Comments on "Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2025/2026 through 2028/2029 Capability Years—Draft Report"

Submitted by the New York Transmission Owners

June 28, 2024

The New York Transmission Owners ("TOs")[1] hereby submit the following comments on "Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2025/2026 through 2028/2029 Capability Years—Draft Report (Updated Version)" ("Draft Report"), released by Analysis Group, Inc. ("AG") and 1898 & Co. (jointly, "Consultants") on June 17, 2024.

Before addressing the content of the Draft Report, the TOs believe it is necessary to reiterate our concerns about the structure and effectiveness of the ICAP market. In stakeholder meetings and at the June 10th joint Management Committee-Board of Directors meeting, representatives of the TOs (as well as representatives of many other market participants in other sectors) indicated the need for a comprehensive review of the procedures and methodology that the NYISO uses to determine compensation for capacity providers and prices paid by customers. We are concerned that the current methodology may not produce reasonable prices or levels of compensation, and may not provide economically efficient incentives for entry or exit. In our view, the NYISO should expeditiously initiate a holistic review of the procedures and methodology once the results of the current demand curve reset ("DCR") are filed with FERC.

1. Peaking Plant Technology

The Draft Report recommends that the ICAP demand curves for the 2025-26 through 2028-29 capability years for all four capacity regions (New York Control Area ("NYCA"), G-J Locality, New York City ("NYC") and Long Island) reflect the net cost of developing a two-hour battery energy storage system ("BESS"). Acknowledging our broader concerns with the current ICAP market and the cost-effectiveness of the DCR stated above, the TOs accept that this recommendation is the best option at the current time.

Unlike past DCRs, the Draft Report does not recommend basing the ICAP demand curves on the net cost of developing a gas turbine. Nevertheless, the Draft Report's recommendation was developed using the same process that led to the selection of the gas turbine in past DCRs. Two decades ago, when FERC accepted the relevant tariff language, it recognized that following this procedure might lead to basing the ICAP demand curves on the cost of entry for a generator that is not a gas turbine. While the NYISO's Control Area Administration and Market Services Tariff ("MST") requires that each ICAP demand curve be based on the net cost of developing a "peaking unit," which it defines as "the unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable,"[2] the tariff language originally proposed by NYISO in 2005 would have required the

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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] MST § 5.14.1.2.2.

NYISO to base the ICAP demand curves on the net cost of developing gas turbines.[3] FERC directed the NYISO "to remove all references in the proposed Services Tariff language to 'gas turbines' and replace them with 'peaking units,'"[4] noting that "[i]t is entirely possible, due to future advancements in technology, that gas turbines may not be the preferred type of unit to use in the future resets of the NYISO ICAP Demand Curves."[5] That day has arrived.

When it filed the currently effective ICAP demand curves, the NYISO stated, "[FERC] has established that economic viability determinations are a matter of judgment that is informed by the consideration of multiple factors. These factors include: (i) the availability of the technology to most market participants; (ii) existence of sufficient operating experience to demonstrate that the technology is proven and reliable; (iii) whether the technology is dispatchable and capable of being cycled to provide peaking service; and (iv) the ability to achieve compliance with applicable environmental requirements and regulations."[6] As the Draft Report indicates, the two-hour BESS using lithium-ion technology, which the Draft Report describes as the "most commercially mature battery storage technology,"[7] meets these criteria.[8]

Additionally, the analysis conducted by the Consultants demonstrates that a two-hour BESS using this technology could enter at capacity prices that would not be able to support entry of other technologies. Table 1, below, shows the Annual Reference Values ("ARVs") for a two-hour BESS, a four-hour BESS, and a 7HA.03 gas turbine generator located in Load Zone F, Dutchess County in Load Zone G, NYC and Long Island, expressed in terms of dollars per kW-year of unforced capacity ("UCAP").[9] As the Draft Report explains, "the ARV is equal to the net annual revenue requirement for each of the peaking plant technology options."[10] The ARV for the two-hour BESS in each location is considerably less than the ARVs for the two most likely alternatives considered by the Consultants (the four-hour BESS and the 7HA.03 gas turbine generator) in each location, thereby demonstrating that the two-hour BESS requires less capacity revenue than the other technologies to support its entry.[11]

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3 *N.Y. Indep. Sys. Operator, Inc.,* 113 FERC ¶61,271 (2005) at P 4.

