Local Market Power Mitigation Enhancements 2018
Draft Final Proposal

Comments by Department of Market Monitoring
February 11, 2019

I. Overview

DMM appreciates the opportunity to comment on the ISO's *Local Market Power Mitigation Enhancements Draft Final Proposal.*[1] DMM supports the general framework and most aspects of the ISO's proposal, which is designed to reduce unnecessary bid mitigation in the Western Energy Imbalance Market (EIM) and ISO real-time energy markets. As discussed in these comments, however, DMM believes several provisions in the proposal involve potential trade-offs between the benefits of market power mitigation versus the potential for increased participation in the EIM. DMM believes these potential tradeoffs merit further review and discussion by stakeholders and policymakers.

When balancing authority areas (BAAs) join the EIM and make additional transmission and energy available for transfers between BAAs, this can increase the competitiveness of the market, reduce prices, and increase the overall benefits of all other entities in EIM. However, several entities have indicated that the market power mitigation procedures applied in the EIM may significantly influence their decisions on the extent to which they participate in EIM.[2] In addition to considering potential mitigation when deciding to join EIM, entities joining may also limit the amount of transmission and energy they make available in the EIM in order to limit the impact of mitigation on their resources.

Several aspects of the *Draft Final Proposal* are designed to encourage Northwest BAAs with substantial hydropower to join EIM and to make their transmission and energy available in

[1] *Local Market Power Mitigation Enhancements Draft Final Proposal*, California ISO, January 31, 2019: http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements-UpdatedJan31_2019.pdf

[2] *Addressing LMPM/DEB Challenges for Energy-Limited EIM Participating Resources*, Powerex, Presentation at CAISO EIM Offer Rules Workshop, April 30, 2018, p. 4: http://www.caiso.com/Documents/PowerexDefaultEnergyBidPresentation-EnergyImbalanceMarketofferRulesTechnicalWorkshop.pdf

Comments on EIM Offer Rules Workshop, Bonneville Power Administration, May 14, 2018, p. 2: http://www.caiso.com/Documents/BPAComments-EnergyImbalanceMarketOfferRulesTechnicalWorkshop-Apr30_2018.pdf

Comments on LMPM Enhancements Issue Paper/Straw Proposal, Chelan County Public Utility District, October 3, 2018, p. 1: http://www.caiso.com/Documents/ChelanComments-LocalMarketPowerMitigationEnhancements-IssuePaper-StrawProposal.pdf

EIM.[3] The potential to encourage EIM participation is particularly critical for assessing the following two elements of the ISO's proposal:

- **Limiting exports when mitigation is triggered within an EIM BAA**. This provision is designed to ensure that energy is not transferred from one EIM area to another area due to market power mitigation lowering the market bids submitted by EIM participants. To the extent market bids accurately reflect resources' marginal or opportunity costs, this provision would increase market efficiency and participation. However, to the extent market bids exceed actual marginal or opportunity costs, this provision would reduce market efficiency and reduce how transfers from one EIM area may help mitigate market power in another EIM area.
- **Default energy bid (DEB) for hydro resources**. This new DEB option is designed to ensure that when mitigation is triggered, bids are not below the opportunity costs of hydro resources. However, several provisions of the new DEB may result in DEBs that appear to exceed the actual marginal or opportunity costs of these resources. These include the provisions allowing opportunity costs used in setting DEBs for Northwest hydro resources to be based on prices in the Southwest (Palo Verde) and on futures prices 12 months in the future – which often extends beyond the current hydro cycle and into the summer of the next year hydro year.

The provisions involving limitation of exports and hydro DEBs discussed in these comments both involve a potential trade-off between the benefits of market power mitigation versus the potential for increased participation in the EIM. Both of these provisions increase the potential for physical and economic withholding in the EIM, but, given the voluntary nature of EIM, they both may also increase the amount of transmission and energy made available to EIM. Analysis in Section III of these comments suggests that if the DEBs for northwest hydro resources include all the provisions proposed by the ISO, the resulting DEBs should be sufficiently high so that it would be unnecessary to also have the provisions limiting exports from an EIM BAA when mitigation is triggered in that BAA.

The potential for market power may not raise a concern for EIM entities whose balancing areas do not include other entities that rely on the EIM area for transmission and imbalance services (such as Powerex and many public power entities in California and other Western states).

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[3] "Economic displacement has the potential to reduce transfer capability within the EIM as BAAs may limit the amount they make available to limit economic displacement. It could potential (sic) also discourage additional EIM participation. The CAISO proposes a market rule that would prevent economic displacement by not allowing transfers between two EIM BAAs to increase beyond a specified amount," *Draft Final Propos*al, p. 26.

"In response to stakeholders advocating for an alternate default energy bid for hydroelectric resources with limited generation capability, the CAISO proposes an additional default energy bid option…If a default energy bid is lower than opportunity costs, it … could result in reducing energy available to markets, or worse not offering any energy into the market and reducing overall market capability and efficiency." *Draft Final Proposal*, pp. 32-33.

However, EIM areas that are operated by investor owned utilities remain subject to FERC jurisdiction and market power mitigation provisions designed to ensure just and reasonable rates for transmission customers within each EIM BAA.

Inclusion of these provisions should encourage Northwest BAAs with substantial hydropower to join EIM and to make their transmission and energy available in EIM. However, the ISO should regularly reassess the extent to which each of the provisions above contribute to increased participation in EIM. If other changes to market design or market conditions could encourage EIM participation, EIM efficiency could be improved by not automating reductions in transfer capacity and by not offering a hydro default energy bid that is not based on each resource's actual marginal or opportunity costs.

