The Economic Potential for Energy Storage in Nevada

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THE **Brattle** GROUP

Notice

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Executive Summary

Highlights

- This study identifies the amount of energy storage that can be incorporated cost-effectively into Nevada's future electricity resource mix.

- In 2020, up to 175 MW of utility-scale battery storage (with 4-hour storage capacity) could be deployed cost-effectively statewide.

- By 2030, the economic potential for utility-scale storage increases to a range from 700 MW to more than 1,000 MW, depending most significantly on the extent to which storage costs decline over time.

- Behind-the-meter (BTM) storage could add up to 30 MW of storage capacity by 2030 under favorable conditions, and this could further increase by up to 40 MW through the provision of cost-effective utility-administered BTM storage incentives

Nevada Senate Bill (SB) 204 (2017) requires the Public Utilities Commission of Nevada (PUCN) to "determine whether it is in the public interest to establish by regulation biennial targets for the procurement of energy storage systems by an electric utility."[1] The Nevada Governor's Office of Energy (GOE) commissioned this study to provide information for the PUCN when evaluating at what levels energy storage deployment would be economically beneficial for the state of Nevada, and whether procurement targets for energy storage systems should be set and, if so, at what levels.

To assess the value of energy storage in Nevada, our study considers the range of benefits summarized in Table 1.

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[1]   Nevada Senate Bill 204 (2017).

Table 1
Energy Storage Benefits

Value Stream	Description
Reducing the production costs of generating electrical energy	Storage can be charged in off-peak periods, when the cost of supplying electrical energy is low. It can then be discharged during peak hours, reducing the need to produce <u>energy</u> from more expensive peaking units. The fast ramping capabilities of storage can also help system operators manage rapid changes in load or variable generation, thereby reducing production costs by reducing the need for (up and down) ramping of conventional generators.
Reducing the production cost of providing ancillary services	The high operational flexibility often allows storage to provide <u>ancillary services</u> (regulation and operating reserves) more cost-effectively than conventional resources. This can contribute to reducing production costs associated with meeting customer loads and associated system needs
Reducing installed capacity needs for traditional power generation resources	Storage can be charged in off-peak periods, when the cost of providing energy is low. It can then be discharged during peak load hours, reducing the need for new <u>peaking capacity</u> that otherwise would have to be built to serve load in those hours.
Reducing distribution-system customer outages	If located on the distribution system, storage can be used to reduce the frequency and severity of customer outages.
Avoiding or deferring the need for transmission and distribution grid upgrades	Storage can be deployed on a geographically-targeted basis to avoid or defer the need for some transmission and distribution (T&D) upgrades.
Reducing emissions and decreasing the curtailment of renewable generation	Storage can reduce emissions either by reducing generation from high-emitting generators or by increasing output from wind and solar generators that would be curtailed otherwise. Avoiding curtailments reduces the production cost of generating energy. Whether storage reduces emissions depends on the marginal emissions profile of the resource mix and the charging and discharging pattern of the storage technology.
Providing additional grid services	Storage can be deployed where additional grid services, such as voltage support, may be needed, deferring other investments needed to provide the same service.

Methodology

In this study, we account for a number of critical considerations when assessing the value of energy storage:

- **Various value streams.** Capturing one value stream for storage can mean foregoing opportunities to fully capture some of the other value streams. Co-optimizing the operation of energy storage relative to the available multiple value streams is therefore important to accurately estimate total storage benefits. We have utilized Brattle's bSTORE modeling suite to account for these tradeoffs. The resulting "stacked" values estimated in this report are additive because we have considered areas where overlapping usages may not occur consistently.

- **Uncertainty in costs and benefits.** Energy storage technology is rapidly developing, and the value streams that it can capture are similarly in a state of evolution. It is important to account for uncertainty in the costs and benefits of storage when establishing future storage procurement targets. We use a range of costs to consider the possibility of relatively rapid versus slow cost reduction for storage. We use a scenario-based approach to consider a range of future developments influencing the benefits storage can provide.

- **The relationship between storage quantity and benefits.** The incremental cost-effectiveness of energy storage decreases as its market penetration grows. This is because the opportunities to provide services such as frequency regulation and local distribution capacity deferral saturate as more storage is added to the power system. In prior energy storage research, we have found that capturing the decreasing marginal value of adding storage is a critical consideration when quantifying overall value and cost-effective storage potential.[2] Our approach accounts for this relationship.

- **Degree of foresight in battery utilization.** Modeling approaches often rely on optimal operation of the storage technology, assuming perfect foresight of system conditions. Our approach accounts for real-world limitations on foresight of future system conditions, and considers how imperfect foresight affects storage operations.

Our methodology is applicable to a broad range of energy storage technologies including, for example, various battery technologies, flywheels, compressed air storage, hydroelectric pumped storage, or thermal storage. To focus the analysis on a representative range of storage costs and performance characteristics, we simulate storage deployment of lithium-ion batteries, which are the predominant energy storage technology currently being deployed and contracted. More specifically we analyze lithium-ion batteries with 4-hour storage capacity.

Consistent with the applicable current law and NV Energy's 2018 Integrated Resource Plan (IRP), our study assumes NV Energy remains the utility responsible for serving most retail customers in Nevada. We assume that: (1) generating resources currently dedicated to serving Nevada loads at their cost of service would continue to be used to serve loads even if they will be subject to competitive pressures in the future, (2) new generation additions and retirements are consistent with NV Energy's IRP, and (3) the transmission available without wheel-out charges between balancing areas remains limited to that available in today's Energy Imbalance Market (EIM) footprint.

If Nevada retail customers were able to choose their power suppliers in the future, the total amount of generating resources needed to serve Nevada's electricity demand would not change. Thus, we do not need to assume that all of the current retail customers must be served by NV Energy or that all generating and new storage resources must be owned by NV Energy. Rather, we focus primarily on how Nevada, as a state, will supply its electricity customers and how the state as a whole may use energy storage as a resource to help meet state-wide system needs and policy objectives. When analyzing the benefits of storage, we evaluate the cost of producing electricity to serve Nevada

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[2]   For further discussion, see Chang *et al.* (2015).

electricity users, regardless of who are the retail suppliers. Any changes to the cost of producing electricity account for the costs of operating power plants located inside Nevada (regardless of ownership) and the net costs of purchased power from other entities to serve electricity users in Nevada.

Findings

Energy storage can be incorporated cost-effectively into Nevada's future power supply mix. Under the assumptions used in this study, a statewide deployment of up to 175 MW of utility-scale storage could be cost-effective in 2020 if storage costs are at the lower end of the expected cost range. By 2030, declining battery costs and evolving system conditions increase this estimate of cost-effective potential to at least 700 MW and possibly exceeding 1,000 MW at the high end. The development of these estimates accounts for constraints that limit the operation of the storage devices relative to that of a peaking unit, in particular limits on battery storage discharge duration.

Within these ranges, the optimal storage procurement target will depend on the state's evolving actual need for new generating capacity. Thus, the incorporation of similar storage scenarios into NV Energy's resource planning process would be valuable to further confirm these conclusions.

The findings of our analysis are summarized in the figures below. Figure 1 illustrates the *total* state-wide ratepayer benefits and costs at various levels of storage deployment as well as the composition of the major storage-related value streams that affect utility ratepayers:[3] (1) avoided generating capacity investments; (2) production cost savings (related to supplying energy and ancillary services as well as avoided curtailments of renewable generation); (3) the benefit of deferred T&D investments; and (4) avoided distribution-system customer outages. Not included in Figure 1 are (5) societal emissions-related impacts (since they do not affect utility rates currently), which result in societal-emissions-cost decreases of $0.7 to $10.6 million in 2020 and decreases of $1.6 to $27.0 million in 2030; and (6) other benefits, such as voltage support and T&D energy losses, which are too small to affect the conclusions about cost-effective levels of storage deployment in the state.

As shown, total 2020 benefits exceed total costs only at the low end of deployments analyzed, and only if the low end range of installed storage costs can be realized.[4] In 2030, total benefits exceed total costs across the full range of cost projections and deployment scenarios, although the net benefit of incremental additions in 2030 drops to zero at 700 MW for the high battery cost scenario, as shown below.

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[3] The GOE and PUCN specified that the Ratepayer Impact Measure (RIM) test be used to evaluate how average retail rates will change as the result of Nevada utilities' storage investments.

[4] The range of storage costs accounts for variations across several industry reports, discussions with storage developers, public cost data from recent utility solicitations, and potential variation in costs across specific installations.

Figure 1
Total System Benefits and Costs of Storage at Various Deployment Levels
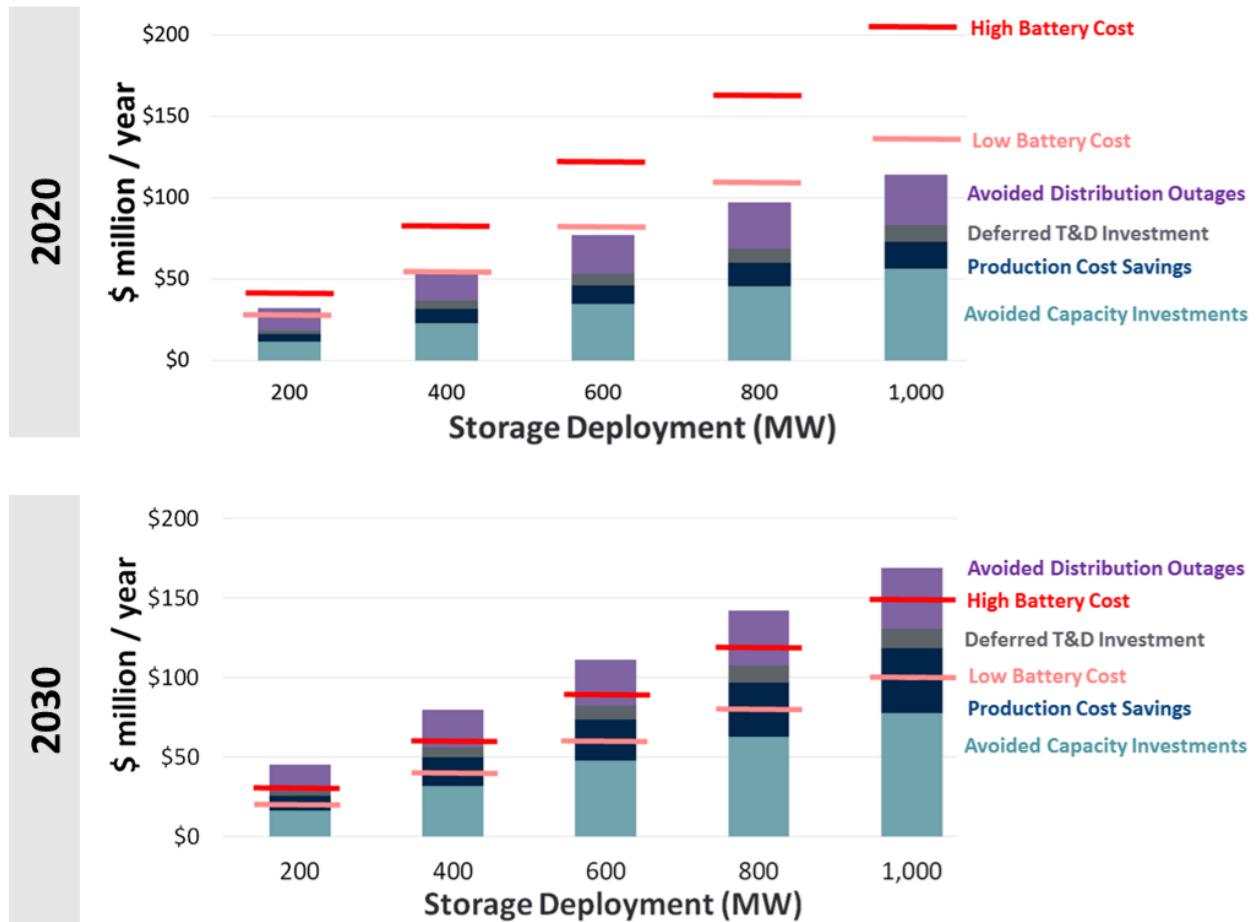
Note:
All values are in nominal dollars.

Figure 2 below shows the incremental *net* benefits of storage at various deployment levels. This perspective is useful for identifying the point at which the benefits of incremental storage additions equal the costs of those additions. Storage additions beyond that deployment level are uneconomic, as incremental costs will exceed incremental benefits. As shown, up to 175 MW of storage deployment are cost effective in 2020 at the low end of the storage cost range. By 2030, the cost effective deployment level exceeds 1,000 MW at the low end of projected cost, with 700 MW being cost effective at the high end of projected costs.

Figure 2
Incremental Net Benefits of Storage Deployment in Nevada

2020

Net system benefits maximized at
↓ ~175 MW deployment.

Low Battery Cost

Storage not cost-effective at high
end of current cost estimates.

High Battery Cost

2030

Low Battery Cost

Net system benefits exceed costs for
all deployment levels < 1000 MW.

High Battery Cost

↑

Net system benefits maximized
at ~700 MW deployment.
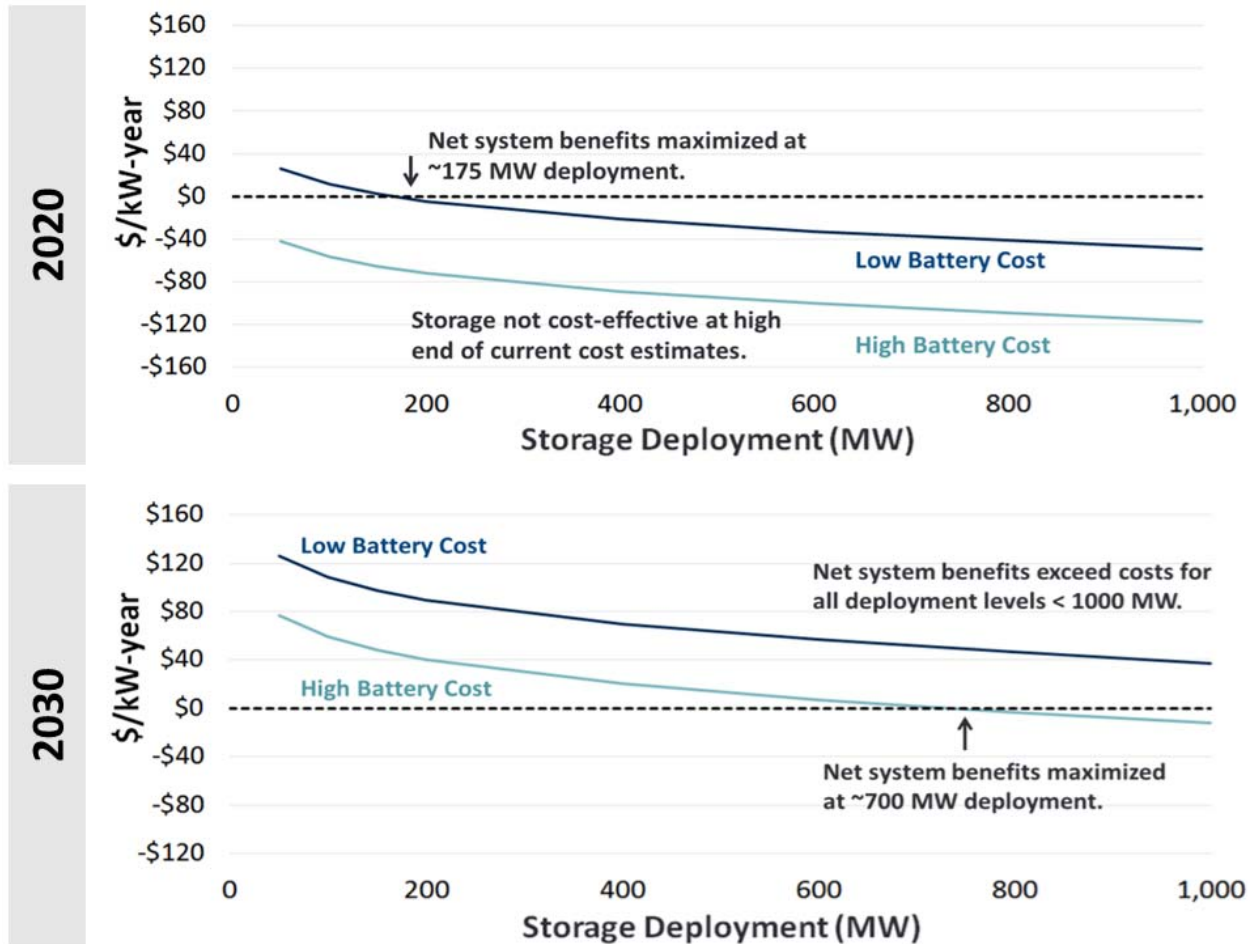
Note:
All values are in nominal dollars.

The estimates of cost-effective storage potential are based on quantitative analyses that capture the primary drivers of storage value at the grid level: avoided generation capacity costs, reduced energy costs, reduced ancillary services costs, avoided T&D capacity costs, and reliability improvements (*i.e.,* customer outage avoidance). We do not include the value of estimated avoided emissions when evaluating the amount of storage that would be cost-effective from a system perspective.

Implementation of and Nevada's participation in a regional power market may reduce the value of storage due to lower production cost savings associated with increased resource diversification that would be achieved through having a market that spans a larger region. The resource adequacy needs associated with serving Nevada loads may not be reduced and other value streams are unlikely to be affected. If the implementation of a regional market were to reduce the production cost savings by half and not affect other value streams, the cost-effective level of storage deployment in 2030 would fall from a range of 700 MW to greater than 1,000 MW (without a regional market) to a range of 400 MW to greater than 1,000 MW (with a regional market).

In addition to the utility-scale and distribution-system-level applications discussed above, storage could add value as a customer-side, behind-the-meter (BTM) application. The avoidance of demand charges and peak-energy charges in the retail electricity bill of large (commercial and industrial) customers likely will be the primary driver of BTM storage adoption within the study's 2030 time horizon. Some "baseline" level of BTM storage adoption would happen irrespective of any utility storage procurement initiatives based on specific targets. To remain consistent with the scope of this study, we quantified the cost-effective *incremental increase* from this baseline BTM storage adoption level that could result from a utility-administered BTM storage incentive program offered to retail customers. In return for an incentive payment, customers would allow the utility to control their storage device for a limited number of hours of the year to address resource adequacy (*i.e.*, generation capacity) requirements.

We considered a range of assumptions that would influence BTM storage adoption, such as battery cost, adoption rate, magnitude of utility incentive payments, and the composition of the commercial and industrial (C&I) customers in the state. At estimated 2020 BTM storage costs, BTM storage adoption in the absence of a utility incentive program could be up to 7 MW. The introduction of cost-effective utility incentive programs could incrementally increase these estimates by up to 24 MW. At 2030 BTM storage costs, baseline BTM storage adoption is estimated to be up to 31 MW without the incentive program, which would incrementally increase between 6 MW and 39 MW with availability of cost-effective utility incentive programs. Results of these BTM storage potential cases are summarized in Figure 3. These values are incremental to the adoption potential estimates for utility-scale storage (including front-of meter distribution-level storage) described above.

Figure 3
Cost-Effective Incremental BTM Storage Potential with Utility Incentive Programs
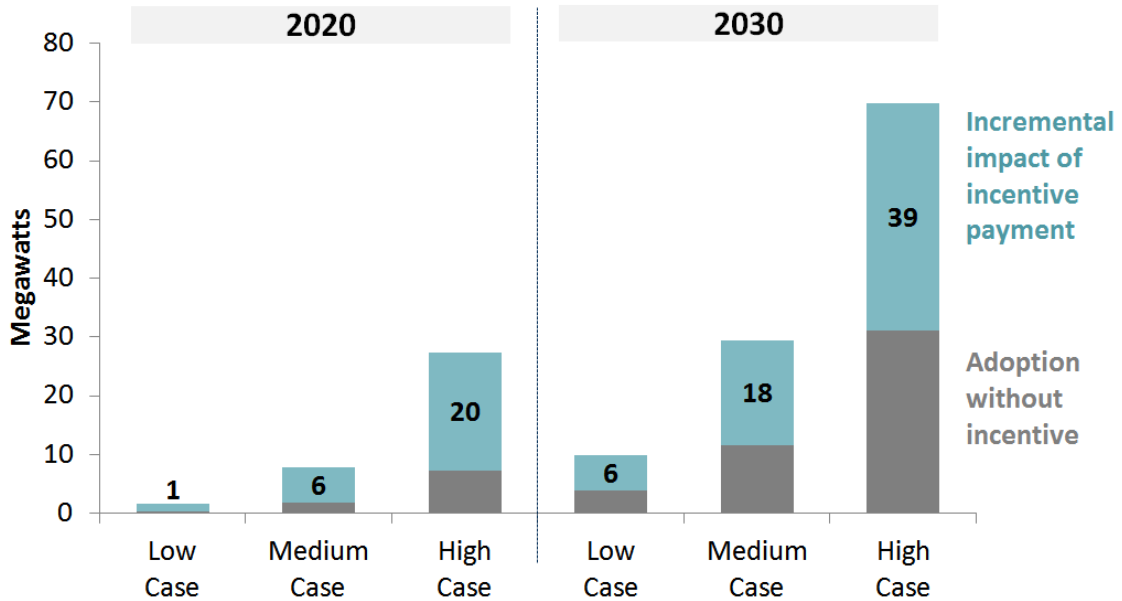
Notes:
The potential estimates represent long-run adoption potential based on assumed storage costs for the years shown in the figure. It would take several years to reach these adoption levels.

In addition to the assumed utility incentive payments for resource adequacy, it is possible that BTM storage could provide additional sources of value, such as ancillary services or avoided T&D costs. Third party aggregators, utilities, or customers could monetize greater value under these conditions, thereby leading to increased BTM storage investments.

As these results show, energy storage can be a cost-effective addition to Nevada's future mix of electricity resources, reducing system costs and benefitting consumers as a result. It can provide value across a range of applications and use cases, whether for resource adequacy, renewables integration, T&D investment deferral, or some combination of these and other benefits streams. This conclusion is robust across a range of modeled scenarios. The economically optimal levels of future deployment depend most significantly on the trajectory at which energy storage costs decline and new generating resources are needed to meet Nevada's electricity demand.

I. Introduction and Background

A. Study Purpose and Scope

Nevada Senate Bill 204 (2017) requires the Public Utilities Commission of Nevada (PUCN) to "determine whether it is in the public interest to establish by regulation biennial targets for the procurement of energy storage systems by an electric utility."[5] The Nevada Governor's Office of Energy (GOE) has commissioned this study to provide information to be used by the PUCN when evaluating whether procurement targets for energy storage systems should be set and, if so, at what levels energy storage deployment would be economically beneficial for the state of Nevada.

This study evaluates the potential economic value of storage for Nevada. The study examines the period between today and 2030, considering multiple "use cases" for energy storage. We document the assumptions made and analyses conducted to assess whether energy storage would provide value to Nevada customers in excess of its costs.

The analyses conducted for this study focus on the value of stand-alone battery energy storage systems located on the transmission and distribution system, as well as on utility-operated behind-the-meter (BTM) storage programs. However, the general observations about the value of storage from this analysis of battery storage devices apply to other types of technologies such as hydro-electric, thermal, and compressed air storage.

B. The Potential Value of Electricity Storage

Due to rapidly falling costs and unique operational flexibility, energy storage is increasingly viewed as a valuable electricity system resource. Storage systems connected to the transmission and distribution grid have the potential to provide a range of services that could ultimately reduce power system costs and create value for consumers, including:

- **Reducing the production costs of generating electrical energy.** Storage can be charged in off-peak periods, when the cost of providing energy is low. It can then be discharged during peak load hours, reducing the need to operate expensive peaking units. The fast ramping capabilities of storage can help system operators manage rapid changes in load or variable generation, thereby reducing the production costs associated with the (up and down) ramping of conventional generators.

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[5]   Nevada Senate Bill 204 (2017).

- **Reducing the production cost associated with providing ancillary services.** The operational flexibility of storage may allow it to provide regulation and operating reserve services more cost-effectively than conventional resources.

- **Reducing capacity needed from traditional power generation resources.** By discharging during peak load hours, storage can reduce the need for peaking capacity that would otherwise have to be built to serve load in those hours.

- **Deferring transmission and distribution investment costs.** To the extent that storage can be used to meet local peak loads, the loading on the transmission and distribution system would be reduced. In such cases, storage can help defer certain transmission and distribution upgrades.

- **Distribution-system customer outages.** If located on the distribution system, the deployment of storage can be targeted to reduce the frequency and severity of customer outages.

- **Reducing emissions and decreasing the curtailment of renewable generation.** Storage can potentially reduce emissions either by reducing generation from high-emitting generators or by increasing output from wind and solar generators that would otherwise be curtailed. Reducing the curtailment of renewable generation will reduce system-wide production costs. Whether or not storage reduces emissions depends on the marginal emissions profile of the resource mix and the charging and discharging pattern of the storage technology.

- **Providing additional grid services.** Storage can be deployed where additional grid services, such as voltage support, may be needed, thereby deferring other investments needed to provide the same service.

In addition to operating storage as a utility-scale and distribution-system resource, it can be located behind-the-meter (BTM) at customer sites or be co-located with wind and solar generation facilities. BTM systems can create additional value to end-use customers by providing the customer with the ability to avoid time-varying volumetric charges or demand-based charges in their retail rate. Other BTM storage applications include operating the technology as backup generation or participating in a demand response program.

Co-locating storage with wind and solar plants can provide value by reducing curtailments and firming the generation output before it reaches the grid. This correspondingly increases the capacity value of the renewable resources.[6] At the time this report is written, NV Energy has

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[6] In addition, the storage component of such co-located systems may qualify for the federal renewable energy Investment Tax Credit (ITC).

contracted with some storage facilities that are co-located with solar and those contracts are subject to Commission approval, as a part of the company's 2018 Integrated Resource Plan.[7],[8]

C. The Nevada Context

NV Energy currently is the primary wholesale power supplier and the transmission and distribution provider in Nevada, serving approximately 90% of Nevada's population.[9] NV Energy's retail electric utility businesses are regulated by the PUCN and are operating in two service territories. As shown in Figure 4, Sierra Pacific Power Company (SPPC) serves northern Nevada including Reno and Carson City and Nevada Power Company (NPC) serves southern Nevada, including Las Vegas. The remainder of the state is served by smaller municipalities, power districts, and cooperative utilities that are not subject to PUCN rate regulation.[10]

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[7] NV Energy (2018a).

[8] Both the benefits and costs of storage co-located with solar generation may be lower than those of stand-alone storage devices. Benefits will tend to be lower due to decreased flexibility in operations and siting. Costs will tend to be lower due to co-location synergies and potential ITC eligibility. The degree to which co-location of storage with solar generation affects the cost effective potential of storage in Nevada will depend on these benefit-cost tradeoffs.

