memo

To: NEPOOL Markets Committee

From: ISO New England

Date: September 7, 2022 *(Corrected 9/9/2022)*

Subject: Performance of Capacity Resources and Pay for Performance

The Federal Energy Regulatory Commission (FERC) approved the Pay for Performance (PFP) capacity market rules in late 2014, for the capacity commitment period beginning June 2018. Since that approval, the New England system has seen both significant resource retirements and an influx of new renewable-energy resources, reshaping the resource mix. With the benefit of nearly a decade since PFP's approval, and amidst a continuing capacity surplus, a number of stakeholders have asked the ISO to share its perspectives on PFP and the performance of capacity resources.

This memo responds to these requests. Individually, stakeholders' questions touch on many details, such as whether the ISO is concerned with the prevalence (or, rather, the absence) of capacity scarcity conditions, whether the current Performance Payment Rate and stop-loss limits may be working at cross-purposes, the impact of excess supply conditions on the efficacy of PFP's incentives, and so forth. Taken more broadly, however, these questions can be viewed as asking simply, "Is PFP working as intended?"

We address these questions, and more, below. Our purpose is to facilitate thoughtful consideration and discussion of these topics. Accordingly, we do not propose any changes to the market rules herein; as a general matter, initiatives to potentially revise market rules are appropriately prioritized within the broader context of all ISO and regional initiatives. As always, we remain interested in stakeholders' input and feedback on these topics, and hope this memorandum proves helpful.

Summary

Our central points are summarized below:

- The objectives of PFP were to improve resource performance and to redress the FCM's tendency to adversely select (*i.e.*, retain) poor-performing resources over better performers. An examination of considerable resource performance data since that time shows significant improvements since PFP was adopted on both issues. We explore this and the supporting empirical trends next (*See* Section 1).

- We offer information and explanations for the low number of capacity scarcity conditions to date, and several design considerations with respect to frequently-asked-questions about 'enhancing'

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PFP with additional trigger conditions to produce more performance measurement events. (*See* Section 2).

- There are possible improvements that could be made to certain PFP parameters, such as the capacity performance payment rate structure and the stop-loss limits. However, given their interdependencies and the complexity of the latter, further analysis would be needed to develop any specific recommendations. It is unclear whether the region should consider this a pressing issue with immediate benefits, relative to the other committed and ongoing major projects underway for 2023, which are currently being discussed with stakeholders. (*See* Section 3).

- Once the system is performing reliably, by the measure of few (or no) actual or anticipated real-time operating reserve deficiencies, PFP's influence in driving further resource retirements is attenuated. Reducing the FCM's persistent excess supply conditions, an understandable concern from the perspective of resource investors, would require other mechanisms than PFP if the system's performance continues to yield few scarcity conditions. (*See* Section 4).

We have grouped these and related points into four major topic categories. We address these categories in enumerated sections below. An appendix to this memorandum provides additional backup detail related to resource performance data.

1. Performance of Capacity Resources

At the outset, it is useful to note that the ISO's PFP design had two specific objectives. In simple terms, they were: (1) to spur suppliers to improve the performance of their resources; and (2) to select resources in the FCM more cost-effectively, by inducing the system's worst-performing resources to exit first (*i.e.,* to address the FCM's adverse selection problem).[1]

In support of those objectives, the ISO filed considerable data showing the declining performance of capacity resources in the years leading up to the PFP filing[2] – a conclusion FERC found largely unchallenged.[3]

To address the immediate question of whether those two objectives have improved since PFP was approved, we have undertaken data analyses to extend, and supplement, those resource performance metrics through the present. Specifically, we have analyzed public and individual (non-public) resource

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[1] *ISO New England Inc. and New England Power Pool,* Filings of Performance Incentives Market Rule Changes, Docket Nos. ER14-1050-000 and ER14-1050-001 (Jan. 17, 2014), ISO-NE transmittal letter at pages 4-6 ("ISO-NE PFP filing letter"); and Testimony of Matthew White on Behalf of ISO New England Inc. included as attachment to ISO-NE Filing of Performance Incentives Market Rule Changes ("White Testimony"), at Sections III.A, III.C, and V.A, *generally*.
[2] Testimony of Peter Brandien on Behalf of ISO New England Inc. included as attachment to ISO-NE Filing of Performance Incentives Market Rule Changes ("Brandien Testimony"), Docket No. ER14-1050-000 (filed Jan. 17, 2014).
[3] *ISO New England Inc. and New England Power Pool,* Order on Tariff Filing and Instituting Section 206 Proceeding, 147 FERC ¶ 61,172 (May 30, 2014) at 26 ("As nearly all parties in this proceeding—including ISO-NE and NEPOOL—recognize, the performance of capacity resources in New England has substantially declined in recent years".)

and performance data since 2010, and tabulated metrics that show trends and changes since that time. We summarize the main findings below on six sets of performance-related measures, and reference below supporting results and figures in the Appendix.

1. **Dual-Fuel Capability.** The ISO noted a significant decline in resources with dual-fuel capability from 2004 through the time of the PFP filing's preparation, in 2013. After 2014, when PFP was approved, that decline arrested. Since 2014, total dual-fuel capability in supply resources has climbed from (approximately) 6,000 MW to a total of 8,416 MW in 2021. While the amount of dual-fuel capable units has not fully recovered to the approximately 9,000 MW level recorded in 2004 (*i.e.,* to the level prior to the shale-gas revolution in 2007-09), it rose modestly after 2014 and more noticeably following the 2018 implementation of PFP, for a total increase of 40% cumulatively from 2014 through 2021 (i.e., 8416 – 6000 / 6000 = 40%). *See Appendix Figure 1 for annual data.*

2. **Magnitude and Frequency of Generator MW Reductions Due to Gas Issues.** The ISO's tracking of generators' power reductions due to gas-related issues spans approximately 2010 to present.[4] Both the frequency and the magnitude of these MWh reductions exhibited periodic declines but varied rates from 2014 through 2017. There was then a large drop (by more than half) in total MWh of gas generators' reductions due to gas issues since PFP's implementation in 2018. *See Appendix Figure 2 for annual data.*

   We have also examined these data at the monthly frequency. The data shows a clear downward trend in the average hourly MWh reductions due to gas issues over time, with a noticeable drop starting in 2014. There is significant variation over time in the granular data, however, as the magnitude and frequency of these events depends (in part) on weather conditions that vary over time, and in some months in the historical data, large reductions can be the result of pipeline-related events. *See Appendix Figure 3 for monthly data.*

   Overall, these results show generally improved performance of systems' gas-fired resources in ensuring their ability to operate, particularly since 2018. However, we also caveat that New England has experienced generally mild winters since 2018, which likely contributes to this result (see also Section 2).

3. **Reductions in Fossil-Steam Units' Real-Time Capability on Extreme Hot/Cold Days.** For this analysis, we examined the reduction in fossil-steam units' EcoMax values in two ways: (a) on the five days with the highest peak load each year (mirroring a method used in the ISO's PFP filing); and (b) during all cold-weather days when the average temperature was less than 20°F.

   Broadly, using measure (a), the fossil-steam fleet capability reductions in summer peak conditions showed a substantial drop (*i.e.,* better performance) in 2017-2019, coincident with PFP's implementation, than in most preceding years. The interpretation is clouded, however, by the

[4] For data prior to 2014, *see* Brandien Testimony, Sections III.B and III.C.

observation that the data since 2019 show a steady subsequent increase (*i.e.,* worse performance). *See Appendix Figure 4.*

Using measure (b), the fossil-steam fleet capability reductions during low-temperature conditions shows a drop in 2019 and since (*i.e.,* better performance), though the data before that period varies. (Note this this newer cold-weather metric is not available for the pre-PFP period). *See Appendix Figure 5.*

In summary, we find this particular set of performance metrics inconclusive. Simply put, the considerable variance in these annual rates across years limits sharp conclusions. That fact may not be surprising, as these performance measures are based on only a few days per year (in most years), and will tend to depend on the severity and duration of summer and winter weather conditions that can vary significantly by year.

4. **System Equivalent Forced Outage Rate on demand (EFORd) Rates and Generator Unavailability.** The ISO observed a significant upward trend in system EFORd rates in the years leading up to and including the PFP filing in 2014, reaching over 8 percent system-wide by 2014. Beginning the follow year, EFORd rates fell significantly. They have remained in a relatively tight range since (averaging approximately 4%). *See Appendix Figure 6.*

   We also examined the average EFORd rates for the fossil-steam and the combined-cycle fleet over the past ten years. While there is significant variation in these data at a monthly frequency, there is a material overall declining trend (i.e., improved performance) for the fossil steam fleet, from approximately 13% in 2013-14 to approximately 8% in 2021. (More on this point in Metric 5, next). The combined cycle fleet's long-term trend in monthly EFORd rates has remained largely flat over time, at a lower level of approximately 4%. *See Appendix Figure 7.*

5. **Fossil-Steam Generator Slow- and Failed-Start Events.** The 2014 PFP filing reported on the slow- and failed-start events for a set of large fossil-steam generating units. Since 2014, the magnitude of slow and failed-start events among fossil-steam units has declined steadily. The largest drop occurred in 2018, the year PFP was implemented (*i.e.,* the first capacity commitment period under PFP). *See Appendix Figure 8.*

   It is useful to consider the drivers of this steady decline (*i.e.,* their improved performance on this metric). Many of the units in the original set of fossil-steam units have retired; some continue to operate. To examine the progress among those groups separately, we can examine the magnitude of slow and failed-start events for only the remaining units in that group. This revealed a markedly different result: The total MW of slow- and failed-start capacity among the *remaining units alone* has remained essentially constant over time (that is, it has remained virtually constant since 2016 at the value shown for 2021, which represents the remaining units only, in Appendix Figure 8).

