Changes in Scenario 2.1 Relative to Scenario 2

- Renewable resources
    - Recalculated solar performance using NSRDB v. 3.1.1 instead of 2.0.1. This may give slight changes in hourly performance.
    - Used cost forecasts from NREL Annual Technology Baseline 2020 instead of 2019
    - Calibrated DER/DESS forecast to match already installed levels (add 112 MW/24.4 MWh in all years)
    - Changed AES West Oahu Solar online date to 2021 to better match HECO data
    - Moved CBRE Phase 1 from 2020 to 2021 because it does not appear to be completed yet
    - Dropped Kaukonahua Solar and Mehana Solar from RFP Stage 2 because they withdrew
- Adopted load forecasts from the Integrated Grid Planning process instead of 2016 PSIP
- Moved retirement dates of HECO steam generators one year earlier because they are start-of-year, not end-of-year
- Fixed error in implementation of predetermined storage capacity (battery depth was previously re-optimized when performing the annual assessment in production cost mode)
- Transmission and Distribution G&A costs
    - Transmission O&M: after two years of cost declines at 2% per year, the rate of inflation was changed to 2% increase per year versus continued cost improvements through the forecast period.
    - Distribution O&M: after two years of cost declines at 2% per year, the rate of inflation was changed to 2% increase per year versus continued improvements through the forecast period.
    - G&A: the forecast was updated to include two years of cost decline, at a rate of 2% per year starting with the 2019 estimated cost, for 2020 and 2021, then reverts to the 2% per year increase through the forecast period.
    - Transmission Capex: The assumption of an annual cost increase of 1.5% per year was modified to show cost improvements of 2% per year for 2020 and 2021. Starting in 2022, the rate of inflation of transmission capex was increased from the prior assumption of 1.5% to 2% through the forecast period. This assumes two years of cost improvements followed by standard inflation of costs.
    - Distribution Capex: The rate of cost improvements was changed from 2.2% to 2% for 2020 and 2021. Starting in 2022, the rate of inflation of distribution capex was increased from the prior assumption of 1.5% to 2% through the forecast period. This assumes two years of cost improvements followed by standard inflation of costs.

Capacity Installed in Scenario 2.1 (MW)

year	Large PV	Large Battery	Dist PV	Dist Battery	Onshore Wind	Offshore Wind
2020	134.6 (existing)		141.0 (existing)	38.1 MW/152.4 MWh (existing)		
2021	5.0 (CBRE Phase 1) 3.5 (Mauka FIT 1) 12.5 (RFP stage 1)	12.5 MW/50.0 MWh (RFP stage 1)	29.5 (DER forecast)	13.0 MW/51.9 MWh (DER forecast)	24.0 (Na Pua Makani)	
2022	127.0 (RFP stage 1)	127.0 MW/508.0 MWh (RFP stage 1)	22.8 (DER forecast)	9.7 MW/38.8 MWh (DER forecast)		
2023	15.0 (CBRE phase 2) 102.0 (RFP stage 2)	287.0 MW/973.0 MWh (RFP stage 2)	19.2 (DER forecast)	3.1 MW/12.5 MWh (DER forecast)		
2024	5.0 (CBRE phase 2) 172.0 (RFP stage 2)	172.0 MW/815.0 MWh (RFP stage 2)	23.1 (DER forecast)	3.7 MW/14.9 MWh (DER forecast)		
2025	150.0 (CBRE phase 2)		24.3 (DER forecast)	4.5 MW/18.2 MWh (DER forecast)		
2026	229.0 (Switch)	0.0* MW/291.4 MWh (Switch)	25.9 (DER forecast)	5.3 MW/21.3 MWh (DER forecast)	40.0 (Switch)	
2027	229.0 (Switch)	0.0* MW/291.4 MWh (Switch)	27.2 (DER forecast)	6.1 MW/24.5 MWh (DER forecast)	40.0 (Switch)	
2028	229.0 (Switch)	0.0* MW/291.4 MWh (Switch)	28.4 (DER forecast)	6.7 MW/26.9 MWh (DER forecast)	40.0 (Switch)	
2029	229.0 (Switch)	0.0* MW/291.4 MWh (Switch)	29.7 (DER forecast)	7.3 MW/29.3 MWh (DER forecast)	40.0 (Switch)	
2030	229.0 (Switch)	0.0* MW/291.4 MWh (Switch) 150 MW/1800 MWh (Lake Wilson pumped hydro, Switch)	30.5 (DER forecast)	7.9 MW/31.7 MWh (DER forecast)	40.0 (Switch)	
2031	23.1 (Switch)	0.0* MW/156.4 MWh (Switch)	31.3 (DER forecast)	8.4 MW/33.4 MWh (DER forecast)		
2032	23.1 (Switch)	0.0* MW/156.4 MWh (Switch)	32.2 (DER forecast)	8.7 MW/34.9 MWh (DER forecast)		
2033	23.1 (Switch)	0.0* MW/156.4 MWh (Switch)	32.4 (DER forecast)	9.0 MW/36.0 MWh (DER forecast)		
2034	23.1 (Switch)	0.0* MW/156.4 MWh (Switch)	33.0 (DER forecast)	9.3 MW/37.3 MWh (DER forecast)		
2035	23.1 (Switch)	0.0* MW/156.4 MWh (Switch)	33.2 (DER forecast)	9.5 MW/38.0 MWh (DER forecast)		
2036	31.5 (Switch)	6.5 MW/43.8 MWh (Switch)	32.8 (DER forecast)	9.6 MW/38.2 MWh (DER forecast)		
2037	31.5 (Switch)	6.5 MW/43.8 MWh (Switch)	33.2 (DER forecast)	9.7 MW/38.8 MWh (DER forecast)		
2038	31.5 (Switch)	6.5 MW/43.8 MWh (Switch)	33.0 (DER forecast)	9.8 MW/39.1 MWh (DER forecast)		

