Comments on "Proposed NYISO Installed Capacity Demand Curves for the 2021-2022 Capability Year and Annual Update Methodology and Inputs for the 2022-2023, 2023-2024 and 2024-2025 Capability Years"

Submitted by the New York Transmission Owners

October 9, 2020

The New York Transmission Owners ("TOs")[1] hereby submit the following comments on Proposed NYISO Installed Capacity Demand Curves for the 2021-2022 Capability Year and Annual Update Methodology and Inputs for the 2022-2023, 2023-2024 and 2024-2025 Capability Years ("ISO Staff Recommendations"), released by ISO staff on September 9, 2020. The TOs also request the opportunity to participate in oral argument regarding this issue before the ISO's Board of Directors ("Board") on October 19, 2020.

The TOs believe that the installed capacity ("ICAP") demand curves included in the ISO Staff Recommendations will provide revenue streams sufficient to ensure that capacity requirements are met.[2] In many cases, there are a range of reasonable values that ISO staff could have assumed to reflect various aspects of the net cost of developing and building new electric generating facilities. With two exceptions, we believe that the ISO Staff Recommendations strike a reasonable balance between making assumptions that are too generous, which would thereby support additional investment even when it is not needed, and assumptions that would not provide sufficient revenue to support investment when needed.[3]

For that reason, the TOs support most aspects of the ISO Staff Recommendations, and we recommend that the Board direct the ISO to file ICAP demand curves that reflect the ISO Staff Recommendations, subject to making the two changes discussed below. In the comments to follow, we will first discuss the need for those two changes. After that, we address two other aspects of the ISO Staff Recommendations

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[1] The TOs consist of Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York Power Authority, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., Power Supply Long Island, and Rochester Gas and Electric Corporation.

[2] In both ISO stakeholder deliberations and in the New York Public Service Commission proceeding on resource adequacy (Case No. 19-E-0530), major resource adequacy and capacity market modifications are under consideration. Any statements in these comments as to the adequacy of the current demand curve reset ("DCR") or potential future DCR are predicated on the current rules and design and are not intended to limit or apply to any future resource adequacy or capacity market structure which may be adopted.

[3] One important example of a conservative assumption is the length of the amortization period. ISO staff's proposed demand curves are based on a 17-year amortization period for the proxy unit (ISO Staff Recommendations at 28), not the 20-year amortization period that was used in the last DCR, and thereby implicitly assume that investors will assign no value whatsoever to the potential that such a unit may be able to continue operating using alternative fuels after the deadline imposed by the Climate Leadership and Community Protection Act ("CLCPA"), which requires that all electricity must be produced by zero-emissions resources as of January 1, 2040. While it may be difficult to quantify the value of the potential for such a unit to remain in operation after 2039, investors would probably assign **some** positive value to this potential in reality, because the opportunity to convert such a generator is effectively a financial option that can be exercised as the 2040 deadline approaches. Even options that are far out of the money may have significant financial value if their expiration date is far away. Therefore, assuming that such a unit has no value after 2039 is a conservative assumption.

that have attracted some opposition from other stakeholders and explain why we support those recommendations.

I. CHANGES TO THE ISO STAFF RECOMMENDATIONS THAT THE BOARD SHOULD DIRECT

A. The Board Should Direct the ISO to Use the TGP Zone 4 (200L) Natural Gas Price Index for a Generator in Zone C for All Months

It Was Reasonable for the ISO Staff to Recommend Using the TGP Zone 4 (200L) Natural Gas Price Index for a Generator in Zone C

The ICAP demand curve for a given capacity zone is based on estimates of the net cost that a developer would incur to construct a generating facility to meet the ICAP requirement for that capacity zone. Net energy and ancillary services ("EAS") revenues—i.e., the revenue earned from the sale of energy and ancillary services, less the variable costs incurred when providing energy and ancillary services—significantly affect the net cost that a developer would incur. Every dollar that a generator earns in net EAS revenue reduces its net cost by one dollar, as that is one less dollar it must earn in the capacity market in order to collect sufficient revenue to justify the investment. The variable cost that a natural gas-fired generator, such as the H Class frame generator that has been recommended as the proxy unit for each capacity zone, will incur in order to provide energy and ancillary services depends on the natural gas price index that is used for that generator. Consequently, incorrect selection of a natural gas price index for a given location can lead to misstated net EAS revenues, which in turn would cause the net cost of developing capacity in that location to be misstated, and that would cause the associated ICAP demand curve to be set too high or too low.

Given the importance of this issue, the ISO's consultant set forth four criteria which are used in both the current DCR and the preceding DCR to guide the selection of a natural gas price index for each capacity zone: Market Dynamics, Geography, Liquidity and Precedent/Continuity.[4] The TOs believe that the Geography criterion is the most important of these four criteria, a view that is shared by the Market Monitoring Unit ("MMU"). The ISO's consultant indicated that the Geography criterion indicates whether a pipeline has "an appropriate geographic relationship to potential peaking plant locations going forward, or otherwise ha[s] a logical nexus to prices at relevant delivery points."[5] Using a natural gas price index that does not indicate the cost that a generator would have incurred to purchase gas at its location would fail to meet the tariff's requirement that the ISO calculate "the likely projected annual Energy and Ancillary Services revenues of the peaking plant for the first Capability Year covered by the periodic review, net of the costs of producing such Energy and Ancillary Services."[6]

We acknowledge that the selection of a natural gas price index for the Zone C proxy unit is challenging, as none of the natural gas price indices considered for Zone C perfectly meets all of the selection criteria.

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[4] *See* ISO Staff Recommendations at 33-34 and Analysis Group, Inc. and Burns & McDonnell, Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/25 Capability Years—Final Report ("Consultant's Report") at 91.

[5] Consultant's Report at 91.

[6] Services Tariff, Section 5.14.1.2.2.

Dominion North and TGP Zone 4 (either 200L or Marcellus) are the only natural gas price indices considered by the ISO's consultant for Zone C that satisfied the Geography criterion,[7] so given the importance of that criterion, we believe that it is necessary to choose one of those price indices. In our view, the most efficient and appropriate price index for a Zone C peaking plant is the Dominion North natural gas price index. While a generator in Zone C might encounter difficulties from time to time in purchasing gas at the Dominion North price (plus a transportation adder), Northeast gas supply is constrained in general, so one could make a similar observation with respect to any of the other natural gas price indices considered by the consultant. The consultant originally leaned towards using the Dominion North natural gas price index, but later decided to recommend using the TGP Zone 4 (200L) natural gas price index for the Zone C proxy unit, and while the TOs believe that the Dominion North natural gas price index is the better choice, the consultant's recommendation is also reasonable.

In a memo that accompanied the ISO Staff Recommendations, the MMU reported the results of additional analysis it conducted, which confirmed the consultant's conclusions that the Dominion North and TGP Zone 4 (200L) natural gas price indices better reflected the cost that a generator in Zone C would have incurred to purchase natural gas than the other price indices considered by the consultant.[8] Fig. 1 compares the number of unit-days for which nine natural gas-fired units in Zone C actually operated during 2017, 2018 and 2019 to the number of unit-days for which those units would have operated in the MMU's backcast simulations, using either the Dominion North or TGP Zone 4 (200L) price indices (plus a transportation adder) to indicate the cost of natural gas.[9] As it shows, the backcast simulation using the Dominion North price index very closely approximated the actual operation of these units: while they actually operated for 4,552 unit-days, they operated for 4,621 unit-days in the backcast simulation that used the Dominion North price index. While it did not match actual operation as well as the Dominion North backcast simulation, the backcast simulation using the TGP Zone 4 (200L) price index also corresponded reasonably well to actual operations, as these units ran for 3,802 unit-days in the backcast simulation that used the TGP Zone 4 (200L) price index.