[9] Lateef and Reyes (2017).

[10] The PUCN regulates certain energy, water, wastewater, and telecommunications service providers. It does not regulate cable, satellite, cellular, internet, or trash removal services. The PUCN does not rate-regulate municipally-owned utilities. The PUCN has limited authority over cooperative utilities, but does not regulate the rates or service quality of cooperative utilities.

Figure 4
NV Energy Service Territories and Transmission Network
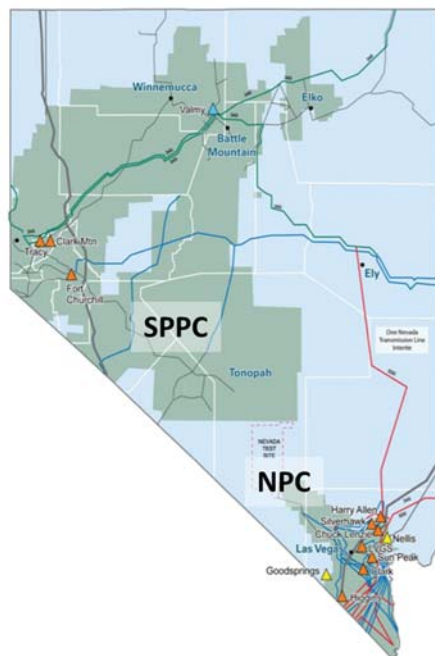
Source:
Lateef and Reyes (2017).

In 2017, NV Energy's two utilities served over 1.2 million customers, with an annual energy demand of 31.3 TWh.[11] NPC is the larger of the two utilities, with a peak load of 5,929 MW and an annual energy demand of 21.5 TWh. SPPC serves a peak load of 1,824 MW and an annual energy demand of 9.8 TWh.[12] According to NV Energy's 2018 IRP, over the next 10 years, peak loads are projected to grow 0.7% per year in NPC's footprint and negative 0.1% per year in SPPC's footprint.[13] Load shapes vary significantly in the SPPC and NPC service areas. SPPC load shapes are relatively flat across seasons and hours of the day, whereas NPC load exhibits large peaks during summer day-time hours.

NV Energy primarily meets its load through natural gas generation, which accounts for over 85% of its owned generating capacity.[14] NV Energy is subject to the Nevada state Renewable Portfolio Standard (RPS), which requires 22% of retail sales to be served from renewable resources by 2022, increasing to 25% by 2025.[15] The majority of NV Energy's renewable energy comes from

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[11] NV Energy (2018b). One Terra-Watt-hour (TWh) is equal to one million Mega-Watt-hours (MWh).

[12] NV Energy (2018a), Volume 5, pg. 54 of 275.

[13] NV Energy (2018a), Volume 5, pg. 5 of 275.

[14] Of its 6,011 MW owned capacity, NV Energy operates 4,364 MW of generating natural gas capacity in NPC and 1,111 MW in SPPC. See NV Energy (2018a), Volume 11.

[15] DSIRE (2018).

contracted resources. NV Energy also contracts a relatively small amount of generating capacity from third-party suppliers.

The Nevada power system is part of the larger Western Interconnection, and NV Energy is a member of the Western Electricity Coordinating Council (WECC). As such, Nevada transacts power with neighboring systems through eight transmission interconnections.[16] In addition, Nevada is a member of the Western Energy Imbalance Market (EIM). As a member of the EIM, Nevada can more readily exchange power during real-time dispatch with neighboring areas to balance load and generation on a 5-minute basis. Participation in EIM thus reduces the cost of serving load through regional diversification, access to lower-cost supply, and export of excess generation.

In 2016, the Energy Choice Initiative was placed on the Nevada ballot, which would require that "electricity markets be open and competitive so that all electricity customers are afforded meaningful choice among different providers, and that economic and regulatory burdens be minimized in order to promote competition and choices in the electric energy market."[17] It was approved by Nevada voters in 2016 but needs to be approved in two even-numbered election years to become a state constitutional amendment in Nevada, and thus needs to pass in 2018.[18]

Consistent with the applicable current law and NV Energy's 2018 IRP, our study assumes NV Energy remains the utility responsible for serving most retail customers in Nevada. However, even if the proposed change in applicable laws is implemented and Nevada retail customers are able to choose their power suppliers in the future, the total amount of generating resources needed to serve Nevada's electricity demand would not change. Thus, we do not need to assume that all of the current retail customers must be served by NV Energy or that all generating and new storage resources must be owned by NV Energy. Rather, we focus primarily on how Nevada, as a state, will supply its electricity customers and how the state as a whole may use energy storage as a resource to help meet state-wide system needs and policy objectives.

The remainder of this study is organized as follows. Section II documents the framework and analytical approach employed. Section III summarizes the evaluation of individual drivers of storage benefits. Section IV presents the total system wide benefits, considering the extent to which individual storage-related benefits can be captured simultaneously. Section V documents our analysis of behind-the-meter storage deployment and the extent to which utility incentives to retail customers can increase cost-effective adoption of utility-controlled BTM devices. Section VI compares our results to other storage potential studies. Section VII presents the implications for the state of Nevada.

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[16] NPC owns three rated transmission paths (Crystal Path, Harry Allen to Red Butte, and Southern Nevada Transmission Interface) and SPPC owns five (Idaho to Sierra, Pacific Gas and Electric to Sierra, Pavant to Gander, Silver Peak to Control, and Alturas Project). NV Energy (2018a), Volume 11.

[17] Nevada GOE (2018).

[18] Griffin and Weber (2017).

II. Analytical Approach to Estimating Storage Costs and Benefits

This study accounts for a number of critical considerations when assessing the value of energy storage:

- **Stacked value streams.** Some of the benefits of storage may not be fully additive. For instance, capturing one value stream can mean foregoing opportunities to fully capture some of the other value streams. Co-optimizing the operation of energy storage relative to the available multiple value streams is therefore important to accurately estimate total storage benefits. We have utilized Brattle's bSTORE modeling suite to account for these tradeoffs.

- **Uncertainty in costs and benefits.** Energy storage technology is rapidly developing, and the value streams that it can capture are similarly in a state of evolution. It is important to account for uncertainty in the costs and benefits of storage when establishing future storage procurement targets. We use a range of costs to consider the possibility of relatively rapid versus slow cost reduction for storage. We use a scenario-based approach to consider a range of future developments in the benefits storage can provide.

- **The relationship between storage quantity and benefits.** The cost-effectiveness of energy storage decreases as its market penetration grows. This is because the need for services such as frequency regulation and local distribution capacity deferral saturate as storage is added to the power system. In prior energy storage research, we have found that capturing decreasing marginal value is a critical consideration when quantifying overall value.[19] Our approach accounts for this phenomenon.

- **Degree of foresight in battery utilization.** Modeling approaches often rely on optimal operation of the storage technology, assuming perfect foresight of system conditions. Our approach accounts for real-world limitations on foresight of future system conditions, and how considers imperfect foresight affects storage operations.[20]

Our approach to evaluating the value of energy storage is summarized in Figure 5 and described in further detail below. We use The Brattle Group's bSTORE model to simulate no additional storage, 200 MW, and 1,000 MW of storage deployed on the Nevada power system in 2020 and 2030. We selectively deploy storage at high-value locations where it may be able to defer some transmission and distribution investments or at feeders that have historically experienced relatively high levels

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[19] For further discussion, see Chang et al (2014).

[20] Our simulations assume system operators forecast system conditions over a 24-hour period but have imperfect foresight of conditions more than 24 hours out. We also assume storage operators cannot anticipate when distribution outages may occur, and cannot know with certainty which days are a peak load day.

of outages. We then compare cases with 200 MW and 1,000 MW of "storage case" simulations with a "Base Case" (without storage). We evaluate four key value drivers of deploying storage. We additionally consider storage's ability to provide value by reducing emissions (including through reduced renewable generation curtailments) and other grid services. Finally, we compare the overall "stacked" value of storage to storage deployment costs to identify the amount of storage that maximizes net benefits for Nevada.

Figure 5
Summary of Analytical Approach
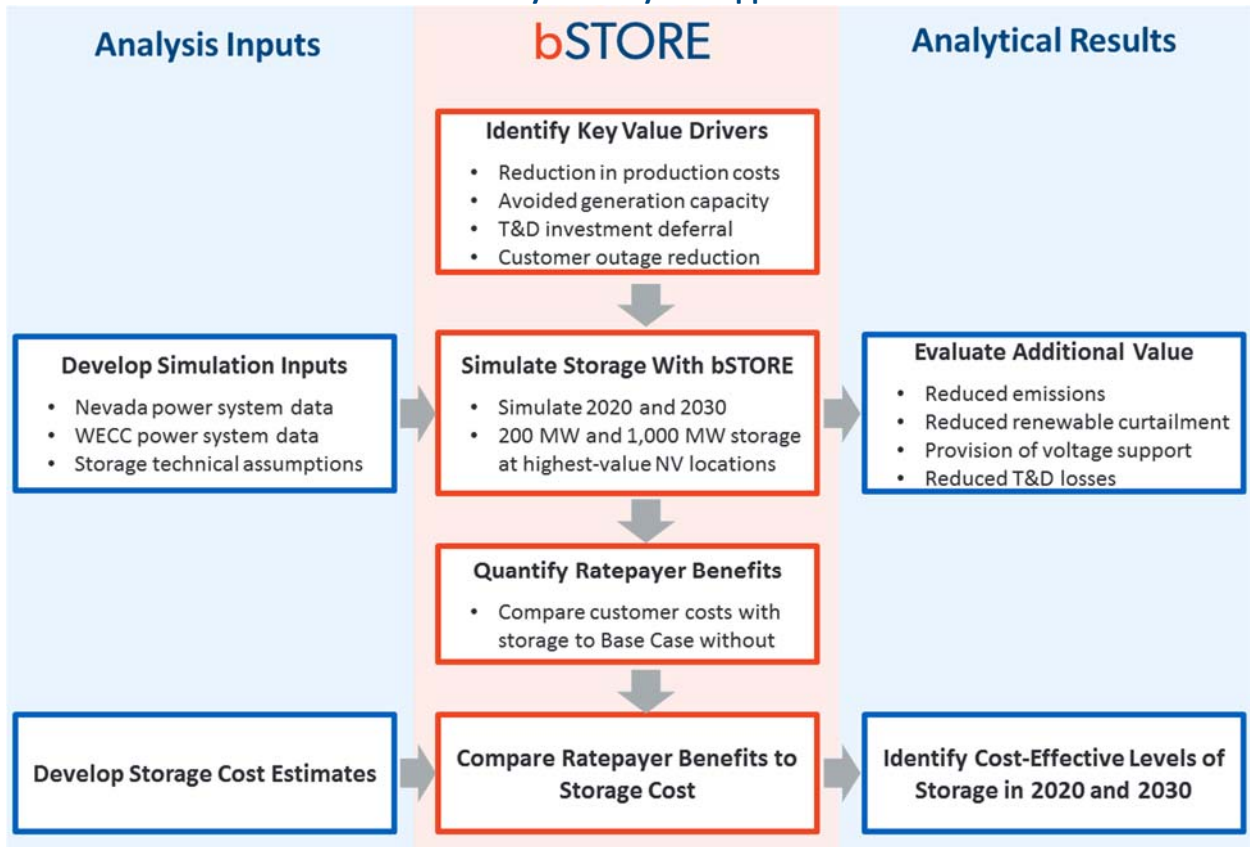
A. Approach and Key Value Drivers Evaluated

The purpose of this study is to evaluate the value of stand-alone storage located on the transmission and distribution system in Nevada. Through this assessment of storage value, we identify the total amount of cost-effective storage that could be added to the Nevada system.

As the amount of storage on the system increases, the incremental value associated with the storage additions will decrease.[21] This is because the need for various ancillary services will be fulfilled, opportunities to defer T&D upgrades in congestion locations of the system will be addressed, and

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[21]   For further discussion, see Chang, *et al.* (2015).

the peak portion of the load curve will flatten, thereby reducing the available incremental benefits. Our approach accounts for the quantities of each value stream that can cost-effectively be provided by storage investments. The total economic potential for energy storage is identified as the quantity at which the overall incremental benefits of the storage additions equal the assumed cost of storage. This concept is illustrated in Figure 6.

Figure 6
Conceptual Illustration of Approach to Identifying Economic Potential of Storage
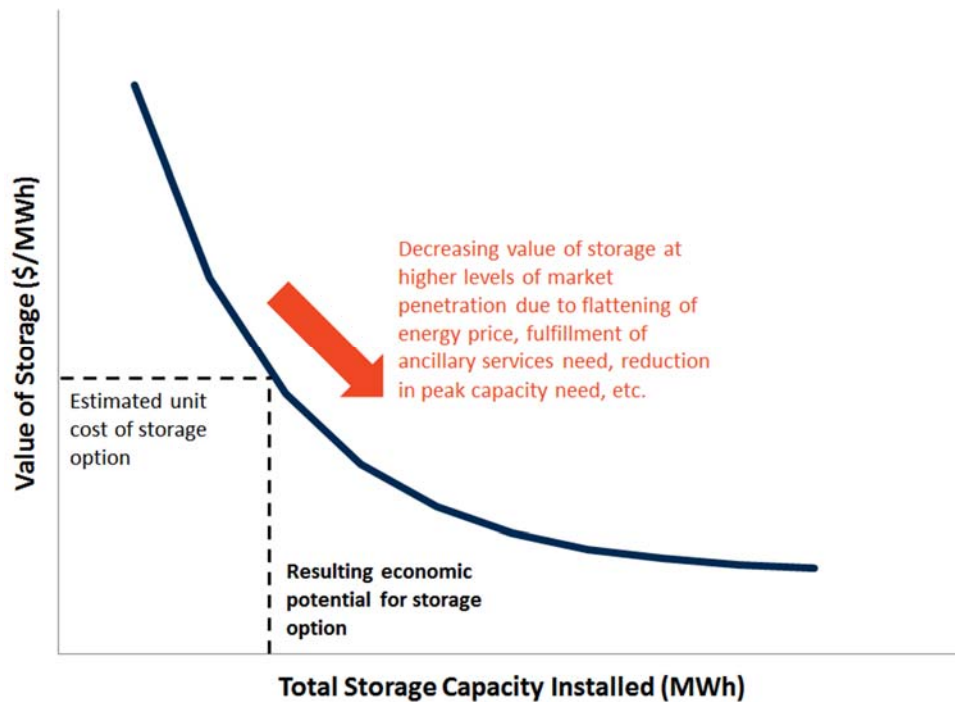
We utilize The Brattle Group's bSTORE modeling suite to evaluate how several key drivers of storage value change as increasing amounts of storage are added to the Nevada electricity system. From a utility rates perspective, the primary drivers of storage value, as described previously, are production cost savings, avoided capacity investments, deferred T&D investment, and reduced distribution customer outages. Other sources of value, including emissions-related societal costs, are evaluated and discussed as well.

The bSTORE model includes a detailed electricity system simulation module, which utilizes Power System Optimizer (PSO) software to determine impacts on system-wide electricity production cost.[22] We use bSTORE to simulate the hourly operations of the entire western power grid (all of WECC) with different levels of storage deployed in Nevada. Through these simulations, we dynamically evaluate storage's potential to simultaneously provide the various value streams listed above.

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[22] Polaris (2018).

In evaluating the ability of storage to simultaneously provide multiple value streams, we account for constraints on the ability of storage to "stack" the individual value streams.[23] Such constraints are due to potential conflicts in the operation of the storage across multiple value streams as well as storage siting decisions, which may limit its ability to provide all of the individual value streams. By simulating realistic operational constraints and siting limitations, we allow storage to co-optimize each of the key value drivers, arriving at an outcome that does not overstate the overall value of the various benefits. The analysis is based on a variety of data sources as outlined in Section II.C, including NV Energy's 2018 IRP.

After using bSTORE to estimate the value of storage across the different value streams, we compare (1) the marginal value of adding incremental amounts of storage to (2) the incremental cost of adding storage. As long as the marginal value of storage exceeds its incremental costs, additional storage investments are economically justifiable. The economic optimal level of storage deployment is reached at the point where the marginal value of adding more storage equals its incremental costs. Going beyond this point would mean that the cost of incremental storage investment would no longer be justified by its benefits.

The study period is from 2018 through 2030, with detailed power system simulations conducted for 2020 and 2030. Our estimates of storage costs in 2020 and 2030 are derived from publicly available analyst reports, discussions with developers, and publicly available data on recent storage contracts, as discussed in Section II.D.

B. Accounting for Locational and Operational Constraints

Although storage can provide value to the electricity grid and electricity customers in many ways, its ability to simultaneously provide multiple value streams can be limited by siting and operational constraints. We account for these limitations and realistically capture the ability of storage to provide multiple value streams simultaneously.

Locational limitations arise because the benefits derived from avoided distribution outages and from deferred transmission or distribution investment tend to be site-specific. For example, locations with large T&D deferral value may be quite different from locations with the greatest customer outage reduction value, as the low reliability level of a given feeder could be driven by factors other than those that drive deferrable T&D investment needs (*e.g.*, growing peak loads).

As discussed in more detail in Section III.C of this report, we find a small number of locations make up the majority of available T&D deferral value. Separately, we find that a limited number of distribution feeders make up the majority of customer outage reduction value. Given that the locations that we have identified are unlikely to overlap, we assume each MW of storage can either provide T&D deferral or customer outage reduction value, but not both. This assumption excludes the few instances where distribution upgrades are driven by a need to improve service reliability,

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[23]   For additional discussion of this topic, see Hledik *et al.* (2017).

and storage could therefore jointly provide both benefits. This topic is explored further in Section IV.

Because we assume T&D deferral and customer outage reduction values cannot generally be achieved at the same locations, our analysis will represent a lower bound on the magnitude of distribution-level storage benefits. Since we are conducting a state-wide storage potential assessment by estimating storage value broadly, rather than a detailed project-specific feasibility study at a particular location, we do not assume that every storage resource deployed can always serve multiple purposes. We assumed that storage investments would be targeted at specific locations that would maximize the potential savings from deferring transmission and distribution investment or from reducing customer outages.[24]

Operational constraints arise because the amount of energy stored in the storage devices is limited and the same device cannot be used to discharge energy and provide operating reserves at the same time. Because discharging is possible only for a limited number of consecutive hours, storage operators must optimize the use of stored energy across different applications. We account for these operational constraints in the following ways:

- **Production cost value.** The production cost simulation schedules storage to charge and discharge in a manner that minimizes system costs of providing energy and ancillary services, given the value of energy and ancillary services during the hours storage is active.

- **Avoided generation capacity value.** In the power system simulations, we have implemented a framework that provides financial incentives which encourage storage to discharge in a manner that aligns with system peak loads, thereby deferring the need to build or procure other supply resources. The financial incentive is commensurate with the value of deferred generating capacity, allowing the storage device to make the optimal tradeoff between capacity, energy, and ancillary services value streams.

- **T&D deferral value.** For storage capacity that is utilized to provide T&D deferral value, we model an additional operational constraint that prioritizes the discharge of storage to reduce local peak load, thereby ensuring that the need to build transmission or distribution assets can be deferred. The simulations allow the storage devices to be used to provide other services, but gives highest priority to local peak load reduction needed for the deferral of the applicable transmission or distribution asset.

- **Customer outage reduction value.** Storage assets deployed on the distribution system (*i.e.*, individual distribution feeders) to reduce customer outages are assumed to have a 50% state of charge (on average) at the time of each distribution-system outage event. This

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[24] We identified the locations of maximum value from transmission and distribution deferrals and separately identified feeders where customers' outage reduction value is the highest. We then ranked T&D deferral and outage reduction locations based on the potential value they provide and chose the highest value locations—assuming that incremental storage would be deployed first in the most valuable locations. We conservatively assumed that storage facilities sited at T&D deferral locations would not be utilized to reduce customer outages and *vice versa*.

realistically captures the ability of storage facilities to mitigate customer outages, considering that the facilities are frequently charged and discharged to capture other value streams. We conservatively assume distribution outage events (even weather-related outages) cannot be predicted ahead of time. This implicitly assumes that the storage facilities are primarily used to capture other value streams, such as energy arbitrage and ancillary services, while addressing infrequent and hard-to-predict outage events only with the state of charge that is available after pursuing the other value streams. The 50% state of charge assumption is based on the average annual state of charge observed in the bSTORE simulations.

C. Nevada Electricity System and Regulatory Assumptions

This study utilizes input data and assumptions from a variety of sources. We simulate the Nevada system using data provided by NV Energy, consistent with NV Energy's current planning outlook and with NV Energy's 2018 Integrated Resource Plan.[25] The relevant data include the status and characteristics of generators located in Nevada, fuel price forecasts, load forecasts, and reserve margin requirements, among other inputs. Our analysis of storage investments' ability to reduce distribution-system outages is based on NV Energy-provided data of historical outages on the company's primary distribution systems assuming that outages occur upstream from the distribution feeders where the storage would be located.[26] The T&D deferral analysis relies on NV Energy data on planned transmission and distribution capital expenditures through 2027.

Since Nevada's electricity system is interconnected with neighboring power systems in the Western Interconnection, we included the rest of WECC in our power system simulations. The rest of the WECC is modeled using the 2026 Transmission Expansion Planning Policy Committee (TEPPC) Common Case.[27] For this study, since the TEPPC dataset provides an outlook for WECC in the year 2026, we adjusted generation, load, and fuel cost assumptions to simulate the Rest of WECC power system in 2020 and 2030. Section III.A provides more details.

Table 2 below summarizes the primary data sources used in this study. Further detail on the data and methods used in the study are reported in Section III and the Appendix.

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[25] NV Energy (2018a).

[26] The primary distribution system refers to the part of the distribution network that interconnects distribution substations to distribution transformers, with typical voltage levels of 4 kV to 35 kV.

[27] We include additional detail added by the CAISO during its 2017 Transmission Planning Process. This data was obtained from CAISO under a non-disclosure agreement.

Table 2
Summary of Data Sources

Data Element	Source(s)
Transmission Topology	2026 TEPPC Common Case (as updated in 2017 CAISO TPP)
NV and WECC Generator List	NV Energy's 2018 IRP, 2026 TEPPC Common Case, SNL
NV and WECC Generator Characteristics	NV Energy's 2018 IRP, 2026 TEPPC Common Case
Fuel Prices	NV Energy's 2018 IRP, 2026 TEPPC Common Case, EIA
NV and WECC Demand	NV Energy's 2018 IRP, 2026 TEPPC Common Case, SNL
NV and WECC Reserve Requirements	NV Energy's 2018 IRP, 2026 TEPPC Common Case
NV and WECC RPS Requirements	NV Energy's 2018 IRP, Database of State Incentives for Renewables & Efficiency (DSIRE)
T&D Deferral Analysis	NV Energy's Transmission and Distribution Capital Expenditure Data
Distribution Reliability Analysis	NV Energy's Distribution Outage Data

D. Storage Technology and Cost Assumptions

This study evaluates the value of electricity storage in the Nevada power system. Although our analysis approach is technology agnostic, we simulate batteries with operational characteristics that resemble lithium ion (Li-Ion) chemistry, as Li-Ion systems are the predominant battery technology being deployed and contracted today. We assume that the battery systems deployed would have a maximum output of 5 to 10 MW and, consistent with likely system needs in Nevada, a MWh:MW ratio of 4:1 (*i.e.*, a four hour discharge capability at full output).[28] We assume the battery storage systems have an 85% round-trip efficiency and a 15-year lifespan.[29]

The installed costs of battery storage systems have decreased considerably in recent years and are projected to decrease further. Figure 7 summarizes cost projections from various analyst reports. Uncertainty in future costs of battery systems is driven by several factors, including the rate at

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[28] We assume four-hour duration systems consistent with the types of storage systems procured in many recently announced solicitations, as well as a common understanding across many recent studies that four-hour systems are typically necessary to provide full resource adequacy value needed to address post-sunset peak loads in the afternoon and early evening hours. These assumptions were developed with input from the PUCN and Pacific Northwest National Laboratory.

[29] Our fixed-cost and cost-levelization assumptions include the costs of replacing worn-out battery cells during the 15-year period. We do not assume degradation over time, consistent with the assumption that worn-out battery cells will be replaced throughout the 15-year period.

which costs continue to decrease, variation in cost across storage chemistry, variations in battery size and application, and methodological differences in estimating costs across various studies.

Given this uncertainty, we assume the high-low ranges of battery costs as shown in Figure 7. Beyond the cost trajectories shown in the chart, our assumed range for costs is informed by a review of recent analyst cost projections for similar battery systems, discussions with developers, and the results of recent competitive storage solicitations.

Figure 7
Installed Cost Projections for 4-hour Lithium-Ion Battery Storage Facilities
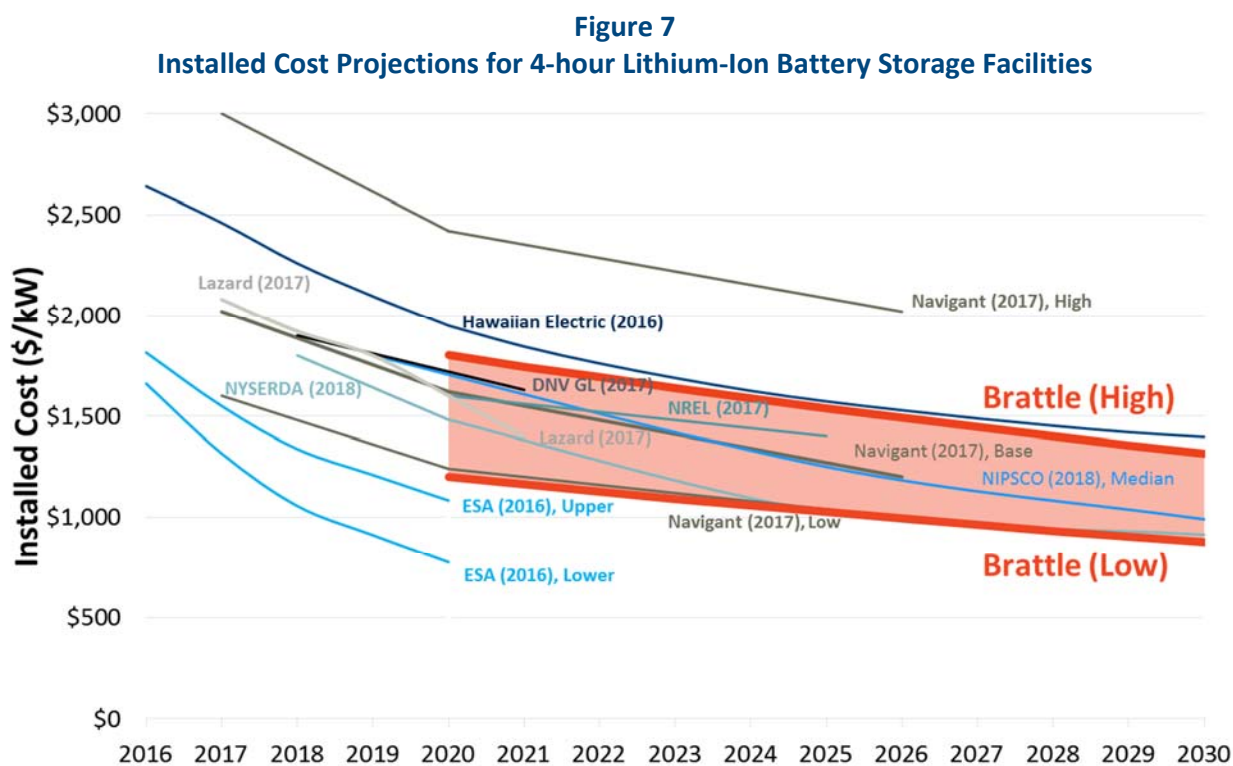
Sources and Notes:
Literature review of Navigant (2017), Hawaiian Electric Companies (2016), NREL (2017), NIPSCO (2018), DNV GL (2017), NYSERDA (2018a), ESA (2016), and Lazard (2017).
Installed cost estimates for a 4-hour storage system. Costs levelized using Table 3 assumptions. All values in nominal dollars.

