

## SWITCH-OAHU ASSUMPTIONS AND DATA SOURCES

**Introduction.** This document describes the data sources and assumptions for the Switch-Oahu model, as used in the study “Real-Time Pricing and the Cost of Clean Power,” by Imelda, Matthias Fripp and Michael J. Roberts. Switch is an electricity capacity planning model that chooses a cost-minimizing portfolio of generation assets for power systems with large shares of renewable energy. Details are given in Johnson et al. (2018). Switch software and tutorials can be downloaded from <http://switch-model.org/>. Instructions for replicating this study’s data and findings can be found at <https://doi.org/10.5281/zenodo.7228323>. This document describes the data sources used when building the Switch-Oahu data warehouse, one of the steps in the process described there.

**Geography and calendar.** For this study, Oahu is modeled as a single zone with adequate internal transmission and no connection to neighbor islands. The generation portfolio is optimized for 2045, taking account of all plant retirements expected before then. Weather and loads during 2045 are represented by 13 one-day timeseries, with 24 one-hour timesteps on each sample day. Decisions about generator commitment, output, storage and demand response are made during each of these timesteps. These weather days were selected and weighted to match historical conditions in 2007–08 as accurately as possible, including the single most difficult weather day (low wind and sun and high loads).

**Financial assumptions.** All costs input into Switch and reported from Switch are in 2020 real dollars. Switch normally minimizes costs on an NPV basis, but since this was a single-year study, the discount rate was set to 0% to give simple cost minimization. Capital costs are assumed to be financed with an annual payment over the life of the asset that is constant in real dollars, i.e., escalating with inflation. The cost of capital for this amortization is assumed to be 6% real (~8% nominal).

**Electricity demand.** We first calculate baseline electricity demand—hourly loads that would be expected if prices were set equal to average generation cost observed in 2007–08 and there is no effort to reschedule loads to better times of day. For this study, these hourly load forecasts were used as baseline loads to calibrate the constant elasticity demand system described in the paper. Then Switch found the system design, marginal costs and corresponding demand that maximize surplus with this demand system, contingent upon the pricing assumptions. In flat-price scenarios, the overall level of demand increases or decreases inversely with the resolved equilibrium average cost, but the load shape does not change. In RTP scenarios, demand can vary across hours and days in accordance with the specified demand system.

These loads are gross loads at the customer premises, including any demand that is self-supplied by distributed generation (DG). The baseline demand is based on hourly Oahu electricity loads in 2007–08 as reported to the Federal Energy Regulatory Commission (FERC). The historical loads are rescaled to have the same peak and average values as forecast for 2045. For this study, we used two forecasts of 2045 load: “flat\_2007” (same peak and average load as 2007) and “PSIP\_2016\_12” (peak and average loads forecast in Hawaiian Electric’s (HECO’s) Power Supply Improvement Plan (PSIP) in December 2016). Peak and average loads from PSIP for 2016–45 are shown in Figure 1.

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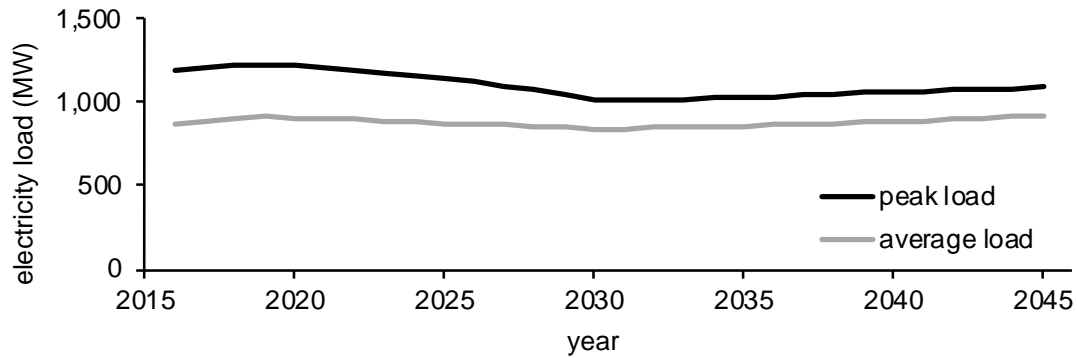