[7] Consultant's Report at 96, Table 43.

[8] See David Patton and Pallas LeeVanSchaick, MMU Comments on Independent Consultant Interim Final Draft ICAP Demand Curve Reset Report and NYISO Staff DCR Draft Recommendations (Sept. 3, 2020) ("MMU Comments") at 14-15.

[9] The data used in Figs. 1, 2 and 3 were obtained from the MMU, and are the same data that the MMU used in the lower portion of Fig. 3 in the MMU Comments.

Fig. 1: Historical vs. Backcast Operation for Zone C Gas-Fired Plants, Using Dominion North and TGP Zone 4 (200L) Price Indices for Backcast Simulations

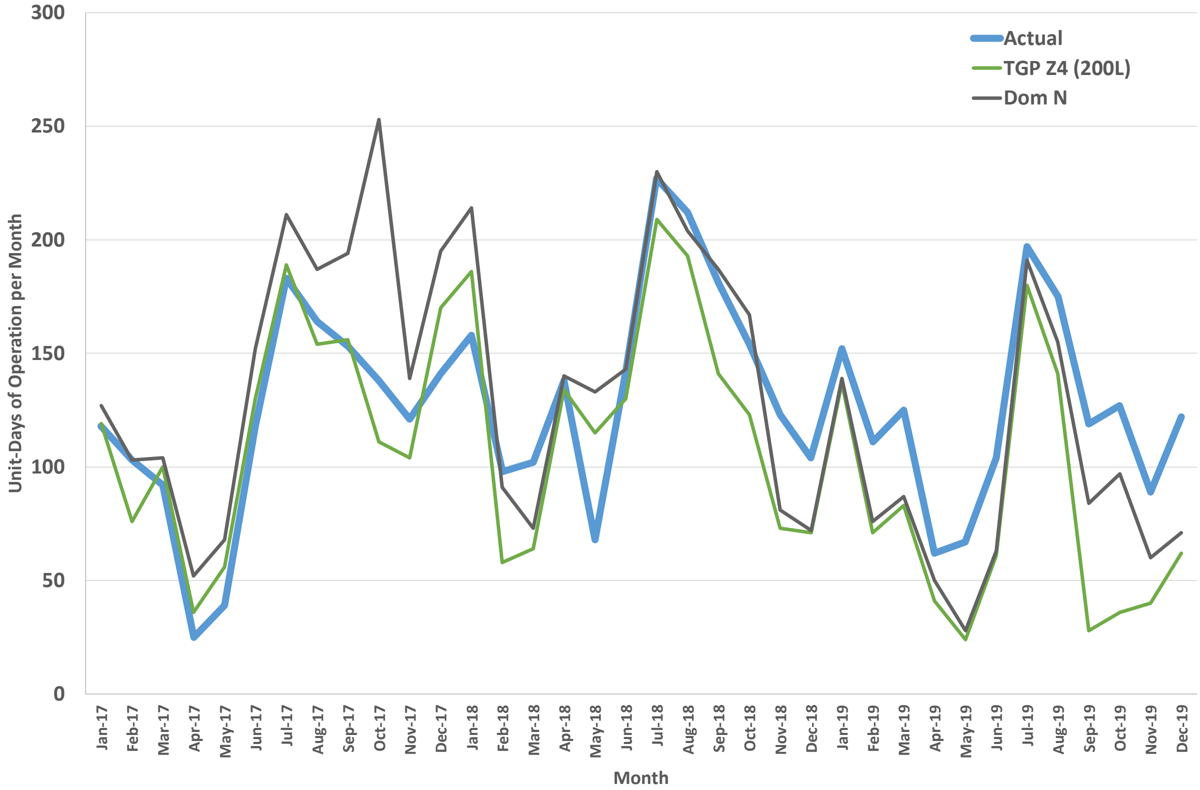
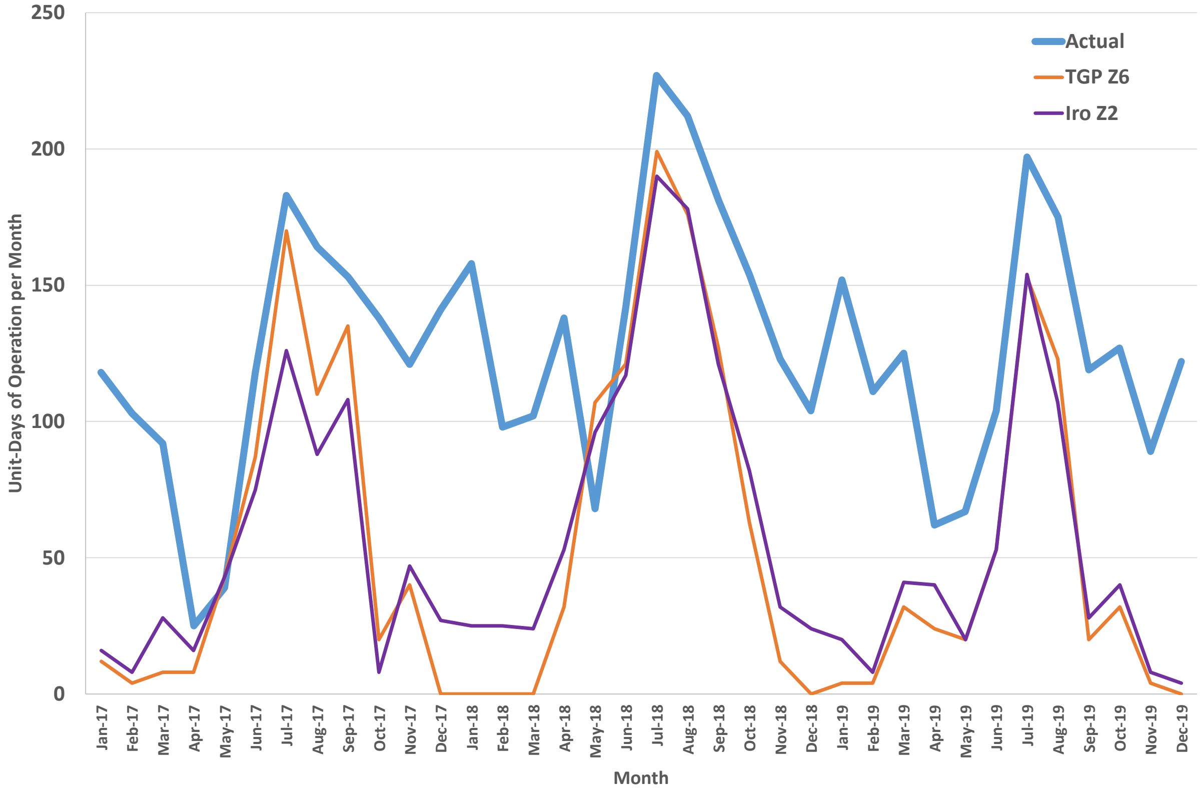


