UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Modernizing Wholesale Electricity Market Design   Docket No.   AD21-10-000

Response of the New York Independent System Operator, Inc.
to Order Directing Reports

In accordance with the Federal Energy Regulatory Commission's ("Commission's") April 21, 2022 Order Directing Reports ("Order") in the above-referenced docket, the New York Independent System Operator, Inc. ("NYISO") hereby submits its Report responding to the Commission's questions.

The electric system in New York State is undergoing significant and rapid change. Part of the change is climate related, which will drive more frequent extreme weather events and higher temperatures, thus impacting the ability of the grid to reliably serve electric demand. Part of the change is the result of New York public policies in response to climate change. New York State public policy requires an economy-wide approach to addressing climate change and decarbonization, mandating that 70% of New York electricity consumed be produced from renewable resources by 2030 ("70x30") and 100% emissions-free electricity supply by 2040 ("100x40") while promoting electrification in other sectors of the economy. The New York grid will require unprecedented levels of investment in both new supply and transmission resources to achieve these policy objectives.

With this transition in mind, the NYISO is working with its stakeholders on a series of wholesale electricity market enhancements focused on improving signals to drive investment in resources with the characteristics and attributes needed for continued grid reliability. Through engagement with stakeholders and regulators, new market rules, including new ancillary services products, will support a more dynamic grid. Market rules that incentivize investment in resources that can respond rapidly to changing conditions will be essential for maintaining reliability of the grid of the future.

The drivers of changes to the New York State Power System require New York-specific solutions. The NYISO is in the process of developing solutions that are specific to the concerns New York faces and the markets that it operates. The NYISO has spent a great deal of time identifying and addressing the conditions in New York, and NYISO will proactively propose any Tariff revisions that it determines are necessary to the Commission. Because the situations that each Independent System Operator ("ISO") or Regional Transmission Organization ("RTO") face are different, and each ISO/RTO has a different market design, the NYISO does not believe it would be efficient or effective for the Commission to impose a series of generic requirements or solutions on all ISOs and RTOs.

I. NYISO's Responses to the Commission's Questions

1. QUESTIONS 1-3

1. What system needs (type and magnitude) has the RTO/ISO experienced that are attributable to changes in the resource mix and customer load profiles? How do these system needs, including types and magnitudes of net load variability and uncertainty, vary over different time horizons in the E&AS markets? For example, does a particular need exist within a real-time market interval, within an operating day, between day-ahead and real-time markets, across multiple days, and between seasons? RTO/ISO materials, such as previously published RTO/ISO whitepapers or previous filings with the Commission, may be incorporated by reference as needed. What specific resource capabilities could address these needs (e.g., dispatchable generation)?

2. Referring to the system needs identified in answering question 1, how does the RTO/ISO expect those system needs to change over the next five years? Over the next 10 years? What does the RTO/ISO expect the magnitude of those system needs to be in five years? In 10 years?

   2.1. In answering, please provide a high-level overview of the methods used to develop the system needs forecast over the next five years and over the next 10 years. Please provide a high-level discussion of any industry trends that are particularly important to the RTO's/ISO's forecast, such as electric vehicle adoption, behind-the-meter distributed energy resource deployment, increased demand response participation and price-responsive load, growth in transmission infrastructure, and other trends. In evaluating the impact of such industry trends, how does input from efforts by states, local agencies, and utility programs inform that analysis?

2.2. What time horizons, such as times of day (e.g., minutes, hours), days, or seasons, are expected to present the biggest challenges with respect to net load variability and uncertainty? Why?

3. What new system needs not already described, if any, does the RTO/ISO expect to emerge over the next five years? Over the next 10 years? What are the drivers of those new system needs? Are those new system needs quantifiable, and if so, please provide information on how you have quantified those needs.

A. NYISO Response

1) State Public Policies Driving Changes in New York State

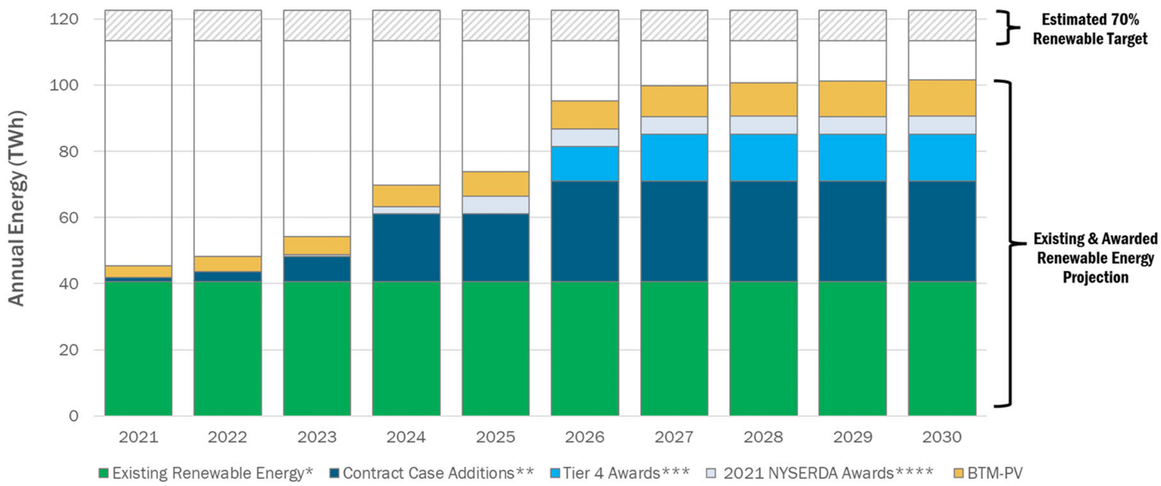
The NYISO is preparing for a monumental shift in the generation mix serving the New York Control Area ("NYCA"),[1] along with the potential incremental increased demand stemming from New York State electrification policies. Together, these circumstances pose a multitude of challenges to the NYISO's primary goal of supporting a reliable and economically efficient electric grid. The new renewable resources required to satisfy various public policies have economic and performance characteristics that differ from traditional generation resources. NYISO also expects widespread electrification of the transportation and buildings sectors of the economy that will change the magnitude and patterns of electric demand.

The New York State Climate Leadership and Community Protection Act ("CLCPA") is currently the primary driver of public policy changes in the state. The CLCPA mandates that 70% of the state's load be served by energy generated from renewable resources by 2030, and that 100% of the energy serving load be zero emission by 2040. The CLCPA also requires the installation of 6,000 MW of distributed solar resources by 2025, 3,000 MW of storage resources

[1] Capitalized terms not otherwise defined herein have the meaning specified in the NYISO's Market Administration and Control Area Services Tariff and Open Access Transmission Tariff.

by 2030, and 9,000 MW of offshore wind resources by 2035.

Figure 1: Progress Towards "70 x 30" Mandate[2]



Prior to the CLCPA, the New York State Department of Environmental Conservation ("DEC") adopted a regulation to limit nitrogen oxides (NOx) emissions from simple-cycle combustion turbines in 2019 (referred to as the "Peaker Rule").[3] Combustion turbines, referred to as "peakers," typically operate to maintain bulk power system reliability during the most stressful operating conditions, such as periods of peak electricity demand, and frequently provide 10 and 30 minute non-synchronous operating reserve. Many of these units also maintain transmission security by supplying energy within certain constrained areas of New York City

[2] *See* pages 5 to 8 of the System and Resource Outlook, A Report from the New York Independent System Operator, available at https://www.nyiso.com/documents/20142/33384099/2021-2040-Outlook-Report.pdf/a6ed272a-bc16-110b-c3f8-0e0910129ade?t=1663848567361.