year	Large PV	Large Battery	Dist PV	Dist Battery	Onshore Wind	Offshore Wind
2039	31.5 (Switch)	6.5 MW/43.8 MWh (Switch)	33.1 (DER forecast)	9.8 MW/39.3 MWh (DER forecast)		
2040	31.5 (Switch)	6.5 MW/43.8 MWh (Switch)	33.3 (DER forecast)	9.9 MW/39.5 MWh (DER forecast)		
2041	249.2 (Switch)	51.0 MW/486.2 MWh (Switch)	33.5 (DER forecast)	9.9 MW/39.8 MWh (DER forecast)		
2042	249.2 (Switch)	51.0 MW/486.2 MWh (Switch)	33.3 (DER forecast)	10.1 MW/40.4 MWh (DER forecast)		
2043	249.2 (Switch)	51.0 MW/486.2 MWh (Switch)	34.1 (DER forecast)	10.2 MW/41.0 MWh (DER forecast)		
2044	249.2 (Switch)	51.0 MW/486.2 MWh (Switch)	34.4 (DER forecast)	10.4 MW/41.5 MWh (DER forecast)		139.5 (Switch)
2045	249.2 (Switch)	51.0 MW/486.2 MWh (Switch)	35.0 (DER forecast)	10.5 MW/41.9 MWh (DER forecast)		139.5 (Switch)

* 0 MW increments occur when additional batteries are installed behind existing inverters to increase the number of hours of storage

Assumptions and Data

Introduction. This document describes how the Switch-Oahu model was configured to choose a long-term generation plan for the “Ulupono #2.1” 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 on Switch are given in (Fripp 2012; Johnston et al. 2018; Switch Authors 2018). The input and output data for this scenario are available at https://github.com/switch-hawaii/ulupono_scenario_2.1. The “readme” file at that location also points to the specific version of Switch used for this scenario and the upstream datasets used to create the inputs for this scenario.

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 2020–2054. New investments are allowed in 2020, 2023, 2025, 2030, 2035, 2040, 2045 and 2050. Weather and loads during each multi-year study period 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). After the portfolio is selected, the wind, solar and batteries selected for each investment period are spread evenly over individual years in the prior period (e.g., investments added in 2030 are divided across 2026–2030). Then Switch is run in production-cost mode to evaluate performance during each year between 2020 and 2045 (2020, 2021, 2022, 2023, etc.). This evaluation is done on the same 13 sample weather days as the optimization stage.

