Distributed Generation and Retail Electric Rates

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1 Abstract

Electric cooperatives are reviewing their rates due to of the growth in solar distributed generation (DG). The cooperatives goal is to promote the use of renewable energy and reduce cost shifting to members without DG. This paper describes the DG rate strategies of four cooperatives that are located in Northeast Iowa and Southeast Minnesota. The cooperatives are reviewing rate options so costs are recovered fairly but at the same time promoting the use of renewable energy. The process of developing a cost of service (COS) rate for DG and non-DG accounts is reviewed. Rate options such as limiting net metering, demand rates, and increasing the monthly service charge are reviewed.

2 Introduction

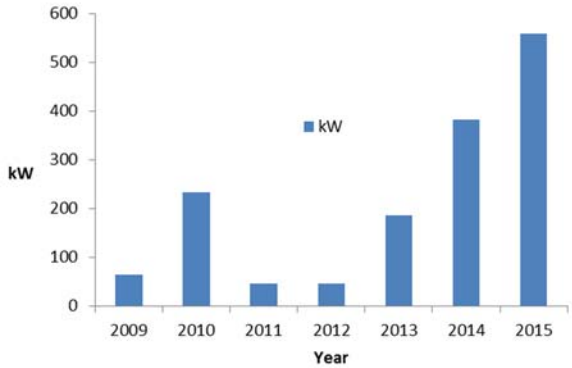
Allamakee-Clayton Electric Cooperative, Hawkeye REC, and Heartland Power Cooperative (Iowa) and Tri-County Electric Cooperative (Minnesota) purchase power from the Generation and Transmission Cooperative, Dairyland Power Cooperative (DPC), located in La Crosse, Wisconsin. The service territory for these cooperatives is located in southeast Minnesota and northeast Iowa. These cooperatives serve a combined total of approximately 36,000 members on 10,000 miles of line.

The amount of DG connected to the 12.5 kV distribution lines of these cooperatives has increased recently due to the decrease in the cost of solar generation. The DG accounts use less energy than the non-DG accounts which results in reduction in the recovery of fixed costs that are included in the energy rate. This increase in DG penetration has caused the cooperatives to review the impact the DG accounts have on recovering fixed costs and to consider new rate strategies to reduce cost shifting to members without DG.

3 DG Penetration

The four cooperatives have seen an increase in the amount of DG installed over the past few years. The growth has occurred due to the installation of solar generation with a nameplate rating of less than 40 kW. Figure 1 shows the historical installation of these units with capacities less than 40 kW at one of the cooperatives.

Figure 1 Annual DG Nameplate Capacity Installed at a Cooperative



The members install DG to provide energy for their own use and interconnect the DG to the cooperative's 12.5 kV distribution so the excess energy is delivered to the grid. Table 1 shows the capacity factor (CF) and the self-consumption (Use) of the DG energy for several installations. The self-consumption describes the amount of DG energy that is directly consumed by the member loads. The CF is the ratio of the annual energy produced by the DG unit to the nameplate capacity multiplied by 8,760 hours/year.

Table 1 DG Self-Consumption & Capacity Factor Data

Type	kW	CF	Use
Wind	10.0	10.3%	38.0%
Solar	4.6	18.4%	26.7%
Solar	4.9	19.6%	30.1%
Solar	38.4	13.4%	37.5%
Solar	8.6	11.7%	30.4%
Solar	16.2	15.8%	29.6%
Solar	16.2	11.6%	20.0%
Solar	12.0	16.2%	43.4%
Solar	3.5	14.1%	24.2%
Solar	8.0	13.0%	21.7%
Solar	7.0	12.2%	52.8%
Solar	4.0	15.3%	17.5%
Solar	4.0	20.9%	24.8%
Wind	10.0	22.0%	48.7%
Solar	1.5	16.3%	19.5%
Average	**9.9**	**15.4%**	**31.0%**

The self-consumption average is 31% which shows the members with DG rely on the grid because the generation does not match the instantaneous load requirements of the member. This is similar to photovoltaic (PV) self-consumption for systems installed in Germany where load data shows the PV self-consumption level range is 20% to 30%. [1] The average CF is 15% which is typical for small solar and wind generation in Iowa and Minnesota.

