REM High-Level Design Stakeholder Feedback

Comment Period: Dec. 13, 2024 to Jan. 17, 2025

The AESO values stakeholder input and invites all interested parties to provide their feedback on the REM high-level design via the following stakeholder feedback **form by Jan. 17, 2025 at 4 p.m. MDT.** Please be as specific as possible with your responses. Thank you for your input.

Purpose

The AESO has been working extensively with industry stakeholders and market participants, partner agencies and government to ensure the Restructured Energy Market (REM) design provides a strong foundation for the Alberta electricity system, ensuring it's affordable, reliable, investable, and sustainable for generations to come.

We have released a REM High-Level Design that will be relied on to progress finalizing a complete design that best fits for Alberta's purposes and reaches the REM objectives. We have progressed the design and narrowed the breadth of options that were being considered through our Design Sprint Sessions and the stakeholder feedback received so far. This round of written feedback will be used to build upcoming consultation activities that will assist in further refining and finalizing the REM.

The sections in this document correspond to those in the REM High-Level Design. We have identified specific areas where we are seeking additional input from stakeholders. Responses in each section are ***optional***.

Instructions

1. Please fill out the sections below as indicated
2. Only one completed feedback form will be accepted per organization
3. To upload your completed feedback form:
   - You will need to be registered and signed in on the AESO Engage platform
   - You will need to be on the REM Technical Design page (https://www.aesoengage.aeso.ca/rem-technical-design), which can be found on the AESO website at www.aeso.ca and follow the path: AESO Engage (found on very top navigation bar) > REM Technical Design > Stakeholder Feedback > Written Feedback on REM High-Level Design | Dec. 13, 2024 – Jan. 17, 2025
   - Click on the "Submit Stakeholder Feedback" box below to upload your completed feedback form
4. All responses will be shared on AESO Engage in their original format
5. Responses due by January 17, 2025 at 4 p.m. MDT

Comments From (Organization): Direct Energy Marketing Limited / NRG Energy

Respondent Name (First and Last): Kevin Thompson

Respondent Title: Manager, Regulatory Affairs

Respondent Email: Kevin.thompson@nrg.com

General

1. **What are the three topics within the REM that you would like us to prioritize for further stakeholder engagement?**

   Topic 1: All North American markets have a two-part energy settlement that trades energy day-ahead and then again in real time (sometimes called an 'imbalance market'). This two-part market incentivises unit commitment on its own and can further be cleared through administrative adjustment. Meanwhile, REM proposes an exotic product, DAC, that appears to both have significantly greater administrative features, does not settle on the same commodity as the energy markets, and is untested from a North American market perspective. Additional scrutiny around this exotic productization of the, until now, 'energy-only' AESO market is called for.

   Topic 2: AESO should extend its collaboration with distribution companies and the AUC to ensure that existing advanced metering infrastructure ("AMI") is operationalised for settlement purposes, and that at a minimum, 'first-generation' AMI is deployed by 2032.

   Topic 3: Scarcity pricing curves, their governance, and ensuring their design does not cause them to bind more often than necessary.

2. **Which components of the REM, as they were presented in the High-Level Design, do you support? (check boxes)**

☒	Registration	☐	Congestion Management
☐	Day-Ahead Market	☐	Market Power Mitigation
☐	Intraday Unit Commitment Process	☐	Scarcity Pricing Curve
☐	Real-Time Market	☐	Market Settlement

   Comments:

3. **Which components of the REM, as they were presented in the High-Level Design, do you have concerns with? (check boxes)**

☐	Registration	☒	Congestion Management
☒	Day-Ahead Market	☒	Market Power Mitigation

☐ Intraday Unit Commitment Process ☒ Scarcity Pricing Curve

☒ Real-Time Market ☒ Market Settlement

Comments:

4. **Do you have any general comments about the REM design that have yet to be addressed? Please specify.**

Direct Energy is concerned that the AESO has unilaterally determined that in the absence of physical day-ahead commitment from generators, the DAC product must be created. This is not the way energy markets work in the rest of the continent, and it need not be the way they work in Alberta. Typically, a well-designed spot energy market will also feature a financial day-ahead market that will lead to physical unit commitment of the required resources to meet demand. To the degree that does not happen, then system operators like AESO may engage in additional commitments that influence the market clearing price, and which then influence the trade in the singular commodity of energy. DAC threatens to unhelpfully bifurcate this market. Direct Energy views the inclusion of a capacity product to be counter to the government's policy direction of maintaining an energy-only market. DAC has simply transitioned the traditional capacity market design and created a day-ahead hourly capacity product that will serve to increase costs to consumers, mute energy price signals, and limit retail product differentiation. Alienating reliability costs from energy prices will harm both reliability as well as the energy price formation that guides innovation and investment.

