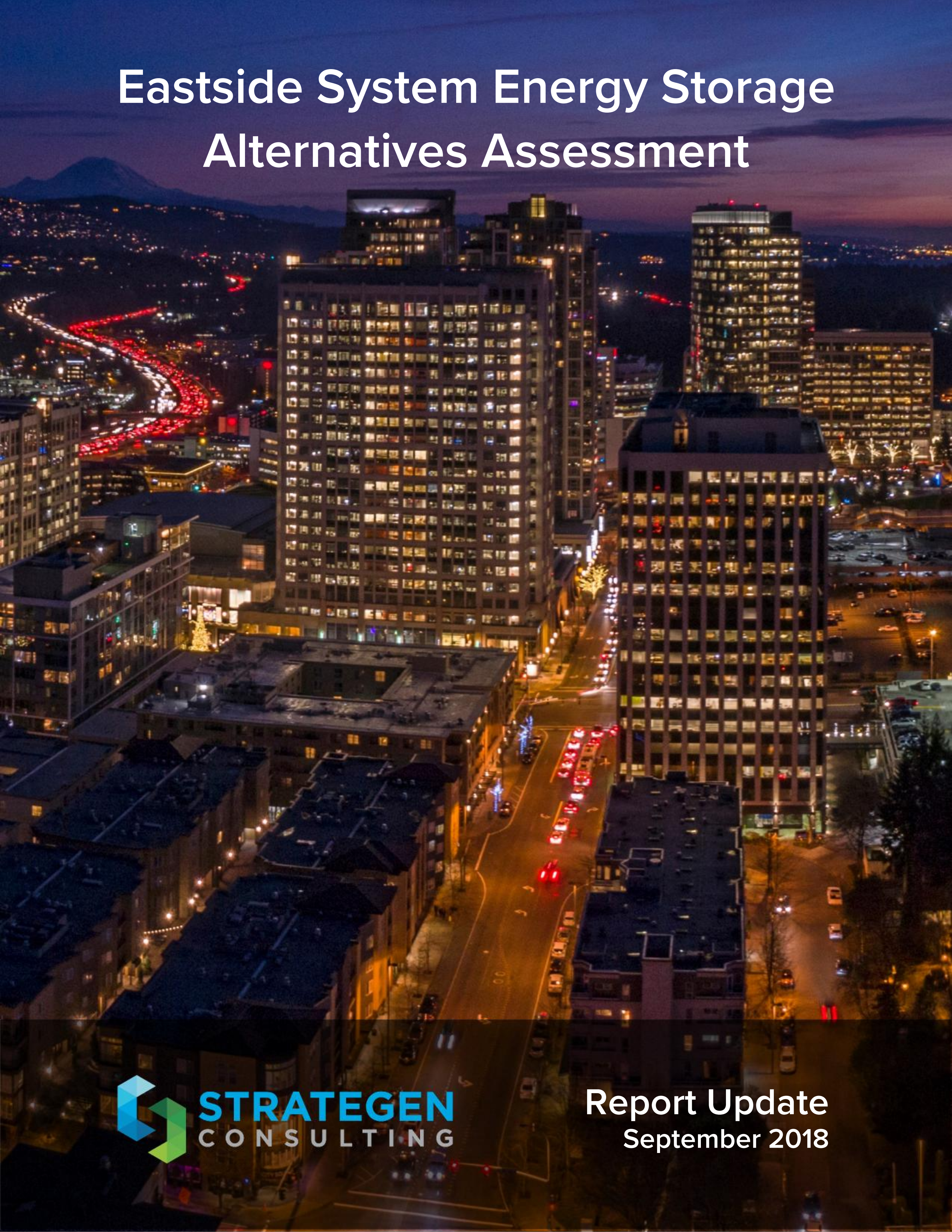
Eastside System Energy Storage Alternatives Assessment



STRATEGEN CONSULTING

Report Update
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Eastside System Energy Storage Alternatives Assessment Report Update – September 2018

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PSE PUGET SOUND ENERGY

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Executive Summary

Background

In 2014, Puget Sound Energy ("PSE") commissioned Strategen Consulting, LLC ("Strategen") to assess energy storage options for PSE's Eastside transmission capacity deficiency. At the time, PSE was evaluating several possible solutions to meet the transmission capacity deficiency identified in its North American Electric Reliability Corporation ("NERC")-required transmission planning studies. These studies concluded that growth in the Eastside area could cause demand for electricity to exceed the capacity of the Eastside's transmission system as early as winter 2017-2018.

Strategen's assessment culminated in the Eastside System Energy Storage Alternatives Screening Study issued in March 2015 (the "March 2015 Study").[1] Strategen's March 2015 Study concluded that an Eastside energy storage solution was not practical given the unique circumstances of the Eastside transmission system. The study recognized that while energy storage technologies were on the cusp of being commercially viable for some types of large-scale deployments, energy storage is not an effective solution for every type of power system constraint or application. The Energize Eastside constraint is a transmission and distribution ("T&D") reliability application, which differs from the applications of most energy storage deployments globally to date (see Figure 34)[2].

In January 2018, Strategen Consulting was asked to update the March 2015 Study to consider:

- Changes to equipment ratings on the Eastside, such as PSE's development of more seasonally precise and equipment-specific rating of the transformer bank capabilities at both Talbot Hill and Sammamish Substations.[3]
- 2017 refreshed PSE system load forecasts, as well as recent advances in the energy storage market.

2018 Findings

The conclusion of this updated analysis is consistent with the conclusion of the original March 2015 Study: energy storage is not a practical solution for the Eastside. Despite the significant commercial and technological progress made by the energy storage industry in recent years, energy storage is still not a practical solution to meet the Eastside transmission system capacity deficiency.

Notably, the technological and commercial readiness of energy storage is not the factor limiting its ability to meet the Eastside transmission capacity deficiency. Rather, the magnitude of the Eastside transmission system capacity deficiency renders storage an impractical solution. The required system (or systems) would be of unprecedented scale, thereby making it difficult to source, site and construct, even if it were broken into multiple smaller projects. And the physical impact of a storage solution would likely exceed that of a poles & wires solution.

[1] The March 2015 Study can be found here: http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/eastside_system_energy_storage_alternatives_screening_study_march_2015.pdf.

[2] While energy storage is becoming more frequently considered for distribution reliability applications, the large power/energy requirements typically necessary at the transmission level have historically rendered storage less practical for transmission reliability.

[3] This rerating dynamically accounts for the age of each individual transformer bank and the effects of seasonal weather on the thermal carrying capacity of each bank.

In this updated analysis, two storage solutions were considered-- an interim solution to meet constraints through 2019 and a complete solution to meet 2027 forecasted need.

1. **Interim Solution**
   The Interim Solution was developed in response to stakeholder interest. Here, Strategen evaluated the feasibility of interim measures sized only to meet the winter 2018/2019 and summer 2019 overload constraints for Talbot Hill Substation and Sammamish Substation, respectively. The Interim Solution assumed all other non-wires alternative ("NWA") load reduction solutions are implemented. The Interim Solution does not comply with planning criteria.

2. **Complete Solution**
   The Complete Solution evaluated an energy storage solution sized to meet the company's 2027 forecasted need, which is required for PSE to be in compliance with planning criteria (the same criteria met by the proposed transmission solution[4]). In this scenario, additional NWA solutions are also included.

The conclusions in this report update are consistent with the findings of the March 2015 Study. The characteristics of an energy storage system designed to meet planning requirements of a solution for the Eastside system are summarized as follows:

1) An energy storage system would be ***significantly more expensive than the proposed transmission wires solution***, costing approximately $825 million for the Interim Solution and increasing to approximately $1.4 billion for the Complete Solution,[5] compared to an estimated $150-$300 million[6] for the transmission wires solution;
2) The energy storage system would need to be of an unprecedented size, ***roughly 19 times the size of Tesla's Hornsdale facility in Australia (the largest currently installed system), just to meet the interim need by summer 2019, and 43 times the size of Hornsdale to meet the 10-year (2027) need***;
3) The commercial and supply-chain viability of an energy storage system for the Eastside area is unclear as ***it would exceed total US energy storage deployments in 2017[7] by approximately 6-13 times[8];***
4) The energy storage capacity required for Eastside by summer 2019 ***is approximately double the 1,233 MWh of total forecasted total energy storage deployments in the US[4] for 2018***[5]; and
5) The physical footprint of an energy storage system of the required scale would be significant: ***approximately 49 acres.***[9]

Strategen also investigated deployment of distributed energy resources such as the installation of small storage systems at homes, businesses, and other buildings in PSE's network. Distributed storage is neither viable nor cost-effective in this case. Even if there was significant customer adoption of behind-the-meter energy storage, it would not materially affect the Eastside transmission capacity deficiency: if every customer in PSE's Eastside area installed a storage system sized comparably to a Tesla Powerwall 2, only about half of the 2019 Eastside transmission

[4] PSE's proposed transmission solution builds a new substation and upgrades approximately 16 miles of existing transmission lines from Redmond to Renton.
[5] See page 55 for cost assumptions.
[6] https://energizeeastside.com/faq/who-will-pay-for-the-project-and-how-much-will-it-cost
[7] Residential, non-residential and in-front-of-the-meter storage systems.
[8] https://energystorage.org/news/esa-news/us-energy-storage-market-tops-gwh-milestone-2017-annual-deployments-exceed-1000-mwh (Accessed: Apr. 25, 2018; 2,394MWh/431MWh = 5.55 & 5,500MWh/431MWh = 12.76)
[9] Based on a double-stacked/two-level battery facility for the Complete Solution

capacity deficiency would be met, and less than a quarter of the 2027 Eastside transmission capacity deficiency[10] would be met. Theoretically, if enough distributed storage could be deployed to meet the entire Interim Solution, the cost would range from $1.1 to $1.7 billion, and $2.1 billion to $3.1 billion for the entire Complete Solution[11].

We focused our 2015 analysis on the batteries required to prevent system overload at the Talbot Hill substation, which was identified as having the largest need during required planning scenarios. By analyzing the system element with the largest constraint (i.e., the largest energy need on peak days), we were able to calculate the battery size needed to prevent overloads for the entire system. Following the imposition of updated equipment- and seasonally-specific transformer ratings and information from the 2017 King County load forecast, our 2018 analysis found that the largest system constraint moved from the Talbot Hill to Sammamish substation. Peak energy demand also shifted from winter to summer.

Table 1, which follows, summarizes our 2015 findings for Talbot Hill and our 2018 findings for both Talbot Hill and Sammamish substations. Sammamish substation results for 2015 are omitted as they were not analyzed in detail in that report as we concluded that overloads would be prevented with the installation of a storage system sized to meet the larger Talbot Hill constraint. In this table, the Interim Solution represents the most optimistic case for the smallest storage system that can meet the immediate 2019 system need. The Interim Solution does not include cell degradation or the increasing uncertainty in load forecasts as they progress further into the future, because the assessment is for the pending 2018/2019 winter and 2019 summer constraints.

[10] Based on the size required to meet the Interim (2019) and Complete (2027) Solutions.
[11] Indicative cost assuming a quoted price of $6,600 per installed 13.5 kWh system, per www.tesla.com (as viewed on August 16, 2018) for the Interim Solution, and a cost of $4,220 per incremental installed 13.5 kWh system to meet the number of BTM installations required to meet the Complete Solution, per Tables 4 and 5.www.tesla.com (as viewed on August 16, 2018) for the Interim Solution, and a cost of $4,220 per incremental installed 13.5 kWh system to meet the number of BTM installations required to meet the Complete Solution, per Tables 4 and 5.

Table 1: Sizing comparison of the March 2015 Study vs the 2018 Analysis

Constrained Element	Power (MW)	Energy (MWh)	Duration (hours)	Meets 2019 System Need	Meets Solution Requirements Through 2027[12]	Feasibility[13]
Original March 2015 Study Results[14]						
Talbot Hill	**545**	**5,771**	**10.6**	✔	not evaluated	✗
Sammamish[17]	*Assessed to be less than Talbot Hill sizing*					
2018 Analysis						
Interim Solution for 2019[15]						
Talbot Hill	290	1,689	5.8	✗ [16]	✗	✗
Sammamish[17]	**365**	**2,394**	**6.6**	✔	✗	✗
Complete Solution through 2027						
Talbot Hill	338	3,679	10.9	✔	✗ [16]	✗
Sammamish[17]	**549**	**5,500**	**10.0**	✔	✔	✗

Both the Interim and Complete Solutions would be of globally unprecedented size. This can be seen in Figure 1 where a comparison to total US energy storage deployments[18] per quarter and year can be seen, as well as the largest currently installed system in the world, the Hornsdale Power Reserve in South Australia (developed by Tesla), and the largest proposed procurement in the world, PG&E's 2,270 MWh local capacity procurement, which is comprised of multiple projects and is pending review by the California Public Utilities Commission[19].

[12] Meets 2027 requirements means satisfying the NERC/FERC planning criteria through 2027, the same planning criteria against which the ultimate Eastside solution must be judged (whether a wires or non-wires solution).
[13] Feasibility relates to electrical sizing, physical sizing, timing and the ability of the market to respond.
[14] The March 2015 Study evaluated solution requirements to meet a deferral need through 2021.
[15] Sized only to meet immediate 2019 constraint assuming all other NWAs per E3 NWA Report (2014) are implemented; size requirement would be larger if other NWAs are unable to be implemented.
[16] The Talbot Hill sizing is insufficient to meet the Sammamish need and therefore does not meet the system need for that entire year.
[17] Sammamish was assessed in the March 2015 Study, but Talbot Hill was the more significant constraint that defined the energy storage sizing. Due to several factors detailed in this report, Sammamish is now the greatest constraint that defines the size while Talbot Hill also exceeds NERC requirements.
[18] This includes all types of energy storage (residential, non-residential and utility) in-front-of-the-meter systems installed in a given timeframe.
[19] Source: Utility Dive. https://www.utilitydive.com/news/pges-landmark-energy-storage-projects-snagged-by-pushback/530007/. Accessed August 21, 2018.https://www.utilitydive.com/news/pges-landmark-energy-storage-projects-snagged-by-pushback/530007/. Accessed August 21, 2018.

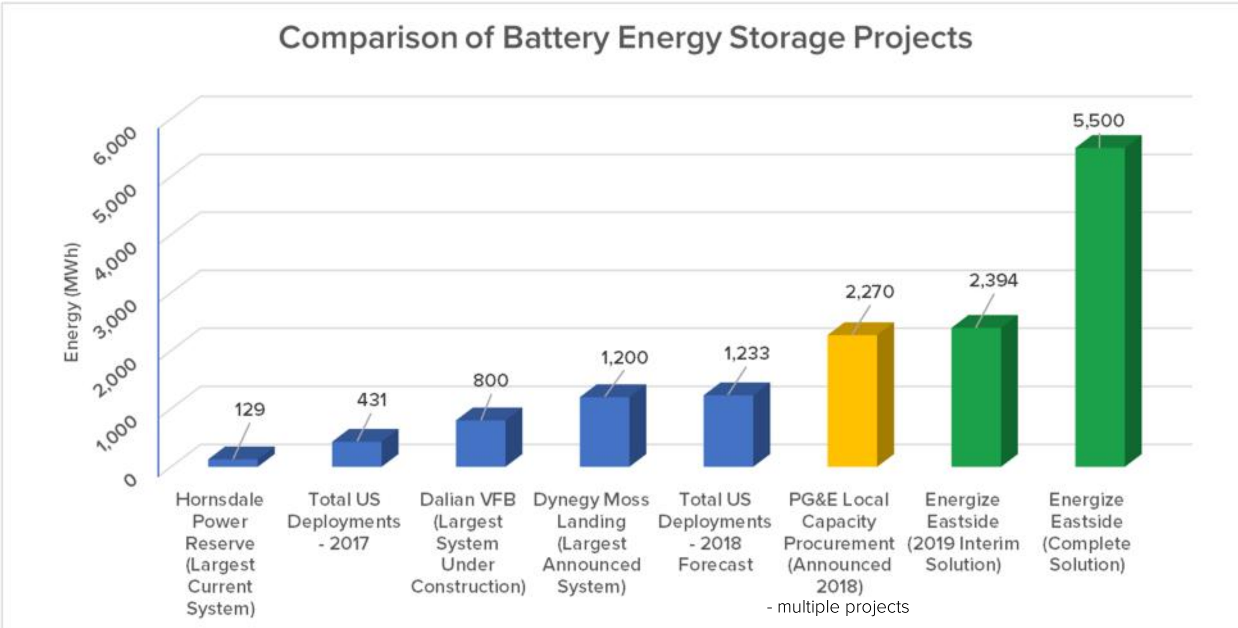

Figure 1: An energy storage system to solve the Eastside constraint in comparison to other projects[20]

In terms of physical impact, the footprint of the Complete Solution is estimated to be 49 acres, approximately one and a half times the size of CenturyLink Stadium. This assumes the solution is built as a single facility, with the Interim solution built as a single-level system and expanded vertically into a double stacked/two-level configuration to meet the Complete Solution. Figure 2 shows an indicative footprint that these arrangements would require if built as a single facility.

Figure 2: Approximate indicative footprint of the Eastside storage solution. Red represents a single-level interim Solution, 59 acres, and yellow represents a double-level Complete Solution, 49 acres.

[20] Source: UtilityDive, PG&E, GTM Research and ESA. PG&E local capacity procurement represents multiple projects with online dates ranging from December, 2019 to December, 2020 if approved by the California Public Utilities Commission.

While storage is becoming a technology embraced by the power sector to modernize and enhance the grid, the specific circumstances and requirements driving the Eastside transmission capacity deficiency are not well-suited to an energy storage solution. Such a solution would need to be of unprecedented scale, exceeding the total forecast 2018 US energy storage deployments,[21] both behind and in front of the meter. It would therefore be impractical to source, site and construct. In addition, it would come at a cost many times that of the traditional poles & wires solution.

For these reasons, despite the commercial and technological progress of energy storage in recent years, the conclusion of this updated analysis remains consistent with the conclusion of the original March 2015 Study. Strategen does not believe energy storage to be a practical option to meet the Eastside transmission capacity deficiency, either as an alternative to the proposed transmission solution or as a way to defer it.

[21] This includes all types of energy storage; residential, non-residential and utility in-front-of-the-meter systems.

1. Eastside System Storage Configurations and Feasibility

Strategen conducted a refreshed analysis to assess how updated conditions in the Eastside area (and of the energy storage market) affect the technical requirements and sizing of an energy storage system that meets the Eastside transmission capacity deficiency.

1.1 Overall Objectives and Methodology

This report evaluates the amount of storage that would be necessary to eliminate overloads at Talbot Hill and Sammamish substations during certain system contingencies each year between 2018 through 2027. Storage deployed in such a use case would avoid or defer the need for a traditional "poles and wires" solution for the Energize Eastside project.

The 2018 Analysis generally used the same methodology developed for the March 2015 Study, with certain exceptions as identified in this report which were designed to refresh or enhance the original March 2015 Study. The methodology is summarized below and detailed in subsequent sections, and sizing using the original methodology was also run for reference, which can be found in the Appendix. The 2018 Analysis did not rerun the cost-effectiveness analysis conducted as part of the March 2015 Study; however, it did reassess whether the original unit cost assumptions remain accurate.

The methodology used to size the storage system relied upon loading forecasts provided by PSE for impacted transformer elements under normal conditions and during N-1-1 system contingencies. In the case of the March 2015 Study, the element loading forecasts were generated using systemwide and King County load forecasts from PSE's 2013 Integrated Resource Plan. In the case of the 2018 Analysis, the element loading forecasts were generated using systemwide and King County load forecasts from PSE's 2017 Integrated Resource Plan.

Strategen assumed that all cost-effective NWAs (other than energy storage) would be implemented according to the timeline identified in the 2014 E3 Non-Wires Alternative Report (see the Appendix for details). Other NWAs include incremental energy efficiency, distributed generation, and demand response.