4 Retail Rates for DG

The cooperatives have retail rates for DG installations that are based on the cooperative's policies and rules required by the States of Iowa and Minnesota. The State of Iowa doesn't require net metering for electric cooperatives. The State of Minnesota requires net metering for DG units that are Qualifying

Facilities (QF) and have nameplate rating of less than 40 kW. The cooperatives in Iowa have rates for DG that pay avoided cost for excess energy or net metering.

Electric utilities are required to follow the Public Utility Regulatory Policies Act (PURPA) for rules related to DG that meet the requirements for QF. QF are power producers and cogeneration facilities that produce power from biomass, waste, renewable resources, and geothermal resources with a capacity no greater than 80 MW. The key obligations from PURPA for electric utilities are as follows: [2]

- Purchase energy and capacity from the QF
- Sell energy and capacity to the QF
- Interconnect with the QF

The Federal Energy Regulatory Commission (FERC) implements PURPA, and the state commissions and non-regulated utilities enforce PURPA. The electric utilities are required to purchase energy and capacity from QF at the "avoided cost." The "avoided cost" is the incremental cost to the electric utility of energy and capacity which the utility would generate itself or purchase from another utility. [2]

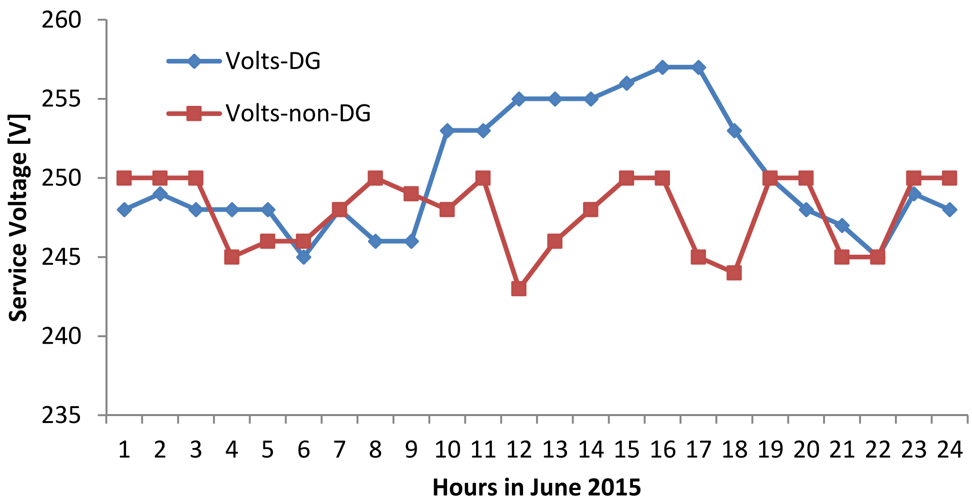
The cooperatives establish DG rates and polices that follow PURPA, state commission requirements, and the cooperative's policies. The cooperative boards consist of directors that are elected members representing geographic areas of the cooperative's service territory. Directors work with the cooperative staff to develop the DG rates and policies that represent the interests of the members and meet the requirements of the regulatory agencies.

The cooperatives in Iowa either pay avoided cost for excess energy or allow net metering. Iowa only requires net metering for investor-owned utilities. Some of the Iowa cooperatives allow net metering because the cooperative's service territory borders Minnesota and serve some Minnesota members. The cooperatives charge the same monthly and energy rate to DG and non-DG users.

5 Retail Rate Design

The electric retail rates are developed to provide sufficient revenue to meet the operating expenses and margin or net income requirements. The margins are required to pay the principal and interest on long-term debt, invest in improvement projects, pay for the retirement of patronage capital and maintain the required financial objectives required by the debt holders.

Figure 2 Voltage at Meter for Account with DG & Neighboring Account without DG



The operating expenses include the cost of purchased power, transmission costs and distribution costs. The distribution costs consist of Operating and Maintenance (O&M) expenses, Administration and General (A&G), depreciation, interest from debt, and margins.