   That finding is insightful. It implies two things: (A) The substantial reduction in slow- and failed-start capacity among the fossil-steam fleet since PFP was approved (Appendix Figure 8), and again after it was implemented, was due to retirements only. It was not due to improved performance on this metric among the (few) remaining units. Moreover, (B) the remaining units had significantly better performance, on this important metric, then and now, relative to the resources that retired. In simple terms, the worst-performing resources within this resource class are the ones that retired first – exactly as should be expected to occur under PFP (and more about which below).

6. **Post-Contingency Offline Fast-Start Resource Performance.** In the ISO's original PFP filing, it discussed concerns with the relatively poor performance of the system's fast-start fleet in response to post-contingency dispatch instructions. Data disseminated by the ISO at the time on that performance was compiled in a quantitative report performed by the Analysis Group, Inc. (AGI).[5]

   Using AGI's original methodology, we have extended that performance metric from 2016 through 2021.[6] Prior to PFP, system-wide performance for fast-start units over a three-year study period was 68% (where, in simple terms, rate of 100% would be perfect performance of all fast-start resources within ten minutes in response to post-contingency dispatch instructions). Since 2016, that rate has varied from a low of 72% to a high of 96%, always higher and mostly significantly higher than in the study period prior to PFP's adoption. *See Appendix Figure 9.*

   It is also worth noting that there is no discernable trend, within that 72-to-96 percent band since 2016, in overall fast-start performance (in response to post-contingency dispatch instructions). And, in absolute terms, those levels represent sufficient non-performance that the ISO continues to maintain a 'Non-Performance Factor' adjustment that increases the real-time reserve requirement quantities to compensate.

   In summary, we draw from these fast-start resource performance data two simple conclusions. First, the fast-start fleet has measurably improved its average performance, at times when its performance matters most, in the years after PFP was approved *relative to* the years prior to PFP's approval. And second, even in most years since, there remains considerable room for further improvement.

Implications and Caveats

By five of these six sets of performance metrics, resource performance has improved since PFP was approved and/or implemented (in one, category 3, we find the evidence inconclusive due to the data's

[5] Analysis Group, Inc., *Analysis of Reserve Resources: Activation Response following Contingency Events* (May 29, 2012), at https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/strategic_planning_discussion/materials/analysis_group_reserve_resource_analyses_5_29_2012.pdf

[6] As a technical note, there are a number of different statistical methods for measuring fast-start resource performance in response to post-contingency dispatch instructions, differing in subtle measures of timing, aggregation, weighting, censoring of outliners, and so forth. For these reasons, the values noted in the text and in Appendix Figure 9 may differ from measures of fast-start resource performance reported by the ISO in other reports. We use AGI's (unweighted) method here to facilitate comparison with the information reported in 2013, before PFP.

high variance and absence of any clear trend). The implication with respect to Objective 1 of PFP ("to spur suppliers to improve the performance of their resources," *page 2*) seems clear: since PFP was approved/implemented, the broad deterioration in the generation fleet's performance (as documented in the original PFP filing) has arrested. And, since that time, the generation fleet has made measurable improvements in its performance overall. By some important metrics (e.g. the drop in system-wide EFORd rates from over 8% in 2014 to approximately 4% since), these fleet-wide improvements are substantial.

That said, a caveat is in order. It is important to note that the ISO has also made a number of other changes to the market rules over the past decade, many of which also serve to improve resources' performance incentives. These include, for example, the Energy Market Offer Flexibility (EMOF) reforms implemented December 2014 (likely impacting performance metric category 2); the Fast-Start Pricing (FSP) reforms implemented March 2017 (potentially impacting category 6); and the Winter Reliability Programs' subsidies for dual-fuel commissioning (beginning 2014/2015, which likely impacted outcomes in category 1).

In sum, the data discussed above no doubt reflect the combined effect of PFP and a number of additional initiatives the ISO has undertaken since that time. It is not practical (nor appears feasible) to quantitatively "separate out" the effects of each of these additional initiatives on the outcome measures reported above; investors respond to the totality of the financial incentives they face.

On Adverse Selection and Resource Performance

As noted at the outset of this section, a second objective of PFP was to induce the system's worst-performing resources to exit the capacity market first, leaving a system with better performing resources overall.[7] This would help resolve what the ISO termed at the time the FCM's adverse selection problem.

In an ideal world, the preferred data to evaluate this objective would be generators' performance (energy plus reserve) during capacity scarcity conditions, observed over a long enough period with sufficient capacity scarcity conditions to distinguish differential performance trends between (a) resources that have exited and (b) the system's remaining resources that have not. In the absence of performance data over numerous scarcity conditions (more about which in Section 2 below), we can examine other, informative metrics.

The adverse selection concerns originally centered primarily, but not exclusively, on the region's older fossil-fired steam fleet. The data that speak to this most directly are the slow- and failed-start information discussed above, in performance metric set 5. As noted, those data show that among the original set of large fossil-steam resources operating a decade ago, it has been the worst-performing resources (by that metric) that have retired first. This is entirely consistent with what we should see if the adverse selection problem is declining: The remaining resources in this class have consistently better performance than the ones that have exited the FCM over the past decade.

[7] *See* White Testimony, pp. 44-46.

That fact also highlights an important conceptual point. It is sometimes suggested that the persistence of excess supply conditions in the FCM (since FCA 9) is evidence that adverse selection continues to be a problem *per se*. This is not accurate, however, because it confuses the distinct concepts of *differential selection* and *excess supply.* Adverse selection specifically refers to differential performance of resources that exit over time, *relative to* the same performance metrics for resources that continue to participate in the FCM – *viz*., the potential for the market to 'adversely' select (*i.e.,* retain) its worst-performing resources while its better-performing resources retire.

In contrast, excess supply is not a relative concept; it occurs when all existing (and new) resources have lower net costs to recover in the capacity market, and are therefore willing to accept lower capacity prices, than the FCM would pay in equilibrium (*i.e.,* the Net Cost of New Entry (CONE)). Given the FCM's downward sloping demand curve, the willingness to accept those lower capacity prices results in the capacity market clearing excess supply (relative to ICR).

The distinction between adverse selection and excess supply can become obscured when performance comparisons are made among *only* remaining resources. For example, the previously-discussed figures showed a system-wide EFORd rate in 2021 of 4.57% (Appendix Figure 6), but an average EFORd rate in 2021 for the remaining fossil-steam fleet of approximately 8% (Appendix Figure 7). That, by itself, is *not* evidence of adverse selection; it is merely evidence that there is variation in performance across technologies. To draw conclusions about adverse selection we would have to make comparisons between the performance of resources that *exit* and those that *remain*. Comparisons of performance between remaining units alone cannot inform that. There will always be some resources that perform worse than the system's average, and some that perform better.

We highlight these distinctions to facilitate constructive discussion on this topic. Empirically, given the data noted above for the fossil-steam fleet, it would not be proper to construe the continued operation of (the limited number of) these older generating stations – which operate infrequently, but have supplied significant energy in extended cold weather conditions (e.g., the severe cold-spell of winter 2017-18) – as evidence that adverse selection is the problem it once was.[8] We offer further observations on the persistence of excess supply conditions, and their relation to PFP, in Section 4 of this memorandum.

We would not, however, go so far as to suggest that adverse selection issues have been completely solved; we readily acknowledge the data on point are not extensive and, therefore, not dispositive. But at least for the class of resources where adverse selection was a prominent concern a decade ago, the system is making evident progress, evolving in a way consistent with PFP's second objective to induce the system's worst-performing resources to exit the capacity market first.

