ESA Comments on Minnesota Department of Commerce

Energy Storage Study Draft Results

The Energy Storage Association ("ESA") appreciates the opportunity to provide these informal comments on the October 11, 2019, workshop of the Minnesota Department of Commerce on the Minnesota Storage Cost-Benefit Analysis conducted by E3. ESA is the national trade association dedicated to energy storage, working toward a more resilient, efficient, sustainable and affordable electricity grid – as is uniquely enabled by energy storage. With more than 190 members, ESA represents a diverse group of companies, including independent power producers, electric utilities, component suppliers, and integrators involved in deploying energy storage systems around the globe. Further, our members work with all types of energy storage technologies and chemistries, including lithium-ion, advanced lead acid, flow batteries, zinc-air, compressed air, and pumped hydro, among others. In these comments, ESA addresses several modeling assumptions and approaches that have undervalued the potential of energy storage and provides suggestions for how to correct them where possible. ESA believes that revising assumptions on curtailment, adjusting assumptions on combustion turbine plant build out, and using a less conservative price assumption will make a significant difference on the study outcomes.

COMMENTS ON MODELING ASSUMPTIONS AND RESULTS

Modeling must include statewide deployment scenarios and quantify sources of value in aggregate

ESA would like to reiterate our previous comments on the importance of including a system-wide analysis under the three scenarios identified by E3. All the successful state-driven cost-benefit studies for energy storage have included modeling that aggregates the costs and benefits of energy storage deployments across the state. Including an optimal statewide deployment amount that provides values that outweigh the costs of the resources, as well as identifies the areas of greatest value (e.g. peak shaving, distribution or transmission deferral), is a critical ingredient to make this study useful to policymakers. While specific end-use analysis is informative and interesting, the reason the Minnesota Legislature included the study in the 2019 energy omnibus bill is to understand the potential level of storage deployment needed and the areas of greatest benefit and value (with a dollar amount).

From our perspective, the study's focus on "Where does storage get its value from the grid?" (header of Slide 6 in the October 11 presentation) points to the disconnect between the current study's approach and what we believe the study needs to answer. A system-wide cost benefit study shouldn't focus on existing value streams for a specific storage project to pencil out from an economic perspective, since the assumption driving the study is that current regulatory and market constructs are not able to capture the value energy storage can provide to the system. Rather, the question is: "Where does storage provide value to the system/State and what is that value?" If you flip the question around, you look for areas of value to the system that we know could provide real savings and benefits to Minnesota, and those values might not all correspond to existing market products or rate design. For example, the system certainly receives value (in terms of cost savings) by energy storage reducing peak demand, but a specific project might not have an existing mechanism to be compensated for that value in the current regulatory and market structure.

ESA strongly supports E3's choice to model three scenarios (Existing Trends, High Natural Gas Price, and High Minnesota Renewables) in recognition of the various policies under consideration by the Minnesota utilities, the Minnesota state legislature, and Governor Walz. However, at least in the initial results, it appears that the cost-benefit analysis only shows the results for the Existing Trends scenario. ESA respectfully suggests that in addition to showing the system-wide cost benefit described above for all three scenarios, the results should show the cost-benefit analysis for the different applications/end uses under all three scenarios as well.

Assumptions for combustion turbine plant build out must be revised downward

Slide 22 of the October 11 presentation includes an assumption that 3,800 MW of combustion turbine (CT) plants will be coming online linearly through 2032 in the business as usual scenario. ESA believes this is an unrealistic assumption for the Existing Trends scenario for the above-mentioned reasons. We understand that this statistic is referenced in the MISO Transmission Expansion Planning report, but we believe that number should be revised downward. ESA suggests using IHS's North American Power Market Outlook as an alternative. The outlook shows approximately 2 GW of CTs being added by 2032 in all of MISO North, which includes Minnesota but also other states. Determining a percentage of that 2,000 MW of CTs for the Minnesota Existing Trends scenario would be much more appropriate.

The value storage can provide to renewables integration is greatly underestimated

ESA believes the value energy storage provides for renewables integration is undervalued in the E3 preliminary analysis for three reasons: (1) the assumption that MISO can absorb all renewables overgeneration ignores transmission constraints across MISO, (2) there is no inclusion of the flexibility value of energy storage in morning and afternoon ramps in the High Renewables scenario, and (3) the AURORA model provides hourly granularity, rather than identifying sub-hourly need.