4 *Id.* at P 12.

5 *Id.* at P 11.

6 *N.Y. Indep. Sys. Operator, Inc.*, 2021-2024 ICAP Demand Curve Proposal (Nov. 30, 2020), Docket No. ER21-502-000, at 7 (citations omitted).

7 Draft Report at 18.

8 *Id.* at 13-14.

9 Since these ARVs do not appear in the Draft Report, they were taken from the model used to calculate the ICAP demand curve reference prices. Consistent with the Draft Report's recommendations, the ARVs reported here for the 7HA.03 generator assumed dual-fuel capability and selective catalytic reduction emissions control; each of the ARVs also reflects the amortization periods recommended in the Draft Report. Load Zone F was used because ARVs for each of these generators in Load Zone F are lower than ARVs for the same generator in Load Zone C, the other location considered for setting the ICAP Demand Curves for the NYCA. Similarly, Dutchess County was used instead of Rockland County, the other location considered for setting the ICAP Demand Curves for the G-J Locality, because ARVs for each of these generators in Dutchess County are lower than ARVs for the same generator in Rockland County.

10 Draft Report at 108.

11 The Consultants also considered basing the ICAP demand curves on the amount of capacity revenue that would be needed to support the entry of a simple cycle gas turbine that would convert to operate on hydrogen in 2040. However, the Consultants did not actually calculate the reference price that would have resulted from basing them

Table 1: Annual Reference Values ($/kW-year)

	Zone F	Dutchess Co.	NYC	LI
2-hour BESS	$ 47.71	$ 55.47	$ 108.78	$ 28.17
4-hour BESS	$ 107.84	$ 119.91	$ 201.06	$ 83.99
7HA.03 (dual-fuel w/ SCR)	$ 161.26	$ 192.60	$ 241.30	$ 150.90

In addition, the fixed costs for the two-hour BESS are lower than the fixed costs for the other technologies considered by the Consultants, which the TOs agree were appropriate for evaluation. Table 4 in the Draft Report lists the gross CONE for each of the candidate technologies, stated in terms of dollars per MW of capacity. As it shows, the gross CONE for the two-hour BESS ranges from 63% to 65% of the gross CONE for the four-hour BESS, and from 45% to 57% of the gross CONE for the 7HA.03 gas turbine generator.

In stakeholder meetings, it has been suggested that a two-hour BESS might not be viable because the capacity accreditation factor ("CAF") for these resources, which reflects the "marginal reliability contribution of the ICAP Suppliers within each Capacity Accreditation Resource Class [('CARC')] toward meeting [New York State Reliability Council] resource adequacy requirements,"[12] will decrease quickly over the next several years. Since the amount of unforced capacity ("UCAP") that a generator can provide is proportional to the CAF of the CARC to which it belongs, such a decline could significantly reduce the amount of UCAP that such a generator could sell and thus the capacity revenue that such a generator would collect.

However, claims that there will inevitably be a swift, sharp decline in the CAFs for two-hour BESS have not been accompanied by supporting evidence. Many factors affect the calculation of the CAF for a two-hour BESS. One of those factors is the amount of storage capacity. If everything else is held equal, the marginal impact of storage facilities (such as a two-hour BESS) towards meeting resource adequacy requirements will decrease as storage capacity is added in New York. But the amount of capacity provided by intermittent generators in New York will also affect the CAF for storage facilities. If the amount of storage capacity is held constant, but the amount of intermittent capacity increases, the marginal contribution of batteries to meeting resource adequacy requirements should rise, because batteries can move more energy produced by intermittent generators from hours that have a negligible impact on loss-of-load expectation ('LOLE") to hours that have a significant impact on LOLE.[13] Given the ambiguity as to the future path of CAFs for a two-hour BESS, the suggestion from some stakeholders that such a generator would not be viable has not been justified.

