Energy Storage Futures, Vol 4, Distributed PV plus Storage

By John Benson

February 2022

1. Introduction

The National Renewable Energy Laboratory (NREL) over the last year released a multivolume study titled "Storage Futures Study," hereafter SFS. The high level goal of this is to model energy storage systems' implementation out to 2050.

I intend to track each of these volumes with a much shorter one of my own.

Section 1 of this report focused on the types of utility-scale energy storage systems and the services that they provide to the electric grid. Our Volume 1 of Energy Storage Futures was a summary of this section, and is linked below.

https://energycentral.com/c/gr/energy-storage-futures-volume-1-types-and-services

Section 2 of this report collected and refined data to use as an input for the model of the future of storage system out to 2050. Our Volume 2 of Energy Storage Futures was a summary of this section, and is linked below.

https://energycentral.com/c/cp/energy-storage-futures-volume-2-model-input-data

Section 3 of this report evaluated the economic potential of diurnal storage. As storage systems penetrated the utility-scale storage market over the last decade, they first penetrated the ancillary services market, which was rather small, then the market for peaking power which was much larger. The next step in this process was to evaluate the economic potential diurnal storage, which is defined as storage with a duration of up to 12-hours. Our Volume 3 of Energy Storage Futures was a summary of this section, and is linked below.

https://energycentral.com/c/cp/energy-storage-futures-vol-3-diurnal-storage-economics

Section 4 of this report evaluates distributed storage. Because distributed storage is almost always paired with photovoltaic (PV) solar generation, this form of generation comes along for the ride. Our Volume 4 of Energy Storage Futures is a summary of this section.

I had assumed that the next SFS section after this (section 5) would further refine the model's inputs, however when I recently read it for the first time, I found that this section is merely a brief discussion of what constitutes "Long Duration Energy Storage." This will have no impact on the overall goal of modeling energy storage systems' implementation out to 2050. Thus I will not include a summary of SFS section 5 as one of my volumes. There is a link to this section below for those that wish to read this discussion.

https://www.nrel.gov/docs/fy22osti/80583.pdf

SFS section 6 will report the final result of this study, and I will post a summary of this as Volume 5 of my series next week (probably on Thursday, March 3).

The service I hope to provide for the readers of this series is to filter out information that I feel has little chance of materially affecting the output over the period that this model simulates, and thus greatly reduce the reading-time for this summary.

2. The Perfect Energy-Pair

The following is excerpted from the SFS Section 4 Executive Summary.

Declining battery storage costs and the growing emphasis on resiliency and grid services have led to heightened interest in pairing battery storage with distributed solar to provide value to customers and the distribution grid. The increasing deployment of distributed energy resources (DERs), including battery storage, is an important and emerging theme in modern power systems. DERs can contribute to grid flexibility, reduce grid power losses, and support demand-side management. Existing behind-the-meter battery capacity is estimated to be approximately 0.8 GW / 1.6 GWh in the United States at year-end 2020. The market for small-scale battery systems is expected to increase dramatically, pushed by a desire for backup power and the deployment of distributed solar photovoltaics (PV). The recently approved Federal Energy Regulatory Commission (FERC) Order 2222 (FERC 2020) enables DERs to participate in regional wholesale capacity, energy, and ancillary service markets alongside traditional (utility-scale) generation. Order 2222 and new DER compensation mechanisms like the New York State Value of Distributed Energy Resources (VDER) (NYSERDA 2020b) are anticipated to unlock new market opportunities for DERs and thus lead to additional deployment of DER capacity.[1]

Due to the nascent market status for distributed battery storage systems, there are relatively few published projections of distributed battery storage deployment. This work addresses that gap by characterizing the potential for behind-the-meter battery storage and identifying key drivers of adoption. This report describes the expanded capabilities of the Distributed Generation Market Demand (dGen) model to analyze the economics of distributed (behind-the-meter) PV paired with battery storage systems and presents projections of adoption for the contiguous United States out to 2050 under a range of scenarios. These scenarios use technology cost and performance assumptions consistent with the National Renewable Energy Laboratory's 2020 Standard Scenarios paired with updated battery cost projections and existing policies. Additional scenarios evaluate sensitivities to the value of backup power and DER compensation mechanisms, collectively characterizing the future potential for behind-the-meter storage and identifying key drivers of adoption.