The remaining need was identified by running hourly power flow assessments assuming:

1. PSE is meeting 100% of its conservation and efficiency goals described in its Integrated Resource Plan; and
2. Normal weather conditions would set the demand forecasts.[22]

To serve as an alternative to the Energize Eastside project, energy storage must reduce loading on the affected transformer banks enough to eliminate overloads that would violate equipment normal thermal operating limits. Given that storage is modular, Strategen evaluated the amount of storage to solve the overloads through 2027 (the "Complete Solution"), along with the amount needed to address the Eastside transmission capacity deficiency incrementally beginning in winter 2018/2019 (the "Interim Solution").

As noted above, the Appendix contains refreshed sizing using the original methodology. It also contains a comparison of the assumptions between the March 2015 Study and the 2018 Analysis. The original methodology and assumptions are detailed in Section 3.1 of the March 2015 Study.

[22] In other words, weather conditions that represent the middle of the climatological bell curve, occurring in approximately 1 out of every 2 years

1.2 Talbot Hill Methodology and Results

1.2.1 Talbot Hill Interim Solution

In this section, we describe the methodology used to calculate the Talbot Hill Interim Solution and discuss the results. In the 2018 Analysis, Strategen found that there may be opportunities to recharge the system in the middle of the day, which the March 2015 Study did not account for. This is because, depending on the load profile, there may be a period during the day between morning peak and evening peak when recharging could occur. This would reduce the total required energy capacity seen in Table 2 (see p. 13 below). This would cycle the battery more than once a day. Increased battery cycling reduces battery operating life; however, more battery cycling allows a system smaller than that identified in Table 2 to be utilized to meet the system need for the Interim Solution. The method described below was used to do this analysis.

- The peak week N-1-1 data was extracted from the complete data set and was shown to occur in January 2019 for Talbot Hill. This represents the peak transformer loading at Talbot Hill within the next five years[23].
- The discharge requirements to maintain the loading on the Talbot Hill transformer were considered and the state of charge ("SOC") of the energy storage system tracked. Any opportunity where the loading was less than the normal rating, the system would be charged as much as possible without exceeding the rating.
    - Over the course of the week, the storage system was assessed, and the sizing increased to maintain the SOC above the minimum 2%.[24]
    - Figure 3 shows the results, where the green line is the loading on the Talbot Hill transformer with the energy storage operating to relieve the constraint through charging and discharging. This system is 290MW/1,689MWh (5.8-hour system).
    - It can be seen in the orange highlighted sections the loading is below the normal rating and during these times the energy storage system can charge, reflected in the SOC increasing. Without these opportunities, the SOC would continue to fall and a larger energy storage system would be required.[25]
    - A cost-benefit analysis could be undertaken to evaluate the reduction in life versus the cost of adding more energy capacity. Figure 4 shows the energy storage output during this period.

[23] The data analyzed assumed other NWA solutions (distributed energy resources) also contributed to reducing the load on Talbot Hill, including energy efficiency, demand response, and DG solar per E3's NWA Report (2014).
[24] Refer to assumptions for 2% minimum SOC.
[25] 2,083MWh – refer to Table 3

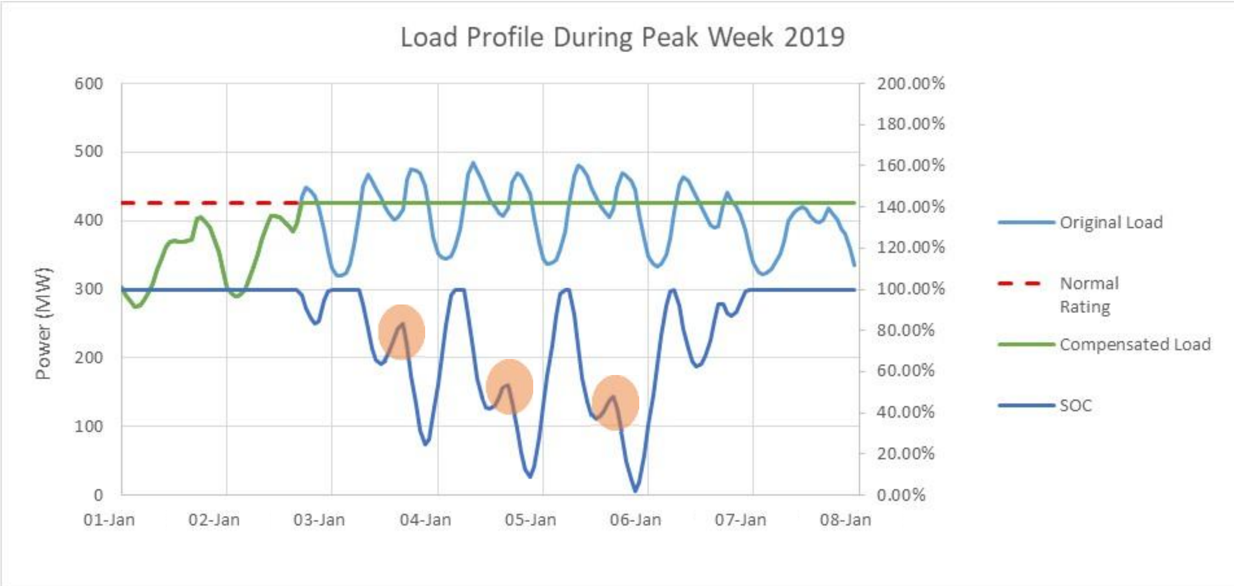

Figure 3: The Interim Solution using the updated methodology during the peak week: 290MW/1,689MWh (5.8-hour system) – circles highlight intra-day recharging

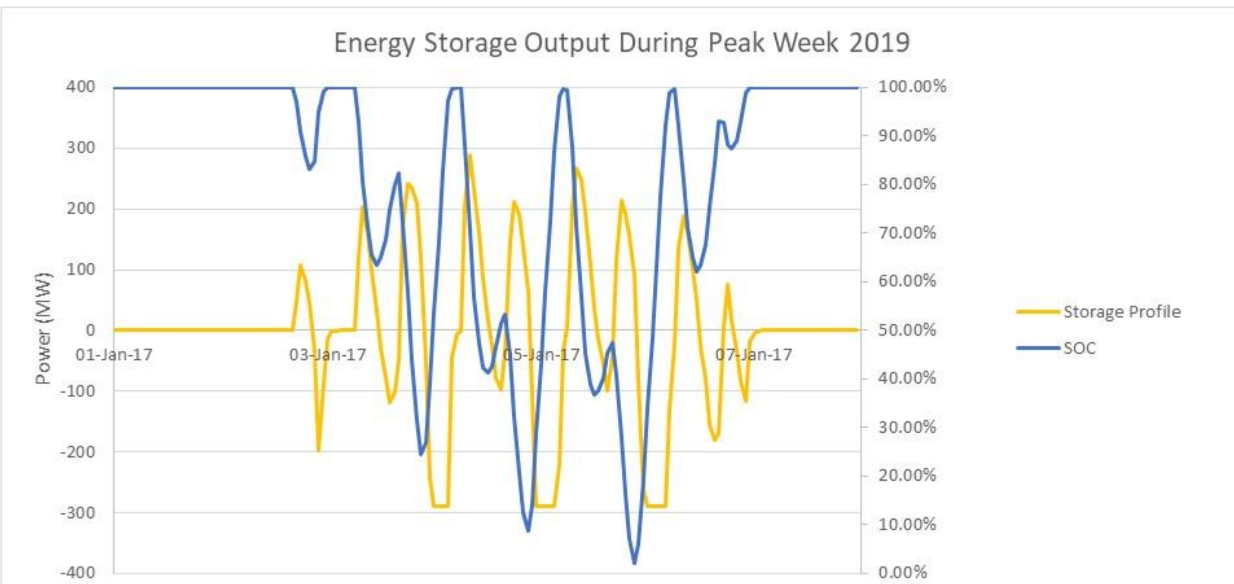

Figure 4: Output of the Interim Solution during the peak week, 290MW/1,689MWh (5.8-hour system)

1.2.2 Talbot Hill Complete Solution

The Complete Solution evaluates an energy storage solution that meets the required 2027 NERC planning criteria (the same as met by the proposed Energize transmission solution). In this scenario, additional NWA solutions[26] are also included to define the minimum plausible energy storage system. In this analysis it was found there was insufficient network capacity to charge the system on a daily basis. However, when there is not enough network capacity to fully recharge the system every day, a larger battery (with a longer duration) can theoretically overcome this issue. The method described below was used to do this analysis.

[26] NWA per E3 NWA Report (2014)

- The January 2027 peak week N-1-1 data for Talbot Hill was extracted from the complete data set. This represented the maximum loading during the 10-year planning horizon.
- The discharge requirements to maintain the loading on the Talbot Hill transformer were considered and the SOC of the energy storage system tracked.
    - Over the course of the week, the storage system was assessed, and the sizing increased to maintain the SOC above 18%. 18% was used to consider cell degradation of 2% per year for nine years.
    - Figure 5 shows the results, where the green line is the loading on the Talbot Hill transformer with the energy storage operating to relieve the constraint by maintaining the loading at the normal rating through charging and discharging. This system is 338MW/3,679MWh (10.9-hour system).
    - Unlike the Interim Solution, where there are actually periods when the system can recharge between morning and evening peak and fully recharge at night, it can be seen in the orange highlighted sections the SOC does not recover to 100% each day as there is insufficient network capacity to allow full charging.
    - Over time the SOC becomes more and more depleted until the load reduces toward the end of the peak week. Therefore, the system is oversized to meet the normal planning overload and maintain a SOC above 18%.
    - At the end of the week the SOC does return to 100% and as this is the peak week, the system should have enough capacity to meet the requirements for all other weeks in 2027. Figure 6 shows the energy storage output during this period.

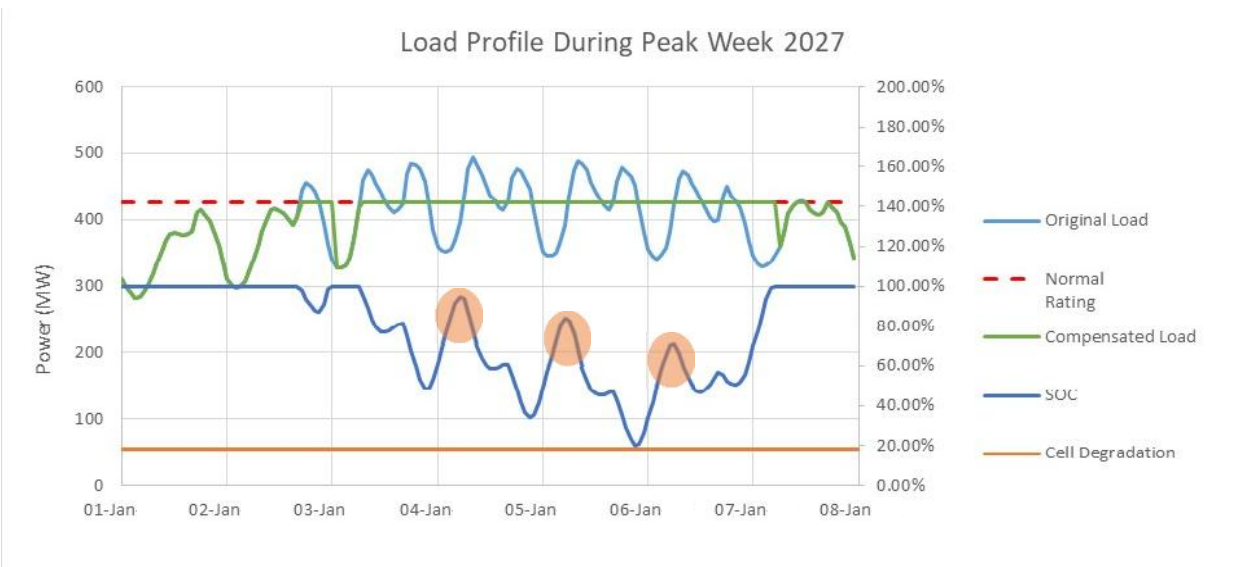

Figure 5: The Complete Solution during the peak week, 338MW/3,679MWh (10.9-hour system) – circles highlight that off-peak recharging insufficient to restore 100% state of charge each night

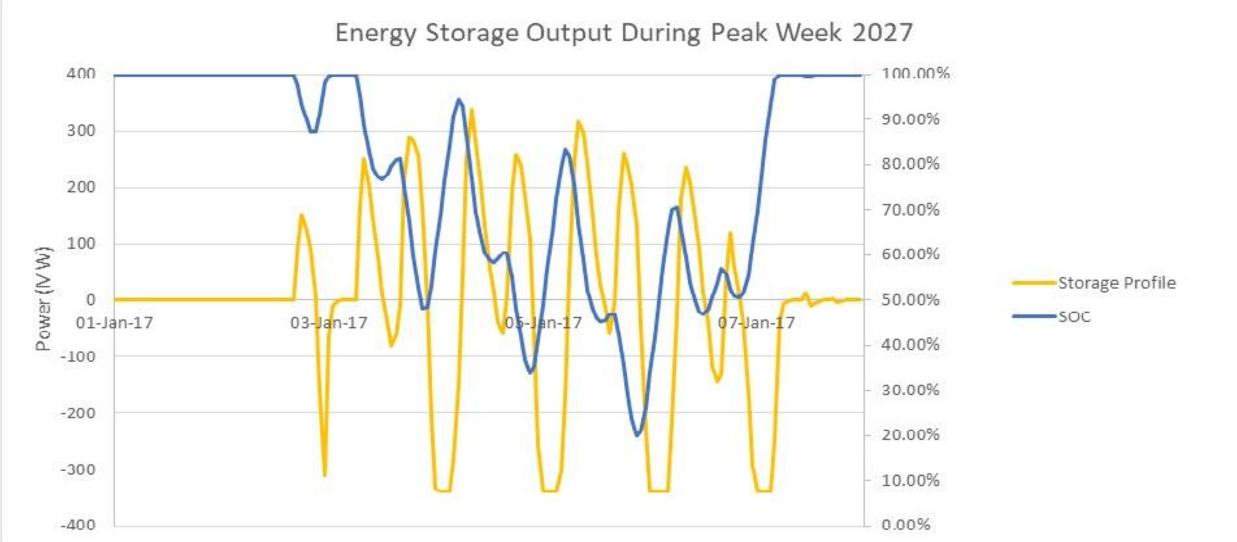

Figure 6: Output of the Complete Solution during the peak week, 338MW/3,679MWh (10.9-hour system)

By considering the Interim Solution and the Complete Solution, a clear picture can be obtained regarding the immediate need that must be met in 2019 and the solution that meets the full requirements over the 10-year planning period for Talbot Hill. Any incremental solution or staged approach would need to be deployed to meet both situations and is summarized in Table 2 below.

Table 2: Talbot Hill Substation Sizing Summary

	MW	MWh	Hours
Interim Solution (2019)	290	1,689	5.8
Complete Solution (2027)	338	3,679	10.9

1.3 Sammamish Methodology and Results

1.3.1 Sammamish Interim Solution

As noted above, the 2018 Analysis represents an update on the methodology used in the March 2015 Study because it considers SOC over the course of the peak week. This allows a more accurate energy storage sizing to be calculated. The methodology and results for the Sammamish analysis are described below.

- N-1-1 data was extracted for the peak week at Sammamish (occurring in August 2019), to determine the peak summer transformer loading within the next five years. This again includes NWA load reductions.
- The discharge requirements to maintain the loading on the Sammamish transformer were considered and the SOC of the energy storage system tracked. If opportunities occurred to recharge mid-day (when loading was less than the normal rating), the system would be charged as much as possible to reduce the system size.
    - Over the course of the week, the storage system was assessed, and the sizing adjusted to maintain the SOC above the minimum 2%.[27]
    - Figure 7 and Figure 8 show the results, where the green line in Figure 7 is the loading on the Sammamish transformer with the energy storage system operating to relieve the constraint.

[27] Refer to the Appendix, p.35, for pre-SOC sizing and assumptions for information about the 2% minimum SOC.

- This system maintains the loading below the normal rating through charging and discharging. This system is 365MW/2,394MWh (6.6-hour system).
- Figure 8 shows the energy storage output during this period.
- Figure 9 shows data from the peak month, which validates the system sizing is appropriate as the SOC remains above the minimum 2%.

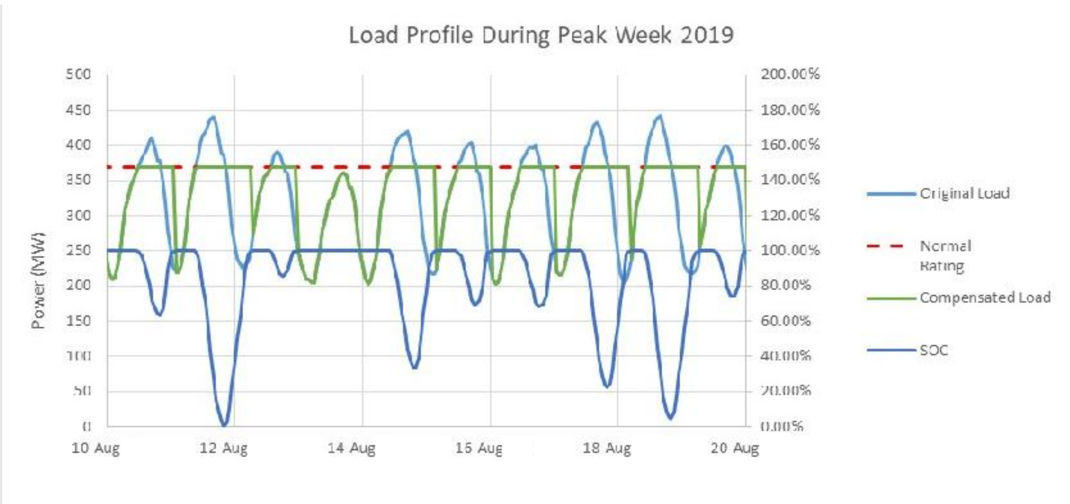

Figure 7: The Interim Solution during the peak week, 365MW/2,394MWh (6.6-hour system)

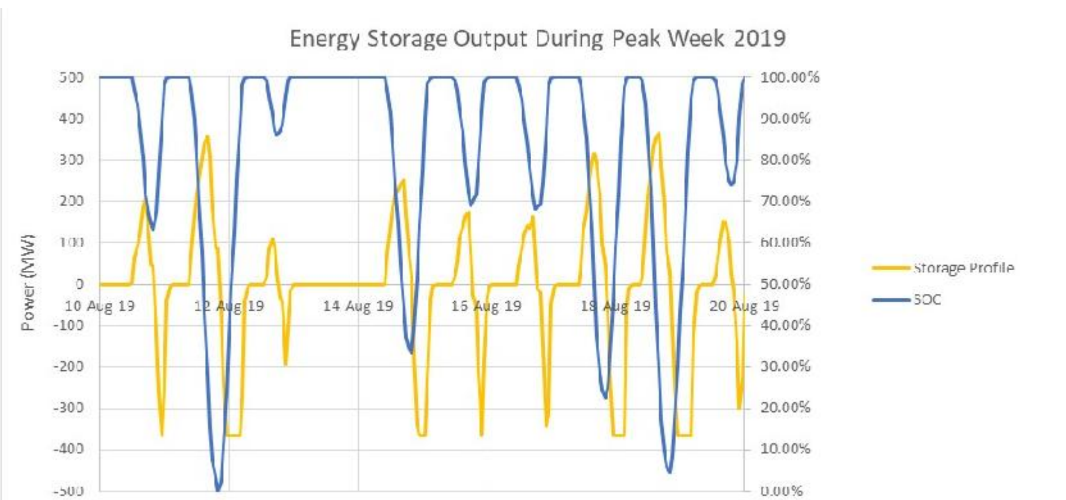

Figure 8: Output of the Interim Solution during the peak week, 365MW/2,394MWh (6.6-hour system)

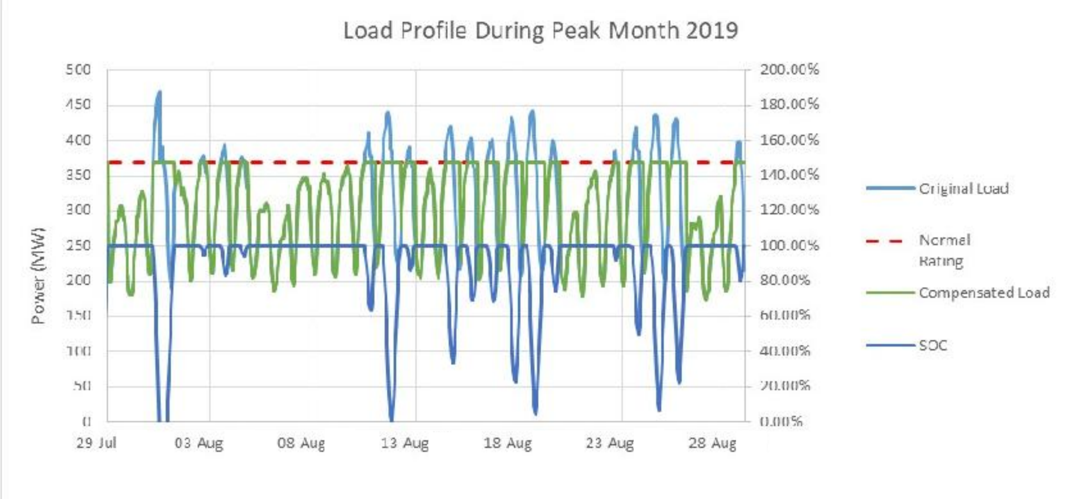

Figure 9: Performance over peak summer month, 365MW/2,394MWh (6.6-hour system)

1.3.2 Sammamish Complete Solution

As noted above, the Complete Solution for Sammamish evaluates an energy storage solution that meets the required 2027 NERC planning criteria (the same as met by the proposed Energize transmission solution). In this scenario, additional NWA solutions[28] are included to define the minimum plausible energy storage system sizing to meet the Sammamish transmission capacity deficiency.