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on such a generator, finding that "the cost of retrofitting a fossil fuel-fired peaking plant to burn 100% hydrogen is currently cost prohibitive." Draft Report at 21. We would have found it useful to include this information.

[12] MST § 2.3.

[13] For an example showing how the joint impact on effective load carrying capability ("ELCC") of increasing the amount of solar and storage capacity exceeds the sum of (1) the impact on ELCC of increasing solar capacity while holding storage capacity constant and (2) the impact on ELCC of increasing storage capacity while holding solar capacity constant, *see* Energy + Environmental Economics, ELCC Concepts and Considerations for Implementation (Aug. 30, 2021) at 25, available at: https://www.nyiso.com/documents/20142/24172725/NYISO%20ELCC_210820_August%2030%20Presentation.pdf/8ac7b020-206e-6dff-4e0f-756bc215ecc0.

At the June 13 meeting of the ICAP Working Group, it was also suggested that the assessment of viability should consider the contributions of resources towards meeting transmission security needs. The Market Monitoring Unit has recommended changes in the procedures used to compensate ICAP providers in Localities at times when locational capacity requirements are based on transmission security considerations,[14] and there is a project currently underway to evaluate these issues, but the MST states that CAFs must reflect marginal contributions "toward meeting … *resource adequacy requirements*,"[15] not transmission security needs. Until and unless a proposal to modify this portion of the tariff to account for contributions to meeting transmission security requirements is developed, approved by stakeholders and the NYISO Board of Directors, and filed and accepted by FERC—none of which have happened—payments to capacity providers will reflect their marginal contributions to meeting resource adequacy needs. Therefore, the assessment of whether such resources are viable must be based on their marginal contributions to meeting resource adequacy needs, as that determines the amount of UCAP they can provide, and hence the UCAP payments that they receive.

Finally, the TOs observe that there are numerous and ongoing requests for interconnection studies by BESS developers but none, or very few, by gas turbine developers. This may be seen as indicative that the market in New York has accepted BESS as a viable option and replacement of gas turbines as peaking units.

2. Amortization Period

In the comments that the TOs submitted at this point in the last DCR four years ago, we observed:

> The [2020] Draft Report also uses a 15-year amortization period for battery storage technologies. Given the combined effect of improvements in battery storage technology and the 2040 deadline set by the CLCPA, battery storage technology may well be the least-cost resource for meeting ICAP requirements when the next DCR is conducted. With that in mind, the TOs are concerned that starting with a 15-year assumed amortization period for battery storage technology is too short. The rationale presented at the May 19 [2020] ICAP Working Group meeting for reducing the amortization period for battery storage technology from 20 years to 15 years was on the basis that there is a lack of operational experience with battery storage technology. By the time of the next DCR, however, there should be much more operational experience with battery storage technology. Thus, once more, the TOs do not believe that the 15-year amortization period assumed for battery storage technologies in this DCR should set a precedent for the next DCR.[16]

The concern that we expressed in those comments has manifested itself. The Draft Report for this present DCR continues to recommend a 15-year amortization period for BESS, citing, among other factors, the

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[14] Potomac Economics, 2023 State of the Market Report for the New York ISO Markets (May 2024), at 144-145 (Recommendation 2022-1).

[15] MST § 2.3 (emphasis added).

[16] Comments on "Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/25 Capability Years—Initial Draft Report" (July 1, 2020) ("2020 TO Comments"), at 4-5, available at: https://www.nyiso.com/documents/20142/13609298/TO-Comments-on-Consultants-Draft-Report-on-ICAP-Demand-Curves-for-2021-25-Final.pdf/11b0122d-c425-c480-2684-69acba7c5082.

fact that the amortization period was set at 15 years in the last DCR.[17] But, as stated above, that should not matter for this DCR. As the Consultants correctly stated in April, "Experience with battery storage units is far greater than at the time of the last DCR,"[18] four years ago. Recognizing this, the Consultants indicated that they were leaning towards assuming a 20-year amortization period for BESS;[19] in fact, that presentation indicated that while the Consultants had not settled on a 20-year amortization period, they were "considering the potential viability of longer amortization periods for battery storage,"[20] not a shorter one.