As shown, we assume that the total installed cost for storage facilities in 2020 will be between $1,200/kW and $1,800/kW ($300/kWh to $450/kWh for facilities with four-hour storage capability). Utilizing the financial assumptions shown in Table 3, this translates to annualized costs of $136/kW-year to $204/kW-year.[30] The lower end of these costs is informed by discussions with storage developers and is consistent with the low-end of analyst projections. The low-end $136/kW-year annualized cost (based on the $1,200/kW low-end installed cost assumption) is

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[30]   We tested the sensitivity of our results to after-tax weighted average cost of capital (ATWACC) and fixed O&M. With 6% ATWACC, we see the range drop to $127–$191/kW-year. With 8%, the range rises to $145–$217/kW-year. With a 2% FOM assumption, we find an annualized cost range of $148–$222/kW-year.

consistent with costs observed in recent competitive solicitations for stand-alone storage. For example, a recent solicitation by Xcel Energy received median bid prices of $136/kW-year for stand-alone storage installations.[31] Another solicitation conducted by Northern Indiana Public Service Company (NIPSCO) reported an average bid price of $135/kW-year. [32] Both solicitations were for systems with 2023 contract delivery dates and reflect the average and median bids received (but not the most competitive or winning bids).

The upper end of our cost estimate is based on the higher end of analyst projections for installed costs in 2020, reflecting the uncertainty we see in current cost projections.

Table 3
Financial Assumptions for Storage Cost Model

Financial Assumption		Value
Fixed O&M	*% of Installed*	1%
Developer After-Tax WACC	*%*	7%
Battery Asset Life	*yrs*	15
Balance of Plant Asset Life	*yrs*	15
Total Income Tax Rate	*%*	21%
Depreciation Schedule		15-yr MACRS
Annual Inflation Rate	*%*	2%

Note:
  Cost and financing assumptions indicative of new development costs in Nevada.

For 2030, we assume installed costs of $876/kW to $1,314/kW (or $219/kWh to $328/kWh for installations with four-hour storage capability). This translates to annualized costs ranging from $99/kW-year to $149/kW-year under the financing assumptions in Table 3. These 2030 estimates assume that costs would decline from their 2020 levels of $1,200/kW to $1,800/kW at a rate of 5% annually in real terms, approximately equivalent to 3% per year in nominal terms. A 3% annualized rate of cost decrease is consistent with projected cost reduction in the majority of studies we have reviewed. Our installed cost and resulting annualized cost assumptions are summarized in Table 4 below.[33]

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[31] Xcel (2017).

[32] NIPSCO (2018).

[33] Cost estimates are stated in nominal dollars.

Table 4
Levelized and Installed Cost Assumptions

	Assumed Installed Costs		Implied Levelized Costs
	$/kW Installed	*$/kWh Installed*	*$/kW-year*
Assumed Costs			
2020 Low	$1,200	$300	$136
2020 High	$1,800	$450	$204
2030 Low	$876	$219	$99
2030 High	$1,314	$328	$149

Notes:
   All values in nominal dollars.

E.   Cost-Effectiveness Framework

The objective of this study is to determine if future energy storage deployments in Nevada could be in the public interest. Consistent with this objective, the GOE and PUCN have specified that the Ratepayer Impact Measure (RIM) test should be used to evaluate the cost-effectiveness of energy storage. The RIM test provides an indication of how average retail rates will change as the result of a new utility initiative.[34] If rates decrease, the initiative passes the RIM test, and vice versa.[35]

On the benefits side of the cost-effectiveness equation, the RIM test includes all reductions in resource costs (*e.g.*, reductions in fuel and capacity costs), as well as the cost savings associated with other services that are procured more cheaply than they otherwise would be (*e.g.*, ancillary services, monetized reductions in carbon emissions). Additionally, we have included the ratepayer value of avoided distribution system outages as a benefit in our interpretation of the RIM test for the purpose of this study, as it reflects a benefit that directly accrues to the ratepayers who experience fewer outages.   We understand the PUCN is required to determine if a storage procurement target is in the public interest. We include customer reliability benefits as consistent with that mandate, even though reliability benefits are not part of the technical definition of the RIM test. Quantified in this study but not included as ratepayer benefits are the societal-cost impacts associated with WECC-wide changes in carbon and other emissions.

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[34]   For example, see CPUC (2001).

[35]   It should be noted that the RIM test is not an actual representation of the year-over-year rate changes that will result from introducing the new utility program. Rate changes are influenced by a variety of external factors, such as the time between rate cases and allowed rates of return. The RIM test only approximates this impact by comparing changes in utility revenues to changes in utility costs.

Costs included in the RIM test are those incurred by the utility (or other administering party) when paying for the storage deployments.[36] To the extent that other parties are incurring the up-front investment costs, we assume that these costs will ultimately be passed on to ratepayers. If third parties were to bear some of the investment risks and do not recover *all* of the storage costs from ratepayers, the net value to ratepayers would be greater than the amount we are estimating in this report. In the context of this study, we account for the all-in cost of energy storage deployments, as described in more detail above, including the wholesale energy cost of charging the storage facilities.

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[36] The application of the RIM test to energy efficiency programs (its original intent) includes lost utility revenue due to reduced sales as a cost, since rates would need to be increased to make up for the lost revenue. However, under the methodological framework of this study, deployment of energy storage would not decrease utility sales, so lost revenues are not a factor in the cost-effectiveness analysis.

III. Evaluation of Key Storage Value Drivers

We quantify the value created by energy storage investments for the following key value drivers: reduction in production cost, avoided need for additional generation capacity, deferred transmission and distribution investments, and customer outage reductions associated with reliability improvements on the distribution system. We evaluate and report separately the potential benefits of emissions reductions from reduced renewable curtailments and changes in generation dispatch. We use the bSTORE model to simulate how this value changes as more storage is added to the Nevada power system in 2020 and 2030. We then identify the level of storage that maximizes total Nevada ratepayer value, defined as the point at which the incremental benefit of additional storage has fallen to be equal to the cost of adding the storage facilities.

A. Reduction in Production Costs

Energy storage can reduce the costs associated with providing the energy and ancillary services needed to serve Nevada loads. Such savings are traditionally known as "production cost savings" because power generators traditionally have provided these services and any reduction in the costs of producing these services are savings to utility costs as a whole. Reducing production costs means that less fuel and variable operating costs are incurred to supply state-wide loads and power system needs. The reduction in production costs, in turn, reduces the costs to electricity users (customers) on the system. Storage can help reduce a system's production cost by charging with low-cost energy and discharging to replace high-cost generation of energy.

To estimate the production costs associated with Nevada's energy and ancillary service needs, we use the security-constrained economic dispatch (SCED) module of bSTORE. We have used a standard nodal model to simulate Nevada's and the rest of WECC's power system. The system representation and the associated assumptions are based on the 2026 TEPPC Common Case with refinements by the CAISO and based on publicly available data. We made further refinements to the representation of the Nevada power system to be consistent with NV Energy's 2018 IRP. Details of these modeling assumptions are included in the Appendix.

We simulate the Nevada system for three cases for 2020 and 2030: (1) a "Base Case" that represents Nevada's resource mix consistent with NV Energy's 2018 IRP; a (2) "200 MW Case" that adds 200 MW of batteries in Nevada; and (3) a "1,000 MW Case" that adds 1,000 MW of batteries in Nevada. The "Base Case" is consistent with the "Preferred Plan" identified in NV Energy's 2018 Integrated Resource Plan.[37] We then calculate the difference between the Base Case and the two storage cases (200 MW and 1,000 MW) to derive the production cost savings associated with the added storage. To quantify the benefits to Nevada, "adjusted production costs" are calculated based on the formula in Figure 8. In this calculation, for each of the cases, we estimate the costs associated with

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[37] NV Energy (2018a).

operating power plants (and contracted resources) in Nevada, add to it the cost of wholesale power purchased to meet the needs of Nevada, and subtract from it the revenues received from selling power in wholesale markets to suppliers of loads outside of Nevada. We estimate the adjusted production cost for each of the simulated cases and estimate the difference to determine the production cost savings to Nevada.

Figure 8
Calculating Nevada Adjusted Production Costs

Nevada Adjusted Production Costs =   Production Costs
                                          + Cost of Purchases
                                          – Revenue from Sales

Production Costs = Cost of Nevada owned generation
- Generation costs include fuel, emissions, variable operating, and startup costs

Cost of Purchases = Deficit in generation × Price Hub
- Purchases priced at the Malin and Mead hubs for Northern and Southern Nevada, respectively.

Revenues from Sales = Surplus in generation × Price Hub
- Sales priced at the Malin and Mead hubs for Northern and Southern Nevada, respectively.

Adjusted production cost savings for 2020 are estimated at $4.5 million in the 200 MW Case compared to the Base Case. As shown in Table 5, 200 MW of storage reduces the cost of the annual internal generation costs by $1.1 million, reduces the cost of wholesale power purchases by $3.1 million, and increases export revenues by $0.4 million. This is a result of storage reducing peak prices in Nevada by charging during low-cost hours and discharging when supply-demand conditions are tighter. By discharging during high-priced hours, storage is able to export to neighboring areas when the prices in export markets are high, shown by the increase in Nevada-wide revenues from the utilities' off-system sales.

For 1,000 MW of storage investments, 2020 annual savings increase to $16.5 million (compared to the 2020 Base Case). These annual savings in the 1,000 MW Case are primarily due to a $7.9 million decrease in market purchases (import costs) and a $10.8 million increase in market sales (export revenues), offset by $2.2 million of increased internal generation costs. The reduction in power purchase (import) costs is largely due to fewer imports during high-cost hours. Storage increases internal generation costs, likely because more generation is needed to charge the storage facilities, some of which is then exported. As shown, the higher Nevada-wide generation costs are more than offset by the increased export revenues—in part due to the ability to export the stored energy when prices in the export markets are at their highest.

Table 5
2020 Adjusted Production Cost Savings
(in nominal $million/year)

	Production Cost			Savings (Storage Case minus Base Case)	
	Base	200 MW	1,000 MW	200 MW	1,000 MW
Production Cost	$421	$420	$423	($1.1)	$2.2
Cost of Market Purchases	$132	$129	$124	($3.1)	($7.9)
Revenues from Sales	($46)	($46)	($57)	($0.4)	($10.8)
Total	**$507**	**$502**	**$490**	**($4.5)**	**($16.5)**

Notes:
All values in nominal dollars. Change in cost for each row item may not align due to rounding in the table.

The 2030 simulations show that storage offers even greater adjusted production cost savings. Adjusted production costs decrease by $9.3 million per year in the 200 MW Case compared to the 2030 Base Case, as shown in Table 6 below. These savings are primarily due to a decrease in the cost of internal generation, which occurs because Nevada is able to import greater amounts of low-cost energy during low-priced hours to charge the storage facilities, which reduces the cost of local generation during high-priced hours when the energy is dispatched from storage. In addition, the added storage provides Nevada with the ability to export more when the prices are high in export markets, as shown by the increase in sales revenues.

Table 6
2030 Adjusted Production Cost Savings
(in nominal $million/year)

	Production Cost			Savings (Storage Case minus Base Case)	
	Base	200 MW	1,000 MW	200 MW	1,000 MW
Production Cost	$701	$690	$693	($10.1)	($7.7)
Cost of Market Purchases	$568	$572	$559	$4.0	($9.8)
Revenues from Sales	($82)	($86)	($105)	($3.2)	($23.1)
Total	**$1,186**	**$1,177**	**$1,146**	**($9.3)**	**($40.6)**

Notes:
All values in nominal dollars. Change in cost for each row item may not align due to rounding in the table.

For the 1,000 MW Case, 2030 adjusted production cost savings increase to $40.6 million per year compared to the 2030 Base Case. Savings occur largely due to a $7.7 million decrease in the cost of internal generation and a $23.1 million increase in revenues from sales to neighboring markets.

Similar to the 200 MW cases, the ability of Nevada to export more to neighboring areas during high-priced periods increases Nevada revenues from export sales. The decreased cost of internal generation is due to storage charging during low-priced hours when solar and wind generation would otherwise need to be curtailed, and discharging that energy during hours with tighter supply-demand conditions. The quantity of imports increases but the average price of imports decreases, due to change in Nevada's ability to import more power when prices are low at the border. Those low-priced hours coincide with periods of excess solar and wind generation in the neighboring markets, particularly California. The energy imported and stored can later displace more expensive internal generation during peak-load hours. These two factors lead to a substantial decrease in the cost of internal generation.

Storage yields greater adjusted production cost savings in 2030 than in 2020 due to several factors. First, the higher gas prices (even in real terms) assumed in the 2030 simulations generally increase the costs of meeting Nevada load. The higher gas prices also increases the value of the storage's ability to discharge during hours when gas-fired peakers would otherwise be dispatched. Second, storage reduces renewable curtailments in 2030 when more renewable generation is expected to be deployed not only in Nevada, but also in California and elsewhere across the WECC. The increase in renewable generation between 2020 and 2030 also causes higher levels of renewable energy curtailment in 2030. Third, storage provides more ancillary services to Nevada in 2030 than in 2020 and these services are more valuable in 2030, consistent with Nevada's increased ancillary service needs.

Figure 9 shows the incremental value of adding storage in terms of Nevada's production costs. As explained further in the Appendix A to this report, our three discrete cases (0 MW, 200 MW, and 1,000 MW of storage) allow us to estimate incremental adjusted production cost savings as a function of storage deployed.[38] Incremental adjusted production cost savings fall as more storage is added and highest-value opportunities saturate. In 2020, the incremental adjusted production cost savings are $21/kW-year for 200 MW of storage and $9/kW-year for 1,000 MW of storage. For 2030, the incremental adjusted production cost savings are $45/kW-year for 200 MW and $33/kW-year for 1,000 MW of storage deployed in Nevada.

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[38] From our model runs, we use the storage deployments (0, 200, and 1,000 MW) and corresponding results to estimate a non-linear quadratic relationship between total adjusted production cost and the amount of storage deployed. The slope of this relationship yields an estimate for the marginal value of adjusted production cost savings as a function of storage deployed at each level of storage deployment. See Appendix for further details.

Figure 9
Estimated Incremental Benefit from Adjusted Production Cost Savings ($/kW-year)
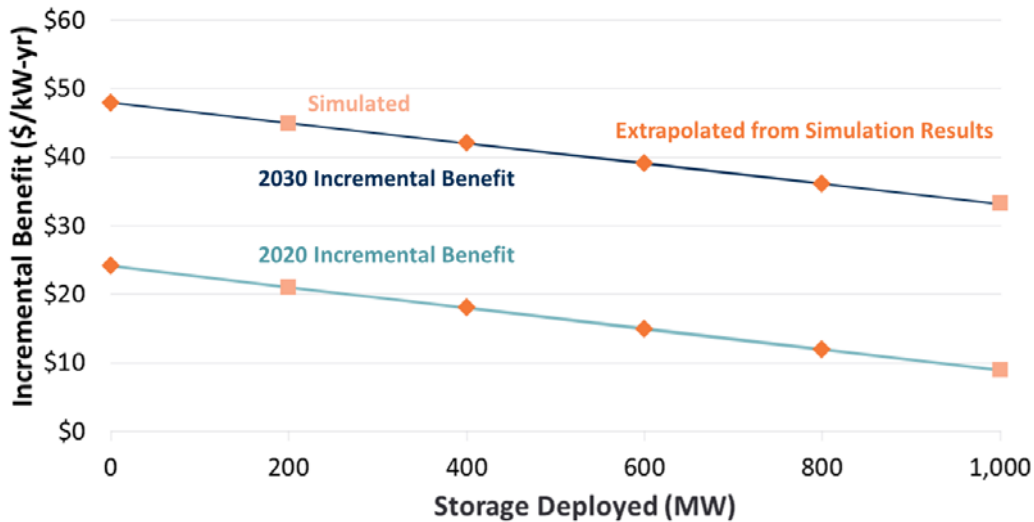
Sources and Notes:
  All values in nominal dollars.
  The total APC savings from model runs with deployments of 200 MW and 1,000 MW were used to estimate a relationship
    between storage deployed and total savings, from which we can estimate the relationship between storage deployed
    and incremental APC savings.

As part of reducing the production costs associated with serving load in Nevada, storage can provide ancillary services needed to balance the Nevada system. These services include regulation up, regulation down, spinning reserves, and frequency response. The simulation of these products requires that the model sets aside parts of the generation resources in "standby" mode, ready to provide more or less energy within a short timeframe (typically between 5 and 30 minutes) as allowed by the specified ramping rates. We assume that the market can optimize the use of resources to meet the system's energy and ancillary services needs. For 2020, the simulations show that storage provides on average 52 MW of ancillary services in the 200 MW Case and 123 MW in the 1,000 MW Case. NV Energy anticipates higher ancillary service requirements in 2030 to balance the system with greater generation from solar PV. The 2030 simulations show that storage on average provides 130 MW of the needed ancillary services in the 200 MW Case and on average 230 MW in the 1,000 MW Case. These results are summarized in Table 7 below.

The fact that storage can more cost-effectively provide ancillary services for a portion of the hours shows that, at times, storage can reduce the need to keep conventional generation online to provide the necessary ancillary services. The simulations will utilize storage to provide ancillary services whenever it is lower cost to do so than to provide the ancillary services from conventional generation. This can be the case when energy prices are relatively low and it would not be cost-effective to discharge energy from storage. Further, as experience in PJM shows, some storage technologies offer unique advantages to provide fast-responding regulation services.[39]

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[39]   Monitoring Analytics (2017), Volume 10 p. 470.

Table 7
Average Ancillary Services Provided by Storage (MW)

	2020		2030	
	200 MW	1,000 MW	200 MW	1,000 MW
Reg Up	11	21	30	45
Reg Down	5	46	12	54
Spin	11	22	24	35
Freq Reserve	24	35	65	96

Typically, energy losses caused by electricity traveling through the transmission and distribution grids increase as line loading increases. Thus, if storage were located close to load, charging storage during low-load periods when line losses are low and discharging to serve load during high-load periods when line losses are high, storage can reduce overall line losses. However, because storage devices require approximately 15% more energy during the charging cycle than they can discharge, total energy losses may actually increase because of it.

Our analysis of production cost savings does not account for the possibility of reductions in average line losses. However, other studies have found that reductions in line losses are small relative to other storage-related value streams.[40] We therefore have not included impacts on line losses in the overall results presented in this report.

Overall, we do not find storage induces a major change in the fuels used to serve Nevada load, and thus any fuel diversity benefits are likely limited.

B. Avoided Generation Capacity

Storage capacity can be used to address resource adequacy requirements. To do so, storage would need to help meet peak load (or net peak load when renewable generation shifts peak system needs). We evaluate the potential for storage to discharge during peak hours when the risk of a loss of load event is greatest, thereby reducing the need to procure or build other capacity resources. We estimate by how much 1 MW of storage is dispatched during net peak load events to estimate the equivalent MW of generating capacity. The value of addressing NV Energy's forecasted capacity needs is the capacity price assumed in NV Energy's 2018 Confidential IRP.[41]

We have internalized resource adequacy in the market-wide simulations of the storage operations by first identifying a subset of "peak days" during which the system operator would likely need to

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[40] For example, EPRI finds the value of storage in terms of reduced distribution line losses is less than 1% of total storage value, see EPRI (2010), p. xvi.

[41] NV Energy (2018a).

discharge the battery in a manner that reduces system net peak and thus provides capacity value. For these days, our production cost simulation provides an additional incentive for storage to discharge in a manner that reduces the daily net peak, realistically capturing the trade-off between using storage for the purpose of reducing overall production costs versus providing generation capacity value.

In both 2020 and 2030, 200 MW of energy storage is dispatched at an average of 179 MW (representing a 90% capacity value) during net peak load hours; and 1,000 MW of storage is dispatched at an average of 864 MW (86% capacity value) during net peak load hours. These results are summarized in Table 8. We multiply these capacity values of storage by NV Energy's forecasted capacity costs to quantify avoided capacity cost savings.[42]

Table 8
2020 and 2030 Net Peak Reduction for 200 MW and 1,000 MW of Storage

	MW	%
200 MW	179	90%
1,000 MW	864	86%

In our analysis, not every MW of storage deployed receives a full MW of capacity credit in estimating the resource adequacy value of the storage. There are two reasons for this. First, some storage systems are constrained in their operations such that they need to discharge during different periods to serve local load and avoid additional transmission or distribution investments. These storage resources have a higher-priority purpose of deferring incremental transmission or distribution investments and consequently need to follow a rigid discharging pattern during local peak load hours (see Section III.C). Such a requirement can limit the storage's ability to discharge during the system net peak hours if local peak load hours differ from system net peak hours. Second, as more storage is added to the system, it will tend to flatten load shapes during peak hours, requiring incremental storage to discharge over more consecutive hours to reduce peak load, as shown in Figure 10. At the 200 MW and 1,000 MW levels of storage evaluated we find the peak flattening effect is limited, although we anticipate peak flattening would become more pronounced at higher storage deployment levels.

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[42] Given the nearly constant capacity values across the 200 MW and 1,000 MW storage Cases, we assume incremental capacity values equal average capacity values. At levels of storage above 1,000 MW capacity values could decline as the "peak flattening" effect becomes more pronounced.

Figure 10
Nevada Net Load Peak Day Reduction (July 27, 2020)
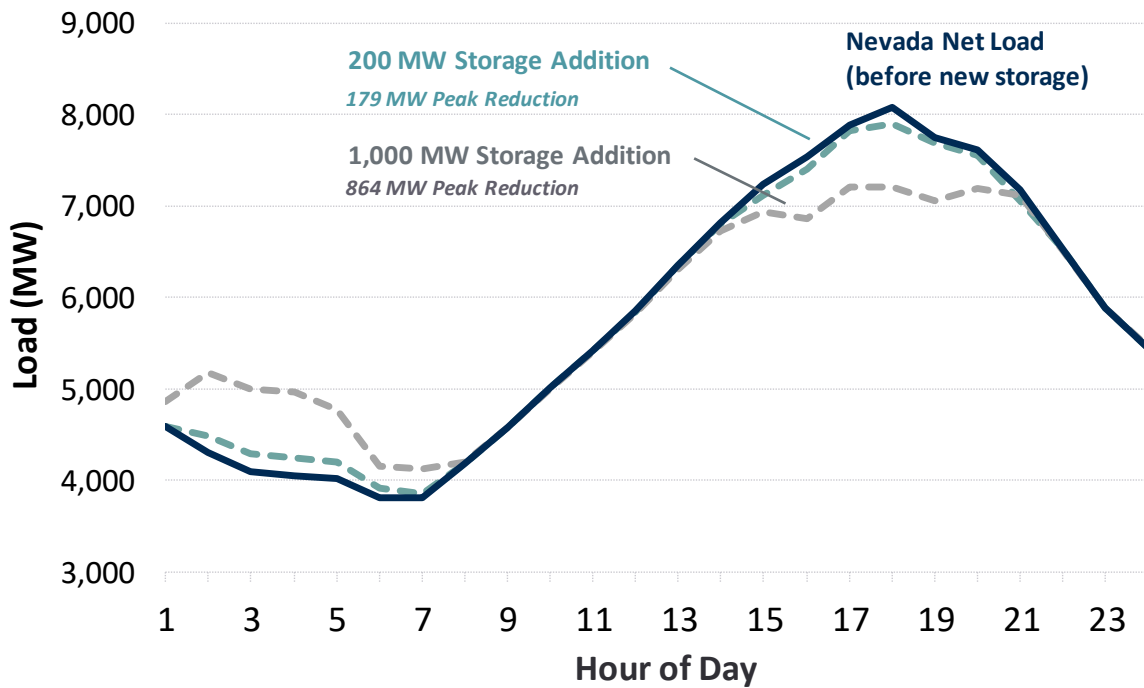
C. Transmission and Distribution Investment Deferral

Another potential benefit of grid-integrated storage is the ability to defer transmission and distribution investments. Storage is not suited to defer all types of T&D investments. Many T&D upgrades must meet technical requirements that storage cannot provide, such as adding new circuit breakers, telemetry upgrades, adding new transmission or distribution lines to connect new customers. However, in many cases, system upgrades are needed to meet anticipated gradual load growth in a local area. At times, system planners must over-size transmission or distribution investments relative to the immediate needs to meet local load to allow for future load growth or utilize equipment (such as transformers) that only comes in certain standard sizes. To the extent that storage can be used to meet local peak loads, the loading on the transmission and distribution system is reduced, which means otherwise necessary T&D upgrades may be deferred. Such deferrals are especially valuable if load growth is relatively slow and predictable such that the upgraded system would not be fully utilized for many years.

Whether storage can defer specific transmission or distribution projects would need to be evaluated on a case-by-case basis. To conduct this analysis, we thus need to make some assumptions about the likely types of transmission or distribution projects that *may* be deferred through investment in storage. We begin our analysis of T&D deferral value by analyzing NV Energy's 2018 transmission and distribution capital expenditure outlook. As explained in greater detail in Section II.B and the Appendix, using that set of transmission and distribution capital project as a baseline, we identify projects that could likely be deferred by investments in

storage. We assume that the period of investment deferral is limited to 15 years, the assumed lifespan of storage devices. Further, when such storage projects are deployed, we assume that the storage's operation would be prioritized to reduce local peak loads above all other potential applications.

Table 9 below illustrates our overall approach to estimating the value of potential T&D cost deferrals. We apply this approach for each deferral opportunity identified in the NV Energy T&D capital expenditure outlook and evaluate the annualized deferral savings on a $/kW-year basis. We then rank such potential opportunities from highest to lowest value, as shown in Figure 11.

