Energy+Environmental Economics

Calgary | San Francisco | New York | Boston | Denver

Alberta Energy Storage Economics

Prepared by: Grant Freudenthaler, Andy Theocharous, Stuart Mueller, Chris Herman, Nathan Miller, and Kushal Patel

Introduction

E3 is a leader in energy storage research including forecasting, operations, and market design across North America markets, and has recently expanded coverage to the Alberta market. A core part of E3's price forecasting process is understanding the economics of all technologies for each market it covers with an off-the-shelf price forecast. For the release of the Alberta Electric System Operator (AESO) forecast, E3 conducted a deep dive on the nascent energy storage market in Alberta. This report evaluates the estimated costs and revenues of the battery storage assets in the AESO market from 2020-2023 and the importance of each revenue stream. We also use our energy storage optimization tool, RESTORE, to evaluate the historic operations of Alberta's battery fleet to inform high level views on how batteries will evolve in this market.

Background: Energy Storage in Alberta

The first battery energy storage system (BESS) in Alberta, the TransAlta WindCharger project, came online in late 2020 and is a 10MW battery storage system.[1] Quickly following, TD Greystone Infrastructure Fund's Enfinite brought nine additional 20MW projects online (a total of 180MW).[2] Looking forward, there are three standalone storage projects and four solar hybrid projects under construction that will add ~170MW by 2026 for a total 360MW.[3] All storage currently in service and under construction are ~2-hour duration li-ion batteries.

---

[1] See details here: WindCharger Battery Storage - TransAlta

[2] See information here: Enfinite energizes three Energy Storage projects, adding 60 MW of energy to the Alberta grid (yahoo.com) and on Enfinite

[3] For under construction projects see the AESO's latest long-term adequacy report: Long-Term Adequacy Metrics » AESO

Cost of Energy Storage

The WindCharger's capital cost of $14.5M CAD was public as it received funding from Emissions Reduction Alberta (ERA) – using this data point for the installed capacity of a 2-hour energy storage system, E3's RECOST tool estimates a pre-ITC levelized fixed cost (LFC) of ~$190 CAD/kW-year.

Since then, the Canadian Federal Investment Tax Credit (ITC) has been announced with a 30% value for battery storage projects. This, in conjunction with battery system cost declines has dropped battery cost to an estimated ~$145/kW-year in Alberta.[4]

Alberta Market Structure and Operations

Alberta's energy-only market has a relatively low-price cap of $999.99 CAD when compared to most jurisdictions, and a floor of $0/MWh. Alberta uses a single real-time price for energy for all market participants, with no day-ahead market. However, contingency reserves (CR) are procured day-ahead and are indexed to the real-time price (AESO's Pool price).

Energy storage is currently subject to the AESO demand transmission service (DTS) tariff for charging and supply transmission service (STS) tariff for discharging. To mitigate DTS costs, BESS will contract for charging service lower than its capacity, which creates long charging and cycle times. We estimate that a 2-hour facility that contracts to charge in 8 hours costs ~ $50 CAD/kW-yr.

Energy Storage Revenue Streams

Currently, the Alberta market has several potential revenue streams for market participants, including, but not limited to:

- **Energy arbitrage – available to storage**
    - Revenues from charging during low-cost hours and discharging during higher price hours
- **Ancillary services (AS)**
    - Contingency reserve (CR) – available to storage
    - Regulating reserve (Reg) – not currently available to storage
    - Fast frequency response (FFR)[5] – available through bilateral contract[6]
- **Black Start[7] – available through bilateral contract[8]**
    - In a system-wide blackout, Black Start services are used to re-energize the transmission system and provide start-up power to generators who cannot self-start

Of note is that Alberta's energy-only market has no explicit capacity prices, though participants are permitted to offer their energy at prices higher than short run marginal cost to recover fixed costs.

