for firm service and benefit from the availability of the capacity resource provided.

SOAH DOCKET NO. 473-15-5257
PUC DOCKET NO. 44941

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S FIFTH REQUEST FOR INFORMATION QUESTION NOS. OPUC 5-1 THROUGH OPUC 5-30

OPUC 5-5:

Please provide documentation of El Paso's standard regarding vegetation management (including but not limited to clearance maintained between line and tree at time of trim and any differences in trimming practices for primary lines, secondary lines, and services).

RESPONSE:

Please see OPUC 5-005 Attachment.

Preparer: Omar Gallegos Title: Manager-Asset Management Services

Sponsor: R. Clay Doyle Title: Vice President-T&D and System Planning

El Paso Electric Company

Vegetation Management Report

P.U.C. SUBST. R. 25.96

May 1, 2015

Project No. 41381

El Paso Electric

El Paso Electric Company
100 N. Stanton
El Paso, Texas 79901

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I. INTRODUCTION

El Paso Electric Company ("EPE") files this report in response to the requirements by the Public Utility Commission of Texas Substantive Rule § 25.96 to file by May 1, 2015, a written report related to Distribution Vegetation Management. Pursuant to paragraph (e) of Rule § 25.96, EPE maintains a Vegetation Management Plan for distribution assets. A full copy of the plan is available to the Commission or Commission Staff upon request. This report summarizes that plan.

EPE's service territory encompasses both desert and river valley areas, thus creating a fairly diverse population of trees. The Rio Grande River Valley has significant agricultural activity associated with large pecan orchards. Other tree-related issues in the Valley areas are in residential subdivisions where trees grow along irrigation canals and planted trees grow fairly rapidly. Development in the desert areas presents some tree-related issues due to customers' landscaping efforts which, while significant, are not of the magnitude of that in the Valley.

II. EPE'S VEGETATION MANAGEMENT PLAN

A. Maintenance Goals and Progress

EPE's Maintenance goals are based on two objectives: Minimize tree-related issues on its 10% worst performing feeders and commit to a 3-year trimming cycle in high tree density feeders and/or geographic areas.

EPE measures the above goals by first identifying the top 10% worst feeders by the end of the preceding year and scheduling the work in January of the working year. The goal is measured on a quarterly basis and is part of the Tree Trimming Supervisor's performance goals.

B. Clearances and Scheduling

EPE applies American National Standards Institute ("ANSI") Standard Z 133.1 as a guide to pruning activities necessary for defining adequate clearances between energized facilities and trees. EPE's application of this standard is intended to account for the three main concerns related to tree trimming: (1) public safety; (2) reliability; and (3) prevention of equipment damage. EPE's top priority is ensuring public safety. Trees contacting energized power lines create a potentially hazardous situation to the public, as human contact with trees making contact with power lines can provide an alternate path to ground for fault current through the individual. If practical, pruning methods are based on procedures and examples set forth by ANSI Standard Z 133.1. As a general rule, trees are pruned to improve or re-establish the clearance provided from previous tree maintenance performed.

To meet the requirements of Occupational Safety Health Administration ("OSHA") Standards 1910.269 and .333 and applicable state regulations, EPE applies American National Standards Institute Standard Z-133.1 as a guide for pruning. Under these standards, non-qualified personnel should not be within ten feet of an energized power line, and EPE tries to minimize the opportunity for that to occur.

Each individual tree is assessed to determine adequate clearance required from the conductor to better prevent threats to public safety, service interruption and damage to EPE facilities.

The tree trimming work is scheduled based on the SAIDI-SAIFI indexes on the 10% worst performing feeders. As a norm, the higher indexed feeders are scheduled first along with other geographical related feeders. In addition, the feeders furthest from the 3-year cycle are taken into consideration.

C. Remediation of Vegetation Issues on Worst Performing Feeders

The top 10% Worst Performing Feeders are initially identified late in the year preceding the work-related year. The feeders are listed in both SAIDI and SAIFI categories based on the data gathered from EPE's Outage Management System.

D. Tree Risk Management Program

Due to EPE's low tree density in its overall service territory, EPE does not have a Tree Risk Management Program. For the most part, any tree that may fall in this category will be identified when the feeder is inspected by either an EPE troubleman or a tree-trimming planning contractor.

E. Adverse Environmental Conditions

Due to EPE's low tree density and dry desert climate in its overall service territory, EPE does not have a different approach for vegetation issues during droughts or other adverse environmental conditions.

F. Distribution Miles

EPE has a total of 2,986 distribution miles in its Texas service territory.

G. Electric Points of Delivery

EPE has a total of 304,477 service points.

H. Achieving Vegetation Maintenance Goals

The work pertaining to the 10% worst performing feeders is tracked based on two methods. First, all tree trimming calls are entered into an EPE database which tracks all pertinent information including feeder identification. Secondly, a feeder map from EPE's GIS data system is created and the work is identified by the tree trimming planner. The progress is reviewed on a quarterly basis. EPE's vegetation management contractor has a performance-based contract that includes a productivity goal to help exceed or maintain the previous year's progress.

I. Vegetation Management Budget

The budget for vegetation management in Texas, for 2015, is approximately $1,230,000. At this time, EPE's budgeting process does not allow for separation of costs as outlined in paragraph (f)(1)(I) of Rule § 25.96.

III. IMPLEMENTATION SUMMARY FOR 2014

A. Maintenance Goals

EPE's goals are based on two objectives: Minimize tree related issues on its 10% worst performing feeders and commit to a 3 year trimming cycle in high vegetation dense feeders and/or geographic areas.

EPE met its goal on the 10% worst performing feeders for 2014. While some of the feeders did not have high vegetation issues, they were still patrolled and inspected. EPE's 3-year trimming cycle is a work in progress due to cycle breakers like mulberry trees which grow at a much faster rate than other native trees.

EPE's goals remain the same for 2015.

B. Strategy Successes and Challenges

EPE completed its 10% Worst Performing feeders for 2014 without any major incident or accident. EPE's contractor's performance metric was higher than the previous year.

Some of the challenges EPE faces are access and scheduling. Most of EPE's feeders with vegetation run along fence lines and are in backyards so trees have to be climbed and access to these yards require scheduling because customers are not home and gates are locked. Although interference from property owners is at a minimum, when it does arise, it is resolved quickly.

For the scheduling issue, the contractor's planner will contact customers in person or by leaving a door hanger, if the customer is not home. If the contractor is denied access, the contractor supervisor will meet with the customer and try to gain access. If the contractor is still denied, EPE will contact police to speak to the customer and explain the laws and safety issues concerning their trees.

C. Remediation of Vegetation Issues on Worst Performing Feeders

At the beginning of each year, a list of the 10% worst performing feeders is compiled by Distribution Dispatch. These feeders are then evaluated to see if a vegetation problem could be a contributing factor to the feeder's poor performance in the preceding year. EPE made good progress on clearing any vegetation issues and was also able to clear any other potential problems.

D. Continuing Education Hours

In 2014, EPE's internal vegetation management personnel logged **12** hours in continuing education.

E. Vegetation Management Work to Achieve Vegetation Management Goals

EPE measures the goals by first identifying the top 10% worst feeders by the end of the preceding year and scheduling the work in January of the working year. The goal is measured on a quarterly basis and is part of the Tree Trimming Supervisor's performance goals.

F. SAIDI and SAIFI Scores for Vegetation-Caused Interruptions for Each Month

See attached spreadsheet.

G. 2015 Vegetation Management Budget

(i) Budget

The 2015 budget for Vegetation Management in Texas is approximately $1,230,000. At this time, EPE's budgeting process does not allow for separation of cost as outlined in paragraph (1)(I).

(ii) Variation From Preceding Year's Vegetation Management Budget

Any variations from the 2014 vegetation management budget were due to invoice delays.

(iii) Total Vegetation Management Expenditures Divided By The Number Of Electric Points Of Delivery On The Utility's System, Excluding Service Drops

4.04

(iv) Total Vegetation Management Expenditures, Including Expenditures From the Storm Reserve, Divided By the Number of Customers the Utility Served

4.04; storm reserve expenditures are not separated out of the budget.

(v) The vegetation management budget from the utility's last base-rate case.

EPE's last rate case was settled and no specific amount was stated for a vegetation management budget.

CATEGORY	INDEX1	ANNUAL	January	February	March	April	May	June	July	August	September	October	November	December
TX Forced/Feeder	SAIFI	12.3309648	0.00905	0.43224	1.20870	0.68230	1.18740	0.22900	1.20693	1.16243	2.73364	1.17075	2.26303	0.04549
[redacted]														

SAIDI (Duration of Outage in Mins)*(Customers affected on the outage)/Customers on that feeder
SAIFI (Number of customers on the outage)/(Number of customers on that feeder)

Vegetation caused outages are responsible for 7.00% of total system outages in Texas

Data for this summary was extracted from the Service Quality Report filed Februaty 14, 2015.

Monthly Load Report for Texas

Distribution Systems Engineering Department

Substation Name	Feeder	Distribution Voltage (KV)	Maximum Capacity Available (KVA)	2014 Peak Demand	2013 Peak Demand		DG kW Att 4	DG % of peak*	No DG =1	Non-Texas with	DG kW
Alamo	ALM-20	23 9	9600	4193	7007			0.000%	1	AIR20	564.8
Alamo	ALM-21	23.9	9600	2699	8834			0.000%	1	AIR22	510.0
Altura	ALT-1	4 16	2260	776	961			0.000%	1	ALA01	33.8
Altura	ALT-2	4 16	2260	509	576	ALT02	3.3	0.652%	0		
Altura	ALT-3	4.16	1800	1358	1422			0.000%	1		
Altura			2260	1795	1902	ALT04	7.5	0.418%	0		
Altura			1800	1504	1614			0.000%	1		
Altura			1800	1164	1403			0.000%	1		
Americas	A		10000	10856	8563			0.000%	1		
Americas	AMR-11		10000	10810	12221	AMR11	52.0	0.477%	0		
Americas	AMR-12		10000	9263	8563	AMR12	5.4	0.058%	0		
Anthony	ANT-20		17250	12800	13343	ANT20	9.4	0.073%	0		
Anthony	ANT-22		17250	15100	14690	ANT22	130.2	0.863%	0	ANT21	60.5
Ascarate	ASC-1		3000	727				0.000%	1		
Ascarate	ASC-2		3000	902				0.000%	1	ANT23	91.8
Ascarate	ASC-3		3000	2634				0.000%	1	ARR20	352.9
Ascarate	ASC-4		3000	2316				0.000%	1	ARR21	200.3
Ascarate	ASC-10		10000	12257	10108			0.000%	1	ARR22	337.7
Ascarate	ASC-11		10000	7958	7476	ASC11	5.1	0.064%	0	ARR23	385 6
Ascarate	ASC-12		10000						1		
Ascarate	ASC-13		10000	10867	7828	ASC13	6 8	0.062%	0		
Ascarate	ASC-14		10000	9162				0.000%	1		
Austin	AUS-1		1440		1681	AUS01	13.9	0.827%	0		
Austin	AUS-2		2880		1845			0.000%	1		
Austin			1440		1787			0.000%	1		
Austin			2880		2652	AUS04	10 9	0.410%	0		
Austin			9970	11508	10526			0.000%	1		
Austin			9970	3772	3586			0.000%	1		
Austin			9970	10194	6847	AUS12	5.6	0.055%	0		
Austin			9970	5501	6801			0.000%	1		
Austin			9970	4472	5560			0.000%	1		
Austin			12000	8314	7948	AUS15	48.3	0.581%	0		
Austin	AUS-16		9970	8909	7814	AUS16	10.2	0 115%	0		
Austin	AUS-17		9970	7454	5113	AUS17	4.1	0.055%	0		
Austin	AUS-18		9970						1		
Beaumont	BEA-1		2880	2717	2555	BEA01	7.4	0.271%	0		
Butterfield	BFD-10		10000	3218	3546			0.000%	1		
Butterfield	BFD-11		10000	4750	4462			0.000%	1		
Butterfield	BFD-12		10000	4000	3832			0.000%	1		
Butterfield	BFD-13		10000	1513	1451			0.000%	1		
Butterfield	BFD-14		10000	10350	10739			0 000%	1		
Butterfield	BFD-15		10000	4016		CAL10	60.3	1.502%	0		
Caliente	CAL-10		10000	9866	10646	CAL11	315.6	3.199%	0		
Caliente	CAL-11		10000	10402	9443			0.000%	1		
Caliente	CAL-12		10000	2679				0.000%	1		
Canutillo	CAN-01								1		
Chaparral	CHA-10		10000	8900	7482	CHA10	22.8	0.257%	0		
Chaparral	CHA-11		10000	10960	13243	CHA11	31.3	0.285%	0	CHA12	10000.0
Chaparral	CHA-13		10000	4570				0 000%	1	CHA14	53.6
Cielo	CIE-01					CIE01	19.4		0		
Cineque	CIN-01		2500		2814			0 000%	1	CLA01	19.6
Clint	CLI-11		10000					0.000%	1		
Clint	CLI-12		10000			CLI12	15.4	0.189%	0		
Copper	COP-10		10000		5705			0.000%	1		
Copper	COP-11		10000		1428	COP11	50.0	3.501%	0		
Copper	COP-12		10000		9173			0.000%	1		
Coronado	COR-01		2625	2018	2229	COR01	6.3	0 314%	0		
Cotton	COT-01				1579			0.000%	1		
Coyote	COY-10		10000	11368		COY10	5.1	0.045%	0		
Coyote	C		10000	4901		COY11	9.3	0.190%	0		
Cromo	C		10000	7600	7930			0.000%	1		
Cromo	CRO-11		10000	8000	9963	CRO11	8.4	0 105%	0		
Cromo	CRO-12		10000	8594	8701	CRO12	14.9	0.174%	0		
Cromo	CRO-13		10000	3911	3380	CRO13	91.3	2.336%	0		
Cromo	CRO-14		10000	2819	7237			0.000%	1		
Cromo	CRO-15		10000	8000	8988	CRO15	37.4	0.467%	0		
Dallas	DAL-01		1875		1715			0.000%	1		
Dallas	DAL -02		1875		908			0.000%	1		
Dallas	DAL-11		9970	5385	4592	DAL11	56.1	1.041%	0		
Dallas	DAL-12		9970	5560	5434	DAL12	5.3	0.095%	0		
Dallas	DAL-13		9970	4494	4157			0.000%	1		
Dallas	I		9970	6590	4026			0.000%	1		