As a retailer, Direct Energy is particularly concerned that DAC will not ultimately be a manageable, hedgeable product, and that it will instead be recovered as a pass-through cost like transmission charges. Ultimately, this diminishes the part of the overall customer bill that is subject to retail intermediation, and consequently decentralises retail competition as a feature of the Alberta marketplace: the very outcome the government sought to avoid through its transition of the Regulated Rate Option to the Rate of Last Resort and its ongoing encouragement of Albertans to engage in retail choice and select a competitive contract. By introducing DAC, more and more costs become common to all retailers, diminishing the robust competition between them that Government rightly expects. These 'wires' costs already account for 50% of residential retail customers' bills and the inclusion of DAC will only increase the non-commodity portion of the bill.

Without DAC, Direct Energy believes generators will be able to make unit commitment decisions based on pricing, load, and renewable forecasts as they do today. Looking back at the January 2024 energy emergency alert, DAC would have provided no reliability benefit to the province given the alert was primarily the result of multiple forced outages. As the MSA reported, "there were no assets commercially offline, price responsive loads had already voluntarily curtailed, and imports were limited due to competition from other jurisdictions."[1]

[1] Alberta Electricity system events on January 13 and April 5, 2024: MSA review and recommendations, August 6, 2024, page 22. Found at https://www.albertamsa.ca/assets/Documents/January-and-April-2024-Event-Report.pdf

While the AESO indicated in Sprint 6 that the April load shed event may have been averted with the inclusion of DAC, it was also clear that the AESO's renewable forecast had at the time failed to account for the impact of icing.[2] Improved forecasting on its own may have led to different commitment decisions. If the AESO still has a significant reliability concern, it has existing tools to manage and mitigate those concerns when they arise without subjecting loads to additional costs in all 8,760 hours. Direct Energy will expand further on this in its comments under Section 7.

Direct Energy recognizes that the government has since directed 5-minute settlement for distribution-connected assets by 2040. While this granularity may provide some benefit for customers by reflecting actual price dynamics, a 5-minute interval is far less important than picking the low-hanging fruit from currently installed and soon-to-be-installed AMI meters. Existing AMI meters are capable of settling sites at the meter level on an hourly (and potentially 15 minute) basis, but this functionality is not yet operationalised for retail settlements. Simply put, despite the installation of AMI meters on its customers' sites, Direct Energy (and every other retailer) has no idea at what times, at what quantity, and under what duration its customers use energy. Without the proper functionality of AMI meters, retailers will never know at what times and at what volumes its customers used energy and will only have aggregated monthly data. This prevents Direct Energy from offering any advanced, time-varying retail product to the market. All settlements made between the customer, distributor, and retailer relevant to the site would not reflect any degree of load-shifting and demand flexibility that might occur in response to a retail offer that provided pricing or programmatic incentives to shift demand. Without the full potential of AMI meters realised, customers have limited opportunity to reduce their costs, particularly if DAC is added to the market design, and support system reliability. The fact that this situation exists in an energy-only market, with its characteristics of both dynamism and potential supply-side market power, is outrageous.

AESO should focus on collaborating with distribution companies and the AUC to ensure existing AMI functionality is utilized. This will provide retailers the ability to expand product offerings that can encourage load shifting, create automatic demand response programs and support a more effective and robust voluntary demand response, such as the one required in January 2024. By utilizing the existing functionality of AMI meters, retailers will be able to help support the reliability, affordability, and decarbonization goals of REM. This can be accomplished with both hourly and sub-hourly settlement intervals. Direct Energy will expand on this in its comments under Section 13.

5. **Do you have any comments or suggestions on the stakeholder engagement and participation options that you want the AESO to consider when building the engagement plan for 2025? (i.e., in-person format, frequency, virtual information sessions, written feedback, governance, decision-making, etc.)**

[2] REM Sprint 6, slide 111, https://www.aesoengage.aeso.ca/42905/widgets/179261/documents/143784.

The AESO must consult with industry and consider the concerns from load customers and retailers regarding the inclusion of DAC. A binding decision, based on this robust consultation, must be made prior to any further market design and rule development.

The AESO should continue to offer sprint sessions, particularly on topics that have received little airtime to date. Notably, congestion management requires further discussion, including if CAM is the optimal solution, along with the terms of the scarcity pricing curves and general governance of the REM design and components.

Registration – Section 6

6. **Is there anything not captured under 'Outstanding Items' relating to Registration that should be considered?**

   Retail demand response program registration and qualification must be considered in advance of AMI settlement capabilities for eligible reserve products, including DAC (if it remains a part of the market design), R10, and R60. The registration process must recognize that retail demand response volumes are likely to be seasonal. Available demand response capabilities will shift with enrolments and attrition.

