April 2016

Business & Technology Strategies

Cost-Benefit Analysis of Demand Response Programs Incorporated in Open Modeling Framework

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EXECUTIVE SUMMARY

What has changed in the industry?

Cooperatives have developed a planning tool to project the expected cost and benefit of demand response (DR) programs. The model is a part of the Open Modeling Framework (OMF), developed by the National Rural Electric Cooperative Association (NRECA).

The OMF allows cooperative engineers to run various distribution models, import data from commercial tools, visualize the results, and collaborate through a web interface. The DR model can simulate time of use (TOU), critical peak pricing (CPP), peak time rebate (PTR), and direct load control (DLC) programs for the purpose of cost-benefit analysis (CBA). It uses the Price Impact Simulation Model (PRISM) developed originally by the Brattle Group, a global economic consulting firm, to estimate changes to system load profiles based on changes in incentives. The model calculates net present value (NPV), payback period, and benefit/cost ratio across a program lifetime.

What is the impact on cooperatives?

The availability of a distribution analysis model that, among other things, will project the costs and benefits of DR programs will allow better evaluation of anticipated programs by cooperatives. With the OMF, cooperative staff will be able to estimate the effects of several different options, and will provide a reliable and consistent means of comparison among program opportunities. Multiple scenarios may be run for planning purposes, and the options narrowed based on most favorable economic impacts.

What do cooperatives need to know or do about it?

NRECA has supported the development of the OMF capability for DR analysis on behalf of the membership. Cooperatives need to be aware of the capability and the features of the DR programs incorporated in the framework. This information will be useful as cooperatives embark on new programs or revisions to existing DR programs.

Benefits of Demand Response

According to the U.S. Department of Energy, demand response (DR) is defined *as consumer change in energy use as a result of changes in the electricity price or rebates during particular times of day*. DR is a prominent application of smart grid technology, and provides multiple benefits to the distribution, transmission, and generation levels of the grid:

- **Distribution**: Distribution cooperatives have been deploying DR since the 1970's and actively pursue opportunities for expanded DR programs to shift and reduce peak demand, meet future energy needs, and delay capital investment in the distribution grid. DR can relieve voltage problems and reduce congestion at distribution substations, as well as contribute other benefits such as lower line losses, reductions in thermal damage to system components (e.g. distribution transformers), and easier integration of renewable energy resources.

- **Transmission:** DR programs help mitigate transmission congestion, delay transmission expansion projects, and improve system reliability. Based on the typical cost structure of power supply arrangements, cooperatives that reduce peak demand provide for reduced operating costs of transmission assets.

- **Generation:** An additional benefit of DR techniques is improvement in power system reliability without the cost of bringing additional generation assets online. Similar to applications for transmission benefits, DR efforts reduce operating costs of generation assets.

Overall, successful DR programs can reduce the cost of electricity for all consumers on a system.

Demand Response Classification

DR programs can be classified as either ***price-based*** or ***quantity-based***. Price-based programs attempt to reduce consumer energy demand through price signals. Quantity-based programs, on the other hand, attempt to lower participant demand through direct utility control of certain loads, such as air conditioners, electric water heaters, and/or pool pumps.

The different quantity-based and price-based programs can be further categorized:

- *Time of Use (TOU) programs* offer consumers multiple electricity rates depending on the hour of the day in which the energy is consumed, typically in two to three rate tiers. In those periods during which DR is applied, a different rate is charged within each tier. A simple TOU program may have the rate tiers established for *on-peak* and *off-peak* time periods. TOU rate structures may have an additional tier defining a *shoulder period* between on-peak and off-peak. Due to the fixed rate pattern, a TOU program can result in persistent load shifting to off-peak times. However, TOU programs may be unable to reduce total energy consumption. TOU programs incentivize the use of modern loads, such as plug-in electric vehicles and smart appliances during off-peak times.

- *Critical Peak Pricing (CPP) programs* are similar to TOU; however, they use time-based pricing on only a limited number of utility-defined, pre-determined days each year – the days when the total system load is expected to be highest. CPP programs typically feature lower rates during the year, in order to impose much higher rates during the critical peaks, which occur on limited days of the year. When developing a CPP program, the peak days are determined based on the system-wide peak loads or peak demand of the cooperative's energy supplier(s). When the forecasted load reaches a critical limit, the cooperatives call for a critical peak day (by initiating a signal) to obtain a load reduction.

