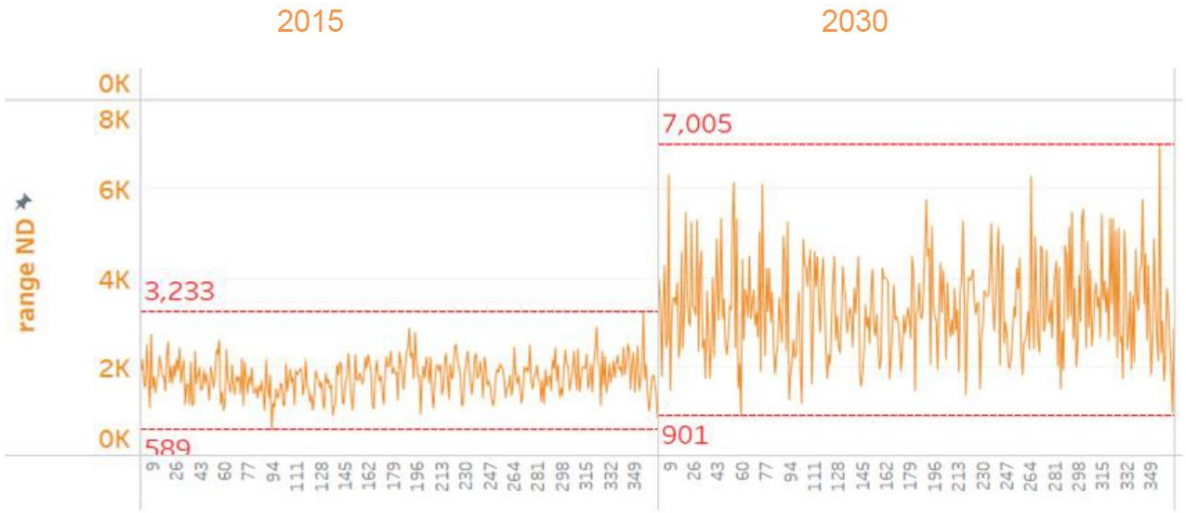
Flexibility and Price Fidelity

The net demand variability (NDV) in Alberta is expected to increase substantially by 2030 due to the expected increases in variable renewable generation and Distributed Energy Resources (DER). What is net demand? Net demand is a term used to describe the demand for electricity from variable generation (wind and solar) resources and changes in load profile. Net Demand = Alberta Internal Load (AIL)[i] – Variable Generation[ii]

As renewables effectively self-dispatch, the merit order for energy is dispatched to meet “net demand”. The AESO currently manages NDV impacts of 1,445 MW of variable generation using a combination of dispatching the merit order (for ramp up and down events) and wind power management (limits wind during extreme ramp up events). The following figure shows the maximum NDV MW per day in 2015 and the forecasted maximum NDV MW per day in 2030.



After testing across three scenarios (reference case, high cogeneration and high coal to gas conversion) simulations have shown that the market may have sufficient flexible capacity in each case that the system can be dispatched to meet increasing variability using the current practices rules (ie. Wind Power Management rules(WPM)); However, these results are based on the assumption of consistent and average ramp behavior. With the current dispatch tolerance rules and a change in market conditions in the future, there is a risk of reliability performance issues if generators took full advantage of the current wide dispatch tolerances. The generator ramp behaviour uncertainty may impact system controller dispatch decision uncertainty. These two uncertainties may enhance and amplify each other especially with an increased reliance on proactive dispatch to provide

ramp and impact price fidelity. Investment decisions will be a function of revenues across all markets so price signals are important to value flexible resources.

Forecast uncertainty and the unpredictability of NDV has impacts from both an operational and market perspective, as further outlined below:

Operational impacts:

- Operational issues on AIES due to speed/volume of ramping changes from a more variable fleet.
- More flexibility of the fleet will be required to respond to high future NDV
- Additional cycling of assets

Market impacts:

- Price fidelity/investor confidence: currently, the price paid for ramp is hidden in the energy price. There is no separation between value for responding to an energy dispatch, and value for providing ramp capability. This has impacts to price fidelity and ensuring that we have transparent price signals to market participants for ramp and energy.

ISO rule/practice changes to better manage dispatch uncertainty

From an operational perspective, uncertainty with respect to ramp response can be difficult to manage, and rules that create additional certainty in terms of response to a dispatch can go a long way to mitigating future market impact of high NDV.