Fig. 2 compares the number of unit-days for these natural gas-fired units in Zone C actually operated during 2017, 2018 and 2019 to the number of unit-days for which those units would have operated in the MMU's backcast simulations, using either the TGP Zone 6 or Iroquois Zone 2 price indices (plus a transportation adder) to indicate the cost of natural gas. As it shows, the backcast simulation using either of these natural gas indices did not closely reflect the actual operation of these units: they operated for only 1,943 unit-days in the backcast simulation that used the TGP Zone 6 price index and for only 2,080 unit-days in the backcast simulation that used the Iroquois Zone 2 price index, each of which is less than half of the 4,552 unit-days for which those units actually operated. The largest differences are in the winter. In reality, these units often operated during the winter, but they would have only rarely operated during the winter in the backcast simulations using either the TGP Zone 6 or Iroquois Zone 2 natural gas price indices. Therefore, using the TGP Zone 6 or Iroquois Zone 2 natural gas price indices would have caused net EAS revenue to be understated significantly and would misrepresent the natural gas price paid by the Zone C proxy unit.

Fig. 2: Historical vs. Backcast Operation for Zone C Gas-Fired Plants, Using TGP Zone 6 and Iroquois Zone 2 Price Indices for Backcast Simulations



It Was Not Reasonable for ISO Staff to Recommend Using the Niagara Natural Gas Price Index for a Generator in Zone C During the Months of December through March

The MMU then went on to propose that the ISO should use prices at the Niagara natural gas hub for the months of December through March, while using the TGP Zone 4 (200L) natural gas price index for only the eight remaining months of the year.[10] It is difficult to understand the basis for this MMU recommendation. Inexplicably, even though the MMU recommended its use, the MMU did not include the Niagara natural gas price index in its backcast simulations, which were intended to assess whether each of the proposed natural gas price indices reasonably reflected the actual natural gas costs for generators in Zone C. But we can infer something about the results of such a simulation by comparing the number of unit-days that the nine Zone C natural gas-fired units actually operated to the number of unit-days during which those units would have operated in the backcast simulation using the TGP Zone 4 (200L) price during only the months of January, February, March, and December—i.e., the months for which the MMU recommended that the ISO use the Niagara natural gas price index instead of the TGP Zone 4 (200L) natural gas price index. Fig. 3 presents that comparison. As it shows:

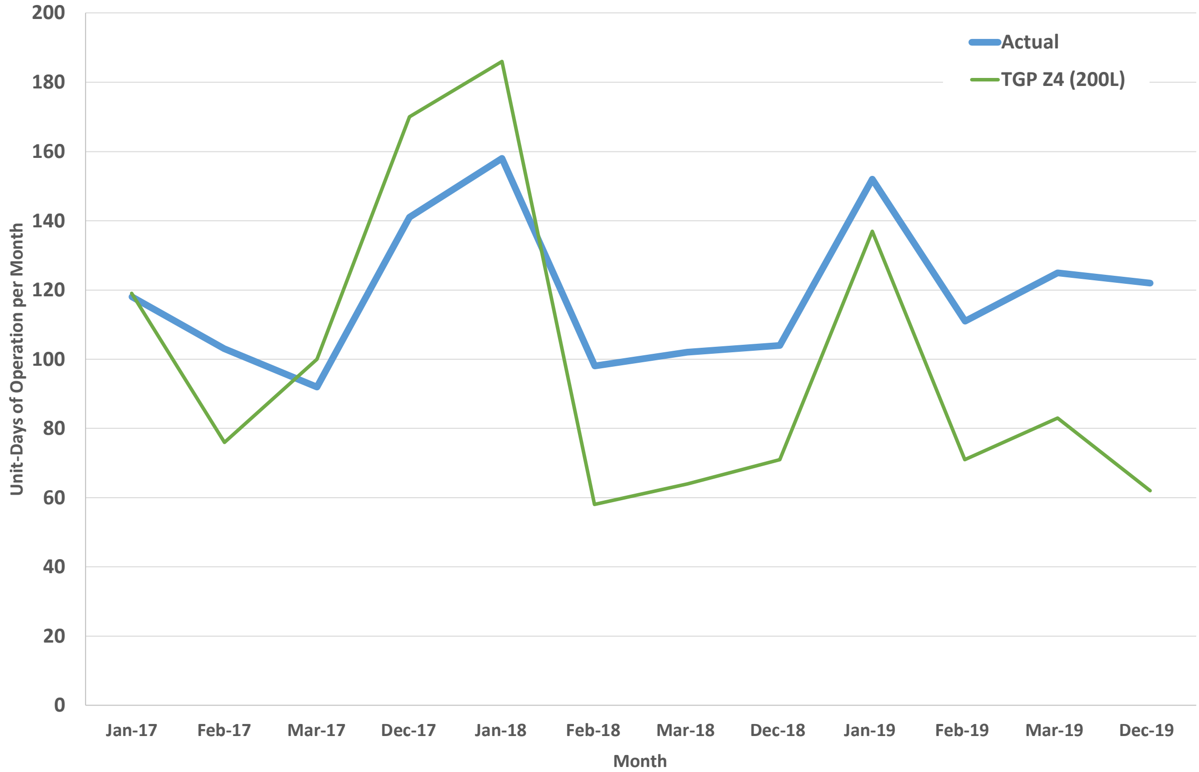
- In one month (January 2017), those Zone C natural gas-fired units actually operated for approximately the same number of unit-days as in the TGP Zone 4 (200L) backcast simulation.

[10] MMU Comments at 19.

- In three months (March 2017, December 2017 and January 2018), those Zone C natural gas-fired units actually operated for fewer unit-days than in the TGP Zone 4 (200L) backcast simulation.

- In the remaining eight months (February 2017; February, March and December 2018; and January, February, March and December 2019), those Zone C natural gas-fired units actually operated for more unit-days than in the TGP Zone 4 (200L) backcast simulation.

Fig. 3: Historical vs. Backcast Operation for Zone C Gas-Fired Plants in Dec. through March, Using TGP Zone 4 (200L) Price Index for Backcast Simulation



In total, the Zone C natural gas-fired generators actually operated for 1,426 unit-days, compared to 1,197 unit-days in the MMU's TGP Zone 4 (200L) backcast simulation.[11] Because the Niagara natural gas price index is usually higher than the TGP Zone 4 (200L) natural gas price index during the four winter months of December through March,[12] a backcast simulation based on the higher priced Niagara natural gas price index would result in a **decrease** in the number of unit-days that the Zone C natural gas-fired generators

[11] These Zone C generators would have operated for 1,352 unit-days in the MMU's backcast simulation using the Dominion North natural gas price index. So once again, the Dominion North natural gas price index more closely corresponded to the actual Zone C generators' output than did the TGP Zone 4 (200L) natural gas price index in the backcast simulation.