---

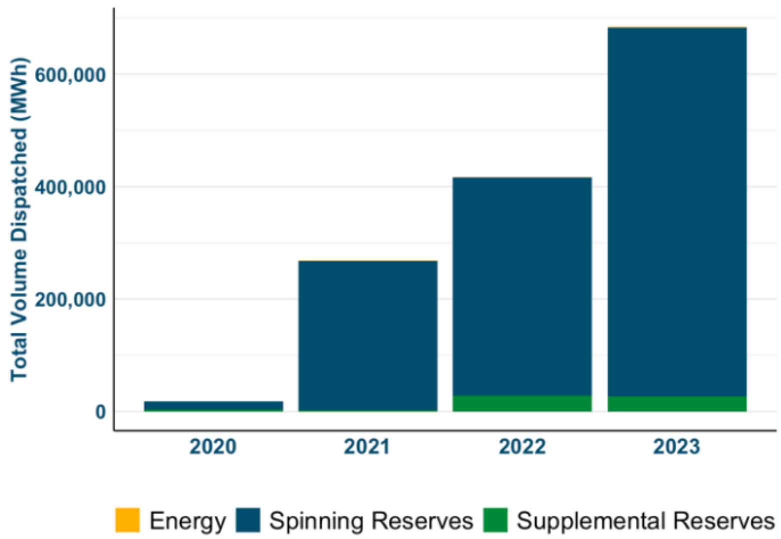
[4] All costs in nominal Canadian dollars.
[5] Currently only available through contracting with the AESO, and is under RFP.
[6] See this announcement for 80MW: Fast Frequency Response (FFR) Update » AESO.
[7] Blackstart services » AESO
[8] Latest procurement: Blackstart Service NW Alberta Procurement | AESO Engage

Therefore, capacity value is embedded in the energy price. Due to the unmitigated energy market, scarcity prices escalate at a more rapid pace as supply cushion tightens in Alberta, providing more frequent price spikes to enable return on and of capital.

Historic Operations and Performance

Historic metered volumes and ancillary services data demonstrate that current energy storage operators are mostly providing spinning reserve, as shown in Figure 1 below. Supplemental reserves and energy market volumes are a very small amount with the latter being so small that it is not visible on the chart.[9]

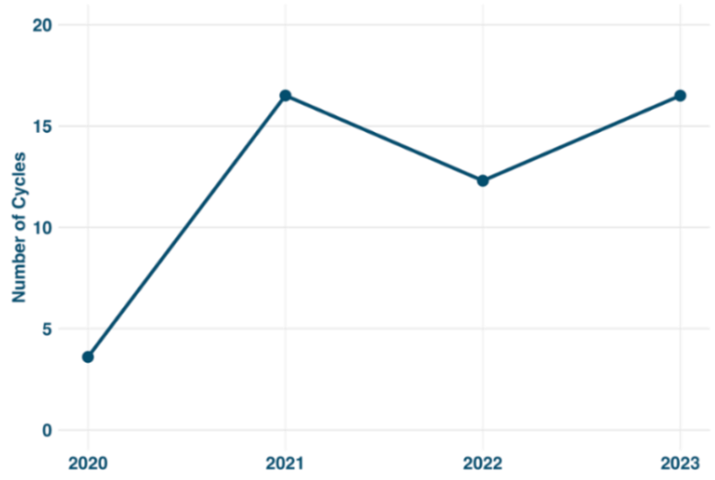
Figure 1: Alberta Energy Storage Fleet Dispatch



Based on total discharge volumes versus the weighted average capacity of the fleet, E3 has estimated that the fleet on average completes a full cycle of energy about one time per month or twelve times per year, shown in Figure 2 below. This estimate is a lower bound and it is possible that batteries are cycling more frequently for volumes below their full capacity, however this provides an indicative metric to limited charge/discharge of the fleet when compared to other jurisdictions where daily cycles are not uncommon.