- **Dispatch ramp tolerance rule:** The current ramp tolerance rule (ISO Rule 203.4 Delivery Requirement for Energy) allows assets up to 10 minutes to start their ramp from the time specified in the dispatch and also allows assets to ramp at a ramp rate of +/- 40% of their submitted asset ramp rate. This amount of dispatch ramp tolerance is not permitted in any other North American market. The amount of dispatch ramp tolerance leads to an unpredictable ramp rate of the energy market, and may not reflect the true ramp characteristics of each asset and block of energy dispatched. Tightening the dispatch tolerance would provide SCs more certainty on ramp response, and provide better tools for the SC to manage instances of high NDV.
- **Add ramp capability and dispatch response (delay) time to price/quantity (P/Q) pairs:** This change would allow participants to submit a different ramp rate and response time for each P/Q pair in their energy market offers to more accurately reflect the assets capabilities. Along with this change, dispatch tolerances would need to be tightened as suggested above, or this rule change would provide little value to manage NDV ramp. This enhancement will not change or mitigate any of the NDV ramp issues alone, however would allow asset owners more flexibility to more accurately submit their ramp rate capabilities and be compliant with tighter dispatch ramp tolerance rules. The dispatch response (delay) time would make energy dispatch more predictable and manageable for system controllers.

Price fidelity issue, and providing value for ramp

As mentioned earlier, the System Controllers (SC) dispatch up and down the energy market merit order in real time as required to meet energy demand and, at times, ramp requirements. At times, there is more energy dispatched in the market than what is required to meet demand to allow time for units to ramp based on their characteristics. This process is currently effective from an operational perspective, however, the result from a market perspective is that the System Marginal Price (SMP) is set at the marginal price for each block as dispatched, and as a result, all assets are

paid the same price, regardless of whether they are providing energy, or if they were in fact providing for the ramp requirement at that point in time. This has impacts to price fidelity, as there is no separation between price for energy provided, and price for ramp provided. This price fidelity issue exists in the market today, and may become more pronounced in the future when there is higher NDV, and thus increased reliance on the merit order for ramp requirement.

Summary of options for addressing the reliability and/or market impacts

Tightening the ramp tolerance rule, and ensuring the predictability of dispatch through assets submitting ramp and delay times by P/Q pair are two key areas that improve the system controllers ability to manage NDV. However, with the price fidelity issue described earlier, and increased operational issues that may occur with increased capacity of variable generation in the future, the AESO may need to develop tools, processes and new products to reliably manage the AIES as we add up to 5000 MW of additional variable generation by 2030. The following tables describes possible options and tools the AESO may consider, what issue they may help solve, and what additional may be required.

Options	Description	Timeframe	Issues/Considerations	What it solves	What it doesn't solve
Wind Power Management (WPM) Tool (Current practice)	The system controllers (SCs) use the WPM tool to prevent wind resources from ramping up faster than the energy market dispatches can manage. This allows time for the energy market dispatches to catch up to the NDV ramping.	T (real time)	-Involves limiting wind generation – may be an issue with market participants as we get more and more wind and other variable generation. -Potential for the cost of curtailments to become more material over time, without other mitigating factors (i.e. locational diversity)	Allows time for energy market dispatches to catch up to NDV by limiting wind.	-Not effective for wind ramp events in the downward direction. -Potential waste of energy from spilled wind.
Proactive Dispatch (Current Practice)	SCs dispatch up and down the energy market merit order (EMMO) to meet energy & ramp	This can be anywhere from T-60min to T-10min. Typically in the T-	-May impact price fidelity; the proactive dispatch results in an increasein the SMP until	Helps to address real time requirement for ramp.	-Does not provide incentives for ramp -Price fidelity – does not provide a clear

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	requirements. At times, there is more energy dispatched in the market than what is required to meet demand to allow time for units to ramp based on their characteristics.	30 min to T-10 min timeframe	all dispatched energy comes on line. Energy and those assets providing ramp are paid the same price, regardless of whether they are contributing to mitigating the ramp event or not. -Additional cycling of assets in the EMMO.		market signal for ramp & flexibility requirement, since flexible and inflexible assets receive the same price
Security Constrained Economic Dispatch (SCED)	SCED is an optimization process that determines what dispatch schedules will meet electricity demand at the lowest cost, given a specific set of constraints. In today's market, the constraints would be offers and supply=demand. Energy price and dispatch schedules would be an output. Ramp could be included as a constraint to the	T-3 hrs look ahead to signal ramp needs if missing from on line assets T-5min look ahead for dispatch	-May be costly to implement –system model and constraints must be incorporated into optimization tool. Cost needs to be weighed against benefit and need. -SCED is based on a complex algorithm that is used in many jurisdictions. Would need to adapt for Alberta.	-Flexible fleet to respond to high future NDV -Incentives for building ramp capability -Price fidelity/Investor Confidence - Energy price and value of ramp are optimized -Only assets that help relieve a ramp constraint are paid for ramp -Ramp prices are efficient as it is priced by the dispatch	Does not solve for real time transparency as the dispatch signal is via an algorithm

