Modeling Distributed Generation Adoption
Using Electric Rate Feedback Loops

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Overview
In the past decade, PG&E has experienced an unprecedented rate of distributed generation (DG) adoption, and this trend is expected to continue into the foreseeable future. In this work, DG is defined as electrical generation on the customer side of the meter – primarily rooftop solar. PG&E has 27% of US rooftop systems within its service territory\(^1\), while serving only 5% of the US population. Extrapolating from current trends, DG capacity is expected to be over 70,000 units and over 700 MW by the end of 2012, compared to a system peak demand of approximately 20 GW.

The cost of DG has declined substantially in recent years. The value proposition for DG to PG&E customers has been especially attractive in an environment featuring high marginal electric rates and a net energy metering (NEM) program\(^2\). Other driving factors, such as the availability of financing, power purchase agreements, and Governor Brown’s statewide DG goal for 2020, ensure that DG will become increasingly significant into the future. As more customers adopt DG, electric utilities must adapt their rate-making procedures to ensure that both DG adopters and non-adopters are fairly charged for their cost of service.

In a decoupled utility environment, if DG adoption causes lost revenues greater than avoided cost, then rates for non-adopters will rise, other things being equal\(^3\). Since the utility’s recovery of capital is independent of commodity sales, costs therefore must shift onto the remaining non-adopters. Higher rates give remaining customers even greater incentive to adopt DG, so the decoupled utility must limit the cost shift\(^4\) from adopters to non-adopters early on, to avoid an uncontrolled acceleration in cost shift later.

The feedback dynamic of this situation makes it difficult to intuitively estimate the impact of various policies and mitigation strategies on DG adoption. By creating a model that quantifies the rise in rates and uses this information as a factor in subsequent years’ adoption, a utility company can gain insight into the effect of different policy proposals on the cost shift impacts and adoption of DG. This paper covers the development and use of such a model created by PG&E to gain insight into this dynamic.

Methods
The core of the feedback model consists of three parts: cost effectiveness, adoption, and rates.

The chosen metric for participant cost effectiveness compares the levelized value of energy (LVOE) not purchased from the utility, to the levelized cost of energy (LCOE) from DG, via a ratio. The cost effectiveness component considers changes in technology costs and performance over time, the evolving marginal costs of grid electricity, the presence or expiration of various incentives in PG&E’s service territory (including Federal and State tax benefits), and other factors that influence DG project economics.

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\(^1\) As of 1/1/12. Based on PG&E internal data and national totals in the Interstate Renewable Energy Council’s Annual Report, published August 2012.
\(^2\) Under NEM policy, customers can count energy exported back to the grid by their DG systems against their energy usage during the same billing cycle. Excess electricity in a given month is credited forward as a monetary credit and can be used to offset charges in other months. Effectively, this policy credits their generated energy at the retail rate, which is high in California.
\(^3\) PG&E operates in a decoupled environment, meaning that company profits are not tied to the volume of energy sold. Instead, rates adjust based on expected sales volume, so that the allowed profit is reached. Because of decoupling, shareholders are indifferent to DG installations.
\(^4\) “Cost shift” is defined as the aggregate amount that non-adopters pay, to subsidize the DG adopters. PG&E’s goal is to minimize this cost shift because with DG adoption, higher-income customers generally shift cost onto middle- and lower-income customers – a fairness issue.
The adoption section of the model is built on customer-level data. PG&E’s population of customers is segmented based on rate schedule, energy usage, and likelihood to adopt DG. For each segment, a regression is used to translate historical responsiveness to cost-effectiveness, among other factors, into a forward projection.

The rates section reflects current rate-making mechanisms, assuming no changes in policy. The output of the rates section is detailed rates down to tiered rates and time-of-use rates\(^5\), and are fed into the cost effectiveness section. Having a detailed rates model is significant because rates are also one of the few tools that a utility can use to influence the cost shift from DG adoption. Potential DG customers make their decision based on the value of DG given current and expected future rates, so a model that captures this aspect of the decision more accurately represents likely future behavior. By modeling rates with high precision, the model also quantifies the cost shift and identifies which customers are most affected by it. Due to statutory limits on rate design in California, most of the cost shift is borne by customers whose usage is in the highest tiers, increasing the likelihood that they will then adopt solar if they can.