7. **Do you have any input to provide on the outstanding items listed?**

   If DAC is to be part of the market design, then any source asset that can provide DAC must have its maximum capability, less any acceptable operating reason, qualified for DAC to prevent physical withholding. All qualified DAC must have a must offer obligation.

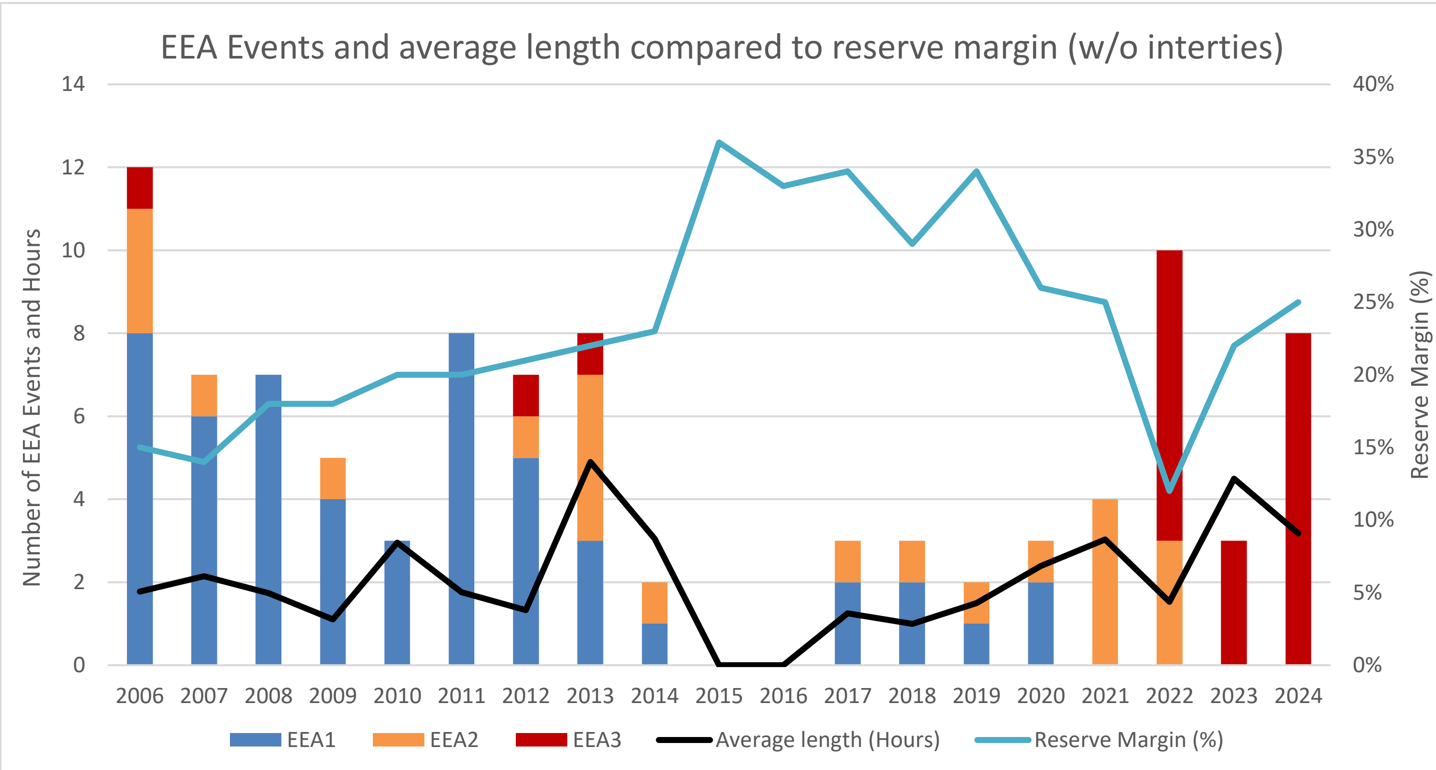
8. **Other comments**

   Direct Energy has concerns that the 4-hour requirement for DAC market participation may have in impact on affordability due to over procurement of DAC and the limitation of storage and demand response. The AESO has stated this is the result of analysis on peak net demand, but this requirement may be better served by ensuring coverage of an EEA event. Direct Energy notes that the AESO's data[3] has shown that there have been longer duration EEA events in recent years. However, this has also been a result of lower reserve margins, which have since improved with the addition of the Cascade units and Suncor Base Plant. The November 2024 Long Term Adequacy report shows reserve margin in 2025 through 2028 at similar levels to the years 2015-2019[4] that had an average of 1.6 EEA events per

[3] In 2022 there were 10 events, with 7 reaching EEA3. The events reaching EEA3 status lasted on average for 1.9 hours. In 2023, there were 3 events, all reaching EEA3 and lasted on average 4.5 hours. In 2024, there were 8 events, all reaching EEA3 and lasted on average 3.2 hours. https://www.aeso.ca/market/market-and-system-reporting/data-requests/historical-energy-emergency-alert-eea-event-data

[4] Long-term adequacy metrics – November 2024, page 3, forecast with generation projects under construction (no intertie), found at https://www.aeso.ca/market/market-and-system-reporting/long-term-adequacy-metrics

year, never reaching EEA3, and each event averaged 1.6 hours in length. Since 2006, EEA events have been on average 2.3 hours and have had a median time of 1.7 hours.