[12] The MMU states that using the Niagara natural gas price index, instead of the TGP Zone 4 (200L) natural gas price index, for December through March would reduce net EAS revenue for the Zone C proxy unit by $4.30/kW-yr. *Id.* at 17. It follows that the Niagara natural gas price index generally must be higher priced than the TGP Zone 4 (200L) natural gas price index in hours when the Zone C proxy unit operated.

ran when compared to the MMU's TGP Zone 4 (200L) backcast simulation. Consequently, using the Niagara natural gas price index during the four winter months of December through March would **increase** the divergence between the number of unit-days that the Zone C natural gas-fired generators actually operated and the number of unit-days these generators would have operated in the backcast simulation. Therefore, the MMU's backcast simulation approach shows that it is inappropriate to use the Niagara natural gas price index, instead of the TGP Zone 4 (200L) natural gas price index, to estimate the natural gas fuel cost for Zone C generators during the four winter months of December through March.

Another concern with the Niagara natural gas price index is the lack of liquidity at the Niagara gas hub. Liquidity, as noted above, is one of the consultant's four criteria for selecting the appropriate natural gas price index. As the MMU stated, "The Niagara gas index is limited for its lack of liquidity. Niagara lacks significant trade volume on many days used to estimate net [EAS] revenues."[13] For this reason, the MMU suggested using the Dawn Ontario price index, "either for all days when Niagara would be used or on days when Niagara lacks trade volume."[14] While this issue was not addressed in the ISO Staff Recommendations, the TOs' understanding is that ISO staff used the Niagara natural gas price index, and only the Niagara natural gas price index, when it calculated net EAS revenue for the months of December through March that was used to set the proposed ICAP demand curve for the New York Control Area ("NYCA") for the 2021-22 capability year, and the ISO plans to continue to use the Niagara natural gas price index for those months when it updates net EAS revenues in the course of determining the ICAP demand curves for the NYCA for the following three capability years.

However, Platts has informed the TOs that on 37 instances over the last three winters (i.e., about ten percent of the time), Platts did not publish a price for the Niagara natural gas price index, whereas Platts publishes a price for the Dominion North and TGP Zone 4 (200L) natural gas price indices for almost every trading session. That calls into question whether the Niagara natural gas price index is sufficiently reliable for use in the DCR, particularly since ISO staff accepted its consultant's recommendation **not** to use the Millennium natural gas price index for a proxy unit in Zone G because the Millennium gas hub "lacks historic trading volume, which raises concerns in regards to liquidity."[15] Liquidity at a given gas hub can be measured either by the "deal count" at that gas hub, or the total volume of natural gas traded at that gas hub. Fig. 4 consists of a scatter diagram, which shows the deal count and total volume traded at the Dominion North, TGP Zone 4 (200L), Niagara and Millennium gas hubs for each day during the months of December through March (i.e., the months for which ISO staff proposes to use the Niagara natural gas price index) over the last three years.[16] As it clearly shows, the Niagara gas hub is much less liquid than either the Dominion North gas hub or the TGP Zone 4 (200L) gas hub, whether measured by deal count or by average volume traded. Liquidity at the Niagara gas hub during those months is similar to (although slightly worse than) the liquidity at the Millennium gas hub.[17] Consequently, the TOs do not

[13] *Id.*

[14] *Id.*

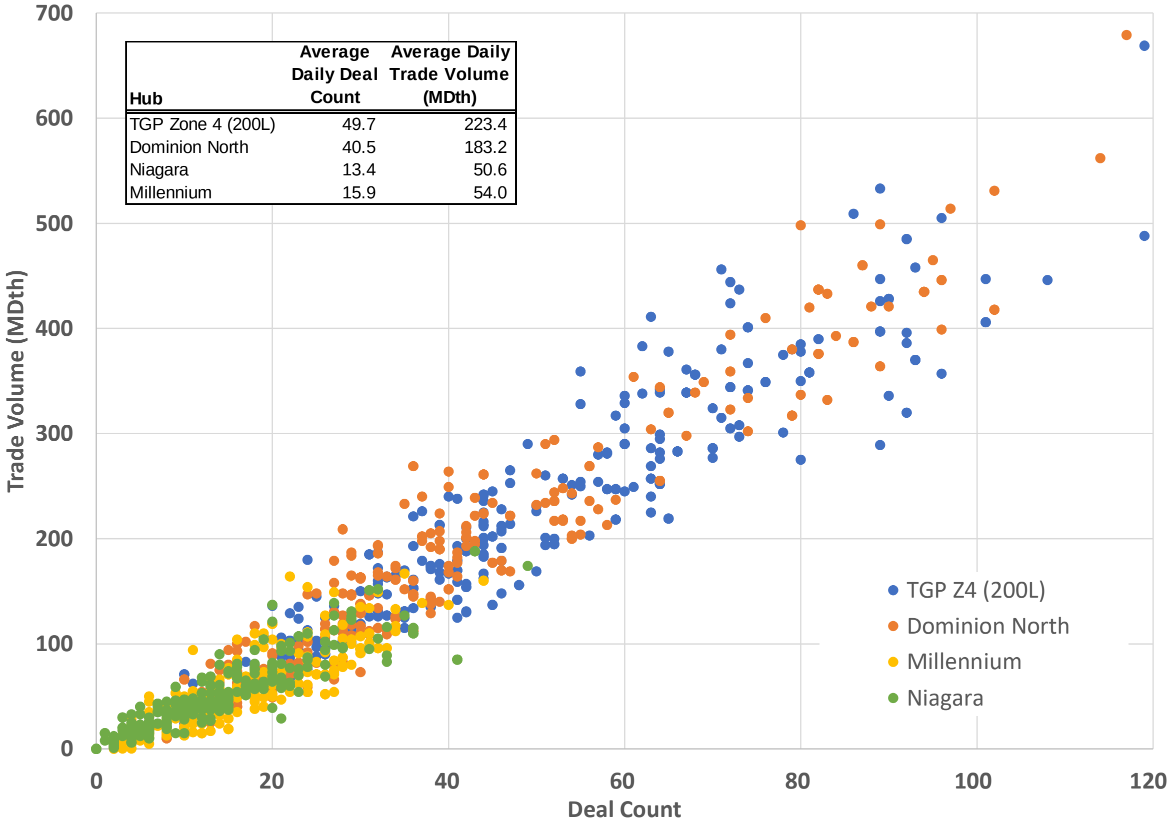
[15] ISO Staff Recommendations at 35.

[16] This is the same three-year period that ISO staff and its consultant used to calculate net EAS revenue.

[17] ISO staff's and its consultant's conclusions regarding liquidity at the Millennium gas hub were based on data covering all twelve months of the year, not just four months. When calculated over all twelve months, the average daily deal count at the Millennium gas hub increases to 19.1, and the average daily trade volume increases to 69.0

understand how ISO staff reached the conclusion that it is reasonable to use the Niagara natural gas price index for Zone C during the winter months despite the lack of liquidity due to inadequate trading volume, after having previously concluded that lack of liquidity due to inadequate trading volume was sufficient reason to disqualify the Millennium natural gas price index, even though liquidity at the Millennium gas hub is better than liquidity at the Niagara gas hub. If the ISO is concerned that prices at the Millennium gas hub are not reliable enough for use in the DCR, or that it needed to use a natural gas price index that is more likely to be available than the Millennium natural gas price index, the ISO should be even more concerned about the reliability and availability of the prices at the Niagara gas hub.