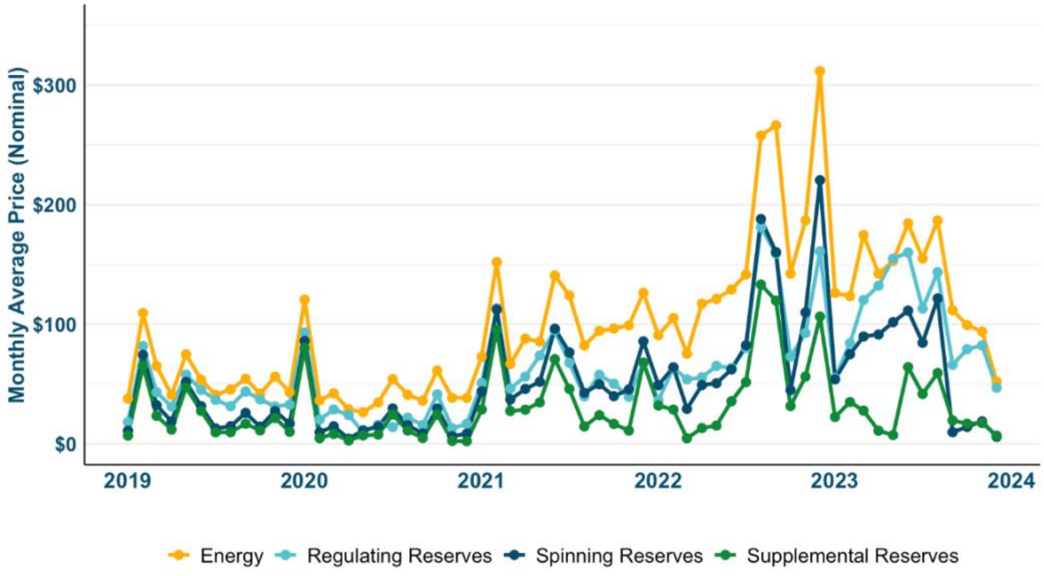
[9] Metered volumes data also includes energy provided from the storage devices when CR is dispatched. This energy estimate may even overstate the amount of arbitrage participation.

Figure 2: Fleet Average Number of Cycles per Year



Since the initial deployment of energy storage, Alberta's energy and ancillary service markets have seen historically high prices. The expiration of the Power Purchase Arrangements at the beginning of 2021, amongst other factors, contributed to historically high energy and ancillary service prices from 2021-2023.[10] Figure 3 below charts the monthly price settlements across energy and ancillary services markets over that time, demonstrating the elevated volatility in energy and ancillary services from 2021-2023. Prices are beginning to stabilize in 2024 with the introduction of new large thermal facilities and continued renewables investment.

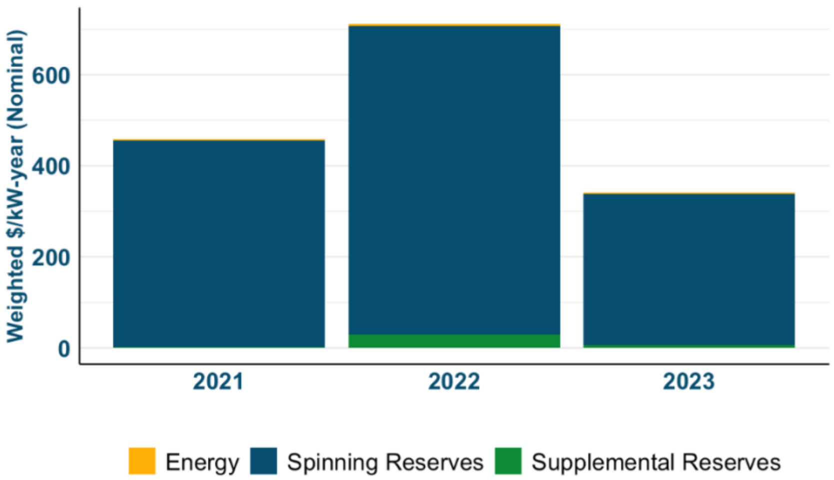
Figure 3: Historic AESO Energy and AS Prices



[10] For a comprehensive review of the contributors to the pricing during 2021-2023 see the Alberta Market Surveillance administrator's (MSA) quarterly reports over that time: [Documents & Reporting (albertamsa.ca)]

Using metered volumes and AS market data, Figure 4 shows the weighted average revenue per kW of storage capacity earned in the Alberta market across the storage fleet.[11] From a revenue perspective, spinning reserves have dominated the market thus far. Since the data on the initial FFR contract is not publicly available, no revenues are assumed from FFR and could be impacting the 2023 estimate, making it appear lower than it is if FFR were included.

Figure 4: Weighted Average Energy Storage Fleet Revenues in CAD[12]



Energy Storage Performance

Based on E3's cost projection of existing projects of $190/kW-year for LFC, and ~$50/kW-year in tariff costs, existing 2-hr energy storage projects need to be earning ~$240/kW-year on average over a 20-year life, net of wholesale energy charging costs. When comparing these costs with the revenues from Figure 4, the first three years of operations have provided a positive IRR for the Alberta fleet,[13] buoyed by the historic energy and ancillary services pricing over that three-year period.