The generally shorter duration EEA events appear to demonstrate that the 4-hour requirement may be too long, given the expected reserve margin. If the REM design works to incent the correct investment in the market, then the 4-hour requirement should be shortened.

Day-Ahead Market – Section 7

9. Is there anything not captured under 'Outstanding Items' on the Day-Ahead Market that should be considered?

Outstanding items have not captured the remaining debate on clearing of the DAM needing to be physically feasible. Market participants have been vocal in their opposition to this requirement in a financial DAM throughout the sprint sessions. Generation should be able to take on and mitigate their own physical delivery risks. There is no guarantee that cleared energy will be deliverable from a given unit as operating conditions can and will change in real-time, nor is there a requirement for that asset to physically deliver the energy under this financial structure.

Given this is "primarily a financial hedging product",[5] the cleared unit does not need to be the unit to deliver energy in any given hour. Long lead time assets can theoretically offer energy in the DAM without a start-dispatch through DAC received. By nature of the asset, it may not

[5] REM High-Level Design, page 11, section 7.1.1.

be online for the DAM hour (particularly if DAC is removed from the design, or if the asset did not clear for DAC) and is theoretically then not "physically feasible"[6]. The AESO also states that the cleared volumes and hourly market prices "will form each asset's day-ahead energy schedule and will be financially-binding, without a physical delivery requirement."[7] In Direct Energy's view, this is contrary to the AESO's proposed requirement that cleared energy must be physically feasible.

The DAM timing and schedule has not been provided with any significant consultation. Direct Energy believes this area deserves feedback from market participants. The current proposal suggests that offers must be in by noon, with the DAM clearing process completed by 3 p.m. In Direct Energy's view, this is too late. The NGX exchange currently closes at 3 p.m., providing no opportunity to trade after the day-ahead results are published. Most other markets close at 10:00 a.m. and trade floors today work with that timeframe. With a close at 10:00 a.m., then the AESO will be able to complete the DAM clearing process by 1:00 p.m. This would negate the need for entities or related firms to amend existing hours and permit firms with an additional avenue to manage their positions.

10. Do you have any input to provide on the outstanding items listed?

Direct Energy does not believe that DAC should form part of the market design. However, if DAC is to be included, then cogeneration supporting behind the fence load should be treated on a net-participation basis. Behind the fence load should not be factored into the AESO's calculation of net demand, reducing forecast error totals and the DAC requirement.

When debating the treatment of net imports in the DAC procurement volumes, the AESO should be endeavoring in a market design that, if it is to include DAC, limits the total that needs to be procured.

Direct Energy is unclear why there would be a need to alter the existing number of price quantity pairs that can be bid into the market. This does not appear to be an area that needs to be altered and the seven blocks should remain for day-ahead energy and for real-time energy. The same number of offer pairs must be provided to load as to generation. There will be continued debate regarding P/Q pairs for DAC that must be settled (i.e. full or partial unit commitment) if it is to be part of the market design.

11. Other comments

The inclusion of DAC in the market design appears to be a foregone conclusion which is not indicative of a robust engagement, as directed by the Government. Direct Energy views that the REM has moved forward with the inclusion of DAC, with neither its need nor an alternative truly considered. Aside from an opportunity to vote on the physical versus financial day-ahead market for those physically in the room of the sprint session, stakeholders have had limited opportunity to oppose the inclusion of DAC. Direct Energy

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[6] "Start times would not be used to clear the day-ahead financial energy market. Participation in the DAM energy market would be limited to an asset's AC without consideration of start-up status." REM High-Level Design, page 14.
[7] REM High-Level Design, page 20, section 7.2.4.

believes there must be a discussion on whether DAC is necessary in the REM, with a binding decision made prior to the start of any rule development process and further design of interrelated market components.

Currently, unit commitment decisions are made absent a payment for capacity or commitment. DAC is contrary to maintaining an energy-only market and the government's cancellation of the previously proposed capacity market. Instead of creating a traditional capacity market with a seasonal or annual clearing price for capacity, the AESO is moving to introduce a capacity market through a day-ahead, hourly offering. This removes the "energy-only" aspect of the market with units receiving availability payments at the expense of load in all 8,760 hours. The AESO currently has the tools required to maintain reliability and can consider additional tools it may need that do not add costs to load in every hour of the year.