Financial assumptions. All costs are reported in 2020 real dollars. The optimization minimizes costs on an NPV basis, using a 3% discount rate, subject to meeting the targets described in the Renewable Portfolio Standard section below. 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 "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 are gross loads including load served by distributed generation and batteries (DER) but not including electric vehicle (EV) charging, which is modeled separately. For use in RIST, DER is then subtracted and EV loads are added to produce net loads.

Nominal demand is based on hourly Oahu electricity loads in 2007–08, scaled and offset to have the same peak and average values as forecast for 2020–45. We use forecasts of peak and average nominal load from the Integrated Grid Planning (IGP) process as of March 9, 2020 (available at https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/forecast-assumptions-documents).

The IGP shows a sales forecast (customer-side view), which is consistently lower than the generation-side production modeled in Switch and reported annually on HECO's FERC Form 714. We raised the average loads in the HECO forecast by 7.1% and peak loads by 2.8%, so that the HECO values for total demand (underlying forecast + efficiency + EV + DER) closely matched demand reported on FERC Form 714 in 2006–2019. Peak and average nominal load for 2006–45 (underlying + EE) are shown in Figure 1.

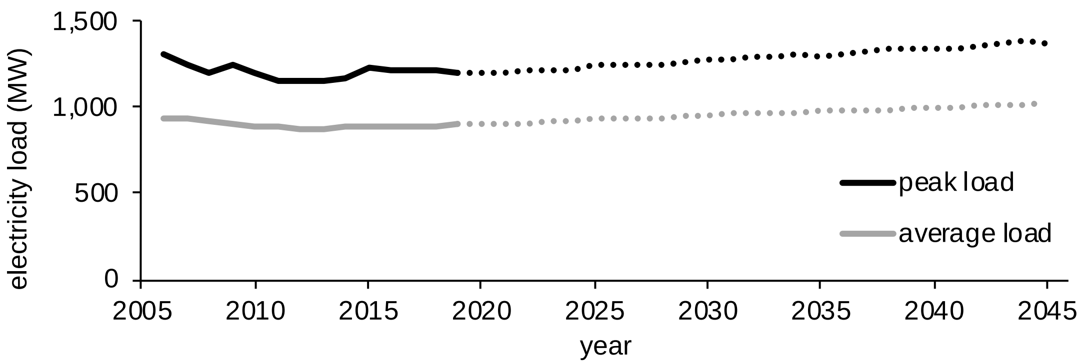

Figure 1. Peak and average nominal load for Oahu (history and forecast)

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 from HECO's Integrated Grid Planning study, reaching 54% by 2045 ("Slide 50," provided by HECO 5/13/20). Heavy-duty vehicles (buses and trucks) are omitted from the scenario. We assume light-duty EVs drive 9,011 miles per year (matching the 2018 Hawaii average) and use 0.31 kWh per mile (based on a review of EV models in use in Hawaii). 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.

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). Output from the Kahuku and Kawailoa wind farms is reduced by 34% and 44%, respectively, to match historical output from these sites. Nameplate potential and quality for all onshore wind farms is shown in Figure 3. It may be difficult to site large amounts of additional wind power on Oahu, so we restrict Switch to add no more than 200 MW of onshore wind capacity in addition to currently existing or planned projects (reaching 323 MW total).

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. Resource quality is shown in Figure 3. Due to economies of scale, we require that onshore wind be added in increments no smaller than 200 MW in each 5 year investment period; these are then spread out in annual increments of at least 100 MW for the annual assessment.

