UM 2005 Distribution Work Group
March 10, 2022 Notes

March 25, 2022

Below are notes from the March 10, 2022, DSP Work Group meeting.

Attendees included (but were not limited to):

- PUC: Nick Sayen, Staff
- PacifiCorp
  - Lee Elder
  - John Rush
  - Erik Anderson
  - Melissa Nottingham
  - Tyler Jones
  - Carla Scarsella
  - Heidi Caswell
  - April Brewer
  - Kathreen Woyak
  - Daniel Morgan
  - Teri Ikeda
- NWEC
  - Marli Klass
  - Fred Heutte
- Energy Trust
  - Jeni Hall
  - Spencer Moersfelder
  - Gina Saraswati
- OSSIA: Angela Crowley Koch
- CCC: Nikita Daryanani
- Renewable NW: Micha Ramsey
- PGE
  - Andy Eiden
  - Bachir Salpagarov
  - Misty Gao
  - Sam Newman
  - Shadia Duery
  - Jennifer Galaway
  - Joe Boyles
  - Nihit Shah
  - Rich George
- Idaho Power
  - Dan Johnston
  - Alison Williams
  - Chris Cockrell
  - Jim Burdick
  - Marc Patterson
  - Kelley Noe
- IREC: Yochi Zakai
- CUB: Sudeshna Pal
- NW Natural: Rebecca Brown

Questions/clarifications/etc. on follow up materials from January 20, 2022, meeting

There were no questions or clarifications on the follow up materials from the January 20, 2022, meetings.

Follow up discussion from March 8 Public Meeting

There was a question about overlap of UM 2111 and UM 2005 in terms of hosting capacity analysis (HCA) and requirements between the two dockets. Nick noted that Staff is aware of the overlap between the dockets, and will work to coordinate and avoid duplication. Specifically, Staff recommended that HCA on the UM 2005 side pause while the scope is finalized on the UM 2111 side. Further, as considered through the lens of IREC's paper, there are about a dozen important questions to answer for HCA, and these questions can be split between UM 2005 and UM 2111 to create clear "swim lanes."

There was also discussion about the role of HCA in distribution system planning, and whether it should guide investments. Staff noted that discussion of HCA in DSP so far has revolved around providing information on interconnection issues. This information can also be helpful informing discussions about utility investments in the distribution system, however discussion of HCA has not yet moved towards using HCA to identify and guide utility investments. That would be a significant departure from how utilities currently approach investments (for example, meeting requirements to demonstrate need, with a prudence review in rate cases). Yochi noted that California and Nevada have established parameters for utility forecasting and use of HCA in that forecasting; he observed that both states had lengthy stakeholder processes to establish those parameters and establish HCA maps. Also, there may be legitimate differences between approach and methodology in HCA used for utility investments and HCA used in providing information on interconnection.

Angela Crowley-Koch noted frustration that locational value will not be addressed in this docket. If not this docket, then where? She indicated Oregon should have a state-wide approach that reflects locational value of solar. Staff referenced the Public Meeting presentation, specifically reviewing Table 1, which called out the evolution of DSP. Heide volunteered to review LBNL's research on HCA and locational value and provide that to this group.

Joint utility meetings

Heide explained that the utilities have heard the feedback from the group that participants would prefer not to repeat discussions of the same topics across each utility. And so the utilities have begun to meet on a monthly basis to start coordinating topics and joint discussions.

Questions for clarification for March 10 DSP Work Group meeting. Bolded orange font reflects discussion during March 10 meeting.

1. Requirement 5.1.b.iii reads as follows:
   For the initial Plan, the methodology for geographical allocation (to the substation) is at the utility's discretion. The Commission may provide direction for subsequent Plans.
   This requirement doesn't seem like a requirement. Is that correct?

   Staff response: That is correct. The intent of this guideline is to make clear that, though the utility is required to develop DER and EV forecasts with high/medium/low scenarios, and allocate those forecasts to the substation level, the utility has discretion on the methodology for that allocation.

2. Requirement 5.1.c.i is the last requirement in the forecasting section. We think this will be addressed in Grid Needs, therefore will not be addressing it in the forecast discussion. Can you confirm this approach?

   Staff response: The intent of requirement 5.1.c.i (*Document existing and anticipated constraints on the distribution system*) is clear documentation of "constraints," or areas which will need investment, identified as a result of the forecasting exercise described in requirement 5.1. Staff would find it acceptable for that documentation to be presented in the Grid Needs discussion, as long as doing so wouldn't result in loss of the reason the need was identified (for example "equipment at end of life" or "forecast constraint" or "additional customer capacity").

   PGE staff clarified that much of the actual work to identify constraints will be uncovered in the Grid Needs step, not in Forecasting. Staff agreed this approach was fine, with the understanding that the reason for constraints would be captured and identified in the plan.

3. Note requirement 5.2.c: *Present a summary of prioritized grid constraints publicly, including criteria used for prioritization*.
   During the last DSP Partners meeting we suggested that we would be presenting this information, and after discussion about stakeholder input, Staff suggested that perhaps we could present the grid needs without prioritization. Please clarify.

   Staff response: Thanks for asking about this confusing direction from Staff and providing a chance to clarify. Staff anticipates that when engaging stakeholders and community, presumably early in plan development, presenting the grid needs without Company prioritization may be a helpful exercise. Once the plan has had stakeholder and community input, and is ready for submission, a prioritized list is appropriate. Staff is happy to continue to discuss this should pragmatic implementation of this approach prove difficult.

   In discussion of this question, PGE staff explained this challenge is driven by timing, specifically the sequencing of the capital planning process and the first DSP process. For example, projects in current DSP plans were identified last year, prior to the existence of a process for public input. PGE is beginning to work on grid needs at this time, and at the same time developing the public input process. PacifiCorp staff noted the Company is working through similar challenges with timing for the Part 2 DSP filing.

   This is a reality of synchronizing a new planning process with an existing one. It seems inevitable there will be some growing pains to get the initial DSP to reflect the intent of the requirements. Given the timing challenge, clearly communicating to stakeholders about what is firm and set for this first DSP, what is open for input, and what will be different in future DSPs, will be very important.

Working Subgroups – Part 1: Review of final topics

Staff reviewed the aggregated list of topics that have been discussed by the group previously, and added topics from the March 8 Public Meeting memo as well as topics from the day's discussion.

These three issues were identified at the August 25, 2021, Work Group meeting as issues that could benefit from separate working subgroups:

1. Equity Issues: A working subgroup to focus on identifying useful demographic and socioeconomic data, useful energy planning metrics, and quantifying measures and data sources for equity; also, consider identifying preferred sources of public data that include demographics and other details that adequately characterize our communities.

2. Common definitions: A working subgroup to focus on establishment of common vernacular for distribution system planning discussions.

3. Data access: A working subgroup to focus on practices for handling public accessibility of data, specifically in the distribution system context.

These three issues are from the Parking-lot for outstanding issues and questions, or were discussed previously:

4. Where and how data will be stored is an important question to discuss early so there is a way to manage, keep safe, and access data as it comes in (from May 7, 2021, Data Transparency Workshop).

5. Volunteers to work on further completing Figure 2 for priority data types (from May 7, 2021, Data Transparency Workshop).

6. Solutions providers: companies and vendors that could provide technology and services to implement DSP.

These six issues were discussed at the January 20, 2022, Work Group meeting:

7. Identifying areas of overlap (and/or potential collaboration) in utilities' current practices **of cost effectiveness methodologies**, with the goals of 1) minimizing discrepancies, but not with a goal of establishing policy in these practices, and 2) maximizing stakeholder bandwidth (in other words, having one conversation about cost effectiveness rather than separate discussions for each utility).

8. Same as #7 but with focus on utilities' current **practices of forecasting approaches**.

9. Same as #7 but with focus on utilities' current **practices/developments in hosting capacity analysis**.

10. Envisioning the future state of DSP in several years (no need to wait for 2023 to consider reviewing the Guidelines).

11. DSP intersections with implementation of HB 2021.

12. How energy efficiency and DER forecasts feed into IRP processes.

This issue was discussed in the Staff's Memo for the March 8, 2022, Public Meeting:

13. Continue steps to advance distribution system data, including assessing maps already developed to identify best practices, inclusion of equity data in maps already developed, and organizing/validating/publishing distribution system data not already made public.

These two issues were identified at the March 10, 2022, Work Group meeting:

14. Locational value.

15. Using HCA to guide proactive utility investments.

Working Subgroups – Part 2: Volunteers; discussion of each group's scope - All participants

Meeting participants expressed interest in some topics (noted below), however, the group suggested it would be helpful to clarify and consolidate topics and recirculate, with participants to review and confirm their interests after that. It was also noted that the consolidation process should be mindful of not conflating data management and access, with equity and socio-economic data. One participant noted that more than three groups may be unwieldy. Proposed clarified and consolidated topics are included in the agenda for the March 31 meeting.