Table 9
Examples of T&D Cost Deferral by Customer Class

			Customer Class	
			Residential	C&I
Starting Peak Load	[1]	(MW)	10	10
Peak Load Growth Rate	[2]	(%)	2%	2%
Total Peak Load in 15 years	[3]	(MW)	13.5	13.5
Required Battery Size / Growth	[4]	(%)	166%	253%
Battery Size to Defer 15 years	[5]	(MW)	5.7	8.7
Substation Upgrade Cost	[6]	($ million)	$3	$3
Cost Avoided by 15-yr Deferral	[7]	(%)	67%	67%
Deferral Savings	[8]	($/kW)	$349	$229
Annual Charge Rate Assumption	[9]	(%)	10%	10%
Estimated Value of Deferral	**[10]**	**($/kW-yr)**	**$36**	**$23**

Sources and Notes:
  Table reflects data and calculations for Nevada Power Company customer classes.
   [1] and [6]: Example assumptions roughly consistent with substation in NPC.
   [2]: Peak load growth assumption uniform for all NV Energy feeders.
   [3]: $[1] \times (1 + [2])^{15}$
   [4]: Calculated using load shapes derived from NV Energy load data. Equal to 123% for SPPC Residential and 175% for SPPC C&I.
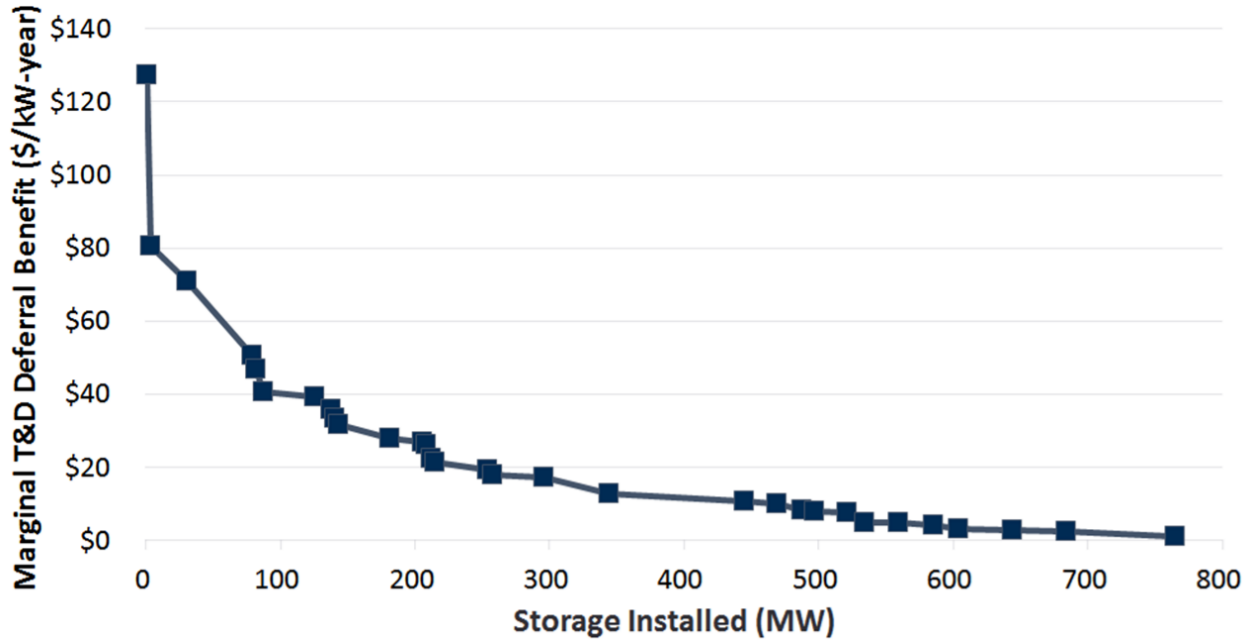   [5]: $[4] \times ([3] - [1])$
   [7]: NPV of 15-year investment deferral, consistent with NVE financing cost rates.
   [8]: $([6] \times [7])/(1,000 \times [5])$. Savings in $/kW of storage installed.
   [9]: Payment on a level-real annualization of [8], levelized over a 30-year investment life.
   [10]: $[8] \times [9]$ Savings in $/kW-year of storage installed.

Figure 11
Marginal T&D Deferral Benefit of Storage for Individual T&D Projects ($/kW-year)

As shown in Figure 11, we were able to identify a small number of high-value opportunities to defer specific T&D investments. These highest-value opportunities (in terms of $/kW of storage investment) represent costly transmission or distribution upgrades that could be deferred by relatively small amounts of storage. We estimate that when approximately 100 MW of storage are deployed to meet these T&D needs, the incremental T&D deferral value per kW of storage deployed would drop to below $40/kW-year. In total, we find that 800 MW of storage could likely saturate the available T&D deferral opportunities, with approximately half of that quantity providing a T&D deferral value of $10/kW-year or less.

Again, detailed project-specific analysis would need to be conducted before replacing T&D upgrades with storage. Our analysis does not account for each individual transmission or distribution project's idiosyncratic features. Further, most transmission projects can provide multiple values simultaneously. Thus, even if the local load-serving need for a transmission upgrade could be deferred by storage investments, it does not necessarily mean that the transmission upgrade would not be worth making considering other potential purposes or benefits of the transmission investment. Given the site-specific nature of these potential additional benefits of transmission and distribution, we exclude them from our analysis.

Another potential value of storage is its ability to provide local voltage support by injecting either real or reactive power. Voltage drops on distribution lines can occur during peak load hours when the T&D system is heavily loaded. Storage can provide local voltage support if deployed at the

specific locations that require voltage support. NV Energy's capital expenditure plan identifies several planned capacitor banks to provide such voltage support. However, we find the value of deploying storage to defer these capacity investments is small relative to other benefits evaluated in this study.[43] This finding is consistent with other studies, which have found the value of voltage support to be small relative to other value streams.[44] While system-wide benefits are very limited, we acknowledge that voltage support applications for storage can nevertheless be valuable in specific locations.

D. Customer Outage Reduction Value

Grid-integrated storage can improve the reliability of electricity delivery to end-use customers. For example, storage can be used to stabilize the transmission grid and mitigate wide-spread outages or controlled load shedding. Storage can also provide backup power at particular distribution feeders to reduce outages on the distribution system. We evaluate the reliability value to customers of deploying storage on specific Nevada distribution feeders that historically experienced relatively high levels of outages. When integrated with automated distribution feeder controls (as discussed further in the Appendix), the storage facilities would be able to reduce customer outages on these feeders.

Our analysis is based on historical data provided by NV Energy detailing approximately 43,000 distribution-level outages that occurred across the SPPC and NPC territories between January 2014 and April 2018. We use this data to identify the feeders that have historically demonstrated the lowest level of reliability, and estimate the cost of lost load that storage assets deployed at these low-reliability distribution feeders could have avoided. We then assume storage will be deployed at the least reliable feeders, using the two-step process illustrated in Figure 12 and discussed further in the Appendix.
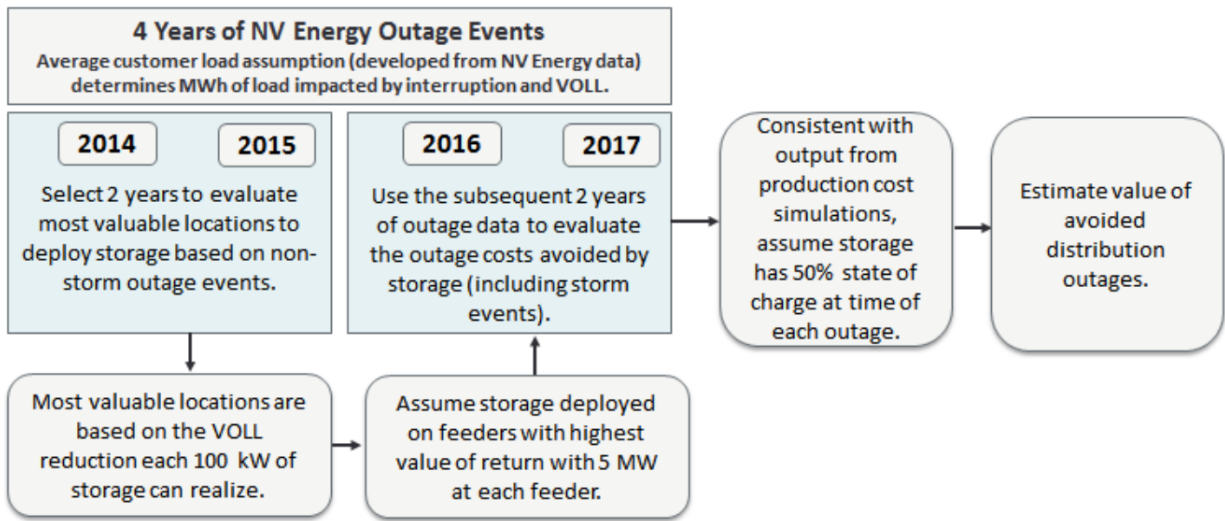
To measure the ability of storage to reduce distribution outages, we account for both the duration (hours) and magnitude (MWh) of each historical outage event. The ability of storage facilities to reduce the severity of customer outages is bounded by both the battery's maximum output (MW) and the battery's state of charge (MWh) at the time of the outage event.

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[43] For example, a typical 24 MVA capacitor bank has a cost of approximately $1 million. Using storage to provide the same service would provide an avoided investment value of $1,000,000 for 24 MVA of storage, approximately $40/kW storage installed or $4/kW-year annualized value. This is small relative to the $20–130/kW-year and higher T&D deferral values identified for 200 MW of storage applications as shown in Figure 11 above.

Moreover, NV Energy's T&D capital expenditure plan identifies only a need for approximately 250 MVAR of capacitor banks, which shows that voltage support is limited both in terms of total quantity and the $/kW value of these applications.

[44] EPRI finds the net present value of distributed storage providing voltage support to be on the order of $9–24/kWh or storage installed, less than one percent of total storage value. See EPRI (2010).

4 Years of NV Energy Outage Events
Average customer load assumption (developed from NV Energy data) determines MWh of load impacted by interruption and VOLL.

2014	2015

Select 2 years to evaluate most valuable locations to deploy storage based on non-storm outage events.

2016	2017

Use the subsequent 2 years of outage data to evaluate the outage costs avoided by storage (including storm events).

Consistent with output from production cost simulations, assume storage has 50% state of charge at time of each outage.

Estimate value of avoided distribution outages.

Most valuable locations are based on the VOLL reduction each 100 kW of storage can realize.

Assume storage deployed on feeders with highest value of return with 5 MW at each feeder.

We approximate the customer value of reliability improvements created by storage by multiplying the MWh of reduced customer outages by the estimated value of lost load (VOLL). VOLL measures of how different customer types value uninterrupted access to electricity. For the purpose of this analysis, we apply an average VOLL for commercial and industrial customers of $20,000/MWh and an average VOLL for residential customers of $3,000/MWh, consistent with a comprehensive survey of VOLL studies.[45] These VOLL values, used in tandem with data on NV Energy's electricity sales by customer class, yields an estimated average VOLL of $12,500/MWh across all Nevada electricity customers.

Figure 13 below shows our estimate for the incremental benefit of deploying storage to avoid distribution outages. Because a small fraction of distribution feeders on NV Energy's system make up a fairly large portion of all outages, the incremental reliability value of adding storage declines as the opportunities to deploy storage at the highest-value locations are exhausted. For example, once 300 MW are deployed, the incremental outage reduction value of adding more storage is only $50/kW-year, approximately half the value of the first MW of storage added to the system.

As described above, our analytical approach of assuming storage deployment at specific distribution feeders accounts for uncertainty in the future level of outages at that feeder. By using a 2-year subset of the historical reliability data to simulate deployment decisions, we may add some storage at feeders that are more or less reliable in the following 2 years. The dotted line in Figure 13 shows that the incremental benefit from avoided distribution outages is somewhat "noisy" due to this uncertainty, which we smooth using the fitted trendline.

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[45]   Sullivan *et al.* (2009).

Figure 13
Incremental Reliability Benefit of Storage ($/kW-year)
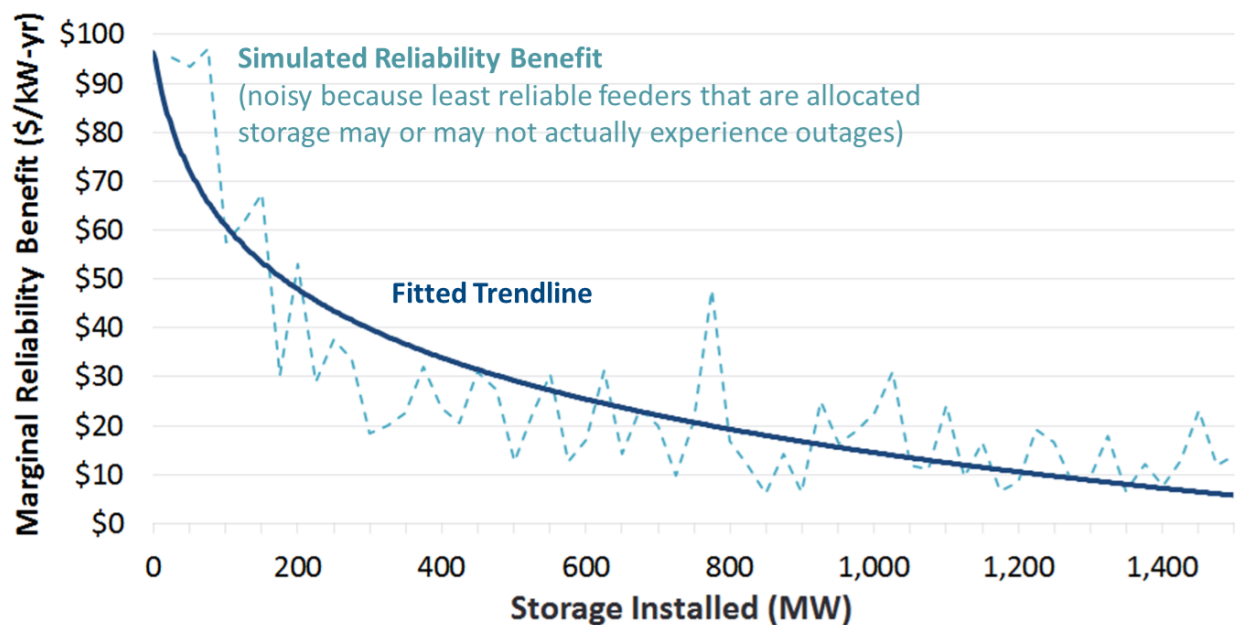
Note:
  All values in nominal dollars.

We understand NV Energy is currently pursuing grid modernization efforts, including automated distribution switching and remote switching.[46] To the extent these grid modernization efforts are ongoing, we anticipate that the integration of batteries would not require any additional network upgrade costs. However, to account for the uncertainty around these costs and the possibility that such upgrades may be cost prohibitive at some feeders, we separately evaluate in Section IV a scenario in which storage provides does not provide any customer outage reduction value.

E.   Renewable Integration and Emissions Benefits

Impact on Nevada Renewable Generation Curtailments

Storage is one of many tools to support the integration of large amounts of renewable generation. Storage can reduce renewable generation curtailments by charging in hours in which wind or solar output would otherwise have to be curtailed due to system-wide over-generation or local transmission constraints. Similarly, storage can provide flexibility that allows operators to more effectively balance the system to address variable-generation-related operational challenges that are associated with high levels of renewable generation.

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[46]   NV Energy (2016).

We assess the value of storage to support renewable integration by evaluating how solar curtailments in Nevada change due to the addition of storage.[47] We determine projected curtailments in each of our three deployment cases for 2020 and 2030 to compare how they change across storage levels relative to the Base Case. Curtailments are calculated as the difference between the maximum available outputs of solar and wind units and their actual output as determined in the power system simulations.[48]

Nevada solar generators experience minimal curtailments in 2020 with or without storage, due to the still limited quantities of renewable generation on the Nevada system. Curtailments of Nevada renewable generation increase by 2030 due to increased solar development to meet the state's RPS target in concert with increased solar development in neighboring states and across the entire WECC. Nevada renewable generation curtailments are 57 GWh in the 2030 Base Case (without storage). Adding 200 MW of storage reduces 2030 curtailments by 5% to 54 GWh while adding 1,000 MW of storage reduces curtailments by over 50% to 28 GWh. Table 10 summarizes these findings. The generation-related production cost savings due to reduced curtailments of Nevada's renewable resources are captured as part of the production cost estimates previously presented in Section III.A. As discussed further below, the regional market benefits of installing storage facilities in Nevada also reduces some renewable curtailments in neighboring balancing areas, which further reduces WECC-wide emissions and additionally benefits Nevada in the form of higher low-cost imports as discussed previously in the context of production cost savings.[49]

Table 10
2030 Reduction in Nevada Renewable Generation Curtailments

| | GWh | | | [Change] - [Base] | |
	Base	200 MW	1,000 MW	200 MW	1,000 MW
Nevada					
Total Solar Generation	6,630	6,633	6,659	3	29
Solar Curtailment	57	54	28	-3	-29
Percent Change in Curtailment				-5%	-51%

Note:
  Our power system simulations find no Nevada wind curtailments in 2030 and there are no Nevada wind or solar curtailments in 2020.

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[47] There is little wind capacity in Nevada and thus no wind curtailments in Nevada, so we focus on solar for this section.

[48] Maximum available output of a wind or solar plant is calculated by taking the hourly profiles provided in the TEPPC Common Case and multiplying it by the installed capacity of the plant.

[49] Reductions in renewable generation curtailments reduce the amount of solar generation needed to produce the same amount of clean energy to meet state RPS requirements. We do not account for savings associated with reduced investment costs.

Impact on WECC-Wide Emissions

The ability of storage to reduce region-wide carbon emissions depends on a variety of factors, including the regional power system's generation mix and resource diversity, relative fuel prices, carbon prices, and transmission interconnections. Storage can reduce regional emissions by reducing curtailment of renewable resources or by reducing the need to run less efficient peaking generation units. However, under some circumstances, adding storage can increase emissions by increasing generation from low-cost high-emitting generators during charging periods. Overall, storage increases total system-wide generation of electricity because approximately 15% of energy is lost during the charge and discharge cycle of storage devices. Thus, unless clean or cleaner energy is used to charge the storage, and charged energy is used to displace higher emitting resources' generation, the emissions reduction associated with storage may be minimal.

For each 2020 and 2030 simulation case we determine the total emissions in the WECC by summing the annual emissions from every generator in the region. To isolate the impact of storage on emissions we take the difference in emissions between the storage cases (with 200 MW and 1,000 MW of additional storage) and the Base Case (without additional storage).

This analysis shows that WECC-wide CO_2 emissions decrease in our 2020 storage cases compared to the 2020 Base Case. As shown in Table 11, the 2020 CO_2 emissions decrease by 47,000 tons in the 200 MW Case and by 132,000 tons in the 1,000 MW Case. This emissions reduction is primarily due to the more abundant use of gas combined-cycle (CC) generation during the charging cycle and displacing a portion of the gas peaker and coal generation during evening ramp hours in both of the 200 MW and 1,000 MW storage cases. The 2020 WECC-wide NO_x and SO_2 emissions increase slightly. Similar to the 2020 results, the deployment of storage is projected to decrease 2030 WECC-wide CO_2 emissions, by 63,000 tons in the 200 MW Case and 235,000 tons in the 1,000 MW Case.

Table 11
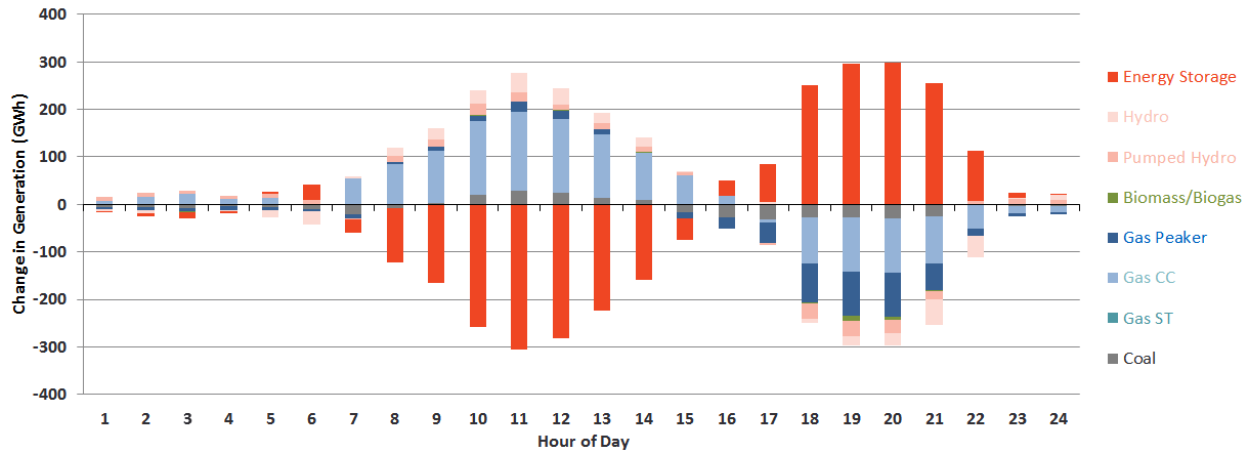**Impact of Nevada Storage on WECC-Wide Emissions in 2020 and 2030**

	Change in Emissions (tons)		Change in Emissions (%)	
	200 MW	1,000 MW	200 MW	1,000 MW
2020 Cases				
CO2	-46,974	-131,998	-0.02%	-0.06%
NOX	135	117	0.06%	0.05%
SO2	161	351	0.12%	0.26%
2030 Cases				
CO2	-63,162	-234,955	-0.03%	-0.10%
NOX	-79	-455	-0.03%	-0.17%
SO2	8	-480	0.00%	-0.26%

To help explain the reasons behind the 2020 emissions impacts, Figure 14 summarizes the 2020 change in WECC-wide generation between the 1,000 MW Case and Base Case. As illustrated by the light grey bars, the storage devices are charged mostly by additional generation from natural-gas-fired combined-cycle units (light blue bars) during the night and first half of the day (from approximately midnight until 3:00 pm). The storage devices are then discharged during the late afternoon and early evening ramp hours (from approximately 4:00 pm to 10:00 pm). The addition of storage results in slightly lower coal generation (dark grey bars) and much less gas peaker generation (dark blue bars) during the evening ramp (up) hours when storage discharges, largely driving the reduction in emissions. The 2020 results for the 200 MW Case are similar but proportionally smaller.

Figure 14
2020 Change in WECC-Wide Generation by Hour of Day (1,000 MW Case minus Base Case)
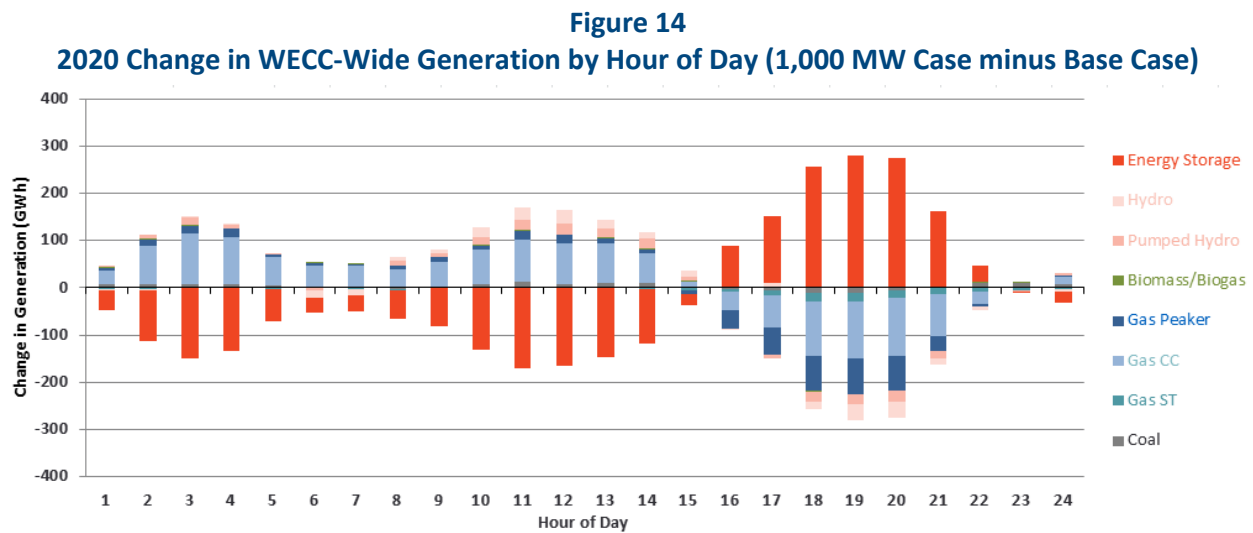
This pattern is similar in the 2030 simulations, but slightly more pronounced during the middle of the day and evening ramp hours as shown in Figure 15. Increased solar generating capacity in 2030 causes net energy demand (energy demand less solar and wind generation) to decrease during the middle of the day when solar output is highest and net demand to ramp up quickly during the evening hours when solar is no longer generating. As a result, load is easily met during the day, resulting in low prices. As shown in Figure 15, this corresponds to the hours when the storage devices charge, using primarily excess generation from natural-gas-fired CC units (light blue bars). Storage then discharges during the evening ramp hours, replacing high emitting coal and gas peaker plants. As a result, WECC-wide NO_X and SO_2 emissions also decrease slightly.

Figure 15
2030 Change in WECC-Wide Generation by Hour of Day (1,000 MW Case minus Base Case)

In total, however, we stress that deploying storage in Nevada has only a very small impact on WECC-wide CO_2 emissions in both 2020 and 2030. In 2020, WECC-wide CO_2 emissions decrease by 0.02% in the 200 MW Case and 0.06% in the 1,000 MW Case, while in 2030 WECC-wide CO_2 emissions decrease by 0.03% in the 200 MW Case and 0.10% in the 1,000 MW Case.

Valuing the Environmental Impacts Based on the Social Cost of Carbon

Consistent with NV Energy's 2018 IRP, we analyze the environmental cost of carbon emissions based on the social cost of carbon (SCC) estimates developed by the Interagency Working Group (IWG).[50] We use the 5% discount rate average SCC estimates as our low estimate, 3% discount rate average SCC estimates as our baseline estimate, and 2.5% discount rate average SCC estimate as our high estimate. The social cost of carbon based on these discount rates is shown in Table 12.

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[50] IAWG (2016).

Table 12
Social Cost of Carbon (nominal\$/metric ton of CO_2)

Year	5% Average	3% Average	2.5% Average
2010	\$11	\$33	\$53
2015	\$13	\$42	\$66
2020	\$16	\$54	\$80
2025	\$20	\$66	\$97
2030	\$25	\$79	\$115
2035	\$31	\$96	\$136
2040	\$40	\$115	\$161
2045	\$49	\$136	\$189
2050	\$61	\$162	\$223

Sources and Notes:
  IAWG (2016).
  Converted from 2007 dollars to nominal dollars using 2%
    inflation rate.