Monthly Load Report for Texas

Distribution Systems Engineering Department

Substation Name	Feeder	Distribution Voltage (KV)	Maximum Capacity Available (KVA)	2014 Peak Demand	2013 Peak Demand		DG kW Att 4	DG % of peak*	No DG =1	Non-Texas with	DG kW
Dallas	DAL-17	13.8	9970	6280	5069			0 000%	1		
Diamond Head	DHD-10	13.8	10000	3980		DHD10	17.2	0.432%	0		
Diamond Head	DHD-11	13.8	10000	5943		DHD11	3.3	0.056%	0		
Diamond Head	DHD-12	13.8	10000	3257		DHD12	6.7	0.206%	0		
Diana	DIA-01		2500		1727	DIA01	2.3	0.132%	0		
Diana	DIA-03		2800	2038	1998	DIA03	5.0	0.245%	0		
Durazno	DUR-10		10000	10426				0.000%	1		
Dyer	D'		10000	13120	16362	DYR11	15.4	0.117%	0		
Dyer	D'		10000	5290	1325			0.000%	1		
Dyer	D'		10000	18677	6060	DYR13	5.3	0.027%	0		
Dyer	D		10000	12373	7719	DYR14	392.0	3.168%	0		
Dyer	D		10000	5094	8208			0.000%	1	ESP01	28.4
East	EAS-01	4 16			1242			0.000%	1	ESP02	18.3
Fabens	FAB-1	4 16	1440						1		
Fabens	FAB-2	4 16	2880		2479			0.000%	1		
Farah	FRH-11	13 8	10700	5556				0.000%	1		
Farah	FRH-12	13.8	10700	6329				0.000%	1		
Farah	FRH-13	13 8	10700	2948				0.000%	1		
Farmer	FAR-21	23 9	5000	6453	5075			0.000%	1		
Felipe	FEL-20	23 9	-	6966	4376	FEL20	200.7	2.881%	0		
Five Points	FPT-01	4.16	1440		1134			0.000%	1		
Five Points	FPT-02	4.16	1440		922	FPT02	10.2	1.106%	0		
Five Points	FPT-03		1440		980	FPT03	10.8	1.103%	0		
Five Points	FPT-04		1440		1249			0.000%	1		
Fresno	FRE-1		1440		1162			0.000%	1		
Frontera	FRO-01		1440	1434	1470	FRO01	26.6	1.851%	0		
Ft. Hancock	FTH-01					GLO10	6.5	#DIV/0!	0		
Global Reach	GLO-10		14000	10030				0.000%	1		
Global Reach	GLO-11		14000	12183		GLO11	17.9	0.147%	0		
Global Reach	GLO-12		14000	535				0.000%	1		
Grace	GRA-01		1725	970	1153	GRA01	8.9	0.920%	0		
Hacienda	HAC-1		3300		1403	HAC01	6.2	0.445%	0		
Hacienda	HAC-2		3300		1518			0.000%	1	HAT20	37.5
Horizon	HOR-10		14000	10123	7297	HOR10	23.4	0.231%	0		
Horizon	HOR-11		14000	11266	10395	HOR11	20.5	0.182%	0		
Horizon	HOR-12		14000	8506	6212	HOR12	57.7	0.678%	0		
Kemp	KEMP-01		1725		1105	KEM01	5.0	0.452%	0	JOR20	347.2
Lane	LAN-11		10500	7254	7917	LAN11	11.1	0.152%	0	JOR21	145.2
Lane	LAN-12		10500	4473	3988	LAN12	30.0	0.671%	0		
Lane	LAN-13		11200	8464	11071			0.000%	1	LAC01	12.7
Lane	LAN-14		8500	4980				0.000%	1	LAC02	5.0
Latta	LTT-01		1750		1465			0.000%	1	LAC20	134.7
Leo	LEO-01		3125	3129	3113	LEO01	16.0	0.511%	0	LAC21	131.5
Leo	LEO-02		1500	485	847			0.000%	1	LAC22	47.1
Leo	LEO-11		10000	7350	6804	LEO11	26.4	0.359%	0	LAC23	76.8
Leo	LEO-12		10000	11260	9278	LEO12	174.9	1.553%	0	LAC24	1231.8
Leo	LEO-13		10000	4000	3775			0.000%	1	LAC25	192.0
Leo Temp	LET-10		16000	2825				0.000%	1	LAC26	27.9
Lomaland	LOM-1		2500			LOM01	6.6		0	LAC27	59.7
Lomaland	LOM-2		2500		1100	LOM02	7.0	0.636%	0		
Mann	MAN-10		10000	8145	5250	MAN10	22.4	0 275%	0		
Mann	MAN-11		10000	6596	5594	MAN11	167 6	2.540%	0		
Mann	MAN-12		10700	10761	8875	MAN12	21.4	0.199%	0		
Mann	MAN-13		10000	3554	4906			0.000%	1		
Mann	MAN-14		10700	9528	4752	MAN14	6.5	0.068%	0		
Mann	MAN-15		10000	6429	7823	MAN15	20.7	0 322%	0		
Mesa	MSA-12		9970	8651	5137			0.000%	1	MCL01	12 8
Mesa	MSA-13		9970	7553	6088			0 000%	1	MEL01	45.0
Mesa	MSA-14		9970	9341	11495			0.000%	1	MEL02	46.2
Mesa	!		9970	7298	11612			0.000%	1	MES01	9.7
Mesa	!		9970	6412	7433			0.000%	1		
Mesa	!		9970	7430	10706			0.000%	1		
Midway			-			MID01	20.5		0		
Midway			-			MID02	23.6		0		
Milagro			12200	9999		MIL11	4.6	0.046%	0		
Milagro			12200	10696		MIL12	31.9	0.299%	0		
Milagro			12200	10746		MIL13	11.3	0.105%	0		
Milagro			12200	7615		MIL14	7.9	0.104%	0		
Milagro			12200	4350		MIL15	6 6	0.152%	0		
Milagro			12200	12453		MIL16	22.8	0.183%	0		
Milagro			12200	7975		MIL17	25.3	0.317%	0		
			12200	8430		MIL18	71.7	0.850%	0		

Monthly Load Report for Texas

Distribution Systems Engineering Department

Substation Name	Feeder	Distribution Voltage (KV)	Maximum Capacity Available (KVA)	2014 Peak Demand	2013 Peak Demand		DG kW Att 4	DG % of peak*	No DG =1	Non-Texas with	DG kW
Milagro	MIL-19	13 8	12200	4710				0.000%	1		
Mission	MIS-01	4 16	3350		1787	MIS01	13.8	0.773%	0		
Mission	MIS-02	4.16	3350		2882	MIS02	32.9	1.140%	0		
Montoya	MON-20	23.9	17250	17472	9993	MON20	24.5	0.140%	0		
Montoya	MON-21	23 9	17250	10185	14163	MON21	90.2	0.885%	0		
Montoya	MON-22	23 9	16800	14603	18613	MON22	71.6	0.491%	0		
Montoya	MON-23	23 9	16800	16860	13623	MON23	65.8	0.390%	0		
Montoya	MON-24	23 9	16800	6771		MON24	5.4	0.079%	0		
Montoya	MON-25	23 9	16800	12280		MON25	68.5	0.557%	0		
Montoya	MON-26	23 9	16800	4014				0.000%	1		
Montwood	MWD-20	23 9	18700	32235				0.000%	1	MSA13	15.1
Montwood	MWD-21	23.9	18700	21281				0.000%	1	MSA14	88.3
Montwood	MWD-22		18700	15748				0.000%	1	MSA16	58 8
Morningside	MOR-01		1725						1	MSR01	14.9
Morningside	MOR-02		1725			MOR02	4.7		0		
Mulberry	MUL-01		1250			MUL01	11.4		0		
Mulberry	MUL-02		1250						1	MWD20	82.5
New Tex	NEWTEX-1		2500					0.000%	1	MWD21	81.5
New Tex	NEWTEX-2		2500						1	MWD22	187.1
Octavia	OCT_01		1875		1453			0 000%	1	NEV01	8.4
Parkdale	PAR-1		1725						1	NEW01	1.2
Parkdale	PAR-2		1825		682			0.000%	1		
Patriot	PAT-10		10000	10091		PAT10	27.5	0.272%	0		
Patriot	PAT-11	13 8	10000	12811		PAT11	138.3	1.080%	0		
Patriot	PAT-13	13 8	10000	10727		PAT13	8.4	0 078%	0		
Pellicano	PEL-20	23 9	18700	18912		PEL20	103.0	0.545%	0		
Pellicano	PEL-21	23 9	18700	17003		PEL21	131.9	0.776%	0		
Pendale	PEN-10	13 8	10000	9666		PEN10	16.0	0.166%	0		
Pendale	PEN-11	13 8	10000	6377				0.000%	1	PIC20	412.3
Pendale	PEN-12	13 8	10000	13142					1	PIC21	140.3
Phelps Dodge	PHD-10		-						1	PIC22	206.4
Phelps Dodge	PHD-11		-						1		
Phelps Dodge	PHD-12		-						1		
Phelps Dodge	PHD-13								1		
Phelps Dodge	PHD-14								1		
Phelps Dodge	PHD-15		-						1		
Ranchland	RAN-1		1440			RAN01	13.7		0		
Ranchland	RAN-2		1440						1		
Rio Bosque	RBQ-10		10000	6759	3600	RBQ10	4.3	0.064%	0		
Rio Bosque	RBQ-11		10000	4249	2744	RBQ11	7.9	0.185%	0		
Rio Bosque	RBQ-12		10000	8932	4839	RBQ12	14.3	0.160%	0		
Rio Grande	RGD-13		9970	9071	9511	RGD13	47.1	0.519%	0		
Rio Grande	RGD-15		9970	9771	9893	RGD15	21.8	0.223%	0		
Ripley	RIF		10000	10100				0.000%	1		
Ripley	RI		10000	11000		RIP11	46.3	0.421%	0		
Ripley	RI		10000	1212		RIP12	11.4	0.944%	0		
Santa Fe			9970	3314	4463			0.000%	1	SAL20	459.7
Santa Fe			9970	4270	4922			0 000%	1	SAL21	141.3
Santa Fe			9970			SFE12	2.0	0.110%	0	SAL22	4 3
			-	336	672			0.000%	1	SAL23	98.0
			2100	384	1105			0.000%	1	SAL24	1139.3
Santa Fe			3350	672	865			0.000%	1	SDL12	16 6
Santa Fe			2775	1556	1614			0.000%	1	SDL15	44.8
Santa Teresa			-	14100	15687			0.000%	1	SDL16	16.8
Scotsdale			10700	4154	1769			0.000%	1		
Scotsdale			10700	8038	32034			0.000%	1		
Scotsdale			10700	6687	4822			0.000%	1		
Scotsdale	S		8200	8510	7852			0.000%	1		
Scotsdale	S		10700	7960	7756			0.000%	1		
Scotsdale	S		8200	5271	6767			0.000%	1		
Shearman	SHE		10000	8690	7994	SHE10	51 5	0.593%	0		
Shearman	SHE-11		10000	4170	6390	SHE11	9.0	0.216%	0		
Shearman	SHE-12		10000	8920	11849	SHE12	12.6	0.142%	0		
Sierra Blanca	SIB-01							#DIV/0!	1	SNO12	10.7
Sierra Blanca	SIB-20		7500	7263	2573			0 000%	1		
Socorro	SOC-10		13200	6719	5826			0.000%	1		
Socorro	SOC-11		14400	10051	7890	SOC11	32.0	0.318%	0		
Socorro	SOC-12		14400	8618	7969			0.000%	1		
Sol	SOL-10		10000	10292	9822	SOL10	22.1	0.215%	0		
Sol	S		10000	9687	10131	SOL11	20 0	0.206%	0		
Sol	S		10000	5532	8533	SOL12	29 0	0.524%	0		
			10000	7292	6863	SOL13	12.0	0.164%	0		

Monthly Load Report for Texas

Distribution Systems Engineering Department

Substation Name	Feeder	Distribution Voltage (KV)	Maximum Capacity Available (KVA)	2014 Peak Demand	2013 Peak Demand		DG kW Att 4	DG % of peak*	No DG =1	Non-Texas with	DG kW
Sol	SOL-14	13 8	10000	5880	11922	SOL14	33.3	0.567%	0		
Sol	SOL-15	13 8	10000	11330	11814			0.000%	1		
Sparks	SPA-10	13 8	10400	9450	11394	SPA10	70.9	0.750%	0		
Sparks	SPA-11	13 8	8100	10686	7586	SPA11	113.4	1.061%	0		
Sparks	SPA-12		8100	5843	10115	SPA12	9.2	0.157%	0		
Summit	SMT-01		1440	849	893			0.000%	1	STA20	102.9
Summit	SMT-02		1440	1650	778			0.000%	1	STA21	68.6
Sunset	SUN-2		1440	1340	1340	SUN02	27.6	2.063%	0	STA23	20000.0
Sunset			-	-	-				1	STA25	100.0
Sunset			1440	1455	1470			0.000%	1		
Sunset			2100	1729	1700			0 000%	1		
Sunset			-	-	-				1		
Sunset	SUN-7		2880	1635				0.000%	1		
Sunset	SUN-8		1440	1037	1095			0.000%	1		
Sunset	SUN-13		8200	1097	1986			0.000%	1		
Sunset	SUN-14		8200	5980	7327	SUN14	9.2	0.153%	0		
Sunset	SUN-15		10900	5478	7200	SUN15	7.7	0.140%	0		
Sunset	SUN-16		8200		4523			0.000%	1	TAT20	472.7
Sunset North	SNO-10		11200	6080	7537			0 000%	1		
Sunset North	SNO-11		11200	8323	7925			0.000%	1		
Sunset North	SNO-12		11200	9059	9333			0.000%	1		
Thorn	THO-10		10000	7017	7854	THO10	13.8	0 196%	0		
Thorn	THO-11		10000	7770	7703	THO11	28.4	0.365%	0		
Thorn	THO-12		10000	9500	9025	THO12	66.1	0.696%	0		
Thorn	THO-13		10000	6000	5651	THO13	10.9	0.182%	0		
Thorn	THO-14		10000	10410	9580	THO14	39.3	0.377%	0		
Thorn	THO-15	13.8	10000	10075	8974	THO15	28.2	0.280%	0		
Tobin	TOB-1	4 16	2880	2135	2037	TOB01	8.4	0.393%	0	TMT20	79.0
Tobin	TOB-2	4.16	2880	2736	2094	TOB02	7.9	0.289%	0		
Transmountain	TMT-20	23 9	12200	6251				0.000%	1		
Transmountain		23 9	12200	2815				0.000%	1		
Valley	VAL-10	13 8	7500	5801	6319	VAL10	7.0	0.125%	0		
Van Horn	VAN -01	4.16	2500						1		
Viscount	VIC-10	13 8	12000	6740	6783	VIC10	13.9	0.206%	0		
Viscount	VIC-11	13.8	10000	8203	4879			0.000%	1		
Viscount	VIC-12	13.8	10000	9206	8860			0.000%	1		
Vista	VIS-10		10000	7090	8484	VIS10	18.1	0.255%	0		
Vista	VIS-11		10000	6126	11123	VIS11	25.2	0.411%	0		
Vista	VIS-12		10000	10656	9592	VIS12	25.2	0 236%	0		
Vista	VIS-13		10000	10184	8470	VIS13	2.2	0.022%	0		
Vista	VIS-14		10000	10140	7016	VIS14	47.9	0.472%	0		
Vista	VIS-15		10000	6150	5970	VIS15	23.7	0.385%	0		
White	WHITE-01		2700		1153			0.000%	1		
White	WHITE-02		3800		615			0 000%	1		
Wrangler	WRA-10		14965	11894	10851	WRA10	50.6	0.425%	0		
Wrangler	WRA-11		14965	5355	5433			0.000%	1		
Wrangler	WRA-12		14965	5206	5052			0.000%	1		
Wrangler	WRA-13		14965	7492	6187	WRA13	6.4	0.085%	0		
Wrangler	WRA-14		14965	9182	10545	WRA14	48.7	0 530%	0		
Ysleta	YSE-01		2500						1	(blank)	0.0
Total				1479350.1	1098893.0		4560.9				
without DG				554998.4291	437127				131 0		
with DG				924351 7	661766 0			0.493%			

* peak used is 2014 if available, 2013 if 2014 number is not available.