DMM supports the other elements of the ISO's proposal. The provision to not carry over a resource's mitigated bids from one interval into subsequent intervals will reduce the impacts of bid mitigation and clearly make market power mitigation provisions more accurate. Updating the reference levels used in the ISO's real-time markets based on conditions observed in same-day gas markets will also reduce the impacts of bid mitigation while also making market power mitigation provisions more accurate.

II. Changes to automated mitigation

Eliminating carry over of mitigated bids to subsequent intervals

The ISO proposes to eliminate the extension (or "carry over") of mitigation from one 15-minute or 5-minute interval to subsequent intervals in that hour or 15-minute period. This carry over of mitigation originally stemmed from a combination of software issues and concerns about accuracy of earlier mitigation designs. Since then the accuracy of mitigation has been dramatically improved by several changes.[4] Given the current levels of mitigation accuracy, DMM supports the provision to not carry over a resource's mitigated bids from one interval into subsequent intervals. This provision will reduce the impacts of bid mitigation and further improve market power mitigation accuracy.

Limiting exports when mitigation is triggered within an EIM BAA

The ISO proposes to give each EIM entity the option of limiting the net exports out of its BAA when resources in the BAA are subject to bid mitigation. This provision is designed to ensure

[4] Local market power mitigation has been significantly redesigned through three previous stakeholder initiatives. These initiatives were the local market power mitigation enhancements initiative in 2011, the dynamic competitive path assessment initiative in 2011, and the local market power mitigation enhancements 2015 initiative. The final proposals are available at:
http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements.pdf
http://www.caiso.com/Documents/RevisedDraftFinalProposal-DynamicCompetitivePathAssessment.pdf
http://www.caiso.com/Documents/DraftFinalProposal_LocalMarketPowerMitigationEnhancements2015.pdf

that energy is not transferred from one EIM area to another area due to market power mitigation lowering the market bids submitted by EIM participants.

To the extent market bids accurately reflect resources' marginal or opportunity costs and default energy bids are below actual marginal costs, this provision would increase market efficiency and participation. For example, consider a case of suppliers in EIM BAA 1 submitting energy bids equal to the resources' actual marginal costs of $50, but having default energy bids set at $40. Assume suppliers in a neighboring EIM BAA 2 submit energy bids of $46 based on their resources' actual marginal costs and that their resources' default energy bids equal this $46 bid price. Also assume that cheaper energy available for import into the two EIM areas from the rest of the EIM causes these two areas to be import constrained and subject to bid mitigation. In the absence of the ISO's proposal to automatically limit net exports, bid mitigation would cause $46 power produced in BAA 2 to be displaced by $50 power produced in BAA 1.

However, to the extent market bids exceed actual marginal or opportunity costs and default energy bids are greater than or equal to actual marginal costs, this provision would reduce market efficiency and reduce how transfers from one EIM area may help mitigate market power in another EIM area. Consider the same scenario described above, but that the suppliers in BAA 1 have actual marginal costs equal to their resources' default energy bids of $40, but bid at $50, significantly above their actual marginal costs. Assuming that BAA 1 would choose to make its transmission and power available to EIM in the absence of the ISO's proposal, the ISO's proposal would increase the overall costs of delivered power by preventing $40 power in BAA 1 from displacing $46 power in BAA 2.

Since the ISO has designed EIM to be a voluntary market, areas can choose whether or not to make their transmission or power available to EIM. If the ISO's proposal to automatically limit net exports would have a significant impact on the quantity of transmission and power that areas choose to make available to EIM, then the ISO's proposal is likely to increase the overall competitiveness and efficiency of EIM. Several EIM entities and entities considering joining EIM have indicated that the market power mitigation procedures applied in the EIM may significantly influence their decisions on the extent to which they participate in EIM.[5]

However, it is not clear that this provision is required to incentivize participation in EIM. Other changes to the design of EIM or changes to market conditions could incent maximum EIM participation in the absence of this provision. For example, as explained more in the section below on the ISO's proposed hydro default energy bid, the hydro DEB will likely be higher than prices so often that the provision to limit net exports may not have a significant marginal impact on EIM participation. Therefore, if the hydro DEB is approved and implemented as proposed by the ISO, DMM recommends that the ISO regularly reassess the extent to which this

[5] See footnotes 2 and 3 in the Overview section, above.

provision contributes to increasing participation in EIM and that the ISO be prepared to terminate or limit this provision.

Allocating congestion rents from the net export constraints on EIM BAAs

When the proposed net export constraint triggered by mitigation is enforced and binding, the ISO proposes to allocate 100% of the constraint's congestion rents to that BAA. The ISO's rationale for this provision is that this will allocate the congestion rents on this net export constraint in the same way that the ISO allocates congestion rents for net export constraints triggered by an EIM BAA's failure of a flexible ramping sufficiency test.

It was only through the current stakeholder initiative that DMM became aware that the ISO is allocating 100% of congestion rents from the sufficiency test net export constraints to the BAA failing the test. Therefore, DMM has sought to assess the current policy of allocating 100% of congestion rents to either type of net export constraint.

The ISO's proposal raises some concern because otherwise the ISO evenly splits the congestion rents from any transfer constraint between two BAAs. The proposal to allocate 100% of congestion rents from a net export constraint to one BAA could create incentives for BAAs to not bid resources at marginal cost. BAAs may do this in order to try to increase the odds that they trigger their net export constraint and increase their share of congestion rents between themselves and neighboring EIM BAAs from 50% to 100%.