Using the storage-related changes in WECC-wide emissions discussed earlier and the SCC estimates in Table 12, we find a small decrease in societal costs associated with the emissions reductions for the 2020 and 2030 storage cases For 2020, societal emissions costs savings range from \$0.7 to \$3.8 million (\$3.6 to \$18.8 per kW-year of storage) for the 200 MW Case and from \$2.0 to \$10.6 million (\$2.0 to \$10.6 per kW-year of storage) for the 1,000 MW Case. For 2030, societal emissions costs savings range from \$1.6 to \$7.3 million (\$8.0 to \$36.4 per kW-year of storage) for the 200 MW Case and from \$5.9 to \$27.0 million (\$5.9 to \$27.0 per kW-year of storage) for the 1,000 MW Case. These results are summarized in Table 13.

Table 13
Change in Societal Cost Associated with Carbon Emissions

	Change in Societal Costs ($M)		Change in Societal Cost ($/kW-yr)	
	200 MW	1,000 MW	200 MW	1,000 MW
2020 Cases				
Low	-$0.7	-$2.0	-$3.6	-$2.0
Baseline	-$2.6	-$7.2	-$12.8	-$7.2
High	-$3.8	-$10.6	-$18.8	-$10.6
2030 Cases				
Low	-$1.6	-$5.9	-$8.0	-$5.9
Baseline	-$5.0	-$18.5	-$24.9	-$18.5
High	-$7.3	-$27.0	-$36.4	-$27.0

Sources and Notes:
  Low estimate uses IWG's 2.5% discount rate SCC estimate, baseline estimate uses IWG's 3%
    discount rate SCC estimate, and high estimate uses IWG's 5% discount rate SCC estimate.
  All values are in nominal dollars.

As these societal benefits and costs would not be reflected in utility rates currently, we do not incorporate them within our assessments of Nevada-wide benefits and costs as measured by the ratepayer-impact test in Section IV below. However, these societal costs do represent environmental consequences that the PUCN may choose to factor into its decision about storage procurement targets.

IV. Aggregate System-Wide Benefits of Storage

Figure 16 summarizes 2020 total annual costs and benefits of storage across all four key value drivers. The figure shows total benefits within the range of total costs for 200 MW through 1,000 MW deployed. Above 200 MW of storage deployed, the benefits of storage are less than the costs of storage.
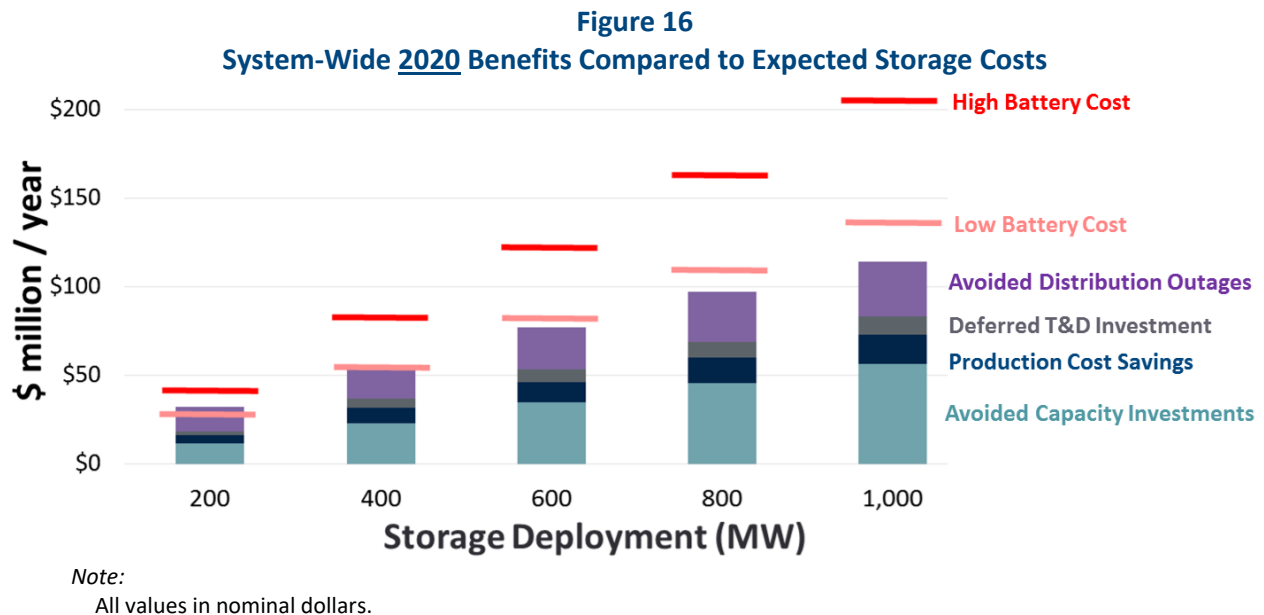
Figure 16
System-Wide 2020 Benefits Compared to Expected Storage Costs

Note:
  All values in nominal dollars.

Figure 17 shows incremental net benefits at various storage deployment levels. Net storage benefits in absolute dollars are maximized at a deployment level where the incremental benefits of deploying additional storage drops to zero. The figure shows that for 2020 the cost-effective storage deployment level is approximately 175 MW for the low-storage-cost scenario. Beyond 175 MW, total net benefits decline due to negative incremental net benefits from additional storage investments. Under the 2020 high-cost assumption, incremental costs always exceed incremental net benefits.[51]

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[51]   Because the locations of distribution feeders targeted for outage reductions may not overlap with battery locations targeted to avoid T&D costs, we conservatively assume each megawatt of storage can provide either distribution reliability benefit or T&D investment deferral, but not both. We test the sensitivity of our results to this assumption by re-calculating the aggregate benefits in 2020 assuming that storage allocated to T&D deferral also provides a distribution reliability benefit of $15/kW-year (the average reliability benefit provided by storage for a typical feeder in Nevada). Under this assumption, net benefits are maximized at 200 MW storage for the low-storage-cost scenario (up from 150 MW), while net benefits remain negative for all deployment levels for the 2020 high-storage-cost assumptions.

Figure 17
Incremental Net Benefit in <u>2020</u> from Each kW (4 kWh) of Additional Storage
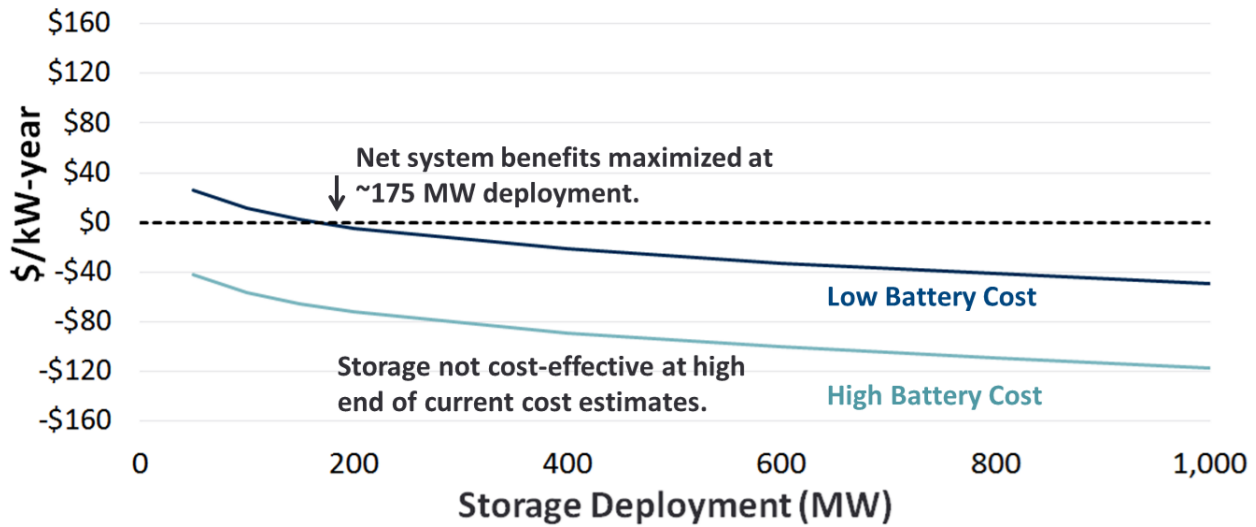
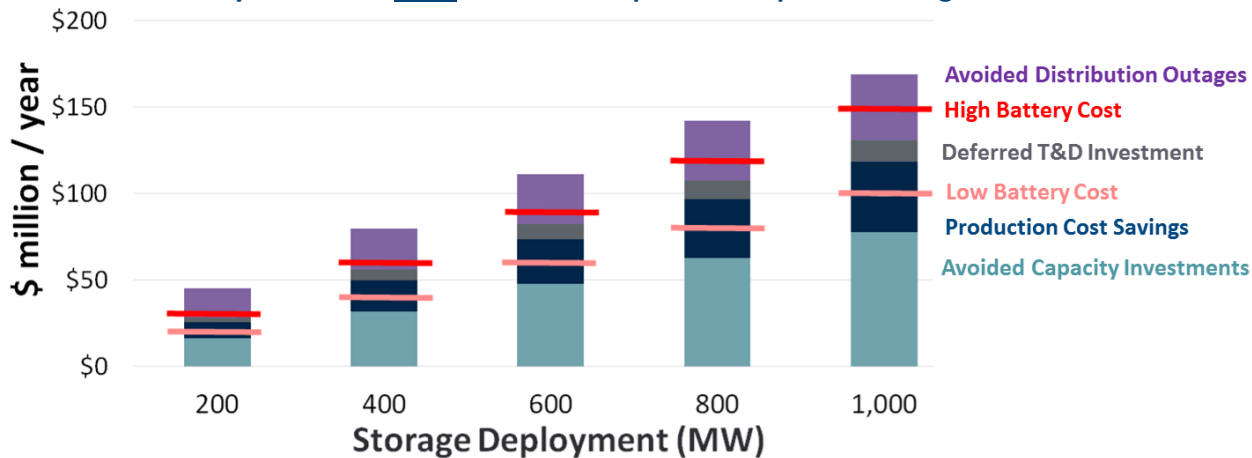*Notes:*
    All values in nominal dollars.
    Incremental net benefit measured as total benefits created by adding an incremental megawatt of storage at
      each deployment level minus incremental cost of that storage.

In 2030, the total benefits of storage exceed total costs for all levels of storage considered in both the low and high cost scenarios, as shown in Figure 18. Under the high 2030 cost assumption, net benefits in absolute dollars are maximized at a deployment level of approximately 700 MW, as shown in Figure 19. Under the low 2030 cost assumption, incremental net benefits exceed incremental storage costs even for the 1,000 MW deployment level evaluated. Based on the slope of the declining incremental net benefits line, the optimal total deployment level for the low 2030 cost assumption may be as high as 1,800 MW.[52]

Optimal storage deployment levels are higher for 2030 than those in 2020 due to both falling storage costs and changing system conditions that allow storage to capture more value. Chiefly, NV Energy anticipates purchased capacity costs will rise approximately 30% between 2020 and 2030, increasing the avoided generation capacity value of storage. Production cost savings due to storage rise, due in part to higher natural gas prices and avoided renewable curtailments (as discussed earlier).

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[52]   We only simulate storage deployments of up to 1,000 MW, consistent with NV Energy's load growth expectations and open capacity position. Above 1,000 MW some components of storage value, including production cost savings and avoided generation capacity, may decline more rapidly than our extrapolated results suggest, which would result in an upper bound of less than 1,800 MW.

Figure 18
System-Wide 2030 Benefits Compared to Expected Storage Costs

Note:
All values in nominal dollars.

Figure 19
Incremental Net Benefit in 2030 from each kW (4 kWh) of Additional Storage
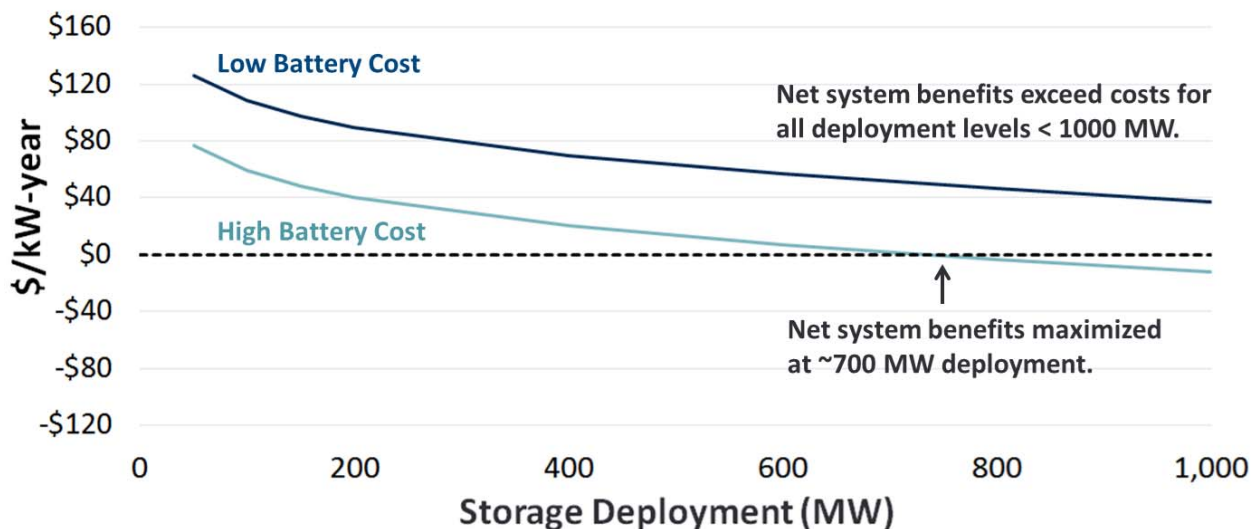
Notes:
All values in nominal dollars.
Incremental net benefit measured as total benefits created by adding an incremental megawatt of storage at each deployment level minus incremental cost of that storage.

The findings suggest storage deployments of up to about 175 MW are cost effective in 2020 from a ratepayer impact perspective, assuming storage costs are consistent with the low end of our range. By 2030, storage deployments of 700 MW or greater likely will be cost effective. However, any storage procurement target set by the PUCN should account for the state's need for new generation capacity. Since avoided generation capacity value is the largest component of storage investments'

overall value, storage-related benefits would be much lower when the state does not have a need for new capacity to meet the state's resource adequacy requirements. For example, if the avoided generation capacity value was zero in 2030, the optimal storage deployment would be approximately 300 MW for the low cost storage scenario and no storage investments would be cost effective for the high-cost storage scenario.

The extent to which distributed storage can provide customer outage reduction value will also depend the configuration and capabilities of the targeted distribution feeders. We understand NV Energy is currently pursuing grid modernization efforts, including automated distribution switching and remote switching, which would facilitate the placement of batteries that are targeted to reduce customer outages. [53] To the extent NV Energy will make these grid modernization investments for other purposes, we anticipate that the deployment of batteries for customer outage reduction would not incur any additional network upgrade costs. However, we also evaluate a sensitivity in which the cost of distribution automation upgrades needed to utilize storage to provide customer outage reductions would be prohibitively high. In that case, none of the storage investments be targeted to provide customer outage reduction. In this "zero outage reduction" sensitivity, the optimal level of storage would fall to zero in 2020 and, depending on storage costs, to a range from 300 MW to over 1000 MW in 2030.

NV Energy currently meets its capacity needs through owned and contracted generators as well as an open capacity position met through capacity contracts that NV Energy values at the market price for capacity. Our analysis envisions that storage additions would offset NV Energy's open capacity position, which under the preferred plan in the 2018 IRP is approximately 1,000 MW through 2030, making the previously-discussed levels of optimal storage deployments cost effective.[54] Exactly how the capacity needs of Nevada's customers will be met in the future will depend on the extent to which NV Energy's IRP changes from the current preferred plan, and whether the regulatory environment and future generation investments in Nevada change due to the pending Energy Choice Initiative. However, the underlying need for capacity in Nevada is unlikely to vary significantly even if retail suppliers change under Nevada's Energy Choice Initiative. If NV Energy will not own all Nevada's future capacity resources, Nevada customers' resource adequacy needs would still need to be fulfilled by a combination of resources suppliers. At that time, energy storage can help meet some of those needs.

Implementation of a regional market construct may reduce the value of storage due to the geographic diversification of loads and variable generation. Some value streams would be unaffected; customer outage reduction value would not change, nor would T&D deferral value. Avoided generation capacity value would not necessarily change, as Nevada's current resource adequacy needs may continue under a regional market construct. The greatest effect may be reduced production cost savings, as a regional market will enable more efficient dispatch of existing resources through the increased resource diversity across a larger region. Assuming a regional

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[53] NV Energy (2016)

[54] NV Energy (2018a) Volume 11 p. 163

market were to *halve* production cost savings but not affect other value streams, cost-effective storage deployment levels for 2030 would fall from a range of 700 MW to greater than 1,000 MW (without a regional market) to a range of 400 MW to greater than 1,000 MW (with a regional market).

V. Behind-the-Meter Storage Applications

In addition to grid-level storage deployment, behind-the-meter storage has the potential to play a meaningful role in Nevada's storage adoption scenarios. Currently, BTM applications account for less than 20% of the U.S. energy storage market, amounting to under 200 MW of total nation-wide installed capacity.[55] However, some industry analysts project that BTM storage could drive a significantly large share of future storage growth. For example, Greentech Media estimates that, on a U.S.-wide basis, annual BTM storage installations would be around 1,300 MW per year by 2022.[56]

Five BTM storage use cases are emerging. Each use case is described below, along with a brief discussion of its applicability in Nevada under current policies and retail electricity rate structures.

- **Retail bill reduction.** BTM storage can be discharged to reduce retail customers' demand charges or the peak prices of time-varying volumetric charges. Additionally, in jurisdictions where exports to the grid receive value-based compensation, storage may be eligible to capture this value.[57] In Nevada, commercial and industrial (C&I) customers have access to rates with price signals that could be attractive for storage owners. Residential rate offerings do not feature a demand charge or a more dynamically varying energy charge, so the current price signal *alone* is unlikely to incentivize BTM storage adoption among residential customers.

- **BTM solar plus storage.** In jurisdictions *without* net energy metering (NEM) policies that allow for the netting of exports to the grid against power consumed during other time periods, retail customers with rooftop solar generation may have a financial incentive to consume the output of their PV panels on-site rather than exporting it to the grid. This can allow the customers to be compensated for that PV output at the full retail rate, which is higher than the wholesale value of that energy if the power were instead exported to the grid. In Nevada, residential customers and small C&I customers have access to NEM that credits exports at the retail rate with an energy charge that exceeds wholesale market prices. The existing NEM policy does not provide additional incentives for retail customers to use storage to self-consume the PV output on-site.

- **Demand response/aggregation.** BTM storage devices can be aggregated across customers to provide bulk system benefits such as resource adequacy, fuel cost reductions through energy price arbitrage, ancillary services, and transmission and distribution capacity investment deferral. These benefits can be passed on to owners of BTM storage in the form

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[55] Smart Electric Power Alliance (2018).

[56] GTM Research and Energy Storage Association (2017).

[57] For instance, in New York, distributed resources are eligible for over $300/kW-year in Value of Distributed Energy Resource (VDER) payments. See NYSERDA (2018b).

of demand response participation incentive payments. We explore the possibility of offering such a program in more detail below.

- **Backup generation / reliability.** BTM storage can provide customers with backup generation during outages. Even if the storage device's capacity is not large enough to serve the full load of its host for an extended period, it can be wired to power essential end-uses, such as garage doors, refrigeration, or lighting. This is a relevant use case for customers in Nevada that place a significant value on power reliability, particularly if coupled with other use cases such as retail bill reduction.

- **Electric vehicle (EV) battery control.** There has been long-standing interest in allowing utilities limited control of the batteries of EVs while they are plugged in and charging. These batteries are effectively a "free" resource that could be used to provide a variety of grid services. For instance, programs could be designed to charge and discharge the battery of personal vehicles to balance the grid while the vehicle is charging at home overnight. Similar programs could be developed for workplace charging or the vehicle fleets at centralized charging stations. Thus far, EV charging control has been limited to testing through pilot programs and demonstration projects. One barrier to further development of these programs is concern about the impact of utility-controlled charging and discharging on the EV's range and battery life.

Given the factors noted above, customers in the C&I segment are most likely to adopt BTM storage in Nevada in the near- to medium-term. The primary BTM storage use cases for C&I customers in Nevada are retail bill reduction, backup generation, and aggregation as a demand response resource. Significant residential storage adoption seems unlikely under current conditions, as it would require a change in the retail rate design, elimination of the state's NEM policy, and/or significant advancements in EV charging control.

In this section of the report, we estimate the economic potential for BTM storage adoption among C&I customers in Nevada. First, we determine the total amount of BTM storage capacity that may be adopted by customers in the future to reduce their electricity bill. This BTM storage adoption would occur irrespective of any utility initiatives to procure storage behind the meter.

Ultimately, our study must inform the PUCN's decisions about if and at what level to establish a storage procurement target. Therefore, it is necessary to determine the extent to which NV Energy might influence this trajectory of BTM storage adoption through new programmatic offerings. Along these lines, as a second step in the analysis we estimate the incremental increase in BTM storage adoption that could result from a utility-administered program that offers BTM storage owners a cost-effective incentive payment. In return for the incentive payment, NV Energy would be able to control the storage device for a limited numbers of days per year to address resource adequacy needs, and thereby reduce customers' costs.

A. Methodology

Our methodology for estimating BTM storage potential is organized around seven steps. These steps are conducted separately from the power system simulations described previously in this report. The steps are summarized in Figure 20 and described in further detail below.

Figure 20
Approach to Quantifying BTM Storage Potential
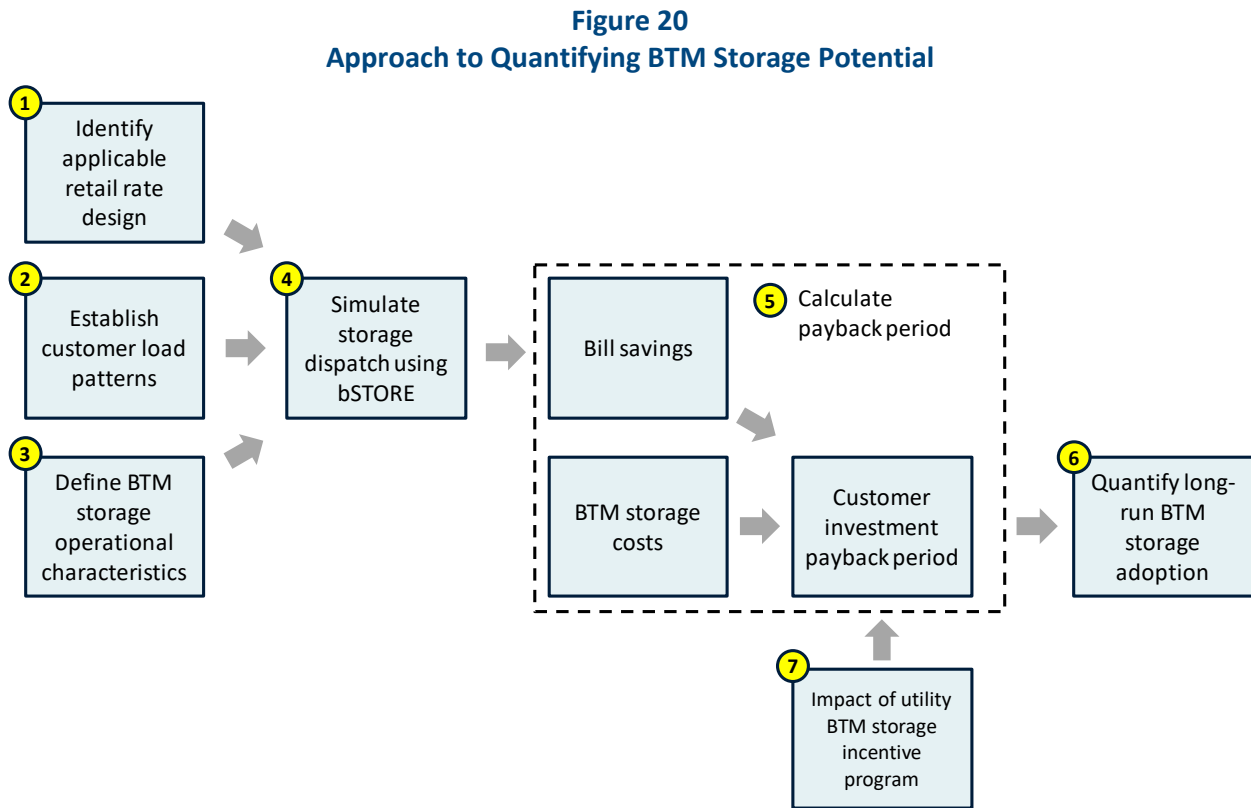
Step 1: Identify the Applicable Retail Rate Design

NV Energy offers a range of retail electricity rates to its C&I customers. The rates vary by customer size and service territory. As an illustrative rate option for this analysis, we used the Large General Service-2 (LGS-2) rate for secondary service in the Southern service territory.[58] The rate's structure is consistent with that of several other C&I rate classes. The LGS-2 rate includes demand charges and time-varying volumetric charges, both of which provide opportunities for customers to utilize BTM storage to reduce their electricity bills. The rate is summarized in Table 14.

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[58]   NV Energy (2018c).

Table 14
NV Energy LGS-2 (Secondary Service) Rate, Southern Service Territory

Description	Charge
Basic service charge ($/month)	193.10
Facilities charge ($/kW-month)	3.14
Demand charge	
Winter ($/kW-month)	0.40
Summer on-peak ($/kW-month)	13.35
Summer mid-peak ($/kW-month)	2.04
Summer off-peak ($/kW-month)	0.00
Energy charge	
Winter ($/kWh)	0.05213
Summer on-peak ($/kWh)	0.08508
Summer mid-peak ($/kWh)	0.06449
Summer off-peak ($/kWh)	0.04573
Riders ($/kWh)	0.00105

Notes: Summer season is June through September. On-peak period is 1 pm to 7 pm daily. Mid-peak period is 10 am to 1 pm and 7 pm to 10 pm. Off-peak period is 10 pm to 10 am.

Alternative cost-based rate designs could further increase the economic attractiveness of BTM storage.[59] In particular, the retail rate design assumptions in this study should be re-examined if retail choice is introduced to Nevada. In that scenario, it is possible that a range of new retail business models would be introduced to capture the flexibility benefits of BTM storage.