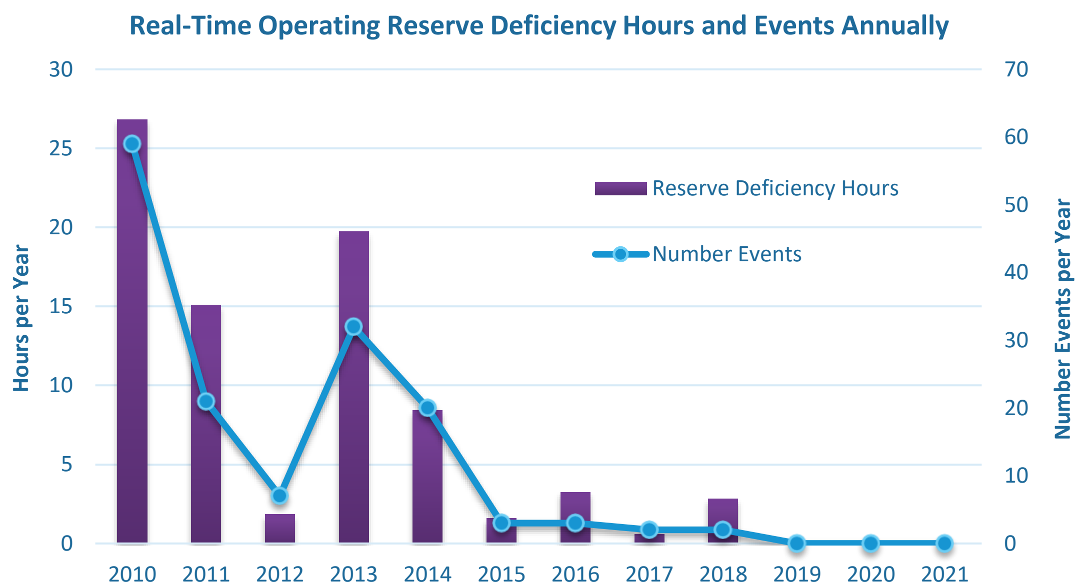
2. The Scarcity of Scarcity Conditions, and What to Make of It

An important phenomenon over the past decade (and more) is that the frequency of capacity scarcity conditions in the New England system has declined, dramatically. In the figure below, we show the total number and total annual hours of system-wide, real-time (minimum) operating reserve shortages from

[8] *Id.*, pp. 23-4.

2010 through 2021. These real-time conditions correspond to (*i.e.,* are the 'trigger' for) a system-wide capacity scarcity condition under PFP.

In the 2014 PFP filing, the ISO indicated in its modeling forecast an annual total of 21 hours of capacity scarcity conditions, on average, in a system at ICR.[9] As the figure below indicates, that forecast value was not out of line with the system's experience prior to 2014 (the aberrantly-low value in 2012 being, at the time, exactly that).



In the four years following PFP's approval in 2014, total annual capacity scarcity conditions fell to a handful of hours annually. Since September 2018, after PFP's first capacity commitment period began, there have been none. The low number of CSCs since PFP's approval is notably smaller than was expected when PFP was proposed, particularly given the frequency of real-time operating reserve shortage events leading up to that time and the deteriorating resource performance documented in the 2014 PFP filing.[10]

Why the substantial drop in the frequency of real-time operating reserve shortages since 2014? We believe there are several contributing factors:

- First, this reflects the overall improvements in resource performance over this time, as discussed in Section 1. The drop in capacity scarcity conditions aligns notably with the PFP approval (late 2014) and implementation (mid-2018) timing.

[9] *Id.,* pp. 107-9.
[10] *Id.,* p. 69-70.

- Second, as noted above, the ISO has undertaken many other actions to help improve resource performance, including various real-time market design improvements (*e.g.*, EMOF, FSP, and Reserve Constraint Penalty Factor revisions) and ISO operational and informational processes (*e.g.,* improved gas-electric coordination, timely fuel surveys, and information reports such as the system's 21-day energy balance forecast).[11]

- Third, as noted at the outset of this memorandum, the system has experienced significant excess supply conditions since FCA 9 (capacity commitment period 2018-19). Excess supply, other things equal, tends to reduce the frequency of real-time operating reserve conditions.[12] This property is only a partial explanation for the precipitous decline in scarcity conditions after 2014, however: the system's excess supply was quite high each year from FCA 1 (commitment period ending mid-2011) until the FCA's "floor price" was eliminated after FCA 7 (commitment period ending mid-2017).

- Fourth, New England has experienced generally mild-to-moderate summers and winters in most years since 2015. The most severe winter overall during the time span in the figure above was the winter of 2013-14. Again, this appears to be only a partial explanation for the dramatic decline in the figure above, insofar as real-time operating reserve shortages were quite high in 2010 and 2011 without similarly cold winter weather.

On What to Make of It

From the standpoint of achieving reliable system operations, the low number of real-time operating reserve shortages in recent years is not a problem. In simple terms, the few annual real-time operating reserve shortages over the last seven years is an indicator of a more reliable system during this period than it was before PFP was developed.

In that context, we highlight that the limited scarcity conditions in recent years have occurred despite many challenging operating situations at times. These include the extended cold-weather conditions during the extended cold-spell of winter 2017-18, and the high-load conditions experienced during hot summer weather in 2018 and, more recently, in July and August 2022.

We also observe that, over the last several years, there have been numerous days with major, and sometimes multiple, source-loss contingencies in real-time. Since September 2018, in each such event the

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[11] The ISO has also performed historical backcast simulations of operating reserve deficiencies for the 2010-2012 period prior to PFP, to account for changes in Reserve Constraint Penalty Factor values implemented in June 2012. See ISO's memorandum *Operating Reserve Deficiency Information – Historical Data* (March 5, 2013), Table 1 and discussion thereof, at https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jul10112013/a12a_iso_memo_07_05_13.pdf.

[12] See ISO's memorandum *Operating Reserve Deficiency Information – Capacity Commitment Period 2025-26* (December 7, 2021), Figure 1, at https://www.iso-ne.com/static-assets/documents/2021/12/a00_pspc_2021_12_iso_memo_or_def_fca_16.pdf.

system's resources have performed sufficiently well for the system to recover promptly, with no depletion of reserves below the minimum real-time operating reserves requirements.[13]

But Uncertainties Remain, Looking Forward

It is possible some may view the last seven years' experience in the figure above and infer, with respect to achieving a reliable power system, that little more may need to be done presently. We are not so sanguine. The dramatic drop in capacity scarcity conditions after 2014 is consistent with what one would expect if PFP has significantly improved resources' performance, PFP's first objective. However, it is an open and important question whether the reliable system performance evident in the figure above should be expected to continue into an uncertain future.

As highlighted as part of the material for the FERC New England Winter Gas-Electric Forum held September 8, 2022, energy adequacy remains a broad concern regionally and the region faces substantial challenges to new energy infrastructure development. These and other risks, notably the region's constrained natural-gas pipeline infrastructure, raise the potential for challenging operating conditions and a greater frequency of capacity scarcity conditions when severe cold winter weather occurs in the future. We expect the ongoing quantitative modeling work underway in the probabilistic Operational Impacts of Extreme Weather Events study will shed greater light on this potential.

As a consequence of these energy adequacy concerns, we view the future predictive value of the last seven years' experience in the figure above cautiously. We are mindful of the adage "Past performance is no guarantee of future results."

Could PfP be enhanced to have additional 'triggers' in less stressed situations than capacity scarcity conditions?

Of course, while the low number of capacity scarcity conditions is not a problem from a reliability standpoint, that is not the only important perspective. The lower number of capacity scarcity conditions is an understandable concern from the perspective of resource owners who have invested in improving and maintaining the high performance of their assets, and who have not received the financial benefit of doing so in the form of recurring capacity performance payments for strong performance. This has led some to ask whether the market rules could be extended to create PFP-like performance events in more frequent circumstances, when the system may be stressed but not at the level of a full-blown capacity scarcity condition.

This is a technical question, in part, and we have given this a fair bit of thought. Unfortunately, while creating stronger incentives for resource performance is a generally laudable goal, the PFP framework is

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[13] For example, the ISO provided a detailed operational review of the system's response to a series of large contingencies that occurred in 2020, where the system's performance in each case was sufficient to avoid a real-time operating reserve shortage. See *ISO New England Informational Session: Recent Operational Contingencies and Pricing* (August 24, 2020), at https://www.iso-ne.com/static-assets/documents/2020/08/info_session_operational_contingencies_and_pricing.pdf.

not amenable to being extended to a broader range of real-time 'trigger' events without creating other, adverse, unintended consequences.

Why not? (A useful design digression on PFP–energy market interactions)

In general, additional performance payments can change generators' marginal incentives in the real-time energy market and, therefore, can have substantial unintended market impacts unless they are designed very carefully. Critical to its design, PFP's performance payments are triggered *only* when the system is experiencing a true shortage of real-time operating reserves, and (therefore) no resource can provide more (combined) energy and reserve than the amounts assigned to it in the ISO's real-time dispatch.[14]

In contrast, if PFP were extended to create additional 'trigger' conditions outside of capacity scarcity conditions, then during those new 'trigger' events, the marginal and extra-marginal resources (whether online or fast-start) will have unloaded capability above their combined energy dispatch and reserve designations. Thus, in those new non-scarcity condition 'trigger' events, the marginal and extra-marginal resources are unconstrained. In such cases, they can financially benefit from 1) reducing their offer prices to increase their energy dispatch instruction, and/or 2) directly increasing their energy output (above their dispatch instruction).