SOAH DOCKET NO. 473-17-2686
PUC DOCKET NO. 46831

APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO	§	OF
CHANGE RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
OFFICE OF PUBLIC UTILITY COUNSEL'S FIFTH REQUEST FOR INFORMATION
QUESTION NOS. OPUC 5-1 THROUGH OPUC 5-14

OPUC 5-12:

Please identify the customer classes that are served by "Major Account Representatives" and estimate the approximate percentage of time spent on each class.

RESPONSE:

The "Major Account Representatives" serve the following customer classes: Commercial/Industrial Large, Commercial/Industrial Small and Public Authority. Based upon customer count by customer class, the approximate time spent on each Customer class is: 28% Commercial/Industrial Large; 35% Commercial/Industrial Small; and 37% Public Authority.

Preparer: Michael J. Graniczny — Title: Manager-Commercial Services

Sponsor: James Schichtl — Title: Vice President-Regulatory Affairs

SOAH DOCKET NO. 473-17-2686
PUC DOCKET NO. 46831

APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO	§	OF
CHANGE RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
OFFICE OF PUBLIC UTILITY COUNSEL'S FIFTH REQUEST FOR INFORMATION
QUESTION NOS. OPUC 5-1 THROUGH OPUC 5-14

OPUC 5-11:

Please identify all costs of "Major Account Representatives" (defined as EPE employees assigned specifically to serve large customers) in the test year by FERC Account. Divide into labor and non-labor expenses.

RESPONSE:

There are four (4) Major Account Representatives assigned to serve large customers. The estimated salaries associated with these four employees for the test year ended September 30, 2016, was $341,051.00, recorded in FERC Account 903000. There are no non-labor expenses for these staffers.

Preparer: Michael J. Graniczny — Title: Manager-Commercial Services

Sponsor: Russell G. Gibson — Title: Vice President-Controller

SOAH DOCKET NO. 473-17-2686
PUC DOCKET NO. 46831

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
OFFICE OF PUBLIC UTILITY COUNSEL'S FIFTH REQUEST FOR INFORMATION
QUESTION NOS. OPUC 5-1 THROUGH OPUC 5-14

OPUC 5-8:

Please divide Account 593 into tree-trimming and other vegetation management costs and all other costs, and divide into labor and non-labor.

RESPONSE:

Please refer to the table below for the division of Account 593 into tree-trimming and other vegetation management costs and all other costs, and the division into labor and non-labor.

Account	**Description**
593000	Maintenance of Overhead Lines

Description	**Labor**	**Non-Labor**	**Unadjusted Total**
Tree Trimming	$ -	$2,198,629	$2,198,629
Other Vegetation Management	-	-	-
Other Costs	2,409,097	842,185	3,251,282
Unadjusted Total	$2,409,097	$3,040,814	$5,449,911

Preparer: Myrna Ortiz — Title: Manager-Financial Accounting

Sponsor: Russell G. Gibson — Title: Vice President- Controller
R. Clay Doyle — Vice President-Transmission & Distribution and System Planning

SOAH DOCKET NO. 473-17-2686
PUC DOCKET NO. 46831

APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO	§	OF
CHANGE RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
OFFICE OF PUBLIC UTILITY COUNSEL'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. OPUC 1-1 THROUGH OPUC 1-17

OPUC 1-8:

Please provide the number of residential customers served by 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20 to 25, and over 25 customers per transformer. If you do not have this information for residential customers, provide it for all customers. If you have any information dividing the residential class between single-family and multifamily, please provide it.

RESPONSE:

EPE does not have the data required in such detail in order to respond to this question. However, there are approximately 6.2 customers per transformer in EPE's Texas service territory. This average includes all rate classes served from single phase transformers. The majority of single phase transformers serve residential loads.

The average number of residential customers served per single phase transformer varies by customer density (urban, suburban, and rural) and the amount of the connected customer load. For example, individual transformers that serve residential customers that have refrigerated air conditioning will serve fewer customers than individual transformers that serve customers without refrigerated air conditioning.

In response to EFCA 4-6, EPE conducted a random sampling of urban, suburban, and rural areas to the number of residential customers served by each transformer. The average number of residential customers per transformer is estimated as follows:

Urban – 10.03 customers/transformer
Suburban – 2.86 customers/transformer
Rural – 1.31 customers/transformer

Preparer: Maximillian Ludwig — Title: Manager – Asset management Technologies

Sponsor: R. Clay Doyle — Title: Vice President – Transmission & Distribution and System Planning

-4SOAH DOCKET NO. 473-17-2686
PUC DOCKET NO. 46831

APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO	§	OF
CHANGE RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
OFFICE OF PUBLIC UTILITY COUNSEL'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. OPUC 1-1 THROUGH OPUC 1-17

OPUC 1-4:

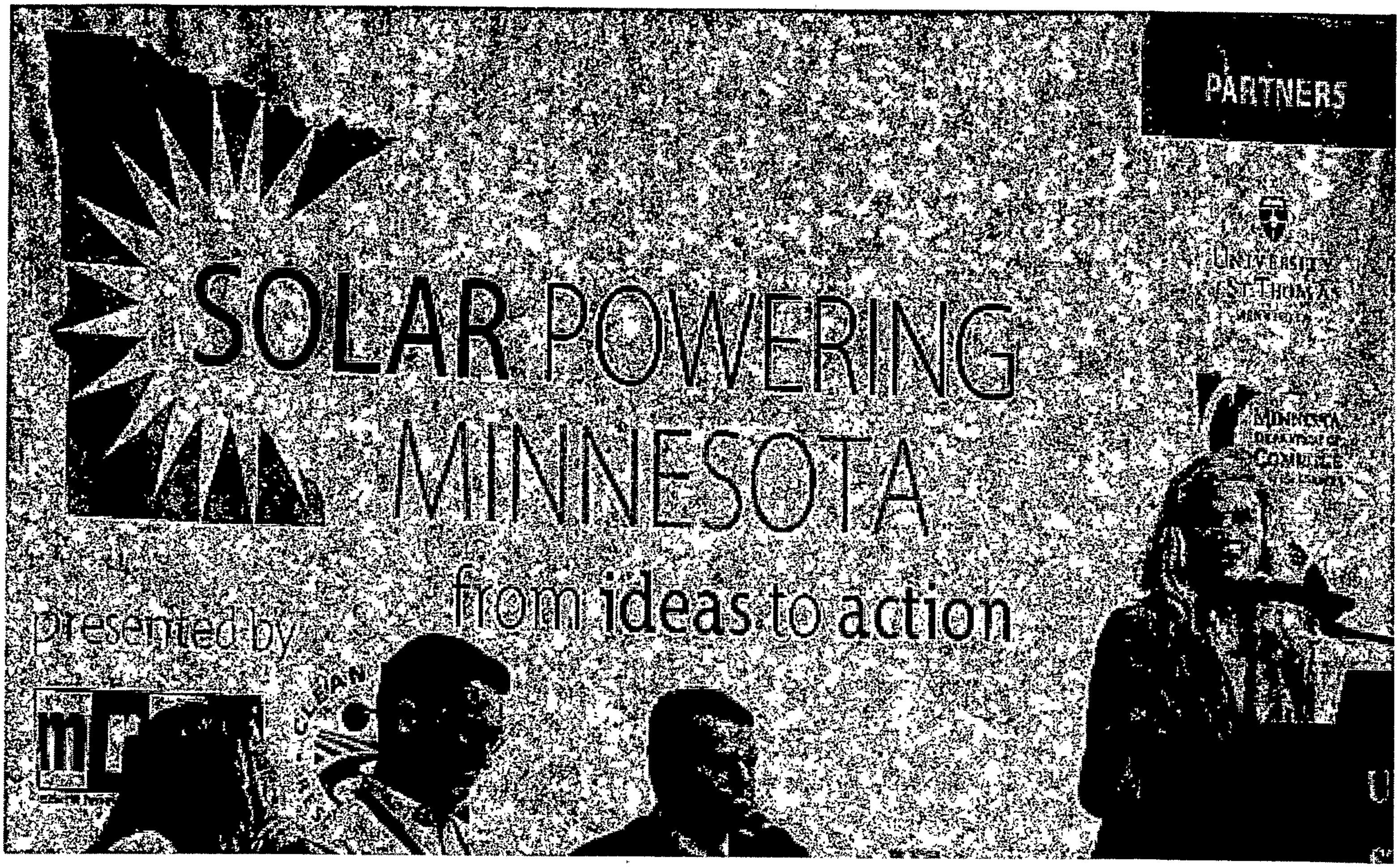
Please provide a calculation of the revenues that interruptible customers would have paid in the test year (adjusted to annualize the rates resulting from the order in Docket No. 44941) had they been charged firm rates from the rate class(es) they would be in if they were not interruptible. Show billing determinants and applicable rates. Divide by rate schedule and voltage level if applicable.

RESPONSE:

Please refer to OPUC 1-3 Attachment 1, pages 7 through 11, electronic worksheet tab labeled "All Firm (OPUC 1-4)." However it should be noted that if each customer were billed under an entirely firm rate, the rates would be different.

Preparer: Manuel Carrasco Title: Supervisor-Rates & Regulatory Affairs

Sponsor: Manuel Carrasco Title: Supervisor-Rates & Regulatory Affairs



Minnesota's Value of Solar

Can a Northern State's New Solar Policy Defuse Distributed Generation Battles?

John Farrell

April 2014

ILSR INSTITUTE FOR Local Self-Reliance

Executive Summary

In March 2014, Minnesota became the first state to adopt a "value of solar" policy. It may fundamentally change the financial relationship between electric utilities and their energy-producing customers. It may also serve as a precedent for setting a transparent, market-based price for solar energy. This report explains the origins of value of solar, the compromises made to get the policy adopted in Minnesota, and the potential impact on utilities and solar energy producers.

The Value Of Solar Concept

The basic concept behind value of solar is that utilities should pay a transparent and market-based price for solar energy. The value of solar energy is based on:

- Avoiding the purchase of energy from other, polluting sources
- Avoiding the need to build additional power plant capacity to meet peak energy needs
- Providing energy for decades at a fixed price
- Reducing wear and tear on the electric grid, including power lines, substations, and power plants

Figure A: Net Metering v. Value of Solar (As implemented in Minnesota)

Net Metering	Value of Solar
Customer earns bill credits	Customer earns bill credits
Credit value = *retail* electricity rate	Credit value = *value of solar* rate
Credit value *fluctuates* with retail price	Value of solar *locked in* on 25-year contract
Solar production cannot exceed 120% of on-site annual consumption	Solar production cannot exceed 120% of on-site annual consumption
Net excess generation *paid at retail rate (for < 40 kilowatt) or avoided cost rate (for < 1 megawatt)*	Net excess generation *forfeit to utility*

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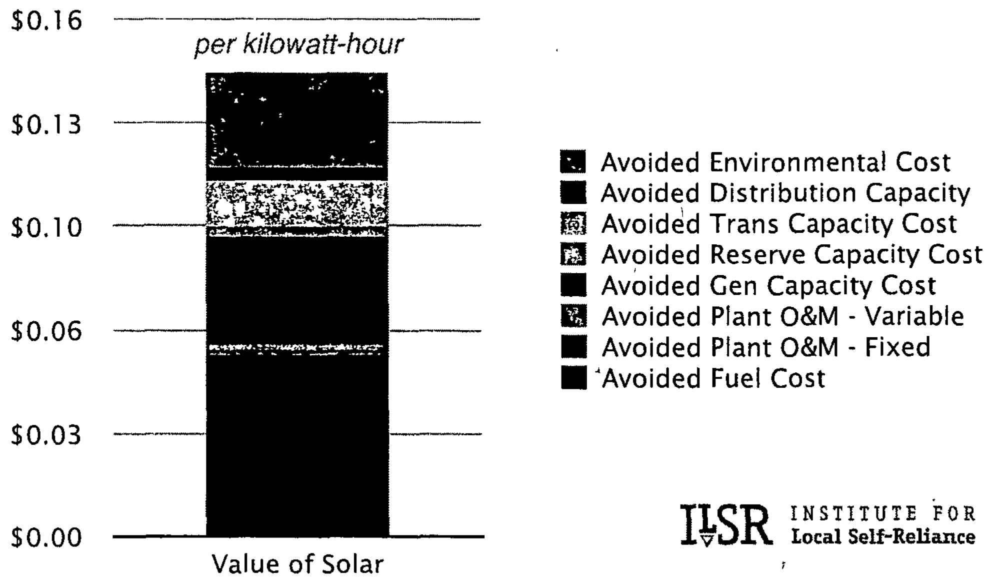
Value of solar is not like net metering, where producing energy reduces your electricity bill just like turning off a light. Fig. A illustrates the difference between net metering and value of solar in Minnesota. It also highlights a few key features of the adopted value of solar policy, including the 25-year contract, and the use of bill credits rather than a separate cash payment.

Minnesota's Value of Solar

As adopted, Minnesota's value of solar formula includes all of the basic components of the theoretical policy. The following chart (Fig. B) shows the relative value of the various components, and the total value, based on early estimates filed during the proceedings at the state's Public Utilities Commission.

Figure B: Preliminary Minnesota Value of Solar (Xcel Energy)



A Caution

Although Minnesota's value of solar policy is a national precedent, the adopted policy had some good elements that were lost in the legislative process, elements that other states may want to revive. The following table (Fig. C) illustrates:

Figure C: Value of Solar, Adopted v. Proposed Elements

Adopted	Proposed
Customer earns bill credits	Customer is paid for solar energy in a separate transaction
Solar production cannot exceed 120% of annual on-site consumption	Solar production is not limited by onsite consumption
Net excess generation is forfeit to utility	Customer is paid for all solar energy production, regardless of on-site electricity use
Utility chooses whether to adopt value of solar or keep net metering	Utility must offer value of solar, but customer may choose between it and net metering
Utility automatically obtains SREC, with zero compensation to customer	Solar customer retains solar renewable energy credit (SREC)

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The Impact on Utilities and Customers

Value of solar offers something for everyone. For utility customers, a 25-year contract at a fixed price makes solar financing much easier, and as the cost of solar continues to fall, quite lucrative.