The costs consist of fixed and variable costs. The fixed costs are costs that don't change with the amount of energy consumed. An example of a fixed cost is the interest expense and depreciation which are a function of capital investments in the utility from installing or upgrading distribution lines. The variable costs vary with the amount of energy used. An example of a variable cost is the energy cost of purchased power. The energy cost is usually related to the cost of fuel for the production of energy.

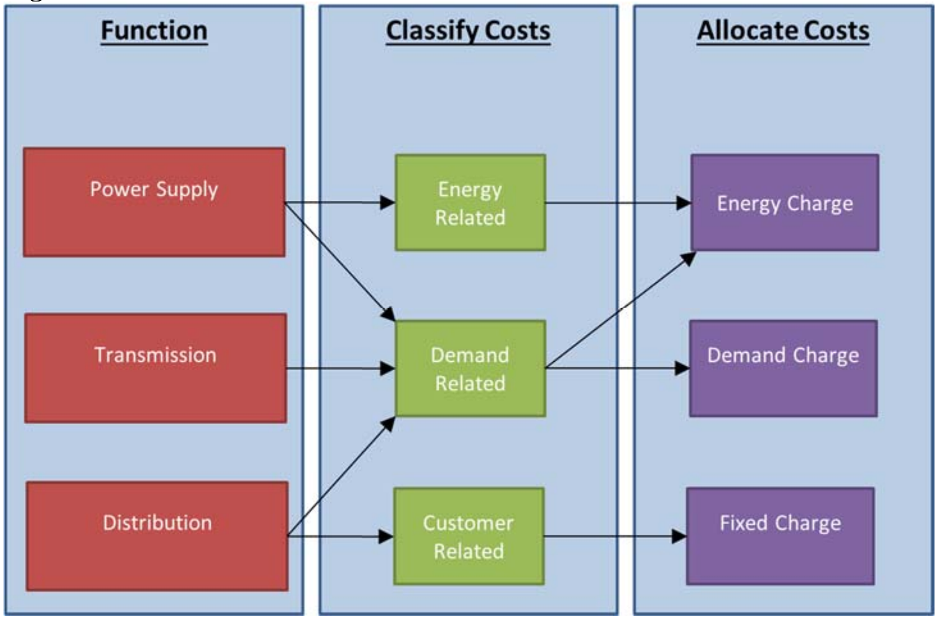
Accounts with DG use less energy than the average account for the single-phase rate class. The single-phase rates recover some of the fixed cost in the energy rate. The reduction in energy use results in DG accounts contributing less than the average non-DG user to fixed costs. The accounts with DG require a reliable grid connection to transfer excess energy when the generation exceed the load and for energy from the grid to the member when the member loads exceeds the generation output. Operational issues can occur with DG users that require additional O&M expenses. Some operational issues have occurred when the service voltage exceeded 250 volts with the DG operating, causing the inverters to shut down. This behavior can be seen in Figure 2, which compares the service voltage for a 29 kW solar DG and non-DG system for a typical day in June.

The regulator controls at the substation were changed with a lower voltage setting and higher compensation settings that reduced the voltage on the line serving the member with the DG. The cooperative will install a transformer with taps if the voltage level continues to cause concerns with the inverter.

6 COS Review

The objective of the COS review is to allocate the various accounting costs associated with the electric utility to the appropriate rate class. The cost allocation process is used as a guideline to establish electric rates. The procedure used to allocate the costs includes assigning the costs to a standard function, classifying the functional cost into categories and allocating the category costs to each rate class. The standard functions are power supply, transmission, and distribution. The rate categories include demand (capacity), energy, and member costs.

Figure 3 Classification of Costs for Allocation to Rates



The capacity or demand costs are related to the peak usage of electric power. These costs include generation and transmission, substations, and a portion of the distribution costs. Energy costs include fuel for generation and the energy charges associated with power purchased. These costs are from the wholesale power supply purchases.

The power supply functions include generation and transmission. The transmission and generation demand charges are allocated based on the cooperative's contribution to the power supplier's peak demands. The energy charges are allocated based on the energy use. Power supply costs are allocated to each rate class based on the group demand and energy use of each rate class.

