Cheaper Home Solar and Batteries Analysis

Methods appendix

Prepared for Permit Power

November 10, 2026

AUTHORS

Caroline Resor
Ruby Aidun
Elise Ashley
Pat Knight
Selma Sharaf
Angela Zeng

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

1. INTRODUCTION 1

2. HOME SOLAR DEPLOYMENT INPUTS 2

3. OTHER POWER SECTOR MODELING INPUTS 4

4. POWER SECTOR MODELING OUTPUTS 5

5. BILL IMPACTS AND SYSTEM COSTS METHODS 6

   5.1. Supply rates 6

   5.2. Solar compensation rates 6

   5.3. Fixed delivery charge 7

   5.4. Non-participants 7

   5.5. Solar participants 7

   5.6. Solar and storage participants 8

   5.7. Average household 8

   5.8. Historical electric bills, energy insecurity, and solar system costs metrics 9

6. JOB IMPACTS METHODS 10

1. INTRODUCTION

In October of 2025, Permit Power published *As Cheap as Our Peers*.[1] In this analysis, Permit Power found that if the United States cut red tape to bring down the cost of home solar (also known as residential solar) to levels seen in peer countries like Australia and Germany, this would accelerate installations, enabling an estimated 18 million additional single-family homes to install about 198 GW of additional solar by 2040 compared to installations at current market prices.

Synapse Energy Economics (Synapse) used state-of-the-art capacity expansion and production cost modeling of the PJM, ISO-NE, and NYISO energy markets – representing the Mid-Atlantic, New England, and New York – to analyze how deploying the region's portion of the additional home solar and batteries by 2040 would affect energy and capacity prices and electricity bills and create jobs compared to deploying these technologies at the current business-as-usual pace.

Synapse prepared briefs summarizing our findings for specific states: Illinois, Virginia, New Jersey, Maryland, Connecticut, New York, and Massachusetts. This methodology appendix describes the technical methods we used to achieve the study findings.

1 As Cheap as Our Peers. Permit Power. October 2025. Available at: https://permitpower.org/wp-content/uploads/sites/35/2025/10/Cheap-as-our-peers-1.pdf.

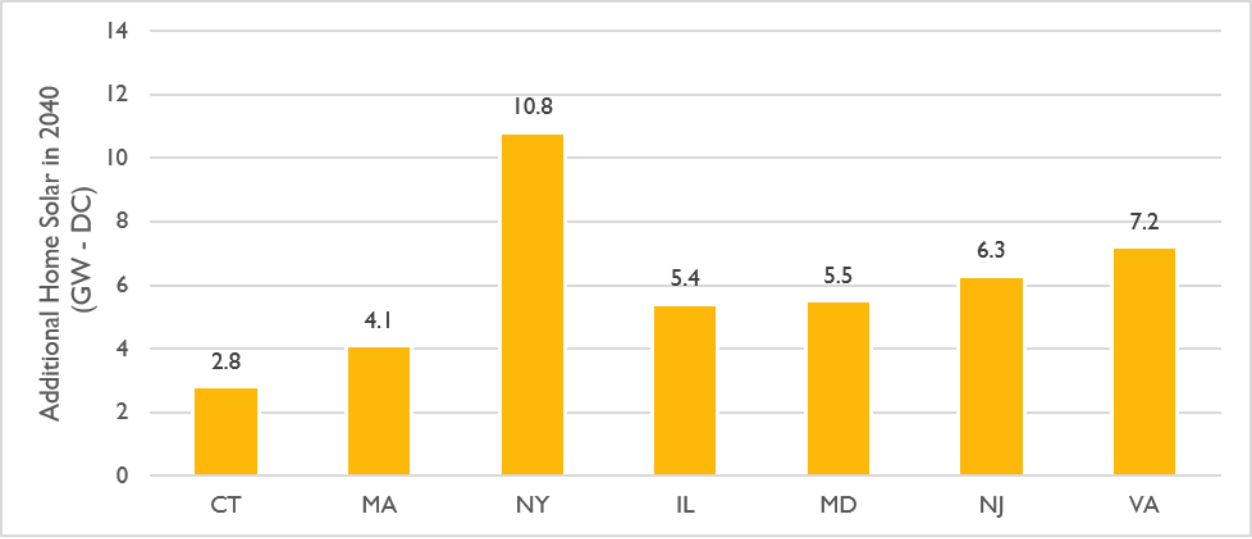
2. HOME SOLAR DEPLOYMENT INPUTS

In *As Cheap as Our Peers*, Permit Power showed that if home solar was as cheap as peer countries, such as Australia or Germany, hundreds of gigawatts more of home solar would be installed. This analysis uses a similar methodology to develop projections of home solar installations through 2040, adjusted for the latest data reflecting more up-to-date baseline costs of home solar, and updated electricity rates, reflecting the recent increases nationwide.