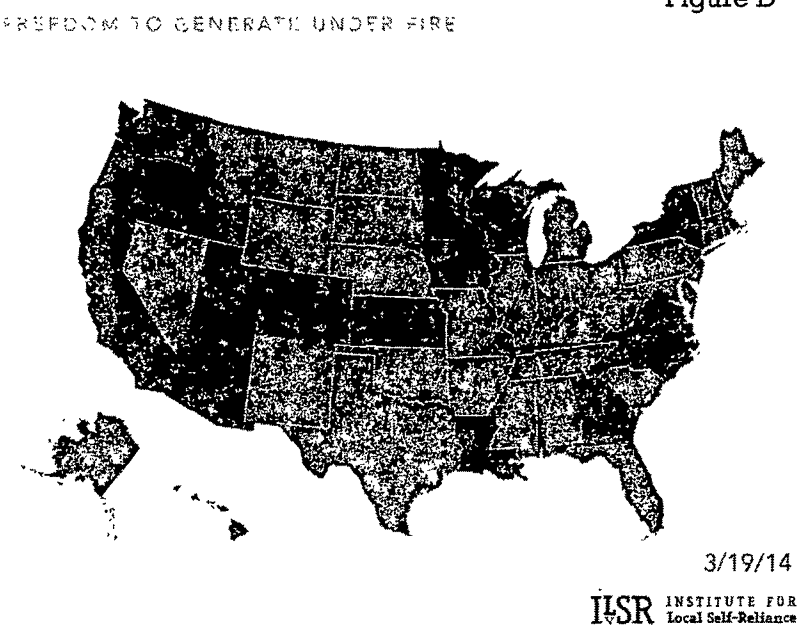
For utilities, the transparency of the market price means no concerns about cross-subsidies between solar customers and non-solar customers. It means a payment for solar energy uncoupled from the retail electricity price. It may also mean a potential for cost recovery on payments made to solar producers, something not allowed with net metering. In Minnesota's case, it also means free access to solar renewable energy credits, at a substantial savings compared to credit prices in states with competitive credit markets, i.e. New Jersey, Pennsylvania, etc.

The environmental value may be the most precedent setting, because it means that when buying solar power under Minnesota's value of solar tariff, a utility is for the first time paying for the environmental harm of its fossil fuel energy generation.

Will Value of Solar End Battles Over Distributed Generation?

If Minnesota utilities report favorably on the value of solar, it may change the debate on other state battlegrounds over distributed generation (Fig. D).

Figure D



The value of solar delivers a transparent, market-based price for solar. It solves problems for utilities and for utility customers around compensation for distributed renewable energy generation. But its ultimate success lies in whether electric utilities can be convinced that accommodation of customer-owned power generation is in their best interest, or whether any concession of their market share is a deadly threat to their economic livelihood.

Acknowledgments

Thanks to all my friends and colleagues in Minnesota for an incredible job in seeing this policy through from draft to approval. It wouldn't have happened without all of us.

John Farrell, jfarrell@ilsr.org

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Since 1974, the Institute for Local Self-Reliance (ILSR) has worked with citizen groups, governments and private businesses to extract the maximum value from local resources.

Table of Contents

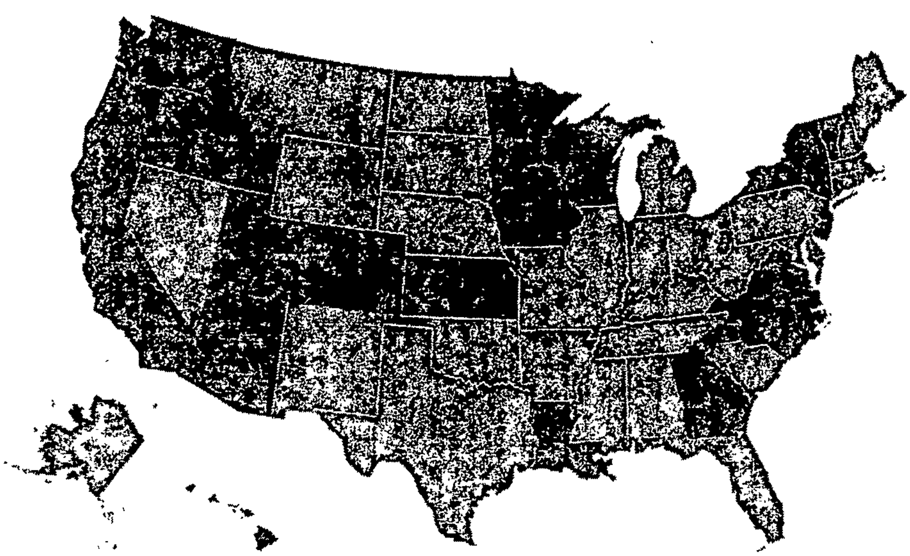
Introduction

On March 12, 2014, Minnesota became the first state to give utilities and distributed solar power producers a new way to negotiate power supply contracts, a method called the "value of solar." If adopted by utilities, it will fundamentally change the relationship between solar-producing customers and their electric utility.

Until now, producing on-site energy from a solar panel has been treated much like any other activity reducing electricity use. Energy produced from solar is subtracted from the amount of energy used each month, and the customer pays for the net amount of energy consumed. This "net metering" policy has guided the growth of distributed solar power in the United States to an astonishing 13 gigawatts (GW) by the end of 2013, made possible because of enormous reductions in the cost of on-site power generation from solar.

But net metering has become the focal point for a utility war on the democratization of the electric grid and the expansion of distributed solar. The following map (Fig. 1) illustrates the many states where utilities have sought to undermine policies and/or incentives supporting distributed renewable energy generation.[1]

Figure 1



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The potential transformation of the grid and the improving economics of self generation have utilities crying foul (or fowl) because as more and more customers use net metering, it reduces electricity sales. Combined with increasing energy efficiency and an economic downturn, this has utilities feeling that their business model is evaporating.

Utilities may feel an economic squeeze, but increasing evidence suggests that the overall economic benefits to the utility's electric grid may outweigh the loss of revenue. This benefit is not transparent because on-site power generators are typically paid based on the cost of using electricity, not the value of their energy production.[2]

The new value of solar policy creates a price for distributed solar energy in an effort to answer utility concerns, but also to reinforce the notion that on-site power generation benefits the customer, her neighbors, and the electric grid.

Interestingly, Minnesota's rigorous formula suggests that in crying "foul," utilities may have been crying "wolf." That's because the initial estimates of the value of solar peg it at more than the retail electricity price. In other words, Minnesota utilities have been getting a sweet deal on solar power, reaping its benefits for their ratepayers and shareholders.

Initial estimates of the value of solar peg it at more than the retail electricity price. *In other words, Minnesota utilities have been getting a sweet deal on solar power, reaping its benefits for their ratepayers and shareholders.*

Does that mean that the value of solar will be better than net metering for solar producers? For utilities? For ratepayers? Perhaps.

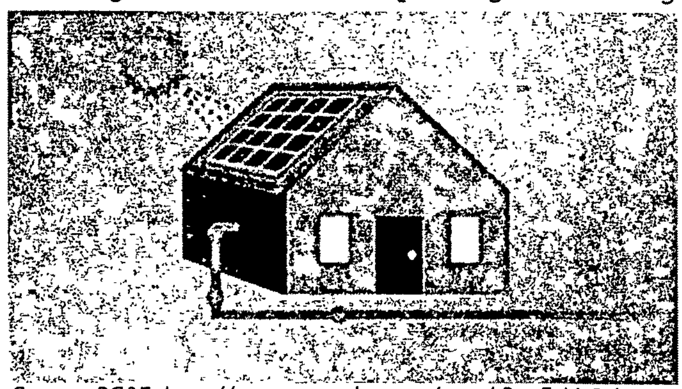
This brief will explain the current policy standard for distributed solar - net metering - the value of solar option, the recent development and approval of the policy in Minnesota, and the implications for the continued expansion of distributed renewable energy.

The Old Standard: Net Metering

By the end of 2013, over 13 gigawatts (13,000 megawatts) of solar power had been installed in the U.S., largely due to a state policy called net metering. This policy mixes interconnection rules (a technical and administrative set of requirements for connecting to the grid), with economics of billing (net energy metering). Net metering policies typically make it much easier to connect a solar array to the electric grid.

Additionally, net metering is a billing policy that simply compensates solar owners for their energy generation. It spins the meter backward during the day when there is excess solar generation, for example, and forward at night when household energy consumption is higher than solar production. It treats on-site renewable energy production like any other method for reducing energy consumption, by having customers pay for their "net" energy usage (total use less on-site production) on their electricity bill.

Figure 2: PG&E video explaining net metering



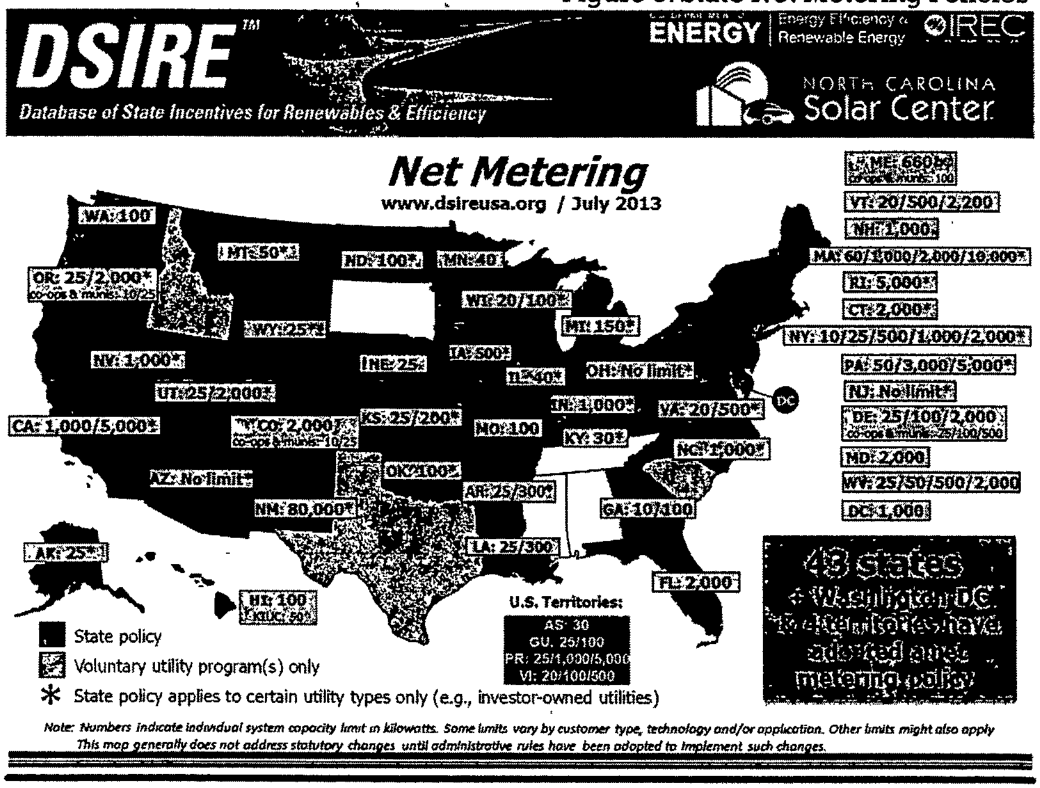
Source: PG&E, http://www.youtube.com/watch?v=5yVgPrhvwyc

Net metering may also reduce extraneous utility charges for "backup" or "standby" power, since such services are typically already covered by a utility's existing energy reserves. Net metering typically allows a customer to be paid for energy they generate in excess of their own usage. In some states, like Minnesota, a customer will get paid for this "net excess generation" at the same rate they are rewarded for energy that offsets their own use. In other states, customers are paid at the utility's much lower "avoided cost" rate, typically reflecting the utility's cost of getting electricity from another existing power plant.

The following map from the Database for State Incentives for Renewable Energy (DSIRE), shows the net metering policies in each U.S. state (Fig. 3). The number on each state is the maximum size of project allowed under the state policy, in kilowatts (kW), and it may vary by utility or customer class, e.g. residential or commercial. A typical residential solar installation is around 5 kW, whereas a solar array on a big box retail store like IKEA is approximately 1,000 kW. The average solar array installed in the U.S. is approximately 40 kW.

States may also cap the total amount of energy a utility must buy from net metered systems. Half of U.S. states have statutory limits, and 16 of those states cap the total energy permitted under net metering at 1% of a utility's annual energy sales.

Figure 3: State Net Metering Policies



Source: DSIRE

Net metering works best for encouraging solar if the cost of producing solar energy is close to the retail electricity price (e.g. in areas with high energy costs, abundant sunshine, or both).

Although there's plenty of evidence that power generation from net metering customers has benefits to their neighbors and the grid, utilities have raised objections to net metering as its use has grown.

In that context comes a new policy: the value of solar.

The New Option: Value of Solar

As implemented in Minnesota, the value of solar preserves much of the simplicity of net metering (simple interconnection and minimal fees), but changes two key items: 1) the accounting method for compensating solar producers for their energy, and 2) introducing a long-term contract for the solar energy producer.

With value of solar, instead of netting the *kilowatt-hours* (kWh) consumed and produced, the customer nets the *dollars* paid for energy (at the retail electricity rate) with the dollars earned selling solar energy to the utility (at the value of solar rate). From an engineering standpoint, the two policies - net metering and value of solar - are identical. From an accounting standpoint, they differ only in the units. Net metering nets kilowatt-hours. Value of solar nets the cost of purchased energy with the value of produced solar energy.

Figure 4: Net Metering v. Value of Solar (As implemented in Minnesota)

Net Metering	Value of Solar
Customer earns bill credits	Customer earns bill credits
Credit value = *retail* electricity rate	Credit value = *value of solar* rate
Credit value *fluctuates* with retail price	Value of solar *locked in* on 25-year contract
Solar production cannot exceed 120% of on-site annual consumption	Solar production cannot exceed 120% of on-site annual consumption
Net excess generation *paid at retail rate (for < 40 kW) or avoided cost rate (for < 1MW)*	Net excess generation *forfeit to utility*

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The other major difference between value of solar and net metering is that the value of solar is locked in by a solar energy producer on a 25-year contract at the time they begin generating. Both the retail energy rate and the value of solar change over time (both could go up or down), but Minnesota's law gives solar energy producers surety by guaranteeing their per-kilowatt-hour payment for the expected life of the solar panels. In the value of solar contract between the customer and utility, the price paid may be a fixed dollar amount (e.g. 14 cents per kWh) or it may inflate over time (with a comparable "net present" value over the 25-year period). We'll discuss this in more detail later.

