**Introduction.** This document describes how the Switch-Oahu model was configured to choose a long-term generation plan for the “Ulupono #1” scenario for the RIST tool. 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/>. This document describes how Switch was run to create the Ulupono #1 scenario on Dec. 14, 2019. Inputs and outputs for this scenario are available from <https://github.com/switch-hawaii/ulupono_scenario_1>. The scenario used Switch version 2.0.6.

**Geography and calendar.** For this scenario, Oahu is modeled as a single zone with adequate internal transmission and no connection to neighbor islands. The generation portfolio is optimized over the period of 2020–2049. Weather and loads during each year are represented by 13 one-day timeseries, with 12 two-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).

The model is run in two phases. Initially, the generation portfolio is optimized with new investments allowed in 2020, 2022, 2025, 2030, 2035, 2040 and 2045. After the portfolio is selected, construction of new renewable generation and batteries in each of these periods are spread equally over the years between the preceding period and the current period. The construction plan is then frozen, and Switch is run in production-cost mode to evaluate performance during each year between 2020 and 2045 (2020, 2021, 2022, 2023, etc.). Only data for 2020–38 are used in RIST.

**Financial assumptions.** All costs input into Switch and reported from Switch are in 2020 real dollars. Switch minimizes costs on an NPV basis, using a 3% discount rate. 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). Real-dollar costs are converted to nominal dollars before use in RIST.

**Electricity demand**. We first calculate “nominal” electricity demand—hourly loads that would be expected if there is no effort to reschedule loads to better times of day—and then allow a portion of the demand to be rescheduled to other hours. These loads are gross loads at the customer premises, including self-supply by distributed generation (DG). For use in RIST, DG is then subtracted to produce net loads. Nominal demand is based on hourly Oahu electricity loads in 2007–08, rescaled to have the same peak and average values as forecast for 2020–45. We currently use forecasts from the 2016 PSIP, increased in all years to make the peak and average forecast for 2018 match actual load in 2018. Peak and average loads for 2016–45 are shown in Figure 3.



Figure 3. Peak and average nominal load forecasted for Oahu in 2016–45

We assume that 10% of each hour’s nominal load can be rescheduled to a different hour of the day, but that the loads in each hour cannot be increased by more than 80%. We assume that this flexible demand cannot be used to provide operating reserves to compensate for forecast errors.

**Electric vehicles (EVs).** For light-duty vehicles, we use the EV adoption forecast in HECO’s Electrification of Transport study, reaching 55% by 2045. We assume the heavy-duty vehicle fleet (buses and trucks) is electrified at the same rate. For light-duty EVs, we use the time-of-day charging pattern that HECO reported for the Electrification of Transport study: 50% following a residential business-as-usual charging profile (provided by HECO 11/20/19) and 50% being charged at optimal times. Charging patterns for heavy-duty vehicles are as follows: 50% of buses charge quasi-continuously while on route, between 6 am and 10 pm; 50% of buses charge off-route at least-cost times between 10 pm and 6 am. Freight vehicles and non-bus diesel passenger vehicles charge at least-cost times while off duty. Off-duty windows for individual vehicles begin at times scattered between 4 and 10 pm and end at times scattered between 5 and 8 am. Energy requirements for vehicle fleet are derived from DBEDT Monthly Energy Trends report and FTA National Transit Database. EVs are assumed to require 3–5 times less energy than gasoline vehicles based on standard test cycles in 2017–18.

A close up of a map

Description automatically generated

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 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; 2018).

**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. 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 use HECO’s forecast of distributed PV and storage adoption provided on 11/20/19, shown in Table 2. Switch is not allowed to deviate from this total level of adoption, but it can prioritize more productive areas for development and can exceed 100% of demand on individual premises. Switch does not consider avoided network costs during the optimization stage; these are added in RIST when evaluating the economic impact of the selected portfolio.