Using this updated methodology, the total amount of home solar nationwide increases by 60 GW from 2027 to 2040 in a baseline case and increases by 270 GW in a case where solar costs $1 per watt, reflecting a decrease in permitting, inspections, and interconnection red tape. This means that in the case with $1 per watt solar (the policy case), there is 210 GW more solar deployed by 2040, nationwide. In the states of interest, this difference ranges from 2.8 to 10.8 GW of additional home solar by 2040 (see Figure 1).

For each state, we assumed a 75 percent attachment rate for batteries. We selected this attachment rate to align with the assumption that excess solar exported to the grid would be compensated at wholesale energy rates. States with time-based or export-limited net metering policies such as Arizona, California, and Hawaii have median 2026 battery attachment rates between 77 and 93 percent, according to recent data from Ohm Analytics.[2] In other words, we assume that 75 percent of home solar installations deployed in both the baseline and policy scenarios also installed a 2-hour battery.

Figure 1. Total home solar added per state by 2040



2 Ohm Analytics. Provided to Permit Power.

In the briefs, we report the percentage of households per state that had home solar as of 2025 to demonstrate the low deployment before the study period. To calculate this, we started with the total solar installations published by the Energy Information Administration (EIA).[3] We used the count of owner-occupied, single-family and small apartment households from the National Laboratory of the Rockies' (NLR) ResStock dataset.[4]

3 Form EIA-861. 2025. Energy Information Administration. Available at: https://www.eia.gov/electricity/data/eia861/.
4 ResStock. National Laboratory of the Rockies. Available at: https://resstock.nlr.gov/.

3. OTHER POWER SECTOR MODELING INPUTS

In this analysis, we relied on the EnCompass model to conduct capacity expansion and production cost modeling to understand the impacts on energy and capacity prices under different future buildouts of home solar. EnCompass is an industry-standard capacity expansion and production cost model developed by Yes Energy. It is capable of modeling the power system at the state, regional, and national levels to evaluate the impact of new supply and demand on the electric grid. We modeled three regional transmission organizations (RTOs): PJM, NYISO, and ISO New England. [5] The model separates the RTOs into multiple zones (six to 12 depending on the RTO), with zones within each RTO and between each modeled RTO being connected by transmission capacity. Each RTO is then modeled as connected to outside regions through a set of simplified import/export assumptions.

We optimized capacity builds over 17 years, from 2023 to 2040, with the model optimizing four years at a time. We modeled a typical peak day and off-peak day each month. The load for each RTO is based on the most recently available forecast published by each RTO.[6] These load forecasts were adjusted to reflect the quantity of home solar produced by the dGen model, rather than the quantity of home solar assumed in the RTO forecast.

We initialized the model with existing generation from the National Database (NDB) with modifications to reflect the latest available data based on data from the EIA and PJM queue. Home solar and storage generation amounts used in the model were provided by Permit Power, as discussed above. We converted these results from DC power to AC power and grossed them up to reflect avoided transmission and distribution losses to accurately model them in EnCompass. We used resource costs based on the NLR Annual Technology Baseline (ATB), 2024 edition. The modeled gas price forecasts used are based on near-term NYMEX futures, blended EIA Annual Energy Outlook (AEO) 2026 gas projections for long-term gas prices. Other state and regional policies, such as state-level renewable portfolio standards and procurements, and the Regional Greenhouse Gas Initiative, were also included in each scenario. Additional model assumptions and data sources are detailed in Table 1.

5 Illinois, one of the states we wrote a brief about, is partly in PJM and partly outside of PJM. We focused our analysis exclusively on the portion of IL within PJM. We found that similar impacts to the ones we calculated for PJM customers are possible for the one third of IL customers who live outside PJM.

6 2026 Load Forecast. PJM. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process. 2026 CELT Load Forecast. ISO-NE. Available at: https://www.iso-ne.com/system-planning/system-forecasting/load-forecast. 2026 Load & Capacity Data Report (Gold Book). NYISO. Available at: https://www.nyiso.com/load-capacity-data-report-gold-book-.