Figure 1. Peak and average baseline load forecasted for Oahu in 2016–45

**Electric vehicles (EVs).** We consider three possible scenarios for conversion of the light-duty vehicle fleet to electric vehicles. In the “Full Adoption” scenario, 100% of light-duty vehicles are converted to electric by 2045, following a simple linear transition that begins in 2020. In the “Half Adoption” scenario, there are half as many EVs in each year. In the “Flat 2016” scenario, electrification is frozen at the 2016 share (0.54%), derived from the DBEDT monthly energy trends report (DBEDT 2018). In all three scenarios, we neglect electrification of the heavy-duty vehicle fleet (buses and trucks).

The size of the overall vehicle fleet (816,908) and the miles traveled per vehicle year (8,706) are held constant at the levels shown for Oahu in 2014, based on county inspections, as shown in the DBEDT economic databook (DBEDT 2017). EVs are assumed to travel 4 miles per kWh of charging, based on the 2013 Nissan Leaf, and the fleet is assumed to obtain enough charge to match the total miles traveled each day.

For non-price-responsive scenarios, EVs use the time-of-day charging pattern from Das and Fripp (2015). In price-responsive scenarios, the charging is rescheduled to the hours with the lowest marginal cost.

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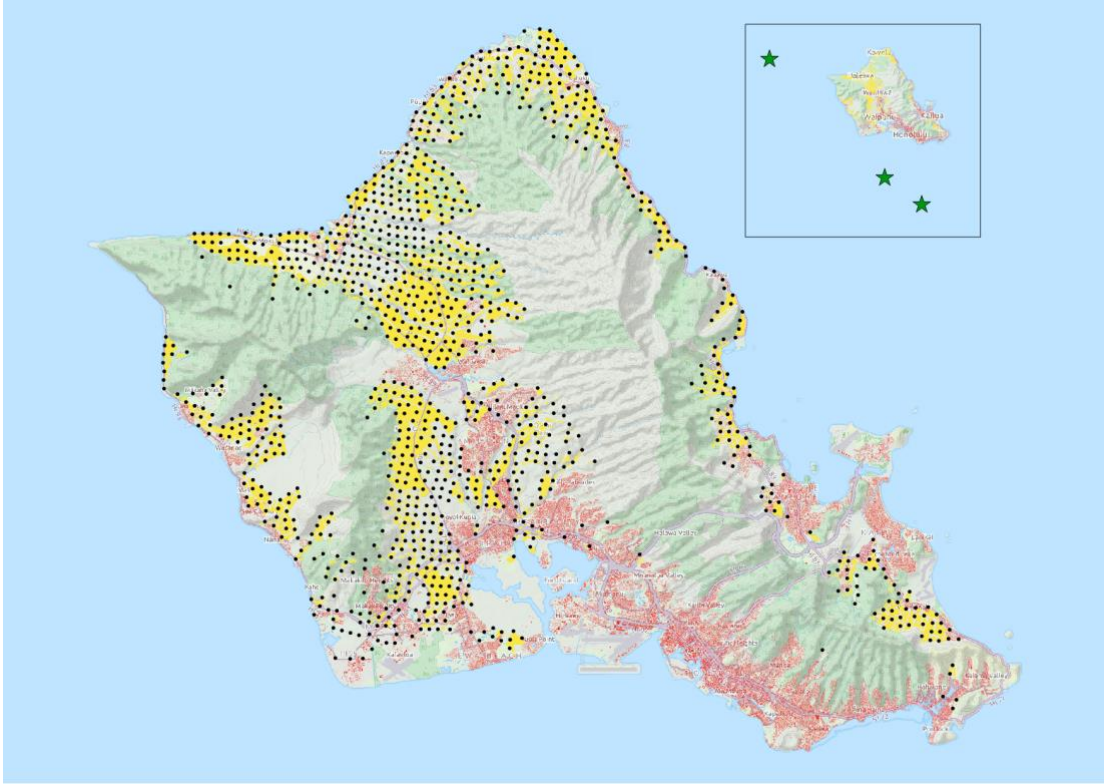