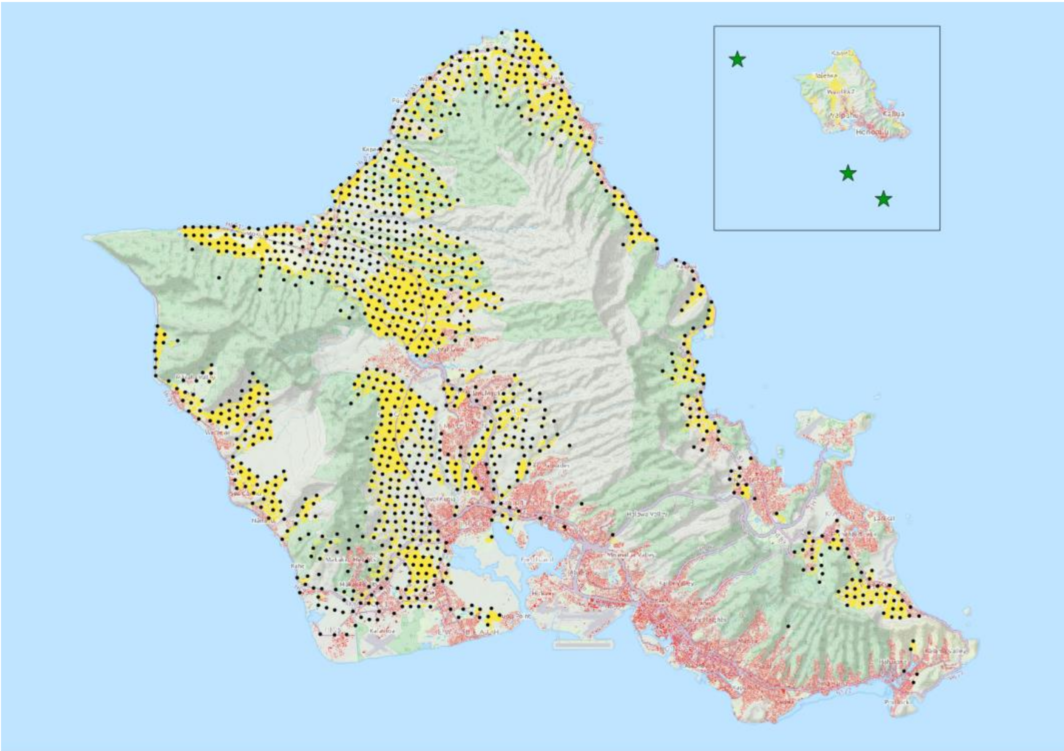

Figure 2. Location of potential renewable resources on Oahu: large solar (gold), rooftop solar (red), onshore wind turbines (black dots) and offshore wind farms (stars in inset)

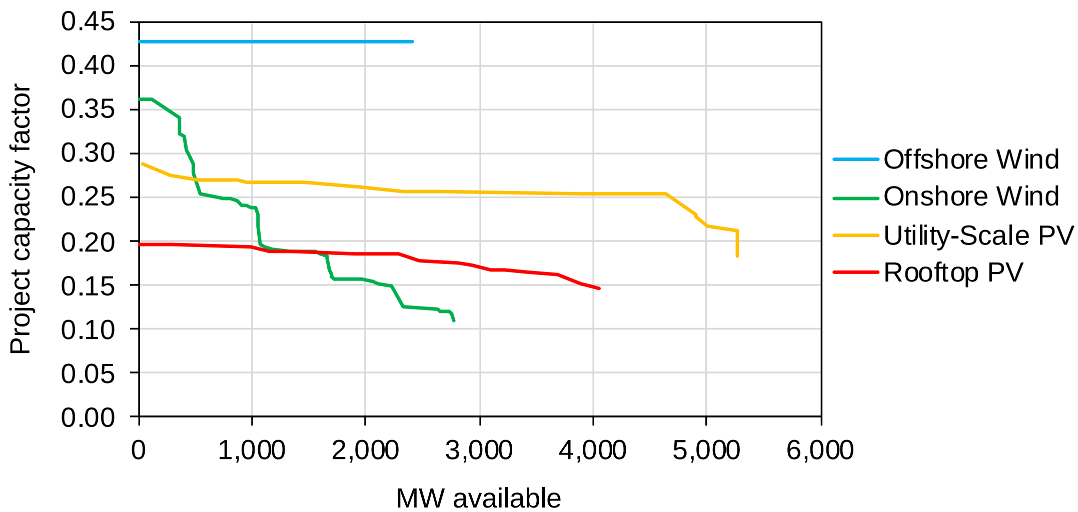

Figure 3. Renewable resource potential on Oahu. Vertical axis shows annual capacity factor (a measure of resource quality) and horizontal axis shows amount of capacity that could be deployed with a particular capacity factor or better.