Name	Topic(s) of interest
Angela Crowley Koch	7, 8, 9
Andy Eiden	1, 7, 8, 9
Yochi Zakai	3, 13, 15, possibly 4, 5, 9
Chris Cockrell	3, 13, 15
Melissa Nottingham, Angela Long	Heide noted Melissa and Angela previously committed to 1 and 10
Marli Klass	1, 11 (tentative)
Micha Ramsey	4, 3, 13
Fred Heutte	3, 4
Sudeshna Pal	1, 13 (tentative)
Heide Caswell	2, 7, 8, 12, 14
Erik Anderson	7
Bachir Salpagarov	7
Shadia Duery	1, 2
Jim Burdick	1, 8 (tentative as topics get consolidated)
Marc Patterson	3, 7, 14
Dan Johnston	8

PGE presentation: inputs to the AdopDER model - PGE Staff

Andy Eiden presented on PGE's AdopDER model using the slides attached.

Adjourn

The meeting adjourned a few minutes after 4 pm Pacific.

Please note for your reference future DSP Work Group meetings dates include:

Date and Time
March 31, 2022, 1:00 – 4:00 pm Pacific
April 21, 2022, 1:00 – 4:00 pm Pacific
May 19, 2022, 1:00 – 4:00 pm Pacific
June 16, 2022, 1:00 – 4:00 pm Pacific

Parking-lot for outstanding issues and questions

1. Where and how data will be stored is an important question to discuss early so there is a way to manage, keep safe, and access data as it comes in (from 5/7/21 Data Transparency Workshop).
2. Volunteers to work on establishing common definitions for distribution system planning discussions (from 5/7/21 Data Transparency Workshop).
3. Volunteers to work on further completing Figure 2 for priority data types (from 5/7/21 Data Transparency Workshop).
4. What are preferred sources of public data that include demographics and other details that adequately characterize our communities? (from 6/30/21 Technical Work Group meeting)
5. Working subgroup to focus on demographic and socioeconomic data, useful energy planning metrics, and quantifying measures and data sources for equity (from 6/30/21 Technical Work Group meeting).
6. Working subgroup to focus on practices for handling public accessibility of data (from 6/30/21 Technical Work Group meeting).

Questions or Feedback

Questions and comments can be directed to Nick Sayen via email at nick.sayen@puc.oregon.gov or by telephone at 503-510-4355.

DER Forecast Inputs

Detailed methodology, assumptions, and risks

Andy Eiden, Distributed Resource Planning,
Principal Planning & Strategy Analyst

March 10, 2022

Objective

Provide detailed overview of AdopDER model inputs and methodologies for each major DER type

Touch on feedback heard from previous meetings

Discuss potential methods and solutions, with discussion

DSP Guidelines for DER Forecasting

Forecasting of Load Growth, DER Adoption, and EV Adoption		
Stage 3		Refine hybrid forecast approach to allow more granular locational and temporal forecasts, aiming for consistent outputs across utilities.
Stage 2		Identify potential locational system benefit from strategic placement of DERs on the distribution grid.
		Examine data to better understand opportunities for customer participation by energy-burdened households.
		Leverage both top-down forecasts and bottom-up customer models to build forecasts (approaches may be specified).
Stage 1	Allocate system-wide DER forecasts from utility IRP filings to greater locational granularity.	
	Document forecasting process and indicate existing and anticipated constraints on the distribution system.	
	2021-2022	2023 and beyond

Past DER Forecast presentations

IRP Roundtable

- December 10, 2020 – IRP Roundtable 20-8, presentation on DER forecasting study overview (slides 15-30)
- August 25, 2021 – IRP Roundtable 21-7 (slides 7-70)

DSP Partner Monthly Meetings

- February 10, 2021 - DER Potential & Flex Load Assessment 101 (slides 31-45 & video)
- March 10, 2021 – DER and Flexible Load Study (slides & video)
- April 14, 2021 – DER Potential & Flex Load Analysis – Phase 1 (slides 12 -21 & video)
- May 12, 2021 – DER Forecast: Final Draft Results (slides 34-54 & video)
- Jan 13, 2022 – DER Forecast Updates (slides 41- 61 & video)

DER Forecasting Timeline

Complete feeder-level DER adoption results from Phase II locational forecast development

Feb 15

Refresh of AdopDER with new corporate load forecast and calibrate to new program data

Feb-Mar

Incorporate data and metrics on EJ communities for locational assessment of DER potential for NWS pilot proposals

May-Jun

Coordination with other filings

We will be tracking and coordinating with a few work streams to inform continued DER forecasting evolution at PGE. A few examples are highlighted below.

TE Plan / HB 2165

Alignment on priority populations stated to receive 50 percent of annual TE charge revenue collections.

Per Staff's guidance, 7 priority communities defined as:

- Residents of rental housing
- Residents of multifamily housing
- Communities of color
- Communities experiencing lower incomes
- Tribal communities
- Rural, frontier & coastal communities
- Communities adversely harmed by environmental and health hazard

Multiyear Plan (MYP) filing

- The DRP team will continue working with Products and Programs teams to develop measure inputs for continued MYP reporting and forecasting
- Before filing DSP in August, planning to incorporate community feedback and equity metrics into additional targeted locational analysis, including community microgrids and related resiliency factors

AdopDER model overview

DER and Flex Load Study with DSP Part I

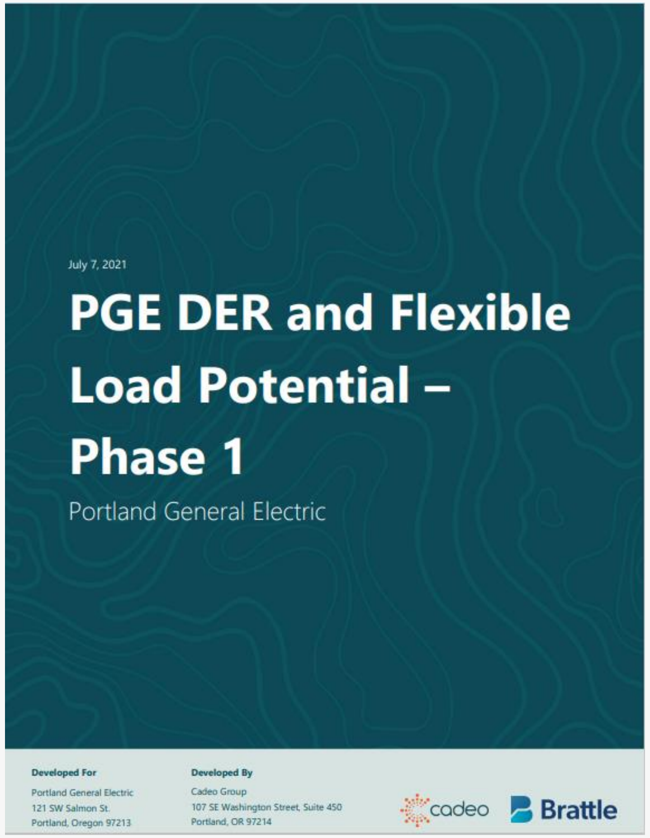
PGE is required to include forecasted demand-side resources in the IRP and DSP

- IRP has long history of forecasting DR and EE
- DSP forecast is new this year as result of UM 2005

Study covers forecast of the following distributed energy resources (DERs)

- Demand response / flex loads
- Distributed rooftop PV
- Distributed battery storage
- Electric vehicles and charging needs

Full study available online as Appendix G to the DSP Part I, available at: https://portlandgeneral.com/about/who-we-are/resource-planning/distribution-system-planning