- *Peak Time Rebate (PTR) programs* are similar to TOU programs, except that the rate changes in real time (e.g. hourly) rather than at pre-defined times and tiers. PTR produces an even more dynamic pricing environment, where consumers are more directly exposed to wholesale market prices with the goal of providing an incentive to reduce load when energy is more expensive to procure. As the program's goal is to produce consumption changes, utilities call for events a day ahead of time; consumers decide if they want to participate in the program, and are not penalized if they are unable to reduce their demand. To determine the amount of load reduction, the cooperatives must determine the baseline load using multiple statistical techniques. PTR programs use a flat rate and call for events on forecasted peaks (e.g. hot and humid summer days or very cold days in the winter).

- *Direct Load Control (DLC)* is a quantity-based DR program. The utility remotely controls particular loads at consumer sites using switching devices installed on particular devices, and compensates consumers for the opportunity to interrupt part of the load as needed. An incentive payment is provided that is based on a lower off-peak rate or a rate credit. DLC can achieve demand reduction and the program has more potential value compared to price-based programs, since it is dispatchable and entirely under the operational control of the utility. These programs usually involve air conditioner and water heater loads.

In general, the time-based programs require AMI data to evaluate the effectiveness of the programs.

There are other programs as well, such as demand bidding capacity market programs, ancillary services, and emergency response.