The 25-year contract is an important difference between Minnesota's value of solar program and others (e.g. Austin) that do not offer customer a fixed price. The long-term contract and its guaranteed payment per kWh can save customers money by reducing their borrowing costs and save ratepayers by allowing utilities to lock in power purchases at a fixed price for many years.

The Principle

The basic concept behind value of solar is that utilities should pay a transparent and market-based price for solar energy. Net metering, for all its benefits, obscures the actual value of solar energy because all compensation is based on the retail electricity price that has no relation to the value of solar power. The value of solar is meant to remedy this obscurity and base the price paid for solar on its value to the grid and its customers.

The value of solar price is based on:

- Avoiding the purchase of energy from other, polluting sources
- Avoiding the need to build additional power plant capacity to meet peak energy needs
- Providing energy for decades at a fixed price
- Reducing wear and tear on the electric grid, including power lines, substations, and power plants

The value of solar concept was pioneered and popularized by Karl Rabago, then of Austin Energy, the municipal utility serving Austin, TX.[3] In the first two published reports on the concept, Rabago and others highlighted two reasons for pursuing the value of solar:

- Net metering causes customers to size solar arrays to their own consumption (as opposed to the size of their roof).
- Net metering can incent customers to use more energy if, as implemented in Austin, production in excess of consumption is credited at a much lower price.

The utility managers and researchers of Clean Power Research set out to design a value of solar rate that would help address these issues. It included the following benefits of solar power from the utility perspective:

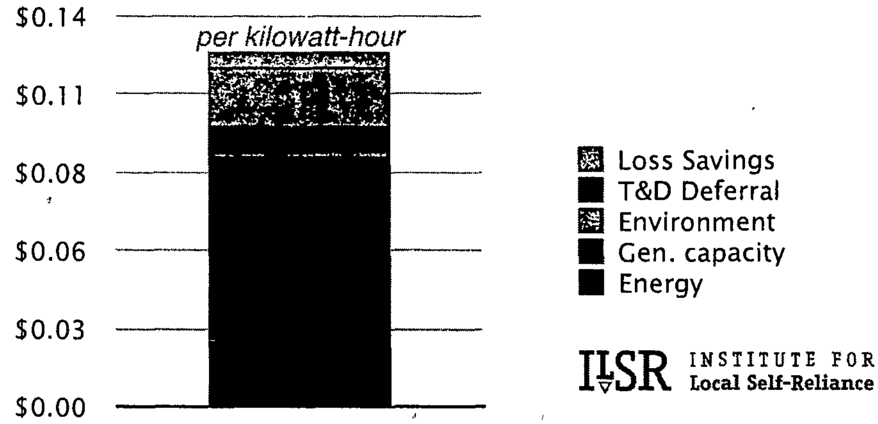
- Loss savings - reducing energy losses by producing energy near consumption, rather than transmitting power over long distances.
- Energy savings - reducing the purchase of other forms of energy, e.g. electricity from natural gas.
- Generation capacity savings - reducing the need for capacity from other power plants.
- Fuel price hedge value - the value of a known (and zero) fuel cost from solar energy, as compared to power plants using fossil fuels with volatile prices.
- Transmission and distribution capacity savings - reducing load on high-voltage transmission and low-voltage distribution portions of the electricity grid during peak periods.
- Environmental benefits - reducing pollution.

Calculating the value of solar is easier said than done, however. The complexity of these benefits explains why the adoption of the *methodology* alone in Minnesota required 6 months of research, stakeholder meetings, and deliberation by two government agencies.

The completed methodology for Minnesota's value of solar includes all of the components proposed in the original 2006 Austin study, though in some cases under different names or combinations. But the basic principle is the same.

When stacked together (literally, in the case of Figure 5), the values of solar may add up to a robust, value-based price for solar power. The chart illustrates the value of solar from the municipal utility in Austin, TX.

Figure 5. Austin Energy Value of Solar, 2013



Minnesota's Value of Solar Law

With the first statewide value of solar program, Minnesota's process, methodology, and implementation are likely to become precedents for policy development in other states and municipalities. As such, some background on the policy's origin and the process of its development are warranted.

Background

In late 2012, reinforced by political winds in favor of solar power, the Solar Works for Minnesota coalition developed a policy package proposing a 10% solar energy standard by 2030 with a specific program (often called a feed-in tariff) to encourage the development of distributed solar (HF 773).[4] The intent was to dramatically expand the development of solar power, and to avoid a scenario where scope, size, and location of solar power developed under the standard would by entirely controlled by utilities.[5]

Minnesota's Solar Standard

The adopted law, including the value of solar provision, requires investor-owned utilities to obtain 1.5% of their electricity sales from solar by 2020. For more on the components of that law, see *Minnesota's New (Standard Offer) Solar Energy Standard*.

The proposed feed-in tariff program had three key elements for supporting smaller scale (1 megawatt and less) solar power generation:

- A simple, standardized contract
- A long-term, fixed price based on solar production
- A price paid for solar that is commensurate with the cost of producing energy from solar, split into a "value of solar" component (inspired by the work in Austin) and an incentive component (that would decline over time), shown in Fig. 6. In particular, the incentive component would be funded with a systems benefits charge (e.g. utility use tax).

Originally a Feed-In Tariff

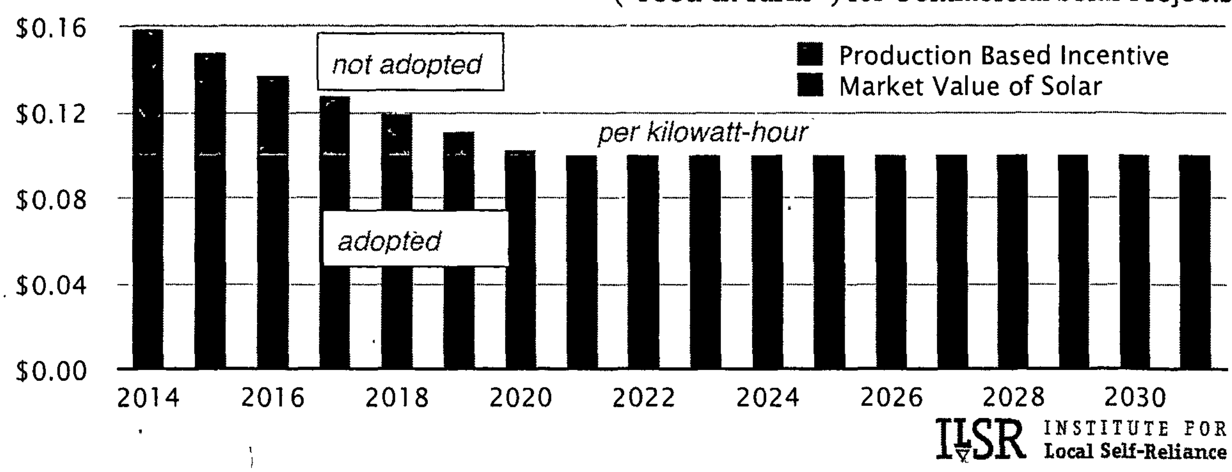
The adopted value of solar law began as a very different proposal to encourage distributed solar, a feed-in tariff with three key elements:

- A simple, standardized contract
- A long-term, fixed price based on solar production
- A price paid for solar that is commensurate with the cost of producing energy from solar

The original proposal also looked very different from net metering, with utilities asked to pay for solar energy in cash, completely separate from the utility bill. In fact, a solar producer wouldn't even have to be a utility customer or have a utility bill.

A final, and crucial, component of the original bill was that utility customers would be able to choose between value of solar or net metering, allowing them to select the most attractive option for on-site power generation (and giving utilities an incentive to be fair in their value of solar calculations).

Figure 6. Illustration of Value of Solar and Production-Based Incentive ("Feed-In Tariff") for Commercial Solar Projects



In the legislative process, just as the solar standard itself was dropped from 10% to 1.5% and certain utilities excluded, the original feed-in tariff concept was substantially revised. In short:

- The separate transaction for selling power was changed back to something very like net metering, including:
    - The solar producer must be a utility customer.
    - The annual output of the solar array could not exceed 120% of the on-site consumption of electricity.
    - The payment for energy produced is in the form of a bill credit, not a separate transaction.
- Unlike net metering, if the customer generates more power than they use during a year, the utility gets all the net excess power for free.

Lost in the Legislature

The adopted value of solar law was substantially different from the original proposal, losing any resemblance to a feed-in tariff. In the adopted version:

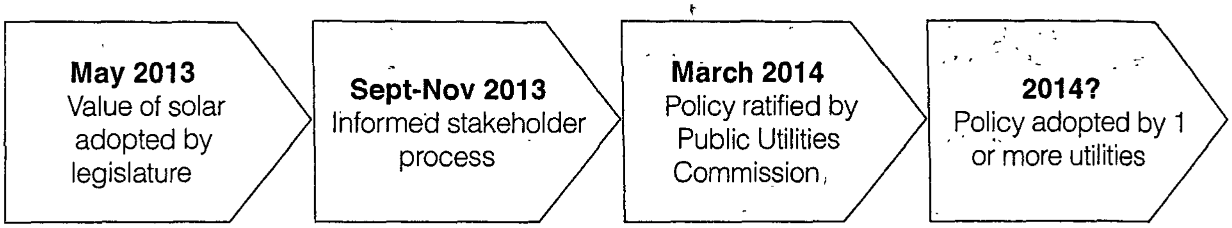
- A solar producer must be a utility customer, and may not produce more than 120% of on-site consumption
- Payment for energy is via bill credits, not a separate transaction
- Utility gets all net excess generation for free.
- The utility, rather than the customer, was given the choice between net metering and value of solar.

- The systems benefits charge was dropped, and incentives were only available for solar arrays 20 kW and smaller.

The value of solar still included most of the key value elements, however, and the direction from the legislature was quite specific:

> *The distributed solar value methodology established by the department must, at a minimum, account for* ***the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses,*** *and* ***environmental value.***

Figure 7. Minnesota Value of Solar Policy Timeline



The legislature also left the door open to include other values that explicitly benefitted the utility, though none of the optional items were ultimately included in the adopted methodology:

> *The department may, **based on known and measurable evidence of the cost or benefit of solar operation to the utility**, incorporate other values into the methodology, including **credit for locally manufactured or assembled energy systems, systems installed at high-value locations** on the distribution grid, **or other factors**.*

With those legislative guidelines established (see the authorizing legislation, Art. 9, Sec. 10 and following),[6] the value of solar policy moved to the next phase. The law stipulated that the state's Department of Commerce, Division of Energy Resources (DER), would be responsible for creating the methodology or formula for calculating the value of solar that would subsequently be used by the state's utilities, should they adopt it.

The DER opted for an informed stakeholder process, where experts from the Rocky Mountain Institute and Clean Power Research provided a wealth of information via several public meetings.[7] The experts provided detailed explanations of the current knowledge about the costs and benefits of distributed renewable energy and existing value of solar policies. The process was informed by local experts from think tanks, the solar industry, and utilities.

Clean Power Research developed a draft value of solar methodology by mid-November 2013 that was followed by a robust public comment period. The Department submitted its final value of solar methodology to the Minnesota Public Utilities Commission in January 2014. For more on the stakeholder process, see ILSR's series on Minnesota's Value of Solar.[8]

Items of Debate

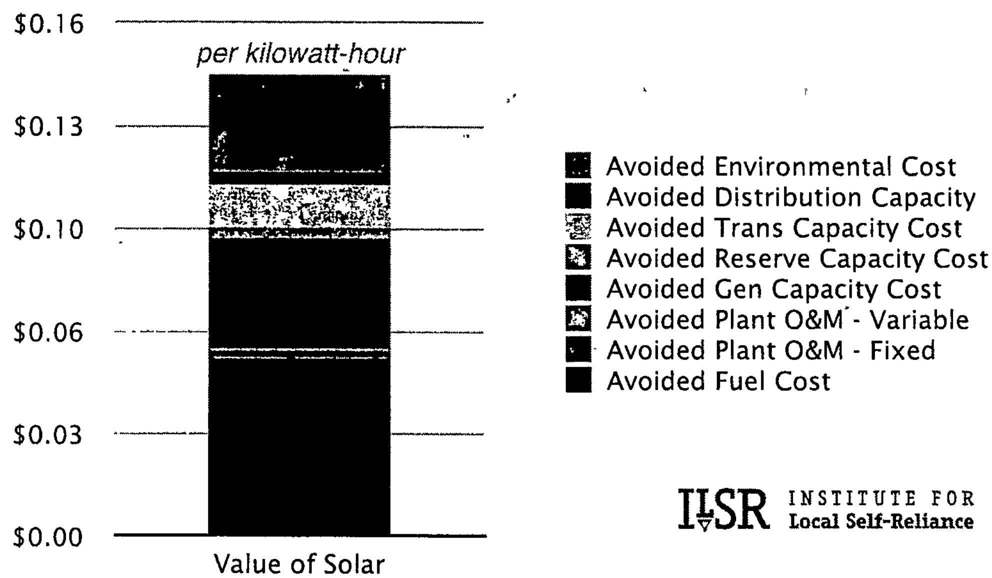
Some of the most contentious issues in the value of solar of calculation ended up being the most valuable:

- **Environmental value** – in a presentation to stakeholders in October 2013, Xcel Energy claimed that there might be zero environmental value for solar despite concurrent claims that their nuclear plant would save ratepayers $175 million over 16 years, but only because of the value of avoided carbon dioxide emissions (worth nearly $500 million). In the end, the PUC approved using the federal social cost of carbon: $37 per metric ton in 2015, contributing to a 3¢ per kWh environmental value.
- **Renewable Energy Credits** (RECs) – although many states have markets or policies setting a price on RECs, the DER and PUC opted not to ask utilities to pay for the RECs they receive under value of solar contracts.
- **Fuel hedge value** – Ultimately the largest portion of the value of solar, Xcel Energy testified in October 2013 that the fuel price hedge had no value, despite testifying just three days later that, when concerning its nuclear power plant, non-fossil generation (like solar...) did provide "a valuable hedge against potential increases in fossil fuel costs" which have been "extremely volatile."

At the commission, there was additional debate on the methodology, particularly over the environmental value. Despite robust resistance from utilities, the Commission ultimately adopted the federal social cost of carbon as the core environmental cost, ensuring a robust price component in the value of solar calculation.

The adopted formula for a solar value price includes eight separate factors (shown in Fig. 8), but the largest four account for the lion's share of the value: 25 years of avoided natural gas purchases, avoided new power plant purchases, avoided transmission capacity, and avoided environmental costs.