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 2020 ATB (NREL 2020), using solar data for 2007–08 from version 3.1.1 of NREL's National Solar Radiation Database (NREL 2019; 2018; Sengupta et al. 2018). Nameplate potential and quality for all utility-scale solar sites is shown in Figure 3.

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 2020 ATB (NREL 2020). PV systems are modeled using parameters from the 2020 ATB and solar data from the National Solar Radiation Database for 2007–08 (NREL 2019; 2018; Sengupta et al. 2018). Nameplate potential and quality for all rooftop solar sites is shown in Figure 3.

Rooftop solar power adoption. We use HECO's forecast of distributed PV and storage adoption from June 2018 (HECO 2019). This forecast is below the actual installed levels in 2020 (HECO 2020c; 2020b, 4), so, to align the forecast with current conditions, we increase distributed PV capacity by 112 MW in all years and increase distributed storage by 24.4 MWh in all years. This is equivalent to beginning with the actual installed level in 2020 and then applying the annual incremental additions from the HECO forecast. The adjusted forecasts are shown in Table 1. Switch is not allowed to deviate from this total level of adoption, but it can prioritize more productive rooftops 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 1. Adoption of distributed PV and distributed storage in Switch-Oahu

Year	Total DGPV Capacity Online	Total Distributed Storage Online
2020	674 MW	152 MWh
2025	793 MW	289 MWh
2030	935 MW	422 MWh
2035	1,097 MW	601 MWh
2040	1,262 MW	797 MWh
2045	1,432 MW	1001 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 batteres 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 2 (DSIRE 2019b; 2019a).

Table 2. Investment tax credits applied in Switch-Oahu

Technology	Year(s)	Investment tax credit
Distributed PV	2020	26%
Distributed PV	2021	22%
Utility-scale PV	2020	26%
Utility-scale PV	2021	22%
Utility-scale PV	2022–2045	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) 2020. 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 (in 2019$) is $0.81/MMBtu for LSFO, $4.62/MMBtu for diesel and $15.36/MMBtu for biodiesel. These factors were found by comparing Oahu utility prices for these fuels to Brent crude over 2006–19 (2013–19 for biodiesel). Fuel cost for the AES coal plant was calculated similarly, using U.S. electricity-sector coal price forecasts from the AEO 2020 and historical U.S. and Hawaii coal prices reported by EIA. To smooth the transition between historical and forecast conditions, the prices for 2020 are set equal to the average of actual prices in 2019 and the forecasted prices for 2021.

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 2020 ATB (NREL 2020). 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 discussed above, 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	$1,870	–	$13	30
	Sloped-roof PV	$4,317	–	$21	30
	Flat-roof PV	$2,790	–	$17	30
	Batteries	$785	$240	$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	$123	$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. (In separate analyses, we allowed Switch to add thermal capacity, but none was selected until 2045.)

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). HECO's existing steam units (Kahe 1–6 and Waiau 7–8) are required to be committed (running at least at minimum load) at all times through the end of 2022, after which they are committed optimally. Generating units are assumed to retire at the start of the latest year shown in the "E3 Plan" or "E3 Plan with Generation Modernization" in the 2016 PSIP: Waiau 3–4 in 2023; Waiau 5–6 in 2026, Waiau 7–8 in 2031, Kahe 1–2 in 2035, Kahe 3–4 in 2039, Kahe 5–6 in 2045. The rest retire after 2045: 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. Fixed and variable O&M costs are taken from the Assumptions to the Annual Energy Outlook (AEO) published by the EIA in the year the plant was built or 1996, whichever is later (the AEO is not available for years before 1996). For the RIST model, an additional non-plant-specific generator O&M term ($19.3M) is added in all years to adjust this O&M expenditure to match generator O&M costs reported on FERC Form 1 in 2018.