Fig. 4: Deal Count and Trade Volumes at Various Gas Hubs During December through March



The TOs would have raised these arguments in the stakeholder process during the ISO Installed Capacity Working Group ("ICAPWG") meetings, but stakeholders were not afforded an opportunity to do so before ISO staff released its final recommendations. The ISO's consultant originally broached the issue of which natural gas price index to use for the proxy units in Zone C (as well as other locations) during the November 6, 2019 ICAPWG meeting. The consultant also addressed the issue in presentations made at the January 30, 2020, February 25, 2020, and March 26, 2020 ICAPWG meetings. In its April 22, 2020 presentation, the consultant preliminarily recommended the use of the Dominion North natural gas price index for the Zone C proxy unit, while noting that this recommendation was "subject to ongoing

MDth, both of which considerably exceed the average daily deal count and the average daily trade volume at the Niagara gas hub during December through March.

evaluation." The consultant returned to the subject at the May 19, 2020 and June 10, 2020 ICAPWG meetings; at the latter, the consultant changed its recommendation for the Zone C proxy unit from using the Dominion North natural gas price index to using the TGP Zone 4 (200L) natural gas price index. At the July 22, 2020 ICAPWG meeting, for the eighth and final time, the consultant addressed the natural gas price indices issue in response to stakeholders' comments on their draft DCR report. During most of this time period, the MMU was also evaluating which natural gas price index to use at each of the generator locations that the consultant was considering. In February 2020, the MMU made recommendations for the other locations while indicating that it was "still evaluating what [natural gas price index] to recommend"[18] for a Zone C generator. Despite this, stakeholders did not learn of the MMU's proposal to use the Niagara (or perhaps the Dawn) natural gas price index in MMU's comments that were posted to the ISO's website until August 25, 2020, which was the day **after** the deadline for stakeholders to submit their comments on the draft version of the ISO Staff Recommendations, and six months after the MMU indicated that it was "still evaluating" the issue.

Accepting this recommendation at this point would make a mockery of the stakeholder process, and would establish a dangerous precedent going forward. The stakeholder process is intended to ensure that stakeholders have an opportunity to review and respond to proposals for conducting the DCR. In this case, stakeholders were given no such opportunity, as the proposal was not released until after the deadline for stakeholders to submit their comments on the draft version of the ISO Staff Recommendations. The TOs recognize that, from time to time, it may be necessary to make changes to correct problems that were identified at the last minute. For that reason, the TOs are not contesting ISO staff's decision to correct an error that caused natural gas prices to be assigned to the wrong days,[19] even though that issue was also first identified at the deadline for submitting comments on the draft version of the ISO Staff Recommendations,[20] and even though correcting that error will cause increases in the monthly reference price ("MRP") (which is the price on the demand curve for a capacity zone when the amount of ICAP supplied is equal to the ICAP requirement for that capacity zone), ranging from $0.37/kW-mo. to $0.61/kW-mo. for downstate locations.[21] While that issue also was not discussed during any stakeholder meetings, it was a clear error, so there is little that stakeholders could have added in reviewing that issue and it was reasonable for ISO staff to correct the mistake.

This case is different, because it is far from clear that the Niagara natural gas price index should be used in lieu of the TGP Zone 4 (200L) natural gas price index for the Zone C proxy unit during December through March. Accepting this recommendation at this stage of the DCR process will encourage the MMU, as well as other stakeholders, to circumvent the stakeholder process in future DCRs by submitting their proposals at the last minute. Considering the lateness of the MMU proposal, the inability of the ISO to give stakeholders an opportunity to respond to this MMU proposal at an ICAPWG meeting as a result

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[18] Potomac Economics, LLC, Comments regarding the gas pricing hubs used in the net revenue analysis for the 2020 Demand Curve Reset (Feb. 26, 2020) at 2.

[19] *Id.* at 32-33 and App. B.

[20] TigerGenCo, LLC, Comments on Proposed Installed Capacity Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years—NYISO Staff Draft Recommendation (Aug. 24, 2020).

[21] Zach T. Smith, 2021-2025 ICAP Demand Curve Reset: NYISO Staff Final Recommendations (Sept. 22, 2020) at 8.

of that lateness, and the evidence offered here to indicate that there is significant doubt as to whether this MMU proposal is justified, the Board should direct ISO staff to revise its recommendation and use either the TGP Zone 4 (200L) natural gas price index or, preferably, the Dominion North natural gas price index for the Zone C proxy unit for all twelve months of the year.

B. The Board Should Direct the ISO to Remove Its Assumption that the Dutchess County Proxy Unit in Zone G Would Use Selective Catalytic Reduction

The ISO Staff Recommendations also assume that the cost of building an H Class frame generator in Dutchess County (which is located in Zone G) would include the cost of selective catalytic reduction ("SCR"). The Board should direct ISO staff to revise its recommendations and assume that an H Class frame generator in Dutchess County would not use SCR, because the assumption to include SCR cost in the Dutchess County proxy unit is unsupported, speculative, and inconsistent with the approach taken in other aspects of the DCR (i.e., setting the amortization period to be 17 years), which would leave the ISO vulnerable to challenges at the FERC level arising from that inconsistency.

There are two reasons why a generator might elect to use SCR. First, it might be required to do so. Second, it might be in its financial interest to do so. We will address those arguments in turn.[22]

The Proxy Unit, if Built in Dutchess County, Would Not Be Required to Use SCR, so There Is No Reason Why the ISO Should Require the ICAP Demand Curve to Reflect this SCR Cost for Building a Generator in a Location Where SCR is NOT Required

The TOs are not contesting ISO staff's recommendation that the proxy units in New York City or Long Island, have SCR. Nor are the TOs contesting this recommendation with respect to the Rockland County proxy unit in Zone G. New York City, Long Island, and Rockland County are all located inside the severe ozone non-attainment area, and are therefore subject to stringent emissions requirements. But Dutchess County, although it is also in Zone G, is outside the severe ozone non-attainment area. Therefore, generating units built in Dutchess County are subject to less stringent emissions requirements, which makes it feasible to develop units without SCR in Dutchess County, whereas it would not be feasible to do so in Rockland County. Indeed, the ISO Staff Recommendations addressed this issue, noting that outside the severe ozone non-attainment area, the proxy unit would be permitted to operate for at least 300 hours per year, depending on how often it must operate on ultra-low sulfur diesel fuel.[23] While ISO staff concluded from this that "reliance on a 'synthetic minor source' approach for a dual-fuel plant design in Load Zone G (Dutchess County) is … not practical for a resource needed to maintain reliability,"[24] it is not clear why ISO Staff reached that conclusion. A unit that can operate for at least 300 hours per year can run for six hours a day on the 50 highest-load days of the year. And as ISO staff noted, such a unit might in fact be able to run for more than 300 hours per year.

The ISO's consultant also claimed that "the installation of SCR emissions control could mitigate potential permitting and siting risk associated with building a new dual fuel unit in the lower Hudson Valley …

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[22] These are largely the same arguments that we made in our comments on the draft version of the ISO Staff Recommendations. While the final version of the ISO Staff Recommendations addressed most of the comments that stakeholders made on those recommendations, it did not address the TOs' comments.

