An Historic Opportunity for Photovoltaics and Other Distributed Resources in Rural Electric Cooperatives[+]

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Abstract

Rural electric cooperatives may be on the verge of an historic opportunity to use photovoltaics (PV) and other distributed resources to satisfy customer demand. This opportunity is a result of an aging infrastructure (1 million miles of distribution wires were originally installed over 40 years ago), low customer density (co-ops have one-tenth the load density of other utilities), and the high cost of new distribution systems. This paper compares the cost of serving rural electric co-op customers using distributed hybrid-PV systems (systems that use PV, generators, and batteries to satisfy demand where it occurs) with the cost of replacing the distribution system as it wears out. The analysis is performed using historical data that the co-ops report to the Department of Agriculture's Rural Utility Service. Results suggest that more than 50 MW of PV could be installed per year initially at a PV price of $6,000 per kW_{AC} if 5 percent of the distribution system is replaced per year. There would be a total investment of 1 GW of PV and a total co-op savings of $3 billion at the end of 10 years. 1 GW of PV would satisfy 1 percent of the co-ops' electricity needs.

Introduction

The nation's 900 rural electric co-ops sell 8 percent of the total electricity sold and own nearly half the electric distribution lines in the U.S. (NRECA 1998). This is enough wire to circle the earth 80 times.

Despite their low customer density and high percentage of residential customers (their average load density is about one-tenth that of investor-owned and public utilities), their 1995 average rate[1] of $0.070/kWh is comparable to the national average rate of $0.071/kWh (RUS 1996, Table 3; EIA 1996, Table A8). Part of the explanation for this is that they have an investment of $11,000 per mile of distribution plant while investor-owned utilities' have an investment of $54,000 per mile and publicly owned utilities have an investment of $72,000 per mile (NRECA 1998).

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[1] Rural co-op rates are defined to be revenue collected divided by electricity sold.

This situation, however, may be changing. First, as much as half of the co-ops' infrastructure was originally installed over 40 years ago (Shultz 1998). Second, new distribution systems cost about $60,000 per mile (see Appendix).

As a result of an aging distribution system that may need replacing, low customer density, and cost of new/replacement distribution plant, rural co-ops may be on the verge of an historic opportunity of using photovoltaics (PV) and other distributed resources to provide electric service to their customers rather than replacing their aging distribution facilities.

Potential Rates

The Department of Agriculture's Rural Utility Service (RUS) collects detailed financial and operating statistics on about 90 percent of the nation's co-ops. Table 1 summarizes this data for 1995. The "Actual" column presents the actual costs that the co-ops incurred (RUS 1996).

The "Potential" column considers the effect on rates if the entire distribution system was replaced immediately. It would cost $115.8 billion to replace the existing distribution system at a capital cost of $60,000 per mile. This translates to an annual cost of $7.7 billion given an interest rate of 5.125 percent (RUS 1998b), and a loan life of 30 years. The table suggests that the average rate would increase from $0.07/kWh to $0.10/kWh.

Table 1. Key operating and financial data (1995).

	Actual	Potential
Cost of Power	$10.0 Billion	same as actual
Admin, Taxes, Misc.	$1.9 Billion	same as actual
Utility Margins	$1.4 Billion	same as actual
Distribution O&M	$1.1 Billion	same as actual
Depreciation & Amort.	$0.9 Billion	$7.7 Billion
Total	**$15.2 Billion**	**$22.0 Billion**
Sales	218 Billion kWh	same as actual
Distribution Line	1.93 Million miles	same as actual
Rates	**$0.07/kWh**	**$0.10/kWh**

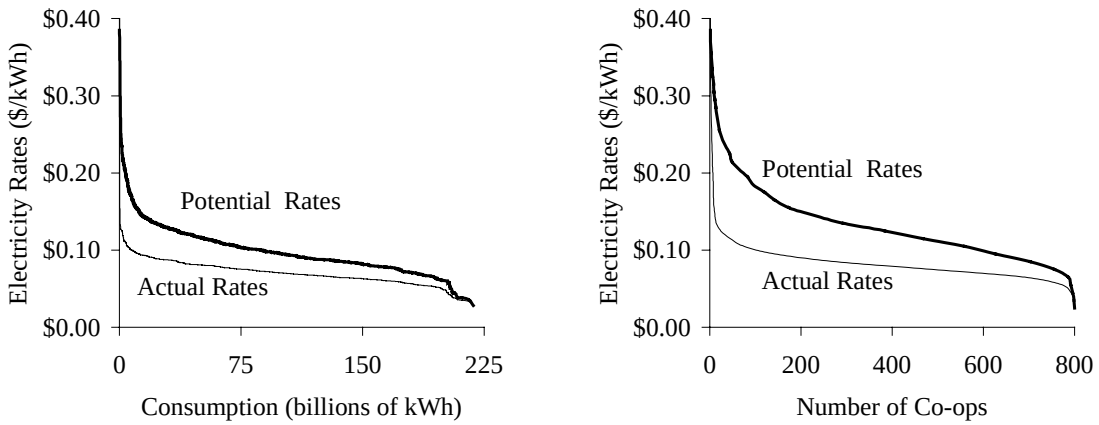
This result is not alarming at a first glance. After all, an increase of $0.03/kWh to install an entirely new distribution system does not seem exorbitant. Table 1 conceals, however, what would happen to the range of rates throughout the nation.