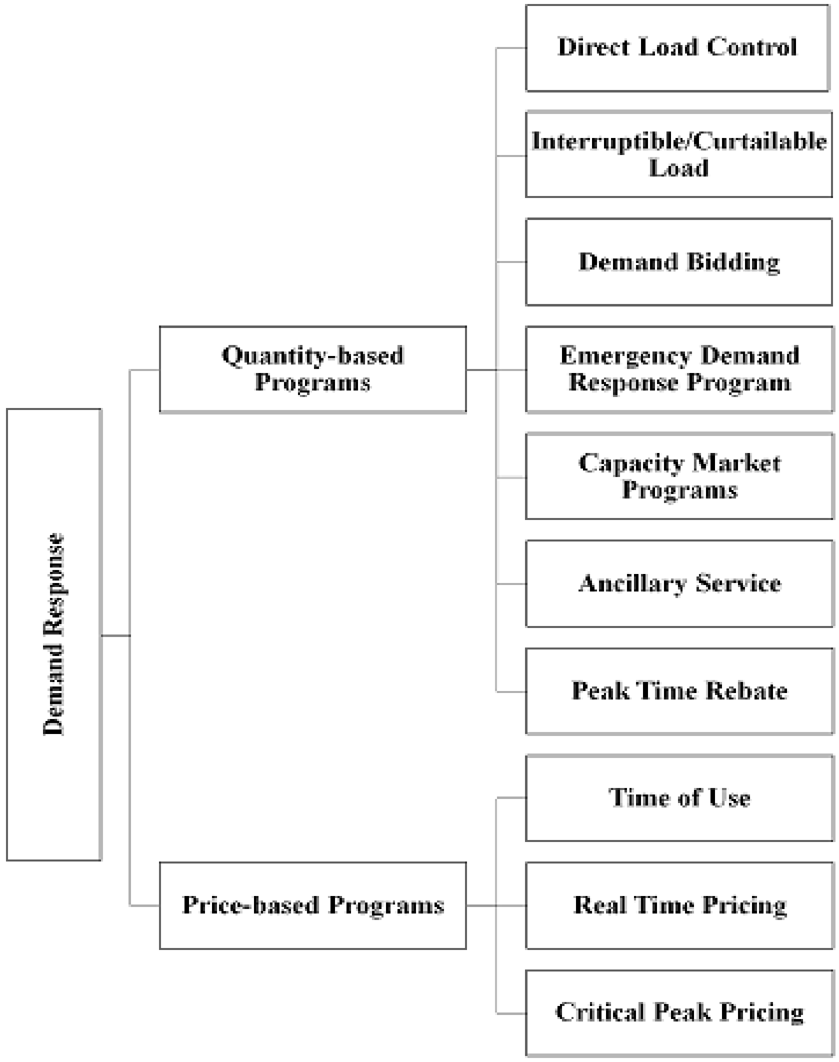

Fig. 1. The classifications of DR programs

Choosing Programs to Implement

Cooperatives are interested in DR programs that are able to shift and reduce the peak demand, delay capital investments in the grid, or reduce wholesale energy demand. To decide which programs to implement, cooperatives consider multiple factors, such as the types of loads in the service territory, end-user demographics and behavior, the current rate structure, generation capacity, and available enabling technologies. Each cooperative is likely to have unique characteristics that would affect the opportunities available, or greater preference for one or another of the programs. Often, programs would be investigated in association with the power supplier, in order to obtain the greatest possible benefit and to avoid adverse results.

Estimating the Impact of DR

In order to quantify the anticipated benefits of DR programs, it is important to estimate the **baseline load profile (BLP)** of participants. There are several statistical models used to estimate BLPs. Evaluation of seven different models, classified into two main types – those that use an averaging method and those that use explicit weather models – found that applying morning adjustments (using data from the day of a DR event to adjust the estimated BLP up or down) and incorporating temperature corrections improve the accuracy of BLP estimation.

Also, prior studies of models for different types of DR programs, including those for emergency demand response, time-of-use, and interruptible or curtailed load, have demonstrated that consumer demand depends on price elasticity of demand and the electricity price. In one such study, an economic model was developed for interruptible or curtailable load to evaluate the impact on an hourly load curve, and attempted to calculate how DR programs can improve both load profile characteristics and consumer satisfaction. Furthermore, NRECA's review of previous studies and DR programs piloted by co-ops has shown that enabling technology, such as advanced metering infrastructure (AMI), leads to greater opportunity for peak reduction.

Cost-Benefit Analysis Model for DR

To assist with the determination of the potential impact of DR programs, a cost-benefit analysis (CBA) model was built with the support of NRECA in association with the Pacific Northwest National Laboratory. The model relies on NRECA's Open Modeling framework (OMF) for data import, visualization, and computational resources. This model is available via the website https://www.omf.coop, as a user-friendly DR planning tool. The model can calculate the costs and benefits of TOU, CPP, PTR, and DLC programs to assist cooperatives in defining their own strategy and implementation plans for DR.

Open Modeling Framework (OMF)

NRECA created the OMF to allow its members to conduct economic analyses of power system investments with an emphasis on emerging and smart grid technologies. This open source platform, as a planning tool, helps cooperatives examine the cost-effectiveness of the programs that they plan to deploy – *prior to making the investment*. For evaluating technologies such as DR, OMF integrates mathematical modeling techniques with a large database of input data, such as regional weather data, load data, and smart grid components, as well as typical financial parameters. The outputs of the models include charts and monetized results.

Price Impact Simulation Model (PRISM)

As the vision of the smart grid evolves toward reality, changes are introduced in grid components and market structures. One change is new mechanisms for electricity pricing, such as dynamic prices. Flat rates for consumers ignore variations in the wholesale electricity costs, leading to competition for system resources during periods of high demand. Rate design based on dynamic pricing can help alleviate that problem.

The Brattle Group, an international consulting firm, has developed a load response model that calculates the impact of the electricity price on demand. The Pricing Impact Simulation Model (PRISM) was developed during the California Statewide Pricing Pilot conducted by investor-owned utilities and the California regulatory commission to assess the response of consumers to dynamic rates. The purpose of the Pilot was to examine the change in the pattern of consumption when the pricing structures change.

Price elasticity is a key determinant of the effectiveness of DR. The CBA model uses two elasticity inputs: the *elasticity of substitution* and the *daily price elasticity:*

- The elasticity of substitution is a measure of responsiveness of energy use to the difference in prices between two time periods. From this, the change in the load shape (shifting in the load) as a response to price differentials can be determined. In other words, it is the willingness of the consumers to *shift* their loads from one time of day to another.
- Daily price elasticity relates to the average daily use of energy as function of the electric price, generally a weighted average of the peak and off-peak prices for the day. This is the propensity to impose load on the system.

PRISM inputs also include the characteristics of the utility, such as weather conditions, load profiles, dynamic rates, and penetration of air conditioning. There is a correlation between temperature and peak reduction from time-based pricing. In general, regions with hotter weather tend to experience more peak reduction. The load profile and the dynamic rate are important inputs to evaluate the load change resulting from the dynamic rate, and to identify the effectiveness of dynamic rates relative to flat rates.