The distribution costs are classified as member and demand costs. These costs include O&M, A&G, interest, depreciation, metering, and billing. The member costs include the cost and expenses associated with the service, metering, billing, and accounting. The demand costs include the investment and expenses associated with the equipment required to deliver the power to meet the peak demand of the members.

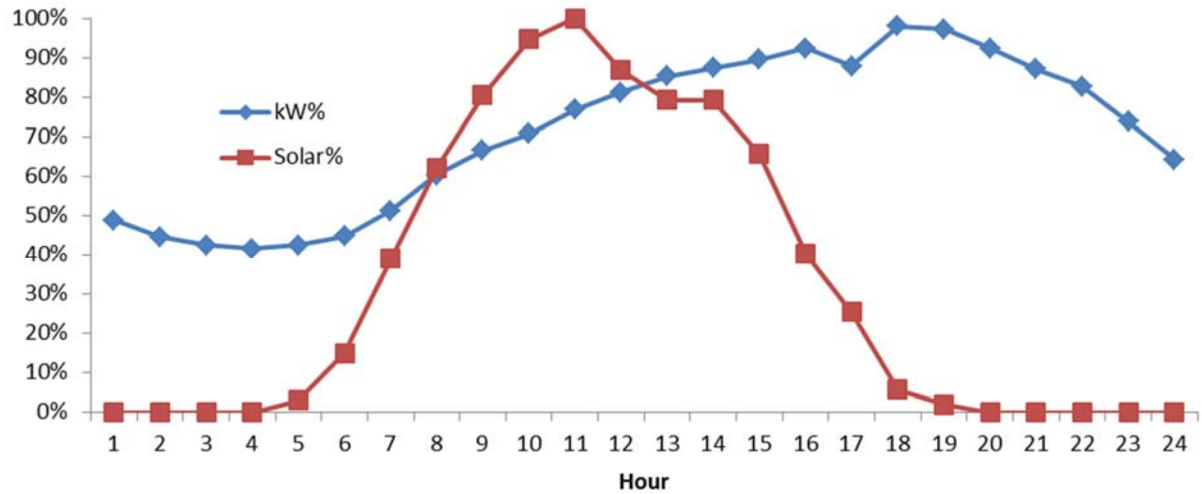
Figure 3 summarizes the cost allocation process. Some of the distribution costs are classified as both a member and demand cost. These costs include O&M, A&G, interest, depreciation, and margins. These costs are divided between the member and demand classification.

The costs are allocated to the various rate classes using allocation factors. These factors include the quantity of members, amount of energy used by each rate class, and the group demand of each rate class. An estimate of the average of the peak coincident demand for each rate class is used to allocate the distribution demand charges.

The member-related costs are used as a guideline to establish the basic monthly service charge. The demand cost is used as a guideline to establish a demand charge for demand-billed members or is included in the energy charge for non-demand billed members.

The final step in the COS analysis is to compare the revenue from each rate to the assigned costs to each rate. This comparison provides a guideline on rate adjustments that may be required. Rates may be adjusted so the estimated rate revenue is similar to the allocated costs. Other factors such as rates of neighboring utilities are reviewed to determine the rates for each rate class.

Figure 4 Load Profile for Iowa Cooperative and Solar Output as a Percent of Peak Demand and Output



7 COS Example for DG Accounts

The members with DG are presently included in the single-phase or residential rate class for the four cooperatives. As the number and members with DG increases, it becomes more essential to review these rates to ensure the costs are allocated equitably to the members with DG.

The distribution costs include the member and distribution demand costs. The member accounts are allocated based on the quantity of accounts in each rate class. The distribution demand costs are allocated based on the estimated group demand for each rate class.

The power supply costs are allocated to each rate class in proportion to the energy use and group demand of each rate class group. The power supply average demand for the DG group could be less than the group demand for non-DG accounts because DG units could be operating during the time periods that the power supply peak demand periods occur. A credit for demand reduction will depend on the amount of solar output that occurs when the power supply demand periods occur.