[23] ISO Staff Recommendations at 14-15.

[24] *Id.* at 15 (footnote omitted).

without back-end emissions control technology. Within this context, a potentially relevant consideration is that the lower Hudson Valley also contains severe non-attainment areas and that selecting a plant without SCR emissions controls would not accommodate potential new plants throughout the region."[25] First, assuming that it would be necessary for generating units in Dutchess County to conform to emissions requirements that do not actually apply to Dutchess County would be speculative and inconsistent with the approach taken in other aspects of the DCR, which intends to limit the extent to which the ISO relies on unverifiable assumptions.[26] Second, as shown by Fig. 5 (which shows the relevant portion of the severe ozone non-attainment zones) and Fig. 6 (which shows the six counties located in Zone G), ,Rockland County is the only county in Zone G that is inside the severe ozone non-attainment zone. Dutchess County and the other counties in Zone G (Greene County, Ulster County, Orange County, and Putnam County) are all outside of the severe ozone non-attainment area, so selecting a plant without SCR would accommodate a generator in any of those counties.

Fig. 5: Map of Ozone Non-Attainment Zones

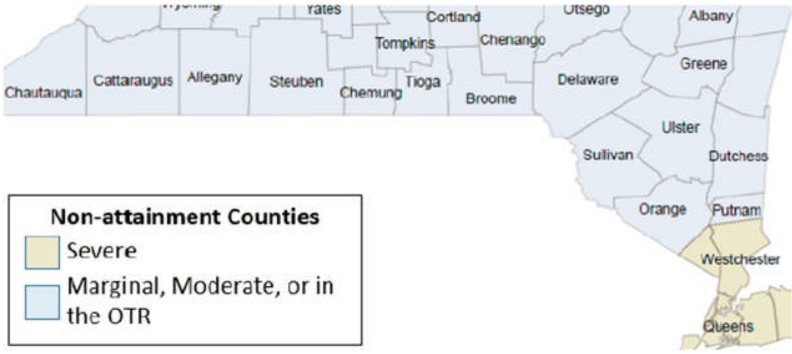
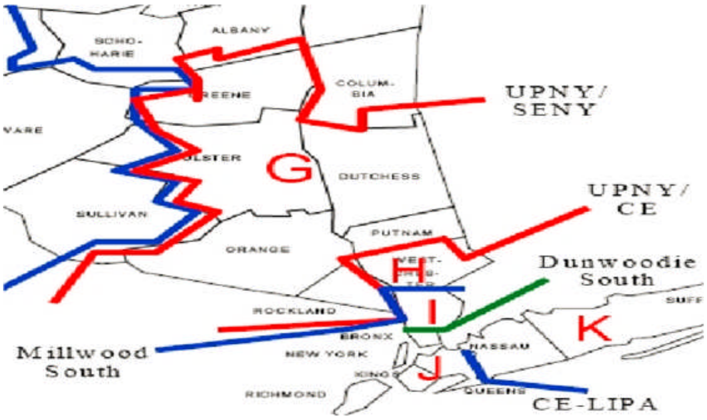


Fig. 6: Map of Load Zones in Southeastern New York



[25] Consultant's Report at 30.

[26] For example, ISO staff's recommendation in this DCR to limit the amortization period to 17 years reflects its judgment that it would be speculative to assume that the proxy unit would be able to remain in operation after 2039. *See* ISO Staff Recommendations at 28. More broadly, the current approach to calculating net EAS revenue using historical data was initially proposed because the previous procedure, which was based on forecasts of future prices, "often [gave] rise to controversy and significant divergence of opinions." *N.Y. Indep. Sys. Operator, Inc.*, Proposed Services Tariff Revisions to Implement Enhancements to the Periodic review of the ICAP Demand Curves, Docket No. ER16-1751-000 (May 20, 2016) at 6.

Moreover, there is no reason to set the demand curve in a manner that would support the development of a generator at every location within a given capacity zone. Given the difference between emissions requirements in Rockland County and the emissions requirements that apply to all counties in Zone G other than Rockland County, it will be less expensive, all other things held equal, to build a generator in one of those other Zone G counties than to build a generator in Rockland County. If that cost advantage is large enough to outweigh any other revenue or cost differences that might result from building in Rockland County, then one would expect that generation developers would build outside Rockland County, because it would be more profitable. There would be no need to set the demand curve in a manner that would support development inside the severe ozone non-attainment zone, because that is not where generation developers would choose to locate and build new units. In other words, if it is cost-prohibitive to build in a given location—due to environmental regulations or for whatever other reason—then the ICAP demand curve does not need to support development in that location.

It is Unlikely that a Developer of the Proxy Unit in Dutchess County Would Find It to be in Its Financial Interest to Use SCR

The other argument supporting the use of SCR is that it might be in financial interest of the generation developer for it to install SCR, even if emissions requirements do not require the installation of SCR. The consultant's analysis indicates, however, that while including SCR would have permitted an increase in net EAS revenue over the three-year historical period that the ISO uses to set the ICAP demand curve for the 2021-22 capability year, that increase would have been only $0.17/kW-yr.[27] This $0.17/kW-yr. impact in increased net EAS revenue is dwarfed by the upfront cost of installing SCR, which increased the gross cost of constructing the Zone G proxy unit in Dutchess County by $11.39/kW-yr.[28] Now, it is certainly possible that the benefits from installing SCR could increase over time. As the ISO's consultant noted, "SCR emission controls provide[] optionality to operate above the synthetic minor operating limit, which could be financially valuable in the future. Our three-year analysis does not fully capture value of this optionality."[29] However, over the last three years, the increase in net EAS revenue due to having SCR installed is less than one sixtieth (1/60th) of the upfront cost of installing SCR. Therefore, an enormous increase in future net EAS revenue due to having SCR installed would be necessary to financially justify the upfront cost of installing SCR for the proxy unit in Dutchess County. Extraordinary claims require extraordinary proof, but in this case, the consultant did not conduct any analysis that demonstrated, or even purported to demonstrate, that the increase in future net EAS revenue due to having SCR installed would grow by the amount needed to make an upfront investment in SCR profitable for the generation developer.

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[27] Cells X87 and X38 in the "Multiple Scenario Output" tab of the consultant's demand curve model show, respectively, that net EAS revenue for the H class frame generator in Dutchess County without SCR was $27.79/kW-yr., while net EAS revenue for the same generator in the same location with SCR was $27.96/kW-yr. (*See also* ISO Staff Recommendations at 52, Table 18.)

[28] Cells AF87 and AF38 in the "Multiple Scenario Output" tab of the consultant's demand curve model show, respectively, that $133.93/kW-yr. would be required to recover the cost of building the H class frame generator in Dutchess County without SCR, while $145.32/kW-yr. would be required to recover the cost of building the same generator in the same location with SCR. (*See also* ISO Staff Recommendations at 52, Table 18.)

[29] Consultant's Report at 30.