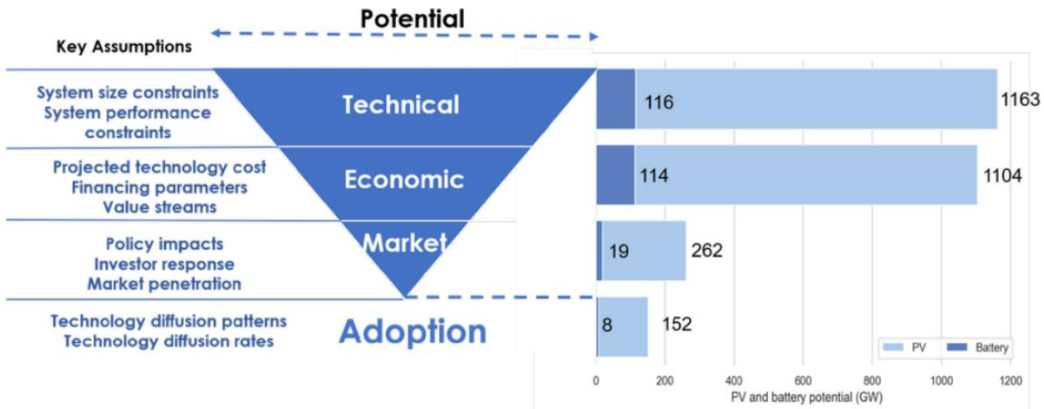
In order to calculate battery storage system and PV adoption, the dGen model first determines the technical, economic, and market potential:

- ***Technical potential:** The maximum amount of technically feasible capacity of PV-only and PV + battery storage systems, with PV system size limited by customer's rooftop area and energy consumption, and battery capacity capped as a fraction of the optimal PV capacity at a specific site.*
- ***Economic potential:** A subset of technical potential, economic potential is estimated as the total capacity that has a positive return on investment or a positive net present value (NPV). Economic potential can also be interpreted as the total capacity of systems that are cost-effective in a specific year.*

[1] Ashreeta Prasanna, Kevin McCabe, Ben Sigrin, and Nate Blair, NREL, "Storage Futures Study, Distributed Solar and Storage Outlook: Methodology and Scenarios," July, 2021, https://www.nrel.gov/docs/fy21osti/79790.pdf

- ***Market potential:*** *The fraction of economic potential representing the customer's willingness to invest in a technology given a specified payback period.*
- ***Adoption:*** *Adopted capacity is the capacity projected to be purchased by residential, commercial, and industrial building owners and installed at the customer premises in a behind-the-meter configuration. Adoption is based on applying a Bass diffusion function where the upper limit of adoption is set to the market potential.*

A description of each level and the key assumptions and corresponding potential capacity for the Base Case scenario in 2050 is described in the figure below.



For all modeled scenarios, we find an economic potential for battery storage capacity ranging from 85 –245 GW / 170–490 GWh and cumulative adopted battery storage capacity in 2050 ranging from 5–17 GW / 10 –34 GWh. Although there is significant economic potential for behind-the-meter battery storage (more than 300 times the existing installed capacity), only a small fraction of this is adopted under our modeled scenarios. Selected insights from our analysis follow:

- *There is significant economic potential for distributed PV + battery storage systems under all modeled scenarios. The Base Case economic potential for distributed battery storage coupled with PV is approximately 114 GW / 228 GWh, which is more than 90 times the 2020 capacity. In the scenarios investigated, the upper bound of economic potential for distributed battery storage coupled with PV is 245 GW / 490 GWh under the 2x Backup Value + Advanced Cost Batteries Scenario, and the lower bound is 85 GW / 170 GWh under the No Backup Value Scenario.*
- *Despite the high economic potential, modest growth in distributed PV + battery storage adoption is projected under our modeled scenarios. Under the Base Case, the projected deployment of distributed battery storage capacity is 8 GW / 16 GWh, 7% of the economic potential, with a range across scenarios from 5–17 GW / 10–34 GWh.*
- *The substantial decrease from economic potential to adoption reflects a long payback period, and consequently a lower share of customers willing to invest. The average payback periods of distributed PV + battery storage systems are fairly long: 11 years for the residential sector, 12 years for the commercial sector, and 8 years for the industrial sector in 2030.*