Figure 8: Preliminary Minnesota Value of Solar (Xcel Energy)



The value of avoided fuel cost recognizes that utilities cannot buy natural gas on long-term contracts the way they can buy fixed-price solar energy (with no fuel costs). It shifts the risk of fuel variability that utilities have previously laid on ratepayers back to utilities.

The avoided power plant generation capacity value recognizes that sufficient solar capacity allows utilities to defer peak energy investments (e.g. similar to how the Minnesota Public Utilities Commission recently ordered Xcel Energy to accept a bid from solar developer Geronimo Energy to meet new peaking energy demand).[9]

Avoided transmission capacity costs rewards solar for on-site energy production, saving on the cost of infrastructure and energy losses associated with long-range imports.

The environmental value may be the most precedent setting, because it means that when buying solar power under Minnesota's value of solar tariff, a utility is for the first time paying for the environmental harm of its fossil fuel energy generation.

Will it Work for Solar Producers?

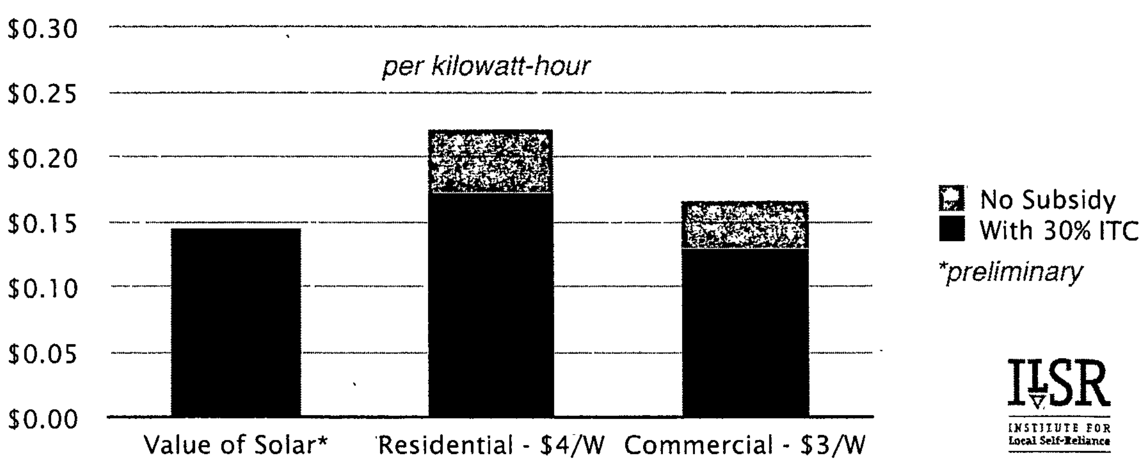
Xcel Energy, the state's largest electric utility, shared estimations for the value of solar in its comments – an effort to reduce the value – to the Public Utilities Commission in mid-February 2014.[10]

The preliminary estimate of the value of solar (it won't be formal if and until the utility actually files to offer the value of solar program) is quite robust. At 14.5¢ per kWh, the value of solar would be 3-4 times higher than the wholesale cost of energy to Minnesota utilities, and even a few cents higher than the 11.5¢ per kWh residential retail electricity rate for Xcel Energy.

It should be noted that in this filing, Xcel Energy recommended several changes to the methodology that would reduce the value of solar by half, to 7.4¢ per kWh. However, their arguments were not sustained by the Public Utilities Commission and, therefore, it's likely that the ultimate value of solar rate will be closer to the original calculation.

This preliminary figure, 14.5¢, comes fairly close to the price needed to economically install solar in Minnesota. When spread over 25 years of production (also known as the "levelized cost of energy"), and including the federal 30% Investment Tax Credit (ITC), the cost of residential solar is a bit higher than 14.5¢ and the cost of commercial-scale solar is a bit lower. Residential projects installed at $4/Watt will cost 17.2¢ per kWh over 25 years (and be eligible for additional state incentives). Commercial projects installed at $3/Watt will cost 12.9¢ per kWh over 25 years (Fig. 9).

Figure 9. Preliminary Minnesota Value of Solar Energy & 25-Year Levelized Cost of Solar



Let's examine a particular example contrasting the economics of the estimated value of solar with net metering (Fig. 10).

John and Jane Doe decide to install a 5 kW solar PV system onto their Golden Valley, MN, ranch-style home. Before their solar PV system went online, John and Jane were spending, on average, $230 per month for electricity. Lets see what their bills look like under the new value of solar and the old net metering:

Figure 10. Simplified Comparison of Value of Solar and Net Metering for Xcel MN Customer

Xcel Energy

Jane and John Doe
Golden Valley, MN

ELECTRICITY USE
Monthly usage (kWh): 2,000
Cost per kWh: $0.115
Total cost of electricity consumption: $230

SOLAR PRODUCTION (5 kW)
Monthly solar production (kWh): 542
Value of solar rate: $0.145
Total value of solar compensation: $79

Net electricity bill: $151

VALUE OF SOLAR

Xcel Energy

Jane and John Doe
Golden Valley, MN

NET ELECTRICITY USE
Monthly usage (kWh): 2,000
Cost per kWh: $0.115

SOLAR PRODUCTION (5 kW)
Monthly solar production (kWh): 542
Net usage (kWh): 1,458
Cost of net electricity consumption: $168

Net electricity bill: $168

NET METERING

In other words, the value of solar will be an improvement over net metering from the consumer's perspective, at least in the short run, and - with federal incentives - make residential and commercial solar cost-effective.

Will it Work for Utilities?

The crucial remaining issue is whether Minnesota utilities will adopt value of solar in place of net metering. Recall that during the legislative session, utilities successfully lobbied that they, and not customers, should have the choice to offer the value of solar policy. Thus, unless a utility files to offer the value of solar, it will continue to operate under the existing net metering law.

A preliminary analysis suggests that the value of solar may cost the utility slightly more in the short run than net metering for a residential solar array, but quite a bit less in the long run.

Fig. 11 shows that a representative residential customer with a 5 kW solar array, as in our previous example, would net an extra $200 bill credit this year (2014) with the value of solar than they would using net metering.

Within five years, however - based on recent utility rate inflation of 4-5% per year - the premium falls to just $12. Over the life of the value of solar contract, 25 years, the net present value (5% discount rate) of compensation for solar production is $3,000 less under value of solar than under net metering.

Figure 11. Annual Bill Credit – Market Value of Solar v. Net Metering

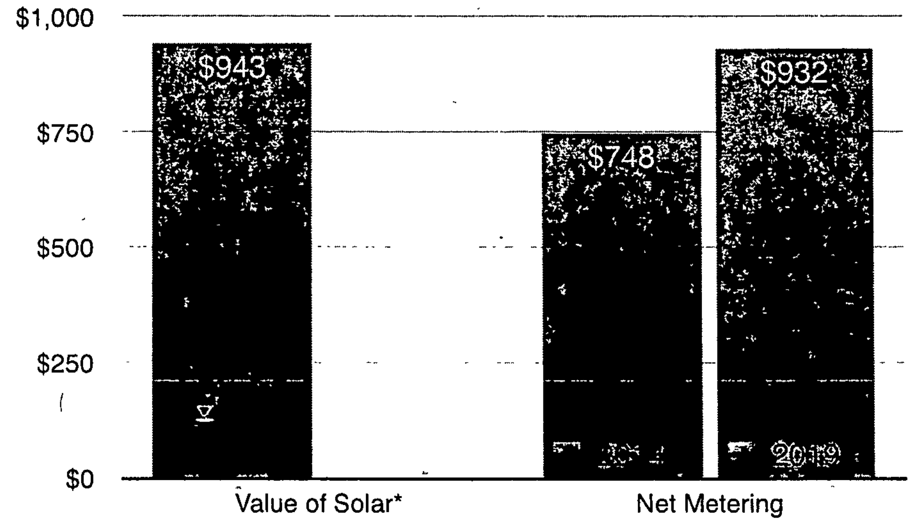
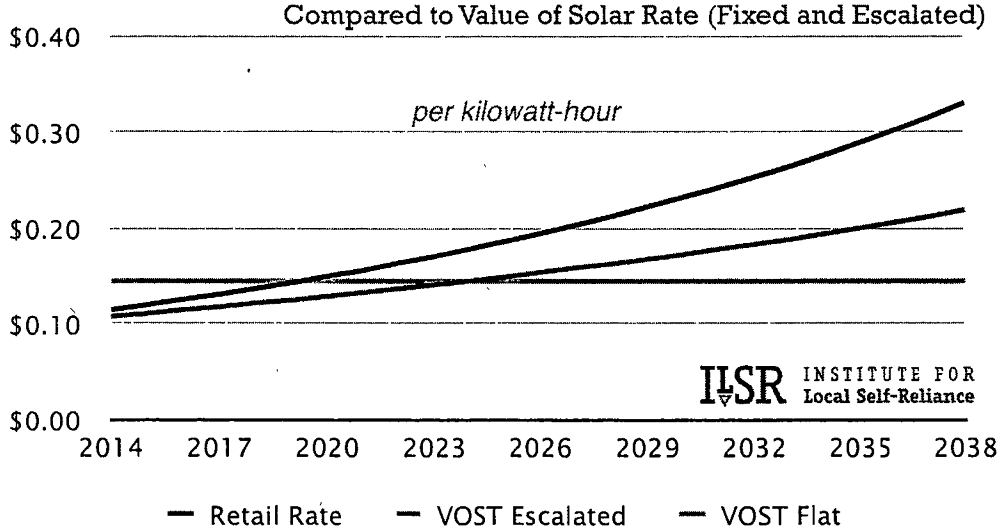


Fig. 12 shows how locking in the value of solar on a 25-year contract is likely to save the utility money compared to residential net metering, whether the value of solar rate is fixed or paid with an inflation escalator (with a comparable 25-year net present value). The top line shows the payment rate for energy generated under net metering, the second line is the rate paid on an escalating value of solar contract, and the flat line is the rate paid under a fixed value of solar (that has an equivalent 25-year net present value to the second line).

Not only that, utilities lock in the market value of solar when signing a 25-year contract, not bad for a business rocked by volatile fuel prices.

Figure 12. Projected Net Metering Rate (Residential)
Compared to Value of Solar Rate (Fixed and Escalated)



Finally, it may be that, due to the different nature of the transaction, a utility may be allowed some measure of cost recovery for solar energy purchased via the value of solar. This question will be addressed and answered when a utility first files to offer the policy.

Who Wins?

In theory, everyone is a winner if utilities adopt Minnesota's value of solar. In the near term, solar energy producers (especially commercial businesses) will get a better price than they have under net metering. In the long term, the cost of solar will fall (perhaps significantly) below the market-based value, and the 25-year, fixed price contract will help small scale producers secure financing.

Utilities should also come out ahead. Over the 25-year life of solar projects, they will pay less for solar energy than under net metering. Furthermore, greater amounts of solar on the grid will (over time) erode the market price for solar energy.

Utilities also get a sweet deal on renewable energy credits. Under net metering policy (in Minnesota), the generator of solar energy keeps the renewable energy credits. But under value of solar, they are automatically (and without compensation to the generator) transferred to the utility.

The market value of solar should also be a victory for ratepayers. First, it's transparent and without subsidy. In fact, it removes hidden subsidies for polluting fossil fuel generation. Ratepayers also get to purchase this renewable resource based on its value to the grid and not an awkward and obscure retail price proxy.

What the REC?

The value of solar law requires the renewable energy credit associated with each megawatt-hour (MWh) of solar generation to be transferred to the utility, but is silent on a value.

Minnesota utilities have argued that the law intends that value to be zero, despite robust prices for solar renewable energy credits (REC) on other states:

Solar REC Price ($ per MWh)

- Maryland - $140
- Massachusetts - $235
- New Jersey - $138
- Ohio - $22
- Pennsylvania - $24
- DC - $480

Prices from SRECTrade.com (Dec. 2013)

What's Next?

The hope is that value of solar can help defuse many of the state policy battles in progress over distributed generation. As shown in Fig. 1 (page 2) from the introduction, local power generation policy is under attack by utilities in many states.

If Minnesota utilities adopt the approved value of solar methodology and see it as a success, then it may encourage utilities in other states to support the option. Similarly, if solar and distributed generation advocates in other states see value of solar as a successful tool for growing on-site power generation, they'll be willing to come to terms with utilities.

The key to success is not just the policy, however, but the process of adoption and implementation. Minnesota's value of solar wasn't without significant controversy, and key provisions in the original law (e.g. customer choice) were lost before the process of setting the methodology. Even some of the enacted options (e.g. local economic development benefit) were left out of the approved methodology. Other states may find that these components are essential to getting all parties to approve of the value of solar.

Additionally, Minnesota had a very robust stakeholder process that was led by a very competent government agency and guided by two superb teams of experts from Clean Power Research and Rocky Mountain Institute. Without a similar process and expertise in another state, the process may not result in a similar level of buy-in. (Indeed, at this report's publication date, no utility had yet filed for value of solar in Minnesota).

Ultimately, value of solar is a promising policy opportunity, a way to address concerns of utilities and distributed renewable energy advocates with a transparent and robust market price. We'll see if it lives up to the promise.

Endnotes

[1] Farrell, John. Distributed Renewable Energy Under Fire. (Institute for Local Self-Reliance, 3/19/14). Accessed 3/21/14 at http://bit.ly/1eZNiGq.

[2] A Review of Solar PV Benefit and Cost Studies. (Rocky Mountain Institute eLab, April 2013). Accessed 3/21/14 at http://bit.ly/1eZNENq.

[3] *Karl was joined in this by Leslie Libby and Tim Harvey of Austin Energy and his future colleagues at Clean Power Research including Benjamin L. Norris and Thomas E. Hoff.*

[4] HF 773. Accessed 3/21/14 at https://www.revisor.mn.gov/bills/text.php?number=HF773&version=0&session=ls88&session_year=2013&session_number=0.

[5] *ILSR Director of Democratic Energy played a lead role in Solar Works for Minnesota coalition that developed the solar legislation.*

[6] HF 729 - http://bit.ly/1iwFn8b

[7] Value of Solar Tariff Methodology. (MN Department of Commerce, 2013). Accessed 3/21/14 at http://bit.ly/1eZTbU4.

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[9] Haugen, Dan. In bid against gas, Minnesota regulators say solar can proceed. (Midwest Energy News, 3/27/14). Accessed 3/28/14 at http://bit.ly/1mb8b6n.

[10] Comments, Value of Solar Methodology, Docket No. E999/M-14-65. (Xcel Energy, 2/13/14). Accessed 3/21/14 at http://cl.ly/3z293S061G3H.

Show Me the Numbers

A Framework for Balanced Distributed Solar Policies

Prepared for Consumers Union

November 10, 2016

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EXECUTIVE SUMMARY

Jurisdictions across the country are grappling with the challenges and opportunities associated with increasing adoption of distributed solar resources. While distributed solar can provide many benefits—such as increased customer choice, decreased emissions, and decreased utility system costs—in some circumstances it may result in increased bills for non-solar customers. In setting distributed solar policies, utility regulators and state policymakers should seek to strike a balance between ensuring that cost-effective clean energy resources continue to be developed, and avoiding unreasonable rate and bill impacts for non-solar customers.