Figure 1 repeats the calculation presented in Table 1 for each of the 805 co-ops that reported to the RUS in 1995. The left side of the figure plots the rates against the electricity consumed and the right side plots the rates against the number of co-ops. The

light lines correspond to actual rates and the heavy lines correspond to potential rates with the cost of a new distribution system.

Figure 1 suggests that 5 percent of the electricity sold and 25 percent of the co-ops would have rates above $0.15/kWh with a new distribution system. This suggests that there are co-ops who may benefit from considering an alternative to providing service by replacing their aging distribution systems.

Figure 1. Actual rates and potential rates with new distribution costs (1995).



Objective

One alternative to replacing the distribution system when it wears out is to satisfy demand using distributed resources. One use of distributed resources is to support the transmission and distribution system in areas that are experiencing load growth by providing generation where the loads are occurring (Hoff, Wenger, and Farmer 1995, and Hoff 1997). Another use is to totally replace the distribution system with the distributed resources (Hoff et. al., 1997 and 1998). This second use is the one considered in this paper.

It is assumed that a hybrid-PV system composed of PV, generators, and batteries will supply customers with electricity. No attempt is made to optimize the size of the components in this system. Rather, it is assumed that PV provides half of the electricity and generators provide the other half.

This paper addresses two specific questions. First, what is the annual market demand for PV in rural co-op applications? Second, how much would co-ops save by investing in hybrid-PV systems?

Model Description

Two economic models are developed in this section to assess the market for PV and the cost savings for co-ops. The first model determines how much it will cost to serve customers by replacing the distribution system as it wears out. The second model

determines how much it will cost to serve customers using a hybrid-PV system. The models are developed in terms of the annual cost and then converted to the cost per kWh.

Distribution System Replacement Cost of Service

The annual cost of serving customers by replacing the distribution system equals the sum of:

- annual finance charge for the distribution system (capital cost in $/mile times the number of miles of distribution system times the capital recovery factor for the distribution system to convert the initial capital cost to an annual cost)
- distribution system O&M cost (O&M cost in $/mile times the number of miles of distribution system)
- electricity cost (electricity price times electricity sold times the distribution system loss factor)
- administrative and other costs

$$\boldsymbol{Annual\ Cost_{dist}} = \overbrace{\boldsymbol{C_{dist} M_{dist} i_{dist}}}^{\text{Distribution Capital Cost}} + \overbrace{\boldsymbol{O_{dist} M_{dist}}}^{\text{Distribution O\&M Cost}} + \overbrace{\boldsymbol{P_{elec} E_{sold} L_{dist}}}^{\text{Electricity Cost with Losses}} + \overbrace{\boldsymbol{A E_{sold}}}^{\text{Admin. \& Other Costs}} \qquad (1)$$

The capital recovery factor, $\boldsymbol{i_{dist}} = \dfrac{(\boldsymbol{1}+\boldsymbol{i})^{\boldsymbol{Life_{dist-years}}}\boldsymbol{i}}{(\boldsymbol{1}+\boldsymbol{i})^{\boldsymbol{Life_{dist-years}}}-\boldsymbol{1}}$, where *i* is the discount rate and $\boldsymbol{Life_{dist-years}}$ is the life of the distribution system in years.

The annual cost is converted to a cost per kWh by dividing by the amount of electricity sold annually.

$$\boldsymbol{Cost\ per\ kWh_{dist}} = \overbrace{\frac{\boldsymbol{C_{dist} i_{dist}}}{\boldsymbol{D_{dist}}}}^{\text{Distribution Capital Cost}} + \overbrace{\frac{\boldsymbol{O_{dist}}}{\boldsymbol{D_{dist}}}}^{\text{Distribution O\&M Cost}} + \overbrace{\boldsymbol{P_{elec} L_{dist}}}^{\text{Electricity Cost with Losses}} + \overbrace{\boldsymbol{A}}^{\text{Admin. \& Other Costs}} \qquad (2)$$

where the load density equals the electricity sold divided by the miles of distribution system ($\boldsymbol{D_{dist}} = \dfrac{\boldsymbol{E_{sold}}}{\boldsymbol{M_{dist}}}$).