* Estimated 2021 renewable energy per NYSERDA CES Compliance Report.

** Additional renewable energy modeled from projects included in The Outlook Contract Case.

*** Tier 4 awards exclude associated renewable projects with existing Tier 1 awards.

**** Max annual contract quantity of renewable energy from projects awarded in the 2021 NYSERDA Tier 1 solicitation.

[3] *See*, DEC Peaker Rule: Subpart 227-3 Ozone Season Oxides of Nitrogen (NOx) Emission Limits for Simple Cycle and Regenerative Combustion Turbines, available at, https://www.dec.ny.gov/regs/2492.html.

and Long Island — known as load pockets. The Peaker Rule, which phases in compliance obligations between 2023 and 2025, will impact turbines located mainly in the lower Hudson Valley, New York City, and Long Island. In response to the Peaker Rule, the NYISO expects approximately 1,500 MW of, otherwise economic, peaker capability to become unavailable during the summer by 2025 in order to comply with the emissions requirements. A subset of those generators would be unavailable starting in 2023. Most of the affected generators will be permanently retired in 2023 or 2025, although the NYISO is permitted to temporarily retain peakers that it determines are needed for reliability for up to four additional years.

As the generating resource mix transforms, the wholesale energy market design in New York will need to evolve between now and 2030 to do a better job of valuing the grid services that will be needed to maintain reliability as the generation fleet changes. Ideally, the wholesale energy market will signal the value of each type of grid service and recognize the value of environmental objectives (either by internalizing into the wholesale markets, or through parallel competitive processes for environmental attribute markets). By evolving energy and ancillary service market design to reflect and incentivize the reliability services needed, wholesale energy and ancillary services markets can meet the full spectrum of New York State policy requirements and needed grid services, with competitive forces guiding the least-cost solution from a diverse set of resources. The wholesale market's ability to meet multiple objectives at least-cost is especially important given the state's ambitions to transform the electric grid.

2) NYISO Studies to Understand the Changing Resource Mix and Evolving Market Design Needs

Since the CLCPA was enacted in 2019, the NYISO has taken steps to better understand the reliability, operational, and market implications of transforming the resource mix operating within the state to achieve the mandated 2030 (70% of load served by renewable resources) and

2040 (100% of load served by zero emission resources) requirements. In late 2019, the NYISO released a report outlining *Reliability and Market Considerations for a Grid in Transition*,[4] its "Grid in Transition report" and a look at the anticipated long-term load impact.[5] In 2020, based on the considerations described in its Grid in Transition report, the NYISO released two important studies, *New York's Evolution to a Zero Emission Power System*[6] and its *Climate Change Impact and Resilience Study*.[7] These studies helped inform the NYISO and its stakeholders about the operational, reliability and investment implications of transitioning to a carbon free grid by 2040. Most recently, the NYISO released the System and Resource Outlook study ("The Outlook"),[8] which continued to evolve and amplify the conclusions from the prior studies. The Grid in Transition report and following studies continue to frame the NYISO's approach to evolving its market design, including the NYISO's consideration of enhancements to the energy and ancillary services markets.

The NYISO Grid in Transition study and the subsequent studies recognized that meeting New York load with high levels of intermittent renewable resource output, particularly solar and wind generation, will require the NYISO to have sufficient flexible, dispatchable and potentially fast ramping supply to balance variations and volatility in intermittent resource output.[9] These

[4] *See* Grid in Transition report, available at https://www.nyiso.com/documents/20142/2224547/Reliability-and-Market-Considerations-for-a-Grid-in-Transition-20191220%20Final.pdf.

[5] *See New York ISO Climate Change Impact Study: Phase 1: Long-Term Load Impact*, available at https://www.nyiso.com/documents/20142/16884550/NYISO-Climate-Impact-Study-Phase1-Report.pdf.

[6] *See Evolution to a Zero Emission Power System* study, available at https://www.nyiso.com/documents/20142/13245925/Brattle%20New%20York%20Electric%20Grid%20Evolution%20Study%20-%20June%202020.pdf.

[7] *See Climate Change Impact and Resilience Study* Phase 2 report, available at https://www.nyiso.com/documents/20142/16884550/NYISO-Climate-Impact-Study-Phase-2-Report.pdf.

[8] *See* System and Resource Outlook, A Report from the New York Independent System Operator, available at https://www.nyiso.com/documents/20142/33384099/2021-2040-Outlook-Report.pdf/a6ed272a-bc16-110b-c3f8-0e0910129ade?t=1663848567361.

[9] *See e.g.*, Grid in Transition report, *Evolution to a Zero Emission Power System* study, and *Climate*

variations will include not only short-term volatility in output during the operating day as a result of changes in wind speed and cloud cover, but also a sustained ramp up of solar output at the beginning of the day as the sun rises and a sustained ramp down of solar output at the end of the day as the sun sets. The Climate Change Study noted in the winter under the 2040 CLCPA scenario that the one-hour ramp requirements could be over 10,000 MW and a six-hour ramp of over 25,000 MW. To put these findings in perspective, in 2021 the largest single hour ramp required was approximately 1,800MW and the largest six-hour ramp was approximately 8,800MW.

The Climate Change Study also offered the following observations:

a. A system with significant amounts of intermittent resources will need significant amounts of dispatchable resources that can run for multiple day periods.
b. Due to the characteristics of sun and wind resources, there will be high ramping requirements needed from the dispatchable resources.
c. All of the dispatchable resources will need to be emissions-free by 2040.
d. Dispatchable resources that are emissions-free, and on the scale needed, are not yet commercially available or currently in the NYISO interconnection queue.

There are numerous risk factors that could adversely affect electric system reliability over the next ten years, and as we approach 2040. These risk factors may arise for a variety of reasons, including climate, economic, regulatory, and policy drivers. A common element among the risk factors centers around uncertainties that will exist over the next ten years and will impact the availability of resources. These uncertainties include, but are not limited to:

a. If expected generation projects are not built, a system deficiency may occur. From a resource adequacy perspective, if expected generation and transmission projects are not built, the LOLE criterion violation advances to earlier years within the study period. From a transmission security perspective, N-1-1 steady state issues in addition to those observed in the RNA baseline results may also occur.

Change Impact and Resilience Study Phase 2 report.