- *At the national scale, the most important drivers of distributed co-adopted battery storage are a combination of advanced (low) future battery cost and a high value for backup power. The highest adoption estimate for battery capacity is under the 2x Backup Value + Advanced Cost Batteries Scenario (+121% compared to the Base Case).*
- *Combined cost reductions in both PV and battery storage technologies drive additional adoption compared to cost reductions in battery technology alone. The Advanced Cost PV + Batteries Scenario, which considers a reduction in future costs for both PV and batteries, has higher battery deployment compared to the Base Case, increasing by 106%.*
- *PV + battery systems have larger PV capacity compared to PV-only systems. Average PV system size in PV + battery storage system configurations (8 kW for residential systems) is larger than in PV-only configurations (4 kW for residential systems). Battery storage thus increases the PV capacity. This is likely due to the ability of the battery to increase the economic value of PV.*
- *Local conditions dictate adoption. Differences in location-specific parameters across the United States also result in significant differences in the amount and rate at which distributed battery storage capacity is adopted in various states and counties.*

3. Important Inputs and Analysis

The following excerpts are from the body of SFS Section 4, and are those inputs and analysis the author feels are important in estimating the future of distributed PV + Storage.

3.1. Elements of Tariffs and Incentives

Having recently written a detailed paper on what might be the future tariff for California distributed storage, and gone through the donnybrook that broke out when it was released (probably the subject for a future paper), I feel this might be good reading (albeit rather lengthy). It is described and linked immediately below.

Rooftop Solar Energy Tug of War – Resolution, Part 2: I started to work on this post on December 13, 2021, because that morning the California Public Utilities Commission (CPUC) released the Proposed Decision for the Net Energy Metering Tariff (a.k.a. NEM 2.0) that will be used in the future for rooftop solar in California. This summary of this decision is very long thus it will require two posts (on 12/21 and 12/22/21).

https://energycentral.com/c/pip/rooftop-solar-energy-tug-war-%E2%80%93-resolution-part-1

https://energycentral.com/c/pip/rooftop-solar-energy-tug-war-%E2%80%93-resolution-part-2

To estimate the value of DER systems to agents, dGen calculates the projected electricity bills derived from location-specific retail electric rates. For this study, rate structures were updated based on recent data from the Utility Rate Database (OpenEI 2020), an open-source database of actual rate data for most U.S. electric utilities.

Incentives for PV and battery storage are also included in dGen and applied across a range of geographic scales, such as electric service territories, counties, states, and the entire country. PV incentives are obtained from the Database of State Incentives for Renewables & Efficiency (DSIRE) database (DSIRE 2020). Incentives for battery *storage are identified for each state from utility websites, the Pacific Northwest National Laboratory's Energy Storage Policy Database (PNNL 2020), and the DSIRE database (DSIRE 2020). States and utilities that provide incentives for battery storage are listed in the table below, along with the specific incentive program considered in dGen.*

Table 1. Incentives for Battery Storage State	**Incentive Program**	**Reference/Website Source**	**Scope**
Arizona	Salt River Project (SRP) Battery Storage Incentive	SRP (2021)	Up to $3,600 ($300 per kWh-DC) per customer; limited to 4,500 customers
California	Self-Generation Incentive Program	State of California (2021)	$1 billion through 2024
Florida	JEA Battery Incentive Program	JEA (2021)	$4,000 rebate per home/business
Maryland	Maryland Energy Storage Income Tax Credit Program	Maryland Energy Administration (2020)	$750,000 in energy storage income tax credit certificates
Nevada	Net metering and energy storage device programs	NVEnergy (2021)	50% of equipment costs or $3,000
New York	NYSERDA's Retail Energy Storage Incentive	NYSERDA (2020a)	$4 million, with a target of 1,500 MW of energy storage by 2025 and 3,000 MW by 2030
Oregon	Oregon Solar + Storage Rebate Program	Oregon Department of Energy (2020)	$2 million

The reference website sources are given below:

SRP. 2021. "Battery Storage Incentive." https://www.srpnet.com/electric/home/batterystorage/default.aspx

State of California. 2021. "Self-Generation Incentive Program." https://www.selfgenca.com/

JEA. 2021. "Solar Battery Incentive Program." (JEA = Jacksonville Electric Authority) https://www.jea.com/residential_customers/residential_rebates/solar_battery_incentive_program/

Maryland Energy Administration. 2020. "Maryland Energy Storage Income Tax Credit - Tax Year 2020." https://energy.maryland.gov/business/Pages/EnergyStorage.aspx