Curtailment assumptions ignore MISO transmission constraints and renewables generation profile

It is our understanding that the E3 modeling exercise found no curtailment events, even in the High Renewables scenario. In the October 11 workshop, E3 noted that MISO is able to absorb all of the renewables overgeneration in Minnesota. ESA believes this is at loggerheads with the findings of the MISO Renewable Integration Impact Assessment (RIIA), which demonstrated that with higher renewables penetrations there will be incidents of curtailment absent transmission build out. Also of note, it is our understand that over the summer nearly 3,000 MW of renewable energy projects dropped out of MISO's February 2017 West region (which includes Minnesota) due to high transmission upgrade costs. Given that, it seems it would be worthwhile to study the transmission deferral benefits of storage, and also storage's ability to enhance the value of existing renewable resources in Minnesota.

Curtailment avoidance through use of energy storage provides significant value beyond the price of energy. There are system efficiency, environmental, and land use benefits to foregoing curtailment of renewable energy generation that would not necessarily be captured if the current market structure is assumed. ESA is also eager to better understand what assumptions are made about renewable generation. For example, did the model factor in the effect of the Production Tax Credit (PTC) on wind production/overgeneration? This would be critical in determining whether there will be overgeneration events.

The value of flexible capacity is missing entirely

Higher levels of renewable energy penetration will require flexible capacity that facilitates ramping up and ramping down. ESA is unclear about where the value of system flexibility is captured in E3's analysis. There is no market mechanism currently available either at MISO or through the utilities Resource

Adequacy to ensure ramping capacity is available. One example of a modeling exercise that attempted to capture the need and value of flexible capacity is Portland General Electric's ("PGE") IRP. PGE ran a sub-hourly model with ancillary revenue and figure out how much value resources could get and compared that to the hourly energy value that those resources would be given by the production costing model. The positive value was estimated to be flexibility value of those resources.

Modeling tools not granular enough to effectively capture storage benefit in this storage benefit study

When considering renewables integration, it is critical to use modeling tools that can assess the system needs on a sub-hourly basis in order to accurately capture the value of energy storage. Given the variable nature of renewable resources on a five or fifteen minute interval, by only conducting hourly modeling through the AURORA model, E3 has significantly undervalued the benefit of energy storage to integrating renewables. ESA strongly encourages E3 to consider ways to compensate for this significant loss in value in its study by foregoing a more granular analysis. On a separate note, the AURORA model likely also underestimates the value of energy storage to address congestion needs because it is a zonal, rather than nodal, model. Employing a Plexus model would have addressed many of these issues.

Storage as competitive alternative to combustion turbines

We continue to believe that E3's analysis underestimates the ability of energy storage to compete with combustion turbine technology to address peak demand. Below ESA provides feedback on the analysis of storage as an alternative to peakers as well as the Existing Trends assumption for Combustion Turbine (CT) buildout.

Analysis of the capacity contribution of storage is insufficient

In the preliminary results, E3 conducted a unit by unit analysis of the existing 3 GW peaker fleet in Minnesota to see how much of it could be met with 4-hour energy storage, and determined only 324 MW (or 10%) of four hour storage can provide the same benefits as the existing fleet. By looking at historical data and individual units rather than modeling across the entire system (and entire fleet), E3 significantly inflates the need for longer duration capacity across the system. The analysis does not differentiate between economic and reliability needs, so it is very likely to that four-hour storage can meet a much greater share of the benefits provided by the existing fleet. ESA respectfully points out the findings of a recent NREL study by Denholm et al, The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States,[1] which conclude a much higher potential for 4-hour storage to address the needs of MISO-S and MISO-E.

Additionally, while a look at the existing 3 GW of existing peaking capacity is informative, ESA is unclear how this translates into the intended purpose of this study, which is to demonstrate the future potential of energy storage to provide peaking capacity. Will the only need in Minnesota be the 3 GW currently in place, or will there be additional peaking capacity need beyond that? A forward-looking modeling exercise would be able to address that by testing the ability of storage to provide a cost-competitive alternative to peaking capacity. ESA urges E3 to include that in the final findings.

Again, we point to the significant body of work on energy storage's ability to compete with natural gas peaker plants in Minnesota specifically. ESA respectfully suggests that in areas where the E3 study's findings diverge or contradict existing research on energy storage in Minnesota, a description explaining the reasons for the discrepancy be included. If the report conducted by Strategen Consulting in July 2017 demonstrated that storage coupled with solar is a competitive alternative to a natural gas peaker

[1] National Renewable Energy Laboratory, Paul Denholm et. al, The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States, June 2019. (Available at: https://www.nrel.gov/docs/fy19osti/74184.pdf).

in Minnesota already (and as a standalone resource starting in 2023), any assumption of new build combustion turbines would have include specific reasons why energy storage would not be selected strictly on a price basis (e.g. was there a system need for longer duration peaking capacity?).