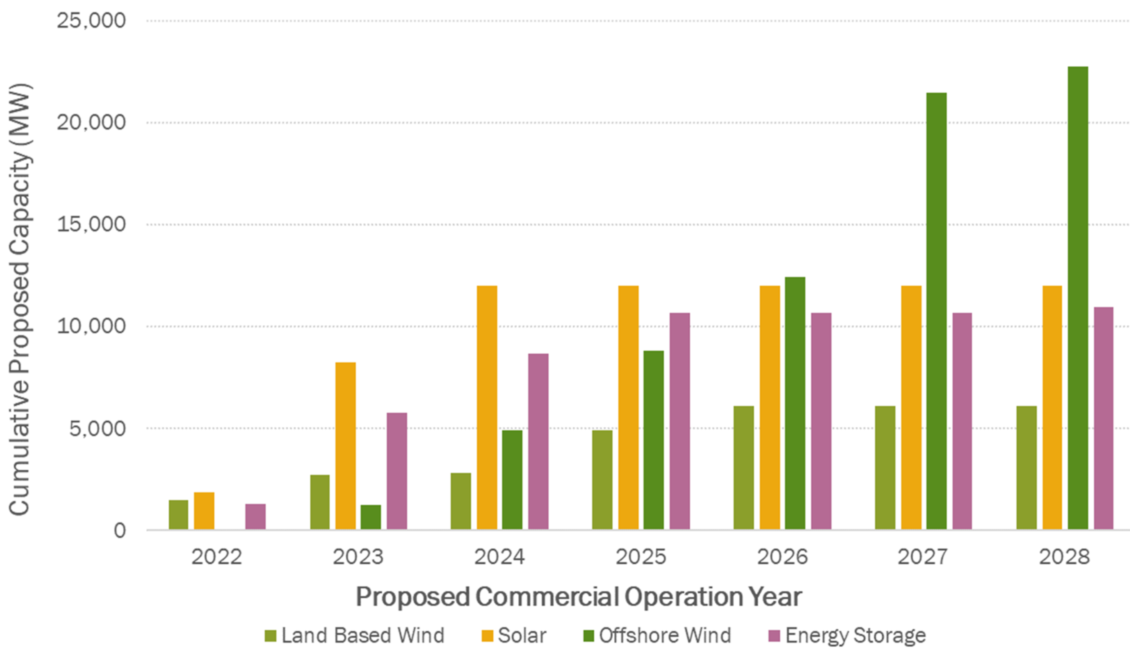
b. If additional generating units become unavailable or deactivate beyond those units already planned for, New York reliability could be adversely affected. As generators age and experience more frequent and longer duration outages, the costs to maintain the assets increase. These costs may drive aging generation into retirement. A growing amount of New York's gas-turbine and fossil fuel-fired steam-turbine capacity is reaching an age at which, nationally, a vast majority of similar capacity has been deactivated.
c. There are numerous risk factors related to the continued viability, compliance with emissions requirements, and operation of aging generating units. Depending on the units affected, the NYISO may need to take actions through its Short-Term Reliability Process to maintain reliability.
d. Capacity resources could decide to offer into markets in other regions and, therefore, some of the capability of those resources may not be available to the NYCA. Accordingly, the NYISO will continue to monitor imports, exports, generation, and other infrastructure.

3) Energy, Ancillary Services, and New Resources in the New York Control Area

The NYISO currently manages energy security through its day-ahead and real-time energy and ancillary services markets. In these markets, energy, regulation, 10-minute synchronous operating reserves, 10-minute non-synchronous operating reserves, and 30-minute operating reserves are simultaneously co-optimized by the NYISO's day-ahead security constrained unit commitment ("SCUC") software, the real-time commitment ("RTC") software, and by the real-time dispatch ("RTD") software. Existing ancillary services products, such as regulation service, 10-minute synchronous operating reserves, 10-minute non-synchronous operating reserves, and 30-minute operating reserves, continue to provide value and support management of Area Control Error, secondary frequency response, contingency management, transmission security requirements, and load balancing. However, considering emerging risks due to uncertainties, the NYISO believes changes to its energy and ancillary services markets will be necessary, before these risks are realized, for the wholesale electricity markets to continue to support safe, reliable delivery of electricity to New Yorkers. Relevant uncertainties include weather, net load forecasts, actual available energy from intermittent wind and solar resources, available energy from limited energy resources, reduced availability of traditional flexible generation resources, and higher probabilities that weather, or other factors, lead to correlated supply and transmission issues. For example, during the week of July 15-21, 2019, there was a 36-hour period when wind resources in New York averaged only a 4% capacity factor (their actual output as a percentage of their maximum possible output).

Many of the resources New York is adding will be weather-dependent (*e.g.*, wind and solar resources), which create new operational challenges and is expected to require large amounts of flexible, controllable resources to maintain a reliable system. While new weather-dependent resources will increasingly enter operation, more traditional generators that are flexible, currently making profits, and can quickly respond to changing system conditions will continue to retire in response to various policy mandates. As the portion of electricity produced from intermittent renewable sources increases and demand increases in response to public policy directives that seek to move heating and transportation away from burning fossil fuels, balancing intermittent supply with instantaneous demand will become increasingly challenging.

Figure 2: Proposed Renewable Energy Capacity in the NYISO Interconnection Queue (as of 6/1/2022)[10]



Variation in intermittent resource output needs to be balanced in six timeframes.

1. The time frame of the regulation service balancing instruction (6 seconds);
2. The time frame of the Real-Time Dispatch (5-minutes);
3. The time frame of the intra-day unit commitment decisions (15-minutes to a few hours);
4. The time frame of the Day-Ahead Market (24 hours);
5. The seasonal time frame (summer, spring, fall, winter); and
6. The time frame in which investments in resources able to provide balancing will be made.

Intermittent renewable resources also have zero or very low variable costs and many receive out-of-market subsidies for each MWh produced, which reduces energy prices, on average and in many hours when they are on the margin. Expected lower energy prices place greater emphasis on precisely identifying ancillary service requirements for operating a reliable grid. Simultaneously co-optimizing energy and ancillary services requirements expands energy and ancillary service market revenues to incentivize flexible, controllable resources to be

[10] *See* The Outlook at pages 31-32.

available when needed to maintain reliable system operation. Absent ancillary services market changes or other wholesale energy market changes to improve incentives for flexible resource availability, market signals to retain and invest in flexible, controllable resources may not be sufficient. Without sufficient flexible, controllable resources, the NYISO will face serious challenges to maintaining grid reliability in the future.

4) Expanded Forecasting Capabilities are Critical to Address System Needs

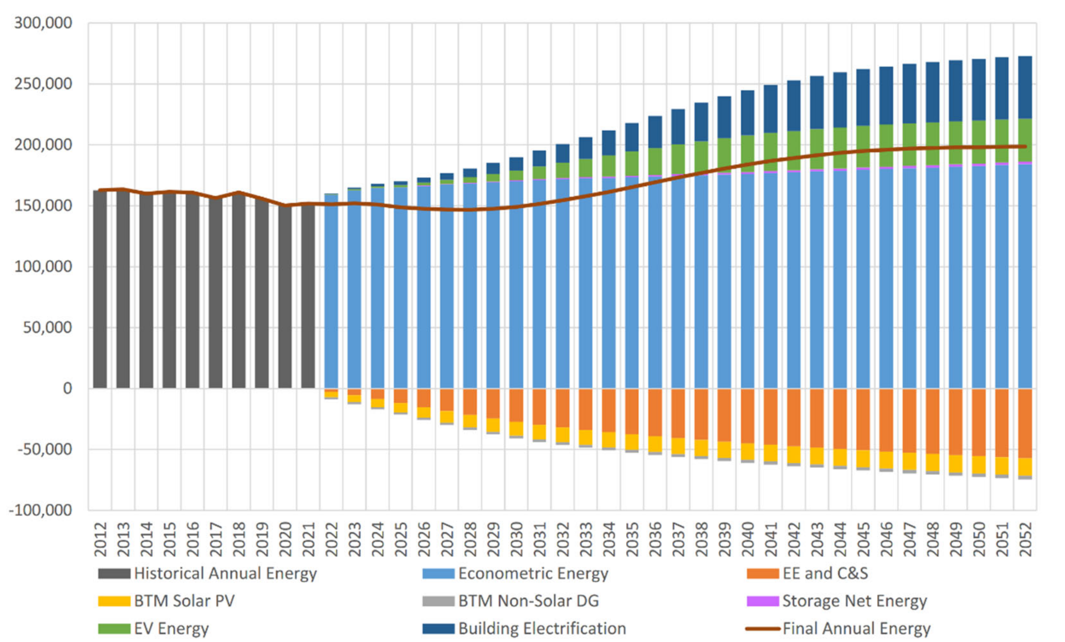
Load forecasting is a critical component of addressing system needs over the next 10 years. Forecasting load and operating the bulk power system will become more complex as additional intermittent resources integrate onto the grid and customers reduce load with behind-the-meter resources. Forecasting of wind and solar resource output is challenging as the weather-dependency of their energy production is difficult to predict accurately across all timescales and output can decrease dramatically without adequate notice. Shifting renewable resources to aggregations, such as DERs,[11] only increases this forecasting challenge because the NYISO may not know which resources are operating within the aggregation, have the ability to forecast intermittent resource output, be able to predict when batteries will charge, or know when a Distribution Utility will restrict the output of a specific DER or of the entire Aggregation to address constraints on distribution facilities that the NYISO does not monitor.