NVEnergy. 2021. Energy Storage Incentives: Program Handbook. Las Vegas, NV: NVEnergy. https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/cleanenergy/handbooks/EnergyStorage-Handbook.pdf

New York State Energy Research and Development Authority (NYSERDA). 2020a. "Retail Storage Incentives." https://www.nyserda.ny.gov/All-Programs/Programs/Energy-Storage/Developers-Contractors-and-Vendors/Retail-Incentive-Offer

Oregon Department of Energy. 2020. "Oregon Solar + Storage Rebate Program." https://www.oregon.gov/energy/Incentives/Pages/Solar-Storage-Rebate-Program.aspx

The Federal Investment Tax Credit (ITC), a key incentive for spurring early adoption, is also considered in dGen. At the time this analysis was carried out, the investment tax credit was scheduled to expire without extension. Therefore, within dGen, we model the credit to expire in 2020 for residential systems and to decrease from 30% of installed cost to 10% for nonresidential systems in 2020. In December 2020, the investment tax credit was extended for another 2 years. However, because our model simulations were complete by then, our results do not consider this 2-year extension. We do not consider *the omission of the 2-year extension to significantly impact our long-term projections. This is because the 2-year extension would only lead to improved economics in a single simulation year of dGen, and its impact would be minimal when compared to the subsequent 16 simulation years in the model. Renewable portfolio standards and storage-specific mandates are also not considered as part of our modeled scenarios because they need to be translated into economic incentives to be represented within dGen. Due to a lack of detailed information of how renewable portfolio standards and storage-specific mandates would provide economic incentives, they were not considered in this analysis.*

…Electricity consumption may result in hours in which generation exceeds consumption. The excess generation, when permitted to be exported to the electric grid, is valued based on state or utility policies that dictate the compensation mechanism available to BTM customers. Typical mechanisms include net metering, in which customers with grid-connected distributed generation receive full retail credit for energy that the customers produce but do not consume, and net billing, in which excess generation is valued at a predetermined sell rate.

In states and sectors where net billing is the prevailing policy, dGen uses wholesale electricity prices as the sell rate.

Author's comment: The earlier paper described and linked at the beginning of this subsection takes a deep dive into the complexity of future tariffs. Although the above dGen model probably has a reasonable simulation of the future tariffs and incentives, in reality the tariffs for electric customers with energy generation and storage resources will probably only become more complex as time goes on.

3.2. Resiliency's Value

An important consideration for customers when deciding whether to install battery storage is its ability to provide backup power. For example, the growth in wildfires in California has led more homeowners to consider having backup power. Also, the role battery storage can play in preventing events such as the Texas blackouts and the corresponding value of having backup power in such situations is an evolving area of analysis. Future climate scenarios imply more extreme weather and therefore an even larger desire—and thus value—for backup power.

To analyze if the ability to provide backup power drives adoption of battery storage, we include a new value stream in dGen financial calculations. This value stream is intended to reflect the monetized value provided by the battery storage system as a source of backup power to customers. We assign the value for backup power to equal a customer's willingness to pay to avoid service interruptions or outages. We consider this a reasonable assumption because PV + battery storage systems are commonly sold as backup power systems. Also, by using this proxy, we can use existing estimates of the value of service reliability for electricity customers in the United States.

A Lawrence Berkeley National Laboratory (LBNL) report on the value of service reliability combines 34 data sets from surveys on interruption cost estimation or willingness to pay. The LBNL report contains customer interruption costs per event by season, time of day, day of week, and geographical regions within the United States. We use that report as our main source of data and compare it with customer willingness-to-pay data from other studies to ensure consistency…

3.3. Detailed PV and PV + Storage Model

The major development work to enhance dGen implemented in this project was the integration of a detailed battery model and the corresponding financial model from SAM [2] *for residential and nonresidential customers. This allows dGen to evaluate the technical and economic potential of PV-only and PV + battery storage systems…*

Author's comment: SFS Section 4 goes into a detailed description of the capabilities of SAM. Although this is an important addition to dGen, I will attempt to summarize its capabilities in a series of bullets below.

- Detailed specification of battery technology and all parameters including those related to battery degradation.
- *…battery dispatch strategy, which dictates the flow of energy between the PV system, battery, and grid.*
- *…comprehensive financial and tariff-specific calculations* (that will) *ultimately, yield more detailed results.*
- *…identification of the optimal system and battery dispatch for each agent* (typical customers) *is based on calculating the net present value for a range of system sizes for a combination of PV and battery systems…*

SFS Section 4 takes a deep dive into dispatching strategies. While this is an important component of system value, and thus the likelihood of adoption, I will not repeat it.