The amount of solar generation can be estimated using solar calculators. Figure 4 compares an estimate of solar generation from the National Renewable Energy Laboratory (NREL) PVWatts® Calculator and the hourly demand for a cooperative's substation demand during a typical summer day. [3]

The solar output peaks around the noon hour and decreases to minimal output around 6 to 7 PM during the summer. The load profile for the typical cooperative substation shows the load begins to increase around 8 AM and reaches a peak around 7 or 8 PM when the solar output is minimal. The solar unit output will usually provide minimal benefit for providing capacity to the cooperative.

The average hourly monthly power output from the solar generation can be used to estimate the contribution from the generation to the reduction in the power supply demand charges. Power supply demand charges recover costs for the wholesale power transmission and generation costs. The charges vary by power suppliers. Table 2 shows a process to determine the demand charge reduction using hypothetical power supply demand periods.

Table 2 Power Supply Demand Reduction from Solar Generation

Month	Time	Solar%
Jan	16:00	6%
Feb	15:00	33%
Mar	15:00	39%
Apr	16:00	25%
May	17:00	14%
June	18:00	5%
July	18:00	5%
Aug	16:00	28%
Sept	17:00	4%
Oct	16:00	8%
Nov	15:00	12%
Dec	15:00	11%
Average		**16%**

Table 2 shows the hypothetical monthly time period (Time) that the power supply demand charges are assessed and the expected percent of maximum solar power available during this time period (Solar%). For example, during the month of February the power supplier charges the cooperative the demand costs using the demand rate multiplied by the peak demand that occurs at 15:00 hours. The average solar output at this time is estimated at 33% of the maximum solar output. A member with a solar unit with a maximum output of 10 kW would reduce the power supply demand allocation by 3.3 kW. The solar output is estimated to reduce the power supply demand on an annual basis by an average of 16% of the maximum solar output of the generation for the example shown in Table 2. This will reduce the power supply demand charge allocation by 16% to the DG rate class.

Table 3 shows the allocation data for DG accounts using typical data from the electric cooperatives.

Table 3 Allocation Data for DG Accounts

Description	Value
kWH average/month DG	500
kWH average/month non-DG	1,000
kW power supply non-DG	3.0
kW power supply DG	2.5
kW average billing	9.0

Table 3 shows the average monthly energy use for an account without DG is 1,000 kWH and the average for the DG account is 500 kWH. The coincident demand for the DG user is estimated to be 16% less than the non-DG user during the billing period for the power supply demand because of the demand contribution from the solar DG. The peak demand of an individual account is 9 kW and is the same for DG and non-DG accounts because the peak occurs at a later evening time period when the solar DG output is minimal.

Table 4 shows the allocation of the annual costs to the non-DG accounts using hypothetical power supply costs. The distribution member and demand costs are average costs from recent cooperative COS studies.

Table 4 Monthly COS Rate for Non-DG Accounts

Cost Description	Units	Rate	Amount
Energy - annual	12,000 kWH	$0.04	$480
Capacity - annual	3.0 kW	$14	$504
Distribution member - annual	1	$630	$630
Distribution demand - annual	1	$240	$240
Total - annual			$1,854
Monthly account costs			$155

Table 5 shows the allocation of the annual costs to the DG accounts using hypothetical power supply costs. The distribution member costs are higher than the non-DG COS because the average transformer size is larger for the DG accounts to accommodate the DG output.

Table 5 Cost Allocation for DG Accounts

Cost Description	Units	Rate	Amount
Energy - annual	6,000 kWH	$0.04	$240
Capacity - annual	2.4 kW	$14	$403
Distribution member - annual	1	$660	$660
Distribution demand - annual	1	$240	$240
Total - annual			$1,543
Monthly account costs			$129

The COS for DG accounts in this example doesn't account for net metering costs. Table 6 shows the monthly COS rate for DG and Non-DG accounts using the data from above.

Table 6 COS Monthly Rate for DG and Non-DG Accounts

Cost Description	COS DG	COS Non-DG
Monthly cost	$55.00	$52.50
Energy $/kWH	$0.04	$0.04
Demand distribution $/kW/mo.	$2.22	$2.22
Demand power $/kW/mo.	$3.73	$4.67

Table 7 shows the monthly revenue from a DG account and the deficit when comparing the revenue and the costs for the account.