July 7, 2021

PGE DER and Flexible Load Potential – Phase 1

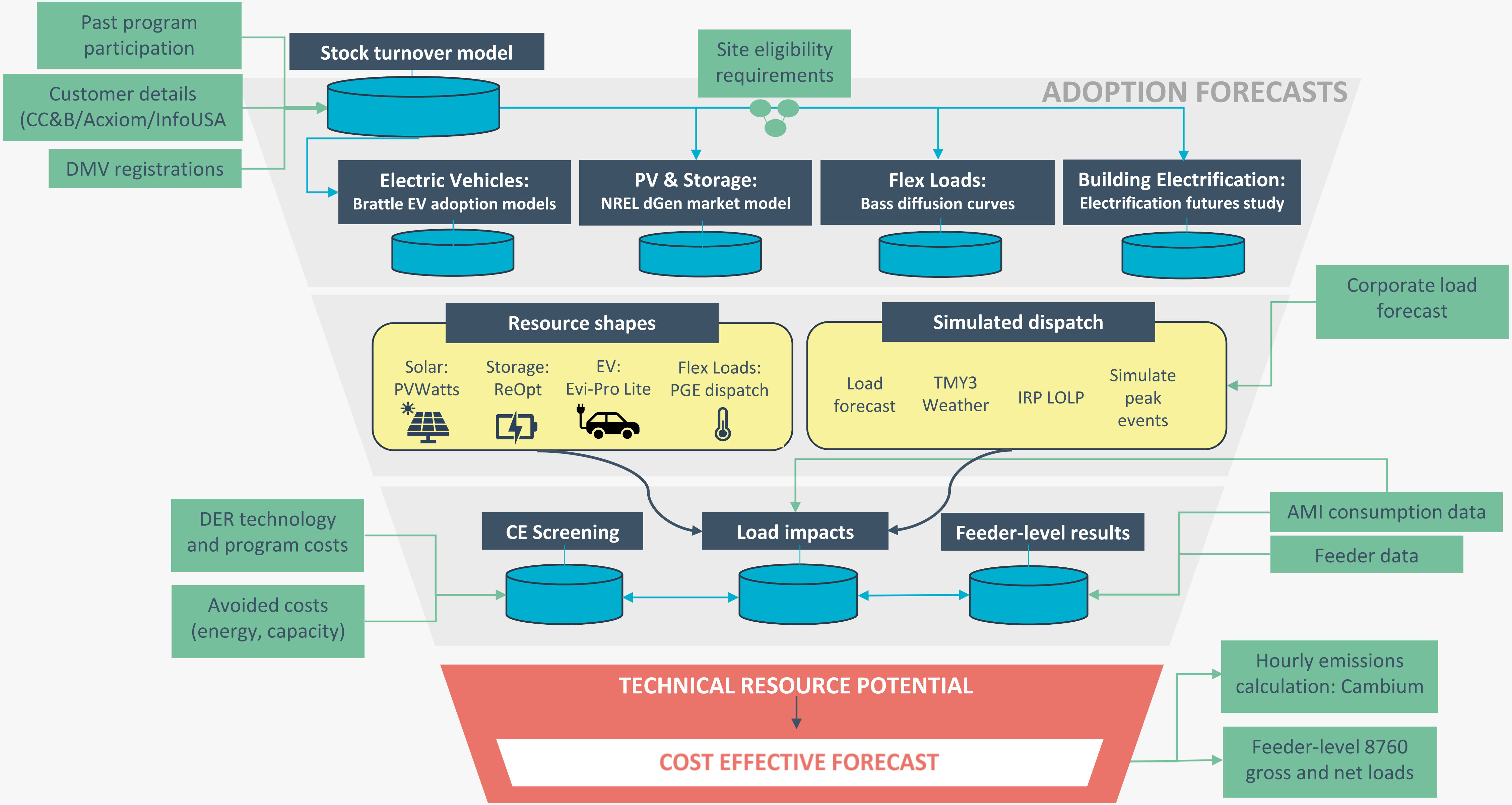
Portland General Electric

Developed For
Portland General Electric
121 SW Salmon St.
Portland, Oregon 97213

Developed By
Cadeo Group
107 SE Washington Street, Suite 450
Portland, OR 97214

cadeo Brattle

AdopDER Flow Diagram



Detailed DER Methodology - EVs

TE Forecast Methodology

LDV adoption based on Brattle econometric model

- Purchase Incentives
- EV Battery Price
- Relative Fuel Price
- Available Models
- ZEV State Mandate
- Vehicle Miles Traveled
- Green Views
- Charging Rate

Fleet LDV/MDV/HDV adoption based on Delphi panel model

Both scaled to DMV registration data and vehicle stock turnover model

For EV charging requirements, estimate plugs needed and vehicle charging loads using:

- LDV, workplace L2, and public L2 using NREL's EVI-Pro Lite model*
- Public DCFC usage patterns come from PGE Electric Avenue sites
- MDHDV shapes are based on combination of engineering calculations and third-party data

* See slide 12 for more details about EVI-Pro Lite

Vehicle Inputs and Eligibility Criteria

Start with DMV registrations for State of Oregon (3.7M), filtered to PGE service area (1.8M)

Match to address (~80% of records) and identify vehicles registered in PGE zip codes for remainder of unmatched (20%)

Run modified VIN through NHSTA VIN-decoder API to standardize inputs around drive-train (PHEV or BEV), battery size, & weight class

Table 4-12. Private EV Charging Eligibility

Measure	Eligibility Criteria	Measure Size
All Level 1	Residential or Non-Residential, has EVs not addressed by other onsite charging, has driveway or garage	Number of plugs
Residential Level 2 (smart and standard)	Residential, has EV, has spare 220V breaker, has driveway or garage	Number of plugs: minimum of number of EVs/2, number of available 220V breakers available
Nonresidential Level 2 (smart and standard)	Nonresidential, has EVs not served by DCQC	Rated capacity multiplied by number of plugs (number of EVs/2)
DCQC	Nonresidential, has MDV/HDV	Rated capacity multiplied by number of plugs (number of MHDVs/4)

Brattle LDV EV Regression Variables

Variable Name	Variable Type	Description
Dependent Variable: EV sales per capita	Continuous	Defined as the total incremental sales of EV (BEV or PHEV) per million residents
State incentives	Continuous	The maximum incentive (rebate, tax credit or tax exemption) offered by a state upon purchase of a BEV or PHEV, in $/vehicle
Federal Tax Credit (FTC)	Continuous	A tax credit offered by the federal government upon purchase of a BEV or PHEV, in $/vehicle
Total Incentive	Continuous	Sum of the state incentives and FTC
Battery price	Continuous	Lithium-ion battery cost index in $/kWh, as a proxy of electric vehicle cost (BNEF)
Vehicle miles travelled (VMT)	Continuous	Average vehicles miles travelled annually, per capita
Tesla Cap dummy	Binary	A dummy variable to indicate a period of spike in EV sales after Tesla hit the cap for the FTC – Q3'18 and Jan'19
Model availability	Continuous	Number of EV models available across a state by year
Green views score	Continuous (0-100)	Average environmental voting score of state House and Senate reps (League of Conservation Voters Annual Environmental Scorecard)
High Occupancy Vehicle (HOV) lane exemption	Binary	Indicates the presence of an HOV lane exemption for EVs
Traffic density	Continuous	Weighted average daily traffic per lane for all principal arterials
Zero Emission Vehicle (ZEV) mandate	Binary	Indicates the presence of a ZEV mandate enacted by the government
EV charging rate	Binary	Indicates whether or not at least one utility offers an EV rate for charging in a given state

EV Forecast Methodology – MDHDV

LDV market has significant historical data to develop mathematical models

Nascent MDHDV market does not have comparable data

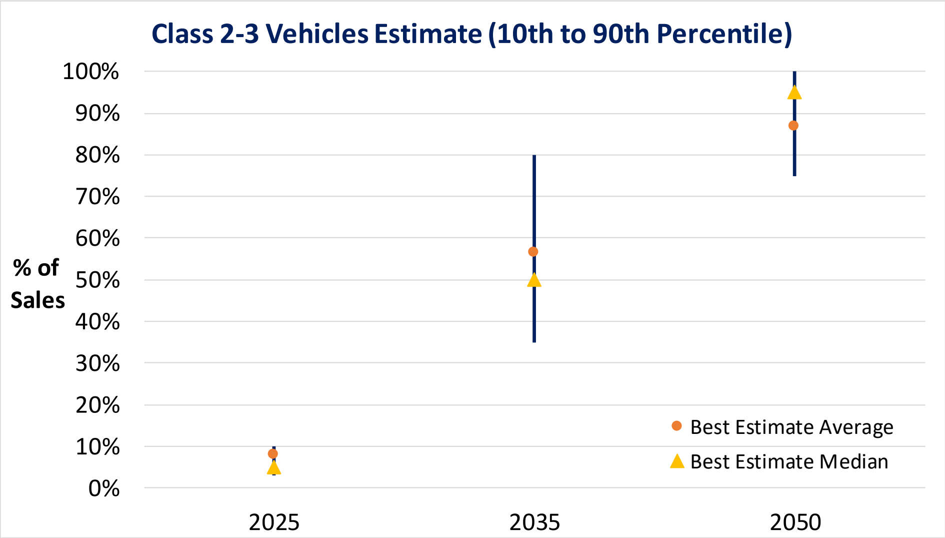
Brattle employed a Delphi Method, which is well established forecasting method the relies on panel of experts over two rounds

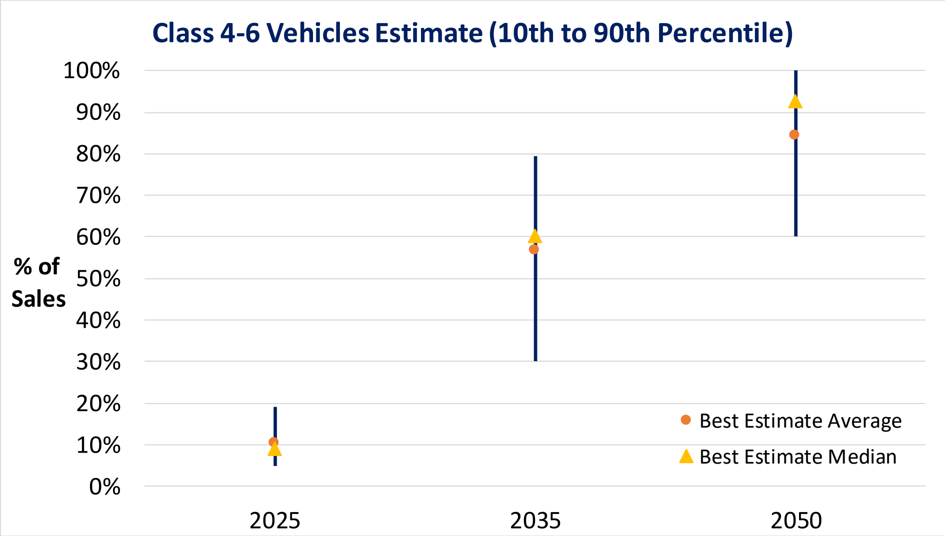
Used range of market size estimates at near/mid/long term to calibrate s-curves for adoption