Existing thermal power plant power purchase agreements (PPAs). We model thermal power plants as having an annual PPA price equal to their amortized cost plus fixed and variable O&M and fuel cost. Incremental heat rates for the Kalaeloa plant are taken from Appendix A of the Hawaii Solar Integration Study. Heat rates for the AES coal plant and refinery cogeneration plants (Hawaii Cogen and Tesoro Hawaii) are set based on total fuel used for electricity production, as reported on EIA Form 923 in 2018. AES, H-Power and the refinery cogen plants are all set to run as baseload, with the average output reported on EIA Form 923. In general, capital cost and fixed and variable O&M for these plants are taken from the Assumptions to the Annual Energy Outlook (AEO) published by the EIA in the year the plant was built or 1996, whichever is later. However, the capital cost for H-Power and the variable O&M for the refinery cogen plants were adjusted to achieve similar total cost to the PPA terms reported in the Hawaii Public Utilities Commission Annual Report for fiscal year 2018 (Hawaii PUC 2018, 66).
The AES coal plant is assumed to retire at the end of 2022 (its current contract ends in September 2022). We also assume that the Tesoro Hawaii and Hawaii Cogen plants retire at the end of 2044 and Kalaeloa retires at the end of 2054. We assume the H-POWER plant produces RPS-eligible power and retires at the end of 2049.

Cogeneration operating rules. The Kalaeloa combined-cycle power plant and refinery combustion turbines are operated by independent power producers. In addition to producing power, they also produce steam for use by Oahu’s oil refineries. 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). We also assume that the Hawaii Cogen and Tesoro Hawaii cogen plants operate at nearly full power most of the time but cease operation under these conditions.

Maintenance outages. Maintenance outages are not modeled explicitly in this scenario, but output from 24/7 baseload plants (AES, H-Power, Hawaii Cogen and Tesoro Hawaii) is reduced to match the average output reported on EIA Form 923 (years 2012–16 for AES, 2015 for H-Power, 2018 for the refinery cogens).

Predetermined utility-scale generation. We assume all generation projects listed in Oahu on the 2019 EIA Form 860 are currently in service. We also assume that renewable projects and storage listed on HECO’s Renewable Project Status Board (HECO 2020a) enter service on the dates specified there or slightly afterward. These include some feed-in tariff projects and RFP Stages 1 and 2. We also assume 5 MW of CBRE Phase 1 solar enters service in 2020 and 170 MW of CBRE Phase 2 solar enters service in 2023–25, based on Hawaii PUC order number 37070 (Hawaii PUC 2020). Switch is prevented from adding any wind or solar in 2020–25 or batteries in 2020-23 other than the projects identified above. We also assume that existing and predetermined renewable projects and batteries are recommissioned at equal size when they reach retirement age. Switch optimizes the selection of batteries after 2023 and all other assets after 2025 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.

Transmission and Distribution, G&A Assumptions. For the Ulupono scenarios, Switch is run as a single-zone model with no limits or costs for transmission or distribution. Transmission and distribution costs are then estimated externally as inputs to RIST. These estimates are described here.

2019 costs for Transmission and Distribution O&M and G&A were estimated based on the 2019 total O&M costs reported in HECO's 10-K. This total O&M cost was allocated to T&D O&M and G&A based on the 2018 cost breakdown provided in the 2018 FERC Form 1 data. The same methodology was used for the total Capital Expenditures from the 10-K. The breakdown between Generation, Transmission, Distribution, and other was from the 2018 FERC Form 1 data. FERC Form 1 data is not available (as of August 2020) through S&P Global for the 2019 reporting year.

Transmission O&M cost is assumed to decline by 2% per year for 2020 and 2021, to better align with historical gap to peers. The costs are assumed to increase at 2% per year after the two years of decline through the remainder of the forecast period.

Distribution O&M cost is assumed to decline by 2% per year for 2020 and 2021, to better align with historical gap to peers. The costs are assumed to increase at 2% per year after the two years of decline through the remainder of the forecast period.

G&A cost is assumed to decline by 2% per year for 2020 and 2021, to better align with historical gap to peers. The costs are assumed to increase at 2% per year after the two years of decline through the remainder of the forecast period.

Transmission Capex is assumed to decline by 2% per year for 2020 and 2021, to better align with historical gap to peers. The costs are assumed to increase at 2% per year after the two years of decline through the remainder of the forecast period.

Distribution Capex is assumed to decline by 2% per year for 2020 and 2021, to better align with historical gap to peers. The costs are assumed to increase at 2% per year after the two years of decline through the remainder of the forecast period.

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