The shift to a shorter amortization period appears to have been driven by concerns about the risk associated with potential changes in the CAF. But, as discussed above, there is significant ambiguity on the future CAFs for storage, and AG has not justified its recommendation to reduce the amortization period to offset the effect of such a decrease in the CAFs. Consequently, the TOs believe that the Consultants should revert to their earlier position and use an amortization period for BESS of 20 years (or longer).

3. Real-Time Net Energy and Ancillary Services Revenues for BESS

The Draft Report describes the model that the Consultants used to estimate the net energy and ancillary services ("E&AS") revenue that a BESS would be expected to earn. As explained therein, it defines real-time bids to inject energy as the sum of the expected cost of recharging the battery (accounting for roundtrip losses), a hurdle rate, and any other costs associated with injecting energy.[21] Real-time bids to charge the battery are defined in a parallel manner.[22] The TOs caution that the net E&AS revenue that the model determines for a two-hour BESS is likely to understate the profit it would earn and is a factor that should be considered when assessing whether the proposed reference prices are reasonable.

The operator of a BESS will not be able to predict future prices or system conditions perfectly. Thus, it is reasonable for the model to permit the operator to make decisions that were expected to increase profits at the time that they were made, but which turn out to reduce profits once real-time prices are known. However, the approach used by the Consultants' model does not consider the expected opportunity costs associated with injecting (or charging now) instead of injecting or charging later. Failing to take this into account may cause the model to make decisions that reduce the real-time profit associated with operating the BESS, even though those decisions were expected to reduce its real-time profit *at the time those decisions were made*.

For example, suppose that a battery will forego the ability to inject energy later if it injects energy now. In that case, its expected opportunity cost reflects the price it expects to receive if it injects later, which it will forego if it injects now. That opportunity cost should be pertinent to the decision as to whether to inject now. So, if we assume that in the DAM, a battery was scheduled to produce energy at noon, at a

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[17] Analysis Group, NYISO 2025-2029 ICAP Demand Curve Reset (DCR) (June 13, 2024) at 9.

[18] Analysis Group, NYISO 2025-2029 ICAP Demand Curve Reset (DCR) (April 17, 2024) ("April 17 Presentation") at 38.

[19] *Id.* at 39.

[20] *Id.*

[21] *See* Draft Report at 79.

[22] *Id.* at 80.

price of $150/MWh, and we also assume that expectations of real-time prices are based on day-ahead prices, then the battery has an expected opportunity cost of $150/MWh if injection before noon means that it cannot also inject energy at noon.

But the model's approach for setting real-time bids for storage does not consider these expected opportunity costs. Thus, the procedure for setting the real-time bid that is described above could produce a bid to inject of, say, $90/MWh, well below the expected opportunity cost of $150/MWh. In this case, if the real-time LBMP at 10:00 a.m. is $100/MWh, the battery would be scheduled to inject energy at 10:00 a.m., even if it expects to forego $150/MWh later because it can no longer inject at noon . Thus, the decision to inject at 10:00 a.m. is expected to reduce the battery's profit *at the time that decision is made*.

As mentioned above, hurdle rates are included in real-time bids for the two-hour BESS. The Consultants determined these hurdle rates with the objective of maximizing the profit earned by the BESS. The real-time hurdle rates the Consultants determined are very high for most locations in most months.[23] By increasing the real-time offer to inject, high hurdle rates can help to protect against situations when the BESS would inject energy based on a forecast of the price that the BESS would pay to recharge, when the actual price paid to recharge turns out to be higher than forecasted. But high hurdle rates also help to protect against the potential for the BESS making profit-reducing decisions to inject that would otherwise be likely to occur when expected opportunity costs when those costs are high, because the model disregards these costs. But there is a downside: while high hurdle rates prevent the BESS from incurring losses in these cases, they can also prevent the battery from injecting or charging at times when the expected opportunity costs are low and it is likely to be able to do so profitably.