3.4. Scenarios

The following table (next page) contains all of the scenarios. I will repeat some text on the base case below.

The Base Case is intended to provide a baseline for comparison with other scenarios. It considers moderate (or mid-range) cost projections for PV and battery storage systems, net billing or net-metering compensation schemes currently in place in each state, and the calculated value for backup power.

3.5. Results

In this section, we present economic potential and adoption projections for distributed PV + battery storage systems considering several scenarios. The scenarios enable us to examine the sensitivity of projected deployment to changes in single or multiple input parameters, and they are important to understand the key drivers of market growth. We present our results in the same methodological order as the simulations are carried out in dGen: Results on economic potential for distributed PV + battery storage systems are first presented, followed by adoption projections at different scales.

Adoption projections are first presented at a national scale, grouped into the three scenario groups: technology cost scenarios, value of backup power scenarios, and DER valuation scenarios (Section 2.9). Each scenario group includes the Base Case as a benchmark, and the sensitivity to different attributes nationwide is discussed…

[2] NREL System Advisor Model, https://sam.nrel.gov

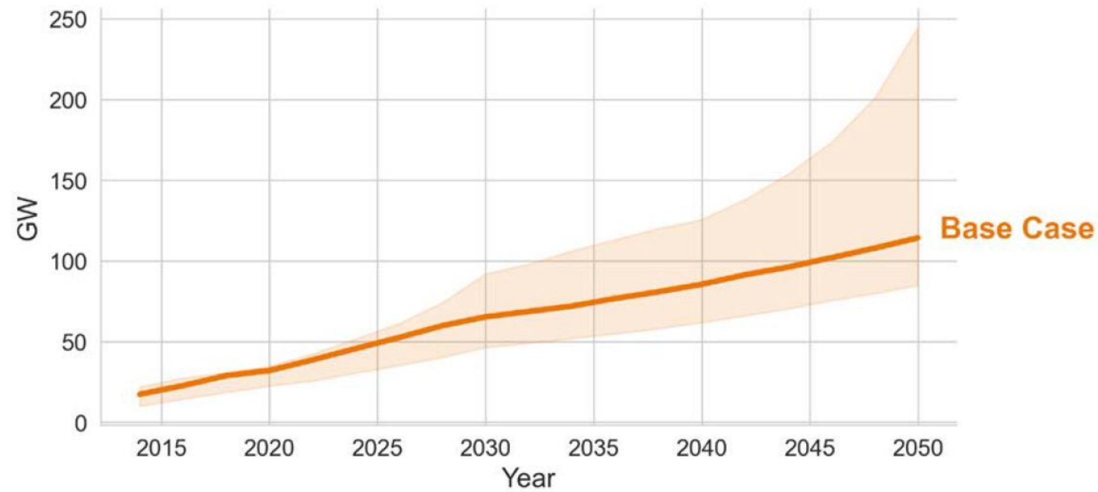
Scenario Group	Scenario Name	Scenario Description
Technology Cost Scenarios	Base Case	Moderate cost projections for both PV and battery storage systems; all other incentives and rates inputs are default values, and the value of backup power is considered.
	Advanced Cost Batteries Scenario	Advanced (low) cost projections for batteries paired with moderate cost projections for PV
	Advanced Cost PV Scenario	Advanced (low) cost projections for PV paired with moderate cost projections for batteries
	Advanced Cost PV + Batteries Scenario	Advanced (low) cost projections for PV paired with advanced (low) cost projections for batteries
Value of Backup Power Scenarios	No Backup Value Scenario	Moderate cost projections for PV and batteries and no value of backup power
	No Backup Value + Advanced Cost Batteries Scenario	Advanced (low) cost projections for batteries and no value of backup power
	2x Backup Value Scenario	Moderate cost projections for PV and batteries and double the value of backup power across all states and sectors
	2x Backup Value + Advanced Cost Batteries Scenario	Advanced (low) cost projections for batteries and double the value of backup power across all states and sectors.
DER Valuation Scenarios	Net Metering Extensions Scenario	All states switch to net metering compensation from 2020 through 2050
	National Net Billing Scenario	All states switch to net billing compensation from 2020 through 2050