These concerns have practical consequences. The first problem undermines the least-cost objective of efficient real-time dispatch: offer prices would no longer reflect resources' actual marginal costs, changing the dispatch solution and increasing total production costs, in general. The second problem creates potential operational concerns, as it can have a number of deleterious consequences for real-time system performance.[15]

For more detailed discussions of these design issues, the ISO provided a series of numerical examples explaining these points in a December 2021 memorandum.[16] While that memorandum was developed in the context of a particular stakeholder proposal at the time, the points there are quite general and are applicable here; with appropriate updates, similar numerical examples would show similar adverse, unintended consequences for any PFP-like additional 'trigger' conditions outside of a true capacity scarcity condition.

In sum, creating additional 'triggers' for PFP-like performance events outside of true capacity scarcity conditions would put generators in the untenable position of facing financial incentives that run directly contrary to following their dispatch instructions, offering in ways that produce an inefficient dispatch solution, or both.

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[14] Indeed, it is precisely *because* resources cannot do anything to increase their total energy and reserves suppled in a capacity scarcity condition that marginal incentives in excess of the LMP (*i.e.,* by the performance payment rate) does not distort dispatch-following outcomes during such events.

[15] These include excess Area Control Error (ACE), excessive costs for regulation service used to correct ACE, inadvertent power flows to neighboring Balancing Authority Areas, or combinations thereof.

[16] See ISO's memo *Concerns with LS Power's Proposal* (December 1, 2021), at https://www.iso-ne.com/static-assets/documents/2021/12/a02b_ii_iso_memo_lspower_mopr.pdf.

Practical implications: Focus is better placed on energy and ancillary services, not extending PFP with new 'trigger' conditions

There is a broader point here, concerning where the region should focus its time and energy if it seeks to improve and better reward resource performance. The issues that arise with additional 'trigger' conditions can be avoided, in general, if desired enhancements are thoughtfully designed through new products, requirements, and constraints *within* a co-optimized (day-ahead or real-time) market. In essence, because of the foregoing limitations on PFP's ability to be 'extended' to additional real-time conditions, further efforts to modify the wholesale market design to reward resource performance are best pursued and implemented in the energy and ancillary service markets.[17]

3. Performance Payment Rates, Stop-Loss Limits, and their Interactions

From time to time, many stakeholders have offered questions or concerns about the PFP Performance Payment Rate (PPR), the PFP stop-loss limits (which limit capacity resources' total non-performance charges), and their current values. Some stakeholders have expressed concern that these values are too high (generally with regard to the PPR). Other stakeholders have expressed concern that they are too low (generally with regard to the stop-loss limits); and for that reason, suggested the two may be working at cross-purposes. We offer the following perspectives on those questions.

The Performance Payment Rate, and Its Implications

As context, the table below shows the value of the PPR each capacity commitment year since PFP's implementation.[18]

Forward Capacity Auctions	Capacity Commitment Periods	Performance Payment Rate ($/MWh)	Descriptive Notes
FCA 9 – FCA 11	6/2018 – 5/2021	$2,000	Transition Phase 1
FCA 12 – FCA 14	6/2021 – 5/2024	$3,500	Transition Phase 2
FCA 15	6/2024 – 5/2025	$5,455	Initial Full PPR
FCA 16 +	6/2025 and forward	$9,337	Updated Full PPR

The PPR was originally developed starting from two basic design principles. One is that the PPR should be set at a value such that a new (merchant) capacity resource is willing to enter the market when new entry is needed to satisfy the ICR (*i.e.,* in equilibrium). That is, of course, one of the central goals of the FCM

[17] We view this recommendation as inclusive of, not exclusive of, developing possible new forward products and services *provided* that they are designed to settle against an appropriately-priced product in the (DA or RT) energy and ancillary service markets.
[18] These values are in Market Rule 1, Section III.13.7.2.5.

generally. The second design principle is that a resource that expects to not supply any energy or reserve during expected capacity scarcity conditions should expect zero net capacity revenue. This second principle is also implemented for a system at ICR. The logic is simply to assure that when new capacity is needed (*i.e.,* the system is at ICR), the FCM does not instead retain, pay for, and rely upon, capacity resources that do not expect to perform – at all – during capacity scarcity conditions.[19]

These principles lead to a simple formula for the PPR. In words, the PPR represents Net CONE (exclusive of any PPR revenue) divided by the expected number of capacity scarcity condition hours for a system at ICR.[20] Conceptually, it spreads the capacity revenue of a new entrant over the MWh (of energy and reserves) it expects to deliver during all scarcity conditions when the system is at ICR.[21]

Using these principles, and the relevant numerical inputs at the time, the ISO proposed the initial full PPR for FCA 15 of $5,455/MWh. There was also a six-year transition to this full rate, as shown in the table above. Importantly, as the ISO's estimated number of capacity scarcity condition hours at ICR has declined over the years since PFP was approved, the denominator in the ratio determining the full PPR has declined. Thus, when the same formula and principles were applied in the last revision to Net CONE and the PPR (in 2020, for capacity commitment period 2025-26), the lower number of estimated scarcity hours at ICR produced a higher value for the updated full PPR presently in effect (as the Net CONE value is now spread over a smaller number of expected annual scarcity hours).

Implications

As a general matter, it is important that specific payment rates put forth to FERC and codified in the market rules be grounded in sound design principles. Even with the significant increase in the PPR over time, it is difficult to identify any factors that should lead the ISO to depart from those two sound design principles going forward. Moreover, the practical impact of the higher PPR is limited in a number of important ways, discussed next.

Quite generally, a higher value of the PPR (resulting from updated inputs in the broader Net CONE process) does not increase consumers' expected costs, or suppliers' total FCM revenue, when the system is at ICR (*i.e.,* if the market is not in excess supply). This is for two reasons. One is that the higher value of the PPR does not increase Net CONE itself, and therefore does not impact the demand curves used in the FCM. The other is that when the system is at ICR, an increase in the PPR should not increase a competitive capacity supplier's bid/offer price. This is because the *annual* costs a supplier expects to incur to 'cover' its

[19] These principles are discussed more fully in White Testimony, p. 88 *ff.*

[20] *Id.,* p. 100-1; *see also* the ISO's presentation *FCM Parameters: Net CONE Deficiency Response and Related Proposed Revisions*, Slide 7, at https://www.iso-ne.com/static-assets/documents/2021/03/a02b_mc_2021_03_19_revised_iso_presentation.pptx (explaining the calculation of the PPR and its relation to CONE; note the numerical values therein (on Slide 8) were subsequently adjusted on compliance to the current rate of $9,337/MWh). Note also that the PPR formula also has a small adjustment for the performance of the benchmark Net CONE resource; that adjustment matters little in practice, and we ignore it here to simplify the discussion of broader issues.

[21] White Testimony*.,* p. 101-2.

PFP obligation, and that it should seek to cover in its FCA bid/offer price, is based on the *product* of the PPR and the expected annual hours of capacity scarcity conditions. Any changes in expected hours of capacity scarcity conditions at ICR therefore cancel out (that is, they raise the PPR, and lower the supplier's frequency of expected credits and charges, in offsetting ways).[22] Taken together, these points explain why an increase in the PPR, when the system is at ICR, does not impact the capacity clearing price.

Of course, as many are well aware, New England's system is not at ICR presently and has experienced excess supply conditions for some time (since FCA 9). In excess supply conditions, the impact of an increase in the PPR should increase the capacity bid/offer prices of the system's relatively worse-performing resources – at least, in theory. The reason is that in excess supply conditions, an increase in the PPR creates greater expected liabilities (per scarcity hour) for the system's relatively poor-performing resources, but without much change in participants' expected frequency of scarcity hours (being already low). Nevertheless, and importantly, when there is a low likelihood of non-performance charges (because actual expected scarcity hours are low), the effect of an increasing PPR on capacity bid/offer prices is quite muted. And, consistent with that 'muted effect' property, we observed that when the PPR increased from $5,455/MWh for FCA 15 to $9,337/MWh for FCA 16, the system-wide FCA clearing price barely budged (increasing from $2.59/kw-mo in FCA 15 to $2.61/kw-mo in FCA 16).

The upshot of all this analysis is that changes in the PPR, even fairly large ones, tend not to have much impact (if any) on the overall total cost of the FCM to consumers, or the aggregate capacity market revenue to capacity suppliers. That's true in theory, and, so far, empirically.

Instead, what a change in the PPR does impact is the potential for *transfers* among suppliers, and the *variance* (in a statistical sense) of a resource's total annual FCM net revenue. Specifically, in years when capacity scarcity conditions do occur, the higher PPR will increase total FCM net revenue to relatively good performers, and will decrease total net revenue to relatively poor performers. As a result, an *ad hoc* reduction in the PPR, if it departs from the two sound design principles on which it is presently based, will tend to systematically disadvantage the system's better-performing assets over time. And, over time, that would run the risk of undermining continued resource performance improvements, as observed to date (*see* Section 1), and raise the risk of recreating the problems PFP was intended to solve.

Thoughts on a graduated performance payment rate

One extension of these ideas merits note. In its *State of the Markets Report* for 2021, Potomac Economics (the External Market Monitor) recommended the ISO consider developing a PPR that would vary with the *severity* of a capacity scarcity condition.[23] Severity, in this context, refers to the 'depth' (total MW) of real-time operating reserve deficiency during a scarcity condition.