Over the next ten-year period, the NYISO is forecasting a decrease in wholesale energy purchases from the bulk power system due to energy efficiency initiatives and increasing

[11] *See e.g.*, *New York Independent System Operator, Inc.*, 170 FERC ¶ 61,033 (2020) and NYISO's presentation to the Installed Capacity Working Group on July 15, 2022, Hybrid Aggregated Storage (HSR) Model – Energy and Ancillary Services Market Design Proposal Update, available at https://www.nyiso.com/documents/20142/32238824/HSR%20Energy%20and%20Ancillary%20Services%207-15%20Final.pdf/3c26ce45-242a-ac73-b1cb-61992d085da9.

amounts of behind the meter solar generation. However, shifting load from being served by the bulk power system to behind-the-meter resources is not the same as eliminating load. This is particularly pertinent for behind-the-meter solar, which is intermittent and expected to provide more energy in the summer than in the winter. NYISO's latest baseline forecast includes 6,000 MW of behind-the-meter solar PV nameplate capacity installed by 2024, and 10,000 MW installed by 2030. The actual impact of these solar PV MW varies considerably by hour of day. When behind-the-meter resources are unavailable to produce energy, the bulk power system is expected to provide energy to the homes and businesses with front-of-the-meter resources. NYISO must, therefore, consider energy provided by behind-the-meter resources when planning for the reliable operation of the bulk power system.

Figure 3: NYCA Baseline Annual Energy Forecast Components (GWh)[12]



The NYISO will continue to expand its load forecasting capabilities to improve its ability

[12] *See* The Outlook at page 24.

to quantify the impacts of electrification in other sectors of the economy and to capture the impacts of more severe weather that may occur in New York State. In particular, the New York State Climate Action Council's Draft Scoping Plan recommends rapid and widespread electrification of the transportation and buildings sectors of the economy.[13] This electrification could significantly increase load on the electric system, and, at the same time, demand further expansion of load forecasting capabilities. Improvements in forecasting must consider the significantly expanded electrification of other sectors throughout New York State and how weather conditions and extreme weather events may impact electric demand.

2. QUESTIONS 4-6

4. Discussions at the technical conferences and in comments noted failures of E&AS market designs to incent resources to offer and perform in a manner that meets system needs that are present now or expected to emerge in the near-term. However, we note that much of the discussion indicated that system needs will continue to change significantly beyond the near-term, which could increase the adverse impacts of current flaws in E&AS market designs. Such increases in adverse impacts, such as insufficient operational flexibility in real-time, could threaten reliability and could also increase out-of-market actions and associated impairments to price formation.

   Referring to the changing system needs discussed in questions 2 and 3, to what extent are current RTO/ISO E&AS market products and compensation schemes not designed to procure the resource capabilities needed to meet these expected changing system needs? To what extent are such prices and products unable to adequately compensate the resources possessing the capabilities necessary to meet these expected changing system needs? To what extent does the risk of disorderly retirements of resources with capabilities that are needed to address such needs (e.g., fast ramping dispatchable resources) increase if E&AS markets are not reformed? Why?

5. Much of the discussion at the technical conferences and in comments about planned reforms concerned near-term reforms that the RTO/ISO is currently developing with stakeholders or has recently implemented to manage system needs emerging in the near-term. However, much of the discussion signaled that system needs will continue to change significantly over time beyond the near-term. The following questions seek to understand how the RTO/ISOs

[13] *See* Chapters 11 and 12 of New York State Climate Action Council Draft Scoping Plan, December 30, 2021, available at, https://climate.ny.gov/Our-Climate-Act/Draft-Scoping-Plan.

are considering and working to identify and address longer-term future needs through E&AS market reforms.

Referring to the changing system needs discussed in questions 1, 2, and 3, what planned E&AS market reforms is the RTO/ISO contemplating or other stakeholder processes, if any, is the RTO/ISO conducting related to meeting those expected changing system needs? How will those specific reforms or stakeholder processes help the RTO/ISO meet those expected changing system needs?

6. Several commenters questioned the incentives created by current E&AS market designs and planned E&AS market reforms. Commenters raised many market design considerations as important for ensuring that E&AS markets incentivize resources to offer and perform in ways that support system needs. For example, some commenters argue that some E&AS market designs pay resources who make no contribution to satisfying system needs or encourage behavior that creates challenging conditions for operators. Commenters also discussed whether current compensation schemes for ancillary services products, such as using opportunity costs, will continue to be appropriate as the resource mix evolves over time. Over the next five years, and over the next 10 years, how well will existing RTO/ISO market designs together with planned reforms adequately incentivize resource behaviors that will enable the RTO/ISO to meet its changing system needs?

   6.1. Discussions at the technical conferences and in comments emphasized the importance of having E&AS products match the time horizon and direction of system needs and uncertainties through shorter-term products (e.g., fast frequency response products and 10- or 15-minute ramp product), and longer-term products (e.g., multi-hour ramp products). However, commenters also noted that RTO/ISO system needs vary, and no "one-size-fits-all" E&AS reform currently exists to meet the unique needs of each RTO/ISO. We are requesting additional details on how the RTOs/ISOs plan to tailor their E&AS market reforms to their unique needs and why the reforms they are considering are appropriate to meet their expected system needs.

   How will existing E&AS market designs together with planned E&AS market reforms create appropriate incentives for existing resources to respond to system needs on operational time horizons (e.g., instantaneously, within five minutes, within 10 or 15 minutes, within one to four hours, etc.), and in the appropriate direction (up versus down)?

   6.2. Parties presented different views on whether the widespread use of opportunity cost-based ancillary service pricing will continue to sufficiently incent and compensate resources for meeting system needs as the resource mix and system needs evolve in the future. Given the critical role RTO/ISO resources play in meeting system needs, more information on how E&AS markets will provide adequate compensation for these costs is needed.

   How will existing E&AS market designs together with planned E&AS market reforms create sufficient fixed cost recovery under existing pricing methods (i.e., opportunity costs, shortage pricing, etc.) for resources to make needed investments, remain in service, and continue to offer the capabilities necessary to meet changing system needs?

6.2.1. How will existing E&AS market designs together with planned E&AS market reforms create an efficient long-run price signal for investment in new resources with the capabilities necessary to meet changing system needs?

6.3. Panelists agreed on the importance of establishing demand curves for ancillary service products carefully and rigorously but disagreed on the best approach, particularly with regard to using VOLL in such demand curves. While some panelists argued that VOLL should be the basis for all demand curves, others highlighted shortcomings of VOLL and suggested alternative approaches. Given the importance of defining demand curves for ancillary service products, further clarification of how such curves will be defined in future E&AS market reforms is needed.

Regarding E&AS products for which the RTO/ISO is contemplating reforms, to what extent will the reforms ensure that the E&AS products have well-defined demand curves that are rigorously designed to reflect system needs and transparently specify the quantity demanded by the market?

6.4. Many commenters raised concerns regarding the risk that E&AS market reforms will pay the incorrect resources, for example, paying all resources instead of resources that actually contribute to resolving system needs. Given the importance of ensuring appropriate incentives and compensation to resources that contribute to satisfying system needs, further clarification of how future E&AS market reforms will ensure appropriate compensation (e.g., that only resources that help operators meet system needs are paid) is needed.