As a result, using high hurdle rates to offset the consequences of a model that disregards expected opportunity costs can eliminate most real-time net E&AS profits. This appears to be what has happened for a two-hour BESS in Zone G and NYC, as shown in Fig. 13 in the Draft Report. But this does not necessarily mean that there would have been no opportunity for a two-hour BESS to earn significant profits in the real-time market. It only means that there would not have been such an opportunity if the operator of such a facility had decided to ignore opportunity costs when formulating its bidding strategy.

Unfortunately, it is now too late to develop a net E&AS revenue model for batteries that would consider expected opportunity costs when it determines real-time bids for batteries to inject and to charge. This means that the net E&AS revenue that the model determines for a two-hour BESS is likely to understate the profit it would earn. This is a factor that the Consultants should consider when evaluating the proposal as a whole, and assessing whether the proposed reference prices are reasonable.

4. Assumptions for Gas Turbines

While the Draft Report did not recommend basing the ICAP demand curves for the 2025-26 through 2028-29 capability years on the net cost of developing a gas turbine, it included a calculation of that net cost. We address some of those assumptions here: (1) whether such a unit would use selective catalytic reduction ("SCR") emissions controls, (2) what the terminal value would be, and (3) the index that would

[23] For all locations in non-shoulder months, the real-time hurdle rates for a two-hour BESS were $70/MWh and above (usually well above). In shoulder months, hurdle rates for ROS locations and Long Island were low, but hurdle rates in Zone G and NYC were $175/MWh to $195/MWh. *Id.* at 85 (Table 42).

be used to estimate the cost that such a generator would incur to purchase natural gas in Rockland County.

A. SCR Emissions Controls

The Draft Report assumes that such a gas turbine would use SCR emissions controls, no matter where it is located within the state. That is a departure from the last DCR, which did not assume that such a unit, if built in the Rest of State ("ROS") region, would use SCR emissions controls. But, as the Draft Report states, "GE does not offer a version of the SCGT 7HA.03 capable of 15 ppm NOx [emissions, which are necessary to comply with environmental regulations] without SCR emissions controls."[24] Therefore, based on the Consultants' finding that "the annual net cost is lower for the SCGT 7HA.03 with SCR emissions control than the SCGT 7HA.02 [the generator used for the 2021-25 DCR] without emissions controls in all applicable locations,"[25] we agree with the recommendation to assume SCR emissions control for such a generator in all locations, including ROS.

B. Terminal Value

In the TOs' 2020 comments, we stated, "[w]hile the [2020] Draft Report acknowledges that newly constructed fossil fuel units would not necessarily need to retire in 2040, as they could continue operation using alternative fuels, this approach effectively assumes that investors would not assign any value whatsoever to their ability to continue operation after 2039 in any configuration. Certainly, given the potential for fuel conversion, it appears that the value to remain in service after 2039 should be greater than zero…. In addition, it will be more important to include an estimate of residual value at that point in time, because using a 13-year amortization period in the next DCR, without any recognition of residual value after 2039, would likely have a material impact on the [reference prices]."[26]

We stand by those comments. Terminal value should also reflect the value of the interconnection, injection and take-away rights. It is simply not realistic to expect investors to attribute zero residual value for these assets. While we recognize that a certain amount of judgement may be required, as it may be difficult to arrive at a precise terminal value, this is also true of many of the parameters involved in the DCR. Surely the terminal value is not zero, so we believe that the Consultants should include a terminal value in their calculation of the net cost of developing a gas turbine.

C. Natural Gas Price Index for Rockland County

The Draft Report calculates net E&AS revenue realized by the 7HA.03 gas turbine generator under the assumption that the unit would have purchased gas at the Tennessee Zone 6 price if the unit is located in Rockland County. The TOs question this assumption.

To determine "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," as required by Section 5.14.1.2.2 of the Services Tariff, it is necessary to determine the gas cost that a gas-fired generator in a given location would have incurred to purchase this

[24] *Id.* at 30.

[25] *Id.*.