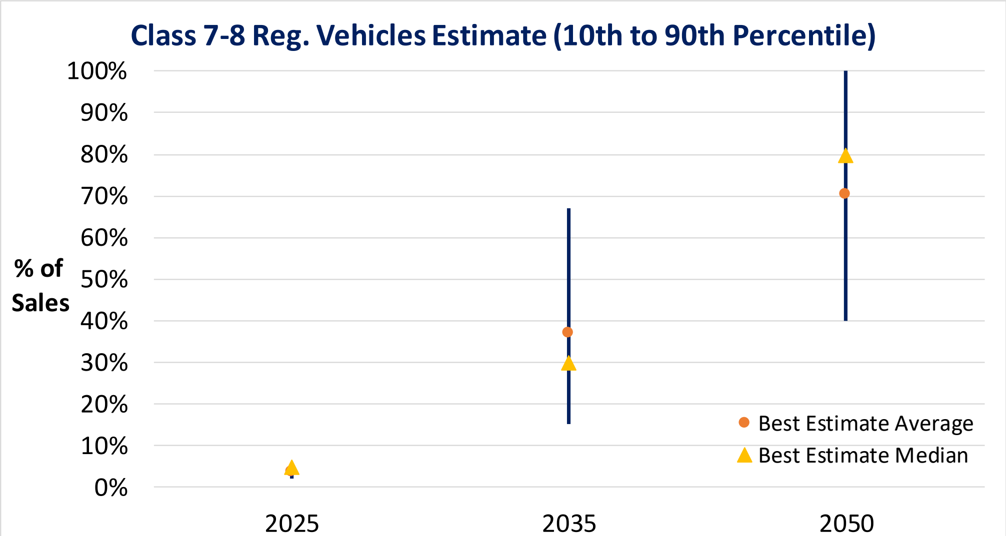
Participating Experts and Affiliations

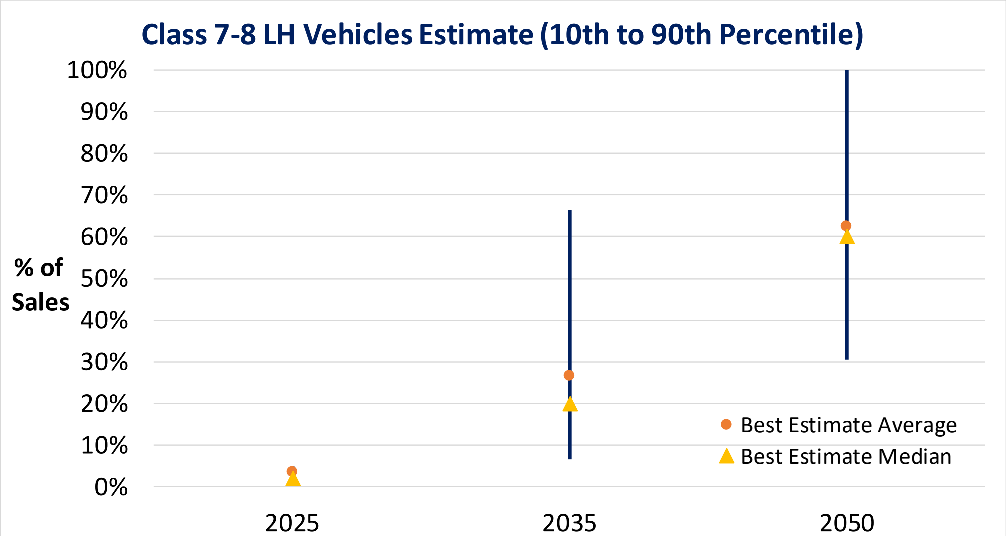
Research/Non-Profit
Atlas Public Policy
CTE
CTE
Electrification Coalition
NREL
Rocky Mountain Institute
Union of Concerned Scientists
Government
DOT
Utility
Duke Energy
Seattle City Light
Industry
ACT Research
American Trucking Associations
NA Council for Freight Efficiency
VEIC
VEIC

MDHDV market shares with uncertainty

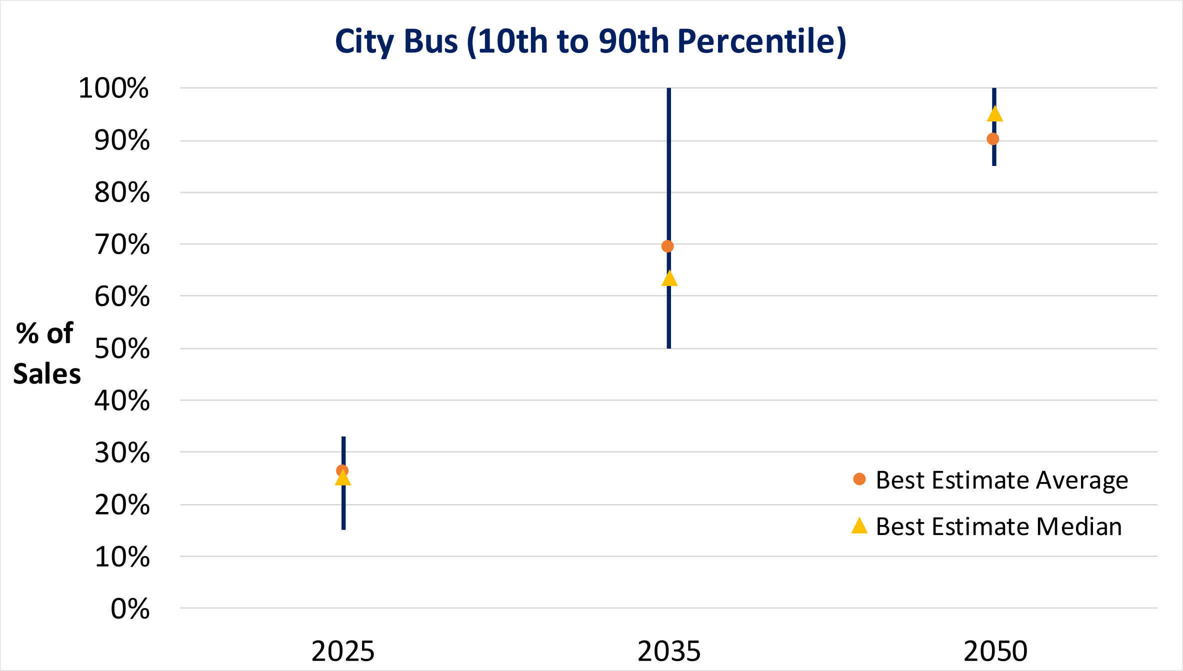


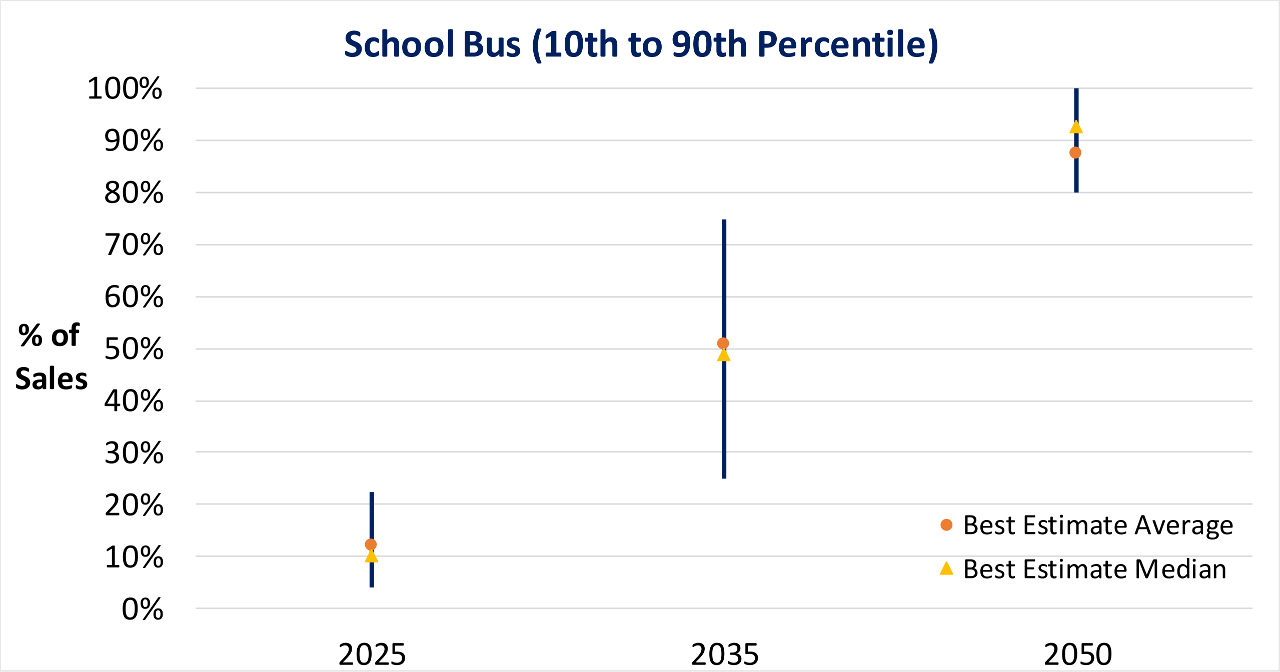






MDHDV market shares with uncertainty





EV Adoption Sensitivities

Brattle's econometric model for LDV adoption uses data from 50 states, from 2011 through 2018 to explain drivers of US EV sales