Hybrid-PV System Cost of Service

The annual cost of serving customers using a hybrid-PV system equals the sum of:

- annual finance charge for the PV (installed capital cost in $/kW times the PV size in kW times the capital recovery factor for the PV)
- annual finance charge for the generator (installed capital cost in $/kW times the generator size in kW times the capital recovery factor for the generator)
- annual finance charge for the battery (installed capital cost in $/kWh times the number of kWh of battery storage times the capital recovery factor for the battery)

- PV O&M cost (O&M cost in $/kWh times the electricity sold in kWh/year times the system loss factor times the fraction of total electricity produced by the PV)
- generator O&M cost (O&M cost in $/kWh times the electricity sold in kWh/year times the system loss factor times the fraction of total electricity produced by the generator)
- battery O&M cost (O&M cost in $/kWh times the electricity sold in kWh/year times the system loss factor times the fraction of total electricity stored in the battery)
- generator fuel cost (fuel cost in $/kWh times the electricity sold in kWh/year times the system loss factor times the fraction of total electricity produced by the generator)
- administrative and other costs

$$\begin{aligned}\boldsymbol{Annual\ Cost_{sys}} = &+\overbrace{\boldsymbol{C_{PV} S_{PV} i_{PV}}}^{\substack{\text{PV}\\ \text{Capital Cost}}} + \overbrace{\boldsymbol{C_{gen} S_{gen} i_{gen}}}^{\substack{\text{Generator}\\ \text{Capital Cost}}} + \overbrace{\boldsymbol{C_{bat} S_{bat} i_{bat}}}^{\substack{\text{Battery}\\ \text{Capital Cost}}} \\ &+\overbrace{\boldsymbol{O_{PV} E_{sold} L_{sys} B_{PV}}}^{\substack{\text{PV}\\ \text{O\&M Cost}}} + \overbrace{\boldsymbol{O_{gen} E_{sold} L_{sys} B_{gen}}}^{\substack{\text{Generator}\\ \text{O\&M Cost}}} \\ &+\overbrace{\boldsymbol{O_{bat} E_{sold} L_{sys} B_{bat}}}^{\substack{\text{Battery}\\ \text{O\&M Cost}}} + \overbrace{\boldsymbol{P_{gen} E_{sold} L_{sys} B_{gen}}}^{\substack{\text{Generator}\\ \text{Fuel Costs with Losses}}} + \overbrace{\boldsymbol{A\, E_{sold}}}^{\substack{\text{Admin. \& Other}\\ \text{Costs}}}\end{aligned} \tag{3}$$

This equation is subject to the constraint that the hybrid-PV system delivers enough electricity to satisfy the annual demand and the losses associated with the electricity that goes through storage.

$$\boldsymbol{E_{sold} L_{sys} B_{PV}} = \overbrace{\boldsymbol{S_{PV} F_{PV}}\,\mathbf{8{,}760}}^{\text{Electricity from PV}}$$

$$\boldsymbol{E_{sold} L_{sys} B_{gen}} = \overbrace{\boldsymbol{S_{gen} F_{gen}}\,\mathbf{8{,}760}}^{\text{Electricity from Generator}}$$

$$\boldsymbol{B_{PV} + B_{gen}} = \mathbf{1}$$

where the ***B***'s are the fraction of electricity produced (or stored) by the various system components, the ***F***'s are the annual capacity factors, and the system loss factor, $\boldsymbol{L_{sys}}$, equals 1 + (percent of electricity that is stored times storage losses).

Component sizes can be expressed in terms of the average load as shown in Table 2.

Table 2. Component size expressed as a percentage of average load.