To address this challenge, many jurisdictions are considering modifying distributed solar policies or implementing fundamental changes to rate design, such as increased fixed charges, residential demand charges, minimum bills, and time-varying rates. While it is prudent to periodically review and modify rate designs and other policies to ensure that they continue to serve the public interest, decision-makers frequently lack the full suite of information needed to evaluate distributed solar policies in a comprehensive manner. As this report demonstrates, it is critical to have accurate inputs, especially for "avoided costs" in order to identify whether a policy will increase or decrease rates for non-solar customers.

Regulators must strike a balance between ensuring that cost-effective resources continue to be developed, and avoiding unreasonable impacts on non-solar customers.

This report provides a framework for helping decision-makers analyze distributed solar policy options comprehensively and concretely. This framework is grounded in addressing the three key questions that regulators should ask regarding any potential distributed solar policy:

1. How will the policy affect the development of distributed solar?

2. How cost-effective are distributed solar resources?

3. To what extent does the policy mitigate or exacerbate any cost-shifting to non-solar customers?

Answering these questions will enable decision-makers to determine which policy options best balance the protection of customers with the promotion of cost-effective distributed solar resources. This report describes the analyses that can be used to answer these questions.

Analysis 1: Development of Distributed Solar

Customer payback periods provide a useful metric to indicate the extent to which different solar policies will affect the growth, or lack of growth, of distributed solar resources. Policies that lead to very short customer payback periods will likely produce rapid growth in these resources, while policies that lead to very long customer payback periods will likely result in little growth. Market penetration curves can be used to estimate eventual customer adoption levels from customer payback periods. Changing a customer's payback period will impact how economically attractive distributed solar is, and thereby affect how many customers ultimately adopt the technology.

Analysis 2: Cost-Effectiveness of Distributed Solar

Distributed solar can offer the electric utility system and society a host of benefits, ranging from avoided energy and capacity costs to reduced impacts on the environment and greater customer choice. At the same time, distributed solar may impose administration and integration costs on the utility system. Many recent studies have assessed whether the benefits of distributed solar outweigh the costs. These studies are most informative when they use clearly defined, consistent methodologies for assessing costs and benefits.

The most relevant cost-effectiveness tests for evaluating distributed solar are the Utility Cost Test, the Total Resource Cost Test, and the Societal Cost Test, which are based on the cost-effectiveness analyses long applied to energy efficiency resources.

- The Utility Cost Test indicates the extent to which distributed solar will reduce total electricity costs to all customers by affecting utility revenue requirements.
- The Societal Cost Test takes a broader look and indicates the extent to which distributed solar will help meet a state's energy policy goals such as environmental protection and job creation, as well as reducing customer electricity costs.
- The Total Resource Cost Test, in theory, indicates the extent to which distributed solar will reduce utility system costs net of the host customer's costs. This test should be used with caution, as it has some structural constraints that limit its usefulness.

Analysis 3: Cost-Shifting from Distributed Solar

Cost-shifting from distributed solar customers to non-solar customers occurs in the form of rate impacts. Distributed solar can cause rates to increase or decrease due to changes in electricity sales levels, costs, or both. A comprehensive rate impact analysis is the best way to analyze the potential for cost-shifting from distributed solar.

When evaluating cost-shifting, it is important to analyze both long-term and short-term rate impacts to understand the full picture. Often, the benefits of distributed solar are not realized for several years, while a decrease in electricity sales occurs immediately, resulting in short-term rate increases followed by long-term rate decreases. Thus a short-term rate impact analysis will not fully capture the impacts of distributed solar.

Because distributed solar resources can create both upward and downward pressure on rates, the combined effect could result in in either a net increase or decrease in average long-term rates.

In their most simplified form, electricity rates are set by dividing the utility class's revenue requirement by its electricity sales. Thus rate impacts are primarily caused by two factors:

1. Changes in costs: Holding all else constant, if a utility's revenue requirement decreases, then rates will decrease. Conversely, if a utility's revenue requirement increases, rates will increase. Distributed solar can avoid many utility costs, which can reduce utility

revenue requirements. Distributed solar can also impose costs on the utility system (such as interconnection costs and distribution system upgrades).

2. Changes in electricity sales: If a utility must recover its revenues over fewer sales, rates will increase. This is commonly referred to as recovering "lost revenues," and is an artifact of the decrease in sales, not any change in costs. Lost revenues should be accounted for in the rate impact analysis, but not in the cost-effectiveness analysis.

Whether distributed solar increases or decreases rates will depend on the magnitude and direction of each of these factors.[1] In very general terms, if the credits provided to solar customers exceed the average long-term avoided costs, then average long-term rates will increase, and vice versa.

Summary of Analytical Framework for Assessing Distributed Solar Policies

The results of the three analyses described above can be pulled together into a single framework to evaluate different distributed solar resource policies in an open, data-driven regulatory process. The framework proposed here includes several steps that policymakers, regulators, or other stakeholders can take to assess the implications of different distributed solar policies. These steps are summarized in Table ES.1.

Table ES.1 Steps Required to Assess Distributed Solar Policies

Step 1	Articulate state policy goals regarding distributed solar resources.
Step 2	Articulate all the existing regulatory policies related to distributed solar resources.
Step 3	Identify all of the new distributed solar policies that warrant evaluation.
Step 4	Estimate the customer adoption rates under current solar policies, and new solar policies.
Step 5	Estimate the cost-effectiveness of distributed solar under current policies and new policies.
Step 6	Estimate the extent of cost-shifting under current solar policies, and new solar policies.
Step 7	Use the information provided in the previous steps to assess the various policy options.

To facilitate understanding and decision-making, it is useful to summarize the results of the three analyses in a single table. Table ES.2 provides an example of how the results could be summarized for reporting and decision-making purposes.

The primary recommendation from this report is that regulators should require utility-specific analyses of: (1) distributed solar development, (2) cost-effectiveness, and (3) cost-shifting impacts of relevant distributed solar policies. This will allow for a concrete, comprehensive, balanced, and robust discussion of the implications of the distributed solar policies.

[1] Whether rates actually increase or decrease is also dependent upon a host of other factors not related to distributed solar.

Table ES.2 Summary of Hypothetical Results

	1. Distributed Solar Development		2. Cost Effectiveness			3. Rate and Bill Impacts	
	Customer Payback	5-Year Penetration	Utility Net Benefits	Total Resource Net Benefits	Societal Net Benefits	Avg. Bill Impact	Long-Term Avg. Bill Impact
	Years	*%*	*$ Million*	*$ Million*	*$ Million*	*$/mo*	*%*
Policy 1							
Policy 2							
Policy 3							

Using the results of the analyses presented above, policymakers, regulators, or other stakeholders can review the projected impacts of various policy options to determine what course of action is in the public interest. Appropriate consideration of all relevant impacts will help decision-makers to avoid implementing policies that have unintended consequences or that fail to achieve policy goals. The results of such analyses can also help to determine the point at which certain distributed solar policies should be reevaluated and modified over time.

Given that each jurisdiction has its own policy goals and unique context, the ultimate policy decision reached may be different in each jurisdiction, even when based on the same analytical results. Nonetheless, the framework articulated above will provide decision-makers with the ability to balance protection of customers with overarching policy objectives in a transparent, data-driven process.

1. INTRODUCTION AND BACKGROUND

Distributed solar[2] can pose a challenge for policymakers, regulators, and consumer advocates as it can reduce system costs over the long-run, but in some cases may also result in increased bills for non-solar customers. This report is intended to provide a guide for decision-makers and other stakeholders who seek to strike a balance between ensuring that cost-effective resources continue to be developed, while avoiding unreasonable rate and bill impacts on non-solar customers.

Nearly every state in the nation has adopted net metering as a compensation mechanism for distributed solar customers. However, jurisdictions across the country are beginning to reevaluate their distributed solar policies. For example, in the first quarter of 2016, 22 states considered or enacted changes to net metering policies (NCCETC 2016). While simple to administer (and simple to understand), concerns have been raised that net metering may lead to unacceptable rate impacts on non-solar customers.

It is prudent to periodically review and modify distributed solar policies to ensure that they continue to serve the public interest. To date, however, many jurisdictions have developed or modified their policies in a piecemeal fashion, rather than based on a quantitative analysis of the various impacts that distributed solar can have on the utility system and other customers. Without appropriate data-driven consideration of all relevant impacts based, decision-makers risk implementing policies that have unintended consequences or that fail to achieve policy goals.

Regulators should strike a balance between ensuring that cost-effective resources continue to be developed, while avoiding unreasonable impacts on non-solar customers.

This report provides a framework for helping decision-makers analyze distributed solar policy options more comprehensively by evaluating three critical indicators:

- The likely customer adoption of distributed solar
- The cost-effectiveness of distributed solar
- The magnitude of cost-shifting to non-solar customers

Once the results of these analyses are available, decision-makers can evaluate their policy options to determine what course of action will be in the best interest of customers as a whole by balancing the protection of customers with development of distributed solar resources.[3]

Appendix A provides sample discovery questions designed to assist stakeholders obtain the key pieces of information required for conducting the analyses recommended in this report. It is critical to have accurate inputs, especially for avoided costs, to accurately estimate the impacts of distributed solar policies. The answers to these questions will differ across jurisdictions, and thus the framework should be applied using the best available information that is relevant to each jurisdiction.

[2] We use the term "distributed solar" to refer to small solar photovoltaic (PV) systems that are located on the distribution system. These systems generally take the form of rooftop PV operating behind the meter, but may also include installations not sited at the point of use, such as community solar.

[3] Regulators are tasked with implementing laws that have been adopted by the state legislature or executive branch. In some cases utility regulators have a wide range of policy options; in other cases the options are dictated by the state government.

2. DISTRIBUTED SOLAR POLICY OPTIONS

A comprehensive analysis of distributed solar policy options should begin with an explicit articulation of the jurisdiction's energy policy goals. Such policy goals may include (a) reducing electricity costs, (b) promoting customer control or choice, (c) reducing environmental impacts, and (d) promoting local jobs and economic development. In addition, jurisdictions generally attempt to balance these goals with the goal of avoiding or mitigating unreasonable cost-shifting to non-solar customers. These policy goals should inform the selection of policy options related to distributed solar and the evaluation of their impacts.

Policies that impact distributed solar include, but are not limited to: compensation mechanisms; rate designs that directly affect the credits that solar customers receive; program enrollment level caps; interconnection standards that govern the processes for connecting to the grid; and other policies designed to reform long-term grid planning efforts such that higher penetrations of distributed solar can be more easily accommodated and optimized on the grid. Regulators and policymakers can adjust these policies to encourage balanced growth of distributed solar and to mitigate rate impacts. The table below provides examples of the various types of policy options and supporting activities.[4]

Table 1. Distributed Solar Policy Categories

Policy	Examples
Compensation Mechanisms	Net metering, feed-in-tariff, value-of-solar tariff, renewable energy certificates, rooftop lease payments, performance incentives
Rate Design	Fixed charges, demand charges, time-of-use rates, bypassable versus non-bypassable bill components
Up-Front Incentives and Financing	Investment tax credits, sales tax exemptions, rebates, loans, grants
Interconnection and Permitting	Expedited review, mandated time limits, zoning exemptions, interconnection and permitting fees
Integration and Planning	Hosting capacity analyses, integrated resource planning, distribution system planning
Ownership	Customer up-front purchase, third-party ownership, utility ownership and lease to customer, loans
Education, Training, And Outreach	Information, tools, workshops, online assistance, community outreach

[4] Many residential and small commercial customers choose to lease their system or enter into a power purchase agreement (PPA) with third-party solar developers. Therefore it may be important to understand how various policies affect these developers, rather than only the host customers, when considering policy options.

In this report, we focus primarily on compensation mechanisms and rate design for residential and small commercial solar customers.[5] Often compensation mechanisms and rate design work in tandem, such as under net metering policies where a change in rate design can affect the net metering credit. Compensation mechanisms and rate design are particularly important policies for decision-makers to consider, as they can impact the rate of adoption of distributed solar, the magnitude of any rate impacts on non-solar customers, and the extent to which utilities are able to recover their allowed revenues.

In this report, we focus primarily on compensation mechanisms and rate design for residential and small commercial solar customers.

2.1. Rate Design and Distributed Solar

The Purpose of Rate Design

When considering rate design modifications, it is important to keep in mind the core objectives of electricity rates. In 1961, Professor James Bonbright set forth eight rate design principles, and distilled these principles into the following three objectives:

1. The revenue-requirement or financial-need objective, which takes the form of a fair-return standard with respect to private utility companies;

2. The fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed fairly among the beneficiaries of the service; and

3. The optimum-use or consumer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received (Bonbright 1961, 292).

The first objective seeks to ensure that utilities are able to recover sufficient revenues; the second objective is focused on fairness of rates; and the third objective addresses efficient resource usage.

These three objectives are still as relevant today as they were in 1961, with one modification. Customers are no longer only consumers; rather, they are increasingly also producers of a range of services, such as energy generation, demand reduction, and even ancillary services. For this reason, the third objective need not be limited to encouraging customers to *consume* electricity efficiently, but also to *produce* electricity (and related services) efficiently. With this modification, Bonbright's third objective also

[5] For simplicity, we assume that rate design and compensation mechanisms will affect the payback period for both third-party developers and host customers who purchase their systems outright in a similar manner.

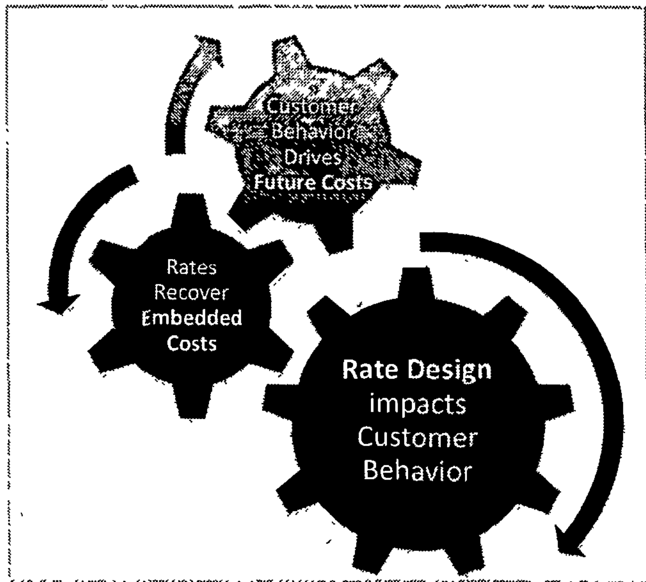
includes the primary objective of resource planning, namely the cost-effective procurement of resources, including distributed solar.[6]

Rate Design as a Balancing Act

Regulators strive to protect the long-run interest of customers by overseeing the provision of reliable, low-cost energy, while also ensuring that rates are fair, just, and reasonable. At its essence, ratemaking requires a balancing of multiple interests, as the principles and objectives enumerated by Bonbright are often in tension with one another.