Starts with the simplest model with one explanatory variable, e.g., total state incentives, and gradually added other variables while paying attention to multi-collinearity issues

The objective was to come up with a robust model, i.e., the addition or removal of a variable or subsets of data (i.e., certain states) does not have a significant impact on coefficient estimates

Final specification is decided based on the in-sample and out-of-sample tests

Model is most sensitive to:

- Vehicle model availability
- State/local incentives
- Chargers in range (i.e., battery capacity and charging infrastructure)
- Vehicle price decline (as proxied through battery pack costs)

EV Charging Requirements Methodology

Main input assumptions for charging infrastructure and load from EVI-Pro Lite (see figure to right):

Input PGE-specific forecast by drivetrain and range

- PHEV 20/50 mi
- BEV 100/250 mi

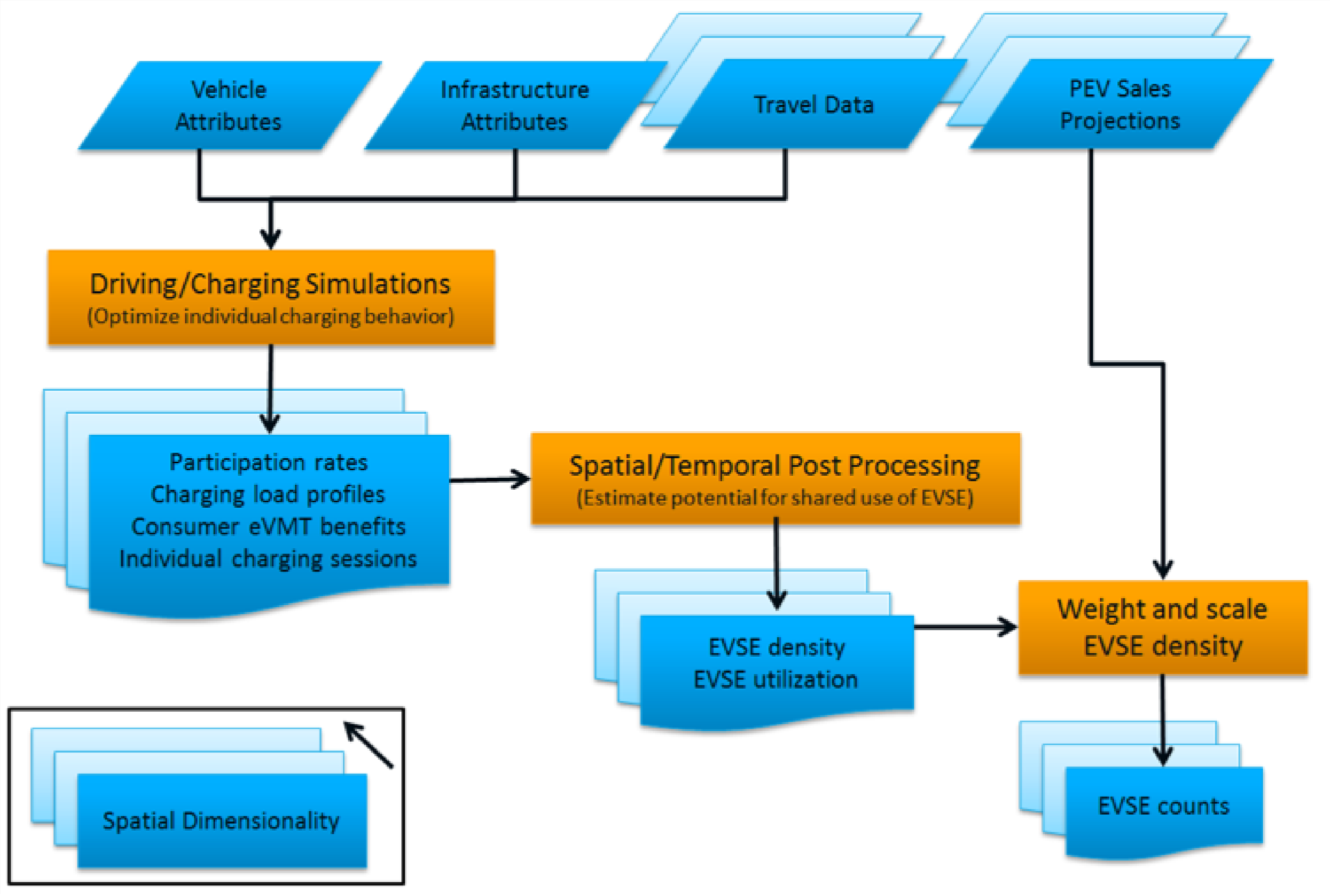
Share of Sedan/SUV in vehicle fleet

VMT determined by national and state travel surveys, weighted by population density

Ambient temperature (affects losses)

Home charging access and charging preferences

Figure 1. EVI-Pro Lite Load Profile Development Data Flow



Source: https://afdc.energy.gov/evi-pro-lite/load-profile/assumptions

Detailed DER Methodology – Solar + Storage

Solar PV Forecast Methodology

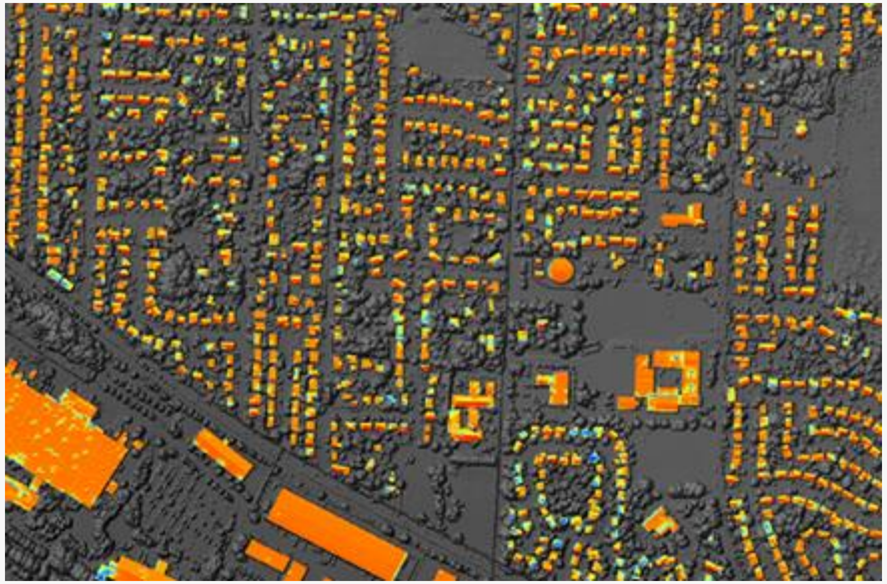
- Used NREL's dGen model to forecast solar adoption rates as a function of Oregon-specific electricity and cost inputs
- Included adjustments for solar and storage capital costs under different scenarios
- These market shares were then calibrated against technical potential modeled using site-level data, PVWatts, Google Project Sunroof

Solar PV Eligibility Criteria

We leverage multiple sources to inform our estimate for non-programmatic solar and storage adoption. The technical potential for solar is informed by eligibility criteria below.

Table 4-11. DER Measure Eligibility – Solar and Storage

Measure	Eligibility Criteria	Measure Size
Solar PV	Residential or Non-Residential, Roof ≤ 10 years old, owns property, solar potential from Project Sunroof > 0, has available breaker	Project Sunroof kW, scaled such that annual generation = annual consumption
Behind-the-Meter (BTM) Energy Storage	Residential SF or MH homeowner, or Non-Residential. Residential must have available breaker.	Residential & non-res with peak load < 50kW: 5 kW Non-res, with peak load ≥ 50kW: 50 kW



Solar radiation potential for residential customers (illustrative only)

Solar + Storage dGen Model Inputs

NREL open sourced the dGen model in 2020

Read an overview of the model setup process here: [Open Source dGen: Beta Release (nrel.gov)]()