[22] A technical note: This condition holds if the marginal supplier's expectations for annual scarcity hours when the system is *at* ICR matches the corresponding value used to update the PPR; if that is not the case, the offsetting described here (and the insensitivity of capacity clearing prices at ICR to PPR updates) would hold approximately, rather than exactly.

[23] See p. xiv, at https://www.iso-ne.com/static-assets/documents/2022/06/iso-ne-2021-som-report-full-report-final.pdf.

As a general matter, in theory, it should be possible to create a marginal reliability impact (MRI)-type "price curve" that specifies a graduated PPR (*i.e.,* one that depends on the severity of a CSC), *and* that does so in a manner that still satisfies the two core PPR design principles as well. However, like the design of demand (price) curves in electricity markets generally, that would require significant analysis and design work; this is a 'new' design problem, not one that has an 'off the shelf' price curve solution.

At present, it is unclear whether the benefits of prioritizing such a design effort would be worth the effort and opportunity cost (of forgone alternative priorities). The benefits may be low if few (or no) scarcity conditions continue to prevail in 2023 or for the near term: When that is the case, the impact of a severity-dependent PPR value on resources' actions is again muted.[24] And, for the reasons noted previously, a severity-dependent PPR should not be expected to materially impact total FCM costs to consumers in any event (*i.e.,* even in a system at ICR). In summary, while this idea may have merit for the future, it is unclear whether it would bring sufficient benefits to pursue as a regional design priority next year.

Stop-loss limits

The stop-loss limits are a mechanism that places a cap on the total PFP non-performance charges that a resource may incur, on a monthly and annual basis, during the capacity commitment period. When originally designed, it was anticipated that that these limits would come into play if a resource did not delivery any energy or reserves during about 3.7 (or more) hours of capacity scarcity conditions monthly.[25] To avoid diluting performance incentives too significantly, the ISO explained at the time that the monthly stop-loss limit should be set so that even poorly-performing resources are likely to reach that financial cap on its non-performance charges infrequently.[26]

As the system has changed since then, with updated values for all other PFP parameters and their inputs, the hours of scarcity conditions before a non-performing resource reaches that stop-loss limit has fallen substantially. Depending on load levels (via the balancing ratio), a non-performing resource would 'stop out' if a single future capacity scarcity condition (or any sequence thereof) lasts longer than about an hour and half. In essence, the stop-loss limit would be reached by poorly-performing suppliers far more quickly than was expected when the limit was designed.

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[24] Another technical point merits note. A severity-dependent PPR could help address another risk raised by certain capacity suppliers: In excess supply conditions, if a single not-very-severe capacity scarcity condition occurs in which an otherwise good performer has a 'bad day' (e.g., trips unexpectedly), the few (or no) scarcity conditions over the balance of the year does not provide any additional opportunities for it to demonstrate its good general performance and therefore to 'dig itself out of the hole'. That is, more capacity scarcity conditions annually statistically tend to average out idiosyncratic performance fluctuations, reducing financial risk for fundamentally good performers. While it is not viable to create 'more' annual capacity scarcity conditions by rule (for the reasons explained in Section 2), a severity-dependent PPR could have a similar salutary effect on such 'one-off' event risks, in practice, if such one-off events involve 'small MW' real-time reserve deficiencies and a graduated PPR's value for such events is less than $9,337/MWh.
[25] White Testimony, p. 189.
[26] *Id.,* p. 188.

This has two potential adverse consequences. First, it can harm the system's better performing resources. Conceptually and mechanically, the stop-loss mechanism is a system of mutual insurance: The burden of covering poor performers' stopped losses is not shouldered by consumers, but is borne by the system's performing resources that do not stop-out (and that take a 'haircut', *i.e.,* receive lower capacity performance payments, if a poor-performer stops-out).[27] Second, stop-loss limits can undermine resources' incentives to undertake costly efforts to maintain the ability to perform in challenging cold weather conditions (*e.g.,* to procure LNG, replenish oil promptly, or such). These actions can have high up-front costs; and when capacity resources' non-performance "money at risk" is capped too tightly, it becomes unprofitable to undertake higher-cost backup fuel supply arrangements as a means to assure performance.

Practicalities

The stop-loss mechanism is complicated. It has multiple design principles,[28] and translating them into specific values that would be both commercially sensible and reasonably address the foregoing concerns is not a trivial endeavor. In general, we would be open to pursuing further analysis of this issue, and to stakeholder feedback and subsequent discussion of how this particular design element (the stop loss provisions) may be improved. Importantly, because there are important design and functional interdependencies between the PPR and the stop-loss limit mechanism, it may be important to consider changes in the stop-loss provisions in conjunction with any effort to create a 'graduated' PPR (as discussed above). That is, the former should not be pursued in isolation, as a change in either may impact the effectiveness of the other.[29]

All that said, we are cognizant that the benefit of enhancements to the stop-loss rules are ultimately dependent on the expected frequency of capacity scarcity conditions, and that fact may play a role in how quickly the region may wish to pursue this potentially technical subject. As noted above, the benefits may be low if few (or no) scarcity conditions continue to prevail in 2023 or for the near term; but, in the face of concerns with escalating energy security risks, the importance of ensuring strong incentives for resource performance in cold weather conditions remains. In summary, while there is merit in considering revisions to the stop-loss mechanism, it is a complex design element and we seek stakeholders' feedback on its potential prioritization among other projects.

4. Should PfP be driving the system back toward equilibrium (i.e., to ICR)?

In assessing the array of stakeholders' PFP-related questions that we have endeavored to address in this memorandum, there is another consideration that became evident. Several stakeholders expressed broader concerns with the FCM's persistent excess supply conditions, the corresponding low capacity

[27] *Id.,* p. 176 *ff.*
[28] *Id.,* p. 173 *ff.*
[29] The stop-loss mechanism and limits are also an important determinant of the financial assurance requirements associated with PFP for market participants with capacity supply obligations.

prices in recent years, and asked whether PFP could – or should – be 'correcting' this by driving the capacity market back toward equilibrium (*i.e.,* ICR).

While excess supply conditions are a different phenomenon (with respect to root causes) than PFP's specific objectives, the two are not unrelated, either. Here we offer two points on PFP, and then some broader considerations on excess supply conditions in the capacity market.

First, PFP's impact on resources' incentives to invest (in performance) or to disinvest (retire) is attenuated when there is significant excess supply (relative to the ICR). This property is both logical and was anticipated when PFP was designed (though, as noted earlier, the scarcity of scarcity conditions was not).

The logic is simple: PFP's incentives to improve resource performance are (much) stronger when the system's capacity is closer to the ICR, scarcity conditions are more frequent, and (thus) reliability risks are greater. In excess supply conditions, there will tend to be fewer scarcity conditions and higher reliability, as measured by the frequency and duration of real-time operating reserve deficiencies – just as we have observed in recent years. In essence, PFP doesn't pose a high financial risk to the system's relatively worse-performing resources in years when their performance isn't contributing to high scarcity hours and reliability risks (as indicated by the real-time operating reserve deficiencies).

This is not to say that good performance, and continued investment to maintain same, become unimportant when the system has excess supply; power system reliability has many dimensions, and PFP is based on but one of them. Rather, it is to say that once annual expected scarcity hours become low, and the system is operating reliably by that measure, differentially remunerating resources that still contribute greatly to the system from those that contribute less to it would require a different market mechanism than PFP.

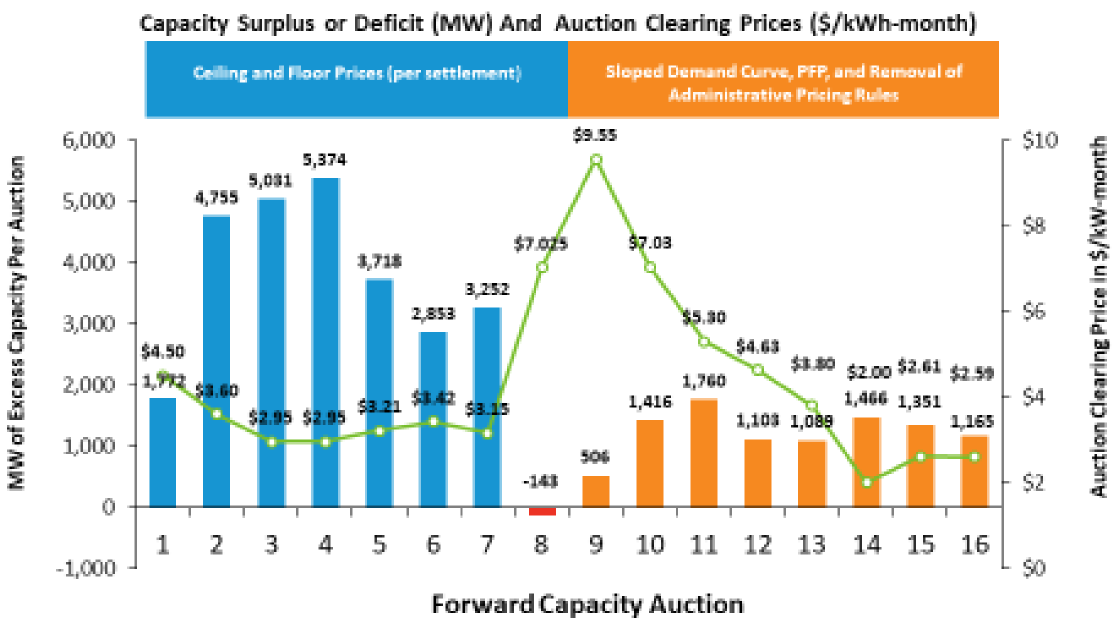
Second, PFP was not designed to drive the system back to equilibrium when it experiences excess supply conditions, as a general matter. That is, in part, a practical consequence of the properties discussed above. Viewed alternatively, PFP was designed to spur market resources to invest in improved performance, or to disinvest by exiting, and these incentives are strongest when the system's aggregate performance is poor and deteriorating (as was case prior to PPF's approval in 2014); and/or the system resource balance is tight overall (*i.e.,* at or near ICR); and/or resources expect challenging operating conditions to prevail over the coming commitment year for some other reason (*e.g.,* an increasingly constrained fuel-supply infrastructure) that would yield a significant scarcity hours. Put simply, if the system is in excess supply and none of those three general conditions apply, PFP's teeth are muzzled. This is not a PFP design flaw, but reflects that it provides incentives to invest in reliability that are proportional to the reliability benefits (in the form of further reductions operating reserve deficiencies) that the investments will provide.