Approach to estimating capacity value of storage misses the true contribution of storage

Given the significant contribution energy storage can provide in terms of capacity, ESA is concerned with several of the assumptions incorporated into the model relating to capacity. Below we discuss what we believe are appropriate assumptions for capacity value and recommend the inclusion of peak demand reduction value.

MISO capacity prices are not an appropriate proxy for capacity value of storage

The modeling exercise relies on MISO capacity prices in the near term to approximate the value of storage capacity in Minnesota. Because most of the MISO states conduct their own Resource Adequacy exercise through state-level resource planning rather than on relying on the MISO capacity market to ensure they have sufficient capacity, it is inappropriate to use MISO capacity values, even in the near term. It is no wonder that there is excess capacity in MISO and prices are low, since almost none of the states procure capacity separately. E3 notes that over time, the price of a combustion turbine becomes the proxy for capacity prices in the model. ESA respectfully suggests that should be done in the near term as well.

Unclear how the model captures the value of peak demand reduction

As we noted in our October 4 comments, many state cost-benefit studies demonstrated that one of the largest system value energy storage can provide for a state is reducing the costs and emissions of meeting peak demand. In fact, Massachusetts identified that over one third of the value of deploying 1,700 MW of energy storage comes from reducing peak demand. While we recognize that Minnesota is different than Massachusetts, we do believe that the inclusion of the value of reducing peak demand needs to be included in this study. The question of how much savings energy storage can provide Minnesota by reducing costs incurred for meeting peak demand is an important value stream that is not currently captured in any of the cases discussed in the model. We hope at least for system-wide results there is an assessment of savings from peak demand reductions.

Cost assumptions are too conservation

ESA recommends using the "Low" cost forecast from NREL's June 2019 "Cost Projections for Utility-Scale Battery Storage"[2] as a better assumption for forward price declines in the coming decade. Below we include a compilation of consultant forecasts from our June 2018 IRP Primer.[3] The "Mid" case used in this modeling exercise is higher than Lazard's high cost estimates from 2017, which was revised in 2018 and is slated for another revision in the coming month.[4]

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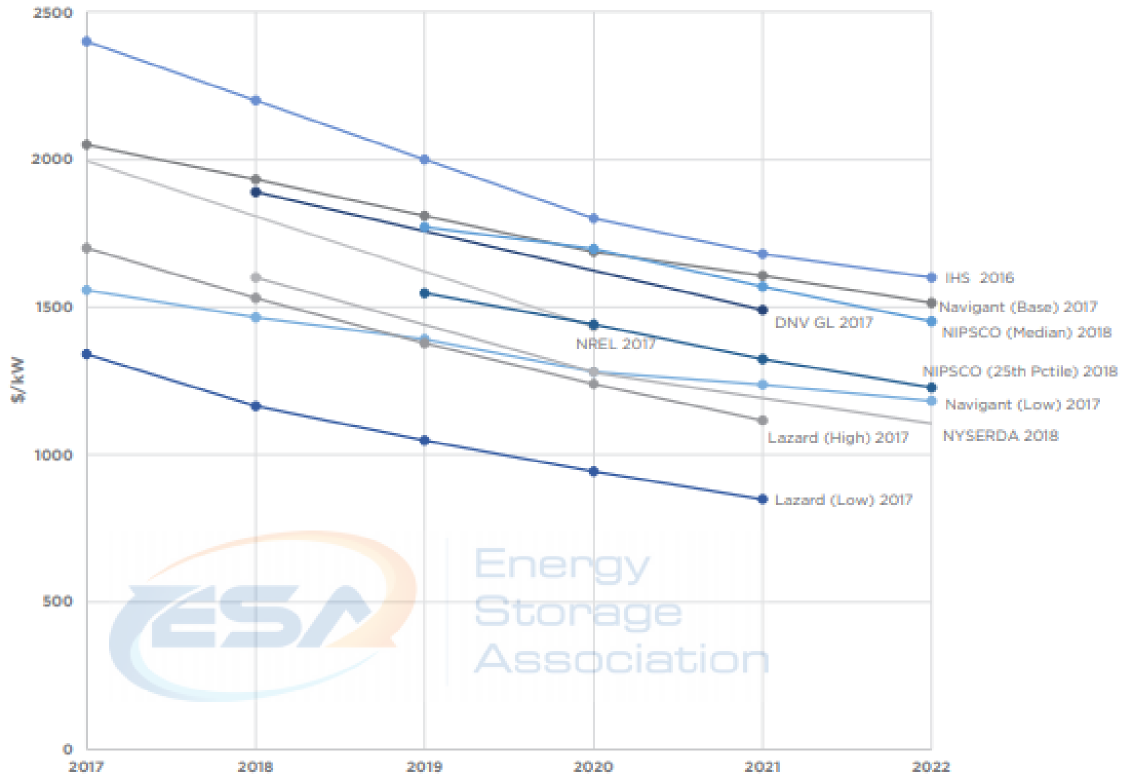
[2] National Renewable Energy Lab, Cost Projections for Utility-Scale Battery Storage, Cole and Frazier, June 2019 (available at: https://www.nrel.gov/docs/fy19osti/73222.pdf).