The consultant did speculate, "Future net EAS revenues may be greater than net revenues in the historical years evaluated given the potential increases in demand for operation from the peaking plant from increased levels of renewables and potential retirements of gas turbines downstate due to the NYDEC 'peaker rule.'"[30] But this forecast does not account for the impact of energy storage resources ("ESRs") that will be added over the next several years in order to meet the CLCPA mandate, or the impact of the T027 and T019 Public Policy Transmission projects, which are planned to go into service by December 2023 and which will increase the UPNY-SENY electric transmission interface limit by at least 900 MW, thereby increasing the electric energy import capability into Zone G.[31] In the TOs' view, it is more likely that the ISO will dispatch ESRs and rely on the additional electric energy import capability into Zone G than that the ISO would significantly increase the amount of electric energy that an H Class frame generator in Dutchess County would be asked to generate. Consequently, it is highly unlikely that the generation developer would risk incurring the upfront cost of installing SCR for the Zone G proxy unit in Dutchess County, because it is unlikely thatfuture net EAS revenue would increase by over an order of magnitude, compared to the historical years evaluated, as would be necessary to financially justify the upfront SCR investment cost.

Failing to Make This Change Will Unnecessarily Increase the ICAP Demand Curve for the G-J Locality

Finally, it is important to note that the MRP for an H class frame generator in Dutchess County without SCR is $13.33/kW-mo.,[32] while the MRP for an H class frame generator in Rockland County with SCR is $14.57/kW-mo.,[33] which is $1.24/kW-mo. higher. Therefore, assuming that a generator would install SCR even if it is located in Dutchess County, despite the absence of any regulatory requirement for it to do so and despite the lack of evidence of a compelling economic reason why it might elect to do so, will unnecessarily increase the MRP for the G-J demand curve by $1.24/kW-mo. This could produce an increase in capacity costs borne by customers of about $40 million per year at the level of excess supply conditions assumed by the ISO and its consultant when developing the proposed ICAP demand curves.

Consequently, the Board should direct ISO staff to remove the unjustified assumption to include the SCR cost for the H class frame generator built in Dutchess County. If, after doing so, an H class frame generator in Dutchess County without SCR continues to yield a lower MRP than would result from the use of an H class frame generator in Rockland County with SCR, then the demand curve that the ISO files for the G-J Locality should reflect the amount of capacity revenue that would be required to support development of an H class frame generator in Dutchess County without SCR.

[30] *Id.*

[31] NYISO Board of Directors' Decision on Approval of AC Transmission Public Policy Transmission Planning Report and Selection of Public Policy Transmission Projects (April 8, 2019) at 1-2.

[32] See cell AJ87 in the "Multiple Scenario Output" tab of the consultant's demand curve model.

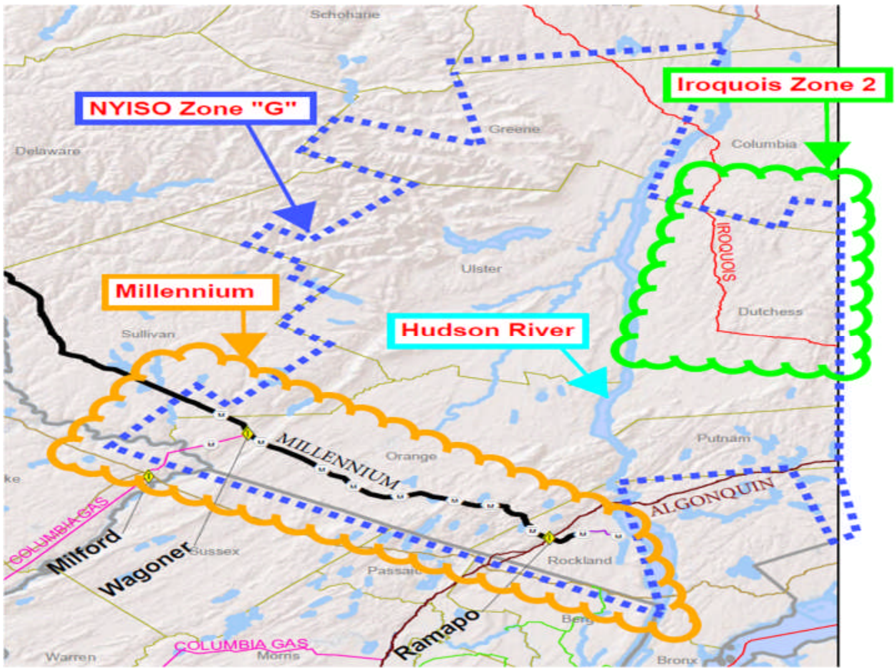
[33] See cell AJ38 in the "Multiple Scenario Output" tab of the consultant's demand curve model, or ISO Staff Recommendations at 52, Table 18.

II. Selected Aspects of the ISO Staff Recommendations

A. *The TETCO M3 Natural Gas Price Index is the Most Reasonable Natural Gas Price Index for a Generator in Rockland County (Zone G)*

As Fig. 7 shows, Zone G is bisected by the Hudson River. Marcellus shale natural gas is more directly available on the west side of the Hudson River than on the east side of the Hudson River. This causes the natural gas price on the west side of the Hudson River (where Rockland County is located) to be lower than the natural gas prices on the east side of the Hudson River (where Dutchess County is located). For this reason, it is important to select natural gas price indices for generators in Rockland County and in Dutchess County that reasonably reflect the price of natural gas in each location. Based on our discussions with natural gas sellers, we conclude that the natural gas price indices that ISO Staff adopted for Rockland County and for Dutchess County (TETCO M3 natural gas price index for the former and Iroquois Zone 2 natural gas price index for the latter[34]) reasonably and fairly represent the cost of natural gas purchased at these locations.

Fig. 7: Map of Natural Gas Pipelines in Zone G



While the selection of Iroquois Zone 2 natural gas price index has not been controversial, some generators have lodged complaints against the selection of the TETCO M3 natural gas price index for a Rockland County generator, suggesting that natural gas pipeline capacity is not available to transport the natural gas to Rockland County. As we pointed out in comments that we submitted on draft recommendations issued

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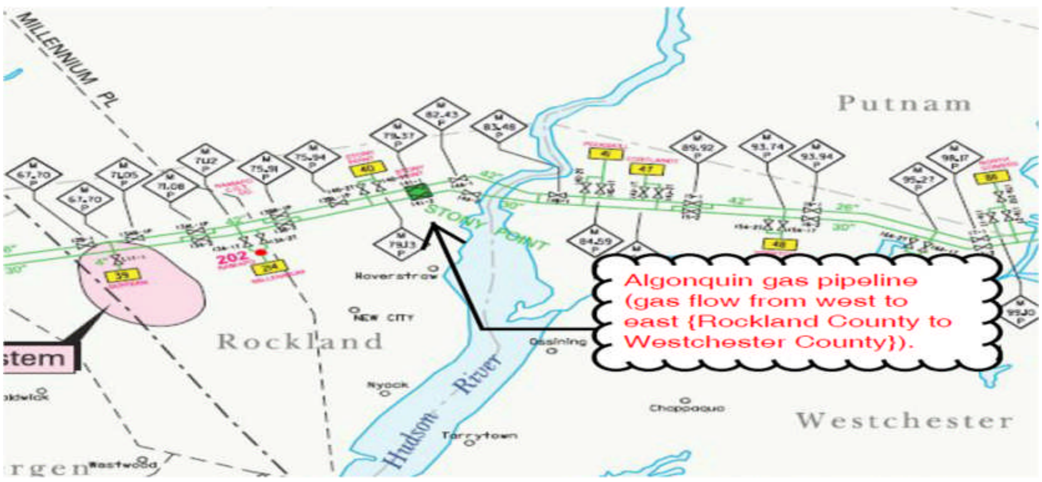
[34] ISO Staff Recommendations at 5, Table 2.