Inputs and Outputs of the DR Cost-Benefit Analysis Model

When considering making a business case for a DR program, distribution cooperatives need to estimate the financial impact of the applied DR programs. For a given DR deployment, having detailed costs of all the components is important to define the CBA as a whole, and the business case should quantify the costs and benefits over the lifetime of the applied programs (e.g., 25 years).

The CBA model differs based on the kind of DR program. Several programs require the purchase and installation of enabling technologies, and this additional cost must be considered. Furthermore, some programs do not reduce consumption, but instead flatten the load curve.

CBA Model Inputs:

The general inputs of the cost benefit model of the DR programs are as follows:

1. DR program: This includes the total cost of deploying the program (purchase cost of the needed technology and the annual operation cost).
2. The baseline energy consumption: This includes historical hourly load data (8,760 hours).
3. The cost of power, which includes the demand charge cost, the wholesale energy

cost, and the retail price.

4. The participation rate: (the percentage of managed load by the program).
5. The dynamic rates (e.g., off-peak and peak rates, or RTP rate), and the estimated elasticities (i.e., the elasticity of substitution and the daily price elasticity).
6. The length of the analysis (e.g. 25 years).
7. The months and the hours when the DR program is applied.

CBA Model Outputs:

The outputs of the cost-benefit model are as follows:

1. The estimated load curve after applying the program.
2. The first year financial impact. This includes annual demand, energy sales, energy cost and peak demand cost for the base case, and the DR case.
3. Total cost, total benefit, and the benefit-to-cost ratio for the whole investment period.
4. Net present value (NPV), program lifetime cash flow, and simple payback period.

Cost-Benefit Analysis Calculations

The following explains the calculations of CBA components. Model users are able to input the values that represent the characteristics of their systems' demand and electricity prices and obtain a CBA report of the deployed program for the lifetime of the program.

The calculations are as follows:

Base case margin calculation

$$\mathrm{ES} = \mathrm{Q}\pi_{\mathrm{r}} \tag{1}$$

$$\mathrm{EC} = \mathrm{Q}\pi_{\mathrm{w}} \tag{2}$$

$$\mathrm{PDC} = \sum_{\mathrm{m}=1}^{12} \pi_{\mathrm{D}}\, \mathrm{P}_{\mathrm{m}} \tag{3}$$

$$\mathrm{M} = \mathrm{ES} - \mathrm{EC} - \mathrm{PDC} \tag{4}$$

Where Q is the energy consumption. π_w, π_r and π_D are the wholesale, retail, and peak demand prices respectively. P_m are the monthly peak demand levels. ES, EC and PDC are the energy sales, energy cost, and peak demand charges respectively. In (4), M is the base case margin.

DR program margin calculation

$$ES' = \sum_{h=1}^{8760} D'_h \, \pi_{DR} \tag{5}$$

$$EC' = Q'\pi_w \tag{6}$$

$$PDC' = \sum_{m=1}^{12} \pi_D \, P'_m \tag{7}$$

$$M' = ES' - EC' - PDC' \tag{8}$$

Where D' is the hourly modified demand curve and π_{DR} is the applied DR dynamic pricing rate. The superscript "′" indicates the modification done by applying DR (e.g. M' is the margin under the DR program).

Total cost calculation

$$TC = DR_{inv} + C_{OM} \tag{9}$$

Where TC, DR_{inv}, and C_{OM} are the total cost, the purchase and installation cost (i.e. the investment cost) of the DR equipment, and the lifetime operation and maintenance cost respectively.

Benefits calculation

$$ESB = \sum_{Y=1}^{Lifetime} (ES' - ES)^{AS} \tag{10}$$

Where ESB is the benefit of the change in energy sales and AS is the annual scaling of the load growth.

$$PCB = \sum_{Y=1}^{Lifetime} (PDC' - PDC)^{AS} \tag{11}$$

Where PCB is the peak change benefit.

$$TB = PCB + ESB \tag{12}$$

Where TB is the total benefit.