4. POWER SECTOR MODELING OUTPUTS

After populating the EnCompass model with inputs, including home solar capacity, we allow the model to run a least-cost optimization simulation to determine the most cost-effective way of meeting load in each model period, across the entire modeled geography. The model then generates information related to resources builds, retirements, and dispatch. It also produces energy prices (measured in $ per MWh) and capacity prices (measured in $ per kW-year) by zone (e.g., NYISO-J, PJM-PENE, ISONE-West). Energy prices are then multiplied by each state's load to generate energy costs, while capacity costs are multiplied by firm capacity, and then assigned to each state based on contribution to peak coincident demand. In the state briefs, we reported the percent energy price difference between the policy and the baseline scenarios for the appropriate region.

5. BILL IMPACTS AND SYSTEM COSTS METHODS

Bill impacts were generated for several different kinds of residential customers in each state. Bill impacts were generated using the following rate components:

5.1. Supply rates

This rate category refers to the costs that all electricity customers pay for supply, which is inclusive of energy, capacity, supplier premiums, and other attributes. For each state, we begin with the combined energy and capacity costs derived from EnCompass. For each state, these two costs are summed and divided by load to generate a single $-per-MWh cost. This $-per-MWh cost is then normalized into a percent change relative to the average historical cost for energy and capacity in 2023 through 2025. We converted these total price values into percentage changes, relative to recent historical costs for energy and capacity (an average of 2023-2025). Those percentage changes were applied to the average 2023-2025 $-per-MWh supply cost for each state to arrive at a final trajectory of supply costs for each state, year, and scenario.

5.2. Solar compensation rates

In this analysis, any energy that solar customers export to the grid is compensated at a rate equal to wholesale energy prices, adjusted to reflect transmission and distribution losses. This reflects the direction many states are moving as solar penetration within the state grows. Applying the same rule in both scenarios ensures that differences in results reflect differences in solar and battery deployment, not differences in compensation policy. It is also consistent with the assumption used to project solar adoption in *As Cheap As Our Peers*. This cost component is calculated using the dollar-per-kWh energy prices estimated by the EnCompass model (see above).

Non-fixed delivery rates

This rate category includes non-fixed (i.e., charged in dollar-per-kWh terms) costs associated with things like distribution, transmission, state policies, and other categories. For each state, recent historical data from Rate Acuity was used to develop a forecast of non-fixed delivery rates for a set of utilities that represents the majority of each state's residential electricity load.[7] Historical delivery rates were compiled into a single rate using a weighted average of each utility's residential load, multiplied by historical residential electricity sales, then forecasted into the future using a linear extrapolation of observed changes in nominal delivery cost requirements from 2020 to 2025. For each scenario, this delivery cost was then combined with two more components to arrive at final delivery costs. First, in each scenario we estimate the value of avoided transmission and distribution (T&D) investment

[7] More information on Rate Acuity is available at https://rateacuity.com/.

associated with solar and storage. This is estimated by multiplying a state-specific avoided T&D rate (typically published in each state's or utility's distributed energy resource plans) by the quantity of firm MW associated with home solar and storage.[8] This value is subtracted from the total delivery costs. We report this delta, or cost savings, in the state briefs.

Second, in each scenario, we estimate the total compensation paid to home solar and storage customers by multiplying the solar compensation rate by the share of electricity produced by home solar and storage that is assumed to be exported to the grid.[9] This value is added to the total delivery costs. Total delivery costs are then divided by the total electric sales, net of the home solar and storage kWh that are self-consumed (i.e., not exported), to produce a final dollar-per-kWh delivery rate.

5.3. Fixed delivery charge

In many states, a portion of each customer's bill is charged as a fixed component (i.e., charged in dollar-per-bill terms). For each state, we used the same representative utility data described above to develop a representative fixed charge. This fixed charge was then carried forward into the future, maintaining the same ratio of costs derived from this bill component relative to non-fixed delivery costs. It is expressed in dollar-per-customer terms.

These rate components were then combined with information related to per-customer electricity consumption and home solar and storage production in the following ways to determine annual bill impacts for each customer type.

5.4. Non-participants

Non-participant electricity consumption is multiplied by the sum of delivery rates and supply rates, then added to a fixed delivery charge to produce a final annual bill. We calculate the average difference between the baseline and policy cases over 2027 through 2040 and report this in the briefs.[10]

5.5. Solar participants

Electricity consumption is multiplied by the sum of delivery rates and supply rates, then added to a fixed delivery charge to produce a final annual bill.[11] Two values are then subtracted from this: first, all kWh that is exported to the grid is multiplied by the solar compensation rate. Second, all kWh that is assumed to be self-consumed is multiplied by the sum of the non-fixed delivery rate and the supply rate. We note

8 This firm capacity rating differs by RTO and year, and was derived based on the most recent data published by each RTO in our analysis.