However, alternatives that DMM has considered for allocating net export constraint congestion rents can create outcomes that are potentially even more problematic. Therefore, DMM does not currently have a proposal for an alternative allocation scheme. The ISO should be aware that its policies to enforce net export constraints for both sufficiency test failures and mitigation can create incentives for inefficient bidding behavior. This undesirable consequence of net export constraints needs to be weighed against the benefits the constraints provide in encouraging EIM participation.

II. Changes to default energy bids

Updating reference levels using same-day gas prices

As noted in DMM's prior comments, DMM supports this aspect of the ISO's proposal. In response to DMM's prior comments noting that many EIM areas have less liquid trading hubs and published prices may not reflect their actual trading conditions, the ISO has revised its proposal to explicitly account for these exceptions.

Hydro resource default energy bid

As noted in DMM's prior comments, the general approach that the ISO has proposed for its new hydro resource default energy bid option is very similar to the approaches that have been available to EIM hydro resources through the negotiated DEB option. DMM is therefore supportive of the overall approach. However, DMM continues to question the validity of the ISO's proposal for using trading hubs that are significantly different (geographically and pricewise) from the geographically closest hub in the formulation of opportunity costs. DMM also has some concerns about the provision that would allow DEBs to be based on up to 12 months of futures prices.

Use of higher priced hubs

DMM's comments on the revised straw proposal expressed DMM's view that the proposed approach for basing opportunity costs on bilateral prices on distant trading hubs inappropriately assigns the value of *transmission* between two regions to the value of *energy i*n the lower priced region. [6] The value of the transmission should be equal to the difference in prices between the source and delivery point of the transmission. Adding the value of this transmission as the value of energy at the lower priced point does not appear appropriate.

In response to these prior comments by DMM, the *Draft Final Proposal* states that:

> The CAISO maintains that hydro resources with the ability to deliver energy to a specific hub, using firm transmission rights, also have the ability to earn revenues on that energy equal to those hub prices. This includes energy sold at futures prices as well as near-term agreements. Energy produced and delivered from hydro facilities may not be equivalent to other energy produced by different fuel types that a resource owner may purchase locally and deliver to a different energy hub. In practice, hydro power with its zero greenhouse gas emissions is not fungible with generic power purchased at hubs. Thus, the power is associated with the output of a specific generator.[7]

This rationale provided in the *Draft Final Proposal* does not appear to address DMM's comments about the value of *transmission* vs *energy.* Instead, the *Draft Final Proposal* introduces the new argument that energy from hydro resources should be valued at a premium since it has zero greenhouse gas emissions. Based on this new argument, however, the ISO

[6] *DMM Comments on Revised Straw Proposal*, pp.4-5. http://www.caiso.com/Documents/DMMComments-LocalMarketPowerMitigationEnhancements-RevisedStrawProposal.pdf

[7] *Draft Final Proposal,* pp.11-12.

should instead consider whether the DEB for hydro resources should include some premium for being GHG free (or *green* resources). [8] Any premium for green energy would be applicable to sales of all hydro energy, and should not depend on whether a supplier has transmission to sell the energy at more distant hubs. However, it remains inappropriate to add the value of this transmission to the value of green energy at the lower priced point.

Use of up to 12 months of future prices

DMM also has some concerns about the provision that would allow DEBs to be based on up to 12 months of futures prices. The effect of this provision is to allow the opportunity costs in the fall of each year to be set based on futures prices for August of the following year. In this case, the 12-month period extends beyond the normal hydro cycle of most hydro resources.

In practice, it seems virtually all hydro resources will have the opportunity to recharge over the winter/spring hydro season and may need to utilize substantial amounts of hydro energy prior to the late summer months of the following year due to storage limitations. Unless the methodology accounts for the various hydro conditions and constraints, such as anticipated reservoir inflows, it seems that the approach proposed in the *Draft Final Proposal* will often systematically overstate actual opportunity costs during the fall months.

III. Analysis of hydro resource default energy bid

This section provides an analysis of the hydro resource default energy bid methodology described in the *Draft Final Proposal*.[9] This analysis compares the default energy bid that would have resulted from this methodology for a typical hydro unit in the Northwest to 15-minute energy imbalance market prices in the 2018 calendar year.

The analysis includes several different scenarios to highlight the impact of the two aspects of the ISO's proposal which DMM finds problematic in terms of reflecting the opportunity costs of a hydro resource in the Northwest: (1) the use of higher priced hubs in the Southwest (Palo Verde) for hydro units in the Northwest; and (2) the use of 12 months of futures prices which extend beyond the current seasonal hydro cycle.

Use of Palo Verde price for Northwest Hydro

Figures 1 and 2 compare the DEBs that would result under the proposed approach for a typical hydro unit in the Northwest (PacifiCorp West) to 15-minute locational market prices (LMPs) for a resource in that area in the 2018 calendar year. One of the DEBs includes the Palo Verde trading hub and 12 months of futures data in the *Geo Floor*. The second DEB also includes 12 months of futures data in the *Geo Floor,* but only includes the Mid-C trading hub.[10]

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[8] For instance, if it is determined that hydro resources do in fact receive a premium in the bilateral markets for being GHG free, any such premium might reflect the cost of GHG emission credits for gas resources and/or the value of renewable energy credits (RECS)..

[9] *Draft Final Proposal,* p. 8.

[10] This analysis uses the gas price index from the CAISO fuel region FRPACW to calculate the gas floor, as would be appropriate for hydro resources located in the PacifiCorp West area. This gas price index reflects the minimum of the Sumas and Kingsgate gas hub prices on a given day.