- N-1-1 data was extracted from the peak week in August 2026, which is when the maximum summer loading during the 10-year planning horizon is forecasted to occur.[29]
- The discharge requirements to maintain the loading on the Sammamish transformer were considered and SOC of the energy storage system tracked.
  - Over the course of the week, the storage system was assessed, and the sizing increased to maintain the SOC above 18%. 18% was used to consider both the minimum SOC of 2%[30] and cell degradation of 2% per year for eight years (16%).
  - Figure 10 and Figure 11 show the results, where the green line in Figure 10 is the loading on the Sammamish transformer with the energy storage operating to relieve the constraint at the normal rating through charging and discharging.
  - This system is 549MW/5,500MWh (10.0-hour system).
  - Figure 12 considers the full month where the peak on the 1st is ignored due to the abnormal system condition.
  - During the remainder of the month it can be seen that the peak days, even where consecutive days face overload, the SOC remains above 18%.

[28] NWA per E3 NWA Report (2014)
[29] PSE's planning forecast shows a slight drop in peak load in 2027.
[30] Refer to assumptions for 2% minimum SOC.

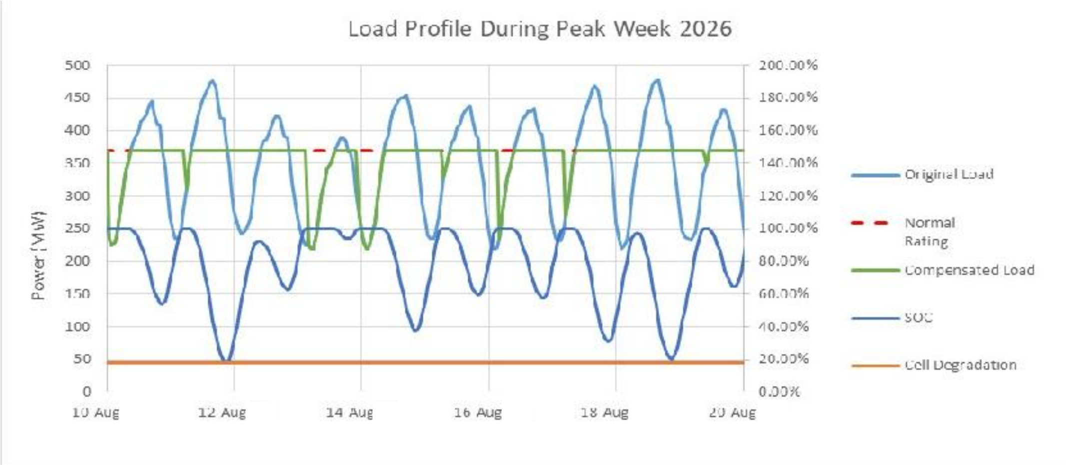

Figure 10: The Complete Solution during the peak week, 549MW/5,500MWh (10.0-hour system)

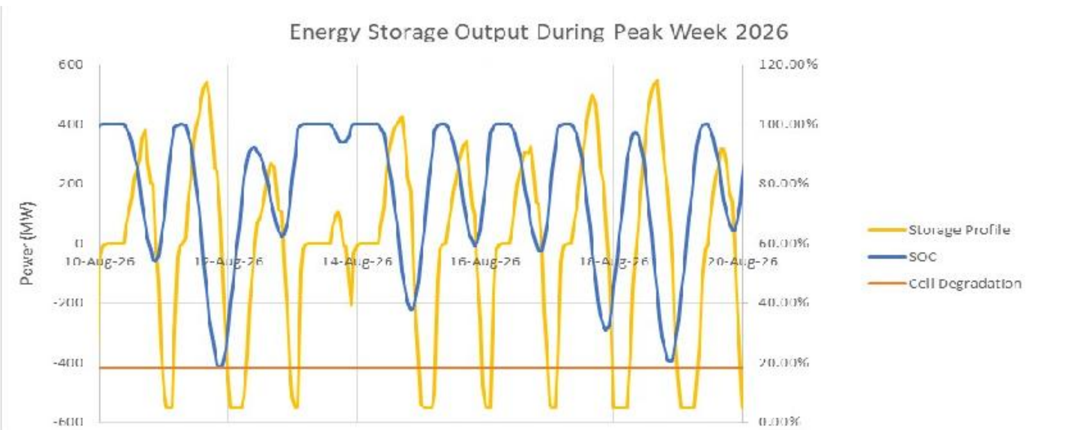

Figure 11: Output of the Complete Solution during the peak week, 549MW/5,500MWh (10.0-hour system)

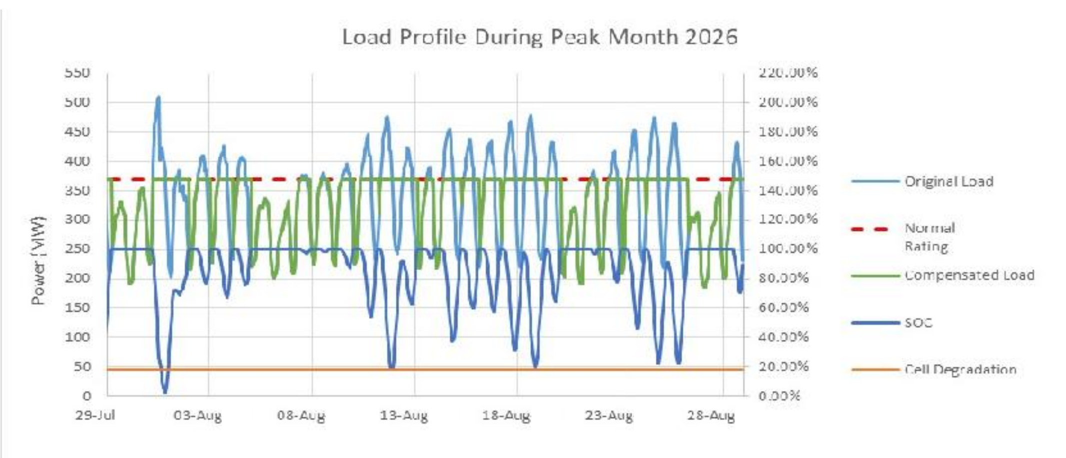

Figure 12: Performance over peak summer month, 549MW/5,500MWh (10.0-hour system)

By considering the Interim Solution and the Complete Solution, a clear picture can be obtained regarding the immediate need that must be met in 2019 and the solution that meets the full requirements over the 10-year planning period. Any incremental solution or staged approach would need to be deployed to meet both situations and is summarized in Table 3 below.

Table 3: Sammamish Substation Sizing Summary

	MW	MWh	Hours
Interim Solution (2019)	365	2,394	6.6
Complete Solution (2027)	549	5,500	10.0

1.4 Behind-the-Meter Energy Storage

Finally, behind-the-meter ("BTM") energy storage was considered as it is becoming more common within the power system. Its aggregated effects can reduce the load on the system, and BTM energy storage can also be controlled and coordinated by utilities to provide specific grid benefits, such as virtual power plant configurations. These arrangements are undergoing trials now but are not yet fully mature planning tools and, as such, in the short term such configurations may result in technical and contractual challenges.

As previously discussed, the effectiveness factor of various locations within the Eastside area was considered, and all locations had a similar effect on the constrained Talbot Hill and Sammamish Substations. Therefore, whether a centralized energy storage system is installed, or a number of distributed storage systems are interconnected, the power and storage requirements remain the same.

When considering BTM energy storage, whether meeting or contributing to the Energize Eastside area, the Interim Solution for Sammamish (365MW/2,394MWh) or the Complete Solution for Sammamish (549MW/5,500MWh) needs to be met. If the Tesla Powerwall 2, a 13.5kWh system or a larger generic 15kWh system is considered, Table 4 and Table 5 portray the number of these systems required to meet the Interim Solution and Complete Solution respectively.

Table 4: Number of residential BTM energy storage systems required to meet the Interim Solution

BTM Residential Energy Storage System	Number of BTM Systems Required	Number of BTM Systems Required (70% confidence factor)[31]	Number of Customers in Eastside Area (130,000)[32]
Tesla Powerwall 2 - 13.5kWh	177,333	253,333	195%
Generic - 15kWh	159,600	228,000	175%

[31] It is not reasonable to assume that all BTM energy storage systems would be online, fully functional, and have all their usable capacity available at the exact time required to relieve the Talbot Hill constraint. Even if controlled and coordinated by the utility, customers would likely use these systems for other utility bill management purposes that could see their system below 100% SOC prior to the event. In addition, even if 1% were offline for maintenance or repair, or on average the SOC was 99% across the entire fleet, this would result in more than a 18MWh shortfall. Therefore, a 70% confidence factor is used to provide a more realistic perspective of the number of BTM energy storage systems required to compensate for some systems being offline, partially discharged or otherwise unable to provide their full usable capacity for the purposes of relieving the Talbot Hill transformer constraint.

[32] Source: (https://energizeeastside.com/need)

Table 5: Number of residential BTM energy storage systems required to meet the Complete Solution

BTM Residential Energy Storage System	Number of BTM Systems Required	Number of BTM Systems Required (70% confidence factor)[31]	Number of Customers in Eastside Area (130,000)[32]
Tesla Powerwall 2 - 13.5kWh	407,407	582,011	448%
Generic - 15kWh	366,667	523,810	403%

Tables 4 and 5 show that the number of BTM energy storage systems required exceeds the number of residential customers in the area. In addition to the information presented in Table 4 and Table 5, there are a number of other reasons that BTM energy storage is an impractical solution for the Eastside's T&D deficiency. These are:

1) The number and timing of BTM energy storage systems required to meet the Interim or Complete solution for the Eastside T&D capacity deficiency far exceed the top residential energy storage uptake rates in leading markets, as seen in Figure 13.

Rank	Residential	Deployments (kW)
1	California	1,870
2	Hawaii	1,218
3	All Others*	728

Figure 13: Top 3 residential energy storage markets, 2017 Q1 deployments[33]

2) The installation of the number of BTM systems required to meet the Interim and Complete Solutions is not realistic from the standpoint of either utility interconnection assessments or local authority permitting processes and capabilities. Installation of a BTM storage system requires an electrical permit. From August 13, 2017 to August 13, 2018, the City of Bellevue processed 309 electrical permits, and had a staff of four people handling electrical permit applications and inspections[34].

3) Purchasing the volume of BTM systems to address the Eastside T&D deficiency would exceed the entire US BTM deployments, as seen in Figure 14, which covers multiple segments.

[33] Source: GTM Research
[34] Source: https://publicrecordscenter.bellevuewa.gov/DSRecords/processing-day-by-permit-type.pdf Accessed August 16, 2018.

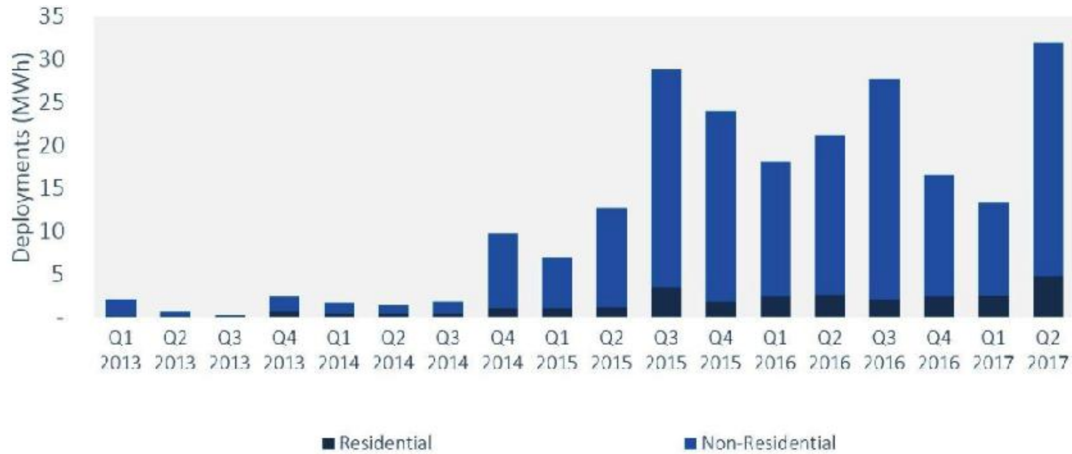

Figure 14: US BTM Energy Storage Deployments by Segment[35]

4) Finally, BTM energy storage systems are often coupled with rooftop solar to store solar energy and enable self-generation. Because of this fact, California uses the number and location of existing rooftop solar installations to predict where BTM energy storage will interconnect.[36] While not the only use case of BTM energy storage, a similar predictive methodology might be applied to King County as a way to estimate customers willing to invest in advanced energy technology. The number of residential distributed generation systems (mostly solar) throughout PSE's King County service territory is approximately 2,300 out of approximately 1.2 million total customers.[37]

If the effect of organic growth of BTM energy storage was considered with regard to reducing the loading within the Eastside area, even if the entire US 2017 Q2 deployments occurred on circuits downstream of Sammamish and Talbot Hill Substations, this would only meet approximately 0.5%-1.5% of the Eastside transmission capacity deficiency[38]. Therefore, the effect of actual installations on downstream circuits can be considered negligible with respect to the Eastside transmission capacity deficiency.

1.5 Capital Cost of Eastside Energy Storage Solution

Strategen reassessed its unit cost assumptions for energy storage in Section 3.4.1. The transmission solution for Eastside is estimated at $150-$300 million.[39] An energy storage system would be significantly more expensive than the proposed transmission solution. An estimate of capital costs can be seen in Figure 15 below and range from approximately $825 million to $1.4 billion.

[35] Source: GTM Research / ESA US Energy Storage Monitor, Q3 2017
[36] Source: DRP working group meetings
[37] Source: PSE 2017 IRP, p.391
[38] 32.5MWh/5,500MWh=0.006, Complete Solution and 32.5MWh/3,007MWh=0.014, Interim Solution
[39] Source: (https://energizeeastside.com/faqs)

PERFORMANCE	Units	Interim Solution (Lithium Ion) Single Level	Interim Solution (Flow-Van'm) Single Level	Complete Solution (Lithium Ion) Double Level	Complete Solution (Flow-Van'm) Double Level
Power	MW	365	365	549	549
Energy	MWh	2,394	2,394	5,500	5,500
Discharge Duration	Hours	6.6	6.6	10.0	10.0
Round Trip Efficiency	%	85%	85%	85%	85%
ASSUMPTIONS					
EPC					
Energy Storage	$/kWh	294	313	194 for incremental 3,106 MWh[40]	207 for incremental 3,106 MWh[40]
Owners Costs					
Land Required	sq ft	2,123,866	1,302,070	2,123,866	1,302,070
Land Cost	$/sq ft	43.60	43.60	43.60	43.60
Permitting	$	Not available	Not available	Not available	Not available
Interconnection	$	28,140,000	28,140,000	28,140,000	28,140,000
RESULTS					
EPC Costs					
Energy Storage	$	703,836,000	749,322,000	1,287,764,000	1,370,522,000
Construction	$	n/a	n/a	n/a	n/a
Owners Costs					
Land	$	92,600,558	56,770,252	92,600,558	56,770,252
Interconnection	$	28,140,000	28,140,000	28,140,000	28,140,000
Subtotal Costs	$	120,740,558	84,910,252	120,740,558	84,910,252
TOTAL COST	**$**	**824,576,558**	**834,232,252**	**1,408,504,558**	**1,455,432,252**
Total $ per kWh		**344**	**348**	**256**	**265**

Figure 15: Capital cost estimate of bulk energy storage to address the Eastside transmission reliability deficiency

If distributed storage were to be pursued in lieu of a centralized solution, costs would likely be substantially higher. For indicative purposes, the cost would range from $1.14 billion to $1.67 billion for the Interim Solution and $2.14 billion to $3.06 billion for the Complete Solution[41].

[40] Assumes an average 36% reduction in capital costs for incremental storage beyond the Interim Solution. See page 55 for cost assumptions.
[41] Indicative cost for the Interim Solution assumes $6,600 per installed 13.5 kWh system, based on the quoted price for a Powerwall 2 per www.tesla.com (accessed August 16, 2018) multiplied by the range of installed systems indicated in Table 4 to meet the Interim Solution. Indicative cost for the Complete Solution assumes a cost of $4,220 per installed 13.5 kWh system for the incremental number of systems required to meet the range shown for the Complete Solution in Table 5 (resulting in a blended cost of $5,258 per system for the Complete Solution).

The March 2015 Study also evaluated the cost-effectiveness of a storage system based on a comparison of the cost with the system benefits it would provide PSE. It is likely that system benefits may be somewhat different today than what was assumed in the March 2015 Study due to changes to load growth patterns, generation mix, and the inclusion of PSE in the Western Energy Imbalance Market. However, Strategen did not reassess the benefits of an Eastside energy storage solution in the 2018 Analysis.

2. Impact Considerations

This part of the report will discuss the physical impacts of energy storage systems and compare these to PSE's preferred transmission solution.

2.1 Physical Impact

System requirements were defined in Part 1 of this report. This section considers some of the practical and logistical aspects of deploying a system of the size defined in the technical requirements section. This will include the location of one or more energy storage systems, the physical sizing requirements as well as upgrades to support the operation of storage and the timing of need to build the preferred solution.

2.1.1 Location

As indicated, the location of a centralized energy storage system or a number of distributed energy storage systems does not impact the effectiveness factor, and therefore the total power and energy required to meet the normal overload condition remains 365MW/2,394MWh for the Interim Solution or 549MW/5,500MWh for the Complete Solution for Sammamish. A centralized system located somewhere between Talbot Hill Substation and Sammamish Substation would offer similar benefits, again as tested through PSE load flow analysis of the effectiveness factor. Distributed systems (provided they are connected downstream of these substations) could provide the same benefit as a single system, requiring coordination of their operation with each other to resolve the constraint.

2.1.2 Footprint

The physical sizing considerations for a centralized Interim Solution and Complete Solution are now considered. Figure 16 shows the Hornsdale Power Reserve, the current largest energy storage project on Earth. This system is approximately 19 times smaller than the Interim Solution and 43 times smaller than the Complete Solution. Its dimensions are used to inform the expected footprint of the Eastside solution along with other projects.