Figure 2. Location of potential renewable resources on Oahu: large solar (gold), rooftop solar (red), onshore wind turbines (black dots) and offshore wind farms (stars in inset)

**Onshore wind farm potential and performance.** We allow wind development on land that meets all of the following criteria: zoned for “country” or “agricultural” use, slopes of 20% or less, not within 300 meters of edge of allowed zone, not on narrow ridge, turbines at least 600 meters apart. Turbine locations are shown as black dots in Figure 2. Hourly production for each turbine is calculated from gridded data prepared for the OWITS study (Corbus et al. 2010; Manobianco et al. 2010) and earlier 200-meter wind maps (AWS Truewind 2004a; 2004b), using Clipper Liberty 2.5 MW wind turbine model C89, C93 or C99, selected for each site based on its annual average wind speed. Losses are assumed to be 12.53% based on 2013 HECO IRP (HECO 2013).

**Offshore wind farm potential and performance.** We define a single, generic offshore wind farm, representing the average of potential production at three proposed offshore wind farms near Oahu (BOEM 2016). We use hourly wind speeds for 2007–08 from AWS Truepower (Corbus et al. 2010; Manobianco et al. 2010), for the center of each farm at 100 meter elevation. We calculate hourly power production from these using a generic offshore wind turbine power curve, with the operating range extended to 30 m/s to match the Repower 6M (King, Clifton, and Hodge 2014). We assume 12.53% losses, matching the onshore wind projects. The generic project was assigned a maximum size of 2,400 MW (three times larger than current proposals) to reflect the large resources available. The centers of the three proposed wind farms are shown as stars in the inset map in Figure 2.

**Utility scale solar potential and performance.** We allow solar development on Oahu land that meets all of the following criteria: zoned for “country” or “agricultural” use; slope below 10%; not designated as Class A agricultural land or “Important Agricultural Lands”; not within

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30 meters of the centerline of roads (i.e., roads and urban areas); parcel larger than a 60-meter disk. Land available for large-scale solar is shown as gold in Figure 2. We assume land use of 7.5 acres per MW of PV capacity, which is 15% higher than the 6.5 acres/MW reported by Oahu developers for recent projects. PV systems are modeled as single-axis solar trackers using parameters from the 2019 ATB (NREL 2019), using solar data from NREL’s National Solar Radiation Database for 2007–08 (NREL 2016; 2018b).

**Rooftop solar potential and performance.** Rooftop locations are derived from the Google Static Maps API (Google Inc. 2016) and roof orientations and covered area are derived from the Google Sunroof project (Google Inc. 2019). We assume that panels on sloped roofs are tilted at 25 degrees and panels on flat roofs are tilted at 5 degrees, matching assumptions in NREL’s 2019 ATB (NREL 2019). PV systems are modeled using parameters from the 2019 ATB and solar data from the National Solar Radiation Database for 2007–08.

**Rooftop solar power adoption.** We include 444 MW of distributed photovoltaics that were installed as of 2016 (HECO 2016a Fig. J-19). We apportion 40.6% of this to flat roofs and the rest to sloped roofs, using the shares in those categories reported by Project Sunroof (Google Inc. 2019).

**Renewable portfolio standard (RPS).** The selected portfolio must meet a renewable energy targets ranging from 0% to 100% in 2045, depending on the scenario. This target is calculated as (all renewable production, including utility-scale renewables, biofuels and distributed generation) ÷ (all production, including distributed generation). This is different from Hawaii’s current RPS law, which omits distributed renewable generation from the denominator of this equation. This calculation includes all generation whether it is owned by HECO, independent power producers or customers.