Regarding E&AS products for which the RTO/ISO is contemplating reforms, to what extent will the reforms ensure that the E&AS products direct compensation to resources that contribute to satisfying the particular system need(s) the product is designed to address and not to resources that do not make such contributions?

6.5. Discussions at the technical conferences and in comments raised the possibility that there is some discrimination in current E&AS markets and stressed that any future reforms should not introduce further discrimination. Given the importance of avoiding undue discrimination in E&AS markets reforms and the disagreement about the degree of undue discrimination in E&AS markets, further clarification on how RTOs/ISOs will avoid or eliminate undue discrimination in future E&AS market reforms is needed.

Regarding E&AS products for which the RTO/ISO is contemplating reforms, including reforms to resource eligibility rules, to what extent will the reforms ensure that the E&AS products permit all resources technically capable of providing a product or service to offer to do so?

A. NYISO Response

Wholesale markets administered by the NYISO continue to harness competitive forces to improve the economic efficiency of operations and investment and encourage innovation. Asset owners and resources that are most efficient and optimally located will thrive in the market while lowering the costs of providing services to consumers. Asset owners who have inefficient resources or make poor investment decisions will bear the consequences and exit the market without placing additional cost burden on consumers.

The NYISO supports reliability primarily through three complementary markets for energy, ancillary services, and capacity. Each market addresses distinct reliability needs, and each provides competitive market pricing designed to meet reliability needs at an overall least-cost to consumers. Resources receive compensation through each market they participate in accordance with the value provided to the system. For example, resources that provide abundant energy but cannot be called upon to increase output in response to rapidly changing system conditions (*e.g.*, intermittent power resources) will receive the bulk of their market revenue from the energy market, with a lesser (or no) share of their revenue from the ancillary services and capacity markets. Thus, NYISO's markets appropriately compensate resources for each of the independent value streams they provide to the electric grid and consumers. NYISO's markets provide marginal pricing on a locational (nodal) level in order to reflect the reliability needs of specific areas of the state. This locational marginal pricing model minimizes overall costs to the state while serving as an important investment signal for investors. Additionally, the locational marginal pricing model, as the NYISO has demonstrated over the last 22 years, is the only model that can adequately support the physical operation of the grid, support many different regulatory and policy objectives including well-structured subsidies, and provide efficient ways to identify and mitigate attempts to exercise market power.[14]

Together, energy, ancillary services, and capacity revenues provide economic signals for new investment, retirement decisions, and participation by demand response providers. If energy and ancillary service revenues decrease such that revenue may not be adequate for the resources needed to meet grid reliability standards, then the capacity market prices increase to facilitate sufficient revenues for needed resources (new or existing). Thus, the NYISO's current market design is structured to allow resources to compete to provide reliability services, while maintaining revenue adequacy for needed resources. The NYISO's markets both retain resources that are providing reliability value and incent entry of new resources to maintain specified reliability levels, including the one event in ten years Loss of Load Expectation. While the capacity market is designed to meet resource adequacy, the energy and ancillary services markets provide the primary incentive for units to perform in real time and to respond to rapidly changing system conditions. Coordinated, well-functioning markets create opportunities for new and existing resources to compete to meet reliability needs.

The NYISO's market design includes various components that collectively encourage sufficient generation and transmission flexibility to exist on the bulk system. Market design features that facilitate adequate flexibility and the scheduling and commitment of sufficient resources to maintain reliability include: (i) the NYISO's Security Constrained Unit Commitment ("SCUC") software used for the Day-Ahead Market evaluation, which specifically includes a reliability commitment pass; and (ii) NYISO's Real-Time Market software, which is comprised of a Real-Time Commitment ("RTC") and a Real-Time Dispatch ("RTD"). Both

[14] The reliability, flexibility and market efficiency benefits of employing locational marginal pricing to develop energy prices are explained in detail in a White Paper developed by Scott Harvey and William Hogan. Their paper titled *Locational Marginal Pricing and Electricity Markets* is included as Attachment A to this Report.

SCUC and RTC award economic Energy, Ancillary Service, and Transaction schedules as well as bundled transmission service to the resources with economic schedules. These same market design components have been refined throughout the NYISO's history to reduce out-of-market actions and the resulting charges to customers.

The NYISO's SCUC process includes a reliability commitment pass to commit sufficient Day-Ahead supply resources to meet NYISO forecasted load. The reliability commitment pass schedules any additional supply resources and the necessary transmission service, through the economic commitment software, to make up any difference between the load bid into the Day-Ahead Market by Load Serving Entities and the NYISO's forecasted load requirements beyond the resources that are expected to be available in real-time. This functionality has significantly reduced out-of-market actions taken in real-time while also minimizing uplift payments.

The NYISO's Real-Time Market, comprised of RTC and RTD, performs a unique *ex ante*, simultaneously co-optimized, multi-period commitment, scheduling and dispatch process that evaluates bids and offers submitted by External Transactions and internal resources. The RTC and RTD evaluations simultaneously solve for all Load, External Interchange Schedules, Operating Reserves and Regulation Service requirements while satisfying transmission constraints in order to minimize the total as-bid production costs. Both RTC and RTD include look-ahead functionality.[15] This look-ahead functionality is intended to schedule the most efficient set of resources, recognizing both the current system conditions and expected future conditions.[16] The software's forward-looking capability recognizes Energy and Transmission

[15] RTC schedules Imports, Exports and internal (NYCA) resources every 15 minutes over a forward-looking 2.5-hour commitment window. The RTD optimization horizon is 55 to 60 minutes, depending on the interval. The NYISO is considering whether increasing the forward commitment windows that RTC and RTD employ can be used to help it address future system needs, including ramping needs.

[16] Many market operators in ISO/RTO regions have real-time look-ahead tools embedded within their Real-Time Scheduling ("RTS") processes that schedule and forecast internal resources and external transactions.

needs and dispatches resources in a manner consistent with real-time system conditions and helps avoid the need for out-of-market action.

1) NYISO Energy and Ancillary Services Markets are Working Efficiently and Improvements are Already Underway

The NYISO Energy and Ancillary Services markets are based on locational marginal pricing with regional reserve pricing. Since the NYISO simultaneously co-optimizes Energy, Operating Reserves and Regulation Service, these prices are based on both the as-bid costs and lost opportunity costs for providing each service. This approach is coupled with shortage pricing mechanisms that price Operating Reserves and Regulation Service when there is insufficient supply. Locational marginal pricing based on as-bid costs, accounting for lost opportunity costs and shortage pricing, has led to efficient compensation of resources for their services. This can be demonstrated by considering the levels of uplift payments being made to resources in the NYISO's Energy and Ancillary Services markets.[17] The NYISO believes pricing based on opportunity costs, along with appropriate as-bid costs, remains an important feature of its market design.

The NYISO continues to look for improvements that will become necessary to support the evolving resource mix and associated changes to grid risk. The NYISO Master Plan[18] and stakeholder driven process for enhancing the markets produces a set of market rules that adequately compensates the resources possessing the capabilities necessary to meet expected changing system needs. In 2021, the NYISO amended its Operating Reserve Demand Curves,

---

[17] The NYISO pays uplift to resources that are not able to recover their as-bid or as-mitigated costs from market revenues. *See e.g.*, uplift metrics within Monthly Reports available at https://www.nyiso.com/documents/20142/28665549/Board-Monthly-Report-August%202022.pdf.