PV	Generator	Battery
$S_{PV} = \overline{S}_{PV}\overbrace{\left(\frac{E_{sold}}{8{,}760}\right)}^{\text{Average Load}}$	$S_{gen} = \overline{S}_{gen}\overbrace{\left(\frac{E_{sold}}{8{,}760}\right)}^{\text{Average Load}}$	$S_{bat} = \overline{S}_{bat}\overbrace{\left(\frac{E_{sold}}{8{,}760}\right)}^{\text{Average Load}}$
$\overline{S}_{PV} = \overbrace{\left[\frac{L_{sys}B_{PV}}{F_{PV}}\right]}^{\text{kW of PV per kW of Average Load}}$	$\overline{S}_{gen} = \overbrace{\left[\frac{L_{sys}B_{gen}}{F_{gen}}\right]}^{\text{kW of Generator per kW of Average Load}}$	

The life of the PV system is a fixed number of years because it is non-dispatchable while the life of the generator and the life of the battery depend upon how they are operated. The life calculations are presented in Table 3.

Table 3. Component life.

Generator	Battery
$Life_{gen-years} = \frac{\overline{S}_{gen}Life_{gen-hours}}{B_{gen}L_{sys}8{,}760}$	$Life_{bat-years} = \frac{\overline{S}_{bat}Life_{bat-hours}}{B_{bat}8{,}760}$

These sizes are substituted into Equation (3) and divided by the electricity sold to determine the cost per kWh of the hybrid-PV system.

$$Cost\ per\ kWh_{sys} = \overbrace{\left(C_{PV}\overline{S}_{PV}i_{PV} + C_{gen}\overline{S}_{gen}i_{gen} + C_{bat}\overline{S}_{bat}i_{bat}\right)\left(\frac{1}{8{,}760}\right)}^{\text{Capital Cost}} + \overbrace{\left[O_{PV}B_{PV} + \left(O_{gen} + P_{gen}\right)B_{gen} + O_{bat}B_{bat}\right]L_{sys}}^{\text{O\&M and Fuel Cost}} + \overbrace{A}^{\text{Admin. \& Other Costs}} \qquad (4)$$

Data

As stated earlier, the RUS collects detailed operating and financial statistics on about 90 percent of all rural co-ops. This paper is based on operating and financial data for 1994-1996 collected by the RUS using RUS Form 7 (RUS 1998a) and on the RUS's 1995 Annual Statistical Report (RUS 1996). Data for all of the variables in Equation (2) except for the capital cost of new distribution facilities and the distribution system life are the specific data that the co-ops reported to the RUS in 1996 (see Figure 2 for the probability distributions of the data). The cost and life of new distribution systems as

well as the costs for the hybrid-PV system are presented in Table 4. The discount rate is 5.125 percent (RUS 1998b).

Figure 2. Probability distributions of various costs and other parameters for all co-ops (1996)