Table 7 Monthly Revenue from DG Single-Phase Energy Only Account

Cost Description	Units	Rate	Monthly$
Monthly	1	$30	$30
Energy	500	$0.125	$63
Total monthly bill			$93
Total monthly COS			$129
Deficit/month for DG account			$36

The COS review in Table 7 shows the DG account monthly deficit is $36 in rate revenue when compared to the costs allocated to the DG account. This deficit reduces revenue leaving fewer dollars for maintenance and improvements for distribution lines. The cooperatives are concerned that with DG penetration increasing, the rate options are needed to recover this loss of revenue to maintain the reliability of the distribution system.

8 Rate Options for DG Accounts

Maintain Existing Rates

Individual rate classes exist for accounts with similar use patterns or accounts that have unique load characteristics or service requirements. The single-phase service rate class is established for residential and farm accounts. The small DG accounts are included in these single-phase accounts. The cooperatives are considering a separate rate for the DG rate users so these accounts recover sufficient revenue similar to the costs allocated to these accounts.

Accounts are assigned to rate classes depending on the average energy and demand use of the account or the transformer size required for the account. The individual accounts assigned to rate classes will have varying amounts of energy use and demands. The ideal rate class would include accounts with identical energy consumption and patterns; however, this isn’t practical due to the large quantity of unique rates that would be required for billing.

The cooperatives review the quantity of individual DG accounts and the unrecovered costs for the DG group. For a small quantity of DG accounts, the additional cost to implement a separate rate may not be worth the effort if the unrecovered costs are minimal. The cooperatives may implement a separate DG rate when the unrecovered costs are significant to avoid cost shifting to the other accounts.

In each rate class, there are accounts that contribute more or less to the calculated COS rate revenue, especially for energy-only rates. The accounts that use more than the average energy use will contribute more revenue than required to meet the COS rate revenue. The accounts with less energy use will contribute less revenue than required. This pattern occurs in most rate classes because rates are developed using average energy and demand use for the accounts included in the rate class. The accounts with minimal energy use will usually have energy charges that are less than the COS revenue. Figure 5 shows the monthly revenue and COS revenue for various energy use amounts using the COS rate from Table 4 and energy rate from Table 7.

Figure 5 Rate Revenue and COS Revenue Comparison

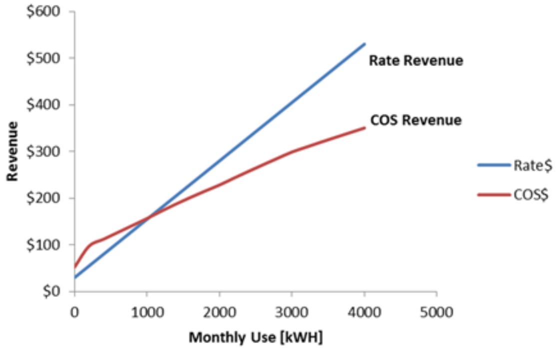


Figure 5 shows that the rate revenue and COS are the same with a monthly energy use of approximately 1,000 kWH. This is the average monthly use of all the accounts. Cooperatives can review the COS revenue for various accounts within a rate class to determine if additional rate classes are required to create more equitable rates.

Limit Net Metering

Net metering isn't required for cooperatives in Iowa; however, some cooperatives offer net metering because of member interest in promoting renewable energy. One of the Iowa cooperatives limits the DG size with net metering to the average annual use of the account. Accounts with DG units that produce more energy than the annual use of the account receive the avoided cost for excess energy generated. The goal of the policy is to encourage members to install units sized to produce the average annual energy used by the member instead of larger units that will produce more energy than the average energy used by the account. The cooperative may limit or eliminate the net metering in the future so this policy allows more members to install DG and receive net metering rather than have members install larger DG units than required which could reduce or eliminate the net metering option for members installing DG in the future.

Demand Rates

The cooperatives may implement a demand and energy rate for DG or modify the rate classification so accounts are required to have a demand and energy rate based on a peak monthly demand. The cooperatives usually require accounts to have a demand and energy rate for accounts with monthly peak demands that exceed 40 or 50 kW. The rate classifications could be changed to reduce the monthly demand for demand and energy billing or require all accounts to be billed with a demand and energy rate.