DAC is counter to the AESO's stated design objective of affordability. Analysis completed by Power Advisory, with details included in its submission, have indicated that DAC will only serve to increase costs with a negligible impact on the energy price. Power Advisory's analysis found that if DAC had been in place in 2023, it would have settled on average at $97.54 /MWh, while only reducing the pool price by an average of $6.54 /MWh. Given the AESO is calling DAC an ancillary service and that a tariff update will not be completed until 2029 at the earliest,[8] it is most likely that DAC costs will be passed on through the transmission charge. As noted in Direct Energy's submission under comment four, mass-market load customers will have no capability to limit their costs under the current settlement structure.

Based on Power Advisory's estimated DAC cost of $97.54 and applying the average cost on an equalized basis to residential electricity consumption, it would have resulted in a wires cost increase of 50% to 111% (see line 9 in the table below), depending on service territory. If we assume that the full average real-time market cost reduction of $6.54 /MWh was applied to available retail rates in January 2023, wires costs would have climbed between 10 and 20 percentage points of the portion of the bill, depending on service territory (see line 16 in the table below). The portion of the bill allocated to wires costs would be even higher for customers that were on lower rates that had been available in the market prior to 2023, as seen in the table below (line 12):

[8] REM Sprint 6, slide 79, found at https://www.aesoengage.aeso.ca/42905/widgets/179261/documents/143784.

Impact of DAC on Residential Customer Bills[9]

2023 T&D Rates	ATCO		Enmax		Epcor		Fortis/AltaLink	
Residential	Per day	Per kWh	Per day	Per kWh	Per day	Per kWh	Per day	Per kWh
1 Transmission	$ -	$0.04810	$ -	$0.04209	$ -	$0.03834	$ -	$0.04363
2 Distribution	$1.23120	$0.07870	$0.64790	$0.01303	$0.66988	$0.01643	$0.90550	$0.02930
3 Other/DAC	$0.23520	$ -	$ -		$ -	$ -	$ -	$ -
4 Total	$1.46640	$0.12680	$0.64790	$0.05513	$0.66988	$0.05477	$0.90550	$0.07293
Monthly Charges								
5 Wires costs	$ 44.60	$ 76.08	$ 19.71	$ 33.08	$ 20.38	$ 32.86	$ 27.54	$ 43.76
6 Total		$ 120.68		$ 52.78		$ 53.24		$ 71.30
7 DAC		$ 58.52		$ 58.52		$ 58.52		$ 58.52
8 Total w/ DAC		$ 179.21		$ 111.31		$ 111.76		$ 129.83
9 % increase		48.49%		110.88%		109.93%		82.08%
	Rate Year		Rate Year		Rate Year		Rate Year	
Total Bill - w/ DAC	2022	2023	2022	2023	2022	2023	2022	2023
10 Retailer Charge	$ 53.54	$71.82	$ 53.54	$71.82	$ 53.54	$71.82	$ 53.54	$71.82
11 Total Bill	$ 232.75	$251.02	$ 164.85	$183.12	$ 165.30	$183.58	$ 183.37	$201.64
12 % Wires	77.00%	71.39%	67.52%	60.78%	67.61%	60.88%	70.80%	64.38%
Total Bill - No DAC	2022	2023	2022	2023	2022	2023	2022	2023
13 Retailer charge	$ 53.54	$ 75.74	$ 53.54	$ 75.74	$ 53.54	$ 75.74	$ 53.54	$ 75.74
14 Total Bill	$ 174.22	$ 196.42	$ 106.32	$ 128.52	$ 106.78	$ 128.98	$ 124.84	$ 147.04
15 % Wires	69.27%	61.44%	49.64%	41.07%	49.86%	41.28%	57.11%	48.49%
16 % Difference	7.73%	9.95%	17.88%	19.71%	17.75%	19.60%	13.69%	15.89%
17 Bill Increase w/DAC	33.59%	27.80%	55.04%	42.48%	54.81%	42.33%	46.88%	37.13%

As demonstrated above, without DAC added to the wires charges, wires already form a significant portion of a customer's bill ranging from 41% in the Enmax/Epcor service territories to 61% in the ATCO territory (line 15, looking at 2023 rates). The inclusion of DAC drives all service territories wires costs to form over 60% of the bill, regardless of the chosen rate (see line 12). This would have a significant impact on the retail market. Retailers are consistently managing customer complaints regarding wires charges and customer's mischaracterization of them as additional fees charged by