User inputs are selected on the model inputs sheet shown on image to the right

Cost and other assumptions from NREL's Annual Technology Baseline (ATB) report series

dGen Model Input

Scenario Options	Value	User Defined File
Scenario Name	or_res_ref	
Technology	Solar + Storage	
Agent File	Use pre-generated Agents	agent_df_base_res_or_revised
Region to Analyze	Oregon	
Markets	Only Residential	
Analysis End Year	2040	
Load Growth Scenario	AEO2019 Reference	
Retail Electricity Price Escalation Scenario	User Defined	ATB19_Mid_Case_retail
Wholesale Electricity Price Scenario	User Defined	ATB19_Mid_Case_wholesale
PV Price Scenario	User Defined	pv_price_atb19_mid
PV Technical Performance Scenario	User Defined	pv_tech_performance_defaultFY19
Storage Cost Scenario	User Defined	batt_prices_FY20_mid
Storage Technical Performance Scenario	User Defined	batt_tech_performance_SunLamp17
PV + Storage Cost Scenario	User Defined	pv_plus_batt_prices_FY20_mid
Financing Scenario	User Defined	financing_atb_FY19
Depreciation Scenario	User Defined	deprec_sch_FY19
Value of Resiliency Scenario	User Defined	vor_FY20_mid
Carbon Intensity Scenario	User Defined	carbon_intensities_FY19
Random Generator Seed	1	

Save Scenario

Solar + Storage Cost Inputs

Evaluated adoption trends under three scenarios impacting DER costs (low/reference/high)

Cost and performance inputs from NREL's dGen open-source inputs, as follows

Low

- **Solar**: pv_price_atb19_high
- **Storage**: batt_prices_FY20_mid

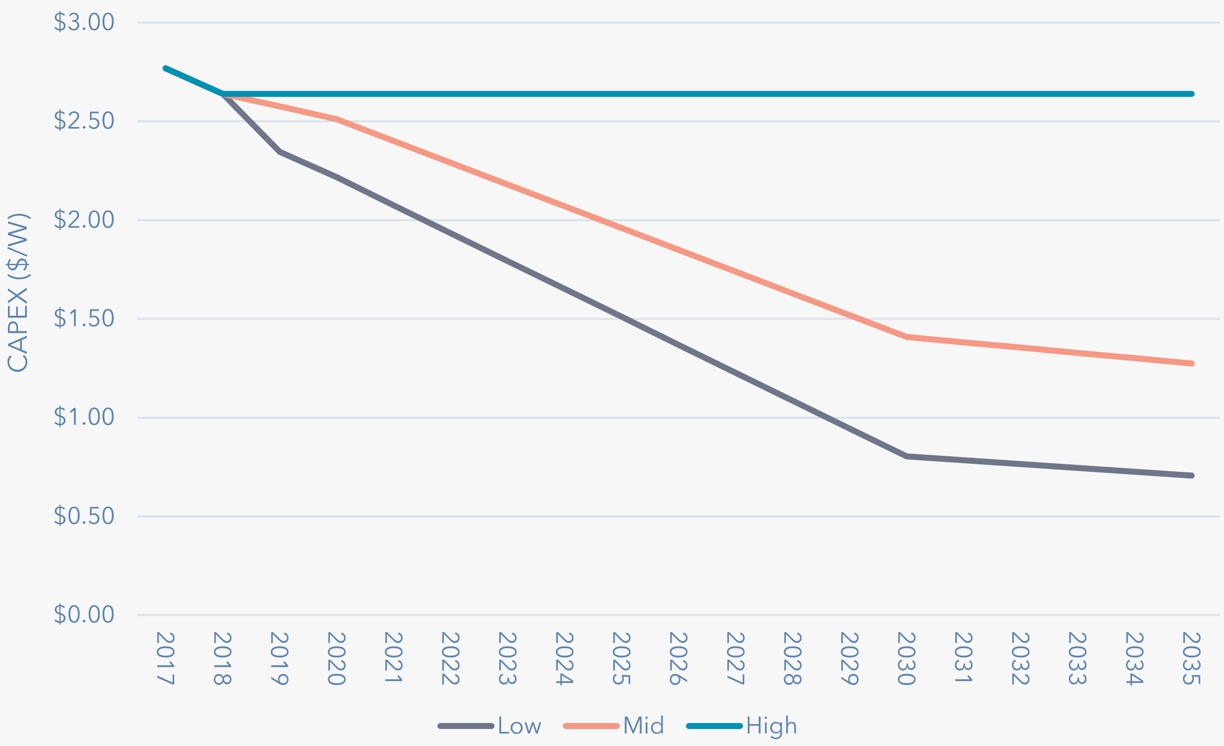
Reference

- **Solar**: pv_price_atb_mid
- **Storage**: batt_prices_FY20_mid

High

- **Solar**: pv_price_atb_low
- **Storage**: batt_prices_FY20_low

Annual Technology Baseline FY19 – CAPEX ($/W) Solar PV



Source: https://atb.nrel.gov/electricity/2021/index

Forecasting Methods Update – Solar PV

During the January DSP Partner meeting, we discussed solar adoption using dGen

Based on feedback, we are reviewing possible changes to better reflect:

- Low- and moderate-income (LMI) solar adoption for both multifamily buildings and renter-occupied buildings
- State tax credits for storage available to low-income customers
- Other data and insights from Energy Trust and stakeholders

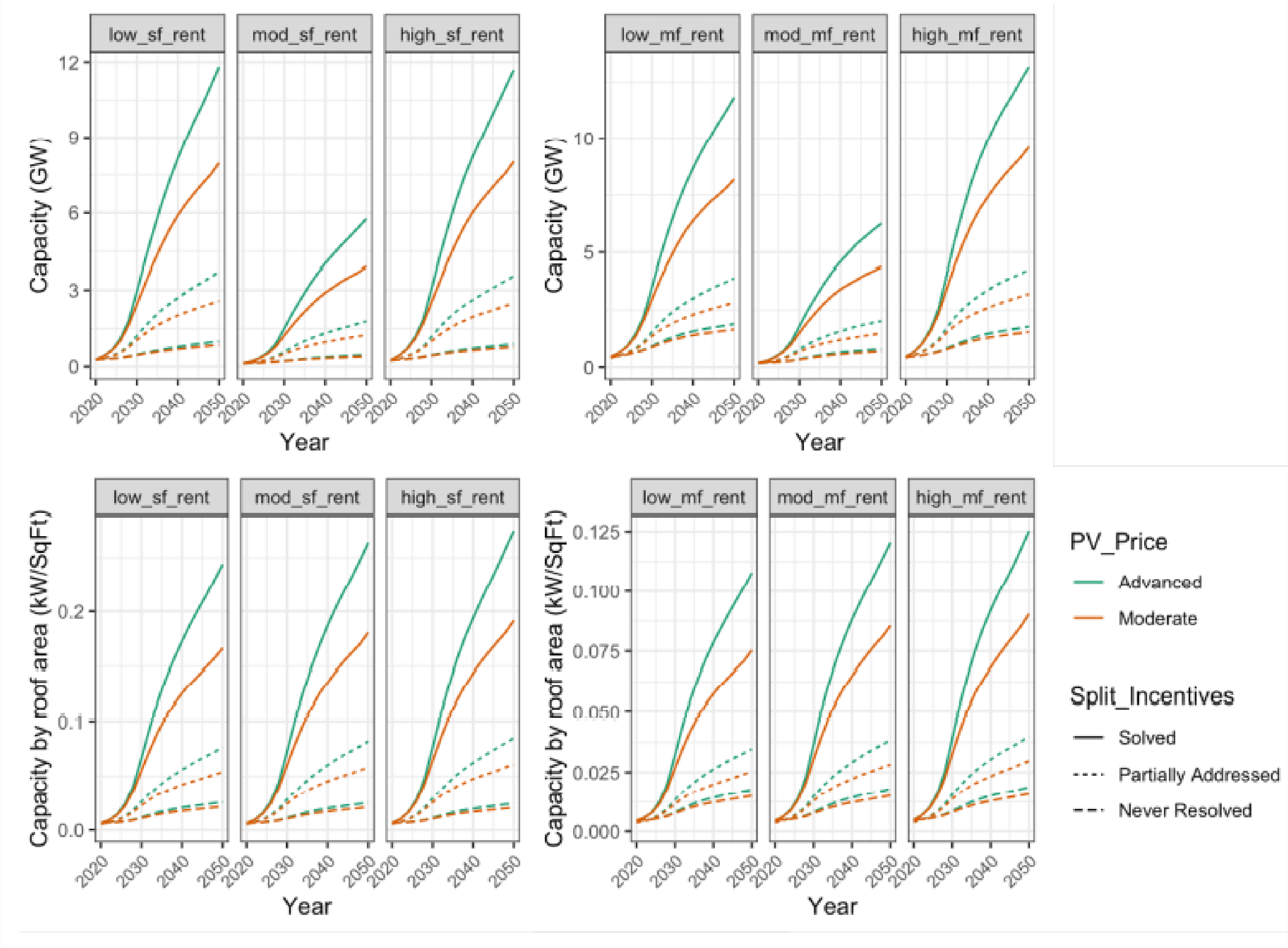


Figure 4. Solar adoption in renter-occupied buildings

Source: Heeter et al. (2021) Affordable and Accessible Solar for All: Barriers, Solutions, and On-Site Adoption Potential. NREL Technical Report available at: https://www.nrel.gov/docs/fy21osti/80532.pdf

Oregon Solar + Storage Rebate Program

Launched Jan 2020 and fully reserved by Sep 2020

HB 2618 allocated additional $10M for solar + storage rebates in 2021 for 2021-2023 biennium

Variety of eligibility screening methods (SNAP, LIHEAP, etc.) or income verification at 100% of state median income