This is not to suggest that persistent excess supply conditions are innocuous (more about which shortly). Rather, it is to highlight an inherent limitation on the 'reach' – and design properties – of PFP. In essence, if the system is in excess supply, it is misplaced to view PFP as a simple mechanical mechanism that drives the capacity market to equilibrium – though it may help do so, *if* the system's reliability declines and operating reserve deficiencies increase.

Further considerations on excess supply conditions

Persistent excess supply conditions in the FCM can place financial pressure on many resource owners and investors – and such pressures are not necessarily limited to the system's worse-performing assets. As noted earlier (*see* Section 2), resources that have made (and continue to make) investments to improve and maintain the high performance of their assets express understandable concern that, to date, they have not seen the financial benefit from doing so in recurring capacity performance payments.

For context, here are some data on the FCM's excess supply. From FCA 10 through FCA 16, each FCA cleared with more than a GW of excess supply system-wide, ranging from a low of 1,089 MW above Net ICR (in FCA 13) to a high of 1,760 MW above Net ICR (in FCA 11). The most recent auction cleared 1,165 MW above Net ICR (in FCA 16). As shown in the figure below, these values are not historical highs; during the "price floor" period from FCA 1 though FCA 7 (inclusive), the FCA cleared between 1,772 MW and 5,374 MW above Net ICR (and cleared over 3,200 MW above Net ICR in five of those seven auctions). While the FCA's price floor is long gone, the data from FCA 10 forward indicate a return to excess supply conditions in the FCM.



Fundamentally, the persistence of current long-market conditions reflects, in large part, incentives external to the FCM. These include, most prominently, the steady influx of energy resources that receive substantial out-of-market financial support from states' programs and initiatives, federal tax credits, and the region's increasing Renewable Portfolio Standard requirements. With the elimination of the Minimum Offer Price Rule, their accelerating development appears likely to continue to place downward pressure on FCM prices; given the downward-sloping FCM demand curves, that in turn leads the FCA to clear capacity in excess of Net ICR.

For the reasons discussed above, PFP should not be expected to somehow 'undo' that external price pressure and return the system to ICR (that is, at least as long as the system's overall performance continues to yield few or no hours of scarcity conditions annually). Rather, left to its own, the market would eventually see retirements that attenuate excess supply. At some point, older generation assets suffer breakdowns that require significant capital expenditures to repair; in the face of low capacity market prices, such expenses make their continued operation no longer viable. And the timing of that force of economic Darwinism, central as it is to markets' equilibration in general, is not always prompt or predictable.

In sum, there is no clear 'silver bullet' that can serve to alleviate the present pressures causing excess supply, at least so long as the system's aggregate performance continues to produce few (or no) scarcity conditions. However, some recent and ongoing FCM enhancements will tend to help address some of these concerns. In late 2020 and early 2021, the Market Committee discussed two potential retirement-related rule reforms that, in simple terms, can reduce the FCM's administrative 'barriers to exit'. Reflecting stakeholders' priorities, the ISO plans to take up these issues in 2022-23. In addition, the ongoing effort on resource capacity accreditation reforms has the potential to significantly change the total qualified capacity of many resources in the FCM, and may therefore temper the excess supply conditions in the marketplace presently. Other insights may emerge with further stakeholder engagement, and we are interested in stakeholders' input and perspectives on this issue generally.

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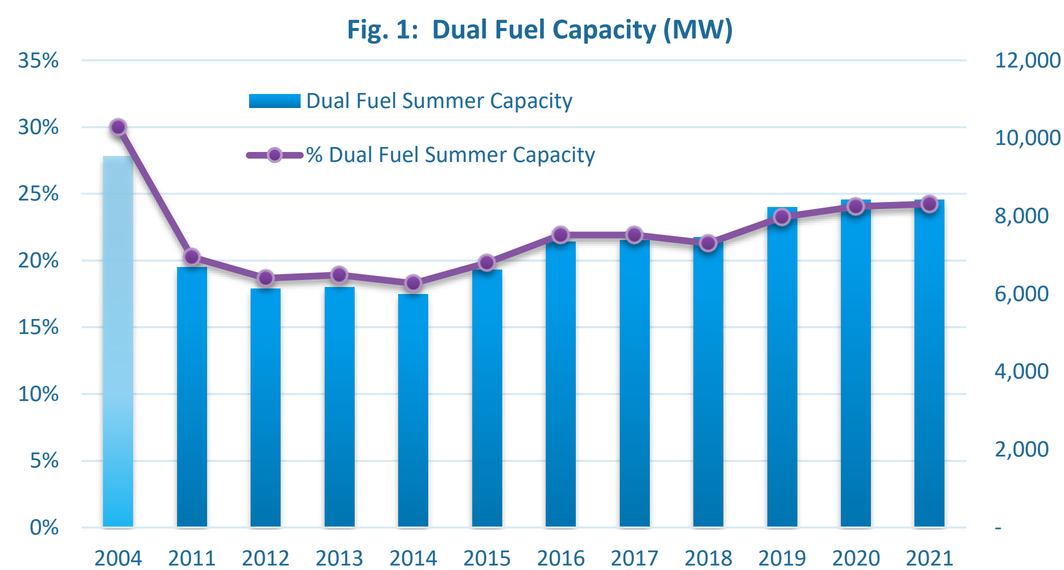
We thank stakeholders for the opportunity to reflect on the many questions and issues discussed above, to share our current thinking on same, and we look forward to stakeholders' feedback and further discussion.

Appendix

This Appendix provides the figures referenced in Section 1 of this memorandum, with additional explanatory notes. All data are sourced from ISO internal databases, excepting certain publicly-available ISO data sources where noted.

1. **Dual Fuel Capability.** Figure 1 below shows the total dual-fuel capability in the New England system, including gas/oil combined-cycle, gas/oil combustion (simple cycle) turbines, gas/oil steam, and gas/oil internal combustion units. Bar heights are in MW (right-axis); the solid line (with percents on left-axis) shows the amount of dual-fuel capability as a percent of total system CSO. These data are available in the ISO's Capacity, Energy, Load and Transmission ("CELT") reports through 2019.

   Note the 'time break' between the first bar (2004) and the second bar (2011) in reading this graph (which we have highlighted using a different color in the first bar).



   Note that there are different ways to calculate total system duel fuel capability, which can produce slightly different total MW and percentage values (depending, *e.g.,* on whether EcoMax or Seasonal Claimed Capability is used; which fuel is used to determine those capabilities; and so forth). We use the values from the CELT here because they are available using a similar methodology for years, facilitating comparisons over time.

2. **Magnitude and Frequency of Generator MW Reductions Due to Gas Issues.** Figure 2 below show the total MW and unit-count reductions in generator availability due to gas issues. MWh reduction are measured by reductions in generators' EcoMax values, summed over all hours for

which the reduction occurred. Gas issues include reductions that may be attributable to pipeline-related events (e.g. pressure issues), generator gas procurement or scheduling, or both.

Both the frequency and the magnitude of these MWh reductions exhibited periodic declines but varied rates from 2014 through 2017. There was then an large drop (by more than half) in total MWh of gas generators' reductions due to gas issues during the period of PFP's implementation (2018 to 2021).