Optimal Historic Operations

Using E3's energy storage optimization model, RESTORE,[14] we ran a back cast for 2021-2023 to assess what optimal operations would have been over the same time horizon. RESTORE optimized across all potential revenue streams on an hourly basis. It is important to note that full optimization

---

[11] Most storage in the market is 1.75-hour duration – therefore this chart reflects revenue from a 1.75-hour duration asset.

[12] Revenues are calculated from the AESO's metered volumes and operating reserve reports. We calculate metered volumes times Pool price, and then the spinning or supplemental volume cleared for each asset multiplied by Pool price minus the spinning or supplemental clearing discount.

[13] The revenue estimates are not net of charging costs. Given the low amount of cycling observed across the fleet – this cost is estimated to be inconsequential.

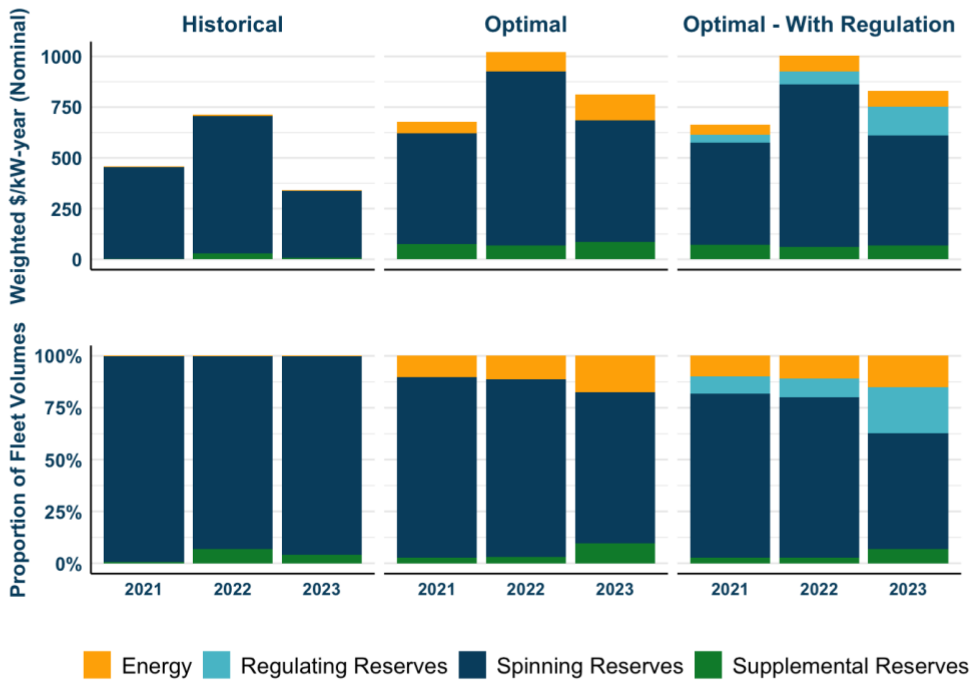
[14] For more information on E3's RESORE model please visit our website.

is not a reasonable target for real world conditions and is used to understand the upper bound of the value batteries can bring to the system. The following assumptions were made to determine what a fully optimized battery dispatch would be:

- Ancillary services were procured hourly, as opposed to the current block procurement methodology
- No DTS or STS tariff costs were assumed to impact dispatch decisions
- Perfect foresight was assumed across all revenue streams
- Battery operations did not impact historic prices
- No downtime/maintenance outages

Under these assumptions, we observed that total revenues between 2021-2023 increased by 66%,[15] driven by an increase in energy revenue and supplemental reserves revenue when compared to actuals. If allowed to participate in regulating reserves, revenues remained largely constant, as regulating reserves replaced spinning reserves in high value hours.