[9] Total wires costs (line 6) are calculated by multiplying the per day charges by (365 /12) and the per kWh charges by 600 kWh, representing the average monthly residential customer usage (7,200 kWh /12). The DAC charge (line 7) was then calculated by multiplying Power Advisory's $97.54 /MWh by 600 kWh. The % increase (line 9) shows the increase in wires costs with the addition of DAC (line 8 compared to line 6). The retailer charges for both "Total Bill – w/ DAC" (line 10) and "Total Bill – No DAC" (line 13) use Encor's publicly available rates from January of each year, with $8 added as the monthly administration fee. The 2022 rate is 7.59 cents /kWh and the 2023 rate is 11.29 cents /kWh. The historical rates can be found here: https://www.epcor.com/ca/en/ab/other/account/rates/historical-electricity-rates.html#accordion-41f24a14c4-item-13f200be89. The 2023 retailer charge with DAC (line 10) had Power Advisory's average real-time energy price reduction of $6.54 /MWh applied in full to the retail rate, reducing it to 10.64 cents /kWh.

the retailer. Decreasing the retailer-managed portion of the bill to 40% or lower will significantly impact retail competition and severely mute price signals that retailers compete on.

Power Advisory's analysis further showed that in a looser supply cushion market, the DAC simply serves to increase costs to consumers. Its May-October 2024 analysis, when supply was significantly more plentiful, shows load would pay $800 million in DAC costs in those six months, while energy prices would have only declined by $1 million over the period. Going back to the 2023 example shown above, the annual cost of DAC to a residential customer would have been $702.29. If the full real-time price reduction was accounted for in available January retail contracts, customers would have still paid $655.20 more than the existing market structure. Depending on service territory, this represents a total monthly residential bill increase ranging from 28% to 48% using the 2023 rate – and even higher using the lower 2022 rate (see line 17). This demonstrates that DAC will produce outcome that are contrary to the AESO's stated affordability goals.

The inclusion of DAC will create unmanageable costs for mass-market customers. Given that distribution-connected customers are billed on a load-profile basis, there will be no avoiding DAC charges. Until this changes, and even if DAC can be allocated on an hourly basis, individual consumers will continue to be settled based on load-profile and limiting consumption in high price hours will not provide them with a proportional benefit. If DAC is to be included in the market design, it is imperative that its allocation can be done on an energy basis.

Intraday Unit Commitment Process – Section 8

12. **Is there anything not captured under 'Outstanding Items' on the Intraday Unit Commitment Process that should be considered?**

    Direct Energy does not have additional comments at this time.

13. **Are there appropriate alternatives to the intraday commitment process to address the reliability needs that may emerge between day-ahead and real-time market clearing?**

    Direct Energy notes that as the AESO stated, this process was not explicitly addressed during the design sprints and believes this is an area requiring further consultation.

14. **Do you have any input to provide on the outstanding items listed?**

    The governance process regarding the established thresholds needs further consultation.

15. **Other comments**

    Intraday unit commitments along with the AESO's existing reliability tools can be used to ensure system reliability when required and could be an alternative to the DAC market that results in costs to load in every hour of the year.

Real-Time Market – Section 9

16. **Is there anything not captured under 'Outstanding Items' for the Real-Time Market that should be considered?**

    The AESO states on page 24 that it "has yet to determine the applicable number of bid and offer blocks." This does not appear in the outstanding items and is not an item that has been thoroughly consulted on.

Direct Energy believes further consultation and process development is needed regarding load participation in the real-time energy market and the clearing of load offers. Amendments to ISO Rule 202.3 Issuing Dispatches for Equal Prices may be required for more enhanced load participation. Certain load offers into the energy market may be available for dispatch but want to ensure they are the last selected offer rather than receiving a pro-rata dispatch. For example, a retailer may have a demand response program for its customers, but to minimize disruption, may want to price its offer at $800 /MWh and ensure that it is only cleared once all available generation offers, or load offers seeking the per MW payment, have cleared.

17. **Do you have any input to provide on the outstanding items listed?**

Direct Energy is concerned with the potential exercise of market power if the offer lockdown period were to shorten. While generation could be incented to lower its offers to get in merit (or load to get paid to reduce consumption), the opposite is just as likely to be true with generators increasingly confident they could raise prices by adjusting their offers. The T-2 lockdown period should be maintained as this can also provide a form of market power mitigation.

18. **Other comments**

Direct Energy is concerned that the additional AS products, including the ramp products, introduce additional costs to load, with limited ability to manage these costs. The AESO's push to 5-minute settlement intervals introduces a price signal to incent higher ramp capability and capable units will be able to better match price signals. Additional payment for ramp may not be required given this incentive. This becomes increasingly likely as the market matures and older, more inflexible generation leaves the market and is replaced by more responsive generation.