A system diagram of the model is shown in Figure 1. In each year of the model, cost effectiveness is calculated for each rate class and segment, based on the ratio of LVOE to LCOE. Adoption is then predicted based on the cost effectiveness, and rates are determined based on predicted adoption. The rates are then fed into the cost effectiveness calculation in the next year of the model, completing the loop.

![Figure 1: SYSTEM DIAGRAM OF DG MODEL](image)

### Cost Effectiveness

A key driver of DG adoption is the cost-effectiveness of DG technologies to the potential adopter. The Cost-Effectiveness module characterizes the cost-effectiveness of DG technologies to potential adopters as a function of the levelized cost of electricity (LCOE) and the levelized value of energy (LVOE). The overall cost-effectiveness metric – the ratio of the LVOE to the LCOE – is calculated for each technology, for each customer segment, for each year of potential adoption, and is utilized in the Adoption module (along with other inputs) as a basis for projecting DG adoption. Levelized values are used because they enable an apples-to-apples comparison of the relative cost and value of DG technologies across a variety of DG acquisition methods (e.g., outright purchases, power purchase agreements, leases).

Because the cost-effectiveness metric is used both (1) in the regression analysis, to determine the relationship between historical cost-effectiveness and historical adoption, and (2) in the adoption model, as a factor that drives future adoption (along with other factors), the metric is really the perceived cost-effectiveness to the potential adopter, since it is this perceived cost-effectiveness that drove historical adoption and will drive future adoption. Correspondingly, the inputs selected for both the LCOE and LVOE calculations are intended to represent a customer’s expectations (e.g., system performance, future utility rates -- see ‘Discussion’ section below).

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\(^5\) California residential rates have four tiers with higher usage meaning higher per kWh charges. In addition, most customers installing PV go on a TOU rate, which is also tiered.
While the cost-effectiveness of DG technologies in California has been evaluated previously⁶, this effort requires customized calculations to enable interaction with the broader model and application of PG&E-specific inputs.

This section describes the key inputs and calculation methodologies for each of the LCOE and LVOE sub-modules.

**Levelized Cost of Energy**

The LCOE sub-module calculates the levelized cost of electricity to the potential adopter for all DG technologies considered for each year of potential adoption. The calculation is based on a year-by-year accounting of generated electricity and project costs, depending on the inputs for each technology. Because the LCOE does not depend on electric rates, the LCOE calculation is not part of the annual feedback loop.

Key inputs to the calculation include:
- Technology costs (capital cost, O&M cost, out-year capital costs such as inverter replacements, PPA costs)
- Technology performance (system life, capacity factor, electrical and thermal efficiencies as appropriate, annual degradation)
- Fuel costs (natural gas) for technologies that rely on natural gas
- Incentives (utility incentives such as the California Solar Initiative (CSI) or the Self-Generation Incentive Program (SGIP))
- Tax rates and tax benefits (federal/state tax rates, depreciation benefits, Investment Tax Credit (ITC))
- Annual generation
- Discount rate for levelization calculation

Key outputs include:
- LCOEs for all technologies, by technology, year of potential adoption, for each scenario
- Breakdowns of levelized costs or benefits associated with each cost/benefit component (e.g., capital costs, fuel costs, tax benefits, incentives, etc.)

The LCOE sub-module captures the impacts of the various scenarios to the extent that they impact the LCOE calculation. For example, in the “Current subsidies sunset” case (see ‘Scenarios’ section below), the LCOE for PV projects that begin after 2016 does not include the 30% ITC⁷. Similarly, in the “Sunshot” scenario, PV prices are assumed to decline much more rapidly than in the base case.