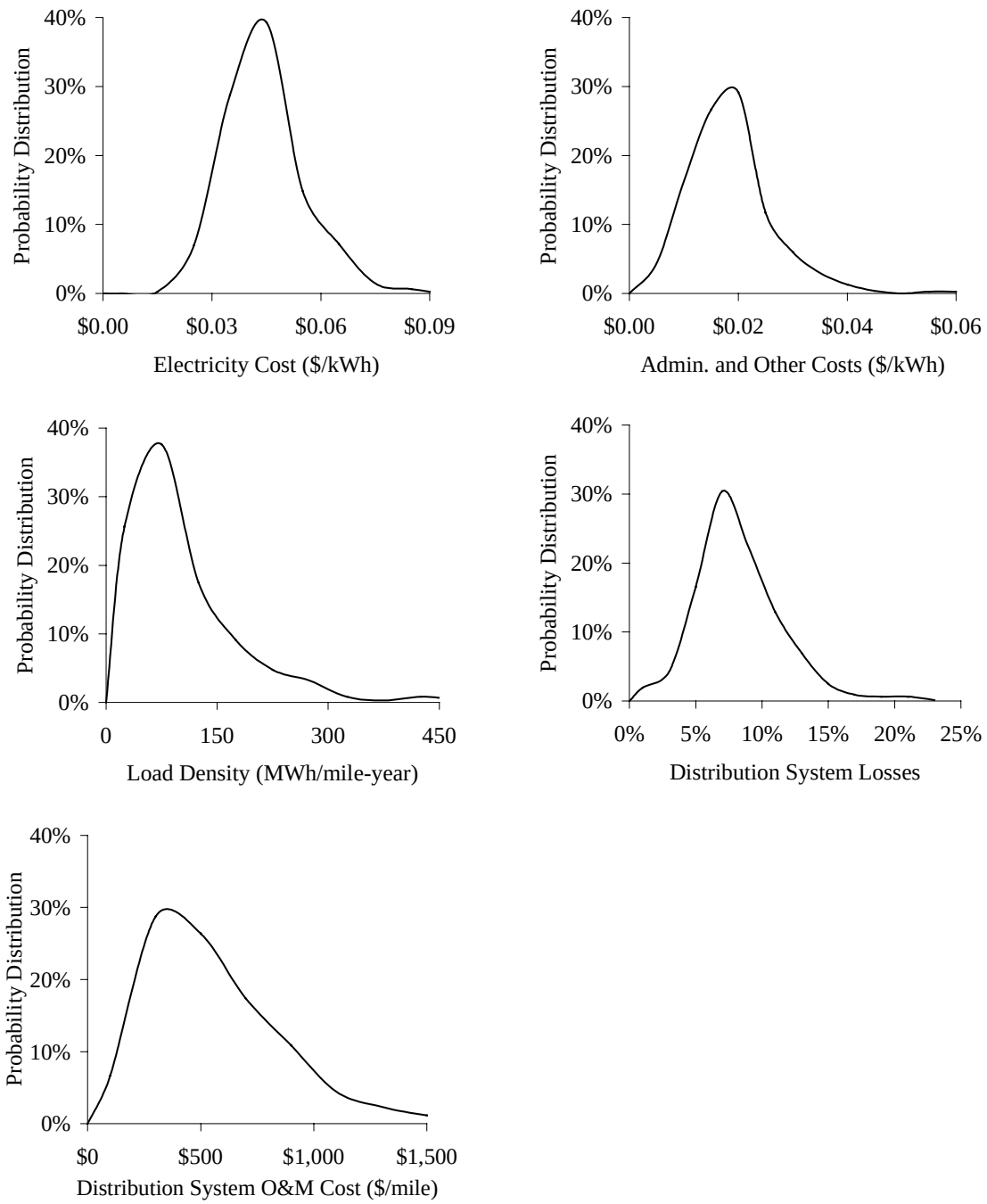


Table 4. Assumptions used in the analysis.

	Distribution	PV	Generator	Battery
Capital Cost (C)	$60,000/mile	variable	$750/kW	$100/kWh
Electricity Prod. (B)		50% of total	50% of total	20% of total[2]
Size ($\bar{S}$)	RUS	2-4x avg. load[3]	2x avg. load	6 hrs. avg. load
Life (Life)	30 years	30 years	15 years[4]	5 years[5]
O&M cost (O)	RUS	$0.01/kWh	$0.02/kWh	$0.02/kWh
Fuel Price (P)	RUS	none	$0.06/kWh[6]	none
System Losses (L)	RUS	5.0%[7]		
Admin. (A)	RUS	RUS		

Results

The RUS data and Table 4 data were input into Equations (2) and (4) to calculate the cost per kWh of the new distribution and the hybrid-PV systems. Assume that 5 percent of the distribution system will be replaced per year over the next 10 years (this is the replacement rate given the "historic opportunity scenario;" as shown in the Appendix, it also equals the peak and electricity growth rates for 1994-1996). Figure 3 presents the annual size of the market for PV, the 30-year present value cost savings to the co-ops, and the number of co-ops that would invest as a function of the price of PV. The figure suggests that 71 co-ops would install a total of 57 MW of PV and have a 30-year present value cost savings of $247 million if the price of PV was $6,000 per kW_{AC},

Suppose that the price of PV declines 5 percent per year from $6,000 per kW_{AC} so that it is $3,600 per kW_{AC} at the end of 10 years. Figure 4 suggests that 1,000 MW of PV would be installed by the end of 10 years; the co-ops would have a corresponding cost savings of more than $3 billion.

[2] This is how much of the combined electricity production from the PV system and the generator first go into storage and then supply the load.
[3] The capacity factor ranges from 12 to 25 percent (see Wenger, et. al. 1996 for a capacity factor map of the U.S.). Since half of the electricity comes from the PV, this implies a capacity of 2 to 4 times the average load.
[4] This assumes that the generator will operate at full capacity for 35,000 hours, that it provides half the annual electricity consumption, and its capacity is twice the average load. The capacity factor of this unit is 26 percent.
[5] This assumes that 20 percent of the electricity goes into storage and batteries have a life of 2,000 cycles at an 80 percent depth of discharge, and that there is sufficient capacity to provide 5 hours of storage at the average load.
[6] This is based on a propane price of $0.60/gallon, a conversion efficiency of 35 percent, and an energy content of 27.6 kWh/gallon of propane.
[7] This is based on storage losses of 25 percent and 20 percent of the total electricity produced (5 hours daily) going into storage.

Figure 3. Annual PV market demand, co-op cost savings, and number of co-ops as a function of PV price (1996 data, 5 percent replacement rate).