Table 2. Adoption of distributed PV and distributed storage in Switch-Oahu

|  |  |  |
| --- | --- | --- |
| **Year** | **Total DGPV Capacity Online** | **Total Distributed Storage Online** |
| 2020 | 562 MW | 128 MWh |
| 2025 | 681 MW | 264 MWh |
| 2030 | 823 MW | 398 MWh |
| 2035 | 985 MW | 577 MWh |
| 2040 | 1150 MW | 772 MWh |
| 2045 | 1321 MW | 977 MWh |

**Renewable portfolio standard (RPS).** The selected portfolio must meet the following renewable energy targets: 30% in 2020–29, 40% in 2030–39, 70% in 2040–49 and 100% in 2045–49. These targets are calculated as (all renewable production, including utility-scale renewables, biofuels and distributed generation) ÷ (all production, including distributed generation). This is different from the current RPS law, which omits distributed renewable generation from the denominator of this equation. This calculation includes HECO-owned generation, IPP-owned generation and distributed generation.

**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. We do not allow the system to obtain reserves from flexible demand or EV charging.

**Tax credits and subsidies.** Federal tax credits are included in the optimization but state tax credits are ignored because they are not a net reduction in total expenditure by Hawaii residents. The rates in effect are shown in Table 1 (DSIRE 2019b; 2019a).

Table 1. Investment tax credits applied in Switch-Oahu

|  |  |  |
| --- | --- | --- |
| **Technology** | **Year(s)** | **Investment  tax credit** |
| Distributed PV | 2020 | 30% |
| Utility-scale PV | 2020 | 26% |
| Utility-scale PV | 2025–2045 | 10% |
| All other technologies | All other years | 0% |

**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 biodiesel delivered to power plants on Oahu. The adjustment factor is –$0.63/MMBtu for LSFO (lower price than crude oil), +$4.78/MMBtu for diesel and +$14.38/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). Future variable costs for the AES coal plant are based on its power purchase agreement (we are awaiting details from HECO).

**Cost of wind and solar projects and batteries.** For newwind 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 zero bulk energy storage, but with cost equivalent to 0.5–1 hour of energy storage, as modeled in the PSIP.

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 reported in section 5.2.1, 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 3. Capital cost, O&M and project lifetime for wind farms, solar arrays and batteries installed in 2020 or 2045

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Vintage** | **Technology** | **Capital cost (2020$ /kW)** | **Storage capital cost (2020$ /kWh)** | **Fixed O&M (2020$ /kW-yr)** | **Asset life (years)** |
| 2020 | Onshore wind | $2,188 | – | $45 | 30 |
|  | Offshore wind | $7,105 | – | $85 | 30 |
|  | Utility-scale PV | $1,879 | – | $13 | 30 |
|  | Sloped-roof PV | $4,317 | – | $21 | 30 |
|  | Flat-roof PV | $2,790 | – | $13 | 30 |
|  | Batteries | $785 | $226 | $34 | 15 |
| 2045 | Onshore wind | $1,500 | – | $37 | 30 |
|  | Offshore wind | $3,083 | – | $42 | 30 |
|  | Utility-scale PV | $1,261 | – | $9 | 30 |
|  | Sloped-roof PV | $1,863 | – | $9 | 30 |
|  | Flat-roof PV | $1,858 | – | $11 | 30 |
|  | Batteries | $402 | $116 | $17 | 15 |

**Pumped-storage hydro.** We model a potential pumped-storage hydro project at Lake Wilson with these parameters: maximum size of 150 MW, up to 12 hours of storage, 10 MW available from water inflow, round-trip efficiency of 77%, capital cost of $3,033/kW, fixed O&M of $45.50/kW-year and lifetime of 50 years. These parameters are based on personal communication from John Wehrheim of Pacific Hydro.

**New thermal power plants.** We do not allow development of new thermal power plants in this scenario.

**Hydrogen storage.** Switch is able to model production and consumption of hydrogen in stationary facilities to provide seasonal and diurnal energy storage. However, we do not allow hydrogen storage in this scenario because it is a pre-commercial technology and because future costs are uncertain. In previous modeling with Switch, hydrogen generally displaces a portion of biofuels and does not have a strong effect on overall costs.