9 All home solar and storage generation avoids the need for that amount of grid generation.

10 In the briefs, non-participants are referred to as "homes that do not install solar and batteries."

11 In this analysis, solar and solar-and-storage participants are typically residential customers living in single-family homes. As a result, they tend to have higher levels of electricity consumption than non-participants or the average participant.

that this compensation framework is different from the net-metering framework that is common in many states today.

5.6. Solar and storage participants

Bills for these customers are calculated using the same methodology as solar customers. However, these customers are assumed to have home storage systems that can only be charged using solar. This means that their total generation quantity is typically smaller (due to losses caused by storage round-trip-inefficiencies) and has a greater share of self-consumption (as storage allows more solar energy to be used at the same time the customer demands it, allowing the customer to receive a greater compensation rate than if the solar were exported). The EnCompass model dispatches home storage at optimal times to achieve lowest system costs.

Bill savings between the baseline and policy cases do not account for upfront installation costs.

5.7. Average household

Annual bills are estimated by estimating an average of the above customers' bills, weighted by the number of customers in each category, in each year.

Total numbers of customers for each state were projected by applying each RTO's projected growth rate of conventional load to recent customer counts from EIA Form 861.[12] Total participants for solar and solar-and-storage were estimated using the dGen model, with solar-and-storage participants making up 75 percent of each state's total pool of participants.

For each customer type and state, bills were compared between the baseline and policy cases to estimate the bill impacts resulting from more home solar and batteries. Customer bills and bill impacts were multiplied by the number of customers in each category to estimate statewide system costs.

We use the phrases average customer and average household interchangeably.

In the state briefs, we report the average annual statewide bill savings between the baseline and policy cases over 2027-2040. We also report the average annual per household savings and the percentage savings over the study period. Additionally, we report the cumulative savings, in both statewide and per-household terms, by 2040.

12 Conventional load refers to standard demand from residential, commercial, and industrial sources. Conventional load does not typically consider home solar, electric vehicles, heat pumps, or data center load. Available at: https://www.eia.gov/electricity/data/eia861/.

5.8. Historical electric bills, energy insecurity, and solar system costs metrics

In the state briefs, we report the 2025 average household monthly electric bill for each state using rate data from Rate Acuity, multiplied by typical household consumption using data from EIA 861. We also report the percent difference between the 2020 and the 2025 bills.

Additionally, we report the percentage of households in each state experiencing energy insecurity. For this metric, we used 2024 data on households reporting any energy insecurity from the EIA Residential Energy Consumption Survey (RECS).[13]

We compare the cost to install home solar in the U.S. against the cost to install home solar in peer countries. To estimate home solar system sizes and costs in various states in the U.S., we use Lawrence Berkeley National Laboratory's Tracking the Sun tool.[14]

13 Residential Energy Consumption Survey (RECS). Energy Information Administration. Available at: https://www.eia.gov/consumption/residential/.

14 U.S. Distributed Solar and Storage Data. Lawrence Berkeley National Laboratory. Available at: https://emp.lbl.gov/tracking-the-sun/.

6. JOB IMPACTS METHODS

We calculate job impacts using Synapse's in-house Eco-IDeA tool. Eco-IDeA is an economic model that assesses changes in jobs associated with spending changes in various sectors. Changes in jobs are reported in job-years, with one job-year equal to full-time employment (FTE) for a single person in a single year.

Inputs to this analysis include modeling results from EnCompass, which provide changes in capital cost spending and operation and maintenance (O&M) spending (e.g., less spending on gas generation and gas capacity) on different energy resources. Eco-IDeA also uses changes in consumer spending on electricity bills, changes in transmission and distribution capital cost spending, and changes in home solar and storage capital spending. The model combines those inputs with data from IMPLAN to estimate changes in jobs resulting from changes in spending, based on the state of the economy in a historical year.[15]

Eco-IDeA provides net jobs (measured in job-years) by state, year, and job type (e.g., solar capital spending, gas O&M spending). Net jobs are the overall changes in jobs resulting from changing spending on different energy resources within a state's borders. Eco-IDeA does not capture changes in out-of-state indirect or induced jobs as a result of changing spending within a state, and does not account for any changes in jobs happening within a state caused by spending occurring outside that state's borders. Thus, our results do not include jobs created outside of the state of interest that involve manufacturing parts that would be used in-state, for example.