Figure 1. Hydro DEBs based on prices at Palo Verde vs. Mid-C (Jan-June 2018)

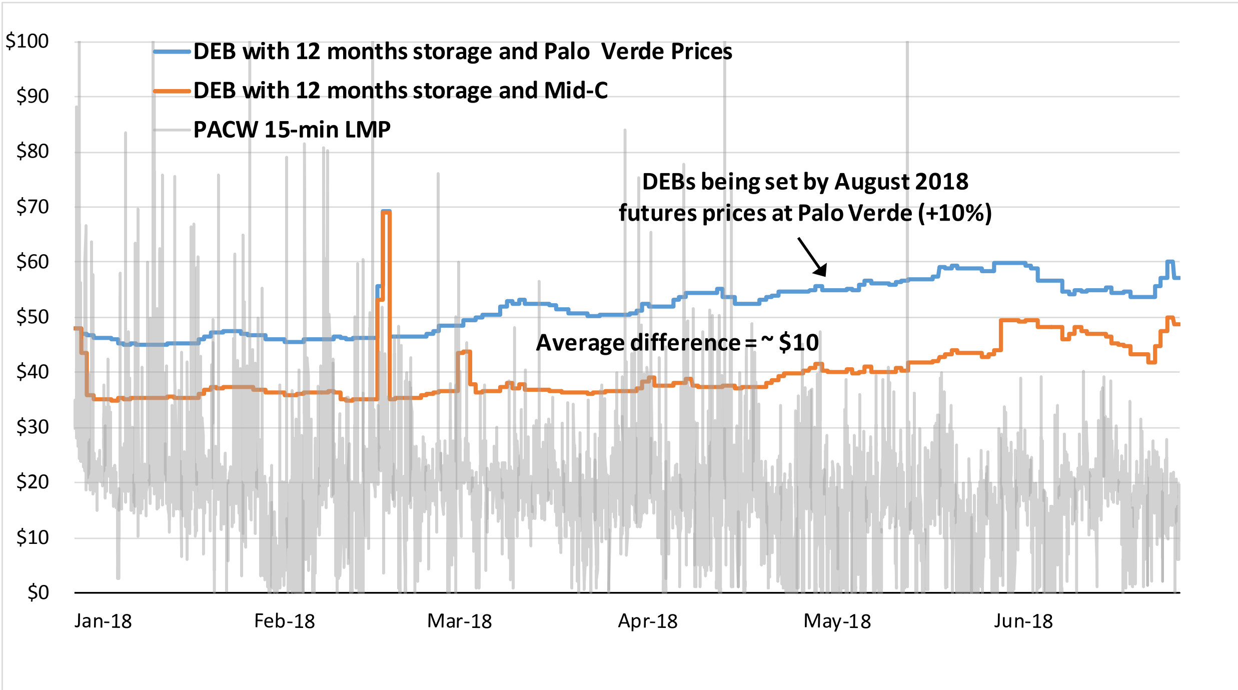
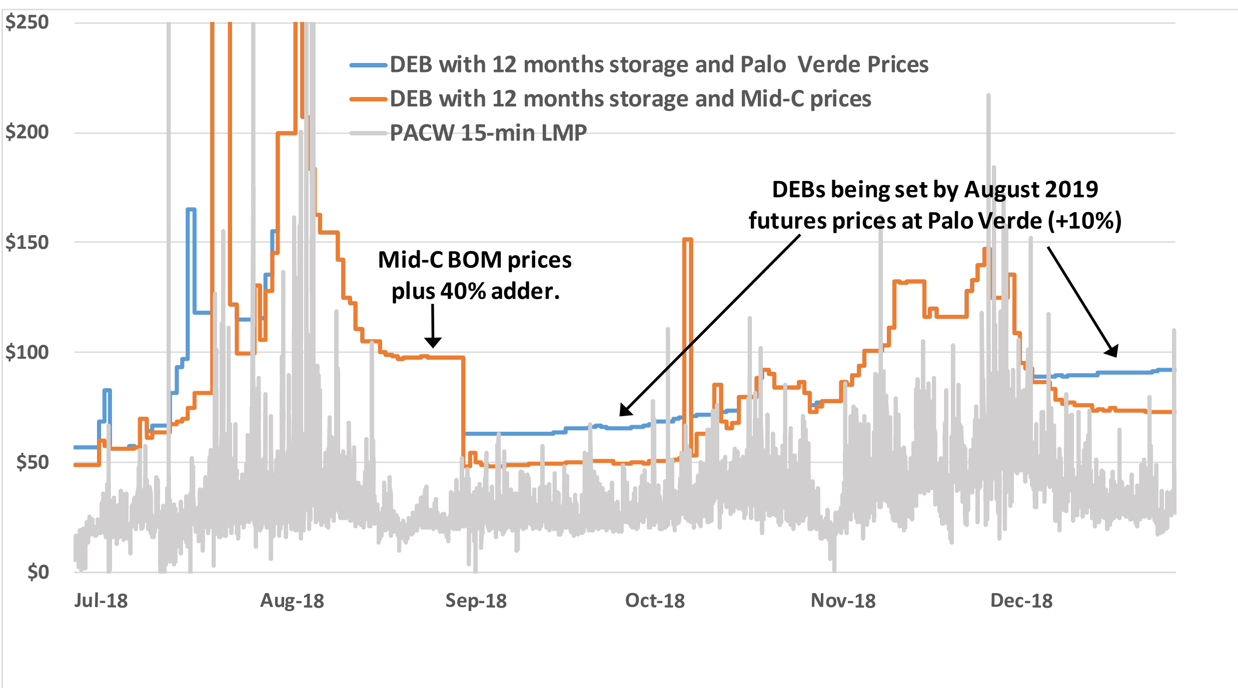