Table 8 provides an example of the savings in the annual electric bill for an account with an energy only rate and a energy/demand rate with 22 kW DG.

Table 8 DG Annual Savings with Energy Only and Energy/Demand Rate

Description	Energy Only	Energy/Demand
kWH use	95,379	95,379
kWH DG	30,835	30,835
kWH net	64,544	64,544
kW annual	347	347
Monthly	$30	$40
$/kWH	$0.130	$0.085
$/kW	$0	$10
Rev non-DG	$12,759	$12,062
Rev DG	$8,751	$9,441
Save	$4,009	$2,621

The DG savings are higher for the accounts with an energy only rate. The rate with a monthly demand charge is a reasonable rate option especially as more energy is produced with renewable energy where the major cost is related to the installed cost of the unit rather than the cost of fuel. An Iowa cooperative is developing a single-phase demand rate that could be implemented in 2016. The cooperative is monitoring the rate policies at other Iowa cooperatives that are considering implementing single-phase demand rates.

Increase Monthly Charge

Cooperatives are reviewing the possibility of increasing the monthly fixed charge to offset the declining rate revenue from reduced energy use in DG accounts. The typical energy only rate recovers fixed cost for distribution and power supply costs in the energy rate.

Some electric utilities have increased the fixed monthly charge for all accounts. Three electric utilities in Wisconsin; Madison Gas and Electric, We Energies, and Wisconsin Public Service recently increased fixed monthly rates for residential users from $9-10/month to $16-19/month. [4] These utilities decreased the energy charge for all accounts which results in a higher percent increase in the electric bill for low energy users such as DG accounts as compared to accounts that use higher amounts of energy.

Salt River Project in Arizona has a separate rate for residential service with member generation which was introduced in 2014. The monthly charge increases from $18.50 to $30.94/month and includes a demand charge that ranges from $3.55/kW to $34.19/kW based on the time of the year for accounts with DG. [4] The Tempe-based utility, which serves much of greater Phoenix, has seen applications to connect solar systems drop 96% since it announced the new rate structure. [5]

Allamakee-Clayton Electric Cooperative, Inc., Hawkeye REC, Heartland Power Cooperative, and Tri-County Electric Cooperative are reviewing their monthly charges for possible future increases. The existing monthly rates are approximately $30/month. The members with DG would be required to pay approximately $50 to $65/month to recover their fair share of the fixed distribution costs.

Community Solar

The cooperatives are installing community solar projects to allow members to participate in solar energy without installing the equipment at their premise. The cooperatives sell panels to the members and the member is reimbursed by an energy or cash credit to the member's account each month equal to their share of the generation output.

Each panel is rated for 275 to 411 watts and produces 300 to 600 kWH/year. The total capacity of the generation varies from 25 to 852 kW DC for the community solar projects. A member receives a monthly credit which provides a return of 3.0% to 6.6% on their investment and a payback of 10 to 12 years. The cooperatives expect to install additional community solar projects in the future as the price of the panels continues to decrease.

9 Conclusion

This report provides information on the retail rates for DG. Changes to the rates are being considered to ensure all members contribute to the recovery of the cooperative's fixed costs. The changes will result in a fair and equitable rate for members with DG and reduce the subsidy of DG from other members without DG.

The rate strategies will be reviewed as the penetration of the DG increases. In the future as more energy is produced from renewable sources, it is expected that the rates will consist of a demand charge and higher fixed monthly charges and the energy charge will be a smaller component of the total bill. This will occur gradually as the power supply becomes a higher share from renewable sources.

References

[1] Thomas Stetz and others, *Twilight of the Grids*, IEEE Power & Energy Magazine, March/April, 2015

[2] Robert E. Burns, Kenneth Rose, *PURPA Title II Compliance Manual*, 2014

[3] National Renewable Energy Laboratory, www.nrel.gov, PVWatts® Calculator

[4] Rate sheets from company websites Madison Gas and Electric, WI; Wisconsin Public Service; We Energies; Salt River Project, Arizona

[5] Peter Fairley, *Innovation amid a Raucous Rooftop Solar Squabble*, IEEE Spectrum, July 2015