[18] The NYISO provides a 5-year outlook of strategic market initiatives with stakeholder input, available at https://www.nyiso.com/documents/20142/33257202/Draft%202022%20Master%20Plan_Sept%2020%202022.pdf/46570f66-c077-f32e-dda6-9200917eca7c.

described throughout Services Tariff Section 15.4.7, to facilitate continued compliance with applicable reliability requirements and better align the cost curves with the value of certain actions taken to maintain reserve availability and system reliability.[19] The updated demand curve values provide targeted market signals that align with actual reliability needs at the times when actions would be required to maintain reliability, including manual operator actions. The NYISO also recently obtained stakeholder approval of its Constraint Specific Transmission Shortage Pricing project[20] to enhance the current transmission constraint pricing logic to enable the NYISO's market software to re–dispatch suppliers efficiently in the short term to alleviate transmission constraints, as well as to identify long-term investment incentives in locations where suppliers could provide the greatest benefits.

There is clearly more to do in anticipation of the changing resource mix driven by public policies, but the NYISO's existing market structure is readily adaptable to changing system needs and public policy priorities.

2) Challenges will Arise in the Future but the Markets Can Respond Efficiently

Going forward, the competitive market framework will continue to serve as an efficient and effective platform to facilitate expanded policy goals and integrate advanced clean energy resources. As grid risks change, it will be ever more important to make sure the Energy and Ancillary Services markets are incenting locational energy deliveries (or load reductions from customers that are price sensitive) where and when the energy is needed. The NYISO

[19] *See* Docket No. ER21-1018, *New York Independent System Operator, Inc.*, Proposed Tariff Amendments to Review the Operating Reserves Demand Curves and to Establish the Process to Procure Supplemental Reserves (February 2, 2021); and *New York Independent System Operator, Inc.*, 175 FERC ¶ 61,241 (2021).

[20] *See* NYISO's presentation to its Management Committee, June, 30, 2022, available at, https://www.nyiso.com/documents/20142/31859086/02%20CSTSP%20MATC%20Proposal.pdf/3d6ca268-e598-3f72-2630-37c01514a4de. The NYISO expects to implement this project in 2023, subject to an upcoming Federal Power Act Section 205 filing.

approaches every potential market enhancement effort with two guiding principles in mind; (1) all aspects of grid reliability must be maintained, and (2) competitive markets should continue to maximize economic efficiency and minimize the cost of maintaining reliability while supporting the achievement of New York's climate policy codified in the CLCPA.

The key challenges that will arise in the Energy and Ancillary Services markets with significant additional penetration of weather-dependent, intermittent resources are balancing intermittency and improving price formation. The grid of the future will require resources that can balance intermittence for extended periods of time, resources that can quickly turn on and are flexible in dispatch, and resources able to meet the sharp and occasionally sustained ramping needs created by the sudden disruption in solar or wind output while also conforming to the New York State's CLCPA goals.

The NYISO's wholesale markets can continue to successfully fulfill the mission and goals of reliability and economic efficiency while also serving as an effective platform for achieving New York State environmental objectives. As such, the NYISO is actively engaging with stakeholders and policymakers in developing plans to meet the future challenges expected to arise from a grid characterized with high levels of energy supply from intermittent renewable and DER. While each of these efforts addresses the concerns and follows the principles outlined above, they must fit together coherently and efficiently satisfy New York's grid reliability needs while maintaining and enhancing grid operations. As technologies change and the asset mixes evolve, continued assessment and on-going market improvements will need to occur.

The NYISO's ongoing Energy and Ancillary Services design initiatives are examining the appropriate price signals for generating resources that are responsive to real-time changes in system conditions. Quick start capability, ramping, and load following are needed for a system comprised of a large percentage of intermittent resources. An approach that emphasizes energy and ancillary services products and locational marginal market prices that are reflective of system conditions and operational requirements is important for incenting those needed attributes. For example, the NYISO realizes that determining the quantity and location of operating reserves more dynamically will be instrumental in preparing the markets for the new grid risks as the resource mix evolves.[21] Dynamic Reserves is a novel approach that is exploring more efficient scheduling of operating reserves based on system conditions and transmission system capability. This approach will not only allow for appropriate reserves to be procured to cover the largest source contingency that could potentially occur under the current system conditions,[22] but it will also allow for more reserves to be scheduled in cost-effective regions when there is sufficient transmission available to allow their use in the case of a contingency. Resources capable of providing reliability services where they are needed will be compensated more commensurate with their locational value and the NYISO will have access to lower cost reserves and more precisely calculated reserve requirements which will lower costs to loads.

Additionally, the NYISO has been studying ramping and flexibility needs as part of its Grid in Transition effort. The upcoming Balancing Intermittency project and the initiative to review Real-Time Market features to enhance incentives to follow NYISO instructions directly respond to expected ramping and flexibility needs. The Balancing Intermittency effort will evaluate new products and review shortage pricing of ancillary services in anticipation of

---

[21] Currently, the NYISO procures fixed quantities of reserves in specified regions across the state. The NYCA-wide reserve requirement is based on the largest single source contingency (a static value). This static modeling approach uses a pre-determined value to procure reserves, which potentially reduces the flexibility of the market model to reflect current grid conditions (*e.g.*, generation commitments and electrical flows on transmission), and to maintain system reliability with a least cost solution. The static modeling of locational reserves requirements does not optimally account for the real-time transmission flows and available transmission capability that could be used to deliver reserves from a more cost-effective reserve region.

[22] Operationally, the largest contingency could change based on the current commitment of generation.

increased intermittent resource participation. This includes another look at using the value of lost load ("VOLL") for establishing ancillary service demand curves. The Review of Real-Time Market Structure project will assess the existing Real-Time Market structure and settlements to determine if changes are needed to improve market efficiency for supporting reliable operation in real time, including lengthening the look-ahead capabilities of RTC and/or RTD to pre-position the system to address increasingly volatile, known ramping needs, manage new technologies, such as short duration storage and better address system condition changes between the Day-Ahead Market commitment and the 5-minute Real-Time Dispatch instructions.

The NYISO and its stakeholders are currently engaged in a number of other market design efforts related to future improvements of Energy and Ancillary Services markets. These efforts include:

1. More Granular Operating Reserves. The NYISO is exploring the implementation of reserve requirements within certain constrained load pockets in New York City and expects to review a complete market design with stakeholders in 2024.
2. Long Island Reserve Pricing. This project will evaluate whether revisions to current compensation rules are warranted to provide additional availability incentives for Long Island suppliers. The NYISO expects to review a complete market design with stakeholders in 2024.
3. 5-minute Transaction Scheduling. This initiative will evaluate how best to schedule external transactions every five-minutes with neighboring areas that are able to support a reduced scheduling horizon, aligning the scheduling of external interchange with internal resources and improving the options for maintaining grid reliability. The NYISO expects to review a complete market design with stakeholders in 2024.
4. Separating Up and Down Regulation Service. This would provide a greater supply of Regulation Service. The NYISO is investigating this opportunity and expects to propose a market design concept in 2025.

The 2021 Grid Services for Renewables study examined relevant reliability rules, as well as the necessary upgrades to typical inverters and controls that can enable renewable generators to provide additional grid services. Additionally, the study considered potential enhancements to current market designs to allow renewable generators to provide all of the grid services they are capable of providing. Specifically, the study identified an opportunity to expand the provision of Regulation Service from generators (both renewable and non-renewable) by separating regulation "up" and "down" products. The project Separating Up and Down Regulation Service will investigate bifurcating the regulation market, which could increase resource participation and competition to provide the services and reduce the overall costs of procuring regulation service. The transformation of the current regulation product into two products would probably not expand participation from renewable generators, but it would also have important implications for other resource types that currently provide Regulation Service.[23]

As intermittent generation grows in certain import-constrained areas, the amount of reserves carried in such areas may need to be increased to address the loss of supply. As part of the More Granular Operating Reserves effort, the NYISO is exploring the implementation of reserve requirements within certain constrained load pockets in New York City that would better represent the value of short-notice on-demand resources in desirable locations.