Figure 2. Hydro DEBs based on prices at Palo Verde vs. Mid-C (July-Dec 2018)



As shown by this analysis:

- Both hydro DEBs are almost always greater than the resources LMP. Without inclusion of the Palo Verde prices in the *Geo Floor*, LMPs exceed the DEB only 1 percent of intervals. With Palo Verde prices included in the calculation, the LMPs exceed the DEB only 0.4 percent of intervals.
- As highlighted in Figure 1, if Palo Verde prices are used, then DEBS are set by the August 2018 futures prices (plus the 10 percent adder included in the *Geo Floor*) on most days from January through late June 2018. If Palo Verde prices were not used, then DEBs for most of the first seven months of 2018 would instead be set by Mid-C prices for the day ahead, prompt month, or remaining summer months in 2018.[11] Using Palo Verde prices increases the DEB by about $12.65/MW in this period, and by about $10/MWh over the calendar year 2018.
- Figure 2 compares DEBs based on Mid-C and Palo Verde prices in the second half of 2018. As noted in Figure 2, hydro DEBs during August 2018 would have been set by the Balance-of-Month (BOM) price for Mid-C that is used in calculating the *Local Floor*, which includes a 40 percent adder.
- As shown in Figure 2, the main impact of using the Palo Verde price in 2018 would have occurred from September to mid-October and most of December. During these periods, the hydro DEB would be set by the August 2019 futures price at Palo Verde (plus the 10 percent adder included in the *Geo Floor*).

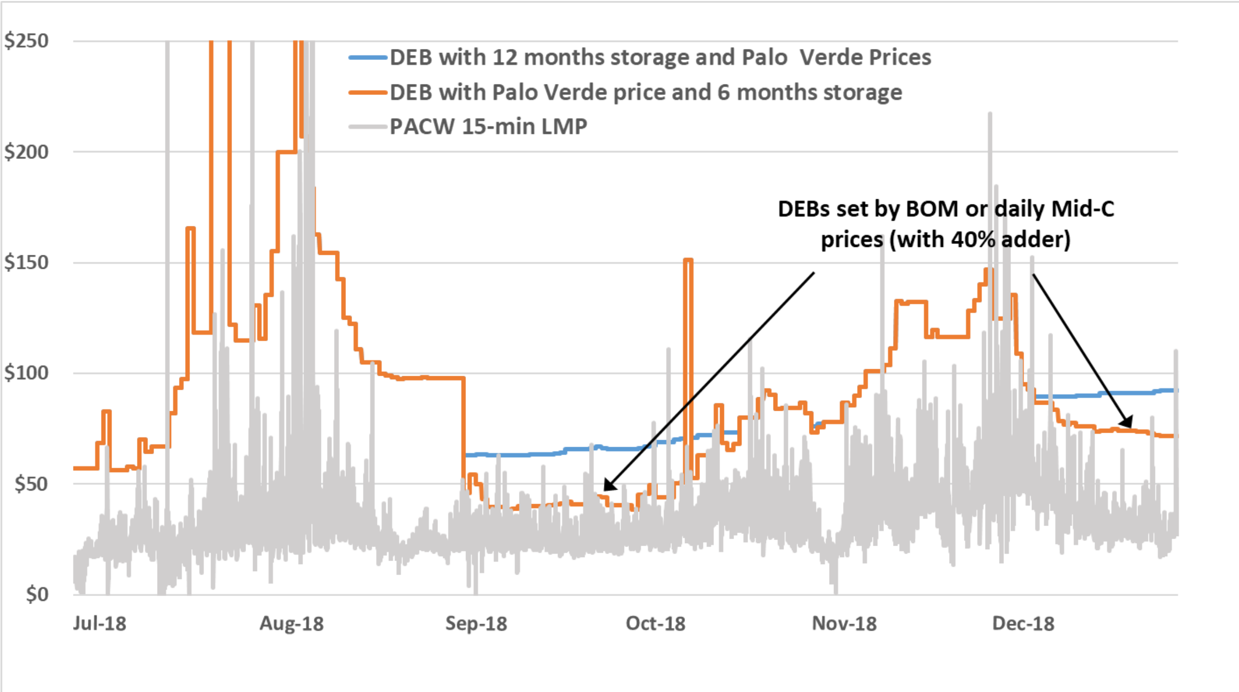
Use of 12 months futures prices extending in next hydro year

Figure 3 highlights the impact of using futures prices in the *Geo Floor* that extend 12 months (or into the summer of the following calendar year). Both DEBs in this figure area include Palo Verde prices, but compare the impact of using 6 months of futures data versus 12 months.

- If only 6 months of futures prices are used, DEBs from September to mid-October and most of December would be set by the Balance-of-Month (BOM) or day-ahead peak prices at Mid-C through the *Local Floor* component.
- Limiting the futures to 6 months results in a DEB that is almost $20/MWh lower than the DEB based on 12 months in the period from September to December (which is usually set by Palo Verde futures prices for summer of the next calendar year). Thus, during these periods, DEBs are set by the *combination* of using Palo Verde prices in conjunction with futures prices from the summer of the following year in the *Geo Floor.*

[11] The Geo Floor component still frequently sets the DEB, however, this component now only includes Mid-C futures prices. For the first seven months of the year, the highest value futures prices will be the upcoming summer prices in the same calendar year.