Step 2: Establish Customer Load Patterns

A customer's electricity usage pattern will influence its ability to use BTM storage to reduce its electricity bill. This is particularly the case for demand charge avoidance. A customer with a very flat usage profile could utilize storage to reduce its demand significantly in one hour, but would not reduce its demand charge by a commensurate amount because similarly high demand hours would become the new basis for the demand charge. Conversely, customers with high demand concentrated in a limited number of hours are more likely to achieve significant demand charge reductions though storage deployment. As such, it is important to capture a range of load profiles when analyzing BTM storage opportunities.

We established three prototypical customer load profiles that represent customers for which energy storage will provide low, medium, and high value as a BTM resource. The source of the hourly load data is based on DOE's Commercial Reference Building Models specifically for Las Vegas.[60] Through prior research, we have found that these three shapes reasonably capture a broad range of outcomes across customer types. The three load profiles were then assigned population

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[59] For further discussion, see Hledik *et al.* (forthcoming).

[60] The low, medium, and high value load profiles are based on the large hotel, supermarket, and hospital customer segments, respectively. See OpenEI (2018).

weights that would approximate Nevada's total C&I customer base. Sensitivity analysis was used to account for uncertainty in the future composition of Nevada's customer mix.

Step 3: Define BTM Storage Operational Characteristics

BTM storage was assumed to have 85% round-trip efficiency, consistent with the efficiency assumptions of the utility-scale storage analysis presented earlier in this study. Unlike the 4-hour duration simulated for the grid-level applications, BTM storage facilities are assumed to have a 2-hour full-capacity discharge capability, reflecting the smaller battery storage capability likely be needed to capture the bulk of demand charge avoidance benefits. The storage technology is assumed to be sized to 5% of each customer's peak demand.[61] Sensitivity analysis was conducted to determine the extent to which alternative sizing assumptions would lead to different results.

Step 4: Simulate Storage Dispatch

The BTM Storage Module of the bSTORE modeling platform was used to simulate dispatch of the storage device. Storage was operated to minimize the customer's bill. For this analysis, we assume perfect foresight, because an individual C&I customer typically has a high degree of control over its electricity consumption pattern and the prices in the retail rate are pre-defined and therefore predictable. The customer with BTM storage is assumed to monitor its usage and reliably discharge the storage device during hours of highest demand. The result of this step of the analysis is an estimate of bill savings opportunities for each customer segment.

In addition to retail bill savings, customers may operate BTM storage as a form of on-site backup generation during outages. Additional configuration and wiring would be needed to provide these services, which would impose higher installed costs—particularly as a retrofit compared to an integrated solution in new construction. Further, a portion of these benefits may be accounted for in the system benefits analysis described earlier in this report. Given the uncertainties in these costs and benefits, the customer value of using BTM storage simultaneously for bill reduction and backup generation purposes is included only as a sensitivity case.[62]

Step 5: Calculate Customer Payback Period

The bill savings calculated in step 4 are compared to the assumed costs to estimate the net economic benefit to BTM storage owners. We assume a range of BTM storage costs that are similar to the

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[61]   The per-kW value of BTM storage decreases as the size of the installed storage capacity increases for a given customer. This is because deeper reductions in customer demand become increasingly harder to achieve (*i.e.*, more load hours must be reduced). We assume a small (5% of peak) deployment initially and then evaluate the economic potential at higher capacities (10% and 20% of peak).

[62]   Our approach to quantifying this value is the same as described in Section III of this report. We determine the battery's average state of charge and combine this with a VOLL estimate and an outage profile to determine the annual customer value of achievable outage avoidance.

utility-scale storage cost assumptions used in this study, though we relied on the higher end of the cost range to reflect the reduced economies of scale associated with smaller BTM applications. We have assumed costs of $450/kWh to $700/kWh in 2020 and $250/kWh to $400/kWh in 2030.[63]

The payback period for a BTM storage owners is calculated simply as the up-front cost of the storage technology divided by the annual retail bill savings.

Step 6: Quantify Long-Run Adoption Rate

It is common to express adoption of technology for a given customer segment as a function of the payback period of the investment. Faster payback periods are likely to lead to higher adoption among customers, and vice versa. For this analysis, we derived the adoption function from prior analysis of C&I adoption of combined heat and power (CHP) technology.[64] Of course, there are differences between BTM storage and CHP. For instance, BTM storage is a less proven technology, which may make it appear to be a riskier investment to some customers. On the other hand, BTM storage would not need to be integrated into existing processes to the same degree as CHP, possibly making it a more attractive option. We established sensitivity cases to account for this uncertainty. The adoption function is depicted in Figure 21.

Figure 21
Commercial &Industrial BTM Storage Adoption Function
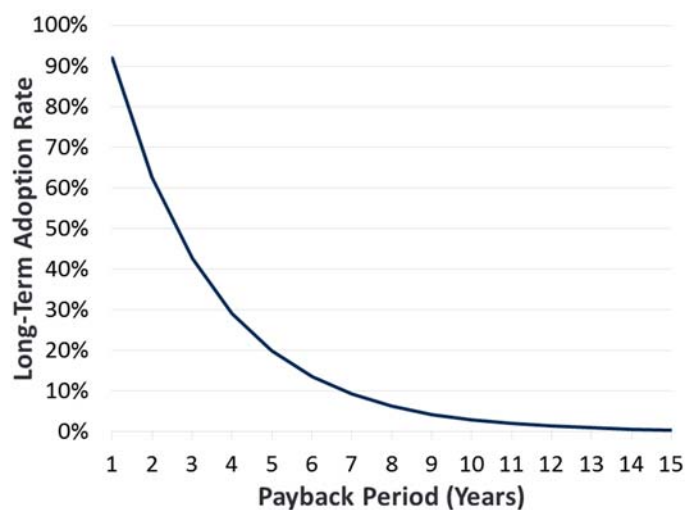
This adoption function provides an estimate of long-run adoption levels given the payback period at the time of deployment. For instance, using the adoption function with a payback period calculation that is based on BTM storage costs and benefits in 2020 would produce an estimate of an adoption level that could be achieved over the several years that follow 2020.

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[63]   This range is roughly 50% higher than the cost range assumed for the larger grid-connected batteries in the prior chapters of this report.

[64]   ICF International (2016).

Step 7: Estimate Incremental Impact of Utility BTM Storage Program

The last step in the analysis is to determine how the introduction of a utility-sponsored BTM storage incentive program would affect payback periods and, consequentially, adoption rates. There are many ways that such a utility program could be designed. For this study, we have assumed that the utility would be willing to pay customers for control of the battery during a limited number of days per year. On these days, the utility would operate the battery to capture the resource adequacy value (*i.e.*, dispatch the battery during high-demand hours that would otherwise need to be served through the addition of new peaking capacity) and thereby pay the customer for the system value that such control would provide.

For this analysis, we assume that the BTM storage incentive program is similar to a pilot program offered by Green Mountain Power (GMP) in Vermont. Under GMP's program, C&I customers are able to install a Tesla Powerwall system and be compensated by the utility in exchange for allowing the utility to control the battery to reduce system peak demand. Customers have the opportunity to lease the unit from the utility for $15/month for the duration of the ten year program, or pay a one-time fee of $1,500. Alternatively, customers can supply their own battery to the program, and GMP will credit their energy bill between $14.50-$36/month.[65]

We assume for this study that the utility would be willing to offer incentive payments at an amount less than the full avoided cost of generation capacity. This would ensure that a portion of the benefits of the program accrue to all customers, and would leave a cushion for program administration costs that may otherwise prevent the program from being cost-effective. Our base assumption is that incentives would be 75% of the avoided generation capacity costs, but a range of incentive payments are tested through sensitivity analysis.

In this final step of the analysis, the utility incentive payment is added to the calculation of the customer's financial benefits and the investment payback period is recalculated. The increase in adoption resulting from the reduced payback period represents the incremental impact of the utility's BTM storage incentive program.[66]

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[65]   Smart Electric Power Alliance (2018).

[66]   We have assumed that the utility's control of BTM storage on a limited number of days per year would not materially impact the customer's ability to reduce its retail electricity bill through the avoidance of demand charges and peak energy charges. For instance, the program could be designed to exempt the customer's load from setting the demand charge on days when the utility controls the storage device. This would eliminate the possibility that the utility could unintentionally increase the customer's bill by charging coincident with the customer's maximum demand.

B. Findings

BTM Storage Potential

To account for uncertainty in drivers of future BTM storage adoption rates, we constructed low, medium, and high adoption cases. The cases varied across assumptions about installed battery cost, adoption rate, magnitude of utility incentive payment, and the composition of the C&I customer base. Assumptions behind the three cases are summarized in Table 15.[67]

**Table 15**
Assumptions behind BTM Storage Adoption Cases

	Low Adoption Case	Medium Adoption Case	High Adoption Case
Battery cost	2020: $700/kWh 2030: $400/kWh	2020: $575/kWh 2030: $325/kWh	2020: $450/kWh 2030: $250/kWh
Adoption function	20% reduction from Medium Case	Base adoption function based on investment payback period	20% increase from Medium Case
Utility incentive payment	50% of avoided generation capacity cost	75% of avoided generation capacity cost	100% of avoided generation capacity cost
Customer mix	Skewed toward segments with lower BTM storage value	Average customer mix	Skewed toward segments with higher BTM storage value

At the 2020 installed cost of BTM storage, the cumulative adoption of BTM storage ranges from 0.3 to 7.2 MW in the absence of a utility incentive program. With the inclusion of the utility incentive program, the cumulative adoption of BTM storage increases to a range from 1.5 to 27.4 MW across the cases, representing an incremental increase ranging from 1.2 to 20.2 MW due to the incentive program.

At the assumed 2030 installed cost of BTM storage, the projected 2030 cumulative adoption increases to a range of 3.8 to 31.2 MW without the incentive program. This increases to 9.8 to 69.8 MW with the incentive program. In this case, the incentive program accounts for 6.0 to 38.6 MW of incremental BTM storage adoption through 2030. The results of these BTM storage adoption cases are summarized in Figure 22.

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[67] For each case, we identified the BTM storage sizing assumption that would maximize adoption in terms of total megawatts of installed capacity. BTM storage sizing options were 5%, 10%, or 20% of customer maximum demand.

Figure 22
Projected Cumulative BTM Storage Adoption with and without Utility Incentive Programs
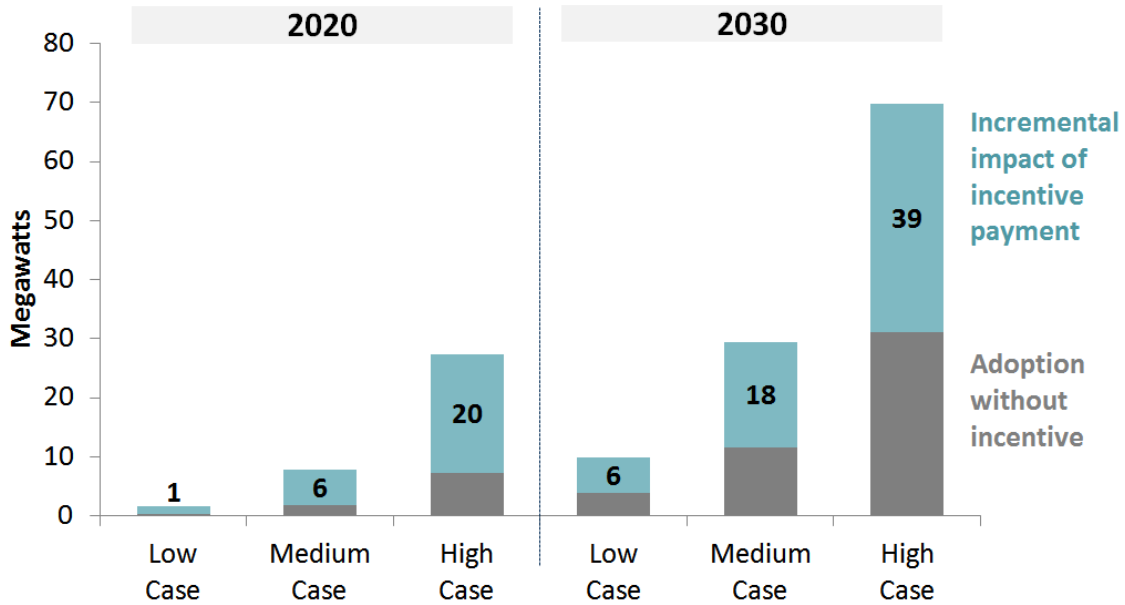

Notes:
The potential estimates represent long-run adoption potential based on assumed storage costs for the years shown in the figure. It would take several years to reach these adoption levels.

Sensitivity Analyses for BTM Storage

We conducted additional analyses to provide an indication of the sensitivity of the results to changes in underlying modeling assumptions. Beginning with the Medium Case results, each assumption was individually modified to reflect the High and Low case assumptions summarized in Table 15 above. Additionally, we tested a case that includes the customer reliability benefit of using BTM storage as backup generation in addition to the retail electricity bill savings benefit.

The results of these sensitivity cases are summarized in Figure 23. The horizontal dashed line indicates the result of the Medium Case (consistent with the results summarized in Figure 22 above). The bars indicate the extent to which this Medium Case value would increase or decrease when modifying that particular assumption using the High and Low values shown in Table 15.

Figure 23
Summary of Sensitivity Analysis of BTM Storage Adoption
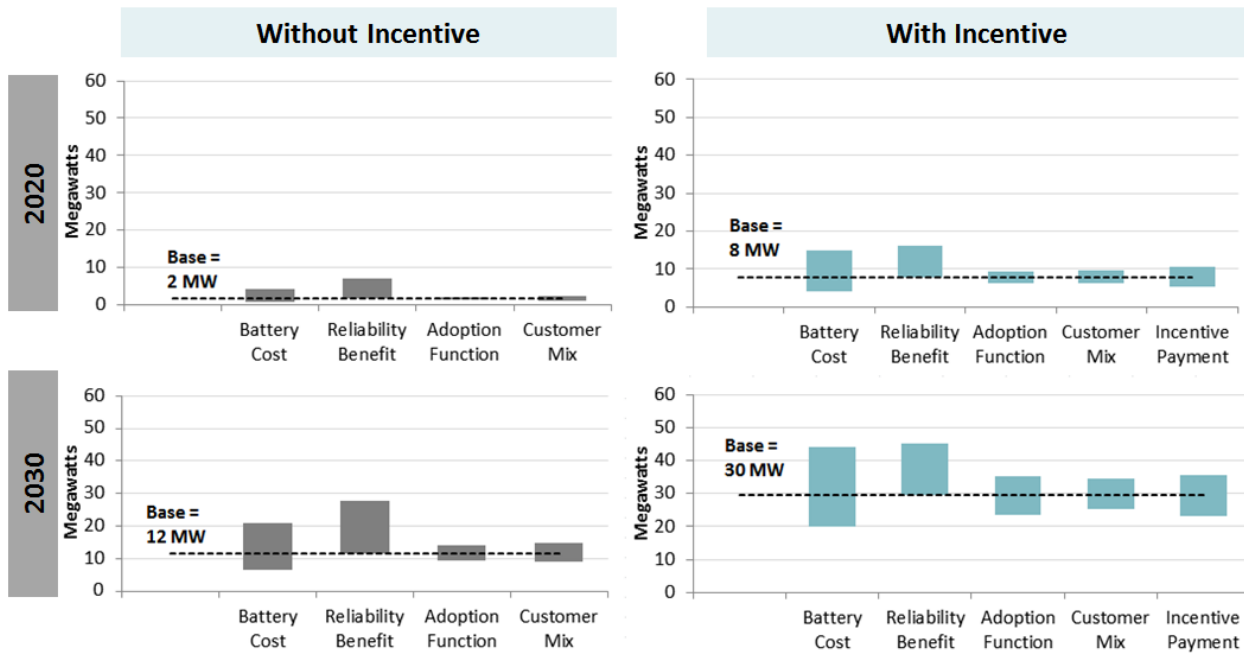
The added customer outage reduction benefit of BTM storage as backup generation is the most significant additional benefits, assuming a backup installation can be implemented at reasonable cost. As Figure 23 shows, the ability to capture customer reliability benefits (*i.e.*, backup services) would incrementally add approximately 16 MW to our estimated 2030 BTM storage adoption levels. Uncertainty in future battery costs is a significant driver of the range of possible future BTM storage adoption outcomes. Uncertainty about customer mix, adoption sensitivity to the investment payback period, and the applicable incentive payment level are secondary to the impact of battery cost uncertainty.

Discussion

We have analyzed the future adoption of BTM storage among C&I customers in Nevada, with a focus specifically on the use of storage to reduce charges in the customer's retail rate. Our findings suggest that, cumulatively through 2030, between 4 and 31 MW of BTM storage capacity would be installed by customers for this purpose at 2030 costs even without utility incentives. Introducing a utility-administered BTM storage incentive program could increase these adoption levels to a range between 10 and 70 MW, representing incremental installations of 6 to 39 MW facilitated through such an incentive program.

These estimates of the cumulative BTM storage potential are incremental to the estimates of cost-effective grid-level storage discussed in prior sections of this report. The generation capacity value provided by the BTM storage incentive program is additive to the value that would be derived from grid-level storage projects.

The projected BTM storage adoption level is cost-effective without additional incentives or subsidies. By definition, we have analyzed a program in which the utility incentive payment to participants is less than or equal to the system-wide benefit of the program (*i.e.*, avoided generation capacity costs). The incentive program thus passes the Ratepayer Impact Measure (RIM) test.

There are many ways to design a BTM storage incentive program. We have considered one example, which resembles the design of pilot programs that are being introduced by other utilities around the U.S. Advanced versions of the program could extract additional value from BTM storage technologies, such as programs designed to provide ancillary services or geographically-targeted programs to defer T&D investments.

Future developments could lead to BTM storage adoption levels that are different than our estimates. For instance, if the state's residential net energy metering policy were phased out, there would be a financial incentive for residential customers to alternatively couple BTM storage with rooftop solar. Modifying retail rate designs to recover a greater share of costs through demand charges or peak energy charges would also increase the financial incentive for BTM storage adoption (and vice versa). Use of electric vehicle batteries to balance the grid while charging at home or at work is another possible driver of increased BTM storage, though technical challenges and concerns about degradation of battery life would need to be overcome.

VI. Comparison of Study Results to Other Storage Potential Studies

To put the findings of this study in context, we reviewed similar studies that have recently been conducted for other U.S. jurisdictions. We specifically identified studies conducted for Massachusetts, New York, and Texas. We focused on these studies as they have similarly quantified cost-effective storage deployment levels. We excluded a broader set of studies that quantify the incremental value of storage but do not estimate optimal storage deployment quantities across an entire region, state, or utility service territory.[68] A brief summary of each study is provided below.

Massachusetts[69]

The Massachusetts "State of Charge" study was a state-funded project performed by a collection of research firms as part of the Massachusetts Energy Storage Initiative (ESI). The purpose of the study was to analyze the statewide economic benefits of storage, as well as to develop policy recommendations for promoting the deployment of energy storage in Massachusetts. Across a range of use cases and possible value streams, the study identified roughly 1,800 MW of cost-effective storage potential in 2020.

New York[70]

New York has proposed a statewide storage deployment target of 1,500 MW by 2025. To explore the feasibility of achieving this target, the New York Department of Public Service (DPS), the New York State Energy Research and Development Authority (NYSERDA), and industry stakeholders have developed a storage deployment "roadmap." Included in the roadmap is a study to determine cost-effective storage adoption. Modeling identified nearly 2,000 MW of cost-effective storage potential by 2025, exceeding the state's proposed deployment target.

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[68] Utilities have begun to incorporate energy storage resource options in into long-term modeling and planning initiatives. As techniques for fully representing the operational characteristics of energy storage in these models continue to advance, integrated resource plans (IRPs) will be another useful source of information on cost-effective storage deployment levels

[69] Massachusetts Clean Energy Center and Massachusetts Department of Energy Resources (2016).

[70] NYSERDA (2018a).

Texas[71,72]

For Oncor, Brattle assessed the potential for economic storage deployment by 2020. The study examined separately the value that storage would provide to a merchant developer, to customers, or to the system as a whole. The Oncor study concluded that there would be economic benefits from allowing transmission and distribution utilities to integrate storage into their planning efforts. The study concluded that system benefits could be maximized at roughly 5,000 MW of storage deployment statewide (at 2020 storage costs).

In addition to the Brattle study for Oncor, Navigant Research developed an estimate of economic storage deployment in Texas as part of the Energy Storage Association's (ESA's) "35x25: A Vision for Energy Storage" study. The ESA study broadly describes benefits associated with 35 GW of national energy storage deployment. Navigant Research's Texas estimate is provided as validation of the findings of the broader study. Navigant Research finds that roughly 3,700 MW of storage could be economic in Texas by 2020, based on "grid operational cost savings." Outage mitigation benefits estimates are included separately in the broader ESA study.

The benefits considered in each study are summarized in Table 16.

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[71] Chang, *et al*. (2015).

[72] ESA (2017).

Table 16
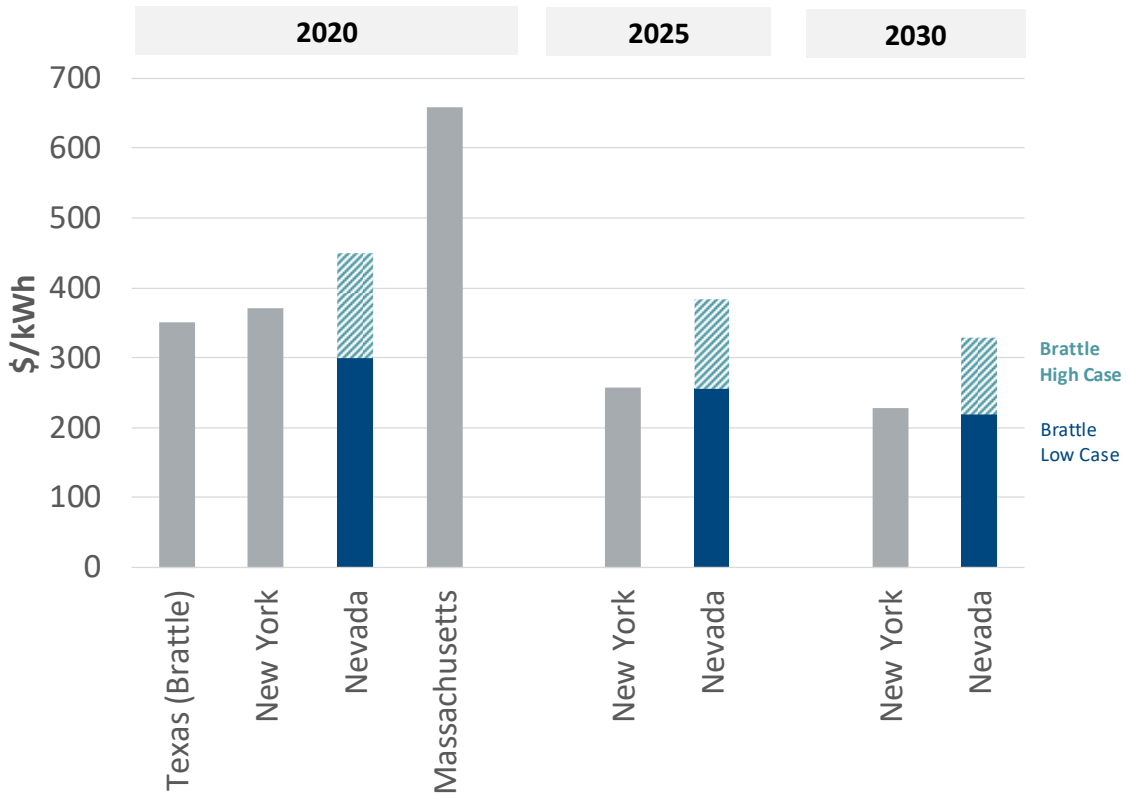**Benefits Considered in Recent Storage Potential Studies**

	Nevada	Massachusetts	New York	Texas (Brattle)
Avoided generation capacity costs	X	X	X	X
Reduced energy (fuel) costs	X	X	X	X
Deferred T&D investment costs	X	X	X	X
Ancillary services	X	X	X	X
Environmental impacts	X	X	X	Discussed qualitatively
Outage mitigation	X		X	X
Distribution voltage support	Discussed qualitatively	X		Discussed qualitatively
Behind-the-meter value	X			
Wholesale market cost reduction	N/A	X	X	X

Notes:

Table reflects Brattle's interpretation of the modeled benefits in each study. Approximations have been made to accommodate differences in terminology across the studies. The analysis of Texas by Navigant Research is not included because insufficient detail was provided on specific categories of value streams. The modeling of cost-effective deployment levels in New York and Massachusetts do not specifically account for BTM adoption, but the studies acknowledge behind-the-meter deployment as one of several use cases.

An important distinguishing characteristic of the studies is the assumed cost of energy storage. Figure 24 summarizes the cost assumptions across studies. One reason for the variation in costs across studies is the assumed MW-to-MWh ratio of the battery. Batteries with a lower MW-to-MWh ratio (i.e. "duration") appear to cost relatively more when expressed in terms of $/kWh and less when expressed in terms of $/kW.

Figure 24
Comparison of Storage Costs Across Studies

| 2020 | 2025 | 2030 |

$/kWh axis: 700, 600, 500, 400, 300, 200, 100, 0

Categories:
- 2020: Texas (Brattle), New York, Nevada, Massachusetts
- 2025: New York, Nevada
- 2030: New York, Nevada

Brattle High Case

Brattle Low Case

Notes:
Battery duration shown in figure is 4-hours for Nevada and New York, 3-hours for Texas, and roughly 2-hours on average for Massachusetts. Massachusetts cost was calculated by dividing the midpoint of the range of total reported statewide storage costs by the total statewide economic storage capacity. Values are in nominal dollars.

A comparison of the findings across the studies is presented in Figure 25. For each study, the optimal level of storage deployment (in megawatts) is expressed as a percentage of the relevant system peak.

Figure 25
Comparison of Cost-Effective Storage Deployment Levels Across Studies

Notes:
  Massachusetts study

In 2020, the optimal storage deployment levels identified for other states are higher than those found for Nevada in this study. A review of those other studies suggests that the following are primary drivers of the differences in study results:

- Our estimate of T&D deferral value is based on a detailed assessment of NV Energy's planned T&D upgrades. Eligibility for T&D deferral value has only been assigned to those projects with qualifying load and cost characteristics. Other studies have not had access to the same level of detailed data for assessing this value stream, and alternatively have used average system-wide T&D costs as proxy for deferral benefits. T&D deferral value is a very location-specific benefit that may vary significantly across the jurisdictions considered in other studies.

- Our study analyzes batteries with a four-hour storage capability at full output ("four hour duration"). This assumed duration is longer than that of some other studies. For instance, the average battery duration in the Massachusetts study is only approximately two hours. A four-hour duration was chosen for this study as this is the level of energy storage capacity that is generally considered to be necessary to fully meet system resource adequacy needs in Nevada, particularly at the levels of storage deployment considered in this study. The higher degree of energy storage capability is not reflected in the megawatt-based values shown in Figure 25. Further, longer-duration batteries are more expensive than shorter-duration batteries.