[26] 2020 TO Comments at 4.

gas. Indices that do not indicate the cost that a generator in a given location would have incurred to purchase gas are therefore not germane. For that reason, the TOs have consistently taken the position that the Geography criterion is the most important of the four criteria that the Consultants used to evaluate potential gas price indices. As the Draft Report states, the Geography criterion indicates whether a pipeline has “an appropriate geographic relationship to the applicable fossil peaking plant locations going forward, or otherwise have a logical nexus to prices at relevant delivery points.”[27]

The G-J Locality is bisected by the Hudson River. This causes the gas price for generators located on the west side of the Hudson River (*e.g.*, generators located in Rockland County), which is the same side of the Hudson River as the Marcellus shale gas supply area, to differ regularly and significantly from the gas price available to generators located on the east side of the Hudson River (e.g., generators located in Dutchess County). For this reason, the last DCR used different indices for generators in Dutchess and Rockland Counties. However, while the Draft Report continues to use different indices for Rockland and Dutchess Counties, it recommends the Tennessee Zone 6 index for Rockland County, even though (as Fig. 14 in the Draft Report shows) that index reflects the cost of gas for a location in New England, which, of course, is well east of the Hudson River. Therefore, the Tennessee Zone 6 index does not meet the Geography criterion for Rockland County.

The Draft Report asserts, “While the Tennessee Zone 6 gas hub delivery point is outside Rockland County, the Tennessee Gas Pipeline (TGP) system delivers to points along the southern side of Rockland County west of the Hudson River.”[28] This may be so, but it does not explain why a generator that is west of the Hudson River would pay the premium associated with delivery to a location that is east of the Hudson River, such as Tennessee Zone 6, if less costly alternatives are available. And less costly alternatives are available. In the last DCR, the Consultants used the TETCO M3 price for a generator in Rockland County, finding that it met the Geography criterion,[29] a conclusion which the Draft Report for the current DCR inexplicably reverses. As the Consultants stated in the report issued at the conclusion of the last DCR, “While TETCO M3 delivery points are outside Rockland County, TETCO M3 delivers to points proximate to Rockland County and the transportation costs … provide a reasonable estimate of the incremental costs needed to obtain fuel in Rockland County relative to points in Northeast New Jersey.”[30]

AG initially proposed using the Tennessee Zone 6 price for generators in Rockland County at the April 17 ICAP Working Group meeting.[31] While AG’s presentation at that meeting indicated that TETCO M3 scored high on the Market Dynamics score, part of the explanation offered at that meeting for using Tennessee Zone 6 instead of TETCO M3 was that the correlation between Zone G LBMPs and TETCO M3 gas prices was relatively low. However, Zone G LBMPs used to reflect the marginal cost of serving electric load in Rockland County could be based on the marginal cost of electric generation in Zone G

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[27] Draft Report at 88.

[28] *Id.* at 100.

[29] Analysis Group, Inc. and Burns & McDonnell, Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years—Draft Report” (Sept. 9, 2020) at 97 (Table 43).

[30] *Id.* at 95.

[31] April 17 Presentation at 12.

Dutchess County or anywhere within New York State; Therefore, Zone G LBMPs does not necessarily reflect the cost of gas purchase and operating a generator in Rockland County especially on high electric load days during the winter months or during the summer months. Consequently, Zone G LBMPs may not be well correlated with the gas prices available to Rockland County generators (i.e., TETCO M3). Furthermore, the congestion point on the Algonquin Gas Transmission ("AGT") pipeline system from the TETCO M3 area through NYISO Zone G area into Connecticut has not changed since the last DCR and remains at the Stony Point Compressor station, which separates the AGT pipeline system between the Zone G area located west of the Hudson River (i.e., Rockland County) and the Zone G area located east of the Hudson River (i.e., Dutchess County). Because there is no congestion on the AGT pipeline system from the TETCO M3 area to Rockland County, Rockland County generators are able to purchase gas based on the TETCO M3 gas prices, whereas Dutchess County generators would need to purchase gas based on a different natural gas index price. As a result, we urge the Consultants to revert to using the TETCO M3 gas prices for a Rockland County gas turbine generator, an assumption from the last DCR that remains well supported.