Figure 3. Hydro DEBs based on 6 vs 12 months storage and Palo Verde prices



Analysis of DEBs and prices

Table 1 provides summary statistics for the two DEBs shown in Figures 1 and 2 by month, including the average LMPs and average DEBs for the 4 hours with highest LMPs each day (i.e. the highest 16 prices for 15-mintue intervals). This represents the percentage of intervals the resource could be dispatched if it was mitigated to its DEB all intervals in which the LMP was greater than the DEB during the highest priced 4 hours of each day.

Figure 4 shows the total number of hours per day that the LMP in the PacifiCorp area would be higher than the DEB for a hydro unit in this area under four different scenarios based on 2018 data. Table 2 shows the total number of hours per day that the LMP in the PacifiCorp area would be higher than the DEB based on Mid-C prices and 6 months storage. As shown by this analysis:

- As illustrated in Figure 4, With a DEB calculated with Palo Verde prices and 12 months of storage, LMPs would exceed the DEB 1 hour or less 98 percent of days and would exceed the DEB for more than 3 hours only 1 day of the year in 2018.
- As shown in Table 2, with a DEB based on Mid-C prices for 2018 and 6 months storage, LMPs would exceed the DEB 1 hour or less about 91 percent of days and would exceed the DEB by 1 to 2 hours about 7 percent of days. LMPs would exceed the DEB more than 3-5 hours less than 1 percent of days. LMPs would never exceed the DEB more than 5 hours on any day.

Table 1. Summary Statistics of DEB and LMPs by Month

	12 month storage and Palo Verde prices					12 month storage and Mid-C prices				
Month	Average of highest priced 4 hours/day	Average DEB	Avg Differce (DEB - LMP)		Average Implied Heat Rate of DEB (mmBtu/MWh)	Average of highest priced 4 hours/day	Average DEB	Avg Differce (DEB - LMP)		Average Implied Heat Rate of DEB (mmBtu/MWh)
Jan	$34	$46	$12	+36%	19	$34	$37	$3	+8%	15
Feb	$28	$47	$20	+71%	23	$28	$38	$10	+36%	18
Mar	$26	$51	$25	+98%	26	$26	$37	$12	+45%	19
Apr	$29	$53	$24	+83%	28	$29	$38	$9	+30%	20
May	$26	$57	$31	+121%	41	$26	$41	$16	+61%	30
June	$23	$56	$33	+141%	41	$23	$47	$24	+101%	34
July	$42	$108	$66	+154%	62	$42	$93	$50	+118%	51
Aug	$68	$140	$71	+104%	62	$68	$139	$71	+103%	62
Sept	$35	$68	$33	+93%	45	$35	$55	$20	+56%	36
Oct	$48	$79	$30	+63%	27	$48	$71	$23	+47%	24
Nov	$55	$110	$54	+99%	26	$55	$109	$54	+98%	26
Dec	$54	$96	$42	+77%	21	$54	$85	$31	+57%	18

Figure 4. Total Hours per day with LMP greater than DEB (2018 data for PacifiCorp West)

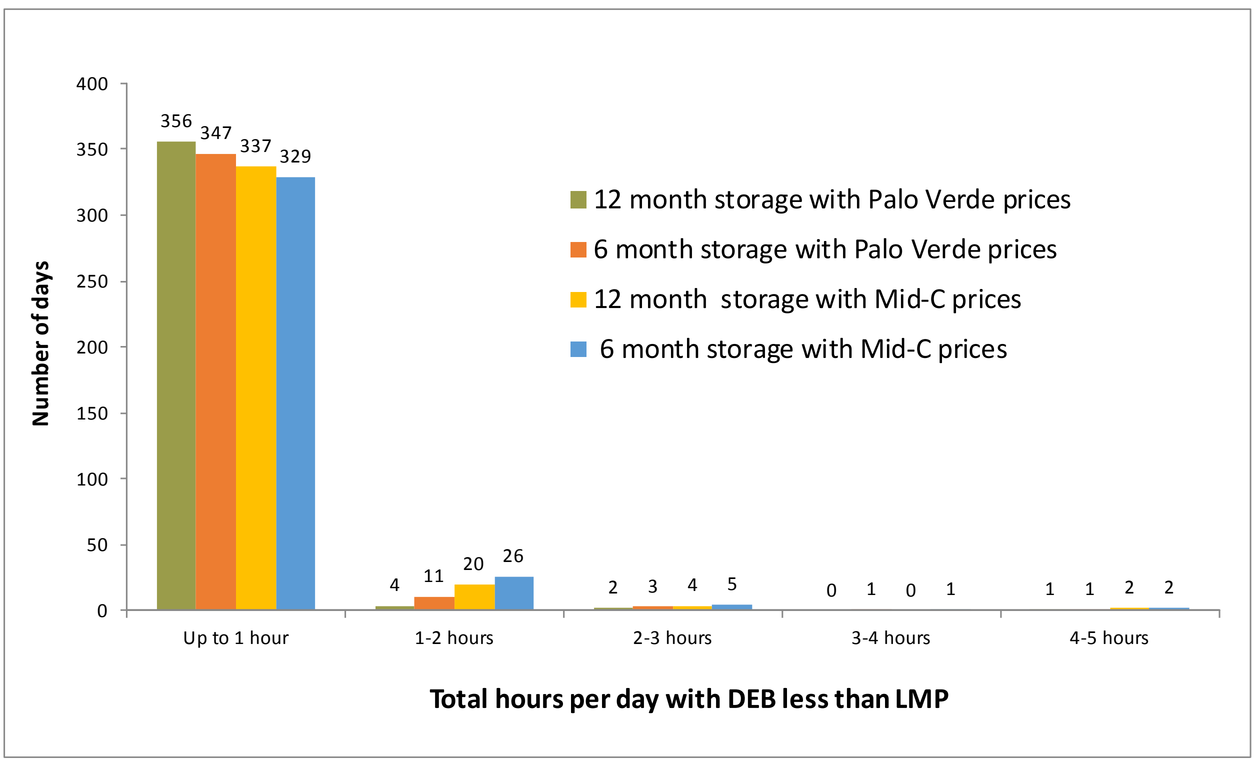


Table 2. Hours per day LMP > DEB (with 6 month storage and Mid-C prices)