**Levelized Value of Energy**

The LVOE sub-module calculates the levelized value of electricity to the potential DG adopter for all DG technologies considered for each customer segment for each year of potential adoption. Like the LCOE, the LVOE calculation is based on a year-by-year accounting of generated electricity and monetary benefits. Monetary benefits are primarily electricity not purchased, and for CHP technologies the change in net cost of natural gas (additional gas to run the CHP unit minus gas saved when using the waste heat to displace gas-fired heating). Unlike the LCOE, the LVOE does depend on electric rates, so the LVOE values are re-calculated each model year, using each year’s calculated electric rates. The LVOE sub-module is a critical piece of the rates loop, as the rate impacts of DG adoption affect the resulting LVOE values (and therefore the overall DG cost-effectiveness metric) which are then transmitted to the Adoption module.

Key inputs to the calculation include:
- Detailed electric rates by component, including energy (kWh), demand (kW), and other charges, both currently existing as well as potentially implemented⁸
- Hourly consumption profiles based on average hourly consumption by rate schedule
- Hourly DG generation profiles modelled according to profile typical for each technology (PV, baseload, peaking, or a blend of baseload and peaking)
- Various compensation mechanisms (net energy metering, feed-in tariffs, etc.)
- Rate of increase in bill savings over time (i.e., projections by potential adopters of future utility rate increases)
- Discount rate for levelization calculation

Key outputs, in addition to the LVOE value, include:

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⁶ For example, the 2011 California Solar Initiative Cost-Effectiveness Evaluation by Energy and Environmental Economics and the 2011 Cost-Effectiveness of Distributed Generation Technologies Report by Itron.
⁷ It is assumed that the “standard” ITC of 10% applies to PV after 2016.
⁸ e.g., customer charges, standby charges
A logistic regression model is used to estimate a likelihood of adoption for every customer segment. Using the system sizes of adopters, the pre-adoption usage of adopters is estimated to allow a fair comparison to the rest of the customer base. Instead of using total usage as an independent variable, the amount of billing in the rate tiers priced above average cost is used, as large amounts of usage in these tiers makes solar particularly cost-effective in PG&E’s service territory. Other key independent variables were income at the census block group level, homeownership, and participation in PG&E’s low income rate discount. Variables with smaller yet still significant impact were level of education, geographic area, and a “green” identifier taken from market research PG&E has procured.

Once segmented by the output of this logistic regression, a multiple linear regression model is used to forecast residential adoption, taking historical cost-effectiveness going back to 2003 as the key time varying input. Additional inputs to the final model include upper-tier usage, income, percent of segment on a low income rate, and percent of segment in single family homes. The parameter estimates of this regression are then used in the DG model to forecast residential adoption.

Due to the much higher heterogeneity of non-residential customers and the lower absolute number of customers and adopters, non-residential customers are segmented differently. Non-residential customers are broken up into small

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9 The current SGIP program has more stringent efficiency requirements, as does the recently implemented Combined Heat and Power Feed-in Tariff.
and medium commercial customers and large commercial and industrial customers. Within these two groupings, customers are segmented on their specific rate schedule. This is done to account for different rate characteristics causing different incentives to adopt DG. For example, a rate with time-of-use kWh charges only will allow substantially more savings due to DG than a non-time-of-use rate. Unlike the residential forecasting regression model, the non-residential forecasting models are based purely on cost-effectiveness. This is because there are far fewer data points for non-residential customers, and using more than one variable generally results in overfitting.

**Results**

Adoption among residential customers varies significantly from scenario to scenario. However, the distribution of that adoption among the segments follows a fairly consistent pattern. The segments that are already cost-effective (CE ratio greater than one) start to saturate by the end of the decade in most scenarios. On the other hand, a negligible amount of adoption occurs in segments composed mostly of customers in the low income program due to the low rates paid by these customers. As rates increase and solar costs decrease, other segments become cost-effective and start to adopt in larger numbers. Since the segments with initially high rates of adoption are also among the highest usage segments, they tend to have the largest capacity systems. A major effect of this is that average system size tends to decline over time even as residential consumption increases. For Non-Residential customers, the purely volumetric time-of-use rate sees the highest rates of adoption, as the summer peak time rate is substantially higher than even the current LCOE for PV. Adoption tends to remain tepid in the large commercial and industrial classes, except in cases with aggressive PV cost decline assumptions.