[3] ESA IRP Primer, Advanced Energy Storage In Integrated Resource Planning, June 2018 (available at: https://energystorage.org/thought-leadership/advanced-energy-storage-in-integrated-resource-planning-irp/).

[4] Lazard will be releasing Levelized Cost of Energy and Levelized Cost of Storage in the coming month that will likely provide a downward revision of the price forecast for storage.

Figure 1: Installed Costs of Large-Format Lithium-Ion Battery Energy Storage, 4-Hour System[5]



ESA also suggests that the Solar + Storage case (Slide 41 of the October 11 presentation) should be revised to better reflect the economies of scale of storage project costs. Using a 1 MW / 4 MWh storage system in the analysis skews the results of the costs of hybrid resources. If a larger system was used in conjunction with a solar resource, the costs difference would be significant.

Finally, ESA would also like to see greater discussion of hybrid projects in Minnesota in the MISO queue (see table below) to better understand how these projects intend to operate and how that compares with the findings in the E3 analysis.

Project #	Request Status	Service Date	Transmission Owner	State	Study Cycle	Study Group	Study Phase	Service Type	Summer MW	Winter MW	Fuel	Download Studies
J1032	Active	10/31/2021	Northern States Power (Xcel Energy)	MN	DPP-2018-APR	West	Study Not Started	NRIS	50	50	Battery Storage	
J1041	Active	10/31/2021	ITC Midwest	MN	DPP-2018-APR	West	Study Not Started	NRIS	20	20	Battery Storage	
J1045	Active	10/31/2021	Northern States Power (Xcel Energy)	MN	DPP-2018-APR	West	Study Not Started	NRIS	20	20	Battery Storage	
J1054	Active	10/31/2021	Northern States Power (Xcel Energy)	MN	DPP-2018-APR	West	Study Not Started	NRIS	30	30	Battery Storage	
J1230	Active	10/30/2023	Great River Energy	MN	DPP-2019-Cycle 1	West	Study Not Started	NRIS	40	40	Battery Storage	

An assessment of how the value streams in this study compare to other study value streams would be productive

ESA is concerned that several value streams are left out of this analysis. We encourage E3 to incorprate these value streams into the final results. Below we provide a useful table from NREL[5] that captures many of the value streams. We encourage E3 to consider a comparison across studies of the values included and excluded in this study to give the readers a sense of the potential values that were left out from the analysis.

Table 1: Applications of Utility-Scale Energy Storage

Application	Description	Duration of Service Provision	Typically Valued in U.S. Electricity Markets?
Arbitrage	Purchasing low-cost off-peak energy and selling it during periods of high prices.	Hours	Yes
Firm Capacity	Provide reliable capacity to meet peak system demand.	4+ hours	Yes, via scarcity pricing and capacity markets, or through resource adequacy payments.
Operating Reserves			
• Primary Frequency Response	Very fast response to unpredictable variations in demand and generation.	Seconds	Yes, but only in a limited number of markets.
• Regulation	Fast response to random, unpredictable variations in demand and generation.	15 minutes to 1 hour	Yes
• Contingency Spinning	Fast response to a contingency such as a generator failure.	30 minutes to 2 hours	Yes
• Replacement/ Supplemental	Units brought online to replace spinning units.	Hours	Yes, but values are very low.
• Ramping/Load Following	Follow longer-term (hourly) changes in electricity demand.	30 minutes to hours	Yes, but only in a limited number of markets.
Transmission and Distribution Replacement and Deferral	Reduce loading on T&D system during peak times.	Hours	Only partially, via congestion prices.
Black-Start	Units brought online to start system after a system-wide failure (blackout).	Hours	No, typically compensated through cost-of-service mechanisms.

[5] NREL, Grid Scale Battery Storage Frequently Asked Questions (available at: https://www.nrel.gov/docs/fy19osti/74426.pdf).