Intervals LMP > DEB	Days	Percent
Up to 1 hour	329	90.6%
1-2 hours	26	7.2%
2-3 hours	5	1.4%
3-4 hours	1	0.3%
4-5 hours	2	0.6%
More than 5 hours	0	0.0%

Analysis of implied heat rates

Figures 5 and 6 show the implied heat rate of the prices and DEBs in Figures 1 and 2. For this analysis, prices and DEBs in Figures 5 and 6 were divided by the gas price index used to calculate the gas floor for each area. As shown in Figures 5 and 6, both these DEBs reflect implied heat rates that should exceed the marginal operating costs of most gas-fired capacity.

DMM believes this analysis indicates the use of Palo Verde prices and futures prices for the summer of the following year is not needed to ensure that hydro resources are not dispatched excessively due to mitigation using DEBs. These components of the proposed approach add about $10/MW to the hydro DEBs during the 12 month period used in this analysis for PacifiCorp West.

In the PacifiCorp area during 2018, hydro DEBs would have virtually never been set by the gas floor component of the proposed methodology, as shown in Figure 7. However, analysis using data for the BC Hydro (BCHA/Powerex) area provided in Figure 8 shows the potential impact of the gas floor. This analysis calculates the gas floor using gas prices for the FRBCHA fuel region. The gas price index for this fuel region is based on the Sumas hub price, which jumped significantly in fall 2018 for an extended period. Results of this analysis illustrate the significant impact that the gas floor may have on hydro DEBs in the event of such gas price increases.

Figure 5. Hydro DEBs based on prices at Palo Verde vs. Mid-C (Jan-Jun 2018)

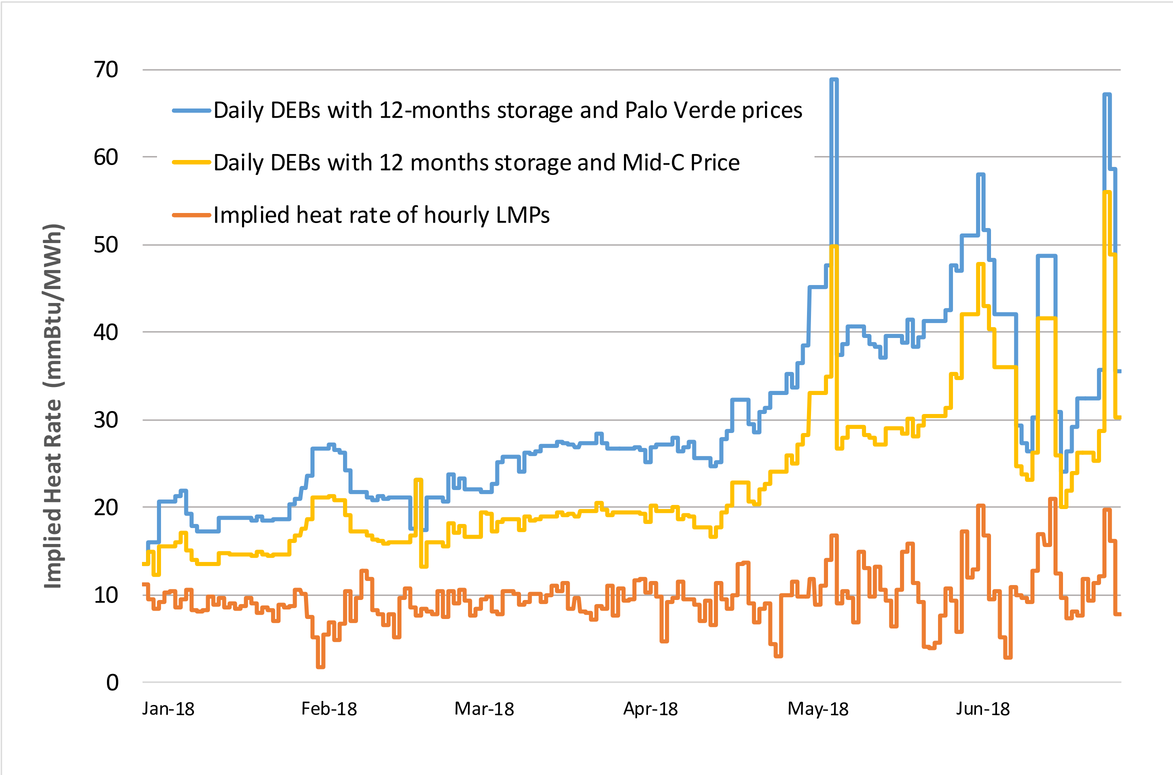


Figure 6. Hydro DEBs based on prices at Palo Verde vs. Mid-C (July-Dec 2018)