**Operating reserves.** The scenario must maintain regulating reserves equal to the lesser of 100% of production from each wind or solar site or 21.3% of the solar equipment rating or 21.6% of the wind equipment rating. These coefficients are based on regression analysis of safe envelopes recommended by GE Energy Consulting (GE Energy 2012, 37–40; GE Energy Consulting 2015, 62; Piwko et al. 2012, 4–6). Switch also maintains upward contingency reserves equal to the largest individual generating unit online each hour and downward contingency reserves equal to 10% of load each hour. Operating reserves can be provided by dedicated contingency or regulating reserve batteries or by maintaining spare capacity in standard batteries or renewable, hydro or thermal generators.

For this study, in cases with dynamic pricing, some (high flexibility) customers are assumed to offer “spinning” reserves to the utility on a price-taker basis. In each hour, the quantity of down reserves offered—equivalent to decreasing generation or increasing consumption—is equal to the difference between the amount of power that would occur if the price were reduced to \$1/MWh and the amount of power purchased at the current price. \$1/MWh is the lowest price we allow in the demand system. The quantity of up reserves—temporary decrease in load—is equal to the total amount of power purchased for flexible purposes at the current price.

**Tax credits and subsidies.** The optimization included the 10% federal tax credit in effect for utility-scale solar in 2045—as of 2019 (DSIRE 2019)—but state tax credits were ignored because they are not a net reduction in total expenditure by Hawaii residents.

**Fuel price forecasts.** Liquid fuel price forecasts are based on the Brent crude forecast reported by the Energy Information Administration in the Annual Energy Outlook (AEO) 2019. We add a fixed offset to the EIA forecast to obtain a cost for low-sulfur fuel oil (LSFO), diesel or

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biodiesel delivered to power plants on Oahu. The adjustment factor is  $-\$0.63/\text{MMBtu}$  for LSFO (lower price than crude oil),  $+\$4.78/\text{MMBtu}$  for diesel and  $+\$14.38/\text{MMBtu}$  for biodiesel. These factors were found by comparing Oahu utility prices for these fuels to Brent crude over 2006–18 (2013–18 for biodiesel). These values are in 2020 dollars.

**Cost of wind and solar projects and batteries.** For new wind and solar resources and batteries, we use capital costs (including construction finance and interconnect cost) and O&M costs and project lifetimes from the NREL 2019 ATB (NREL 2019). We adjust capital costs to Hawaii-specific values by applying adders from EIA reports on this subject (EIA 2017; 2016) as recommended by the ATB. These are 35% for wind projects, 64% for large PV, 62% for distributed PV and 28% for batteries. We assume all of these systems (including DG PV) are dispatchable, i.e., they may be limited by available wind or sun, but can produce any amount of power below this limit. We model reserve-only batteries as having zero hours of bulk storage, but with cost equivalent to 0.5–1 hour of energy storage, as modeled in the PSIP (HECO 2016c).

We assume an additional cost of \$1000 per MW-km for transmission upgrades required to carry power from utility-scale onshore wind and solar projects to the load center. The distances are calculated from the center of each cluster to the population-weighted center of Oahu. This produces upgrade costs in the range of \$1,000–36,000 per MW of capacity from these technologies. Tie-line costs for offshore wind are included in the NREL ATB costs, and we assume these tie lines connect to a strong point on the transmission network, requiring no additional upgrades. We assume that distributed solar, batteries and thermal power plants use existing transmission capacity, so they also don't require transmission upgrades to carry power to market.