Calculation of net present value, cash flow, payback period, and benefit-to-cost ratio

$$\mathrm{NPV} = \sum_{\mathrm{Y}=0}^{\mathrm{Lifetime}} \mathrm{NB}/(1+\mathrm{r})^{\mathrm{Y}} \tag{13}$$

Where NPV is the net present value, NB is the net benefit, and r is the discount rate.

$$\mathrm{n_p} = \frac{\mathrm{DR_{inv}}}{\left(\frac{\mathrm{TB}}{\mathrm{Lifetime}}\right)} \tag{14}$$

Where n_p is the payback period.

$$\mathrm{BCR} = \frac{\mathrm{TB}}{\mathrm{TC}} \tag{15}$$

Where BCR is the benefit-to-cost ratio.

Simulation Results

The following presents simulation results based on an example data set. Figure 2 depicts the model inputs as they appear in the user interface, including the base case and the DR program case variables.

The base case inputs include the general utility operating parameters, such as the cost of power (e.g. demand charge, wholesale costs, and retail energy costs), annual load growth, discount rate, and the historical demand curve.

The DR program variables include the applied program options with their respective rates, hours of the day and the months where the program is applied, and estimated elasticities of demand. Many studies have been done that estimate elasticities for given circuits, climates, and locations. As part of this work we have collected a survey of typical elasticities and made this data available online[1].