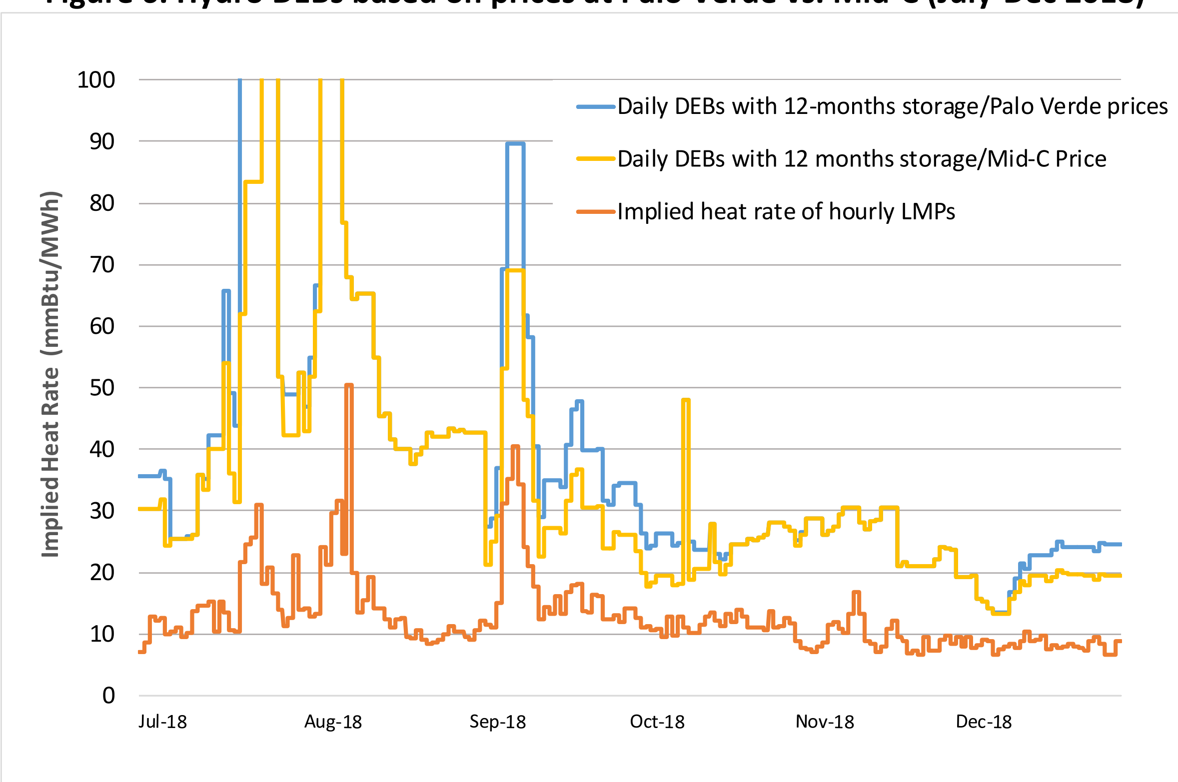


Figure 7. DEB setting components for PACW area (Jul-Dec 2018)
Based on 12-months storage and including Palo Verde prices

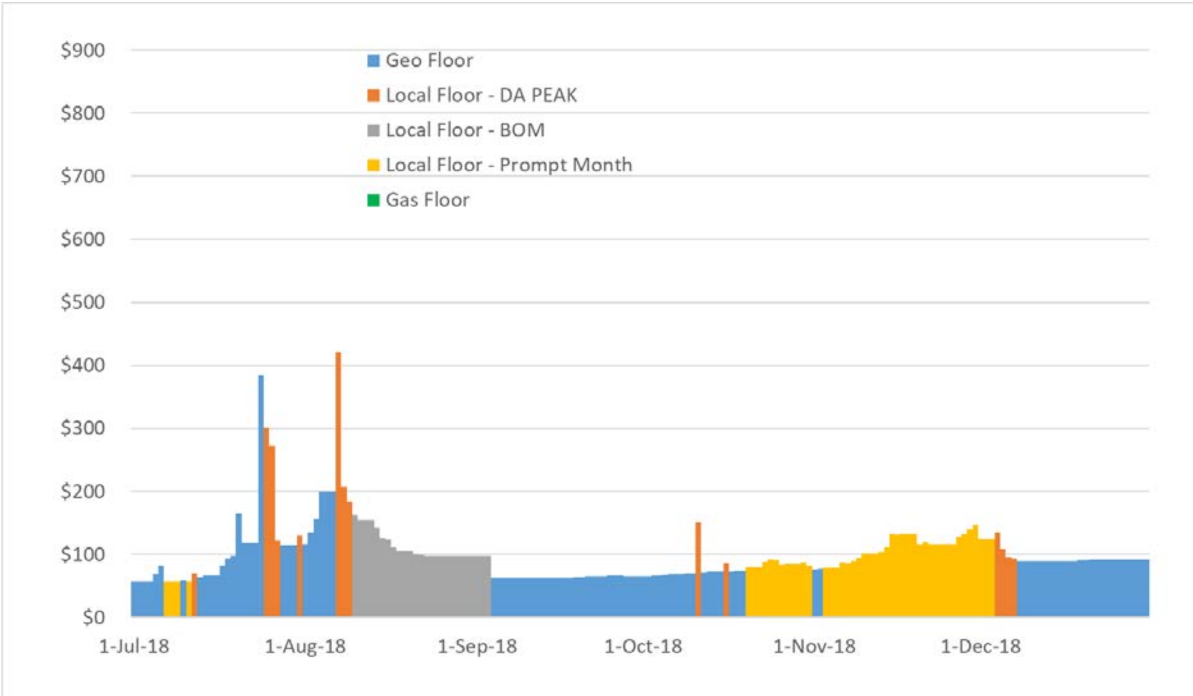


Figure 8. DEB setting components for BCHA area (Jul-Dec 2018)
Based on 12-months storage and including Palo Verde prices