*Table 1. Capital cost, fixed O&M and project lifetime for wind farms, solar arrays and batteries; current costs and 2045 projections (2020 dollars)*

Cost Scenario	Technology	Capital cost (2020\$ /kW)	Storage capital cost (2020\$ /kWh)	Fixed O&M (2020\$ /kW-yr)	Asset life (years)
Current	Onshore wind	\$2,188	—	\$45	30
	Offshore wind	\$7,476	—	\$89	30
	Utility-scale PV	\$1,934	—	\$14	30
	Sloped-roof PV	\$4,493	—	\$22	30
	Flat-roof PV	\$3,005	—	\$18	30
	Batteries	\$859	\$244	\$37	15
2045	Onshore wind	\$1,522	—	\$37	30
	Offshore wind	\$3,128	—	\$42	30
	Utility-scale PV	\$1,280	—	\$9	30
	Sloped-roof PV	\$1,890	—	\$9	30
	Flat-roof PV	\$1,886	—	\$11	30
	Batteries	\$408	\$116	\$17	15

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**New thermal power plants.** The model can choose to add any whole number of 152 MW combined cycle power plants. These plants can burn low-sulfur fuel oil, diesel or biodiesel fuel. Capital, O&M and connection costs, reliability and fuel consumption curves for this plant design are taken from the PSIP (HECO 2016b).

**Hydrogen storage.** We allow production and consumption of hydrogen in stationary facilities to provide seasonal and diurnal energy storage. The plant design consists of an electrolyzer, refrigerator, liquid hydrogen storage tank and fuel cell, each of which can be sized and operated independently. Once produced by the electrolyzer, hydrogen can either be used the same day or refrigerated to liquid form and stored in the tank for future use. The tank is sized to hold all the hydrogen used in the year. Current and future costs for and performance for these elements came from the following sources: centralized PEM electrolyzer (NREL 2018a v. 3.2018), liquefier and tank (Amos 1998) and fuel cell (Steward et al. 2009).

**Existing HECO thermal power plants.** We use heat-rate curves, fuel type, min/max load and variable O&M costs for HECO power plants from the Hawaii Solar Integration Study (GE Energy 2012 App. A). We set fixed O&M to zero for these plants. Generating units are assumed to retire on the schedule shown in the PSIP (HECO 2016c): Waiau 3–5 in 2020; Waiau 6–8 and Kahe 1–4 in 2022; Kahe 5–6 in 2045; and the rest after 2050: Waiau 9–10, CIP CT, Airport DG and Schofield. All these plants are assumed to be able to use either biodiesel or their primary fuel.

**Power purchase agreements (PPAs) with existing thermal power plants.** PPA costs for independent power producers are modeled as a capacity payment and an energy payment. The capacity payment is based on amortized capital cost and fixed O&M costs and the energy payment is based on variable O&M costs and a fuel cost passthrough. All the terms other than fuel are constant in real dollars. For both the Kalaeloa combined cycle cogen plant and the H-POWER municipal solid waste plant, we assume a capital cost of \$1,850/kW, approximately equal to the cost of a new combined cycle power plant in the PSIP (HECO 2016b). Fixed O&M costs for these plants are assumed to be zero and variable O&M costs come from Coffman, Bernstein, and Wee (2014, 18). We assume both plants retire after 2045. We assume the H-POWER plant runs at 42.8 MW at all times (average production in 2015) and that its power production is RPS-eligible. We omit the small Tesoro Hawaii and Hawaii Cogen plants at oil refineries.

**Kalaeloa plant operating rules.** The Kalaeloa combined-cycle power plant is operated by an independent power producer. In addition to producing power, it also sells steam to the Par Hawaii refinery, the largest of two on Oahu. Due to this arrangement, the Kalaeloa plant has a contract with HECO under which it produces at least 75 MW of power whenever possible. However, it appears likely that this obligation would be dropped in high-renewable scenarios, so we do not enforce this rule in this study.

**Existing utility-scale generation.** We assume all generation projects listed in Oahu on the 2018 EIA Form 860 are currently in service. We also assume that renewable projects and scheduled for completion by the end of 2019 on HECO's Renewable Project Status Board (HECO 2020) enter service on the dates specified there. We assume that existing wind and solar projects that reach their retirement age before 2045 can be recommissioned in 2045 at the same annual capital recovery (amortization) as new greenfield projects built on the same date.

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