[1] https://github.com/dpinney/omf/wiki/images/DR%20Elasticity%20Estimates.xlsx

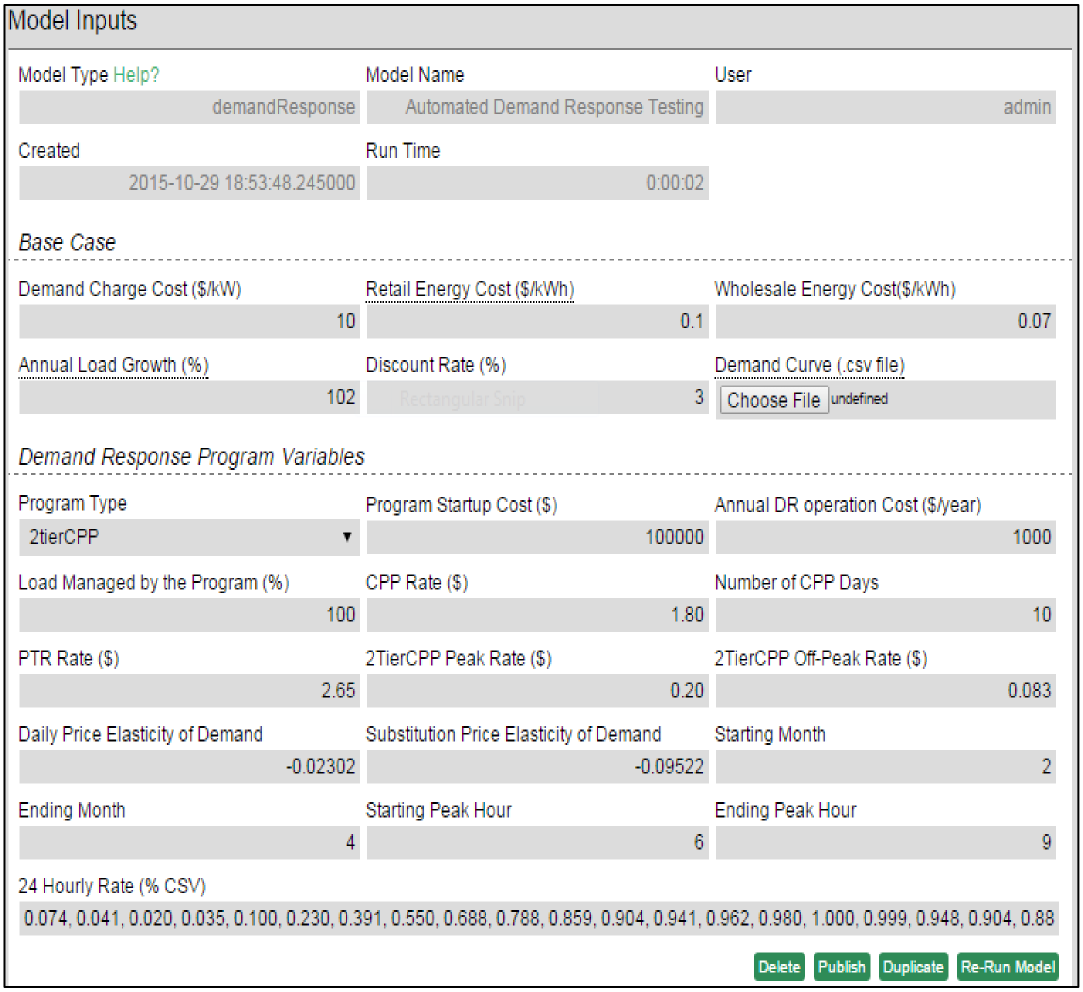

Fig. 2. Demand Response inputs of the model as visualized in the web interface

The results of the CBA are presented in the OMF in graphic and numerical form, as available from the model, and described herein. The following outputs of the model are available:

(i) The demand curve in the base case, as well as the simulated demand curve after applying particular DR program, as shown in Figure 3.

(ii) The first year financial impact of the DR program, listing the annual demand, energy sale, energy cost, peak demand, and program cost for both the base case and DR case, as shown in Figure 4.

(iii) The program lifetime cash flow, a chart shown as Figure 8, that includes all associated costs and benefits, the net present value, the payback period, and the benefit-to-cost ratio that are detailed in Figures 5, 6, and 7.

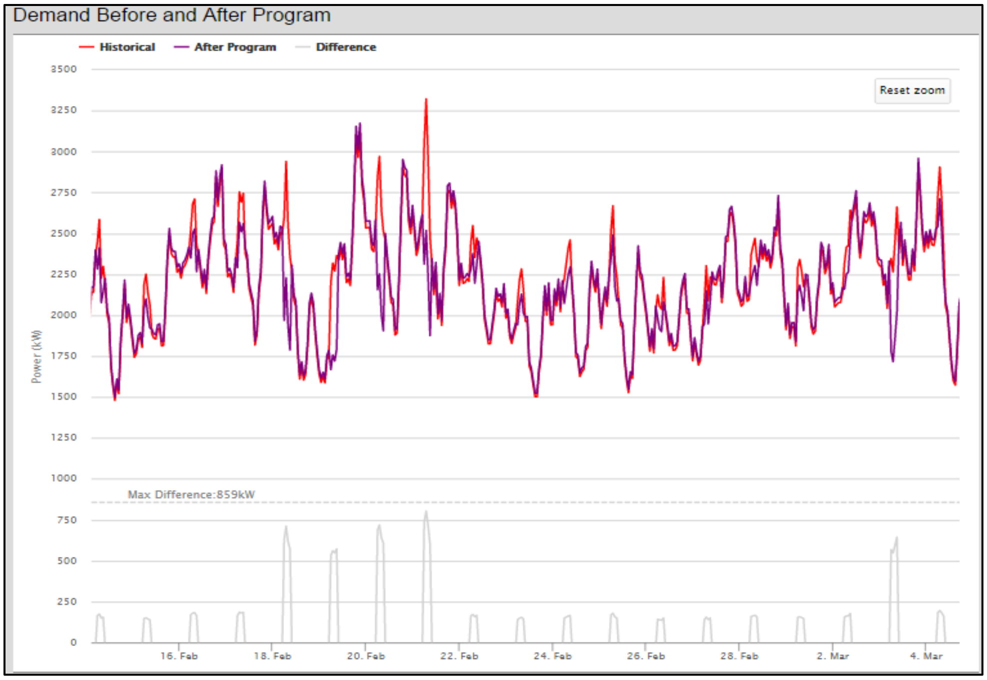

Fig. 3. Demand curve before and after applying the demand response program (Historical demand in red, the modified demand in purple, and the reduction in gray)

First Year Financial Impact

	Annual Demand (kWh)	Energy Sales ($)	Energy Cost ($)	Peak Demand Cost ($)	DR Program Cost ($)
Base Case	14,222,776	1,422,278	995,594	325,690	0
Demand Response Case	14,201,354	1,448,621	994,095	323,906	100,000