Figure 16: Hornsdale Power Reserve is 100MW/129MWh, approximately 43 times smaller than the Complete Solution[42]

Table 6 summarizes deployed and proposed large-scale energy storage systems. These include lithium-ion and flow batteries on one and two levels. This sizing information is then applied to the power and energy requirements of the Eastside solution.

Table 6: Space requirements for the Energize Eastside solution based on installed and proposed large-scale energy storage projects

Per MWh		Hornsdale Power Reserve	Dalian VFB Rongke Power	Average Single Level	Single Level Halved	Dalian VFB Rongke Power	Average Double Level	Extrapolated Size	Eastside Interim Solution 365 MW 2,394 MWh		Eastside Complete Solution 549 MW 5,500 MWh	
		Single Level			Double Level				Single	Double	Single	Double
	Acres	0.04	0.01	0.025	0.013	>0.01	0.01		58.87	21.22	135.25	48.76
	Sq. ft	1,669	473	1071	536	237	386		2,564,333	924,461	5,891,325	2,123,866
	Size compared to CenturyLink Stadium (1,500,000 Sq. Ft.)								171%	62%	393%	142%

Note: As the projects considered for the sizing are four hours in duration or less, it is more appropriate to use the energy (MWh) rather than power (MW) rating to calculate the Eastside footprint.

CenturyLink Stadium has a footprint of 34.4 acres[43] and the Interim Solution Eastside footprint would, therefore, be more than one and a half times the size if designed over one level. The Complete Solution would require a similar footprint to this if double-stacked over two stories, which is the most likely engineering approach. There have not been any large-scale energy storage projects to date that have been deployed with more than two levels. Figure 17 highlights the

[42] Source: (https://hornsdalepowerreserve.com.au/)
[43] 1,500,000 square feet. Source: (http://www.architravel.com/architravel/building/centurylink-field/)

indicative footprint of a single-stacked Interim Solution (red) vs a double-stacked Complete Solution within the Eastside area (yellow)[44].

Figure 17: Indicative footprint of the Eastside storage solution red, single-level Interim Solution 59 acres, and yellow double-level Complete Solution, 49 acres

2.1.3 Timing of Need to Build the Solution

The 2018/2019 overload constraints represent the largest exceedances in the normal rating within the next five years and drive the timing of any permanent or incremental solution. The following two projects are therefore considered for context on the feasibility of storage given the timing constraint.

Aliso Canyon – Approximately one year to complete a 94.5MW/342MWh project

On May 26, 2016, the California Public Utilities Commission ("CPUC") approved a resolution to expedite a competitive energy storage procurement solicitation to help alleviate an emergency capacity constraint in the 2017 summer, due to a gas leak at the Aliso Canyon natural gas storage facility, which constrained local generation capacity in the Los Angeles basin.

The resolution instructed San Diego Gas and Electric ("SDG&E") to "leverage" its ongoing 2016 Preferred Resource LCR RFO to approach "qualified respondents," and determine if an energy storage solution could be online in time to resolve the immediate Aliso Canyon constraint.

By the date the resolution was issued, SDG&E had completed its pre-evaluation and identified qualified contractors for turnkey, utility-owned projects. SDG&E approached qualified bidders to assess their willingness and ability to execute expedited projects in the 2016 timeframe. The RFO had already allowed pre-evaluation of respondents, which materially shortened the pre-bid activity.

To achieve the targeted January 31, 2017 online date, SDG&E required approval from the commission by August 19, 2016, before which the energy storage supplier could not make significant financial investments in battery modules, inverters, transformers, or containers for the project. The project timeline can be seen in Figure 18.

[44] This assumes a square footprint where the Interim Solution requires a 1,601x1,601 ft. (2.56 million sq. ft.) area and the Complete Solution requires a 1,457x1,457 ft. (2.12 million sq. ft.) (two levels).

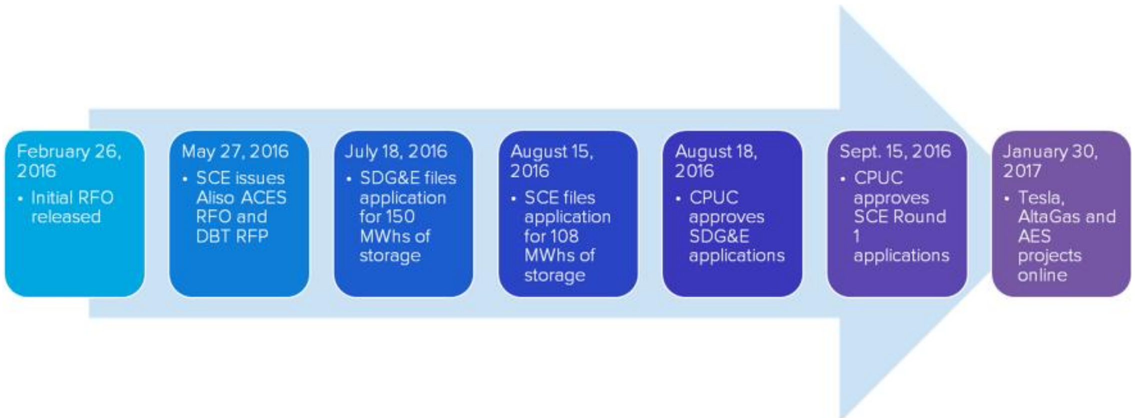

Figure 18: Aliso Canyon battery energy storage system response timeline

The Aliso Canyon Energy Storage Project saw a number of energy storage systems that aggregated to 94.5 MW / 342 MWh, brought online in approximately seven months. However, the original RFO began on February 26, 2016, which materially shortened pre-bid activity for this project. The overall project could, therefore, be considered to take approximately one year.

Hornsdale Power Reserve – Majority of a year to complete 100MW/129MWh project

The Hornsdale Power Reserve, while touted as a 100MW buildout in 100 days, took the majority of 2017 to solicit, award and complete. Neoen and Tesla selected the existing Hornsdale Wind Farm as a suitable site in early 2017 and were selected as the developers in June 2017 after a solicitation. The construction took four months from the signing of the interconnection agreement, which was the period the 100 days focused on. The overall project, therefore, took the majority of 2017.[45] For the Hornsdale Power Reserve, Tesla signed a contract with Samsung to supply the batteries because of uncertainties regarding Panasonic's (its usual supplier) ability to deliver 129MWh of batteries in the required timeframe.

The scale of the Eastside solution is unprecedented but based on a 100MW/129MWh system taking most of 2017 to complete, it is a reasonable assumption that the Interim Solution (365MW/2,394MWh), the most pressing constraint, would take substantially longer. The combination of these factors makes it highly unlikely an energy storage project for Energize Eastside could be permitted, sited, sourced, designed, built and brought online within a year, to relieve the pending 2018/19 winter constraint.

[45] Source: (https://hornsdalepowerreserve.com.au/faqs/)

3. Commercial and Technological Developments

As part of the 2018 Analysis, Strategen was asked to evaluate what technological or commercial advancements have occurred with battery energy storage since the publication of the March 2015 Study. The objective was to determine if there were developments that substantively would impact the technological readiness, commercial readiness and/or cost-effectiveness of a storage solution to meet the Eastside reliability need.

3.1 Methodology

Strategen reviewed publicly available research and news on battery technology developments and cost data (historic and projections). Further, using publicly available information contained in the US Department of Energy's ("DOE") Global Energy Storage Database,[46] Strategen reviewed commercial deployments since the publication of the original March 2015 Study to characterize the ability of storage to be deployed in a scale of magnitude similar to the Eastside reliability need. We evaluated whether there are energy storage facilities currently in operation at the general scale of magnitude sufficient to meet the Eastside reliability need, and whether there are energy storage facilities with operational experience meeting a transmission reliability need similar to that on the Eastside. Strategen also reviewed publicly available operational data for utility-scale storage projects to evaluate any operational challenges or considerations that may impact the ability of a storage solution to reliably address a transmission deferral need, or additional experience (or limitations) identified in deploying storage as a multi-purpose asset[47] (which would impact its cost-effectiveness).

Key factors that have changed since the original March 2015 Study have been highlighted, along with a qualitative assessment of their likely impact on the technological or commercial feasibility of the storage alternative.

3.2 Energy Storage Applications

There are numerous applications for energy storage, which makes energy storage versatile and useful to the modern power system. Figure 19 shows some common applications for energy storage with respect to time.

[46] The Global Energy Storage Database is located at (http://www.energystorageexchange.com).
[47] By multi-purpose asset, we mean the use of storage to meet a transmission reliability need as well as other system needs, such as system (generation) capacity, system flexibility, oversupply reduction, etc.

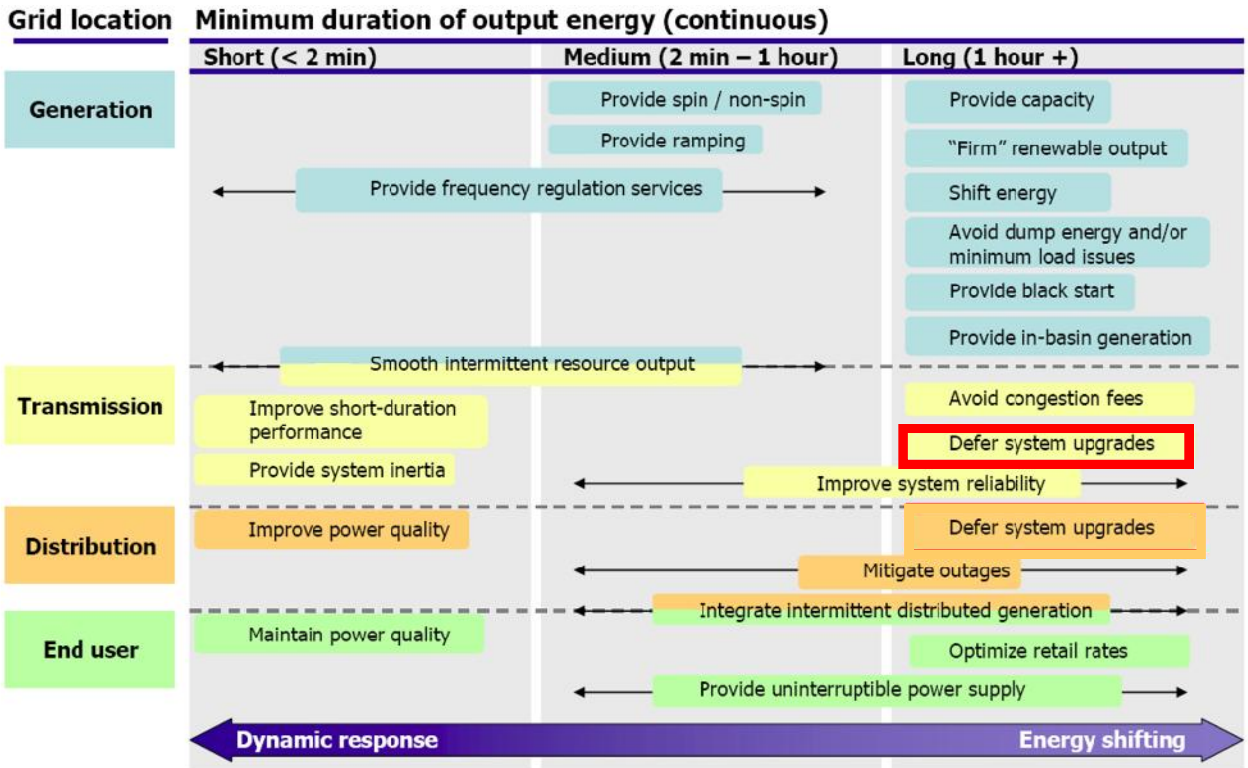

Figure 19: Various use cases for energy storage with respect to time (red box indicates Eastside storage use case)[48]

It is important to understand the application required by energy storage to effectively assess its ability to solve the power system constraint. The Energize Eastside constraint is a transmission reliability application, used to defer system upgrades, as portrayed in Figure 19. Energy storage would be used in this case to reduce the loading on the transformers to within their normal rating. In addition, it could provide other services presented in Figure 19 to increase the value proposition of the installation, but only once it has met the primary purpose and resolved the thermal rating issue.

Not all energy storage applications will be discussed below, only the most relevant. These are frequency regulation, capacity, and T&D deferral as they include the most common use cases and the Energize Eastside use case.

3.2.1 Frequency Regulation/Response

Frequency regulation/response has been the biggest application for energy storage systems to date.[49] This is a high power, low energy application, as shown by its position in Figure 19. Frequency support is required over a short timeframe, from seconds to minutes, and as such, energy storage systems to meet this need do not require a significant amount of batteries, making this typically a more cost-effective application than applications requiring longer timeframes (such as the Eastside need). Energy storage systems installed for frequency regulation are typically 15 minutes to one hour in duration. The Hornsdale Power Reserve in South Australia is approximately a 1.25-hour system (100MW/129MWh), which provides frequency regulation services in addition to

[48] Source: Southern California Edison
[49] Source: DOE Global Energy Storage Database

capacity services. Most of the large energy storage systems installed to date target frequency or stability services that are located on the left side of Figure 19.

Frequency disturbances are caused by an imbalance between generation and load. The variable output of renewable generation such as wind and solar can also add to frequency instability, which inverter-based energy storage can correct effectively with fast responding charging or discharging. In this application, the location of the energy storage system does not play a major factor, as it can contribute to addressing the net difference between generation and load, anywhere within an interconnected power system. The contribution also has a direct effect where every MW of power injected or absorbed by an energy storage system benefits the discrepancy between generation and load within the interconnected power system at a 1:1 ratio if losses are ignored.

Some examples of frequency response markets and installations are below:

- PJM Frequency Response Market – Approximately 265MW of energy storage[50]
- Hornsdale Power Reserve – Tesla and Neoen - South Australia – 100MW/129MWh (this is a secondary service)
- National Grid (UK) Enhanced Frequency Response Solicitation 2016 – 200MW in total

3.2.2 Capacity Services

Capacity services provide power as needed by the power system and as coordinated and dispatched by an electricity market operator. Conventional generation provides capacity services, and battery energy storage can also provide this service by charging at off-peak times to provide this service when required. Capacity services is a growing market for energy storage, particularly coupling energy storage to renewable generation. This allows charging from clean energy sources that are continually becoming more cost-effective, and adding storage to allow the dispatch of this energy at beneficial times as instructed by the market operator. This is the operating method of the Hornsdale Power Reserve in South Australia, which is coupled to an existing wind farm and provides capacity as directed by the market operator.

This capacity service, as discussed, is a fungible service coordinated and dispatched by a market. If there is a failure to deliver, another resource can be procured in its place. Location influences, but is not a major factor in, providing capacity services. This resource fungibility is fundamentally different than what would be required to meet the Eastside reliability need.

Some examples of capacity service installations are below:

- Hornsdale Power Reserve – Tesla and Neoen - South Australia – 100MW/129MWh
  This is the primary application where it is coupled with an existing wind farm to supply energy as directed by the Australian Energy Market Operator.
- Aliso Canyon – Provides capacity at peak times. The gas-fired power station would provide energy during peak times as a "peaker," and Aliso Canyon replicates this service, charging at off-peak times to provide capacity and peak times.

[50] Source: (https://www.energy-storage.news/news/pjms-frequency-regulation-rule-changes-causing-significant-and-detrimental)

3.2.3 T&D Deferral

T&D deferrals are additional applications for energy storage as seen in Figure 19. In both cases, storage is used as a location-specific load serving resource that allows a traditional wires-based solution not to be built or upgraded for some amount of time. The location of an energy storage system is critical in T&D deferral use cases, as is the assurance to operate when required. Unlike capacity and frequency response services that are less dependent on location and can be substituted by other resources if they do not provide the required service, T&D deferral use cases cannot be replaced by another resource and therefore the consequences in failing to deliver are more severe.

T&D deferral applications can vary in size and duration. While frequency response systems only require minutes to an hour of duration, deferral cases require the amount of energy to offset load on a constraint element which is determined on a case-by-case basis.

The primary differences between transmission deferral and distribution deferral is that transmission deferral use cases generally require offsetting much more power and energy than distribution deferral projects, and transmission deferral applications are typically on a highly networked grid (so the power flow can go in multiple directions), whereas some distribution deferral projects are able to be located within a radial network topology (so power flow is only possible in limited directions). The effect of this on efficacy is described on page 36.

The energy storage market has not been heavily driven by T&D deferral to date, as it is a more energy-intensive application, as seen in Figure 19, and therefore more expensive. As a result, energy storage projects deployed for T&D deferral to date have been much smaller in scale compared to the notable large installations of storage projects used for other purposes around the world. Deferral use energy storage projects have also generally been sited on the lower voltage distribution system rather than the high voltage, networked transmission system. Nevertheless, the market for T&D applications is growing as market and regulatory barriers are removed. An estimated global energy storage system capacity for T&D deferral in 2017 is 331.7MW.[51] This is expected to grow by about 50-fold over the next 10 years as seen in Figure 20. An Energize Eastside non-wires project, however, would be a transmission deferral use case of unprecedented size.

[51] Source: Navigant Research

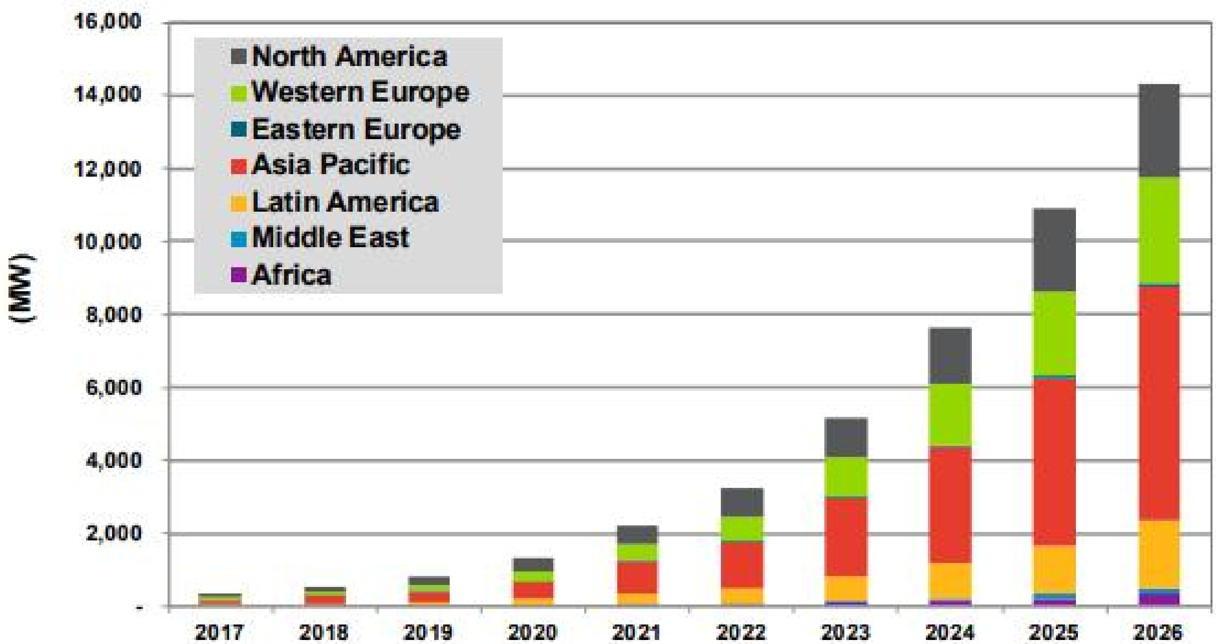

Figure 20: Forecast annual installed energy storage power capacity for T&D deferral by region, 2017-2026[52]

Some examples of proposed T&D deferral installations are below:

- Arizona Public Service (Proposed) – 2MW/8MWh (4-hour system)[53]
- National Grid Massachusetts (Proposed) – 6MW/48MWh (8-hour system)[54]

3.3 Technological Developments

The March 2015 Study compiled by Strategen suggested an energy storage solution for the Eastside system would be technologically possible, although challenging due to electrical infrastructure constraints, supply chain challenges and physical impact considerations. Some relevant advances to the technical aspects of energy storage are discussed in the Appendix.