Increased flexibility is essential as the penetration of intermittent renewable resources increases. Currently, RTD schedules a significant portion of internal generation on a five-minute basis. However, interchange with external control areas is scheduled either on a 15-minute or an hourly basis by the RTC software. Scheduling external transactions with our neighboring control areas on a five-minute basis would increase flexibility in the energy and ancillary services markets and improve reliable grid operations. The 5-Minute Transaction Scheduling initiative will evaluate how best to schedule external transactions every five-minutes with neighboring areas that are able to support such scheduling, aligning the scheduling of external interchange

[23] *See* Grid Services from Renewable Generators report, available at b47e9923-c2bd-faa6-e81d-29300dd56df2 (nyiso.com).

with internal resources and improving the options for maintaining grid reliability.

Given all of the public policy activity in New York State as well as the NYISO's Energy and Ancillary Services market design efforts, the NYISO strongly supports tailoring solutions to the changes occurring within the NYCA and avoiding a one size fits all approach to any market reforms considered by the Commission. New York's needs will differ from other ISOs needs in both timing and scale. The mandates of the CLCPA require that NYISO prepare its markets for heavily intermittent generation sector at a different pace than its neighbors ISO-NE and PJM.

The NYISO's market design, including resource modeling, provides an even playing field for all resources. As the resource mix evolves and includes aggregation of different technologies, the NYISO market models will also evolve to represent the intended operation of such resources. However, as explained in the NYISO's request for rehearing in response to FERC's Order No. 2222 on July 18, 2022, certain combinations of participation or product eligibility cannot be accommodated. The Commission's instruction, read in the light least favorable to the NYISO, would require the NYISO to permit DER with different capabilities to provide Operating Reserves,[24] to participate together in a heterogeneous DER Aggregation, and to allow each DER in that heterogeneous DER Aggregation to simultaneously provide all of the Operating Reserves it is capable of providing. This requirement presents an intractably difficult problem for the NYISO to solve. DERs cover a broad range of resource types with very different operating characteristics, and the mathematical models underlying the SCUC, RTC, and

[24] There are three different Operating Reserve products in New York. Spinning Reserves (a 10-minute product that can only be provided by resources that are synchronized to the grid), 10-Minute Non-Synchronized Reserve and 30-Minute Reserve. An offline combustion turbine that can start-up and synchronize to the grid in 10 minutes cannot provide Spinning Reserve, but it can provide 10-Minute Non-Synchronized Reserve. A combustion turbine that requires more than 10 minutes to start-up and synchronize to the grid cannot provide 10-Minute Non-Synchronized Reserve, but can provide 30-Minute Reserve. In all cases, the Operating Reserves a Resource is permitted to supply are consistent with its physical capabilities.

RTD software that support the Day-Ahead and real-time energy markets cannot accommodate the potentially infinite combinations of resource characteristics. Instead of specifying a single participation model (heterogeneous DER Aggregation), the NYISO has explained to the Commission why it should be permitted to develop a combination of heterogeneous and homogeneous participation options to achieve Order No. 2222's goal of ensuring non-discriminatory access to DER with different operating capabilities.[25]

3) NYISO Efforts to Accommodate Increasing Penetration of Intermittent Renewable Generation and Storage Resources

New York's electric grid is transitioning to a clean energy system in direct response to state energy and environmental policies and technological innovation.

The NYISO has a number of projects underway to enhance intermittent and storage resource participation in wholesale markets in addition to the DER participation model. The NYISO submitted its Order No. 841 compliance filing, proposing Tariff revisions to implement Energy Storage Resources ("ESR") in its markets in December of 2018. The Commission accepted an amended set of rules to govern ESR participation in December of 2019[26] and the NYISO's ESR Tariff rules became effective in August of 2020. There are several ESR participating in the NYISO's markets today, with more on the way.

In early 2021, the NYISO submitted a Federal Power Act filing to FERC describing enhancements to enable an ESR and a wind or solar Intermittent Power Resource ("IPR") that share a common Point of Injection to participate in the ISO Administered Markets as a Co-located Storage Resources ("CSR").[27] The NYISO is currently working with its stakeholders to

---

[25] *See Request for Clarification or, In the Alternative, Rehearing of the New York Independent System Operator, Inc.*, Docket No. ER21-2460-002, at 20 (July 18, 2022).

[26] *New York Independent System Operator, Inc*., 169 FERC ¶ 61,225 (2019).

[27] *See New York Independent System Operator, Inc*., 174 FERC ¶ 61,242 (2021).

build on the CSR framework with its Hybrid Aggregation Storage Model ("HSR"), which aims to allow energy storage resources to aggregate with one or more Intermittent Power Resource (*i.e.*, solar, wind, and/or landfill gas) and/or Limited Control Run of River Hydro generators that are all co-located behind the same point of interconnection to form a single resource. In addition, as part of its HSR project, the NYISO will update the CSR model to allow combustion turbines ("CT"), landfill gas generators, and Limited Control Run of River Hydro generators to participate as CSR.[28]

Increasing reliance on both grid-connected, weather-dependent generation sources, as well as behind-the-meter clean energy resources (such as distributed solar generation resources), presents more potential for frequent, unanticipated, real-time system volatility.[29] The NYISO is considering processes to establish dynamic reserve procurement levels that reflect the expected operational and system risks, which may lead to larger reserve requirements than the static reserve requirements that are in place today. In early 2021, the NYISO proposed to establish a process to implement supplemental reserves when warranted in the future as a direct result of system conditions. The proposal contemplated implementing and/or adjusting requirements for the existing reserve products (*i.e.*, spinning, 10-minute, and 30-minute reserves) in excess of the current minimum quantities required for compliance with current reliability requirements.[30] The

---

[28] *See* NYISO's presentation to the Installed Capacity Working Group on October 4, 2022, Hybrid Aggregated Storage (HSR) Model – Tariff Modifications, Energy and Settlements, available at https://www.nyiso.com/documents/20142/33562316/Hybrid%20Aggregated%20Storage%20(HSR)%20Model%20-%20Tariff%20Modifications,%20Energy%20and%20Settlements.pdf/70cc4067-48f0-865b-e838-228faf0fe3ab.

[29] *See e.g.*, NYISO, *Proposed Approach for Considering Grid In Transition Recommendations* (presented to the Market Issues Working Group on December 7, 2020) at 10 (for a summary of New York's clean energy policies), available at: https://www.nyiso.com/documents/20142/17450815/20201201%20NYISO%20-%20Approach%20for%20Considering%20Grid%20in%20Transition%20Recommendations%20FOR%20POSTING.pdf; and NYISO, *Reliability and Market Considerations for a Grid in Transition* (December 20, 2019), available at: https://www.nyiso.com/documents/20142/2224547/Reliability-and-Market-Considerations-for-a-Grid-in-Transition-20191220%20Final.pdf.

[30] The proposal only permits the establishment and/or adjustment of supplemental reserve requirements for existing reserve products. The NYISO would be required to work with stakeholders on a new project to propose

supplemental reserves mechanism was intended to primarily address potential needs that could arise quickly, while seeking to avoid unnecessarily procuring additional products and services, and potentially increasing costs to Load before a system need arises. While the NYISO's specific proposal was rejected by the Commission, the proposal was developed in response to an expectation that such needs could arise quickly as intermittent, weather-dependent resources connect to both the bulk electric system and distributed systems at a rapid pace to achieve state environmental and energy policy mandates. This expectation still exists and the NYISO continues to review opportunities to address operating reserve needs as intermittent, weather-dependent resources are likely to connect to both the bulk electric system and distributed systems at an unprecedented pace.