by ISO staff,[35] a generator in Rockland County purchasing gas at the TETCO M3 natural gas price index could obtain transportation capacity on the Millennium pipeline to transport that gas to Rockland County. While the Millennium Pipeline has sold all of its firm natural gas transportation capacity, approximately 42 percent of its gas transportation capacity was sold to non-Gas Local Distribution Companies ("LDCs"), who use this pipeline capacity to buy natural gas from the Marcellus shale supply area and resell this gas to interested natural gas buyers anywhere between the Marcellus shale supply area and Rockland County using the Millennium pipeline. This 42 percent of gas transportation capacity on the Millennium pipeline that was sold to non-Gas LDCs is significantly much more gas transportation capacity than is needed to serve the Rockland County proxy unit.

The MMU also analyzed this issue, pointing out that the Algonquin pipeline could be used in a similar manner. It stated, "Pipeline data supports the finding that gas transported from the TETCO M3 zone via [the] Algonquin [pipeline] is available in Rockland County…. In 2019, Algonquin announced restrictions on interruptible nominations sourced from points west of its Stony Point Compressor Station for delivery east of Stony Point on 363 days, but did not announce restrictions on west-to-east transport for delivery west of Stony Point on any days. Stony Point is located on the west shore of the Hudson River at the eastern border of Rockland County…. Hence, while transport on Algonquin is frequently restricted, the main bottlenecks are located downstream. Transport to points in Rockland County such as the interconnect with Millennium Pipeline at Ramapo is generally available."[36] Fig. 8 shows the relevant portion of the Algonquin pipeline. Together, these analyses demonstrate that it is reasonable to use the TETCO M3 natural gas price index for a generator located in Rockland County.[37]

Fig. 8: Map of Algonquin Pipeline in Rockland County and Adjoining Counties



[35] These arguments, as well as others, are laid out in more detail there. *See* New York Transmission Owners, Comments on "Proposed NYISO Installed Capacity Demand Curves for the 2021-2022 Capability Year and Annual Update Methodology and Inputs for the 2022-2023, 2023-2024 and 2024-2025 Capability Years" (Aug. 24, 2020).

[36] MMU Comments at 20.

[37] As noted above, if the Board directs ISO staff to remove the cost of SCR from the calculation of the net cost of the H class frame generator in Dutchess County, then (all other things held equal) which natural gas price index is used for a generator in Rockland County would not affect the demand curve for the G-J Locality, because the demand curve would reflect the net cost of developing an H class frame generator in Dutchess County.

B. *With the Exception of Parameters that Are Included in the Annual Updates, Demand Curve Parameters Should Reflect Expected Conditions over the Entire Four-Year DCR Cycle*

During the last DCR, stakeholders approved and the ISO filed tariff changes that extended the DCR cycle from three years to four years. As part of those tariff changes, the ISO stated that three demand curve parameters—the escalation factor used to determine the annual increase in the cost of building a new proxy unit, the net EAS revenues that the proxy unit would earn, and the ratio of the amount of capacity available in the winter compared to the summer—would be updated annually.[38] Even though there might be changes in other parameters during the DCR cycle that would have had a material impact if they had been included in the annual update, all other parameters would be fixed for the full four-year DCR cycle.

In its comments on ISO staff's draft recommendations, Independent Power Producers of New York ("IPPNY") asserted that "no new fossil peaking plant similar to the proxy unit is under construction or could be expected to reach commercial operation until the second half of the DCR period (2023-2025) at the earliest."[39] Taking into account the CLCPA requirement for that all electricity to be produced by zero-emissions resources by 2040, IPPNY concluded that "considering probable construction timelines, and taking into account some potential for delays … a reasonable amortization period is 15 years."[40] But this is effectively an argument that the amortization period for the full DCR cycle should be based on the time remaining before the 2040 deadline at the end of the DCR cycle. In fact, there is no reason why the demand curves should be set based on the conditions expected to prevail during the last year in the DCR cycle, the first year in the DCR cycle, or any other particular year in the DCR cycle. The decision not to include the amortization period among the parameters that are updated in the annual update entails an implicit judgement that it is sufficient to base the demand curves for the full four-year DCR cycle on one set of assumptions that remains static throughout the cycle. Thus, the amortization period should reflect the conditions that are expected to apply throughout the cycle, on average, so there is no reason to set the amortization period at 15 years based on the lifespan of generators entering at the very end of the DCR cycle.[41]

IPPNY made similar arguments with respect to level-of-excess adjustment factors ("LOE-AFs"), which are adjustment factors that account for the fact that historical values for net EAS revenue reflect the actual amount of excess capacity, relative to the ICAP requirement, that was present in the market during that

[38] Services Tariff, § 5.14.1.2.2.

[39] IPPNY, Comments on Proposed Installed Capacity Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years—Consultants' Interim Final Draft Report & NYISO Staff Draft Recommendations (Aug. 24, 2020) ("IPPNY Comments"), at 4.

[40] *Id.* at 5.

[41] At the beginning of the current DCR process (and at the request of the representative of an IPPNY member), the ISO asked all stakeholders to identify any changes to the DCR process that they would like to propose. See, e.g., Ryan Patterson, 2021-2025 ICAP Demand Curve Reset: Notice of Request for Potential Process Enhancements (Sept. 5, 2019). The TOs responded by proposing several changes to the annual update process that were ultimately approved by stakeholders and filed with FERC. *See N.Y. Indep. Sys. Operator, Inc.,* Letter Order, Docket No. ER20-1049-000 (Apr., 3, 2020). Neither IPPNY nor any of its members availed themselves of this opportunity to propose changes to the annual update process. Setting the amortization period at 15 years to reflect the lifespan for the last year in the DCR cycle would reward them for their failure to propose such changes.

historical period, but the measure of net EAS revenue used when setting the ICAP demand curves must reflect the level of excess capacity that is prescribed in the tariff. IPPNY argued that these adjustment factors should reflect retirements that are expected to occur in 2023, stating that failing to do so would be "inconsistent with the process for setting the LOE-AF[s]—a process that by design is forward looking over the entire DCR period."[42] This completely misses the point. Since they are not included in the annual update, a single set of LOE-AFs will apply throughout the four-year DCR cycle, and once more, there is no reason to assign more weight to one part of the DCR cycle than to any other part when determining that set of LOE-AFs. As the MMU showed in its comments, these retirements would not have any effect on the three-year historical period used to calculate net EAS revenue upon which the demand curves for the first three years in the 2021-25 DCR cycle are based. They would only apply to a small portion of the three-year historical period used to calculate net EAS revenue for the demand curves for the 2024-25 capability year.[43] Consequently, it would be unreasonable to base the demand curves for the full four-year DCR cycle on conditions that apply to only a small part of that cycle.

[42] IPPNY Comments at 20.

[43] MMU Comments at 11-13.