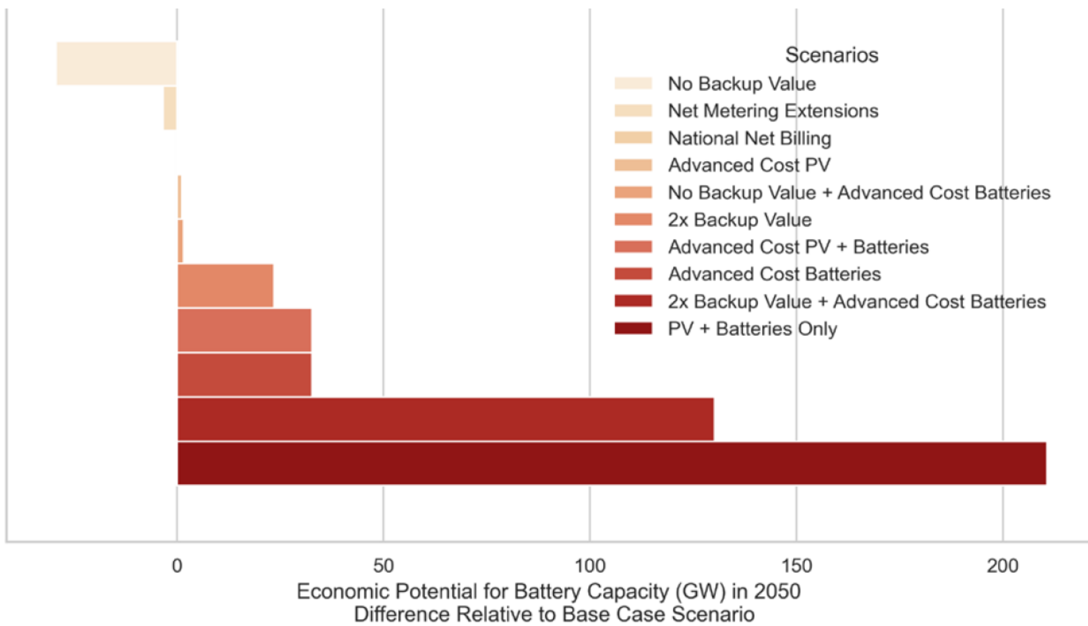
***Economic potential** is essential in determining the amount of adoption, as it represents the upper bound for the subsequent filter of market potential and adoption in dGen. Economic potential is defined as the total capacity in a given year that could return a positive NPV. A discounted cash flow analysis determines the profitability (e.g., the payback period, NPV, and monthly electricity bill savings) over the system's lifetime. This approach assumes the DER value is created through the sum of three value streams: (1) value created by reducing the electricity or fuel bills the agent would have paid had they not adopted, (2) value of backup power, and (3) revenue from selling excess PV generation.*

In the figure immediately below (next page), the total battery capacity in the United States estimated to have a positive NPV (economic potential) is shown for the Base Case, with the colored range representing the upper and lower estimates from other scenarios. The economic potential for battery storage systems co-adopted with PV is approximately 114 GW in the Base Case.

In the second figure below highlights that the value of backup power along with battery cost are by far the most important drivers for improving the economic attractiveness of PV + battery storage systems; the 2x Backup Value + Advanced Cost Batteries Scenario has the highest economic potential for battery storage, with 245 GW of battery capacity.18 The economic potential for battery capacity is almost the same as in the Base Case and Advanced Cost PV Scenario; however, the economic potential for PV capacity is higher in the Advanced Cost PV Scenario. Similarly, the Net Metering

Extensions Scenario also shows a lower difference in economic potential for battery storage systems, but a higher economic potential for PV-only systems.





The economic potential presented in the second figure above considers PV-only systems and PV + battery storage systems as possible system options. To quantify decision-making between these two system options, NPV is used as a decision variable and the system with the highest NPV is the selected technology. In practice, customers might select PV + battery storage systems based on other reasons or preferences, as long as they have a positive NPV. For several customers in dGen, both PV-only and PV + battery storage systems have a positive NPV. However, despite having a positive NPV, PV + battery storage systems might not be the selected technology because of the selection process where systems with the highest NPV are adopted. The economic potential of battery storage systems is therefore higher when PV + battery storage systems are the only available system configuration (excluding PV-only systems). ***The economic potential of battery storage systems when PV + battery storage is the***

only available system configuration is presented as the last row in figure immediately above, labeled as "PV + Batteries Only." *As seen in the figure, this scenario results in even higher economic potential for battery capacity with 325 GW under the Base Case. Although PV-only systems are more cost-effective compared to PV + battery storage systems for a significant proportion of customers, the adoption of distributed battery capacity could be higher than the results presented in this report if customers select systems due to factors other than economics.*

Author's comment: The text that I highlighted above (in bold), point out an issue that my state (California) has been struggling with. PV without storage is very cost effective, but under our present net energy metering tariffs, it shifts costs to customers without PV. With over a million customers that have PV-only, this is no longer sustainable.