Report found barriers to low-income service providers accessing rebate due to conflict with Federal ITC

87 out of 369 projects were for LMI residents or low-income service providers

System Component	Customer eligibility type	Incentive	Incentive unit	Incentive cost cap
Solar	Res Low-moderate Income (LMI)	$1.80	per watt (DC) of installed capacity	$5,000 or 60% of project cost
	Low-income service providers	$0.75	per watt (DC) of installed capacity	$30,000 or 50% of project cost
	Non-LMI not eligible for utility incentives	$0.50	per watt (DC) of installed capacity	$5,000 or 40% of project cost
	Non-LMI eligible for utility incentives	$0.20	per watt (DC) of installed capacity	$5,000 or 40% of project cost
Storage	Low-income service providers	$300	kWh of installed capacity	$15,000 or 60% of project cost
	LMI customers	$300	kWh of installed capacity	$2,500 or 60% of project cost
	Non-LMI residential customers	$300	kWh of installed capacity	$2,500 or 40% of project cost

Source: Oregon Solar + Storage Rebate Program, 2021 Program Report. Available at: https://www.oregon.gov/energy/Data-and-Reports/Documents/2021-Solar-Storage-Rebate-Program-Legislative-Report.pdf

Detailed DER Methodology – Flex Load + Building Electrification

Flex Load Adoption Methodology

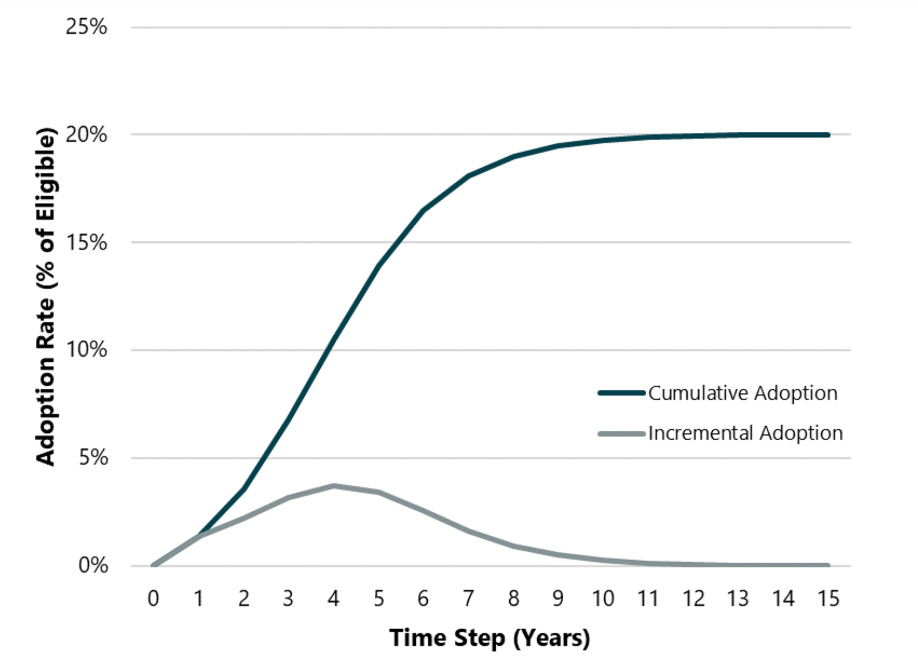
Developed Bass diffusion curves to estimate adoption of each measure

Many products still early in pilot stage and do not necessarily represent long-term designs/costs

Cadeo team estimated the M and T parameters for each program by:

- Estimate empirical M and T parameters from PGE program participation data.
- Conduct literature review to find M and T parameters from similar programs.
- Average empirical and literature review to determine final M and T parameters

Figure 4-5. Example of Bass Diffusion Curve (M=20%, T-10)



$$Cumulative\ Probabilty(t) \approx M * \frac{1 - Exp\left(-14 * \frac{0.5}{T} * t\right)}{1 + 13 * Exp\left(-14 * \frac{0.5}{T} * t\right)}$$

Flex Load Economic Screening

Cost-effectiveness screening applied after initial pilot phase (5-years after inception)

Only assesses the DR portion of measures that have shared EE and DR benefits

Table 4-18. Key Cost Effectiveness Assumptions

Variable	Value	Units	Source
Avoided cost of generation capacity	109.74	$/kW-yr	2021 IRP Update
Avoided cost of transmission capacity	9.57	$/kW-yr	2020 Flexible Load Plan
Avoided cost of distribution capacity[1]	24.39	$/kW-yr	2020 Flexible Load Plan
Incremental avoided cost of flexible capacity	25.4	$/kW-yr	Using a 2.7-hour battery value (via res storage, interpolated from 2019 IRP)
Distribution losses	4.74%		PGE staff
Distribution marginal-to-average line loss ratio	70%		PGE staff
BPA line factor	1.90%		PGE staff
Reserve margin requirement	15%		PGE staff
Real discount rate	4%		PGE staff
Inflation rate	2%		PGE staff
Pilot life	5	Years	Analytical assumption
Program life	10	Years	Analytical assumption

1. We include distribution avoided costs only in the high DER adoption scenarios.

Building Electrification Forecast Methodology

- Modeled turnover of HVAC, WH, and cooking equipment for all sites
- Developed adoption curves for fuel switching based on LBNL Electrification Futures Study results for Oregon
  - Factors in trends in codes & standards, policy changes, carbon pricing, etc.
- Assumed no new code changes or any programmatic intervention
- Used Energy Trust assumptions as baseline probabilities for different equipment types
- Applied fuel switching probabilities incrementally
- For March 2022 update – will explore integrating IECC contemplated electrification proposals which have gained momentum as another scenario

Locational adoption methodology

This study informs DER adoption for PGE DSP

Cadeo developed AdopDER model in 2020-2021 to simulate the load impacts from the co-adoption of 40+ distributed energy resources in PGE service area between 2021 and 2050

Examples

Two project phases

Phase 1

- **Service territory** technical, economic, achievable potential study for PGE IRP
- Measure feasibility varies by customer
- Adoption probability varies by DER and time, but not by premise

Phase 2

- **Locational** technical, economic, achievable potential
- Measure feasibility varies by customer
- Adoption probability varies by DER, time, and premise

We are here

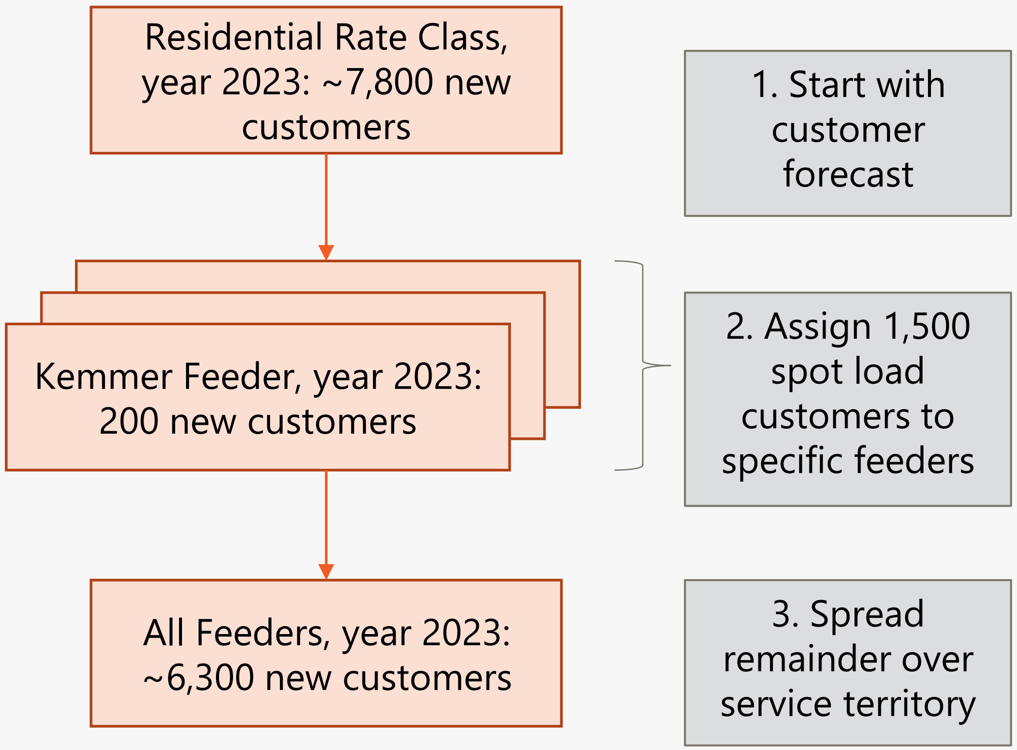
Example of top-down calibration

Key improvement here is to **establish connection** between <u>granular</u>, <u>revenue-class level forecast</u> at Corporate load forecast level, with the <u>bottom-up known additions</u> captured by distribution planning

In the past, we were looking at peak MW added to the distribution system and did not capture 8760 new load additions (didn't need to)

- New process is moving towards an integrated approach with the DER forecast
- We will assign new known customers in AdopDER model specific to each feeder
- Spread the remainder of revenue class-level customer forecast proportionally across other feeders