- The battery dispatch algorithm in our study systematically accounts for limits on the ability of storage to simultaneously capture multiple value streams. Value attributed to any

individual benefit is derated to account for its coincidence—or lack of coincidence—with other value streams. Some studies have tended to attribute multiple benefits to batteries based on the assumption that the value streams can be "stacked" in a fully additive fashion. In some cases, prior analyses may double-count certain benefits (e.g., by adding storage owner revenues to customer benefits and assuming that energy, ancillary services, peak load reductions, and renewables integration costs savings are independent and fully additive benefit streams) or apply benefit-cost tests that count more benefits than the ratepayer impact test employed in this Nevada study.

- Differences in market structures and market conditions will cause potentially significant variations in battery value. For example, it is likely that market conditions in Texas (ERCOT) make storage more valuable than in Nevada for several reasons. First, the ERCOT market is an energy-only organized wholesale power market with periodic price spikes and scarcity pricing of up to $9,600/MWh. Second, Texas is not integrated with neighboring states, which reduces geographic diversity benefits which would otherwise help to reduce energy price volatility. And third, ERCOT does not have any significant existing storage facilities (such as flexible or pumped hydro generation) and is not interconnected with neighboring states that have significant hydro resources with such storage capability. Each of these three factors will tend to make storage additions more valuable in Texas than in Nevada.

For 2030, our Nevada storage potential estimates are similar to those of the New York study and exceed most studies' 2020 estimates. The primary drivers of the higher estimated 2030 potential in our study are the projected reduction in battery costs and the expected increased need for peaking capacity. Additionally, the largest components of total value—avoided generation costs and reduced energy costs—are value streams that do not quickly "saturate" with increased deployment of energy storage, and therefore do not dramatically reduce as battery costs decline and market penetration increases by 2030.

VII. Conclusion

Energy storage deployments can be cost-effectively incorporated into Nevada's future power supply mix. Under the assumptions used in this study, a statewide deployment of up to 175 MW of grid-level storage could be cost-effective in 2020 if storage is at the lower end of the projected cost range. By 2030, declining battery costs and evolving system conditions increase this estimate of cost-effective storage potential to a range starting at 700 MW at the low end and exceeding 1,000 MW at the high end. The high end of this deployment range suggests that storage has the potential to replace the state's entire projected 1,000 MW need for new generation capacity. The development of this cost-effective storage potential estimate accounts for constraints that would limit the operation of a battery relative to that of conventional generation (*e.g.*, a battery storage capability limited to 4 hours of discharge at full capacity). Additional feasibility studies and the incorporation of similarly high storage scenarios in NV Energy's resource planning process would be valuable complementary research to further validate the realism of this conclusion.

In addition to the utility grid-level applications discussed above, storage could add value as a behind-the-meter application at individual retail customers' locations. At projected 2020 BTM storage costs, storage adoption in the absence of a utility incentive program could be up to 7 MW under favorable conditions. The introduction of utility BTM storage incentive programs could incrementally increase the 2020 BTM adoption level by up to 20 MW. At projected 2030 BTM storage costs, the estimated BTM storage adoption level is up to 31 MW without the incentive program, and would incrementally increase by between 6 and 39 MW in the presence of a BTM storage incentive program.

Based on the findings of this study, future initiatives in Nevada may seek to establish a statewide energy storage procurement target.[73] A key finding of this study is that there is significant uncertainty in storage costs. This cost uncertainty is the primary driver of the fairly broad range of the estimated cost-effective storage deployment levels. Consequently, to the extent that future procurement targets are established, it may be desirable to design the targets in a way that accounts for this cost uncertainty. For instance, storage procurement targets could be expressed as an "optimal deployment curve" that defines procurement levels as a function of cost. If realized storage costs (e.g., as the result of a competitive procurement process) are at the low end of the range assumed in this study, the procurement quantity could be set at the high end of the identified optimal range. If realized costs are at the high end of the estimated range, procurement targets could be set at the low end of the estimated optimal quantities. This same design has been successfully applied in centralized capacity markets. In establishing such a procurement curve,

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[73]   We use the term "target" to broadly account for targets, requirements, goals, or other such policies. California, Massachusetts, New York, and Oregon are examples of other states that have established or are pursuing energy storage procurement targets.

additional policy decisions would need to be made, such as whether to define minimum or maximum amounts of energy storage to be deployed.

Figure 26 illustrates how the findings of this study could be used to establish future procurement targets. Our analysis of the relationship between incremental storage value and quantity deployed is extended to identify optimal storage levels at a broad range of future storage costs. The shape of the "optimal deployment curve" indicates that optimal storage deployment rises rapidly as the cost of storage falls. For example, a 30% decline in storage costs – from $1,200/kW ($300/kWh) to $840/kW ($210/kWh) – would increase optimal deployment levels by 200% to 500%. Optimal procurement levels in 2030 exceed those in 2020 at a given storage cost, because evolving market conditions such as an increased need for system flexibility increase the total value of energy storage relative to 2020.

Figure 26
Optimal Storage Deployment Curves, 2020 and 2030
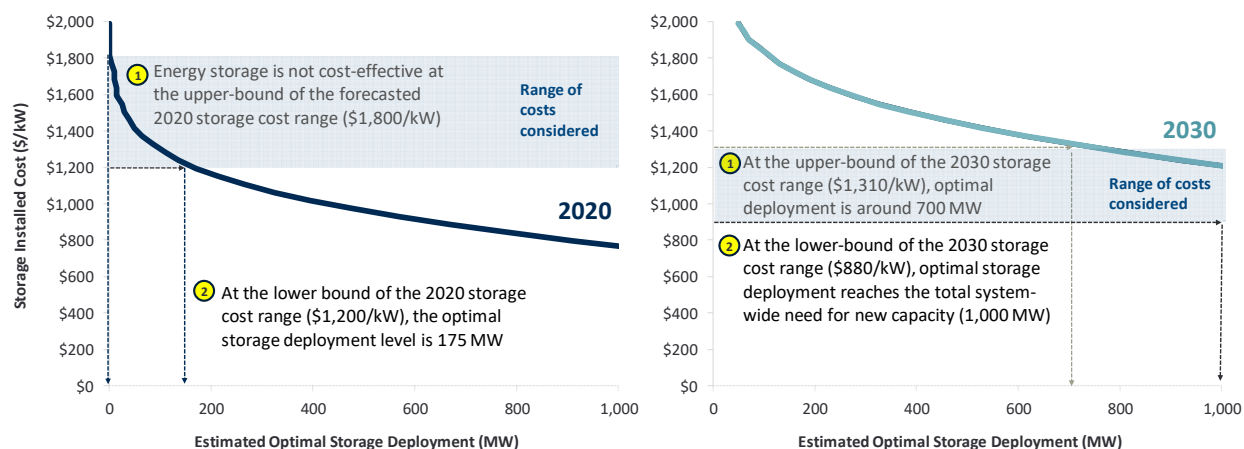
Notes:
Costs are shown in nominal dollars. Values are based on an assumed energy storage configuration of 10 MW / 40 MWh. Values shown in Figure 26 are derived from the results that are summarized in Figure 2 of this report.

Energy storage can be a cost-effective addition to Nevada's future mix of electricity resources, reducing system costs and benefitting consumers as a result. It can provide value across a range of applications and use cases, including for resource adequacy, renewables integration, T&D investment deferral, reducing generation costs, reducing customer outages, and combination of these benefits streams. This conclusion is robust across a range of modeled scenarios. The economically optimal levels of cumulative storage deployment will depend in large part on the speed with which energy storage costs continue to decline.

Appendix: Analytical Approach Details

A. Reduction in Production Costs

To estimate the cost of meeting Nevada's electricity demand and ancillary service needs we use the Power System Optimizer (PSO) power system simulation module of The Brattle Group's bSTORE storage modeling platform.[74] Like other commercially available power system simulation tools, PSO simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system based on a direct-current (DC) load flow algorithm. PSO has the capability to capture the full range of operational and economic considerations relevant to system planning, including transmission constraints, contingency constraints, co-optimizing for energy and multiple reserve products, GHG pricing/costs, and limits on unit flexibility due to commitment (*e.g.*, startup costs, minimum generation, minimum up times) and ramping considerations.

Figure 27 below illustrates the different day-ahead and real-time time horizons over which the unit commitment and dispatch decisions are made in the WECC. As indicated by the red box surrounding the day-ahead unit commitment and day-ahead unit dispatch steps, the power system simulations undertaken for the purpose of this study roughly approximate the scope of day-ahead operations. The analysis therefore does not capture additional storage benefits that may accrue in real-time operations (considering uncertainty between day-ahead and real-time market conditions), although our analysis does capture some of the benefits associated with Nevada's participation in the Energy Imbalance Market (EIM), as described later in this section.

Figure 27
Scope of Production Cost Modeling
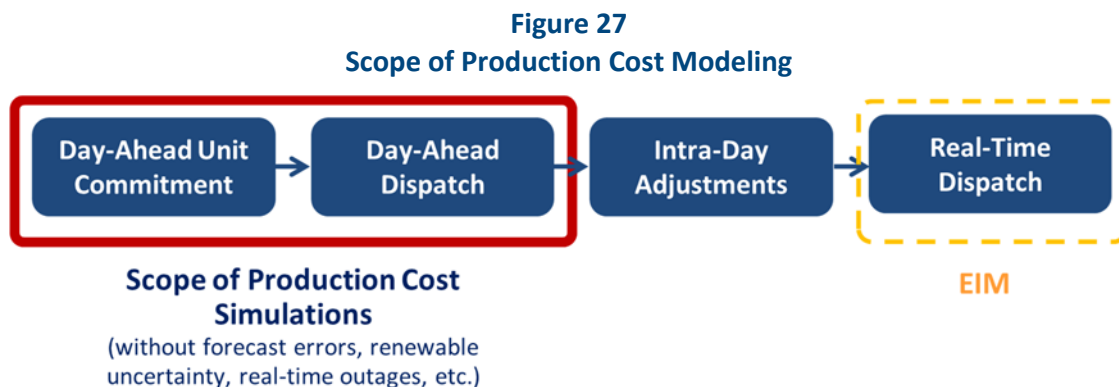
To simulate WECC power system operations, we begin with the 2026 TEPPC Common Case as refined by the CAISO for its 2017 Transmission Planning Process (TPP) and make further refinements for 2020 and 2030 using publicly-available data and data provided the NV Energy to model Nevada consistent with NV Energy's 2018 IRP. The TEPPC Common Case is widely used across the WECC by load-serving entities, transmission planners, transmission owners, and

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[74]   Polaris (2018). For an overview of bSTORE, see http://www.brattle.com/bstore.

balancing authorities for purposes including transmission studies and evaluations of major policy and technology changes for the future of the Western Interconnect. For example, the TEPPC Common Case model as refined by CAISO was recently used as the starting point for evaluating the impact of a regionalized market in the WECC.[75]

WECC develops the TEPPC Common Case data based on all participating balancing authorities' forecasts of load, transmission, and generation supply. The 2026 TEPPC Common Case reflects expected loads, resources, and transmission topology across the WECC in 2026, 10 years after the study reference year of 2016.[76] Its primary goal is to provide a detailed and accurate representation of the 2026 WECC power system, accounting for the most recent planning information, generators and transmission developments, regulations, and policies. Using the 2026 TEPPC Common Case as refined by the CAISO as a starting point provides thousands of carefully vetted assumptions on generator characteristics, transmission lines and limits, bus-node mappings, hourly load and solar/wind generating profiles, and hydro inputs necessary to accurately model the WECC-wide footprint.[77] We rely on the CAISO's version of the TEPPC Common Case (with CAISO permission) because doing so provides the added benefit of modeling the CAISO market more accurately (including California carbon charges on internal generation and imports), which is important given the close proximity to Nevada and the significant interties, bilateral trading opportunities, and EIM transfers between Nevada and California.

We make the following refinements to the CAISO's version of 2026 TEPPC Common Case datasets to better align our model with updated forecasts of load and generation supply described in NV Energy's 2018 IRP:[78]

- **Hourly Load Profiles.** For the modeled hourly load profiles, we take the shape of the Nevada load profiles given in the 2026 TEPPC Common Case and adjust for the total energy demand and peak load forecasted for 2020 and 2030 in NV Energy's 2018 IRP.[79] By making this adjustment we keep the same hourly load profile shape from the TEPPC data but ensure that total Nevada energy demand and peak loads are correctly modeled for each of our cases. Table 17 shows our modeled total energy demand and peak load for 2020 and 2030. These values reflect total energy and peak load for NPC and SPPC only. To account for the rest of Nevada, we use SNL and the 2026 TEPPC Common Case to increase total energy and peak load to align with the state-wide values.

- **Generating Capacity.** We align Nevada's generating capacity in the simulations with NV Energy's 2018 IRP, including updates to nameplate capacity, installation and retirement dates, and planned new generators. This includes 1,001 MW of additional solar

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[75]   The Brattle Group, *et al.* (2016).

[76]   WECC (2016).

[77]   WECC (2018).

[78]   NV Energy (2018a).

[79]   This includes accounting for the 2020 leap year.

and 100 MW of battery storage by 2030 in the Base Case.[80] We include non-NV Energy generators located in Nevada in our modeling.

- **Natural Gas Prices.** NV Energy provided confidential gas price forecasts for seven natural gas hubs (SoCal, Rockies, Malin, Alberta, Sumas, Waha, and San Juan) while the 2026 TEPPC Common Case includes prices for 25 natural gas hubs. To keep consistency with NV Energy's 2018 IRP we mapped each hub in the TEPPC Common Case to one of the seven hubs provided by NV Energy, as shown in Table 18.

- **Plant Operating Characteristics.** NV Energy provided confidential unit operating characteristics of generating plants in Nevada such as heat rates, ramp up/down rates, start-up costs, and regulation up/down capability—which we use to update the input data for Nevada generating plants in our model.

- **Behind-the-Meter Generation.** We update Nevada's Behind-The-Meter (BTM) generating capacity to stay consistent with NV Energy's 2018 IRP. Table 17 shows the BTM generating capacity for 2020 and 2030.

- **Regulating Reserve Requirements.** We update Nevada's 2020 and 2030 hourly regulating reserve requirement based on the confidential data received from NV Energy. The spinning reserve and frequency reserve requirements are taken from the 2026 TEPPC Common Case, which are 3% of modeled load and 98 MW in each hour, respectively.

Table 17
NV Energy Model Inputs

		2020	2030
Nevada Power Company			
Total Energy	(GWh)	20,985	22,260
Peak Load	(MW)	6,000	7,107
Behind-the-Meter Capacity	(MW)	149	284
Sierra Pacific Power Company			
Total Energy	(GWh)	9,855	9,323
Peak Load	(MW)	1,811	1,894
Behind-the-Meter Capacity	(MW)	36	100

Sources and Notes:
  NV Energy (2018a) reports data for NPC and SPPC, which excludes some load and capacity in the Nevada footprint. We use SNL to account for the difference in our model inputs.

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[80] Consistent with NV Energy's 2018 IRP, our study assumes NV Energy remains the utility responsible for serving most retail customers in Nevada and Energy Choice Initiative does not pass. If it were to pass then this planned capacity would not proceed.

Table 18
Gas Hub Mappings

2026 TEPPC Common Case	2018 IRP Hub Mapping
NG_AB	NG_Alberta
NG_AZ North	NG_San Juan
NG_NM North	NG_San Juan
NG_CA SoCalB	NG_SOCAL
NG_CA PGaE BB	NG_SOCAL
NG_CA SDGE	NG_SOCAL
NG_CO	NG_Rockies
NG_BC	NG_Sumas
NG_MT	NG_Rockies
NG_ID North	NG_Alberta
NG_OR Malin	NG_Malin
NG_ID South	NG_Sumas
NG_WY	NG_Rockies
NG_WA	NG_Sumas
NG_NV North	NG_Malin
NG_NV South	NG_SOCAL
NG_CA SJ Valley	NG_SOCAL
NG_TX West	NG_Permian
NG_UT	NG_Rockies
NG_NM South	NG_Permian
NG_CA SoCalGas	NG_SOCAL
NG_CA PGaE LT	NG_SOCAL
NG_Baja	NG_SOCAL
NG_AZ South	NG_SOCAL
NG_OR	NG_Sumas

Source:
    S&P Global Market Intelligence (2018) for hub mapping.

Model Input Adjustments for the Rest of WECC

After making refinements for Nevada, we adjust inputs for the rest of WECC. These refinements include the following:

- **Generating Capacity.** We adjust generating capacity outside of Nevada for both 2020 and 2030. The 2026 TEPPC Common Case identifies those generators expected to be online in 2020 and those expected to have retired prior to 2020. We use NV Energy's 2018 IRP and other public sources to confirm the installation and retirement dates for large generators across WECC in the 2026 TEPPC Common Case align with the most current available

data.[81, 82]   We account for all new builds and retirements between 2026 and 2030 as specified in the 2026 TEPPC Common Case. In addition, we confirmed that the 2030 wind and solar generating capacity in each WECC state is consistent with the levels required to meet state Renewable Portfolio Standard (RPS) goals.[83]

- **Behind-the-Meter Generating Capacity.** Our 2020 model utilizes preliminary demand forecasts from the California Energy Commission to estimate growth in Behind-the-Meter (BTM) generation between 2020 and 2026 in California. With this trend, we scaled back BTM capacity from the assumptions made in the 2026 TEPPC Common Case across all of WECC, excluding Nevada (we modeled Nevada BTM based on NV Energy's 2018 IRP, as described earlier). For our 2030 model, we use the 2026 TEPPC Common Case model inputs for behind-the-meter capacity.

- **Non-Gas Fuel Prices.** To adjust fuel prices for our 2020 and 2030 cases, we use a combination of the 2026 TEPPC Common Case fuel prices and Energy Information Administration (EIA) fuel price forecasts. For non-gas fuel prices outside of Nevada, we use the EIA's 2018 Annual Energy Outlook forecasted price change between 2020 and 2026 by fuel type and apply the percentage change to the 2026 TEPPC Common Case fuel prices to arrive at our model 2020 prices.[84] We use the same method to make refinements for the 2030 prices.

- **Hurdle Rates for Transactions Between WECC Balancing Areas.** Generator operations and energy transfers between regions are subject to transactions costs and transactional barriers. We simulate these transactions-related charges and/or inefficiencies as pre-specified "hurdle rates" between Balancing Authority (BA) areas in PSO. These hurdle rates include wheeling and other transmission-tariff-related charges for transactions between BA areas, additional transactions costs associated with bilateral trading, and GHG charges for any emissions associated with market-based energy imports into California. Wheeling charges are the fees transmission owners receive for the use of their transmission system to export energy and are set in transmission owner's FERC-regulated Open Access Transmission Tariffs (OATTs). Other transmission-tariff-related charges include charges for scheduling, system control, reactive power, regulation, and operating reserves imposed by each balancing authority in addition to the wheeling charge for transmission service. Further, we include transaction costs to represent the bilateral trading margins that need to be obtained by buyers and sellers before bilateral purchase and sale transactions will take place.

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[81]   Sources include ABB Inc.'s Energy Velocity Suite (2018) and S&P Global Market Intelligence (2018).

[82]   For example, the 2026 TEPPC Common Case models Navajo coal plant's units 2 and 3 as online in 2020 and we update this to reflect recent announcements that Navajo is expected to retire at the end of 2019. Maloney (2018).

[83]   We calculate the RPS percentage of the 2026 TEPPC Common Case generating capacity and for any state that is below their RPS target, we add generic wind and solar plants in order to meet the RPS target. DSIRE (2018).

[84]   EIA (2018).

When we simulate the unit-commitment cycle in the production cost simulations, the transmission hurdle rates include additional "friction" costs to reflect the preferences for committing generation units within each BA area (over imports) consistent with the experience from actual system operations. We adopted the hurdle rates utilized in the SB 350 study for CAISO as they account for the additional costs associated with bilateral purchase and sale transactions. These hurdle rates are shown in Table 19.

- **EIM Adjustments.** The Energy Imbalance Market (EIM) is a real-time market that allows participants to buy and sell energy with no wheeling charges (up to a specified transfer limit) to resolve any imbalances not resolved from the day-ahead market. As we described above, within the PSO day-ahead modeling framework we approximate EIM real-time market operations by implementing "hurdle-free" paths between EIM balancing authorities areas specified in Figure 28.

- **Carbon Pricing.** Our 2020 simulations include a generic carbon price for all emitting California generators and imports into California, consistent with California's current cap-and-trade program. We use the 2015 Integrated Energy Policy Report (IEPR) Updated "mid-baseline" scenario as the carbon price applicable in California. For our 2030 run, we implement a WECC-wide carbon price consistent with the assumption in NV Energy's 2018 IRP—assuming that there will be a federal cap-and-trade regime starting in 2025.[85] This means we remove the carbon price adder applied to emitting California generators and imports into California and, instead, charge all emitting resources across the WECC a carbon price for every ton of carbon emissions. The 2030 carbon price we model is $12.50/ton in 2016 dollars, based on the assumption used in NV Energy's 2018 IRP.[86]

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[85]   NV Energy (2018a), Volume 11.

[86]   NV Energy (2018a), Volume 11. The price was based off of the IRP's "MidC" carbon price. "The second is a 'Mid CO$_2$ Price' scenario, in which a national cap-and-trade program is assumed to be put in place, with a cap consistent with allowance prices assumed to begin in 2025 at $10 per metric ton (2017$) and increase each year at a 5 percent real rate." We use a 2% inflation rate to convert from 2017$ to 2016$.
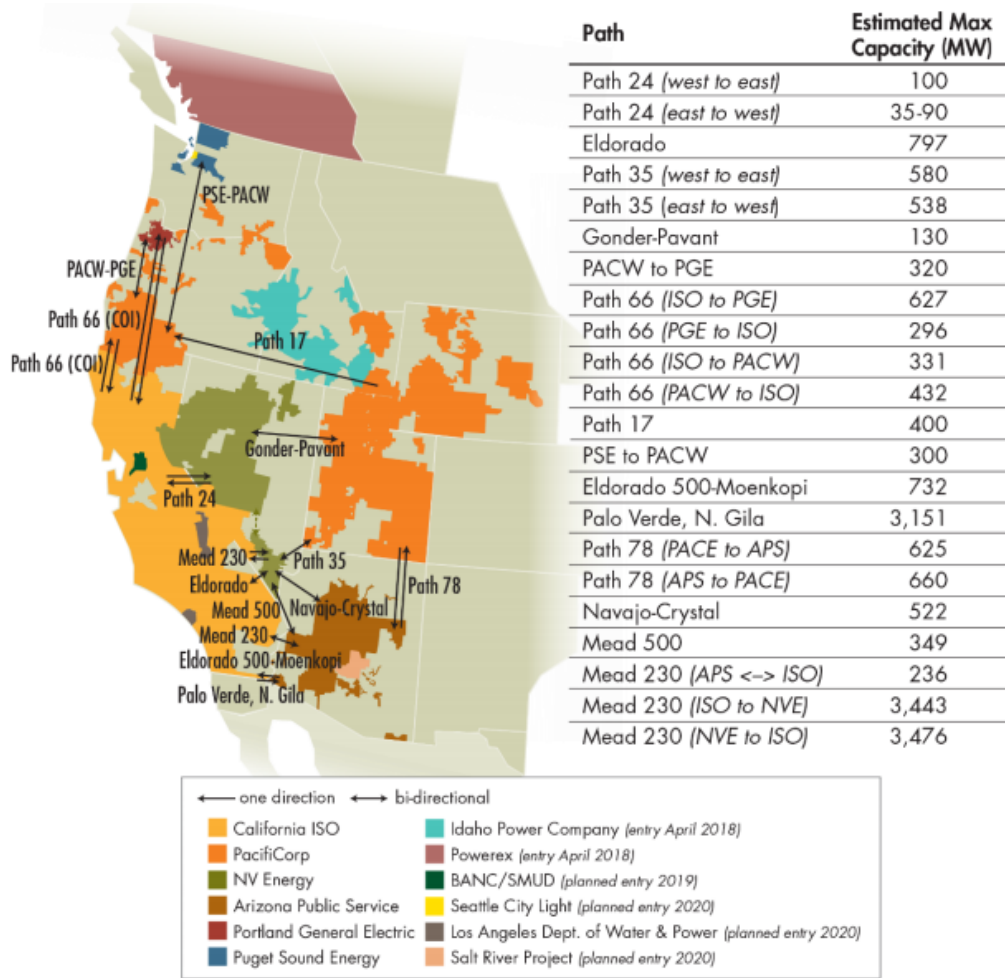
Table 19
Hurdle Rate Assumptions (2016$/MWh)

Balancing Authority	Modeled Hurdle Rate for Dispatch	Additional Hurdle Rate Applied During Unit Commitment
AESO	$7.2	$4.0
AVA	$7.8	$4.0
APS	$6.1	$4.0
BANC	$4.1	$4.0
BCHA	$7.4	$4.0
BPA	$6.3	$4.0
CAISO	$13.5	$4.0
CFE	$4.3	$4.0
CHPD	$6.3	$4.0
DOPD	$6.3	$4.0
EPE	$5.2	$4.0
GCPD	$6.3	$4.0
IID	$3.0	$4.0
IPCO	$4.7	$4.0
LDWP	$7.1	$4.0
NEVADA	$5.8	$4.0
NWMT	$6.3	$4.0
PACE	$5.3	$4.0
PACW	$5.3	$4.0
PGE	$2.7	$4.0
PNM	$8.0	$4.0
PSCO	$6.6	$4.0
PSEI	$4.5	$4.0
SCL	$3.1	$4.0
SRP	$4.2	$4.0
TEPC	$5.1	$4.0
TIDC	$4.5	$4.0
TPWR	$5.0	$4.0
WACM	$7.4	$4.0
WALC	$4.2	$4.0
WAUW	$6.0	$4.0

Sources and Notes:
  Brattle analysis based on Schedule 8 of Open Access Transmission Tariffs (OATTs) and other public data on transmission rates.

Figure 28
EIM Transfer Capabilities

Path	Estimated Max Capacity (MW)
Path 24 *(west to east)*	100
Path 24 *(east to west)*	35-90
Eldorado	797
Path 35 *(west to east)*	580
Path 35 *(east to west)*	538
Gonder-Pavant	130
PACW to PGE	320
Path 66 *(ISO to PGE)*	627
Path 66 *(PGE to ISO)*	296
Path 66 *(ISO to PACW)*	331
Path 66 *(PACW to ISO)*	432
Path 17	400
PSE to PACW	300
Eldorado 500-Moenkopi	732
Palo Verde, N. Gila	3,151
Path 78 *(PACE to APS)*	625
Path 78 *(APS to PACE)*	660
Navajo-Crystal	522
Mead 500	349
Mead 230 *(APS <–> ISO)*	236
Mead 230 *(ISO to NVE)*	3,443
Mead 230 *(NVE to ISO)*	3,476

← one direction ←→ bi-directional

- California ISO
- PacifiCorp
- NV Energy
- Arizona Public Service
- Portland General Electric
- Puget Sound Energy
- Idaho Power Company *(entry April 2018)*
- Powerex *(entry April 2018)*
- BANC/SMUD *(planned entry 2019)*
- Seattle City Light *(planned entry 2020)*
- Los Angeles Dept. of Water & Power *(planned entry 2020)*
- Salt River Project *(planned entry 2020)*

Sources and Notes:
  CAISO (2018).
  Imports into California are charged a generic carbon price for the 2020 model runs.