The recent preliminary ruling by the California PUC (see the earlier paper described and linked at the beginning of section 3.1) created a tariff that is economically sustainable, but a PV-only system will no longer be very cost-effective. Of course, the companies that sell these systems have gone berserk. Since these companies are very large and influential (yes, we created these monsters), Governor Newsom put this ruling on hold.

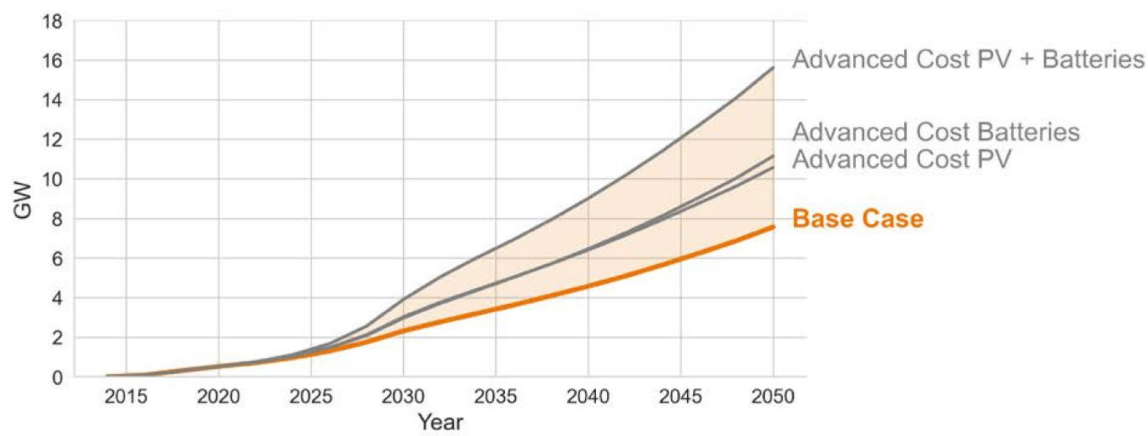
These new tariffs have the elements to reduce the negative economic impact on PV-only systems in the short-term. It uses a "*Market Transition Credit"* that already does this to a degree, but goes away in a few years. Even if this credit is extended, it will need to ramp down in the long run so that everyone is treated fairly.

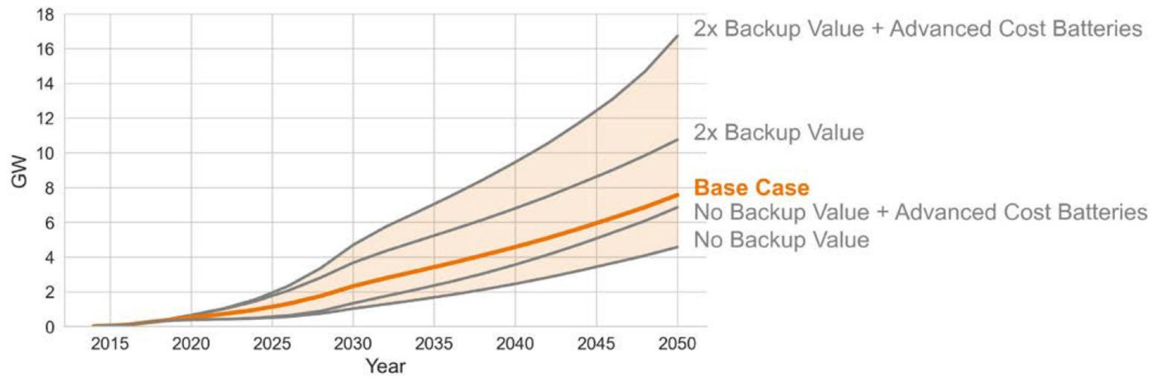
I feel that there will be an intense negotiation session by all parties shortly. Note that public-interest groups plus and large electric utilities support the new tariff, and were heavily involved in the proceeding that led to this ruling (as were the PV-sellers). It could be that the CPUC anticipated the push-back, and the preliminary ruling has an intentionally brief transition period that can be easily extended.