[52] Source: Navigant Research
[53] Source: (https://www.utilitydive.com/news/aps-to-deploy-8-mwh-of-battery-storage-to-defer-transmission-investment/448965/)
[54] Source: (https://www.utilitydive.com/news/national-grid-plans-to-install-a-48-mwh-battery-storage-system-on-nantucket/510444/)

4. Conclusion

While storage is becoming a technology embraced by the power sector to modernize and enhance the grid, the specific circumstances and requirements driving the Eastside transmission capacity deficiency are not well suited- to an energy storage solution. Such a solution would need to be of unprecedented scale, exceeding the total forecast 2018 US energy storage deployments,[55] both behind and in front of the meter. It would therefore be impractical to source, site and construct. In addition, it would come at a cost many times that of the traditional poles and wires solution.

For these reasons, despite the commercial and technological progress of energy storage in recent years, the conclusion of this updated analysis remains consistent with the conclusion of the original March 2015 Study. Strategen does not believe energy storage to be a practical option to meet the Eastside transmission capacity deficiency, either as an alternative to the proposed transmission solution or as a way to defer it.

The overall amount of storage required to meet the Eastside transmission capacity deficiency was calculated to be 549 MW, 5,500 MWh, compared with 545 MW, 5,771 MWh in the March 2015 study. See Table 7 below for a complete comparison.

Table 7: Comparison of the March 2015 Study and 2018 Analysis for the sizing of an energy storage system for Eastside

Constrained Element	Power (MW)	Energy (MWh)	Duration (hours)	Meets 2019 System Need	Meets Solution Requirements Through 2027[56]	Feasibility[57]
Original March 2015 Study Results[58]						
Talbot Hill	**545**	**5,771**	**10.6**	✓	not evaluated	✗
Sammamish[91]	*Assessed to be less than Talbot Hill sizing*					
2018 Analysis						
Interim Solution for 2019[59]						
Talbot Hill	290	1,689	5.8	✗ [60]	✗	✗
Sammamish[61]	**365**	**2,394**	**6.6**	✓	✗	✗
Complete Solution through 2027						
Talbot Hill	338	3,679	10.9	✓	✗ [90]	✗
Sammamish[91]	**549**	**5,500**	**10.0**	✓	✓	✗

[55] This includes all types of energy storage; residential, non-residential and utility in-front-of-the-meter systems.

[56] Meets 2027 requirements means satisfying the NERC/FERC planning criteria through 2027, the same planning criteria against which the ultimate Eastside solution must be judged (whether a wires or non-wires solution).

[57] Feasibility relates to electrical sizing, physical sizing, timing and the ability of the market to respond.

[58] The March 2015 Study evaluated solution requirements to meet a deferral need through 2021.

[59] Sized only to meet immediate 2019 constraint assuming all other NWAs per E3 NWA Report (2014) are implemented; size requirement would be larger if other NWAs are unable to be implemented.

[60] The Talbot Hill sizing is insufficient to meet the Sammamish need and therefore does not meet the system need for that entire year.

[61] Sammamish was assessed in the March 2015 Study, but Talbot Hill was the more significant constraint that defined the energy storage sizing. Due to several factors detailed in this report, Sammamish is now the greatest constraint that defines the size while Talbot ill also exceeds NERC requirements.

Appendix: Technical Analysis - Additional Information

Technical Analysis Assumptions

The following assumptions were used to conduct this updated analysis. In general, Strategen maintained the assumptions in the original March 2015 Study but where updated data and details are available, those were updated.

The ***assumptions that have remained*** the same between the original March 2015 Study and this assessment are:

Effectiveness factor – The effectiveness factor used in the March 2015 Study was approximately 20%. An explanation and example of effectiveness factor is presented on page 36. *It is important to recognize this is a characteristic of the Eastside system and is not related to the energy storage's round-trip efficiency.*

Note, other energy siting locations were considered (both bulk and distributed) within the Eastside area, and the effectiveness factor remained similar. Therefore, whether the solution is a centralized system located within the area, a distributed solution within the area, or a combination of the two, the total aggregate sizing requirements as identified in this analysis would be very similar. For example, if a 100MW/400MWh system is required, two 50MW/200MWh systems or ten 10MW/40MWh systems would be required and considered equivalent. From an effectiveness factor point of view, there is no benefit to a centralized energy storage system versus a distributed system (or vice versa).

Round-trip efficiency – The round-trip efficiency ("RTE") of the energy storage used in the March 2015 Study was 85% and this remained the same in this study. Lazard's latest annual Levelized Cost of Storage Analysis (LCOS 3.0) uses 85% efficiency in its analysis.[62] As an additional reference, the Tesla Powerwall 2 has a 90% RTE. This is at the start of its operating life, prior to any degradation, and under test conditions where the system is discharged at 66% of its rating.[63] A system designed for the Eastside application would not operate at a 90% RTE during peak times due to the higher charge and discharge rate required. 85% RTE, therefore, remains an appropriate RTE for this analysis. Flow batteries generally have lower RTE due to reduced performance at high charge and discharge rates and also require energy to operate the electrolyte pumps.

Cell degradation – The original March 2015 Study used a 2% per year rate of cell degradation. This is an industry standard for lithium-ion (it is expected that 80% of the installed energy is available after 10 years) and the same 2% rate was considered in this updated analysis. As the energy storage sizing is assessed to meet the 2019 load forecast, cell degradation has very little impact on this sizing. Flow batteries do not generally degrade as much as lithium-ion batteries over time. However, an 85% RTE is being assumed, which is high for flow batteries and therefore the assumption of 2% cell degradation per year will not unfairly diminish a flow battery's capabilities in the assessment. Cell degradation is inherent to electrochemical energy storage, and anyone with a smartphone would have witnessed reduced battery performance and capacity after several years of use due to this phenomenon.

2014 E3 NWA Report – A report in 2014 identified possible NWA and load reductions associated with these measures. As in the March 2015 Study, these were incorporated into the storage sizing

[62] Source: (https://www.lazard.com/perspective/levelized-cost-of-storage-2017/)
[63] Source: (https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%202_AC_Datasheet_en_northamerica.pdf)

analysis to provide the maximum identified reductions. The NWA reductions are presented in Table 8.

Table 8: 2014 E3 NWA Report with potential load reduction opportunity values

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation Potential (MW)	18.9	22.7	26.5	30.1	30.1	30.1	30.1	30.1	30.1	30.1
DR Potential (MW)	11.7	11.9	24.3	24.7	24.7	24.7	24.7	24.7	24.7	24.7
DG Potential (MW)	0.5	0.6	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Total (MW)	31.2	35.3	51.6	55.6	55.6	55.6	55.6	55.6	55.6	55.6

The ***assumptions that have changed*** since the original March 2015 Study due to updated information and data are:

Load data –Talbot Hill and Sammamish representative load data was generated by PSE for the updated analysis, and scaled to account for projected load growth from 2018-2027.

Load forecasts – As part of its 2017 Integrated Resources Plan ("IRP"), PSE updated its system load forecast reflecting a gradual shift from a winter to a summer peaking system. This reduced winter loading at Talbot Hill, and increased summer loading at Sammamish versus the March 2015 Study, which was based on data from PSE's 2013 IRP. Load forecasts are inherently uncertain, especially further out into the future. For this reason, much of the analysis focuses on the near-term load data. Load forecasts inherently contain some degree of uncertainty: the load may either increase or decrease from the forecast. While energy efficiency and DER offer some load reduction opportunities, electric vehicles may add significant additional load, and the timing of this will be important (and remains uncertain). The load forecast below is consistent with distribution planning approaches to meet NERC and FERC planning requirements and is used for this analysis.

Scenarios considered – Both the Talbot Hill winter load data and Sammamish summer load data were evaluated to define the energy storage sizing. The original March 2015 study also considered both data sets but only presented Talbot Hill because it had the greatest exceedance in the normal rating and therefore defined the size of the storage system required to meet the system constraint. In other words, a system that met the larger Talbot Hill exceedance would also meet the lesser Sammamish exceedance. As shown in the load forecast data above, the Sammamish summer load has now become the greatest exceedance and therefore the sizing of both the Talbot Hill and Sammamish are presented.

Normal and emergency ratings – The transformer ratings have changed since the previous March 2015 Study due to the adoption of a new computer simulation that provides a more dynamic, seasonally adjusted and element-specific rating for each element designed to maximize infrastructure performance.[64] In June 2017, PSE established new ratings for transformers using this

[64] PSE chose EPRI's PTLOAD program as it is a widely accepted tool in the industry for rating transformers and is being used by nine out of the 11 utilities PSE surveyed. Moreover, the in-house software and EPRI PTLOAD software are developed using the same IEEE standards. EPRI PTLOAD was rigorously tested and compared to in-house software. EPRI PTLOAD calculates both individual and group ratings similar to the in-house software, which is one of the requirements the unit-specific rating process targets when the individual transformer would experience an accelerated loss of life.

simulation. To meet NERC requirements, PSE plans its infrastructure in accordance with facility ratings.[65] This has resulted in an increase in the normal winter rating at Talbot Hill from 398MW to 426MW. With respect to Sammamish, the normal summer rating has increased from 369MW to 387MW.

To meet NERC requirements, PSE plans its system using normal ratings on its equipment. Both the normal winter rating for Talbot Hill Substation and the normal summer rating for Sammamish Substation increased by 28MW, which reduced the required contribution of any energy storage system compared to the sizing of the original March 2015 Study.

Minimum SOC – In the additional analysis conducted in this report, the SOC is considered. The minimum SOC limit used was 2%. It is not possible to fully discharge a lithium-ion battery without damage. Such systems have a total energy capacity and a usable energy capacity. For example, the Tesla Powerwall 2 has a total energy capacity of 14kWh but has a usable energy capacity of 13.5kWh. To extract this full amount of energy (13.5kWh), the system must be discharged at 3.3kW or less, (66% of the rated at 5kW continuous discharge).[66] The Eastside application would require higher charge and discharge rates and therefore would not be able to extract as much usable energy, making 2% very aggressive. A flow battery can allow for a 100% depth of discharge and provide all the stored energy as usable capacity; however, the electrolyte pumps consume energy and the 85% RTE assumption is high for a flow battery. Therefore, a 2% SOC limit is used to be technology agnostic and provide a conservative assumption for a lithium-ion system. An actual lithium-ion system would need to be sized larger to cater for the inability to use all of the stored energy capacity.

N-1-1 configuration – The N-1-1 configuration occurs when two different elements go out of service in succession. This is the NERC/FERC planning requirement that the system must be able to handle two elements out of service while continuing to reliably supply the system. Due to the specific electrical topology of the Eastside system, the worst-case N-1-1 contingency during the summer has a more significant impact on Sammamish than the worst-case N-1-1 contingency during the winter has on Talbot Hill.

[65] PSE correspondence (3/7/18)
[66] Source: (https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%202_AC_Datasheet_en_northamerica.pdf)

Explaining “Effectiveness Factor”

The effectiveness factor is the ratio of power injected at particular locations to the reduction of power across a constrained element elsewhere in the system. This differentiates energy storage for T&D applications versus energy storage for frequency response or capacity services. Power for frequency and capacity can be measured at the point of injection, while power for T&D deferral depends on the reduction at the constrained element. Frequency response is a correction to the net imbalance to generation and demand, which is not dependent on where the injected power flows. Similarly, capacity adds power to the system; regardless of where it flows, it provides that capacity to the system. However, in T&D deferral applications, the power flows are critical. The energy storage system’s primary purpose is to reduce the power flow through one or more constrained elements and therefore *where* the power flows.

There are two typical configurations for a power system, radial and meshed. Radial, as the name suggests, is one or more radial lines connected in one direction between two nodes, while meshed is a number of lines interconnected to provide more redundancy. Radial configurations are more typical in rural applications at the distribution level while meshed configurations are more common in the urban environment and at the transmission level. The trade-off being radial is cheaper, consisting of fewer lines and connections, but is less reliable because a single failure can cause an outage.

A meshed network, however, can sustain a failure, isolate that section, and provide power through a different line route. Meshed systems allow customers to experience both fewer and shorter duration outages. This reliability aspect is important and is why meshed topologies are typically used to supply urban areas. The comparison between radial and meshed networks can be seen in Figure 23.

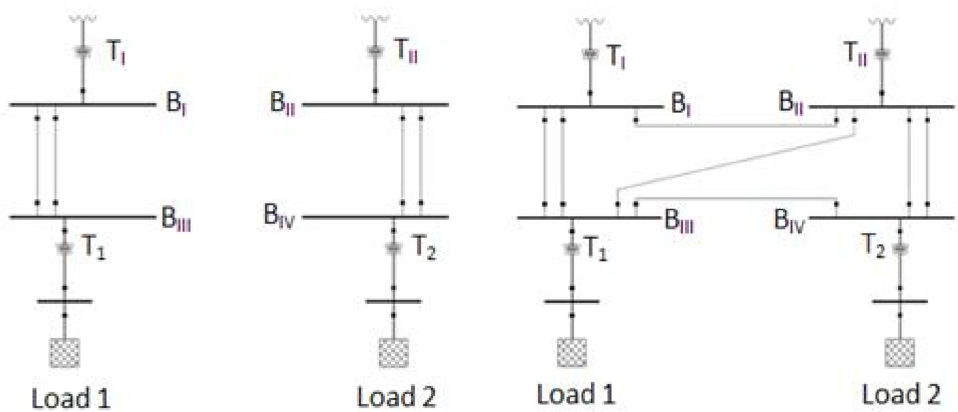

Figure 23: Radial configuration left (dual circuit) and mesh configuration right

When considering energy storage for T&D deferral on a radial line, the effectiveness factor is generally much higher as there are fewer paths for injected power to flow. This concept is shown in Figure 24.

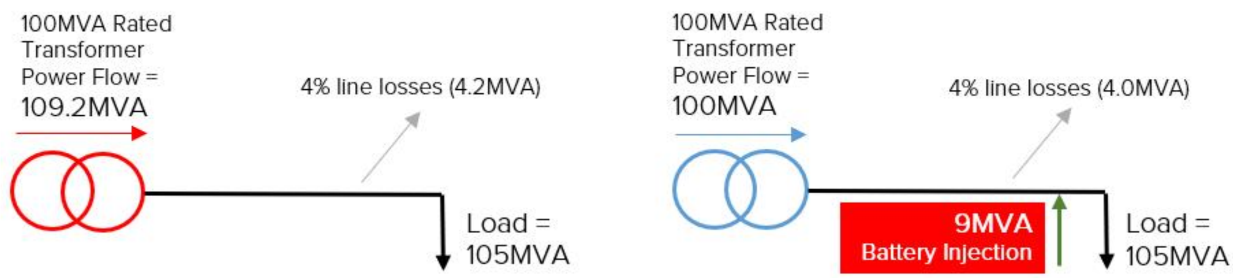

Figure 24: Example of energy storage providing benefit to a radial system

In Figure 24, a transformer rated at 100MVA is overloaded to 109.2MVA. This is a thermal constraint due to the downstream load. In this example, 4% line losses were considered to demonstrate an additional benefit of energy storage. The load consumes 105MVA and 4.2MVA is lost in the power system due to heat (I^2R losses). By installing a 9MVA battery energy storage system near the load, the system has reduced the power flow through the transformer and relieved the constraint. The load still consumes 105MVA but now 9MVA comes from the battery while the power through the transformer supplies 96MVA to the load and 4MVA of power system losses. In this case, the effectiveness factor is 1.0222 because 9MVA of injection by the energy storage system reduces the power through the transformer by 9.2MVA (9.2/9=1.0222). The reason the reduction through the transformer is greater than the energy injected is because the storage system is located closer to the load, so its energy reduces the flow through the transformer, while also reducing the flow through the line, thus reducing the line losses.

The Eastside transmission network is a meshed configuration. In a meshed system, the power flows are very different. Electricity, like water, will take the easiest path which is determined by the resistance (impedance) it faces. The only way to change this is if the physical power system is changed through switching (reconfigured). Figure 25 shows this concept.

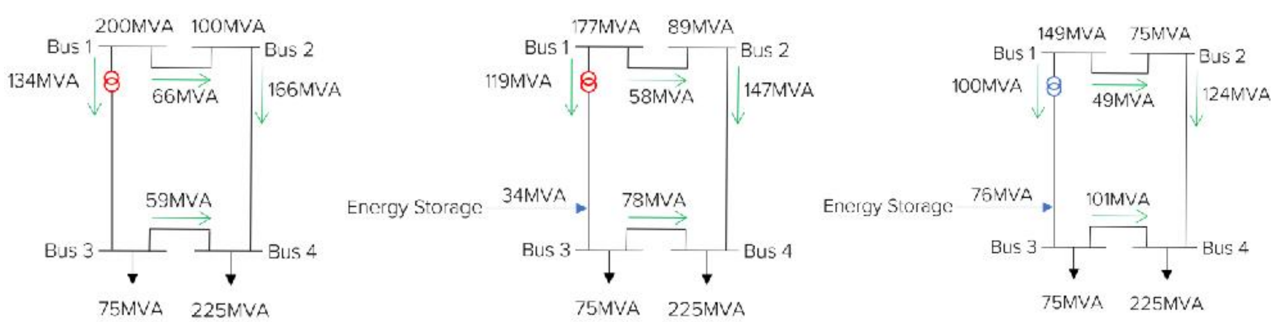

Figure 25: Example of meshed network response to injection and the fact it is not a 1:1 benefit

In Figure 25 the transformer again has a 100MVA rating and is overloaded to 134MVA. However, in this case, simply adding 34MVA of storage does not resolve the thermal constraint as seen. This is because power flows take the path dictated by the system impedance. One-third of the battery injection reduces the contribution at bus 2 while the other two-thirds reduce the contribution at bus 1. The resulting power flows then reduce by that seen in Figure 25. Increasing the battery energy storage system to 76MVA does bring the transformer to its 100MVA rating as seen in Figure 25. In this case, the effectiveness factor is 0.4474 (34/76=0.4474). Therefore, to reduce the loading on the constrained transformer by the required 34MVA, 76MVA of energy storage is required because only 44.74% of the injection of energy storage contributes to reducing the constraint while the remainder reduces the power flows on other lines that are not relevant to the constraint.

The Eastside power system has an effectiveness factor of approximately 20%. The system is highly interconnected, much more so than the simple example shown in Figure 25. This is typical of networks supplying high-density urban areas. This is because a failure can affect so many customers, and the power system is designed to be more interconnected to provide more redundancy, ensuring that customers receive a reliable supply. Various locations were considered within the Eastside area, and all interconnection points had a similar effectiveness factor to the transformer constraints. This again is because of the number of interconnected networks. This effectiveness factor is an important point to understand when comparing systems installed for other applications to the need in the Eastside area.

Explaining "Ability to Charge"

Energy storage, unlike a generator, also acts as a load. For an energy storage system to effectively provide support, it must also have the capability to charge sufficiently without causing a constraint. This ability is determined by network capacity. Figure 26 highlights an example of the required energy discharge (red) and the capacity to charge (green).