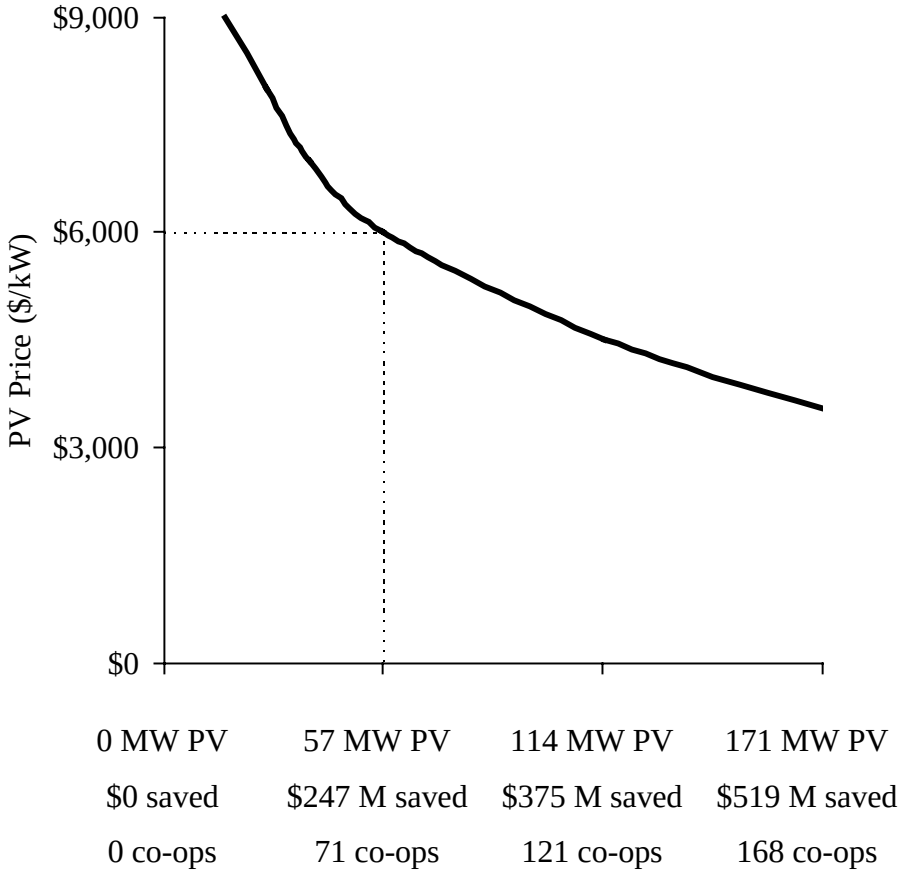
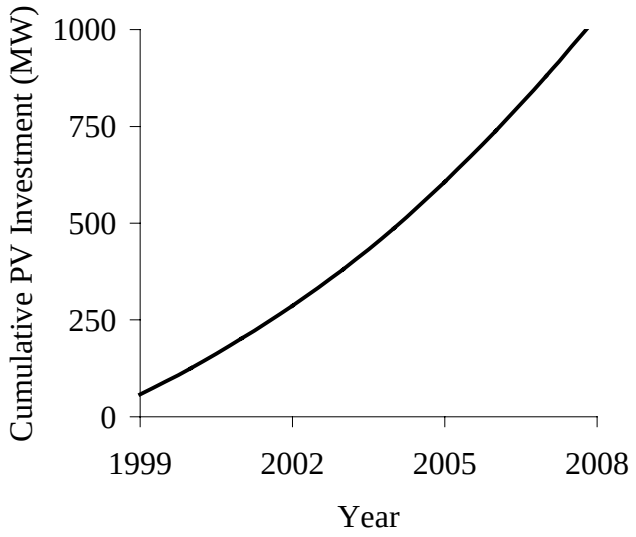


Figure 4. Cumulative PV investment (5 percent replacement rate, 1999 PV price of $6,000/kW, and PV price decline of 5 percent per year).



Conclusions and Further Research

Rural electric cooperatives may be on the verge of an historic opportunity to use PV and other distributed resources to satisfy customer demand. This opportunity is a result of an aging infrastructure (1 million miles of distribution wires were originally installed over 40 years ago), low customer density (co-ops have one-tenth the load density of other utilities), and the high cost of new/replacement distribution systems.