Figure 5: RESTORE Back Cast Results

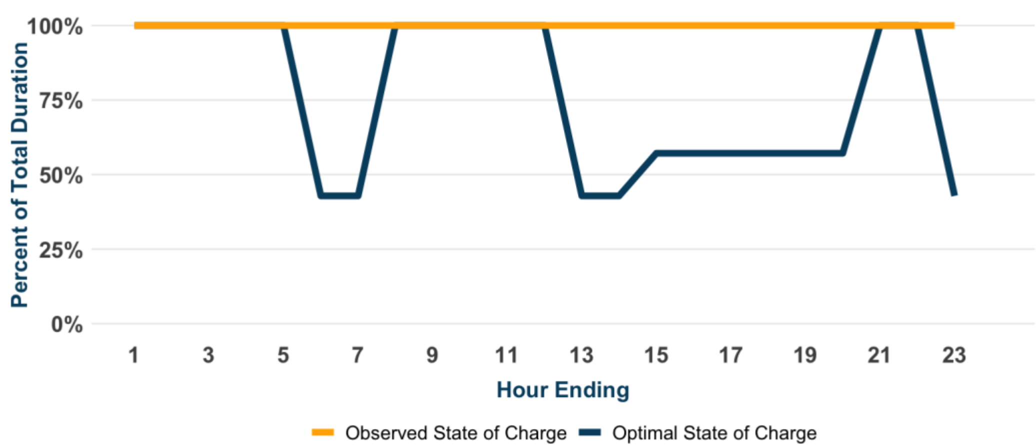


[15] 2023 was omitted from this calculation as some of the existing fleet may have been suppling the AESO with FFR via a bi-lateral contract. This would make the 2023 revenues look reduced.

Market Design Implications

To better understand how block procurement and the tariff are impacting energy storage operations and revenues, we use an example day to illustrate the difference between observed operations and optimal operations. On August 21, 2023, hot temperatures drove energy prices into scarcity price levels. Off-peak spinning prices settled at $0/MWh, and in real time the 2-hour arbitrage spreads were attractive. Because battery storage operators were required to bid into the spinning reserves market the day-ahead, batteries decided to enter the market for both blocks and were unable to provide arbitrage to the market and thus did not dispatch. Figure 6 shows the state of charge under optimal and ideal conditions for this sample day. The optimal battery without tariff costs improved revenue by cycling while spin prices were $0/MWh and discharging during peak prices, while maintaining enough energy to sell spin for the remaining on-peak hours.

Figure 6: Optimal and Observed Asset State of Charge



Forward Looking Energy Storage Operations

Battery storage economics in Alberta have been strong over the past years, and the energy-only market structure is likely to provide price signals to developers to continue deployment of new projects. However, changing supply and demand conditions in the ancillary services markets will drive a change in the revenue streams battery storage leans on to meet IRRs.

Specifically, we are anticipating that the Alberta spinning and supplemental reserves markets will begin to saturate as more battery energy storage solutions are added to the system, resulting in less revenue in these markets, and a pivot to arbitrage in the energy market to meet project IRRs. It will be critical at this point that the market for AS becomes hourly to match the energy market, to ensure full value from storage is unlocked.

Anticipated FFR procurements and adding storage into the regulating reserve market will buoy ancillary services revenue for batteries. Growing demand for grid services from BESS in contrast with continued investment will set the near-term equilibrium revenues for storage projects. It will be important for investors to understand the full picture of AS market saturation pace and shifting BESS operations towards energy arbitrage in their duration and sizing decisions.

About E3

Founded in 1989, Energy + Environmental Economics (E3) is a fast-growing energy consulting firm that helps utilities, regulators, policy makers, developers, and investors make the best strategic decisions possible as they implement new public policies, respond to technological advances, and address customers' shifting expectations. E3's Asset Valuation and Markets practice leverages decades of experience and insight across all our practice areas to help clients identify market opportunities, quantify future revenue streams, and make investment decisions. We support the full spectrum of market players – from large utility holding companies and multi-billion-dollar private equity firms to leading developers, financiers, and technology companies – and our investment-grade, bankable analyses have supported billions of dollars of deployed capital. For more information on E3's forecast of the Alberta market and storage integration, see our market forecast here: AESO Price Forecast – 2024 First Edition – Core Case | Energy + Environmental Economics (ethree.com).

For further information please contact:

Stuart Mueller: stuart.mueller@ethree.com

Grant Freudenthaler: grant.freudenthaler@ethree.com

Kush Patel: kush.patel@ethree.com