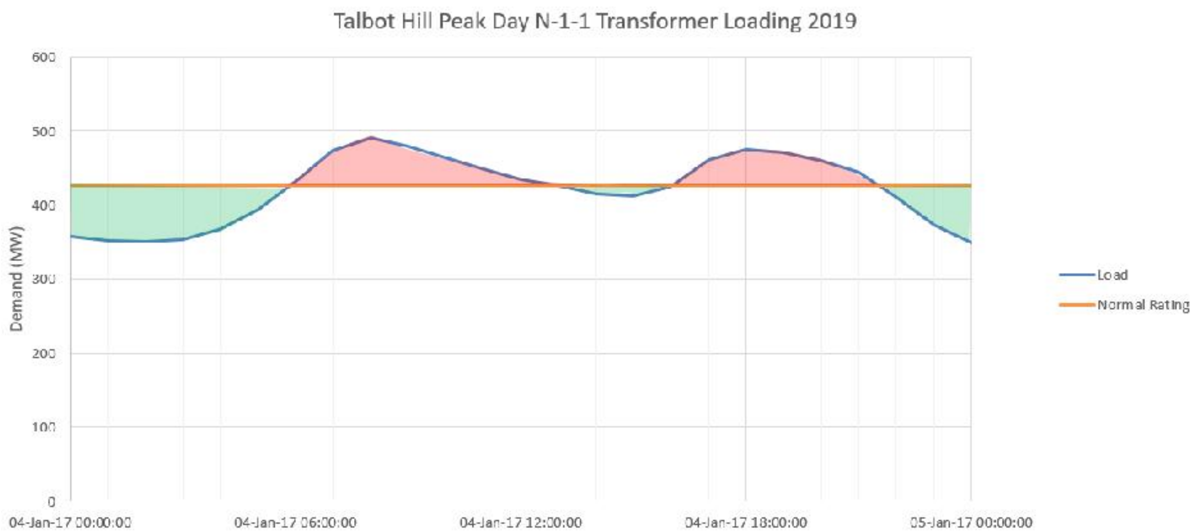

Figure 26: Talbot peak 2017 day (actual load data) and charge capacity (green) and discharge requirement (red)

The green area must be greater than the red area by an amount to compensate for the RTE to effectively charge. For example, if the red area is 80MWh and the green area is 100MWh, with an RTE of 85%, there is sufficient energy to charge the system. 100MWh of charging will enable 85MWh of discharge with 15MWh in energy losses. If the red area is 90MWh and the green area is 100MWh, with an RTE of 85%, there is insufficient energy to charge as 100MWh of charging will only allow 85MWh of discharge. To meet the 90MWh discharge requirement, 105.9MWh of charging must be available to cater for the 85% RTE (90MWh/0.85). If the network cannot support this 105.9MWh of charging without causing an overload, there is insufficient network capacity to allow adequate charging within the daily period studied.

Talbot Hill Solution – Methodology Description, with Comparison to Original Methodology Results

The following steps were taken to assess the energy storage requirements for Talbot Hill Substation based on the original methodology from the March 2015 Study.

1) The recorded Talbot Hill Substation load data was considered and the peak day was extracted. This peak demand is the maximum loading on the substation's two transformer banks and will define maximum power contribution required by a potential energy storage system.
2) During a winter N-1-1 contingency for Talbot Hill Substation, the loading on the remaining transformer at the Talbot Hill Substation would be 78.1% of the full (two transformer) load. The peak day is scaled by this number to compare what the loading would have been on the remaining Talbot Hill transformer.
3) The peak day transformer loading is scaled by the load forecast and relevant N-1-1 scaling factor to provide an N-1-1 load profile for each peak day over the next 10 years, which is presented in Figure 21. Note that even a small change in peak demand has a relatively large impact on the area between the peak loading (solid lines) and the normal transformer rating (dotted red line).

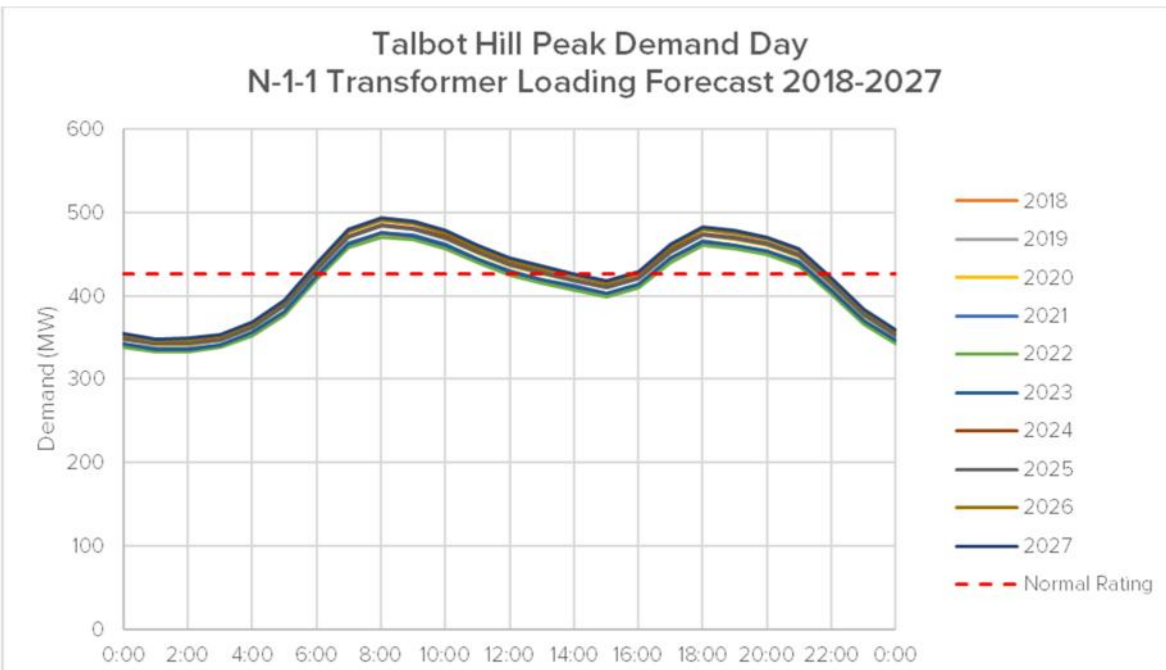

Figure 21: Peak demand loading forecast from 2018 to 2027

4) The peak day of each year is then considered with respect to the normal rating seen in Figure 21. By subtracting the normal rating, the amount the load exceeds the rating defines the load reduction required to meet planning standards.

5) Loading on the overloaded transformer element must be reduced to the normal rating by injecting power onto the grid. Injection of power at the appropriate location on a networked (mesh) power system would reduce this loading at ratio less than 1:1, so this exceedance (which is the exceedance on the transformer element) is then divided by the effectiveness factor. Dividing the exceedance by the effectiveness factor determines the required level of energy injection. The effectiveness factors are approximately 20% for all

scenarios. More information on effectiveness factor concept can be found elsewhere in the Appendix.

6) The NWA load reductions, as identified by the 2014 E3 NWA Report, are then subtracted from the required injection to determine the remainder that must be met by an energy storage system. Similar to the effect of the energy storage system, NWA reductions do not reduce the loading on the constrained element at a 1:1 ratio, and therefore must be subtracted after the effectiveness factor is applied. The NWAs also need to be scaled by the same N-1-1 scaling factor to provide the accurate reduction contribution on the remaining transformer loading.

7) This process identifies the required power and energy of an energy storage system **during the peak demand day** (after NWAs are considered) to reduce the load on the constrained transformer element to the normal rating.

Table 9: Energy storage requirements by year to alleviate Talbot Hill Substation constraint

Net Energy Storage Injection Requirement, by Year[67]										
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Power (MW)	210	**290**	244	208	181	204	255	247	282	**294**
Energy (MWh)	1,239	**2,083**	1,559	1,198	935	1,160	1,668	1,586	1,968	**2,105**
Duration (hrs.)	6	**7**	6	6	5	6	7	6	7	**7**

8) It can be seen in Table 9 that 2019 presents the largest energy storage requirement prior to 2027. This year is therefore significant and is considered as the Interim Solution using the old methodology. 2027 is the maximum size required and provides an alternative that is equivalent to the requirements of the proposed transmission solution which meets the need in all years and is therefore considered as the Complete Solution using the old methodology.

9) The sizing required for the Complete (2027) Solution must also be adjusted to assess the energy storage system requirements for a system installed in 2018 and account for 2% per year cell degradation, as any energy storage system installed to meet the Interim Solution requirements will degrade over time prior to meeting the Complete Solution. Table 10 shows the results of cell degradation.

Table 10: An energy storage system installed in 2018 would need to be 2,515MWh to supply 2,105MWh in 2027

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Energy (MWh)	**2,515**	2,466	2,418	2,370	2,324	2,278	2,234	2,190	2,147	**2,105**

At this point, the original March 2015 Study compared this discharge need to the charging capability discussed elsewhere in the Appendix.

[67] Cell degradation and usable energy capacity are not considered.

Sammamish Solution – Methodology Description, with Comparison to Original Methodology Results

The following steps were taken to assess the energy storage requirements for Sammamish Substation based on the original methodology from the March 2015 Study.

1) The recorded Sammamish load data was considered and the peak summer day was extracted. This peak summer demand was the maximum loading on the transformer during the 2017 summer that was of a consistent shape and representative of likely future peak load days. This will define the maximum power contribution required by a potential energy storage system.
2) During an N-1-1 contingency for Sammamish, the loading on the remaining transformer at the Sammamish Substation is 101.4% of the full (two transformer) load. The peak summer day is scaled by this number to compare the loading on a Sammamish transformer under an N-1-1 contingency.
3) The peak summer day transformer loading is scaled by the load forecast and relevant N-1-1 scaling factor to provide an N-1-1 load profile for each peak summer day over the next 10 years as seen in Figure 22.

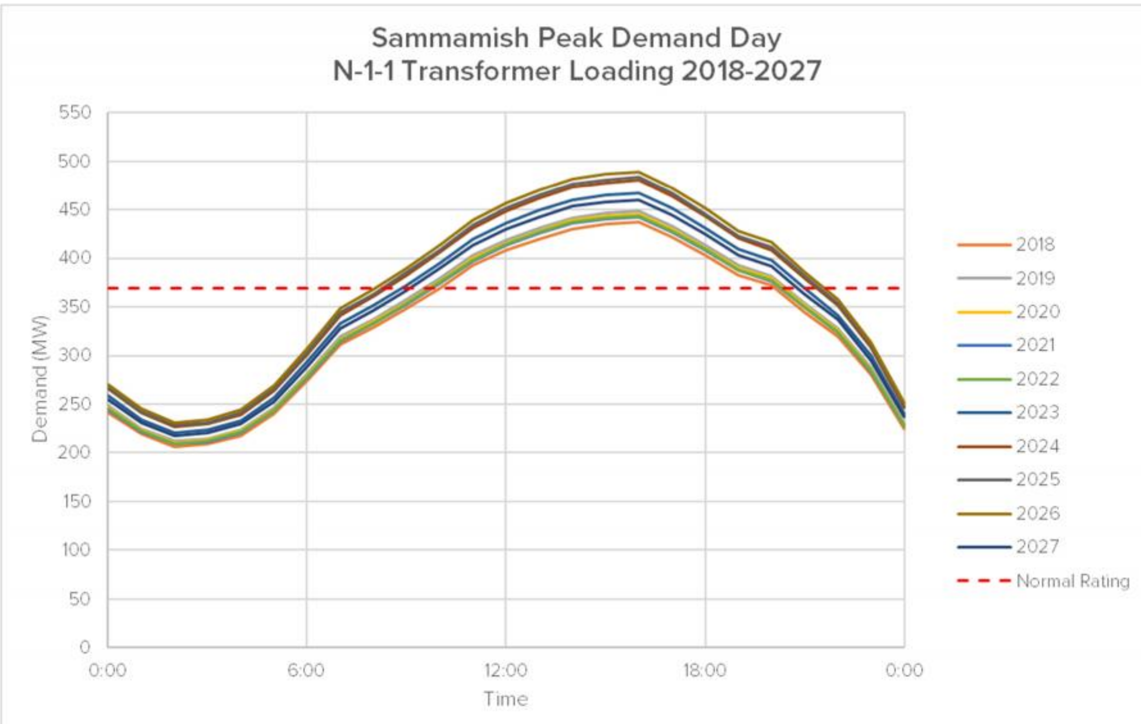

Figure 22: Peak demand day transformer loading forecast from 2018 to 2027

4) The peak summer day in each year is then considered with respect to the normal rating. By subtracting the normal rating, the amount the load exceeds the rating defines the load reduction required to meet planning standards.

5) This exceedance (which is the exceedance on the transformer element) is then divided by the effectiveness factor. The overloaded transformer element must be relieved to the normal rating, and the injection of power reduces this at the ratio of the effectiveness factor. Dividing the exceedance by the effectiveness factor determines the required level of energy injection. The effectiveness factors are approximately 20% for all scenarios, and more information can be found in the Appendix.

6) The NWA load reductions, as identified by the 2014 E3 NWA Report, are then subtracted from the required injection to determine the remainder that must be met by an energy storage system. Similar to the effect of the energy storage system, NWA reductions do not reduce the loading on the constrained element at a 1:1 ratio, and therefore must be subtracted after the effectiveness factor is applied. The NWAs also need to be scaled by the same N-1-1 scaling factor outlined in the Appendix, to provide the accurate reduction contribution on the remaining transformer loading.

7) This process identifies the required power and energy of an energy storage system, after NWAs are considered, to reduce the load on the constrained transformer element to the normal rating. These results can be seen in Table 11.

Table 11: Energy Storage Requirements by year to alleviate Sammamish Substation constraint

Net Energy Storage Injection Requirement, by Year[68]										
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Power (MW)	310	**365**	332	313	318	439	504	519	**549**	405
Energy (MWh)	1,773	**2,277**	1,953	1,786	1,830	3,033	3,713	3,886	**4,240**	2,687
Duration (hrs.)	5.7	**6.3**	5.9	5.7	5.8	6.9	7.4	7.5	**7.7**	6.6

8) It can be seen in Table 11 that 2019 presents the largest energy storage requirement prior to 2023. This year is therefore significant and considered as the Interim Solution using the original methodology. 2026 is the maximum size required in Table 11 and provides an alternative that is equivalent to the requirements of the proposed transmission solution which meets the need in all years. 2026 is therefore considered as the Complete Solution for Sammamish.

9) Finally, the sizing required for the Complete Solution using the original methodology, 2026, must be adjusted to assess the energy storage system requirements for a system installed in 2018 and account for 2% per year cell degradation. Any energy storage system installed to meet the Interim Solution will degrade over time prior to meeting the Complete Solution and must be considered. Table 12 shows the results of the cell degradation.

Table 12: An energy storage system installed in 2018 would need to be 4,968MWh to supply 4,240MWh in 2026

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Energy (MWh)	**4,968**	4,871	4,775	4,682	4,590	4,500	4,412	4,325	**4,240**	4,155

At this point, the original March 2015 Study compared this discharge need to the charging capability as discussed elsewhere in the Appendix.

[68] Cell degradation and usable energy capacity are not considered.

Technical Readiness

Battery energy storage in the power system, until recently, was primarily installed for research and development purposes and proof of concept pilots. In recent years, however, energy storage has advanced, and systems have and are being installed as effective and credible options in some use cases instead of conventional power system solutions. This is depicted in Figure 27 where the progression from demonstration to deployment and now mature technology can be seen in EPRI's energy storage progression plot.

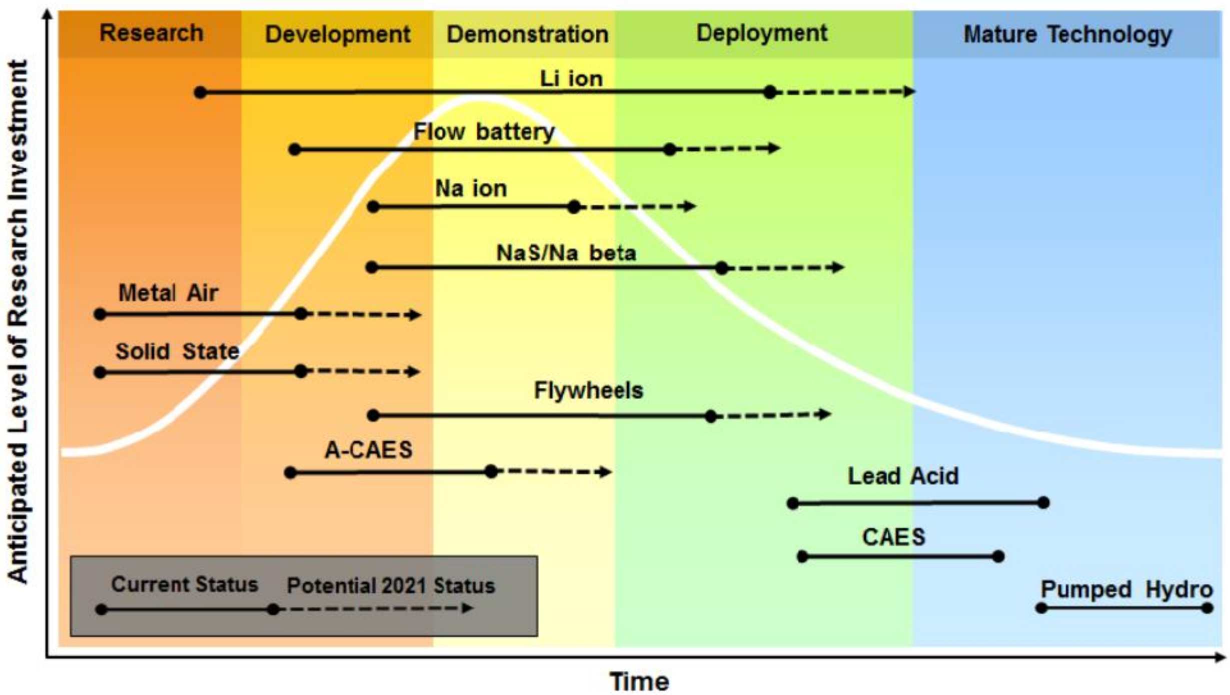

Figure 27: Energy storage progression plot to 2021[69]

The progression is shown in Figure 27 and the transition from demonstration and deployment to a mature technology is evident from the growth of the energy storage industry. Since the March 2015 Study, the deployments of energy storage in terms of energy rating have increased approximately 46% year on year. Figure 28 and Figure 29 capture the annual deployments and quarterly deployments of energy storage respectively. 431MWh of energy storage was deployed in the US in 2017 and it is expected approximately 1,233MWh will be deployed in 2018. This growth rate illustrates the increasing maturity of storage as a technology class, such that today it is generally viewed as a technology that is evolving beyond pilot deployments into commercial applications.

[69] Source: MacColl, Barry. "An EPRI Perspective on the future of distributed energy storage". EPRI, 2017.