In the state briefs, we reported for each state the average annual (from 2027 through 2040) net FTE job-years, referring to this as the number of jobs sustained each year of the study period.

Eco-IDeA categorizes job impacts into three categories: jobs produced directly from the investment (e.g., on-site solar or battery project installation jobs, or solar or battery manufacturing jobs), jobs resulting indirectly from the investment (e.g, upstream jobs manufacturing parts), and jobs induced from the investment (e.g., jobs in ancillary industries creased from increased spending in construction or manufacturing).

Eco-IDeA further segments direct jobs into labor direct and materials direct jobs. Labor direct jobs are the jobs associated with construction, installation, or operations and maintenance of the resource. Materials direct jobs represent the in-shop material manufacturing jobs. To calculate annual average direct jobs, we calculate the jobs (measured in full-time equivalent job-years) for each state in each year and take an average from 2027 to 2040.

15 Developed by IMPLAN Group, LLC, IMPLAN is an economic input-output model that assesses positive and negative GDP and job - impacts (measured in job-years) associated with spending changes on various sectors. IMPLAN does not account for long-term economic shifts and trends.

Table 1. EnCompass inputs and sources

Utility-scale resource costs and other operational parameters	
Resource	**Assumptions**
New conventional gas plants	Near-term costs are based on recent estimates from EPRI. We assume that current supply chain constraints are resolved by 2035, and interpolate from high near-term costs to ATB's cost trajectory by 2035. No operational constraints related to EPA 111 rules assumed.
New advanced nuclear reactors / SMRs	Cost projections from AEO 2026. New SMRs can be built starting in 2040. Three Mile Island Unit 1 assumed to be repowered in Summer 2027. Note that there are sources suggesting that Three Mile Island may not be repowered until 2031. See "TMI owners affirm 2027 restart date despite grid readiness questions. PennLive Patriot News. Published March 27, 2026. Available at: https://www.pennlive.com/business/2026/03/tmi-owners-affirm-2027-restart-date-despite-grid-readiness-questions.html.
New solar, onshore and offshore wind	Use NREL Annual Technology Baseline 2024 "Conservative" trajectory for costs generally. We include a cost adder on top of ATB's projections to represent supply chain and interconnection queue challenges. Use data from U.S. EPA's IPM modeling for local cost adders and capacity factors. Utilizes compiled supply curve that varies for each modeled zone. It includes different tranches of wind and solar MW potentials, as well as cost adders that reflect increased costs of building transmission to certain areas. Each tranche of wind and solar has a separate capacity factor. Offshore wind: Assume that all projects under construction come online on schedule and additional offshore wind can be added starting in 2037.
New battery storage	Prices based on NREL's Annual Technology Baseline 2024. Assumes "moderate" trajectory, which is aligned with recent observed costs. 4-, 6-, 8-hour storage allowed.
New long-duration storage	100-hour battery costs from Form Energy. Assume long duration energy storage can be added starting in 2035.
Load flexibility	Market cost of energy. Increasing quantities of demand response are available over time. A small portion of data center load is assumed to be curtailable.
Additional utility-scale resource availability constraints	
Topic	**Assumption**

Near-term build constraints for new resources (2026-2030)	Rate of completion of projects currently in PJM, NYISO, and ISO New England interconnection queues are modestly improved relative to the historical rate of completion. For PJM, assume Reliability Resource Initiative (RRI) selected resources come online by projected dates.
Mid/long-term build constraints for new resources (2030-2040)	Assume build constraints gradually improve from 2031-2040. For PJM, assume that other PJM initiatives are addressed in this period, and overlap with deployed resources selected by the model.
Thermal plant retirement decisions	All units must retire on or before their currently scheduled retirement dates. Early retirement decisions are enabled and based on modeled economics.
Gas prices	
Time period	**Assumption**
Historical gas prices	We use the volume-weighted average of daily prices to generate historical prices using price and trade volume data from Natural Gas Intelligence. For all three parts of this process, we start with hub price data and then incorporate a basis adder to estimate the nodal price.
Near- and long-term projection	We build a long-term projection (2028-2040) based on the EIA's Annual Energy Outlook 2026 Counterfactual Baseline case for Henry Hub. We model a transition year (2027) by calculating the simple average of (a) Natural Gas Intelligence futures for 2026 and (b) projected gas prices for 2028 based on data from Annual Energy Outlook.