Fig. 2: MWh and Unit Reductions Caused by Gas Issues

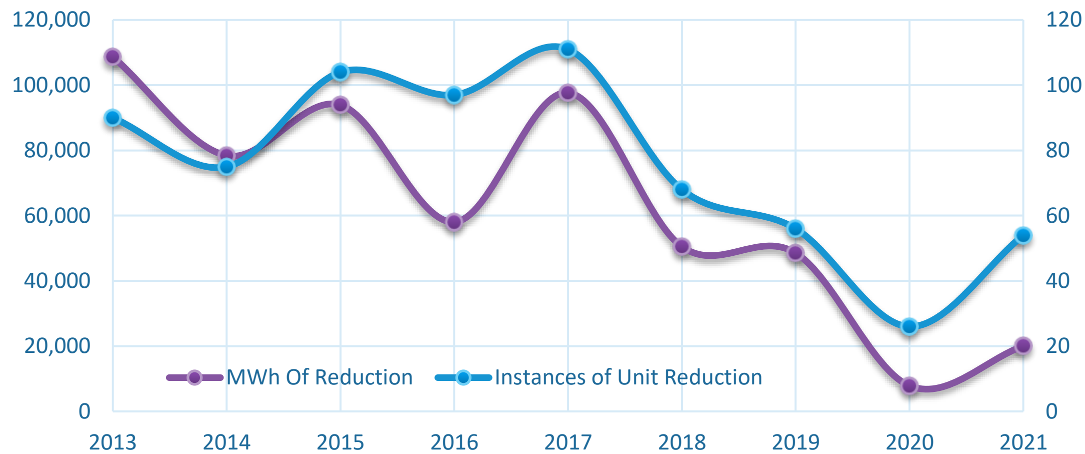
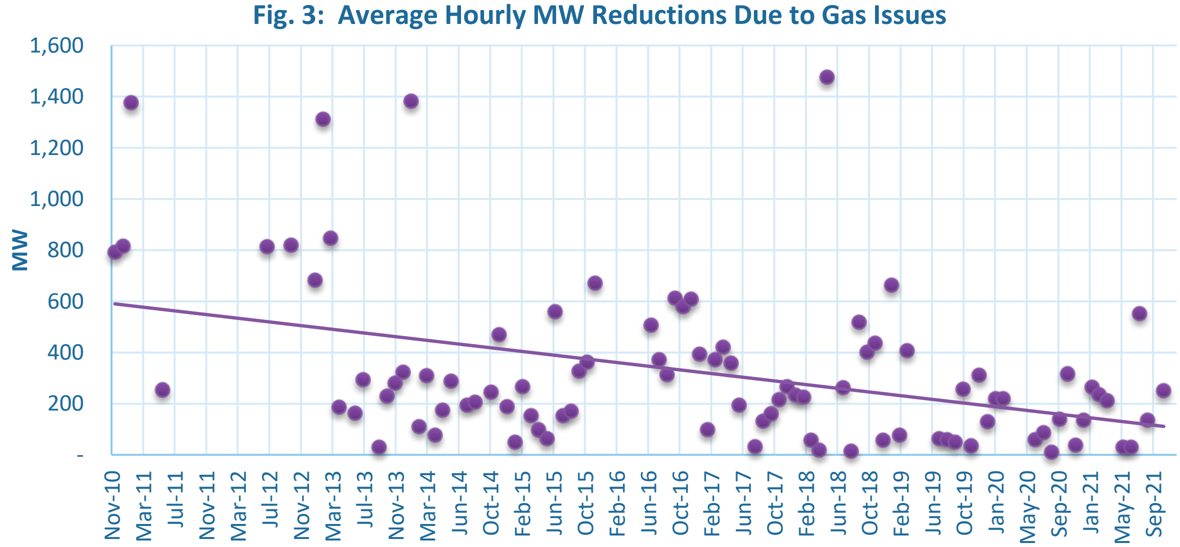


Figure 3 below shows the underlying data on MW of gas reductions at a monthly frequency. Here we report the reduction magnitudes, in average hourly MW, *during the hours in which events occurred that month.* The solid line shows the linear trend (regression line) over time. There is significant variation over time in the granular data, with an overall downward trend in the average hourly MW reductions due to gas issues over time.

Fig. 3: Average Hourly MW Reductions Due to Gas Issues



3. **Reductions in Fossil-Steam Units' Real-Time Capability on Extreme Hot/Cold Days.** For this analysis, we examined the reduction in fossil-steam units' EcoMax values in two ways: (a) on the five days with the highest peak load each year (mirroring a method used in the ISO's 2014 PFP filing); and (b) during all cold-weather days when the average temperature was less than 20°F.

   Figure 4 below shows the reductions by year for method (a), the "peak days" sample. For this analysis, we considered the five days with the highest peak load in each year from 2010 through 2021.[30] We quantified the MW by which these units reduced their EcoMax below their Capacity Supply Obligation in the peak hour of each of these days.

   Fig. 4: Ecomax Reductions During Peak-Load Days, Fossil-Steam Units

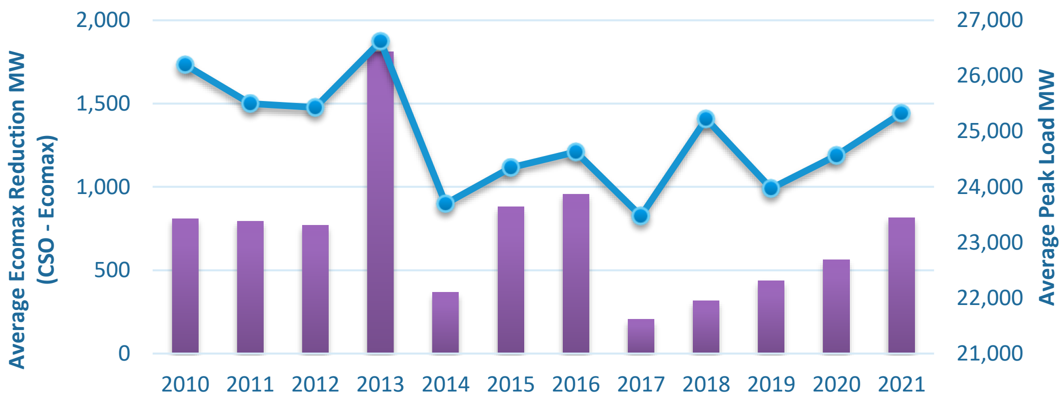
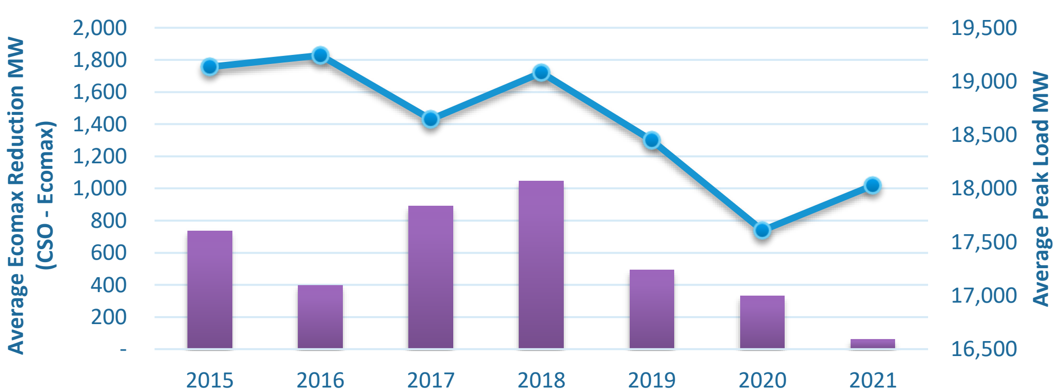


   Figure 5 below shows the reductions by year for method (b), the "low temperature days" sample. Note this method results in an unequal number of days of analysis each years. For instance, 2015 had 34 days with temperatures below the 20F degree threshold, while 2021 had only 4 days. This variation may explain the absence of any clear trend; in effect, resources are not 'equally tested' every year.

   Fig. 5: Reductions on Low-Temperature Days, Fossil-Steam Units



[30] Note that, due to a data availability issue, the data for 2014 in Figure 4 may be incomplete (*i.e.,* too low).

4. **System EFORd Rates and Generator Unavailability.** Figure 6 below reports the system average annual EFORd values (individual resource EFORd values are weighted by summer Seasonal Claimed Capability (SCC)).