**Existing HECO thermal power plants.** We use heat-rate curves, fuel type and min/max load for HECO power plants from Appendix A of the Hawaii Solar Integration Study (GE Energy 2012). We use fixed and variable O&M for the equivalent technology from the Assumptions to the Annual Outlook for the year the generating unit was built, converted to 2020 dollars (EIA 1996; 2009; 2013). The earliest edition of the Annual Energy Outlook currently available is 1996, so we used those costs for plants built before 1996. Generating units are assumed to retire on the schedule shown in the 2016 PSIP: 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 biodiesel in addition to their primary fuel.

**Power purchase agreements (PPAs) with existing thermal power plants.** PPA costs 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 Kalaeloa and AES, we use construction and O&M costs for combined cycle and pulverized coal plants in the Assumptions for the Annual Energy Outlook 1996 (EIA 1996). When these terms are used with 2018 production data, they result in energy charges that are within 2.2% of the energy charges that HECO reported to the PUC in 2018 (Hawaii PUC 2018, 66). HECO does not report capacity payments to the PUC, so we are not able to verify those. We assume the AES coal plant retires by 2022 and Kalaealoa retires in 2050 or later.

For the H-POWER plant we assign a variable O&M cost that is equal to the average energy charge that HECO reported to the PUC in 2018 (Hawaii PUC 2018, 66). We assign a capital cost and fixed O&M make the total capacity payment equal the value that HECO reported on 12/12/2019 in response to an informal information request ($17,685,360/year). We assume the H-POWER plant runs at 42.8 MW at all times (average production in 2015) and retires after 2050. It is assumed to be RPS-eligible.

The Tesoro Hawaii and Hawaii Cogen plants are omitted from this scenario but may be added at a later date.

**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. We assume this requirement is relaxed if the vehicle fleet exceeds 75% electric or the RPS exceeds 75% (i.e., in 2045 and later).

**Maintenance outages.** HECO-owned thermal power plants and AES and Kalaeloa are placed on maintenance outage 2–36% of the time, using reference schedules from GE Energy Consulting, as described in Fripp (2018).

**Predetermined 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 storage listed as completed, under construction or approved by regulators in 2019–2022 on HECO’s Renewable Project Status Board (HECO 2019) enter service on the dates specified there: 24 MW onshore wind in 2020 (Na Pua Makani), 8.5 MW of utility-scale solar in 2020 (feed-in tariff projects) and 139.5 MW of utility-scale solar with 4-hour batteries in 2021 (results of RFP Phase 1 in 2018-19).

We assume 4.990 MW of CBRE Phase 1 solar enters service in 2020 and 150 MW of CBRE Phase 2 solar enters service in 2022. The 150 MW for CBRE Phase 2 is a “best guess” based on recent discussions of a 235 MW target for all islands in the CBRE docket (Joint Parties 2019). HECO commented on 11/19/19 that “The Companies are only able to assume what is included in the current PUC D&O framework of 64MW, although the Companies have recommended that the program be large enough to attract larger developers and proposed increasing the capacity to 235MW (either solar or wind) over 5 years and revisit capacity availability as part of the IGP process.”

We include 560 MW of additional utility-scale solar in 2022, representing RFP Phase 2 acquisitions. This matches the “Up to 1,300,000 MWh annually” listed for Oahu in 2022–25 on HECO’s Renewable Project Status Board (HECO 2019). We allow Switch to select the optimal amount of battery storage to complement this resource.

Although CBRE Phase 2 and RFP Phase 2 allow for both solar and wind power, we assume the additions will be only solar power. If wind power were added in this time frame, it would likely decrease the amount of wind selected by Switch for later years, and possibly cause Switch to add more solar later.

The projects listed above are the only generating capacity that Switch is allowed to add in 2020–22. We also assume that renewable projects and batteries built in 2022 or earlier are recommissioned at equal size when they reach retirement age. Switch optimizes the selection of all other assets after 2022 to minimize costs.

**Reconstruction costs.** Projects that reach their retirement age and are then recommissioned are assumed to require the same annual capital recovery (amortization) as new greenfield projects built on the same date. This somewhat inflates the cost of projects reconstructed during the later years of the scenario. This only affects PV and wind built in 2015 or earlier and replaced after 30 years, or batteries built in 2020-2030 and replaced after 15 years.

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