Fig. 4. The first year financial impact

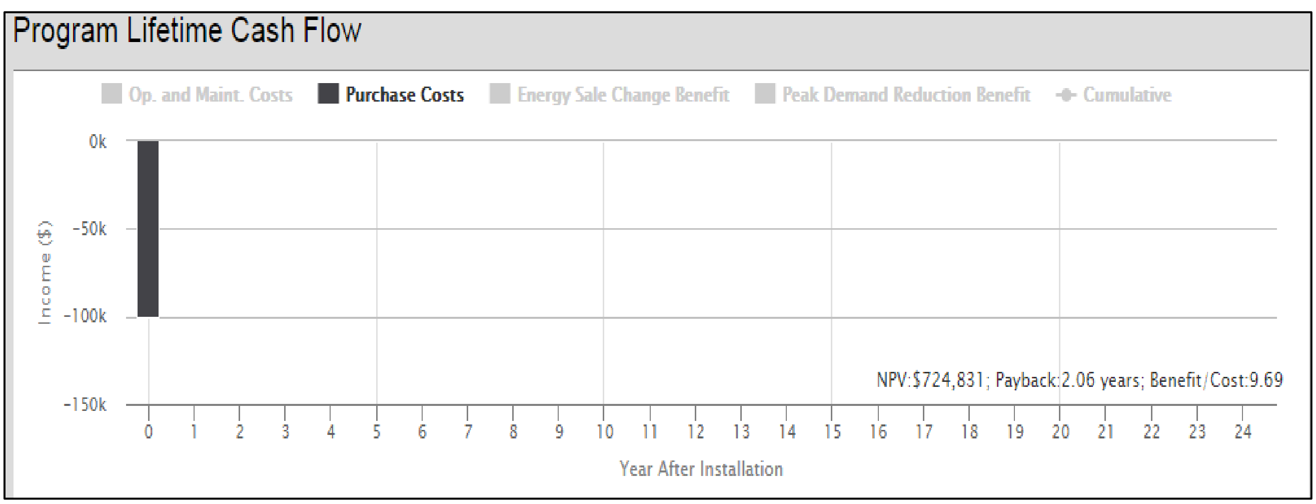

Fig. 5. Purchase cost is shown in the program lifetime cash flow chart

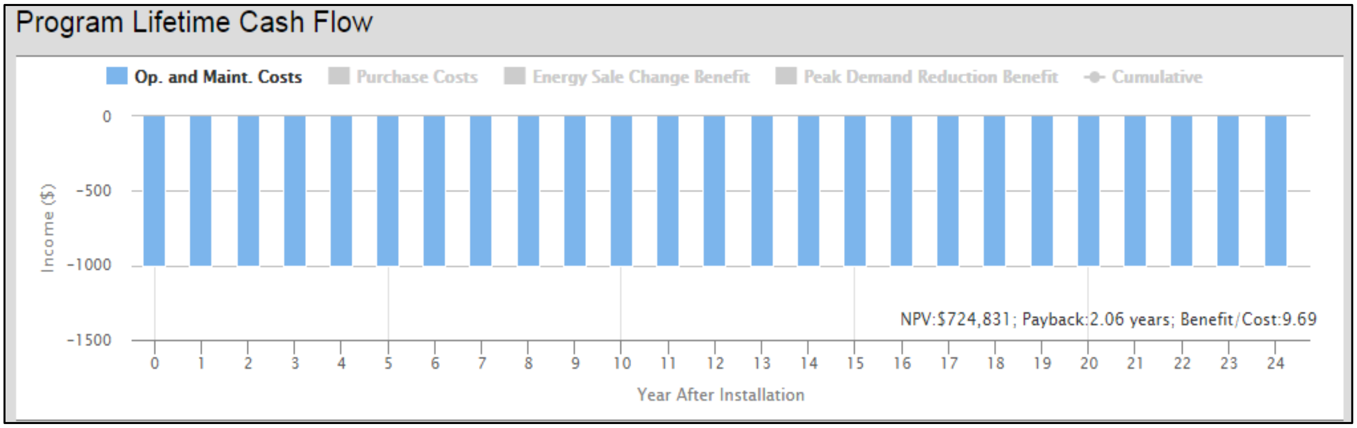

Fig. 6. Operation and maintenance cost is shown in the program lifetime cash flow chart