We estimate the incremental adjusted production cost savings from an additional MW of storage at both the 200 MW and 1,000 MW storage deployment levels using a non-linear quadratic relationship between total adjusted production cost and the amount of storage deployed, as shown in Figure 29. The slope of this relationship yields an estimate for the marginal value of adjusted production cost savings as a function of storage deployed at each level of storage deployment.

Figure 29
Incremental Adjusted Production Cost Savings
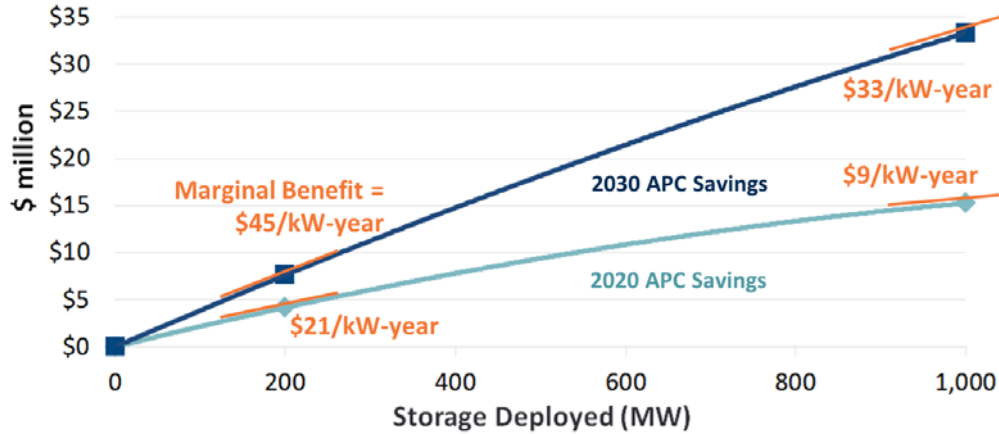
Sources and Notes:
   Savings estimated using a quadratic fit. All values in nominal dollars. Orange lines represent estimates of
   marginal benefit at each simulated eployment level.

B.   Avoided Generation Capacity

We evaluate the ability of storage facilities to discharge in hours with the highest net peak loads, thereby offsetting the need for generation capacity to meet resource adequacy requirements. We then value the quantified reductions in the need for capacity at NV Energy's forecasted future market prices for capacity, which NV Energy uses to value its open capacity position.[87]

We assume that reducing annual net peak loads by 1 MW offsets the need to build or procure 1 MW of incremental generation capacity, and that future capacity needs for resource adequacy are driven by Nevada net peak load.[88] Peak loads are concentrated in summer months, and the reliability modeling in NV Energy's general rate cases shows that that peak loads during July and August represent more than 90% of loss of load event risk in Nevada.[89]

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[87]   NV Energy (2018a), Volume 11 p. 161.

[88]   Peak load is evaluated net of Nevada solar generation, wind generation, behind-the-meter generation, and energy efficiency.

[89]   NPC (2017), Volume 10 p. 60.

Figure 30
Nevada Average Daily Load Shapes, by Season
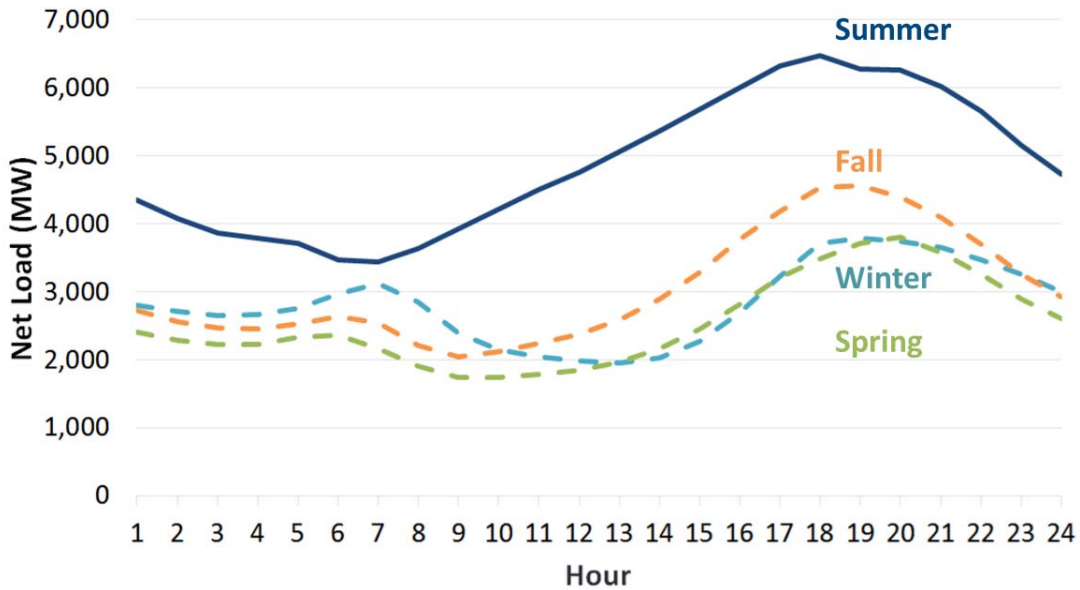
Sources and Notes:
   Hourly load data from 2026 TEPPC Common Case.
   Net load is net of renewables, distributed generation, and energy efficiency.

The likelihood of each day being the annual peak load day cannot be known precisely *ex ante*. To account for this uncertainty, we identify a subset of "peak days" during which the system operator would likely need to discharge the battery in a manner that reduces system net peak and thus capture capacity value. Before each day, we assume the system operator will flag the upcoming day as a potential annual peak load day, based on that day's net peak load and their forecast of annual peak load. If the daily net peak load is within a sufficient margin of the forecast annual peak less the MW of storage deployed, the day is categorized as a peak load day.[90] In 2020, we identify 10 potential "peak days" for a 200 MW deployment, and 44 potential "peak days" for a 1,000 MW deployment. For our 2030 mode, we identify 8 and 33 days, respectively, for the same 200 MW and 1,000 MW storage deployments. For days identified as potential peak days, we assume the system operator will utilize the storage facilities to discharge in hours with the highest system net peak load.

To simulate these operations of storage facilities to reduce net peak loads, we added the necessary constraint to the PSO simulations in our bSTORE model. The constraint is associated with a new term in the objective function that incurs a cost proportional to capacity costs multiplied by the net load less the battery output. In other words, the additional constraint rewards the storage for each MW that it reduces the daily net peak on "peak days". The reward per MW is determined by

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[90]   The daily net peak load is deemed sufficiently close if it is within the "1 in 10 peak temperature" margin from the 2018 NV Energy Confidential IRP. Though this margin was originally intended to estimate an upper bound on the amount by which annual peak exceeds forecast peak, we instead use it to describe an upper bound on the amount by which forecast peak exceeds annual peak (90% of the time).

distributing capacity costs across the identified "peak days." This approach allows our simulations to realistically capture the trade-off between using storage for the purpose of reducing production costs versus providing generation capacity value for resource-adequacy. Otherwise, the storage may discharge to reduce production cost even though discharging to reduce net peak might capture much more value during other hours of the day. In that case the storage investments would capture a capacity value that is lower than is economically optimal.

C. Transmission and Distribution Investment Deferral

Our analysis of transmission and distribution deferral value is based data from NV Energy's 2018 transmission and distribution capital expenditure outlook. This dataset summarizes all major T&D projects currently planned through 2027, providing projected annual project costs, the projects' location, and a brief description of each project and why it is needed. Based on the provided descriptions, we identified those projects needed for load growth—which may have the potential to be deferred with storage. These load-growth-related T&D projects were typically transformer upgrades or other types of feeder reinforcement needed to accommodate load growth. We flagged 35 individual projects, or 14% of all projects in the data provided as potentially deferrable by storage. We scale up the number of opportunities by 30%, consistent with NV Energy's understanding that the current expenditure plan likely understates the need for investment in out years due to planning uncertainty. The capital expenditure plan shows approximately 30% higher annual expenditures in years 2018–2021 than for 2022–2027 in support of this scaling approach.

Once we have identified projects potentially deferrable by storage, we estimate the value of deferring the investment by 15 years, the assumed lifespan of the battery assets. We value investment deferrals assuming a cost of capital consistent with the weighted average cost of capital reported in NV Energy's 2018 IRP.[91] We assume the full, undiscounted cost of the investment is deferred by 15 years.

We next evaluate the size of storage required to defer each investment by 15 years. We make several assumptions to approximate how much storage may be required. These assumptions include:

- **Initial Peak Load.** We assume each potential project has an initial peak load based on the descriptions provided in NV Energy's capital expenditure outlook. For example, if a project description identifies that an existing 7 MVA transformer will be upgraded due to anticipated load growth, we assign an initial peak load of 6.3 MW (assuming a 90% power factor).

- **Rate of Load Growth.** We assume feeders experience a 2% annual load growth rate. This rate of growth is intentionally higher than NV Energy's average system-wide peak growth

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91 NV Energy (2018a), Volume 11, p. 205. 7.64% average weighted cost of capital assumed, based on reported 7.95% weighted cost of capital for NPC and 6.65% weighted average cost of capital assumed for SPPC, weighted based on each utility's contribution to NV Energy's total system peak load (24% SPPC, 76% NPC).

rate, reflecting that locations requiring upgrades may be experiencing higher than average load growth. Under a lower rate of load growth, smaller storage systems would be able to support a 15-year deferral.

- **Hourly Load Shape.** The local hourly load shape affects the size of storage required to fully offset a 15-year deferral, both in terms of the MW and MWh requirement. For example, a substation experiencing flat, long-duration peaks will require storage with more MWh of capacity than a substation experiencing large but short-duration peaks. Given a lack of data on local load shapes at each substation, we assume each opportunity either experiences a typical residential customer load shape or commercial and industrial customer load shape.[92] Figure 31 illustrates the average load shapes experienced by NV Energy customers during a typical peak day. Our allocation of each substation to either a residential or commercial and industrial feeder is based on each customer class's contribution to peak load growth.

Figure 31
Average Peak Day Load Shapes by Customer Class
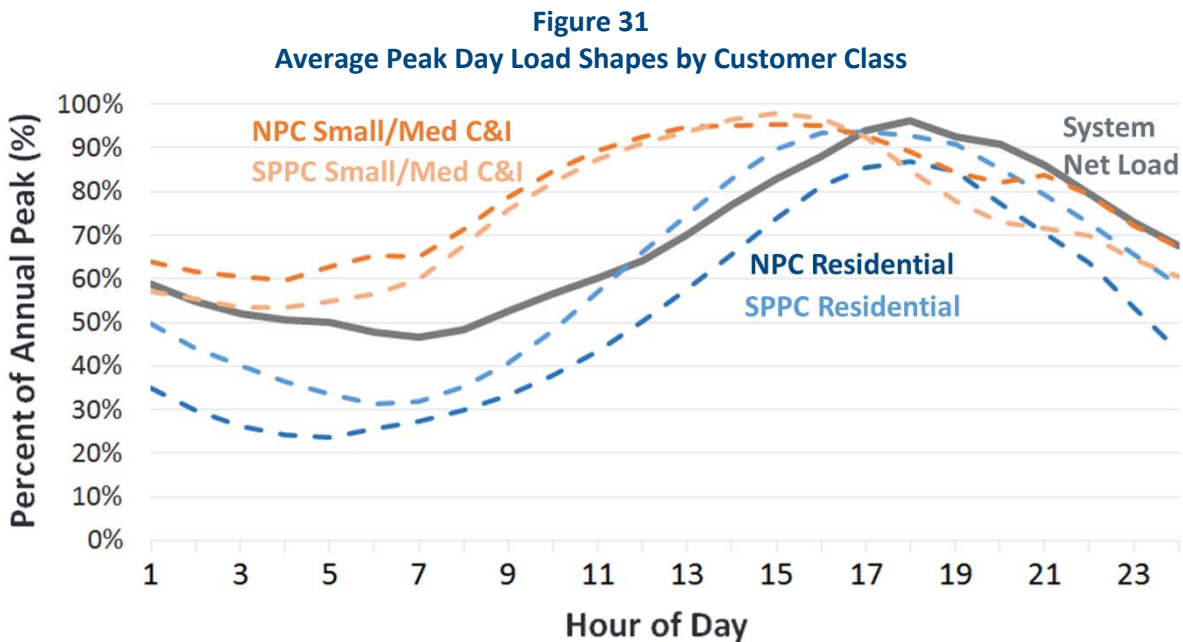
Sources and Notes:
  Load by Customer Class data, provided by NV Energy.
  Load Shapes are averaged over top 10 peak days.

Table 20 illustrates our overall approach to estimating transmission and distribution cost deferral. We conduct this approach for each deferral opportunity and evaluate on a $/kW-year basis the annualized deferral savings of using storage to defer each opportunity. We then order the identified opportunities from highest to lowest value, as shown in Figure 11 (in the body of this report).

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[92] NV Energy provided class-average hourly load shapes for residential, small/medium commercial and industrial, and large commercial and industrial customers in both SPPC and NPC. We utilized the residential and small/medium commercial and industrial load profiles.

Table 20
Examples of T&D Cost Deferral by Customer Class

			Customer Class	
			Residential	C&I
Starting Peak Load	[1]	(MW)	10	10
Peak Load Growth Rate	[2]	(%)	2%	2%
Total Peak Load in 15 years	[3]	(MW)	13.5	13.5
Required Battery Size / Growth	[4]	(%)	166%	253%
Battery Size to Defer 15 years	[5]	(MW)	5.7	8.7
Substation Upgrade Cost	[6]	($ million)	$3	$3
Cost Avoided by 15-yr Deferral	[7]	(%)	67%	67%
Deferral Savings	[8]	($/kW)	$349	$229
Annual Charge Rate Assumption	[9]	(%)	10%	10%
Estimated Value of Deferral	**[10]**	**($/kW-yr)**	**$36**	**$23**

Sources and Notes:
  Table reflects data and calculations for Nevada Power Company customer classes.
  [1] and [6]: Example assumptions roughly consistent with substation in NPC.
  [2]: Peak load growth assumption uniform for all NV Energy feeders.
  [3]: $[1] \times (1 + [2])^{15}$
  [4]: Calculated using load shapes derived from NV Energy load data. Equal to 123% for SPPC
  Residential and 175% for SPPC C&I.
  [5]: $[4] \times ([3] - [1])$
  [7]: NPV of 15-year investment deferral, consistent with NVE financing cost rates.
  [8]: $([6] \times [7])/(1,000 \times [5])$
  [9]: Payment on a level-real annualization of [8], levelized over a 30-year investment life.
  [10]: $[8] \times [9]$

We assume NV Energy will need to prioritize discharging storage to reduce local peak loads above all other potential applications, as described in greater detail in Section II.B, to achieve the T&D deferral. This means storage providing T&D deferral value may provide fewer production cost savings and avoided capacity cost savings than storage deployed to serve other purposes.

D. Customer Outage Reduction Value

Our analysis is based on historical data provided by NV Energy detailing outages on the Nevada distribution system. The historical outage data contains approximately 43,000 outage events that occurred across the SPPC and NPC territories between January 2014 and April 2018. For each outage event, the data provides the date and time, locational data such as substation and feeder name, outage cause, duration, number of customers affected, and whether the outage was forced or scheduled. We use the first two years of these data to identify the feeders that have historically demonstrated the lowest reliability, and use the remaining outage data to estimate the cost of lost load that storage assets deployed at these low-reliability feeders could have avoided.

Historical outages are an imperfect predictor of future outage patterns due to the random and unpredictable nature of outage events. Just because a feeder has experienced outages in the past

does not mean it will continue to experience outages in the future. To account for this limitation, we assume that storage would be sited to address reliability concerns based on historical outage data (2014–2015), and then assess the extent to which storage sited at those locations would mitigate outages in later years of the historical outage data (2016–2018). This two-step process allows us to incorporate some degree of uncertainty regarding the likelihood of future outages at each feeder. Figure 32 summarizes this approach.

The first step of the siting process uses two years of the available data (2014–2015) to rank the feeders by reliability. Reliability is estimated as the reduction in customer outages that could be achieved by storage asset deployed at each feeder. We exclude outages categorized in the dataset as storm-related, because storms can result in large system-wide outages that may not be representative of a feeder's typical reliability level.

The second step of this process uses the remaining outage data (2016–April 2018) to measure the ability of batteries located at the least-reliable feeders (identified in the first step) to reduce distribution outages. This second step includes storm outages as well because, once installed, the storage facilities will be able to reduce outages irrespective of whether or not they are storm related. To measure the ability of storage to reduce customer outages, we account for both the duration (hours) and magnitude (MWh) of each outage event. Storage facilities' ability to reduce outage severity is thereby bounded by both the battery's maximum output (MW) and the batteries' state of charge (MWh) at the time of the event.

Figure 32
Probabilistic Process for Deploying Storage to Reduce Distribution Outages
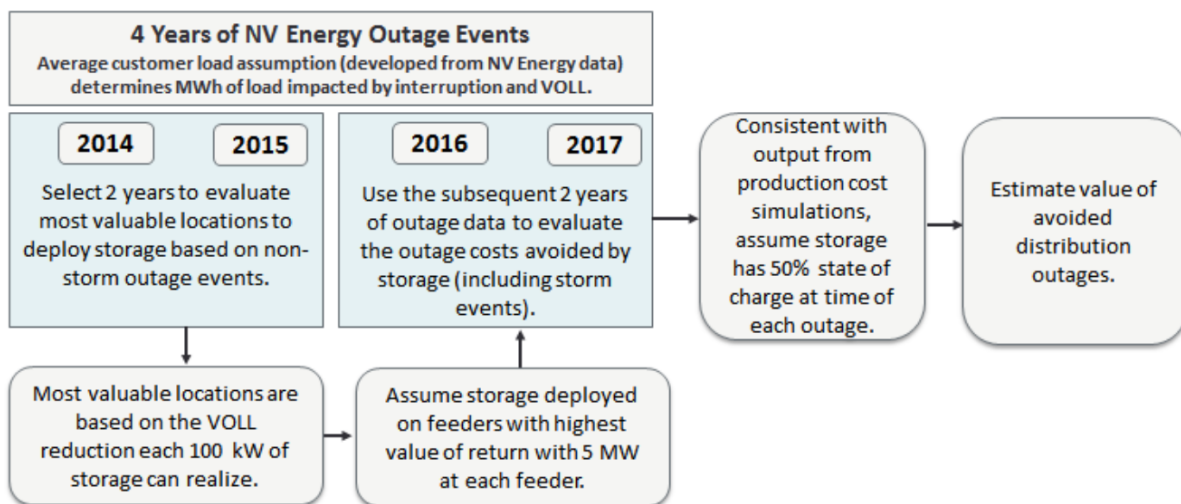
The deployment of storage facilities on distribution feeders is typically combined with pre-existing distribution automation initiatives that allow for the necessary remote switching of distribution feeders to isolate faults and utilize storage assets as backup systems to reduce distribution outages and while also providing system benefits. Various storage deployment configurations are possible and currently being tested in the field. For example, Southern California Edison, has deployed storage facilities at T&D substations, in community storage configurations, and in home storage

and zero-net-energy (ZNE) home storage applications (as illustrated in Figure 33) to operationally test customer outage reduction and other storage-related benefits.[93]

Figure 33
Examples of Storage Deployment on Distribution Networks
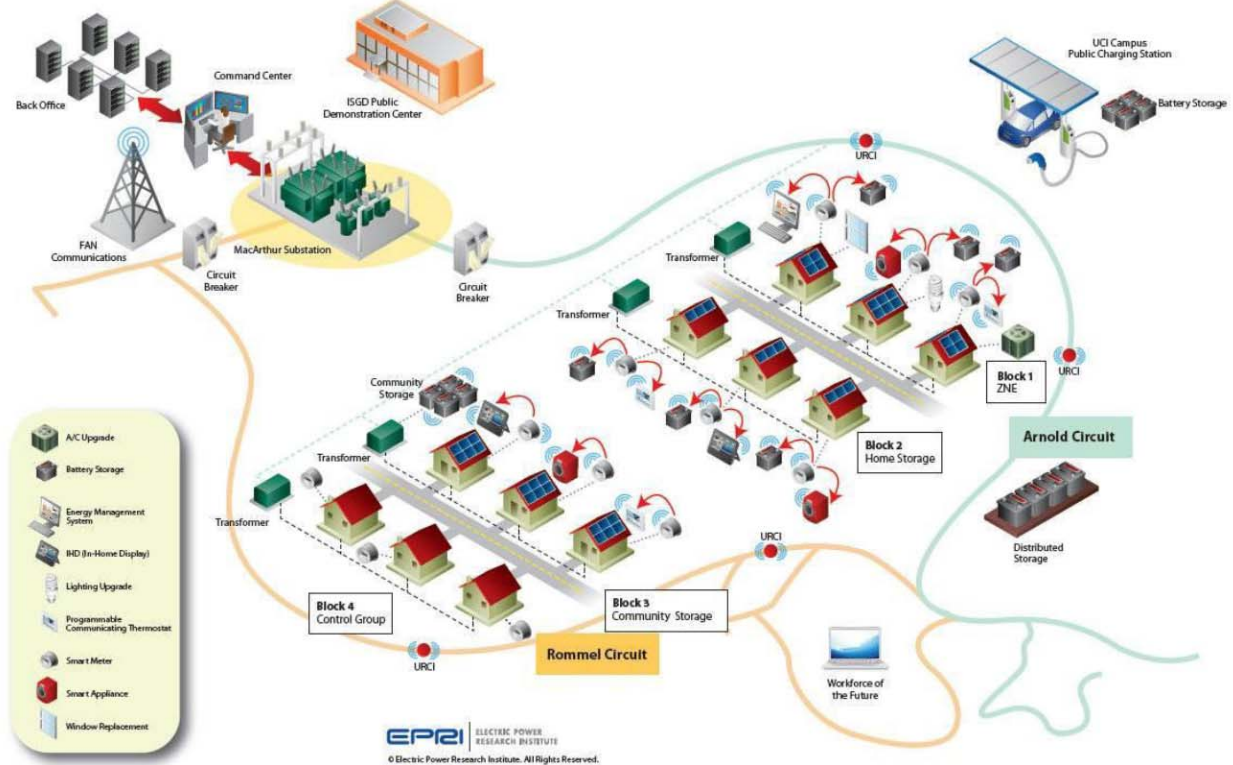
Source: SCE (2016)

Assumptions in our analysis of customer outage reduction benefits include the following:

- **Storage size.** We assume 5 MW (20 MWh) of battery storage is deployed on each of the feeders identified in Step 1. This sizing is roughly consistent with the average peak load at feeders in NV Energy's system.[94] This is an approximation as the size of each feeder varies depending on the number and class of customers served by the feeder.

- **Customer mix.** We assume the proportion of residential, commercial, and industrial customers at each location is consistent with Nevada's system-wide distribution of customers, about 88% residential, 12% commercial, and 0.3% industrial customers. This assumption influences both our estimates of the MWh of load shed during an outage event and the value of lost load (VOLL) customers would face due to the outage (as described more detail below).

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[93]   Southern California Edison (2016), Figure 209.

[94]   See Navigant (2010), p. 21.

- **Customer load profile.** Using historical sales data by customer class and hourly class load profiles, we develop a class-weighted hourly load profile that reflects Nevada's system-wide distribution of customers.

- **Limitations on types of outages avoided.** We assume storage can reduce any outage identified in the NV Energy dataset, regardless of outage code. We also assume the local distribution network is configured (and can be switched automatically during outage events) such that storage has the potential to fully offset any local outage that may occur as long as the storage facility has sufficient MW output and MWh of charge. We measure only the ability of storage to reduce outages on the primary distribution network, consistent with the scope of data provided by NV Energy.[95] We conservatively do not account for the ability of storage that can be deployed in a more distributed fashion in order to also reduce outages on the secondary distribution system. We also conservatively assume that any storage assets deployed for T&D cost deferrals would not be utilized to simultaneously reduce distribution-related outages at those locations.

- **Storage initial state of charge during outage events.** We assume each storage device on average holds a 50% state of charge when outage events occur. Data provided by NV Energy indicates that outage events are equally likely to occur at any time of year, suggesting it is generally difficult to anticipate such events. We also assume NV Energy would have little or no advanced notice with which to pre-charge storage immediately before an outage. Therefore, it is most likely that batteries would be generally used to provide other services such as energy arbitrage and ancillary services, rather than holding energy in reserve at all times due to the unlikely and unpredictable chance of a local outage event. The 50% state of charge assumption is consistent with the average state of charge we observe for storage as it is operated in our cost simulations.

- **Cost of associated distribution system automation upgrades.** Our analysis assumes the local distribution network is configured in such a way that it can be "islanded" automatically from the remaining transmission and distribution system and storage can activated to supply customer loads (and reduce the local outages) when islanded. This capability currently is not present in all NV Energy feeders and may require further network upgrades. We understand NV Energy is currently pursuing grid modernization efforts, including automated distribution switching and remote switching.[96] To the extent these grid modernization efforts are ongoing, we assume the addition of batteries would not incur additional distribution system upgrade costs. However, to account for the uncertainty around these costs and the possibility that such distribution system upgrades may not be cost effective for some feeders, we separately evaluate in Section IV of this report a sensitivity in which storage provides zero customer outage reduction value.

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[95] The primary distribution system refers to the part of the distribution network that connects from the substation to distribution transformers, with typical voltages of 4 kV to 35 kV.

[96] NV Energy (2016).

We approximate the customer value of outage reduction associated with such targeted storage investments by multiplying the MWh of reduced outages by the estimated value of lost load (VOLL). VOLL is an estimated measure of how different customers value access to reliable electricity. For the purpose of this analysis, we estimate the average VOLL for commercial and industrial customers to be $20,000/MWh and an average VOLL for residential customers to be $3,000/MWh.[97] These values, used in tandem with NV Energy's historical sales by customer class, yield an estimate of $12,500/MWh average VOLL across all Nevada electricity customers.[98]

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[97] Sullivan *et al.* (2009).

[98] Commercial and Industrial load makes up 57% of NV Energy load and Residential makes up 43%. 57% × $20,000 + 43% × $3,000 = $12,724.

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