This paper compared the cost of serving rural electric co-op customers using distributed hybrid-PV systems (systems that use PV, generators, and batteries to satisfy demand where it occurs) with the cost of replacing the distribution system as it wears out. The analysis was performed using historical data that the co-ops report to the Department of Agriculture's Rural Utility Service. Results suggest that more than 50 MW of PV could be installed per year initially at a PV price of $6,000 per kW_{AC} if 5 percent of the distribution system is replaced per year. There would be a total investment of 1 GW of PV and a total co-op savings of $3 billion at the end of 10 years. 1 GW of PV would satisfy 1 percent of the co-ops' electricity needs.

There are several areas for further research.

- co-ops have isolated remote loads where PV is economical that are not part of the distribution system and thus were not considered in this analysis; this will increase the size of the market for PV
- the capital cost for new distribution was assumed to be $60,000 per mile independent of load density; this relationship needs to be verified because the market size rapidly diminishes as this cost decreases
- it was assumed that 5 percent of the distribution system will be replaced per year for the next 10 years; this assumption needs to be verified

- the feasibility of cogeneration needs to be evaluated because the market doubles when the generation's waste heat is used (see Appendix)
- hybrid-PV systems may provide a higher level of reliability than distribution systems, particularly in remote areas; this value needs to be accounted for
- system component sizes were not optimized to minimize cost; further cost-savings will be realized with an optimized system
- the potential for energy efficiency investments was not considered in the analysis and that may further increase the cost savings (Hoff, et. al., 1998)
- it is likely that there will be area specific applications that will be even more cost-effective than those identified in this paper; these applications need to be evaluated on a case by case basis
- more detailed analysis can be done on the historical cost of capital investments for co-ops that have high potential costs

Appendix

Distribution System Capital Cost

Table 5 presents the cost of new distribution system investments from 1990 to 1995 (RUS 1996, Table 1). The table suggests that the average cost for new distribution is $60,000 per mile. This is the capital cost that is assumed throughout this paper.

Table 5. Cost of New Distribution System Investment

	Dist. Loans ($ billions)	Dist. Miles	Cost per mile
1990	$19.84		
1991	$20.57	12,632	$57,606
1992	$21.45	14,846	$59,216
1993	$22.52	15,710	$68,111
1994	$23.08	11,555	$48,002
1995	$23.87	11,811	$67,323
		Average	$60,052

Peak Demand and Electricity Growth Rates

Table 6 presents the average annual peak demand and electricity consumption growth rates for 1994 through 1996.[8] The growth rates for each of the individual co-ops was calculated and the average was taken.

[8] While, the total electricity consumption for all co-ops reporting to the RUS increased at a rate of only 1 percent per year from 1994 to 1996, this is due to the fact that the number of co-ops reporting declined from 838 to 805 and then to 767 in 1994, 1995, and 1996 respectively.

Table 6. Growth rates based on average co-op consumption and peaks (%/yr).

	1994-5	1995-6	1994-96
Peak Growth	2.9%	6.0%	4.5%
Electricity Growth	5.6%	5.4%	5.5%

Results for Other Scenarios

Figure 5 presents the annual size of the market for PV, the 30-year present value cost savings that co-ops will realize by investing in the PV systems, and the number of co-ops where PV will be economically viable given the assumption that 1 percent of the distribution system is replaced per year. Figure 6 presents the annual size of the market for PV, the 30-year present value cost savings that co-ops will realize by investing in the PV systems, and the number of co-ops where PV will be economically viable given the assumptions that 5 percent of the distribution system is replaced per year and that the generation is run in a cogeneration mode. Running the unit in a cogeneration mode reduces the fuel cost because the unit simultaneously satisfies both electric and heat needs.

Figure 5. PV market demand, co-op cost savings (present value), and number of co-ops as a function of the price of PV (1996 data, 1 percent replacement rate).