Fig. 6: System Annual EFORd Rates

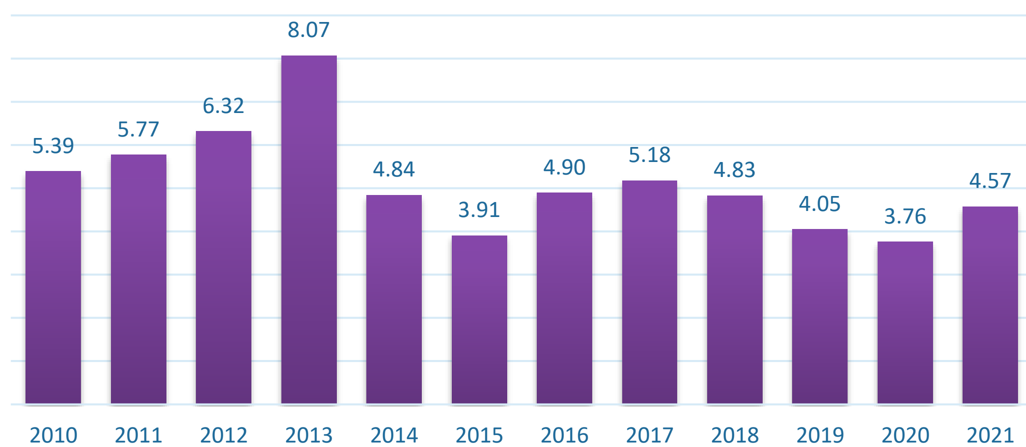
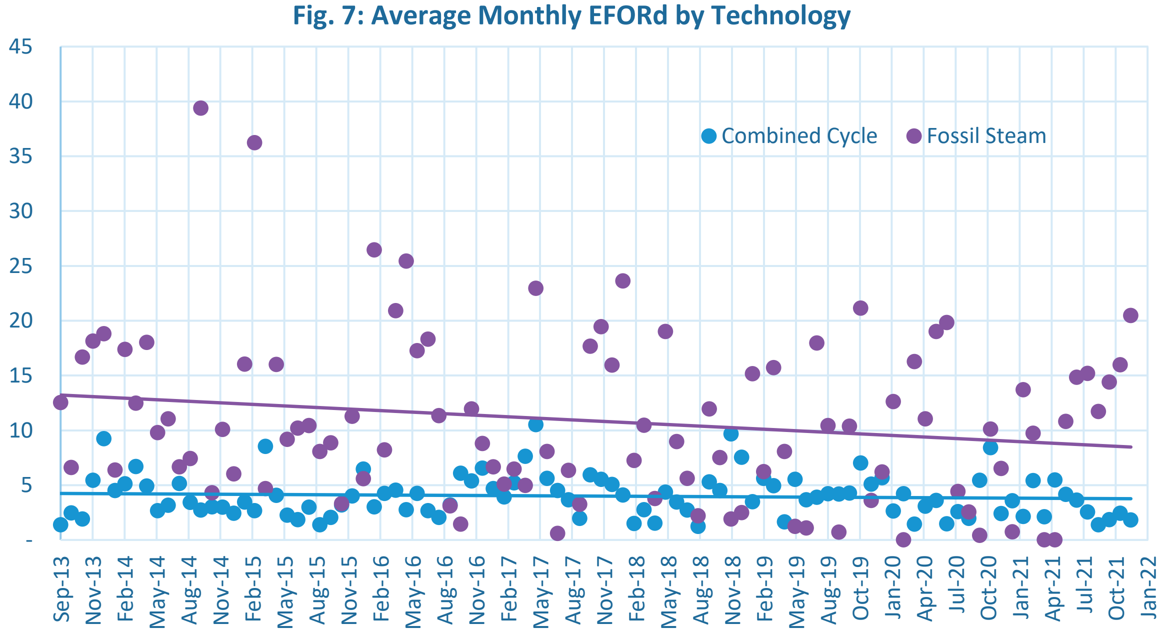


Figure 7 below shows the average monthly EFORd rates for the fossil-steam and the combined-cycle fleet over (approximately) the past ten years. The solid lines show the linear trend (regression lines) for each technology type. While there is significant variation in these data at a monthly frequency (given the random nature of forced outages), there is an overall declining trend (i.e., improved performance) for the fossil steam fleet; the combine cycle trend is flat.

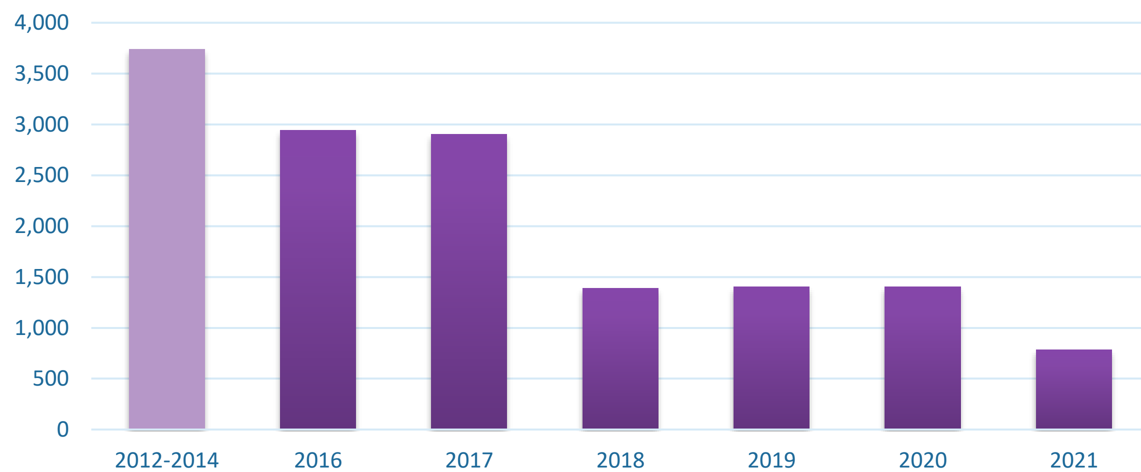
Fig. 7: Average Monthly EFORd by Technology



5. **Fossil-Steam Generator Slow- and Failed-Start Events.** Figure 8 below reports the total MW of slow-to-start or failed-to-start capacity for the fossil-steam fleet. Each bar represents the total MW (by winter SCC) of all resources in this group that had one or more failed- or slow-starts that year. Thus, for example, if a 400 MW unit had only one slow- or failed-start that year, and another similar size unit had five slow- or failed-start events in the same year, both would contribute only 400 MW to the bar height in the graph below.[31]

   Note that the sample of fossil-steam units in these data declines over time due to retirements (see main text, p. 4, 7). Note further there is a time 'break' and aggregation of years in the left-most bar (for 2012-2104); annual values a provided below for 2016 since (the aggregation for 2012-2014, and omission of 2015 data, are due to limitations on the time range presently available of the ISO's underlying source data).

Fig. 8: Slow-to-Start Or Failed-to-Start Capacity (MW), Fossil-Steam Units

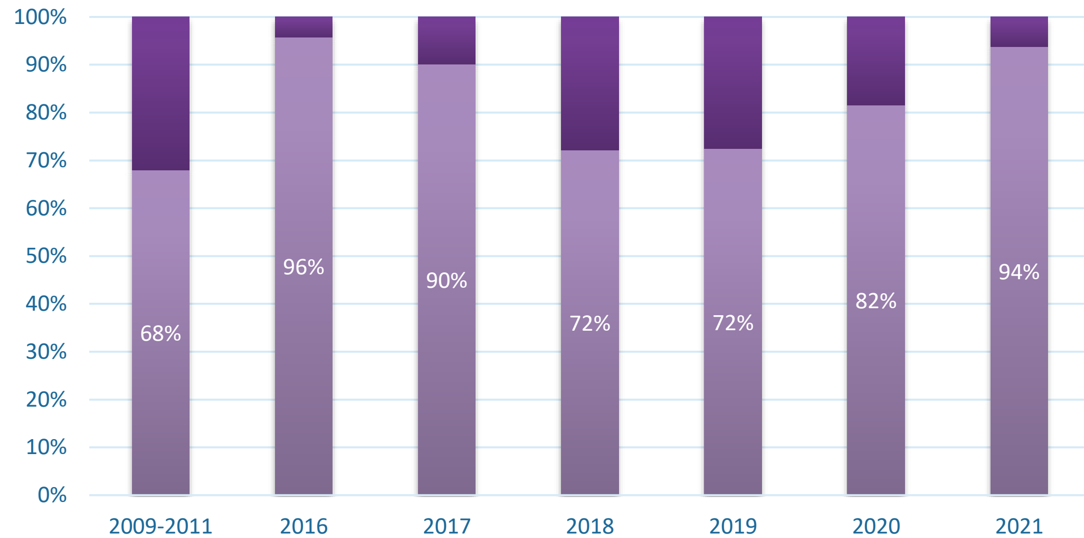


6. **Post-Contingency Offline Fast-Start Resource Performance.** In 2012, the ISO retained the Analysis Group, Inc. to perform an evaluation of the performance of unit response rates to post-contingency dispatch instructions.[32] In Figure 9 below, we show the results from applying AGI's original methodology to subsequent years data from 2016 to present. In simple terms, rate of 100% would be perfect performance of all fast-start resources within ten minutes in response to post-contingency dispatch instructions.

[31] A unit is "slow-to-start" if the unit's real-time output reaches its EcoMin *after* the hour for which it was committed and scheduled to be at EcoMin, and does so at some point *during* the period for which it was committed. A "failed-to-start" event occurs when the unit's real-time output does not reach EcoMin at any time during period for which it was committed.

[32] For a summary of AGI's original methodology and the ISO's interpretation thereof at the time, see Brandien Testimony, pp. 38 *ff*.

Fig. 9: Post-Contingency Response Rate for Offline Fast-Start Resources (AGI Methodology, Unweighted)



Note there is a time 'break' after the first bar, and an aggregation of years in the left-most bar (for 2009-2011). Annual values are provided since 2016 (the aggregation for 2009-2011, and omission of data for 2012-2014, are due to limitations on the span of time for which this information is presently available in the ISO's underlying source data).

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