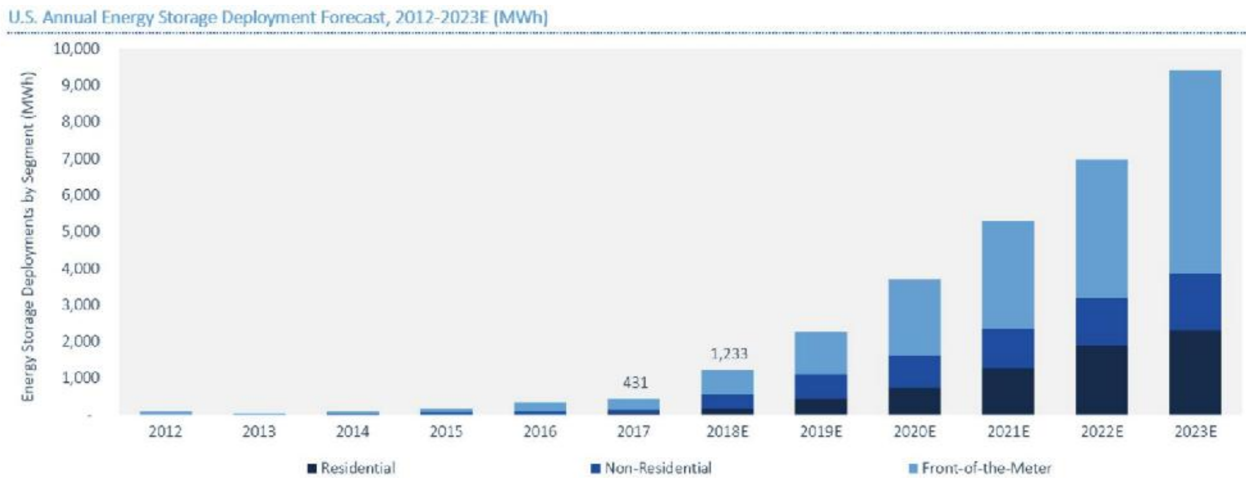

Figure 28: Annual US energy storage deployments by energy capacity (MWh). E = Estimate[70]

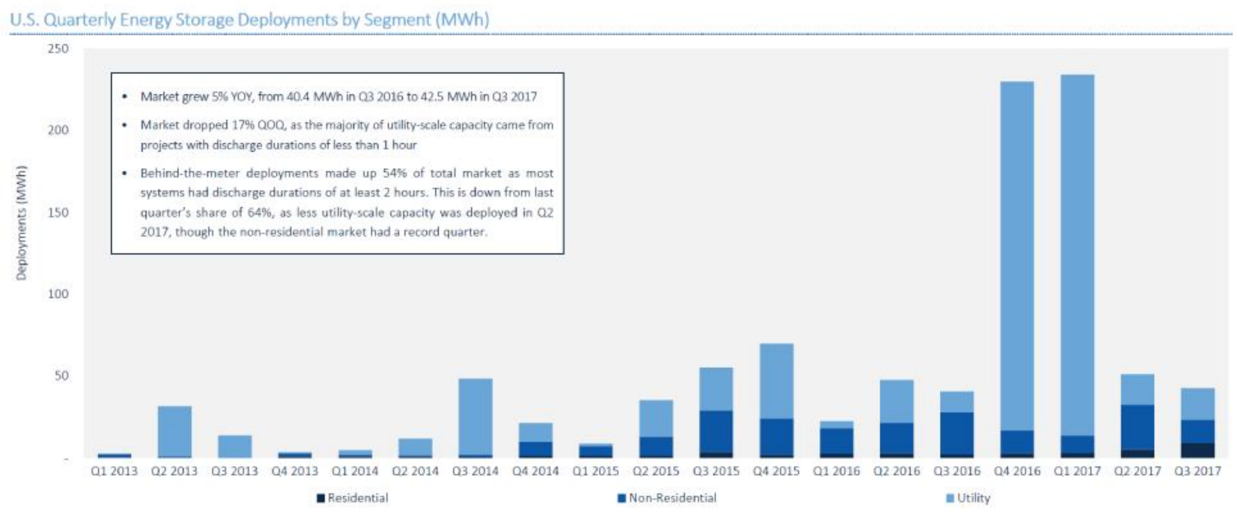

Figure 29: Quarterly US energy storage deployments by total energy (MWh)[53,71]

Excluding pumped hydro, approximately 90% of energy storage capacity deployed in 2016 was a lithium-ion battery chemistry. Other battery chemistries (e.g., redox flow or lead acid) amounted to an estimated 5% of capacity additions, and all other storage technologies combined accounted for the remaining 5%.[72] More recent (Q2 2017) data showed that 94.2% of battery energy storage systems installed were lithium-ion varieties, 5% were flow batteries and approximately 0.5% were lead acid.[73]

It is evident that lithium-ion remains the dominant technology, while flow batteries are also seeing deployments for certain applications. The March 2015 Study assessed a lithium-ion storage system as it anticipated this technology to lead the market, which has proved to have been appropriate on the evidence of recent years.

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[70] Source: GTM Research and ESA (https://www.greentechmedia.com/research/subscription/u-s-energy-storage-monitor#gs.f6=Ow5Q)
[71] Source: GTM Research and ESA (https://www.greentechmedia.com/research/subscription/u-s-energy-storage-monitor#gs.f6=Ow5Q)
[72] Source: (https://www.iea.org/etp/tracking2017/energystorage/)
[73] Source: (https://www.energy-storage.news/news/flow-batteries-leading-the-way-in-lithium-free-niches1)

While they lack the widespread commercialization of lithium-ion,[74] flow battery technology appears to be gaining ground in proposed utility-scale projects, particularly with the announcement of UniEnergy Technology's partnership with Rongke Power in China to develop a 200MW/800MWh flow battery facility in Dalian province of China. According to recent news about the project, groundwork is underway and the project is anticipated to come online in 2020, and "most of the [vanadium batteries] that will fill the site is already built in the manufacturer's nearby facility."[75]

Flow battery technologies may have a few advantages over lithium-ion applications for transmission deferral applications addressing reliability scenarios similar to the Eastside transmission capacity deficiency. They are capable of providing a long-duration, high-power solution and a 20-year ~15,000 cycle life and, unlike lithium-ion solutions, the operational efficiency of flow batteries generally does not degrade over time. However, flow battery solutions generally have a lower round-trip efficiency than lithium-ion solutions, with UET's product fact sheet estimating AC-AC round-trip efficiency of approximately 70%.[76]

Several major deployments further reinforce battery storage becoming a viable alternative grid solution in appropriate circumstances, either where energy storage has been specifically sought due to its technical benefits or where energy storage has been economically competitive in its own right through procurements for grid services. These include:

> **PJM Frequency Response Market -** Between 2011 and 2015, hundreds of megawatts' worth of energy storage have been interconnected to provide frequency response services in PJM's territory. This strong market signal, which has since reduced due to changes in the market, encouraged development extremely effectively, causing an explosion of growth.[77]
>
> **National Grid (UK) Enhanced Frequency Response Solicitation 2016 -** National Grid sought enhanced frequency response services to assist in stabilizing the power system as the level of synchronous (fossil) generation in the supply mix decreased. The solicitation sought 200MW of service, with a maximum of 50MW from any one system to respond to a frequency disturbance within one second. All winning submissions were energy storage.[78]
>
> **Aliso Canyon Energy Storage Deployment -** In an emergency response to a gas leak at the Aliso Canyon power station storage facility, which resulted in insufficient capacity to meet the 2017 summer load, 94.5MW/342MWh of energy storage from a variety of vendors and with a variety of configurations was procured, installed and commissioned in less than a year.
>
> **Hornsdale Power Reserve -** In South Australia, a 100MW/129MWh Tesla energy storage system was installed at the end of 2017 in response to a series of high-profile power outages. This system, coupled to an existing wind farm, will provide capacity, peak shifting, and frequency stability services to the National Energy Market of Australia. The Hornsdale

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[74] Source: (https://www.lazard.com/perspective/levelized-cost-of-storage-2017/)
[75] Source: (https://electrek.co/2017/12/21/worlds-largest-battery-200mw-800mwh-vanadium-flow-battery-rongke-power/)
[76] Source: (http://www.uetechnologies.com/images/product/UET_UniSystem_Product_Sheet_reduced.pdf)
[77] Source: (https://www.greentechmedia.com/articles/read/new-market-rules-destroyed-the-economics-of-storage-in-pjm-what-happened#gs.=X5cRS4)
[78] Source: (https://www.nationalgrid.com/uk/electricity/balancing-services/frequency-response-services/enhanced-frequency-response-efr)

Power Reserve energy storage system has since outperformed conventional generation in providing frequency response services.[79]

In addition to these large in-front-of-the-meter energy storage deployments, there are planning mechanisms in place to routinely consider NWAs, such as energy storage, within the distribution planning process. These assist the distribution network by resolving constraints to avoid or defer conventional infrastructure upgrades. Such frameworks highlight that energy storage is now an important consideration in the distribution planning process and implementable as a solution to enhance the grid. Two of these frameworks include:

New York Joint Utilities Non-Wire Alternative Solicitations - The joint utilities of New York were directed by the Reforming the Energy Vision initiative to pursue NWAs to grid constraints in lieu of building conventional infrastructure. This will both allow the optimal solution to be selected, conventional or NWA, with the likely result being that energy storage may play a larger and larger role in the distribution systems of New York in conjunction with other technologies.

The Brooklyn-Queens Demand Management ("BQDM") program was one project that arose from this process. Since this initial project, NWA opportunities are now regularly identified by joint utilities and request for proposals ("RFPs") listed on their websites.[80] And while every NWA need is unique,[81] we note that some projects such as the West 42nd Street Substation deferral are designed to meet transformer overloads in the tens of megawatts.

California Energy Storage Solicitations - As part of the energy storage targets set by the State of California, the CPUC explicitly enabled energy storage to meet the target as being a combination of BTM, third-party owned, and utility-owned. The investor-owned utilities have designed energy storage RFPs and local capacity resources RFPs to routinely procure energy storage to add capacity and defer the need for distribution upgrades.

Energy storage has become a credible tool used in grid planning, and there have also been various technical advances including energy density, manufacturing, configuration, operating life and operation. These all present the case that energy storage has matured since the March 2015 Study, although the deployments have still been significantly smaller than would be needed for the Eastside need. Some of these aspects will be further discussed.

Energy Density/Physical Sizing

Energy density is the amount of energy that a battery can store per given weight or volume. Historically, the energy density of lithium-ion cells has doubled approximately every 10 years, as seen in Figure 30. This represents an increase in density of approximately 8% per year.

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[79] Source: (https://electrek.co/2017/12/19/tesla-battery-save-australia-grid-from-coal-plant-crash/)
[80] Source: (https://www.coned.com/en/business-partners/business-opportunities/non-wires-solutions)
[81] For example, distribution deferral needs might be more easily offset by distributed energy resources, such as storage, because the distribution substation acts as a radial "bottleneck" through which all power must flow, one way or the other, whereas transmission infrastructure may require a higher ratio of generation or storage to offset the need, because power flows are not similarly constrained to flow through a particular point.

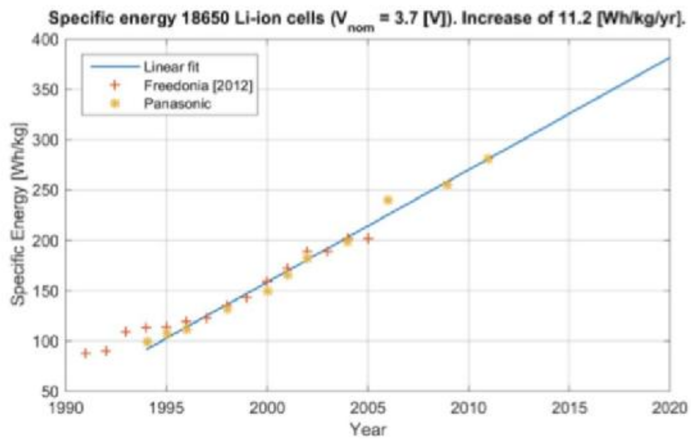

Figure 30: Historic and projected energy density improvement[82]

However, the cells, packing of modules, configuration and auxiliary equipment all contribute to the overall space requirements of an energy storage system, and advances in all areas will ultimately determine the space consumed by a potential energy storage solution. The March 2015 Study provided information on the size of an energy storage solution for the Eastside system. Recent deployments provide additional context for the likely footprint of a modern solution in the Eastside area. The Hornsdale Power Reserve, a 100MW/129MWh energy storage system installed at the end of 2017 in Australia, comprises approximately five acres and can be seen in Figure 31.

Figure 31: Hornsdale Power Reserve (100MW/129MWh) is approximately 2 hectares in size[83]

The Alamitos Energy Center, being constructed by AES in Long Beach, was initially proposed as a 300MW/1200MWh system[84] while it now appears the sizing may have been reduced.[85] The proposal for 300MW called for three 100MW containment buildings. Each building would be 50 feet in height, 270 feet in length, and 165 feet in width and would be composed of three levels: two battery storage levels separated by a mezzanine level. The mezzanine level would contain mechanical equipment such as electrical controls and heating, ventilation, and air conditioning (HVAC) units. Buildings would be set back at least 50 feet from each other and more than 50 feet

[82] Source: Prof. Maarten Steinbuch, Director Graduate Program Automotive Systems, Eindhoven University of Technology
[83] Source: (https://hornsdalepowerreserve.com.au/overview/)
[84] Source: (http://www.renewaesalamitos.com/Alamitos-Fact-Sheet.pdf)
[85] Source: (https://www.businesswire.com/news/home/20170724006035/en/AES-Breaks-Ground-Alamitos-Energy-Center)

from off-site properties.[86] Figure 32 shows the footprint of the original 300MW/1200MWh proposed system in the Long Beach area.

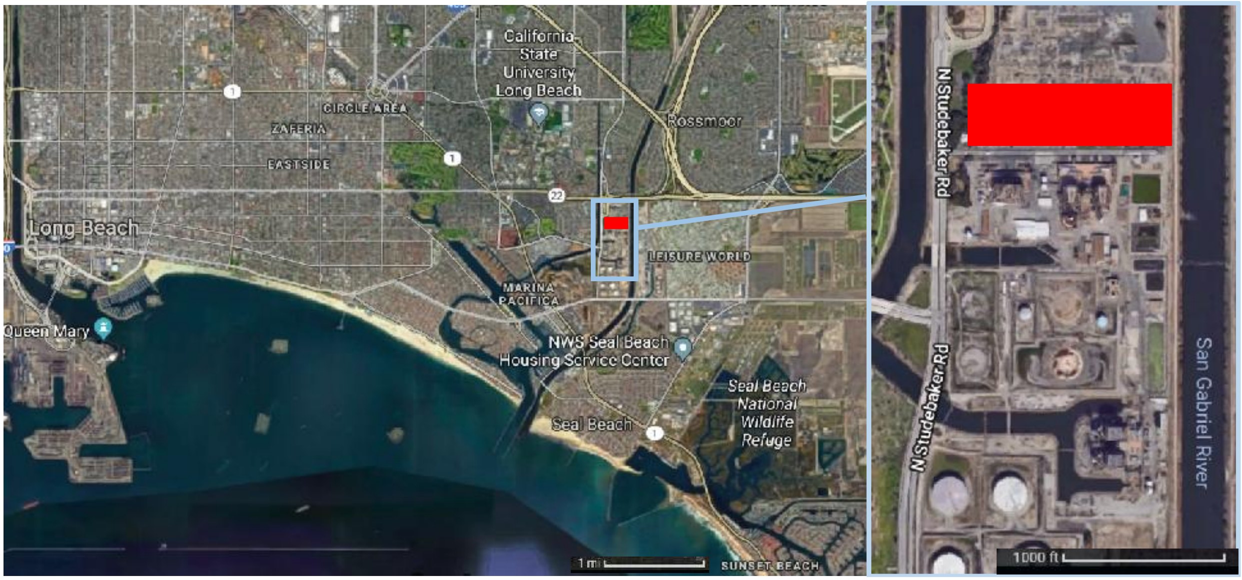

Figure 32: Aerial view of long beach area with Alamitos Energy Center, 300MW/1200MWh shown in red.

As noted above, Rongke Power is developing a 200MW/800MWh flow battery in the Dalian province of China that will be supplied by UET. UET states the following footprint for its flow battery solution on its website:

- Up to 92MWh/acre[87] behind-the-fence deployed footprint
- Up to 184MW/acre[88] behind-the-fence deployed footprint (double-stacked configuration)

Based on these three case studies, Table 13 presents a summary of energy storage system footprint. This will be used to provide an updated perspective for the Eastside system in Section 2.1.2.

Table 13: Summary of space requirements for large-scale energy storage systems constructed and proposed

Per MWh		Hornsdale Power Reserve	Dalian VFB Rongke Power	Average Single Level	Single Level Halved	Dalian VFB Rongke Power	Average Double Level	Extrapolated Size	Eastside Interim Solution 365 MW 2,394 MWh		Eastside Complete Solution 549 MW 5,500 MWh	
		Single Level			Double Level				Single	Double	Single	Double
	Acres	0.04	0.01	0.025	0.013	>0.01	0.01		58.87	21.22	135.25	48.76
	Sq. ft	1,669	473	1071	536	237	386		2,564,333	924,461	5,891,325	2,123,866
								Size compared to CenturyLink Stadium (1,500,000 Sq. Ft.)	171%	62%	393%	142%

System Life

The March 2015 Study modeled a 20-year system life with 2% per year cell degradation[89]. In other words, after 10 years, the system's energy discharge capacity would be 20% lower than at commercial operation date (although the power rating or maximum instantaneous discharge would

[86] Source: (http://www.lbds.info/civica/filebank/blobdload.asp?BlobID=6142)
[87] Assuming a four-hour system based on the 23MW/acre stated on website (http://www.uetechnologies.com/products/unisystem)
[88] Assuming a four-hour system based on the 46MW/acre stated on website (http://www.uetechnologies.com/products/unisystem)
[89] For comparison, the expected system life for the Energize Eastside poles & wires solution is approximately 40+ years.

remain the same). The life of an energy storage system depends on many factors including materials used, operating profile (e.g., depth of discharge and discharge rates), operating environment as well as calendar life.

While it is difficult to predict the life of any proposed solution for the Eastside system, recent deployments can inform what could be expected. The largest energy storage system in the world currently, the Hornsdale Power Reserve in South Australia, has a 15-year warranty.[90] Flow batteries, such as the ones proposed for the Rongke Power Energy Storage System, claim to have an operational life of approximately 15,000 cycles and a cycle and a design life of up to 20 years.[91]

The actual life of a system will vary based on operation. However, the option for 15-year warranties with some products and the potential for longer life for flow batteries mean that an investment in energy storage can be expected to provide a solution for beyond the 10 years expected for many earlier storage systems. This helps validate the assumption of no explicit cost for cell replacement during a 20-year system life.

[90] Source: (https://hornsdalepowerreserve.com.au/faqs/)
[91] Source: (http://www.uetechnologies.com/images/product/UET_UniSystem_Product_Sheet_reduced.pdf)

Commercial Developments

Since the publication of the March 2015 Study, there has been an increasing awareness of and development of programs utilizing battery storage as a multipurpose grid asset, including applications involving distribution and transmission reliability. Utilities in the western US and elsewhere around the world are frequently considering energy storage as part of a basket of resources being evaluated in their integrated resource planning processes, and all-source solicitations are more frequently being launched where storage is being considered amongst a basket of diverse resources for system capacity.

The most common uses of battery storage to date include providing grid ancillary services such as frequency regulation, energy arbitrage (time shift), renewables integration, providing system (generation) supply capacity and capacity firming, and customer electric bill management.

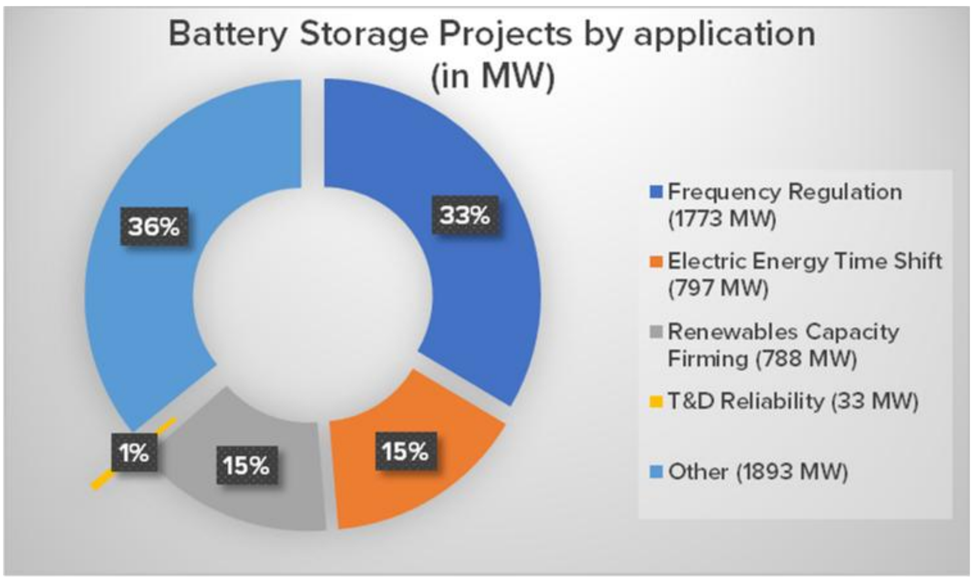

Figure 34: Battery Energy Storage Primary Applications

Source: US DOE Global Energy Storage Database. Accessed 17th of August 2018

Transmission or distribution reliability applications constituted a small portion of the overall total, with 32.8MW (0.62%) of all operational, under construction, proposed, offline, or decommissioned battery energy storage projects in the Global Energy Storage Database classifying T&D deferral as their primary application, with 2.0MW (0.06%) as transmission congestion relief, and 110kW (0.1 MW – 0.003%) as transmission support. It should be noted, however, that primary applications are self-reported in the DOE Global Energy Storage Database, and the above may not account for potential secondary applications. For example, while Tesla's Hornsdale Power Reserve plant is primarily a merchant plant earning revenues in Australia's wholesale market, it arguably is serving a reliability function in South Australia's grid. However, it is a fungible market asset rather than a transmission asset with location-dependent transmission delivery requirements.