Congestion Management – Section 10

19. **Is there anything not captured under 'Outstanding Items' around Congestion Management that should be considered?**

Direct Energy notes that congestion management has not been adequately discussed and requires significant attention during future sprint sessions. Details surrounding incumbency and any retroactive measures must be carefully consulted upon as the PPAs that loads have entered with generation, notably renewables, are impacted.

20. **Is CAM the appropriate market-based congestion management mechanism to manage congestion? If not, why not?**

Direct Energy notes that CAM was the only solution presented during the sprint sessions and believes this proposal, and other proposals that may be presented in this feedback, will require further consultation.

21. **If not, can the CAM be modified in such a way to become an appropriate to manage congestion? If yes, how?**

Direct Energy does not have a view at this time but looks forward to reviewing and consulting on any alternatives presented.

22. **What additional [other] market-based congestion management mechanisms should be considered? And how do they meet the recent policy directions?**

    Direct Energy does not have a view at this time but looks forward to reviewing and consulting on any alternatives presented.

23. **Do you have any input to provide on the outstanding items listed?**

    Direct Energy believes that if CAM, or another market-based system is implemented, it should be done so in the real-time market only.

24. **Other comments**

    Regardless of the system put in place, the government direction letter states that "any revenue generated from this mechanism will be applied towards the cost of transmission projects prioritizing congested areas of the province." The AESO must consider how congestion revenue will be tracked, managed, and allocated. Questions such as "Must congestion revenue be allocated to the area it was collected from?" or "Can congestion revenue be directed to projects solving the highest priority congestion?" need to be addressed. The magnitude of congestion payments allocated to projects should be managed by the AUC to ensure that rate base is reduced by these payments. This is likely a process that is best jointly developed by the AESO and the AUC.

Market Power Mitigation – Section 11

25. **Is there anything not captured under 'Outstanding Items' on Market Power Mitigation that should be considered?**

    The price of the secondary offer cap is not presented. The REM High-Level Design presented a cap of $400 which represents a significant increase from the $250 cap presented during the REM sprint sessions. For this reason, the AESO should consider the determination of the secondary offer cap an outstanding item that requires further consultation.

26. **Do you have any input to provide on the outstanding items listed?**

    Direct Energy believes the 12-month evaluation period should begin in April. Beginning in April will help limit the exercise of market power during the winter months when power demand peaks and when generation from solar is at its lowest.

    The five-year review cycle on market power mitigation parameters may be too long for both generation and load concerns regarding the impact of market power mitigation. The AESO, or potentially the MSA, should prepare annual reports on the impact of market power mitigation. One method may be to establish mandatory review of the parameters every five years, with the MSA able to trigger an earlier review based on its annual assessment, if appropriate.

27. **Other comments**

    Direct Energy has concerns with the $400 secondary offer cap and its impact on affordability. This had not been presented as an option in previous consultations and is a deviation from the proposed $250 secondary offer cap from the sprints. With $4/GJ gas (which is higher than the current four-year outlook), the $400 secondary offer cap represents a significant spark spread of $372.84 (using the reference unit heat rate), not including operation and maintenance costs. Even a less efficient unit with a heat rate of 10 would see a $360 spark spread. A secondary offer cap of $250 still provides significant revenue potential ($222.84 spark spread for the reference unit, $210 for the less efficient unit) for mitigated generation and only binds if and when generators have achieved significant revenues through the previous months. If the energy market was achieving competitive outcomes, then there should be little concern of the secondary offer cap binding. Direct Energy does not view a 60% increase in the secondary offer cap as consistent with the five-percentage point increase in average realized revenue as a percentage of CONE, presented in the AESO's footnote.[10] This proposal raises affordability concerns, as the increased cost significantly exceeds the increase in revenue potential.

The AESO's analysis in Sprint 6 presented the following average realized revenues as a percentage of CONE between 2013 and 2023:

- 145% unmitigated
- 129% with a secondary offer cap of $125 /MWh
- 134% at $250 /MWh
- 142% at $500 /MWh[11]

The REM High-Level Design document provides minimal explanation of why a secondary offer cap of $400 /MWh resulting in 139% revenue as a percentage of CONE is a better result for the overall market compared to $250 /MWh and 134%, as affordability concerns must be balanced against investability on the supply side. Direct Energy believes further consultation and analysis must be conducted on this topic.

Scarcity Pricing Curve – Section 12

28. Is there anything not captured under 'Outstanding Items' on the Scarcity Pricing Curve that should be considered?

Direct Energy notes that the REM High-Level Design is unclear if the scarcity pricing curves will be using a smooth or a stepped methodology. A footnote appears to indicate smooth,[12] but Direct Energy requests that the AESO clarify this detail.