**Rates**

Because of decoupling, electric rates are primarily a function of the utility’s revenue requirement (RRQ) and electric sales (in kWh). To obtain the after-DG RRQ, both avoided and additional costs components within the RRQ are considered. Avoided costs include energy procurement costs and capacity costs (if any) that the utility saves because of DG adoption; additional costs consist of integration costs, interconnection costs, and incentive costs (both SGIP and CSI incentives) caused by DG adoption. To calculate net sales after DG, cumulative DG adoption is passed from the Adoption module to the Rates module and subtracted from expected gross sales. The RRQ is then allocated to different rate classes, including both residential and non-residential rate classes, according to standard rate-making procedures. The rates within each class are calculated using the RRQ and expected sales volume specific to each rate class.

The residential rates have a tiered structure where prices are higher at higher usage levels. Revenue collected from residential customers is based on volumetric (per kWh) rates. Besides minimal bill charges (low use customers are charged a minimum of $4.50 per month for basic services such as metering and billing), there are presently no demand or customer charges. Lower-tier rates and special rates for low income customers are allowed to increase only minimally year-over-year due to legislative limitations. Therefore, most of the cost shift to residential customers from DG adopters is absorbed by higher tiers, and these higher-tier rates see the most rapid increase. This rapid increase could lead to a backlash at some tipping point.

On the non-residential side, rate schedules are even more diversified. Although there are no protected rate classes, the charges are based on customer (per meter) rates, demand (per kW) rates and volumetric (per kWh) rates. Moreover, the demand rates and volumetric rates can vary by time-of-use period, including peak/part-peak/off-peak summer and peak/part-peak/off-peak winter. Following PG&E’s present allocation procedures, different RRQ components are split up into customer charges, demand charges and energy charges. In this way, the model simulates the situation that the revenue collected from each year can always recover the adjusted required revenue given the decreasing sales.

**Results**

Before the model was built, PG&E had examined the impact of DG on customers, but had difficulty comprehensively comparing the net cost shift impacts of different policy proposals. The DG model enables the simulation of different scenarios and policy options, to see how they would play out. “Scenarios” are a set of assumptions, while “policies” are the solution set – mostly rate policies. By examining how the scenarios play out under each policy, PG&E can gain insight into the impact of DG on both adopters and non-adopters, weighing the positives and negatives of each policy.

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10 Self-Generation Incentive Program
11 California Solar Initiative
Scenarios
The model was run under several scenarios, to gain insight on the impact of major external drivers on DG adoption and cost shift. The scenarios of most interest are:

- Current subsidies sunset (CSI, SGIP)
- Current subsidies extend through 2020
- Sunshot – the price of solar decreases faster than expected and reaches $1/W in 2020\(^{12}\)
- Virtual Net Energy Metering allowed for everyone

Comparing the scenarios, the case that maximizes the cost shift is the virtual net metering case. In this scenario, customers would be allowed to count solar generation at a remote location against their bill at the retail rate, greatly increasing the pool of potential DG adopters contributing to the cost shift.

Policy Responses
Different policy options are chosen to represent a range of feasibility in getting agreement among external DG stakeholders. Apart from the DG effort, PG&E has been considering a rate reform that would reduce the highest marginal rates. A moderate version of this proposal simulated in the DG model, and potential rate and policy changes were added on top of this proposal. The policy options simulated are:

- Adopt moderate rate reforms
- Adopt a more aggressive case of rate reforms
- Add customer charge on top of rate reforms
- Add standby for solar customers only on top of rate reforms

Under a moderate version of the proposed reforms, the model predicts a significantly lower cost shift. Additional rate changes on top of the rate reform case will lower the cost shift even more, but the effect would be less dramatic. The relative cost shift over time, under the different policy options is shown in Figure 2.

![Figure 2: COST SHIFT, UNDER DIFFERENT POLICY OPTIONS](image)

Conclusions
PG&E seeks to support solar and DG adoption in a sustainable way. The DG adoption model allows PG&E to gain insight into the impact of proposed policy changes and identify options that increase fairness and promote long-term sustainability of customer DG. The model has been used to evaluate the impact of pursuing less volumetric rates and reduced high tier rates, along with an alternative to net metering as the keys to supporting DG adoption while fairly assigning the cost of grid usage.