Table 14: Largest Battery Energy Storage Systems, Operational and Under Construction, by Power Rating

Project Name	Technology Type	Rated Power (MW)	Rated Energy (MWh)	Duration (hours)	Status	Primary Application
Dalian VFB - UET / Rongke Power	Vanadium Redox Flow Battery	200	800	4.0	Under Construction	Black Start
Alamitos Energy Center - AES	Lithium-ion Battery	100	400	4.0	Under Construction	Capacity and stability (combined with NG generation)
Hornsdale Power Reserve 100MW / 129MWh Tesla Battery	Lithium-ion Battery	100	129	1.29	Operational	Frequency Regulation
Kyushu Electric - Buzen Substation - Mitsubishi Electric / NGK Insulators	Sodium-sulfur Battery	50	300	6.0	Operational	Frequency Regulation
Nishi-Sendai Substation - Tohoku Electric / Toshiba	Lithium-ion Battery	40	20	0.50	Operational	Frequency Regulation
Minami-Soma Substation - Tohoku Electric / Toshiba	Lithium-ion Battery	40	40	1.0	Operational	Renewables Capacity Firming
Notrees Battery Storage Project - Duke Energy	Lithium-ion Battery	36	24	0.67	Operational	Electric Energy Time Shift
Rokkasho Village Wind Farm - Futamata Wind Development	Sodium-sulfur Battery	34	238	7.0	Operational	Electric Supply Reserve Capacity - Spinning
AES Laurel Mountain	Lithium-ion Battery	32	8	0.25	Operational	Frequency Regulation
Invenergy Grand Ridge Wind Project BESS	Lithium-Ion Titanate Battery	31.5	12	0.38	Operational	Frequency Regulation
Beech Ridge Wind Storage 31.5 MW	Lithium Iron Phosphate Battery	31.5	n/a	n/a	Operational	Frequency Regulation
Imperial Irrigation District BESS - GE	Lithium-ion Battery	30	20	0.67	Operational	Black Start
Escondido Energy Storage	Lithium-ion Battery	30	120	4.0	Operational	Electric Energy Time Shift
West-Ansung (Seo-Anseong) Substation ESS Pilot Project - 28 MW ESS - KEPCO / Kokam / LG Chem	Lithium-ion Battery	28	90	3.20	Operational	Frequency Regulation

Source: Strategen; US DOE Global Energy Storage Database, www.energystorageexchange.org, 17th of August 2018.

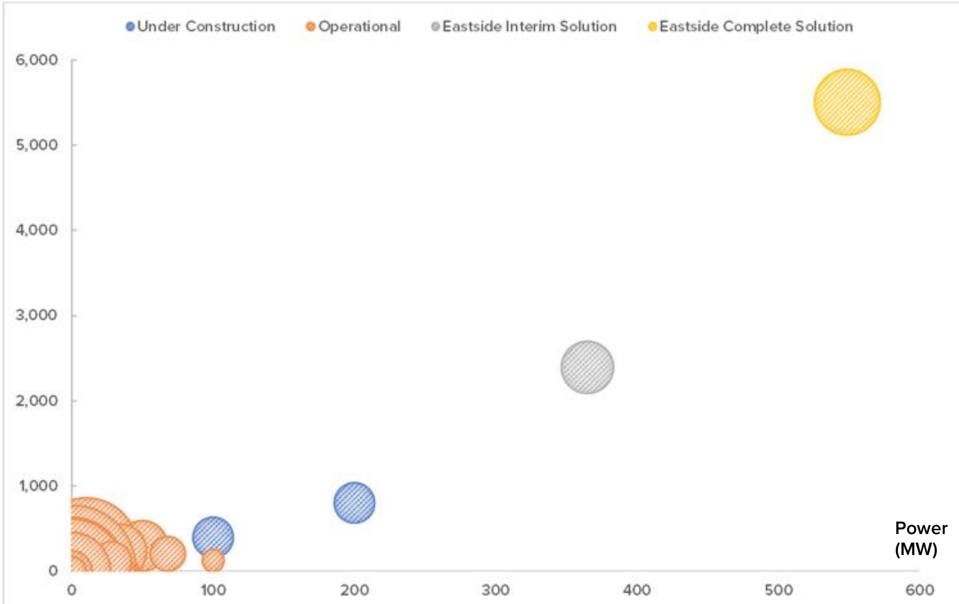

Figure 35: Visual representation of Eastside solutions versus storage projects that are operational or under construction. Size of bubble represents duration in hours. Source: US DOE Global Energy Storage Database, www.energystorageexchange.org, 5th of January 2018.

Recently, there have been some announcements of battery storage procurement for T&D reliability applications. For example, in its 2016 Energy Storage RFO, Pacific Gas & Electric Company ("PG&E") announced it was soliciting bids for a new 10MW/40MWh dual-use energy storage system ("ESS") that would enable PG&E to defer otherwise necessary investments at the Llagas Substation, to provide Resource Adequacy capacity credit and to participate in the CAISO Non-Generator Resource market.[92] This system will be entering operation in 2022 and is intended to serve a deferral need through 2031.

Consolidated Edison ("ConEd") in New York is another utility evaluating battery storage and other DER as non-wires solutions to traditional wires-based solutions. ConEd's activities began in earnest with the BQDM program, which was designed to reduce peak load in the affected area by 69MW, of which 52MW ended up being reduced by NWA investments on the customer- and utility-side of the meter and the remaining 17MW reduced through traditional wires-based solutions. ConEd has extended the BQDM to provide additional load reduction beyond the original scope of the pilot and has a number of other active solicitations for non-wires solutions. For example, the 42nd Street Load Transfer Project[93] seeks to achieve a peak load reduction of 42MW from 9 am to 7 pm from 2021 through 2026, implying a substantially higher need in terms of MWh, met through a basket of solutions (distributed generation, storage, advanced controls for demand response, etc.).

[92] Source: (https://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/Energy_Storage_2016/Information_Distribution_ Deferral_ESS_Final.pdf)
[93] Source: (https://www.coned.com/-/media/files/coned/documents/business-partners/business-opportunities/non-wires/west-42-street-non-wires-solutions-soliciation.pdf?la=en)

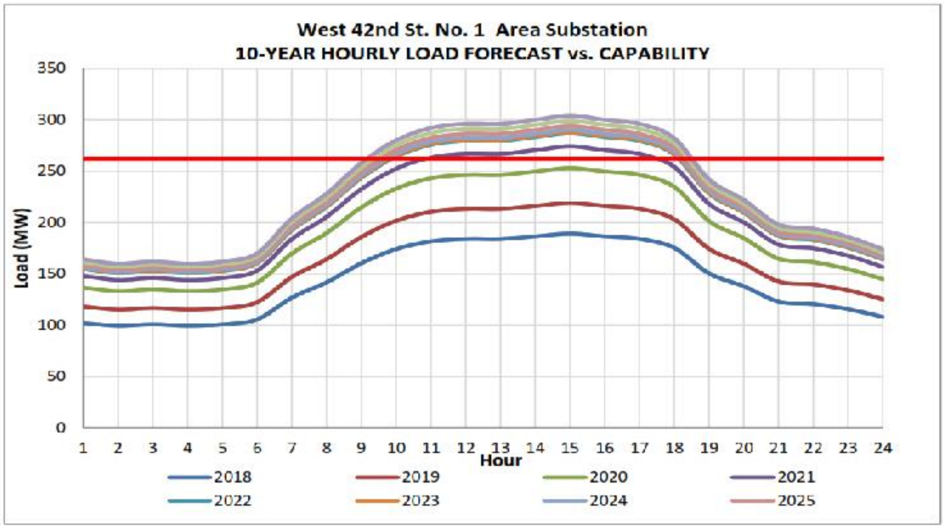

Figure 36: ConEd"s 42nd Street Transfer Project Overload Profiles
(Source: ConEd)

Currently, operational projects providing demand reduction for transmission/distribution reliability are generally much smaller than those in the planning or solicitation stages, such as the ones mentioned above. The Village of Minster project, as shown in Table 15, is a large solar plus storage project that includes 4.2MW of solar PV, along with a 7MW/3MWh energy storage system that is expected to save the local municipal utility $350,000 in deferred T&D costs over the life of the project.

Table 15: Largest Battery Energy Storage Systems Used for Transmission/Distribution Reliability, Operational and Under Construction, by Power Rating

Project Name	Technology Type	Rated Power (MW)	Energy (MWh)	Duration (hours)	Status
Village of Minster - S&C Electric Company	Lithium-ion Battery	7.0	3	0.42	Operational
Smarter Network Storage	Lithium-ion Battery	6.0	10	1.67	Operational
Northern Powergrid CLNR EES1	Lithium-ion Battery	2.5	5	2.0	Operational
SCE Distributed Energy Storage Integration (DESI) Pilot 1	Lithium-ion Battery	2.4	3.9	1.62	Operational
Santa Rita Jail Smart Grid - Alameda County RDSI CERTS Microgrid Demonstration	Lithium Iron Phosphate Battery	2.0	4	2.0	Operational
Enel Puglia ESS	Lithium-ion Battery	2.0	1	0.50	Operational
Enel Dirillo Substation BESS Project	Lithium-ion Battery	2.0	1	0.50	Operational
Enel Chiaravalle Substation	Lithium-ion Battery	2.0	2	1.0	Operational
Powercor 2 MW Grid Scale Energy Storage - Kokam	Lithium-ion Battery	2.0	1	1.0	Operational

Source: Strategen; US DOE Global Energy Storage Database, www.energystorageexchange.org, 17th of August 2018.

Virtual Power Plants

Since the original March 2015 Study, the installation of BTM energy storage systems that are coordinated and aggregated for grid benefits has become a new operating model. This is commonly referred to as a virtual power plant ("VPP") and has mostly been operated as a proof of concept trials, but in early 2018 a significant announcement in South Australia was made where a large number of BTM energy storage systems would be installed to reduce customer energy bills. South Australia is the most relevant market when considering VPP and the role they can play, and both AGL's[94] VPP trial and the recent announcement of the world's largest VPP, in partnership with Tesla, are discussed.

Australia – AGL's Virtual Power Plant Project

The South Australian power system is experiencing several complex challenges as the state progresses towards its clean energy goals and has experienced high-profile blackouts. As large, synchronous generators retire, intermittent, non-synchronous renewable generation comprises a larger share of the energy supply mix. South Australia has the highest level of rooftop solar PV per capita in the world, greater than 25% of customers.[95]

This high proportion of rooftop solar PV in the state's distribution network made it an ideal location to test the potential of a VPP. This VPP helps to stabilize the grid while delivering extra value to customers, the networks, and the retailer. The VPP is a centrally managed network of BTM battery storage systems that can be controlled to deliver multiple benefits to the household, the retailer, and the local network. The VPP is composed of 1,000 homes with existing rooftop solar PV, and BTM energy storage was installed through a shared funding arrangement. These systems aggregate to provide 5MW/7MWh of stored energy. The batteries are charged and discharged using sophisticated algorithms to maximize the benefits to the consumer while ensuring that the network and retailer can also gain value during specific network or wholesale events. Figure 33 shows a diagram of the VPP setup. The VPP can realize multiple benefit streams that can reduce the costs of the system to the customer and provide coordinated and efficient use of the distributed energy resources ("DERs") to support the power system and reduce energy charges for all ratepayers.

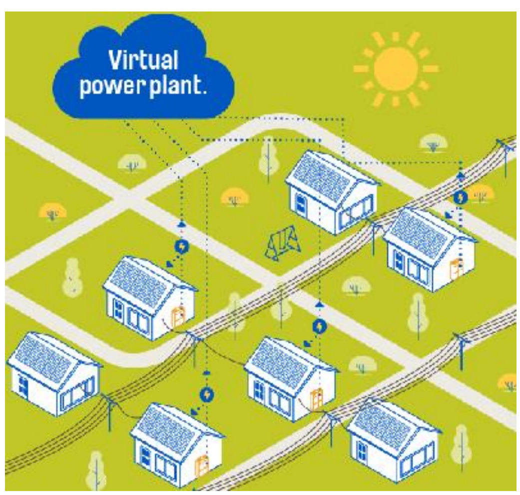

Figure 33: Diagram of the VPP utilizing dispersed PV coupled energy storage to provide aggregated grid benefits[96]

[94] AGL is an energy retailer in Australia
[95] Source: (https://www.energycouncil.com.au/media/1318/2016-06-23_aec-renewables-fact-sheet.pdf)
[96] Source: (https://aglsolar.com.au/blog/virtual-power-plant-bringing-solar-energy-everyone/)

Given the expected increase in BTM battery storage and the reducing opportunities to gain value from exporting excess solar, VPPs represent an important opportunity to provide benefits to individual customers as well as the grid as a whole. The VPP can potentially provide a cost-effective medium-term solution to smooth intermittent renewable energy. In aggregated form, VPPs can add frequency response to the network and allow location-specific DER to be operated to avoid peak demand capacity investment. It also offers opportunities for customers to maximize the value of their existing solar PV systems. To effectively implement, a VPP needs to innovate in the way that technology is deployed and operated through appropriate commercial arrangements and balance the utilization of the batteries between grid and customer benefits.[97]

World's Largest Virtual Power Plant Announcement 2018

In early 2018, the State Government of South Australia unveiled a plan to roll out a network of at least 50,000 home solar and battery systems to form the world's largest VPP over the next four years. Beginning with a trial of 1,100 Housing Trust properties, a 5kW solar panel system and 13.5kWh Tesla Powerwall 2 battery will be in participating homes. For perspective, this trial that is being implemented over four years would meet approximately 28% of the Interim Solution and 13% of the Complete Solution for Eastside.

Following the pilot, which has now commenced, systems are set to be installed at a further 24,000 Housing Trust properties, and then a similar deal offered to all South Australian households, with a plan for at least 50,000 households to participate over the next four years.

Cost Trends

In the March 2015 Study, Strategen reviewed publicly available data on utility energy storage projects, as well as research reports identifying cost trends over time. These sources were evaluated to come up with a cost estimate for a generic multi-hour lithium-ion solution.

The key cost components for utility-scale energy storage projects include battery cells, balance of system, power electronics, building facilities, and interconnection, permitting, land and other indirect/soft costs.

At the time, cell pricing was approximately $600/kWh, and price forecasts suggested costs in the $200-$354/kWh range in the 2015-2020 timeframe. Balance-of-system costs at the time were estimated to be in the $400-$500/kWh range (although Strategen found that estimating this on a per kW basis to be a more accurate methodology). Strategen also evaluated the 100MW/400 MWh system developed by AES and recently procured by Southern California Edison ("SCE") and deemed it to be a reasonable cost comp, despite having a 2021 online date.

Strategen estimated the total cost and revenue requirements of storage alternatives, using cell costs of approximately $250/kWh and balance-of-system costs of approximately $500/kW, with land, permitting, and interconnection costs estimated by PSE. This resulted in a 20-year levelized cost of $218.60/kW-yr, of which approximately 57% was attributable to the cells, power electronics, and building structures, while 43% was attributable to the interconnection facilities, land, permitting, and contingency.

Recent case studies suggest Strategen's original assumptions remain accurate estimates of current pricing. Lazard's Levelized Cost of Storage v3.0 provided an Illustrative Value Snapshot of a 100MW/400MWh CAISO Peaker Replacement case study, assumed to be built in 2017, based on

[97] Source: (https://arena.gov.au/projects/virtual-power-plant/)

cost estimates developed with data from DOE, Enovation Partners, and Lazard's internal estimates, using storage module costs of $97.6 million ($244/kWh), and inverter/AC system, balance of system, and EPC costs of $72.9 million ($729/kW or $182/kWh, depending on the metric used),[98] while assumptions for interconnection facilities, land, and permitting were not explicitly detailed. Translated into a levelized cost, Lazard indicates that the range for such unsubsidized "peaker replacement" storage systems built in 2017 ranged from $395-$486/kW-yr, and Lazard estimates a median cost of $375/kW-yr[99] for projects built in 2018, assuming a 10-year useful life. Strategen's assumption of a 20-year useful life is the driving factor in the lower levelized cost assumption used in our March 2015 Study.

Utility capacity procurement efforts provide data points suggesting continued cost declines are likely. However, costs below the estimates provided in Strategen's March 2015 Study are unlikely until well beyond the timeframe needed to meet the Eastside reliability need (at least with respect to the Interim Solution). For example, in Xcel Energy's summary of the Public Service Company of Colorado's ("PSCo") 2017 All-Source Solicitation 30-Day Report published on December 28, 2017, RFP responses by technology were summarized. PSCo received bids for 21 different standalone battery storage projects totaling 1,614MW to meet a capacity need that begins in 2023. The median bid price was $11.30/kW-mo ($135.60/kW-yr).[100] Furthermore, Lazard indicates that "lithium-ion capital costs are expected to decline as much as 36% over the next five years." We therefore estimate capital cost for the incremental capacity necessary to build the Complete Solution to be 36% lower than capital cost for the Interim Solution.

[98] Lazard's Levelized Cost of Storage Analysis, Version 3.0, published November 2, 2017. https://www.lazard.com/perspective/levelized-cost-of-storage-2017/, p.35. We assume the balance-of-system cost also includes some estimate of cost for interconnection, land, etc., although these costs are not explicitly broken out in the analysis.
[99] Ibid., p.13.
[100] PSCo, 2017 All-Source Solicitation 30-Day Report, CPUC Proceeding No. 16A-0396E. https://www.documentcloud.org/documents/4340162-Xcel-Solicitation-Report.html, p.9.

Impact on Technical Readiness, Commercial Feasibility, and Cost-Effectiveness

The March 2015 Study did not identify any overt barriers to technical readiness, commercial feasibility or cost-effectiveness of energy storage to meet a generic transmission reliability need. However, the scale of projects deployed as of the date of the March 2015 Study was many orders of magnitude smaller than the identified Eastside transmission capacity deficiency, which indicated a higher commercial risk may exist than for technologies with a track record of deployments in similar circumstances.

Globally, there are no currently operational deployments of energy storage on a scale comparable to that necessary to meet the Eastside transmission capacity deficiency. The operational project with the closest scale is Tesla's 100MW/129MWh Hornsdale Power Reserve project in South Australia,[101] and the Dalian VFB 200MW/800MWh Vanadium Redox project currently under construction in China for Rongke Power[102] is the closest proposed project. In addition, there is limited operational history at that scale, and the largest *operational* project (as identified by the DOE's Global Energy Storage Database) *specifically intended to meet a distribution or transmission reliability need* as its primary purpose is the 7MW/3MWh Village of Minster project.[103]

Given that the current cost of storage appears consistent with the cost forecast contained in the March 2015 Study, and because the March 2015 Study indicated that certain storage configurations would already be potentially cost-effective in PSE's system, further assessment of the cost-effectiveness of energy storage was not completed as part of this update. The March 2015 Study showed energy storage within PSE's system (albeit a smaller system than is needed to meet the Eastside reliability need) had a positive benefit-cost ratio. This is because it could leverage its capacity to provide a variety of system services. With the market progressing there is no reason to suggest that energy storage (broadly speaking) within PSE's system would now no longer have a positive benefit-cost ratio.

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[101] Source: (https://energystorageexchange.org/projects/2271)
[102] Source: (https://energystorageexchange.org/projects/2169)
[103] Source: (https://energystorageexchange.org/projects/1976)

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