The tension among ratemaking objectives stems not only from the need to balance the interests of different parties (utilities, customer classes, and individual customers), but also the need to recover *historical* (embedded) costs while sending price signals that drive efficient *future* investments by affecting customer behavior.

Figure 1. Relationship Among Historical Costs, Future Costs, and Rate Design



In order to meet both of these objectives, rate design should be informed by two different types of analyses: embedded cost of service studies and forward-looking resource plans.

Cost-of-service studies help to establish relationships between utility costs and customer consumption, and allocate historical costs equitably by dividing the revenue requirement among customer classes based on each class's contribution to past investments and operating expenses.

Once the revenue requirement for each class has been set, the focus shifts to minimizing *future* costs, rather than simply recovering historical costs. Rates are designed to recover a set amount of revenues, but also to provide customers with appropriate price signals to help customers make efficient consumption and investment decisions (including investments in distributed solar) that will help minimize long-term system costs.

The connection between the two primary analyses and rate design can be summarized as follows:

- **Cost-of-Service Studies:** The primary purpose of embedded cost-of-service studies is to identify how to allocate the revenue requirement across the rate classes. The revenue requirement is largely the product of *historical* investments made by the utility to serve

[6] This discussion assumes continuation of the current electric utility structure. However, the electric utility model is beginning to evolve to accommodate a more distributed, customer-centric future, and to better address policy goals such as reducing greenhouse gas emissions. As such, the primary objectives of rate design may need to evolve as well.

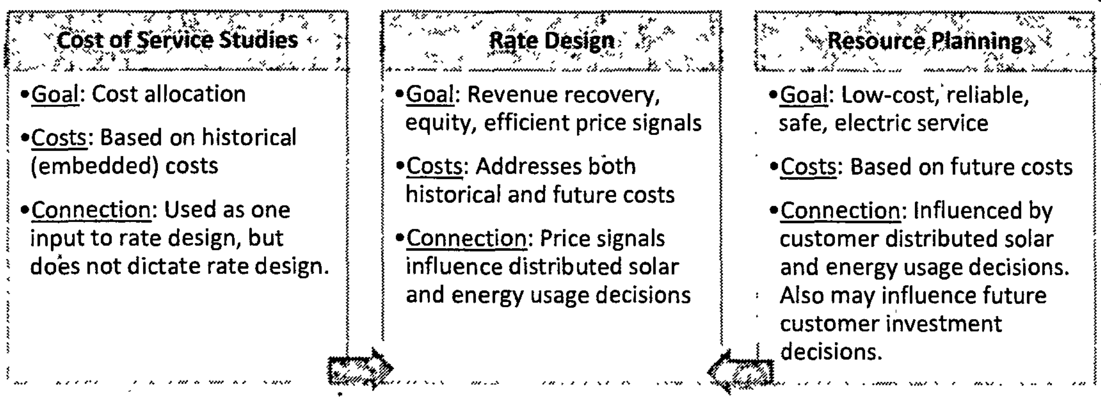
various customer classes. While cost-of-service study results can be used to inform rate design, the cost-of-service study should not be used to dictate rate design, as it does not account for future costs.

- **Resource Planning:** The purpose of resource planning is to identify those *future* resources and investments that are cost-effective and in the public interest. Cost-effective resources may include distributed energy resources as an alternative to supply-side resources or investments in traditional utility infrastructure. This exercise provides an indication of how much distributed solar should be implemented or encouraged by the utility to cost-effectively meet future resource needs and minimize long-term system costs.

Rate design plays an important role in the procurement of distributed solar. Unlike traditional supply-side resources, distributed resources are rarely procured directly by a utility. Instead, distributed resources are generally installed by individual households and business owners. Since rate design can significantly impact the economics of distributed solar systems installed by such utility customers, it serves as a primary tool for stimulating or stifling the installation of additional distributed solar on the utility system.

Figure 2 summarizes the connections among cost of service studies, rate design, and resource planning, as well as the different types of costs considered in each analysis.

Figure 2. The Role of Cost of Service Studies, Rate Design, and Resource Planning



Rate Design Options

The underlying rate design has a direct impact on the financial viability of distributed solar, as it determines the degree to which customers can reduce their electricity bills by investing in distributed solar. For example, increasing the fixed charge reduces the variable rate, effectively also lowering the net metering compensation rate, and can thereby substantially reduce incentives for customers to install distributed generation (Whited, Woolf, and Daniel 2016).

Fixed charges are not the only form of rate design that can impact the adoption of distributed solar. Other rate designs include:

- **Demand charges:** A demand charge is typically based on a customer's highest demand during any one period (e.g., hour or 15-minute period) of the month. A demand charge often reduces the economic attractiveness of solar, since solar generation generally reduces demand much less than it reduces energy consumption.[7]

- **Minimum bills:** A minimum bill is similar in appearance to a fixed charge, but only applies if the customer's bill would otherwise be lower than the minimum threshold. While a minimum bill ensures that all customers contribute a certain amount to the system each month, it does not distort the variable rate.

- **Time-of-use rates:** Time-of-use rates are a simple form of time-varying rate that has been used for decades. A time-of-use rate assigns each hour of the day to either a peak, off-peak, or shoulder period. The energy rate is then set to be highest during the peak hours and lowest during off-peak hours to better reflect the actual underlying costs of providing electricity during those hours. A time-of-use rate can be designed in many ways. The particular design of the rate can either increase or reduce the economic attractiveness of distributed solar.

- **Inclining block rates:** These rates are set so that the first block of kilowatt-hours consumed each month (e.g., the first 200 kWh) is billed at a lower rate than the next block of consumption. Because net metering offsets a customer's highest block of consumption first, inclining block rates can increase the value of distributed solar to the host customer.

- **Declining block rates:** Declining block rates are the inverse of inclining block rates. Under a declining block rate, the electricity price declines as energy consumption increases. These rates are rare for small residential and commercial customers, but are more common for large commercial and industrial customers.

2.2. Compensation Mechanisms for Distributed Solar

Net Metering

Net metering allows customers to offset their electricity consumption with their system's generation on a one-to-one basis at the end of a month. Net metering is currently the most common method of compensating solar generation for the individual home or business, having been adopted in more than 43 states (NCCETC 2016). It has traditionally been applied to customers who install solar on their premises, but is increasingly also being applied to community solar options (discussed below).

There are many varieties of net metering, and the specific program design parameters can impact the economic viability of distributed solar. These parameters may include:

- **Program caps:** A cap closes the net metering program to new customers once a certain penetration level has been reached.[8]

[7] Solar customers frequently have high usage during non-daylight hours when solar panels are not producing energy. In addition, an hour of cloud cover during daylight hours can cause a solar customers' usage from the grid to spike temporarily.

[8] Caps can be expressed in different ways, such as a percent of historical peak demand, a percent of electricity sales, or in absolute megawatts of capacity.

- **System size limits:** Often net metering is limited to customers with relatively small systems, such as under 500 kW. In some cases, the size limit is based on the host customer's load.
- **Treatment of excess generation:** Programs vary in terms of how excess generation is compensated (i.e., when total generation exceeds consumption for the month), and whether bill credits can be rolled over to the next month.
- **Underlying rate design:** Residential customers are typically billed through a combination of fixed charges and variable rates (in cents/kWh), with net metering compensation provided at (or close to) the variable rate.[9] Changes to the variable rate can affect the ability of customers to offset their bills with net metering credits.

Buy All/Sell All

A buy all/sell all tariff requires that all energy consumed by the host customer be purchased from the utility at the retail rate, and all generation be sold to the utility at a different rate. This rate may be higher or lower than the retail rate. Two variants of the Buy All/Sell All approach are value-of-solar tariffs and feed-in tariffs, described in the following sections.[10]

Value-of-Solar Tariffs

Value-of-solar tariffs are an alternative to net metering that is based on the estimated net value provided by solar generation. This net value can be estimated in many different ways, but the key elements typically include:

- Avoided energy costs (e.g., fuel, O&M)
- Avoided capacity (generation, transmission, and distribution)
- Avoided line losses
- Avoided environmental compliance costs
- Costs imposed on the system (integration costs, administrative costs)

An example of a jurisdiction that uses a value-of-solar tariff is Austin Energy. The value-of-solar rate is set on an annual basis through Austin Energy's budget process (City of Austin 2016). Because it is set

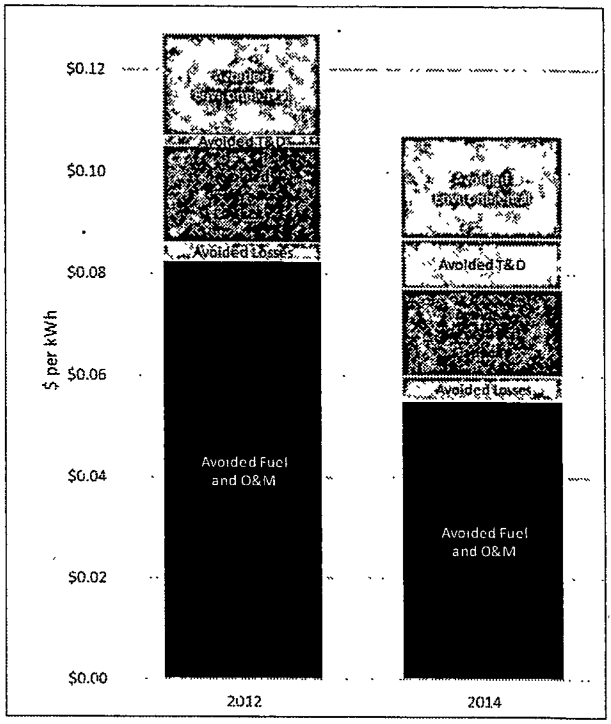
[9] This compensation rate does not include certain non-bypassable riders or fees.

[10] Some concern has been raised that a Buy All/Sell All mechanism may create tax liabilities for solar owners. Under a Buy All/Sell All mechanism, the owner may be viewed as engaging in the sale of electricity, the proceeds of which could constitute gross income.

annually, the rate fluctuates from year to year but is generally in the range of 10 to 12 cents per kilowatt-hour.

The methodology used by Austin Energy to calculate the value-of-solar rate was originally set in 2012 and considers loss savings, energy savings, generation capacity savings, fuel price hedge value, transmission and distribution capacity savings, and environmental benefits (Karl Rábago et al. 2016).

Figure 3. Austin Energy's Value-of-Solar Tariff 2012 and 2014



Value-of-solar tariffs may be applied in different ways. One method is to require that all energy consumed be purchased from the utility at the retail rate, while all generation is sold to the utility at the value-of-solar rate (i.e., a buy-all/sell-all arrangement). Under this option, no netting is permitted. Other jurisdictions may apply the value-of-solar rate only to excess generation, while any generation consumed behind the meter is effectively netted at the retail rate.

Feed-In Tariffs

A feed-in tariff (FIT) operates similarly to a value-of-solar tariff, in that it compensates solar generation at an administratively set value. However, the goal of a FIT differs from a value-of-solar tariff in that a FIT is designed explicitly to provide an incentive to install distributed generation. Typically FITs are used to stimulate early adoption of new technologies that would otherwise be cost-prohibitive for most customers. As such, the FIT is generally designed to allow distributed generation customers to earn a reasonable return on their investment.[11]

Instantaneous Netting

Net metering has traditionally netted energy consumption against generation at the end of a billing cycle (e.g., on a monthly basis). However, recently some jurisdictions (such as Hawaii) have begun to experiment with what can be called "instantaneous netting." Under this approach, any generation consumed on-site offsets grid-supplied energy at the retail rate on a near-instantaneous basis, while any generation exported to the grid is credited at a lower rate (Public Utilities Commission of Hawaii 2015).

[11] FITs have been widely used in Europe (particularly Germany), and on a more limited basis in the United States. For example, Portland General Electric (PGE) solar customers can choose a feed-in-tariff option called the Solar Payment Option, which currently compensates customers at a rate much higher than the net metering rate for a period of 15 years. *See:* PGE, "Solar Payment Option - Install Solar, Wind & More," https://www.portlandgeneral.com/residential/power-choices/renewable-power/install-solar-wind-more/solar-payment-option.

This rate structure encourages customers to use as much of their generation as possible (or store it in batteries), rather than pushing it onto the grid.

2.3. Additional Options

Community Solar and Other Virtual Net Metering

Community solar allows customers who are unable to install solar PV on their homes or businesses to benefit from the solar energy produced by an off-site solar installation (also called "virtual net metering").[12] Customers typically purchase a subscription or "share" of the electricity generated by the installation. Subscribers then receive both a charge for the subscription and a credit for the reduction in grid-supplied energy that are applied to their electricity bill. This credit may be equal to, more than, or less than the retail rate. Community solar installations have the advantage of removing some barriers to entry for installing solar systems. For example, community solar expands access to renters or other customers without suitable roof space, and to customers who have limited access to financing.

While community solar installations are typically much larger than the average residential system, smaller forms of virtual net metering are possible. In Massachusetts, a hybrid between large community solar arrangements and traditional net metering exists whereby an individual host customer can share his or her net metering credits with other customers who take service from the same utility (Public Utilities Commission of Hawaii 2015).

Renewable Energy Certificates and Solar Renewable Energy Certificates

Renewable Energy Certificates (RECs) and Solar Renewable Energy Certificates (SRECs) offer customers a financial incentive to install distributed solar by allowing customer generators to sell their RECs or SRECs to electricity suppliers, who are required by law to purchase a minimum number each year to comply with the jurisdiction's Renewable Portfolio Standard (RPS) or its RPS solar carve-out.

Currently 29 states and the District of Columbia have RPS policies, while a smaller number of states have solar carve-outs. States with solar carve-outs and an SREC market include Massachusetts, New Jersey, New Hampshire, Pennsylvania, Ohio, Delaware, Maryland, and the District of Columbia (Barbose 2016). However, many other states in the eastern United States are able to participate in the SREC markets of states with solar carve-outs (SREC Trade 2016). Some states have adopted an approach that does not use separate SRECs, but provides solar customers with a multiplier on their RECs (Barbose 2016). For example, a state might provide 3 kWh worth of RECs for 1 kWh generated by distributed solar.

Basic market forces determine the value of a REC or SREC: the supply of credits is determined by the quantity of eligible resources currently in place, while demand is determined by the jurisdiction's requirements. SREC prices are generally higher than RECs, and therefore tend to provide a stronger

[12] We note that the terms "community solar" and "virtual net metering" are used quite inconsistently across the country and also go by different names. For example, community solar may also be called "shared solar," "community distributed generation," or "neighborhood net metering."