3.6. Summary

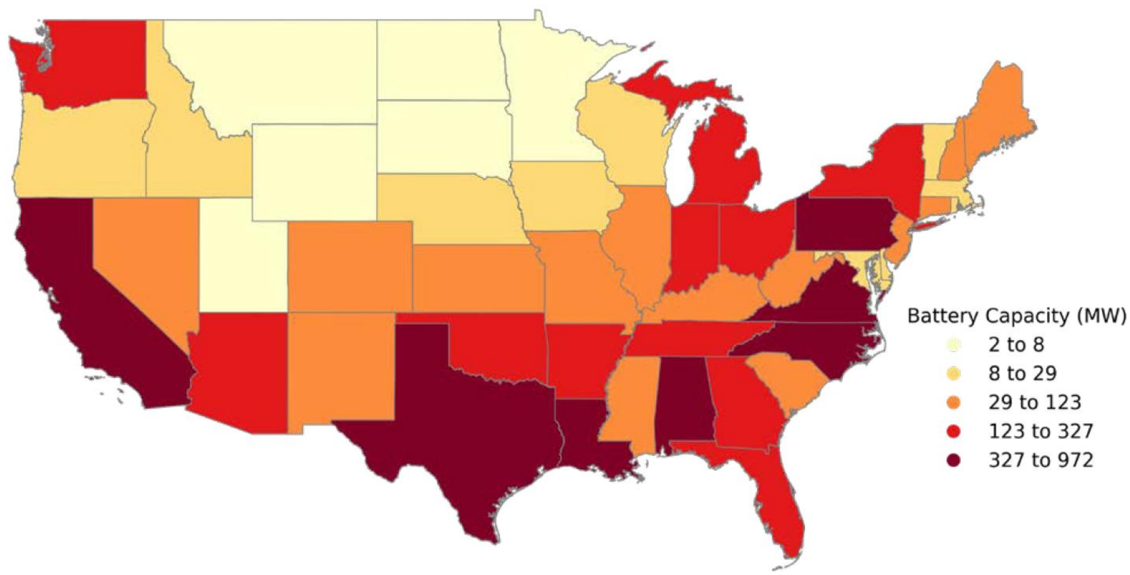
There was much text in SFS Section 4 regarding methods and data and several interesting graphics. I will use three of the latter below as the conclusion of my summary. The charts are for cumulative distributed battery capacity (DER), showing the base case and different scenarios.

Note that there is a final section to this paper after the two charts and map/graphic below.





Base Case - Cumulative Battery Capacity in 2050



4. California Net Energy Metering Direction

At the end of subsection 3.5 above, I wrote four short paragraphs summarizing the situation regarding California's attempt to rewrite its Net Energy Metering rules for distributed PV and PV + Storage. I am writing this (the day before this paper is posted), I went to the main page for this proceeding (referenced at the end of the paragraph below) and found the following statement by the PUC:

The following procedural email was sent to the Service List of R.20-08-020 by the proceeding's Administrative Law Judge on February 3, 2022:[3]

This procedural email provides notice to the parties of Rulemaking 20-08-020 that the proposed decision, which was issued on December 13, 2021, will not appear on the Commission's voting meeting agenda until further notice. On January 11, 2022, the Commission reassigned Rulemaking 20-08-020 to President Alice Reynolds. The assigned Commissioner has requested additional time to analyze the record and consider revisions to the proposed decision based on party comments. Furthermore, the

[3] California Public Utilities Commission, "Net Energy Metering Revisit - Rulemaking (R.) 20-08-020," https://www.cpuc.ca.gov/nemrevisit/

assigned Commissioner wants to ensure all five Commissioners participate in oral arguments. Accordingly, the oral argument hearing will be rescheduled at a later date. After additional analysis is conducted, I will issue a subsequent ruling providing information on the proceeding schedule and details regarding the oral argument hearing. A copy of this procedural email will be placed in the correspondence file of Rulemaking 20-08-020. Due to the size of the service list, this procedural email is being sent in batches.

Thus the "…intense negotiation session by all parties shortly." I predicted above has started.