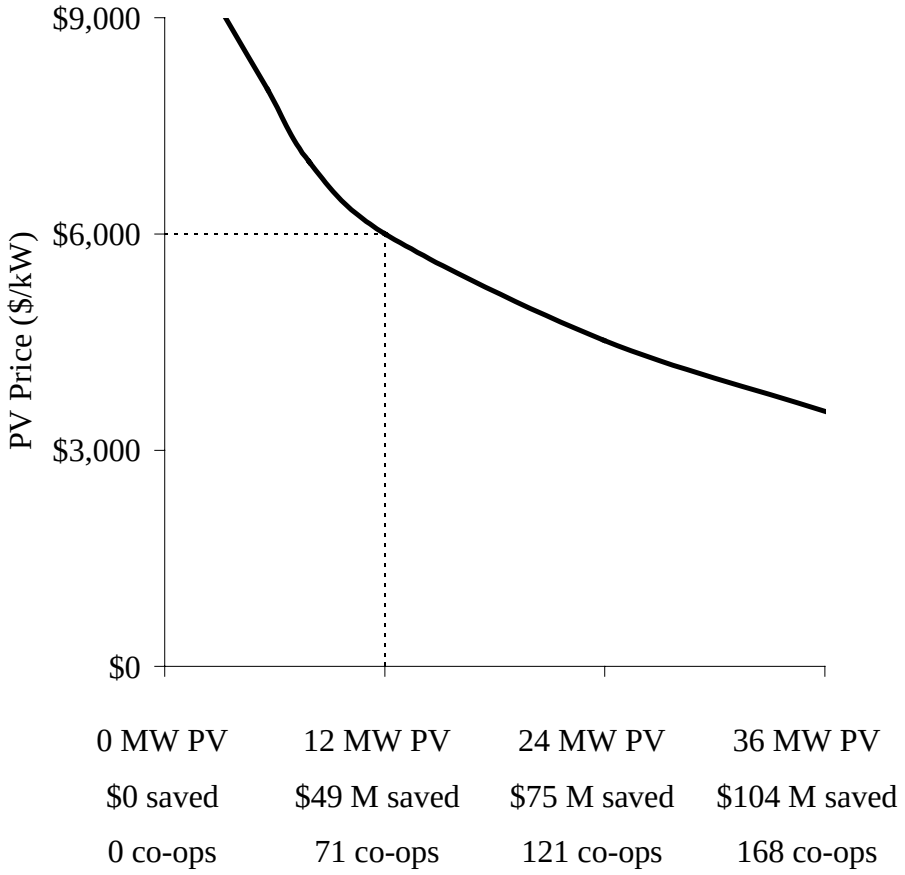
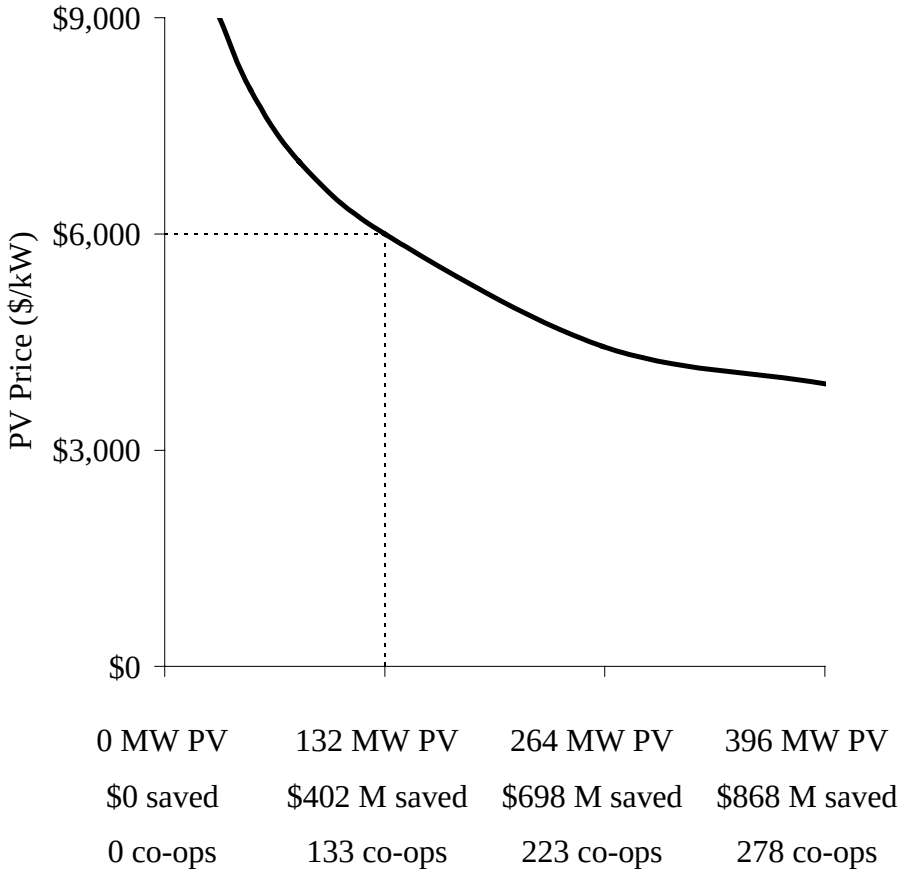


Figure 6. PV market demand, co-op cost savings (present value), and number of co-ops as a function of the price of PV (1996 data, 5 percent replacement rate, cogeneration).



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