Illustration of Spot Load Allocation



Adoption propensity methodology

Premise-specific measure adoption probability with statistical and heuristic models

Statistical models where sufficient data exists, heuristic elsewhere

Statistical Model

- EV LDV (Res, non-Res Fleet)
- Solar PV (Res, non-Res)

Heuristic Model

- EV Charging
- BTM Storage (Res, non-Res)
- Microgrid

We use a structured framework for statistical modeling

For all DER types modeled with statistical modeling approach, we follow the below steps to:

- select variables
- test the strength of the model, and
- apply to the full population

Acquire Data
- Identify candidate variables

Combine
- Join all candidate variables into single dataset

Sample
- Train model on 70% of premises
- Validate model on 30% of premises

Train
- Variable Selection
- Model specification

Validate
- Test rank order with validation KS

Deploy
- Add scorecard to AdopDER
- Dynamic scoring in AdopDER

Model selection and validation uses an empirical process

- Example of **statistical** model selection and validation for residential solar
- Similar process for other models

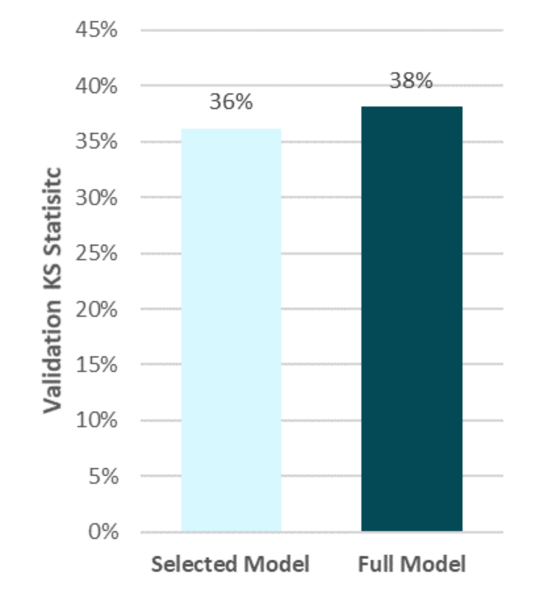
Univariate Screening and Model Selection: Res Solar

Variable	Information Value
building_type	0.788
ct_med_hh_inc	0.637
ct_num_solar_adopt	0.554
ct_tot_pop	0.492
HomeOwnerRenterPremPlusAX	0.438
ct_num_bev_adopt	0.365
xEstimatedIncomePremPlus	0.327
ch_num_vehicles	0.302
AgeCustName	0.256
AX_Score_GreenAffinity	0.242
consump_last_12_mos	0.240
ct_pv_kw_median	0.231
vintage	0.176
AX_Score_TechPropensity	0.084
has_battery	0.058
ct_avg_energy_burden_pct	0.040
ct_urban_rural	0.014
psps_zone	0.011

Selected Variable

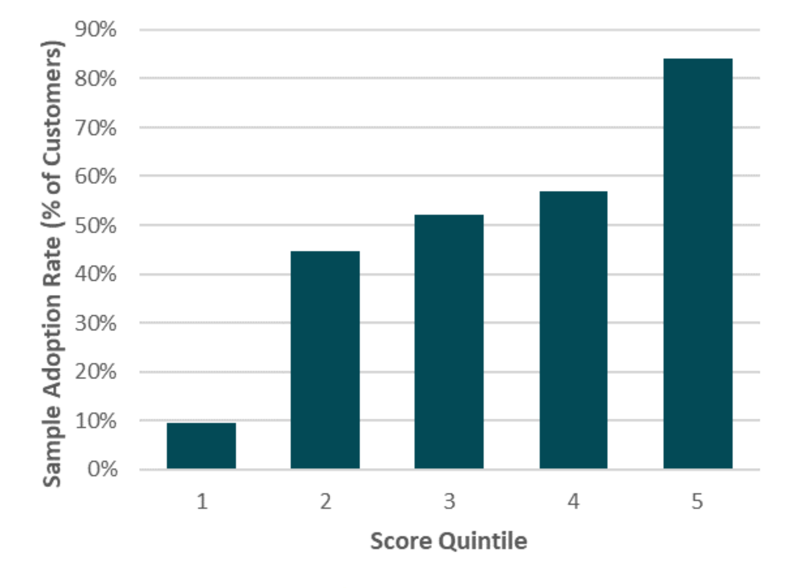
Fails Univariate Screen

K-S Fit Statistics: Res Solar



- Selected model = model with blue-shaded variables in univariate screening table.
- Full model = model with all variables that pass univariate screen

Validation Sample Adoption Rate by Score Quintile: Res Solar



We're looking for rank ordering here.

We use statistical “scorecards” to rank-order adoption probability

Scorecard is a transformation of logistic regression coefficients

More points = Higher adoption probability

Model scoring is simple, fast – important when done at AdopDER scale

Model Scorecard: Residential Solar

Variable	Bin	Score Points
basepoints		493
building_type	MF	-325
	MH%,%SF	31
ct_med_hh_inc	missing	-17
	[-Inf,40000)	-26
	[40000,50000)	-13
	[50000,65000)	-2
	[65000, Inf)	7
ct_num_solar_adopt	missing	-80
	[-Inf,10)	-169
	[10,20)	-64
	[20,25)	-25
	[25,75)	22
	[75, Inf)	95
HomeOwnerRenterPremPlusAX	missing	-97
	O	34
	R	-112

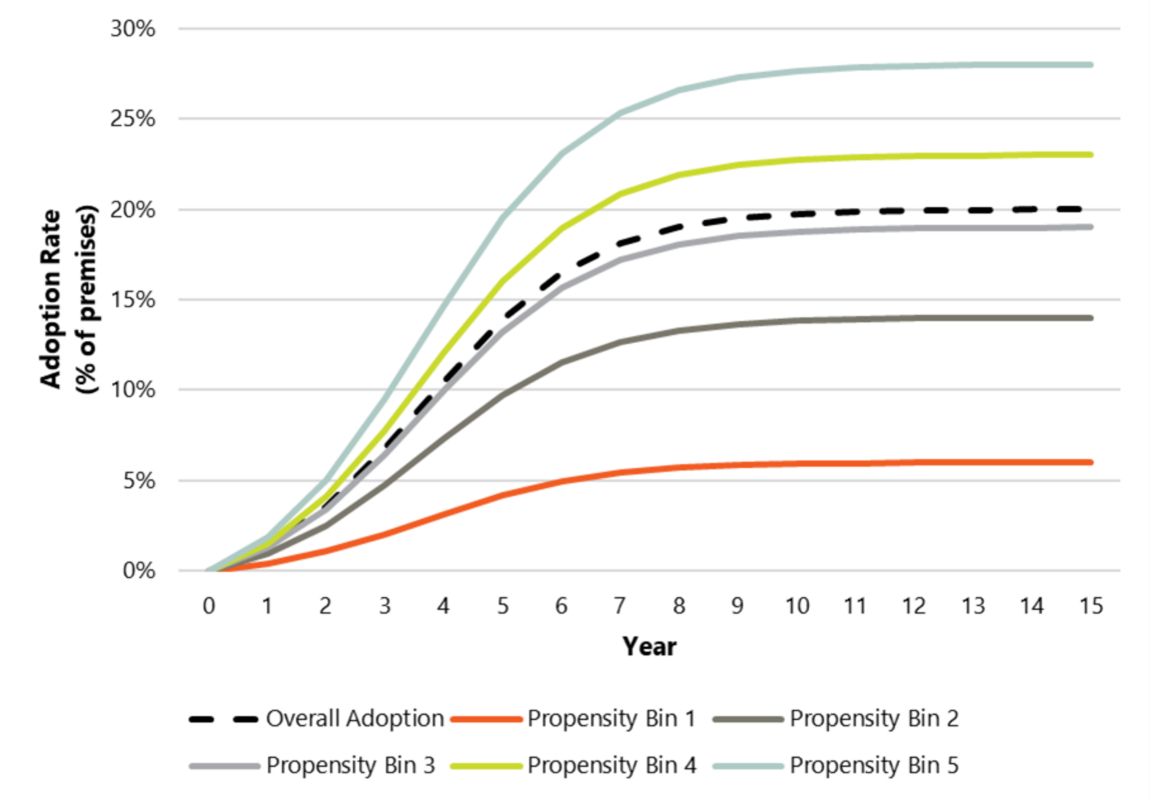
AdopDER uses scorecards to adjust adoption probability

Add variables (statistical and heuristic) to AdopDER customer input files

For each year, premise, and measure, we use a function to

- Calculate score from scorecard
- Assign each score to a quantile-based bin
- Adjust adoption probability

Illustration: Scorecard-based Adjustment to Adoption Rate



Future Improvements

Working with NREL and Cadeo to update dGen modeling

Incorporating more data from TE pilots (especially residential Smart Charging Pilot and Fleet Partner Pilot)

Integrate equity- and resiliency-focused modeling, as part of May/June model runs to inform NWS pilot proposal concept

Welcome other ideas for data sources / collaboration

An

Oregon

kind of energy