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	algorithm where the output of the algorithm would be energy price, dispatch schedules, and the shadow price of the ramp requirement (if the ramp constraint is binding). The dispatch schedules output from SCED would provide the least cost solution to meet the ramp requirements in the future interval. In this way, ramp would be valued separately from energy to ensure price fidelity. The SCED would run in advance to support the SCs in dispatching for these constraints. An additional benefit would be to add the co-optimization of operating reserve, minimizing cost over all of these constraints to ensure the most efficient outcome.			algorithm—no separate calculations outside of the energy market -Can accommodate both up and down ramp -Ramp needs are calculated for the next interval based on current system conditions, including forecasts, variability and uncertainty—no overprocurement of ramp -Ramp is only paid for when it is needed (constraint is binding); otherwise there are no payments for ramp -Would provide real time price signal in advance of scarcity, eliciting a response from flexible resources -Optimization across online assets.	

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Additional regulating reserve (RR)	Procurement of additional regulating reserve specifically for mitigating high NDV. Could also be procured through a separate AS product.	D-1 procurement (assuming current procurement practice continues) Use in real time (T)	-May be costly – AGC expensive to install, RR expensive to procure -Difficult for forecast how much additional RR we would need to procure. -Potential for over procurement: May result in procurement of RR when a ramp event is forecasted, however does not occur in real time. No ability to adjust volume in real time (up or down) -Could be coordinated with SCED look ahead period	-Incentives for building ramp capability -RR and energy prices valued separately	-Does not provide a price for ramp -Does not allow a market response to additional needs - AESO must determine requirements in advance of operation
New NDV (10 min – 20 min) reserve product (ramp product)	Similar to supplemental reserve product, however with a slower response (10 to 20 minutes instead of within 10 minutes)	T-20min to T	-May be less costly than procuring additional RR for ramp, however results in similar issues in terms of forecast uncertainty. -Also, would not address	-Incentives for building ramp capability -Ramp and energy prices valued separately	-Likely that will be over/under procured -Amount cannot be adjusted in real time -Would not provide a real time price signal in advance of

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			immediate need due to the 10 to 20 min delay. -Consideration needs to be made for ramp up and down. -May be coordinated with SCED look ahead.		potential scarcity
Explore new AS products to manage variability.	New product dispatched to "store" energy to manage NDV ramp in the upward direction and would "give back" the stored energy to manage NDV ramp in the downward direction. This product could be supplied from an internal Alberta storage asset, or via the interties.	T	-Losses may need to be taken into account in this product as normally storage is not 100% efficient. -Dispatch rules and market utilization would need to be developed. -Examine cost of new product versus value / use. Examine technical specifications for product and applications (examples include battery, pumped storage, intertie)	-Incentives for building ramp capability -Ramp and energy prices valued separately	Need to examine cost impact of option
Shorter settlement	Current settlement interval is hourly. Shorter settlement intervals	T-15min to RT	-Not a solution for flexibility, however does improve price fidelity.	-Improved price fidelity. -May provide some	There is no separation between price paid for energy

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	improves the price fidelity of the settlement price as energy is paid at a price closer to the market value of energy at the time when it is produced. One option is to shorten to a 15 min. settlement interval.		-Due to metering data limitation, it is anticipated that 15 minute settlement can be applied to all pool assets except for retail loads which will continue to settled on an hourly basis.	financial incentives for market participants to respond more quickly to dispatches when ramping up.	and ramp

[i] AIL: “a number in MW: (i) that represents, in an hour, system load plus load served by on-site generating units, including those within an industrial system and the City of Medicine Hat; and (ii) which the ISO, using SCADA data, calculates as the sum of the output of each generating unit in Alberta and the Fort Nelson area in British Columbia, plus import volumes and minus export volumes.”

[ii] Variable generation resource: “Generation capacity whose output is dependent on the availability of its fuel source. These resources could either be transmission or distribution system connected”