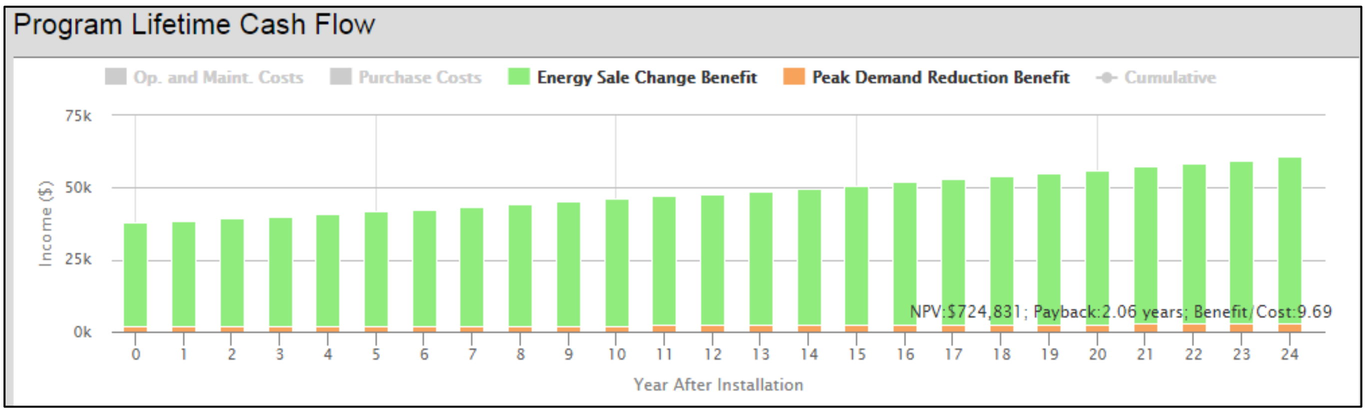

Fig. 7. Energy sale change benefit and peak demand reduction benefit

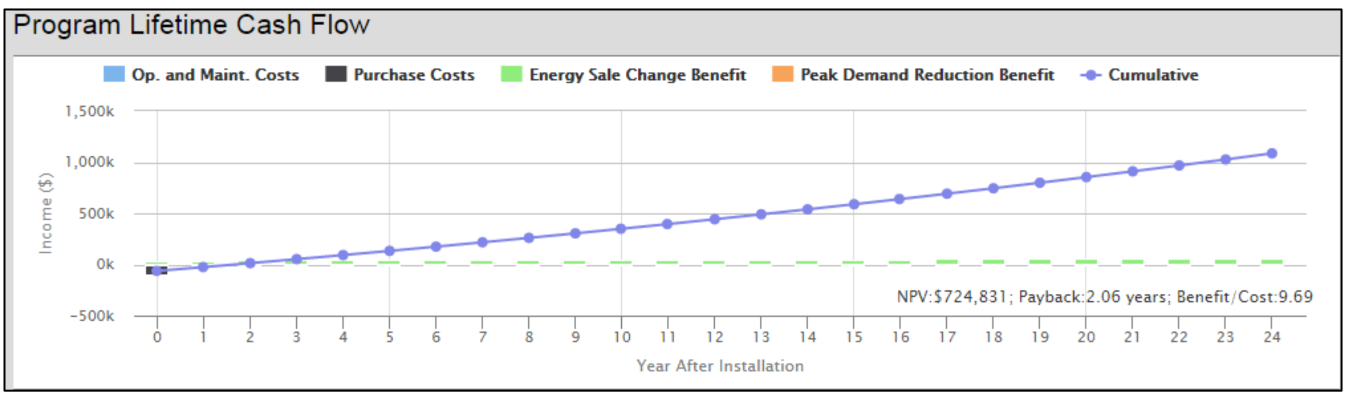

Fig. 8. DR program lifetime cash flow

Conclusion

NRECA's OMF planning tool allows cooperative engineers to run various distribution models, import data from commercial tools, and visualize results. It supports the latest research on power system analysis and operation, while providing an easily accessible user interface. The DR model incorporated in the OMF can provide cooperatives insight into the technical and financial feasibility of various DR programs. With a relatively limited set of system-specific inputs, cooperatives can evaluate the impact on their system load due to DR programs, and consider the potential financial benefits of a given program.

Expanding the functionality of the model by adding energy efficiency programs would allow utilities to analyze the full set of demand side management resources. This enhancement is a consideration for future work in this area.

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