29. Do you have any input to provide on those outstanding items?

Several parties have raised concern regarding the changing inputs in calculating the scarcity pricing curve and related governance. The AESO has stated that quarterly updates would be required to net-load forecast errors. Direct Energy has concerns with this frequency of change and attempting to forecast and mitigate hours where prices settle at an administrative level. With the potential to change multiple times a year, this can make forecasting difficult for multi-year mass-market products. Direct Energy recognizes that the changing inputs may have the effect of reducing the frequency and scale of administrative pricing, but any changing values should be easy to understand, formulaic, and simple to

[10] See footnote 53 on page 36 of the AESO's REM High-Level Design.
[11] REM Sprint 6, slide 25.
[12] See footnote 62 on page 40 of the AESO's REM High-Level Design.

derive for market participants (such as adding newly commissioned generation or subtracting retired generation from the calculation).

30. Other comments

If DAC is to be a market component, Direct Energy maintains its concern of including scarcity pricing within the DAC market. Given a tight DAC market likely insinuates higher commodity prices, assets should be able to recover sufficient start up and cycling costs through their energy revenues. As such, scarcity pricing in the DAC market is not required. Direct Energy is concerned about considerable cost impact to consumers if scarcity pricing were to bind both in the DAC capacity market and the day-ahead and/or real-time energy market. If the AESO is concerned that certain units will require additional DAC payments in other hours (such as long lead time assets), then this may be a situation where out-of-market payments are more prudent to the AESO's stated affordability goal than subjecting load to all DAC being paid an administrative price in certain hours. In Direct Energy's view, this would be done by paying an asset its DAC bid over its entire minimum run time rather than implementing scarcity pricing to any unit or the market as a whole. Under the AESO's posted scarcity curve data,[13] there is the potential for prices to bind above the DAC price cap at an uncertainty volume of 1,300 MW at the long-term renewable level, which raises concerns with how often scarcity pricing could bind.

Market Settlement – Section 13

31. Is there anything not captured under 'Outstanding Items' on Market Settlement that should be considered?

Direct Energy has provided its overall feedback in response 33.

32. Do you have any input to provide on the outstanding items listed?

Direct Energy has provided its overall feedback in response 33.

33. Other comments

Direct Energy maintains its concern regarding 5-minute settlement at the distribution-connected level. Within the sprint sessions and breakouts, feedback had generally been that 5-minute settlement was not required for distribution-connected assets. Direct Energy had also heard from large generators and loads that 15-minute settlement intervals provided the price fidelity they need. While Direct Energy recognizes that there has now been a policy direction to move to 5-minute settlement, we maintain this direction is counter to affordability and leads to unnecessary costs for consumers.

Stakeholders had routinely outlined that existing meter infrastructure is not capable of measuring at a 5-minute settlement and would require meter replacements, or at the very least, costly reconfiguration and resealing of existing meters. In addition, systems related to meter data management, data storage, and settlement systems will all require costly updates.

[13] Found on https://www.aesoengage.aeso.ca/rem-technical-design, in the "data" folder, "Smooth Scarcity Pricing Curve" posted November 14, 2024.

This change is being pushed onto mass-market loads prior to existing AMI being properly utilized. Without a central data hub, similar to SmartMeter Texas[14] or the Smart Meter Entity in Ontario,[15] retailers are unable to develop innovative products for mass-market customers which take advantage of load-shifting opportunities. Direct Energy notes that this must be done at the distribution level and is outside the jurisdiction of the AESO. Retail load participation in the energy market becomes possible once existing AMI technology is properly utilized. This must be implemented prior to any discussion of distribution-connected sub-hourly settlement.

Direct Energy notes that while it looks forward to developing improved retail offerings, load shifting and virtual power plant opportunities in Alberta may be initially limited in comparison to jurisdictions with significant air conditioner load. However, this potential will increase over time with the advancement of electrification, automated smart-home systems, and as consumers increasingly install microgeneration and become more active prosumers.

Further, without the proper utilization of existing and soon to be installed AMI, retail customers will not be able to manage or mitigate their DAC costs if DAC remains part of the market design. If DAC is allocated through the transmission charge, then settlement must be done at the meter level to ensure the DAC charge to a customer's corresponding usage can be applied. This means retailers may be able to develop products and processes to alert customers to higher priced hours (after the DAC market clears) to encourage a demand response and ensure customers who do shift their consumption are not charged disproportionate DAC costs.

[14] Smart Meter Texas is a collaborative effort from Texas distribution providers and is a data hub that stores energy data recorded by smart meters across the state. Retailers can use this hub to develop new products and offerings, while enabling customers to view and manage their consumption habits. More details can be found at https://www.smartmetertexas.com/aboutus.

[15] The Smart Metering Entity, operated in Ontario by the IESO, operates the province's meter data management repository, which serves as a central database for hourly electricity consumption and supports the billing processes of the provincial billing agents. More information can be found at https://www.ieso.ca/Sector-Participants/Smart-Metering-Entity.