The existence of various market products (*e.g.*, Energy, Ancillary Services, Installed Capacity) and differentiated payments based on resources operational capabilities is an important, necessary, and justified attribute of efficient electric markets that promote and protect reliability. As grid needs evolve and certain needs (*e.g.*, the need for operational flexibility) grow in importance, markets must exist for the attributes needed to reliably operate the grid, and resources must be compensated in accordance with their ability to satisfy reliability needs.

4) Avoiding Disorderly Retirements is Critical to Maintaining Electric System Reliability through New York's Clean Energy Transition

A balanced approach to achieving a clean energy grid is essential. Deactivating existing generation without having sufficient resources that are capable of providing comparable reliability services risks the NYISO's ability to maintain a reliable electric system. The NYISO has not observed disorderly retirements caused by lack of Energy and Ancillary Services market

---

tariff revisions to implement any new reserve product types/durations.

revenues. However, retirements driven by public policy requirements are reducing reliability margins and decreasing fleet flexibility especially where these retirements are happening ahead of the entry of anticipated new resources.

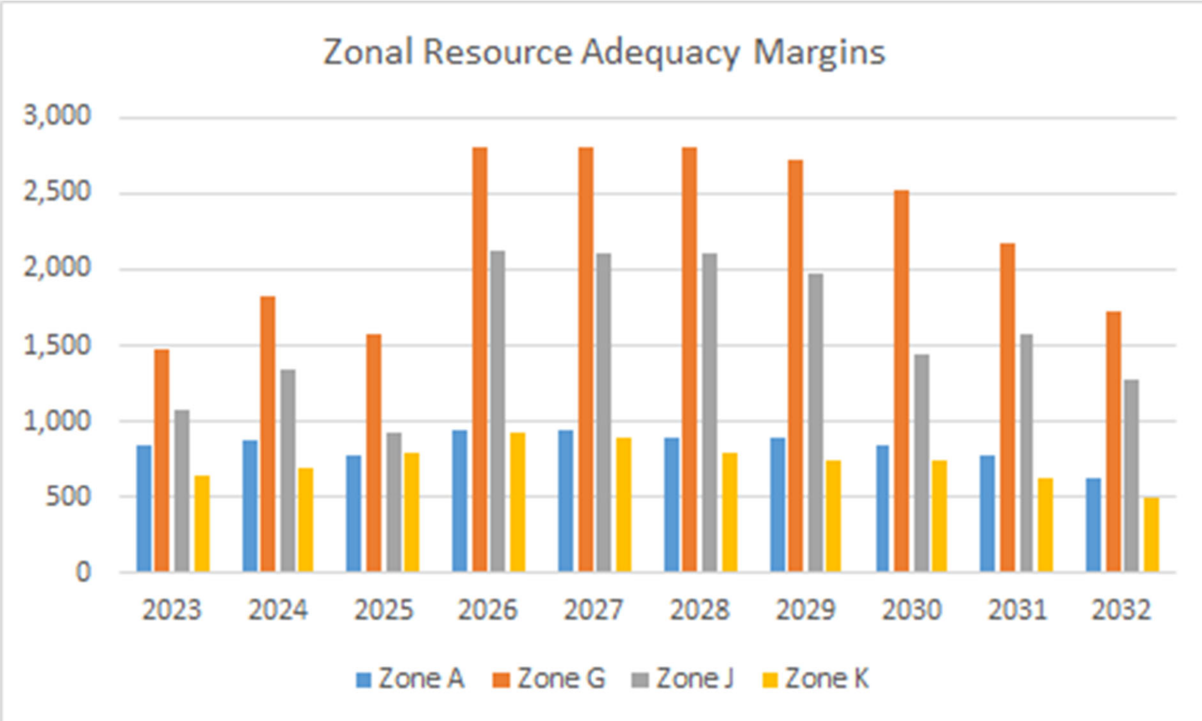
New York is experiencing the retirement of economic, flexible generating capacity. Currently, 1,000MW of quick start resources, which can quickly and flexibly come online to meet system needs, are in the process of retiring in response to an environmental regulation.[31] The CLCPA, discussed above, requires an economy-wide approach to addressing climate change and decarbonization. As a result, a significant number of operationally flexible fossil generators are expected to retire. Understanding the impacts of these deactivations, among others, on the generation, transmission, and load components of the bulk electric system is critical to understanding the challenges in the coming years.

With reliability margins shrinking, the NYISO's ability to facilitate a reliable electric system, including delivery to consumers, requires that the introduction of new resources with the ability to provide needed reliability services, such as dispatchability, be coordinated with and occur prior to the orderly retirement of existing generators that provide comparable services. Energy storage is a part of the potential solution, but battery storage cannot currently sustain operation for several days during a cold snap, like a fossil generator with on-site, back-up fuel can. The electric system will require electricity production and delivery from renewable resources and flexible resources to reliably meet demand and provide sufficient charging capability for the large levels of storage that are expected to enter the system.

---

[31] *See* DEC Peaker Rule.

Figure 4: Zonal Resource Adequacy Margins: 2024-2030[32]



Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. Coordination of renewable energy additions, commercialization, and development of dispatchable technologies, fossil fuel plant operation, and staged fossil fuel plant deactivations over the next 18 years will be essential to facilitate an orderly transition of the grid. This order of operations is critical for maintaining reliability after such retirements. Electric system reliability margins are already close to minimum reliability requirements in certain areas across New York and are tightening. If these margins are totally depleted, which could happen if a significant resource suffers an unexpected forced outage, the reliability of the grid would be at risk and power outages could disrupt normal life or negatively impact public health, welfare, and

[32] *See* pages 8 to 10 of the NYISO 2022 Reliability Needs Assessment Draft Report ("2022 RNA Draft") presented to stakeholders at the Electric System Planning Working Group on October 3, 2022, available at https://www.nyiso.com/documents/20142/33545961/08_2022RNA_Draft4Report_forOct3ESPWG-v1.pdf/e7f603bb-6bf1-339e-73c2-c08961fe403a.

safety.[33]

The reliability of the electric system is heavily reliant on the timely completion of planned transmission projects and generator additions. If planned projects are delayed for any reason, the system's ability to reliably serve customer demand would be jeopardized. As the NYISO recently reported in the 2021-2030 Comprehensive Reliability Plan and the 2022 Quarter 2 Short-Term Assessment of Reliability, the New York grid may not have the transmission system and generation resources to reliably serve electric demand in the future. In fact, the 2022 Reliability Needs Assessment ("RNA") Base Case includes the Champlain Hudson Transmission Partners ("CHPE") 1,250 MW HVDC project from Hydro Quebec to Astoria Annex 345 kV in Zone J and the NYPA/National Grid Northern New York Priority Transmission Project starting in 2026. In an August 2022 press release,[34] CHPE updated the project's full operation date to the spring of 2026, shifting from the originally anticipated in-service date of late 2025. If the CHPE project experiences a significant delay, or the forecasted demand in New York City increases by as little as 60 MW in 2025, or there are additional generator deactivations beyond what is already planned, some generation affected by the Peaker Rule may need to remain in service until permanent solutions are completed to avoid exceeding applicable reliability margins.[35]

3. <u>QUESTION 7</u>

7. Discussions at the technical conferences and in comments identified challenges to existing RTO/ISO operational practices and corresponding solutions, such as improvements in forecasts and tools to assist operators that RTOs/ISOs are developing or plan to develop. While discussions centered on changing operational practices such as these in the near-term, other discussions indicated that system needs and the associated operational challenges will

---

[33] *See* 2022 RNA Draft at page 92.

[34] The press release is available at: https://chpexpress.com/news/champlain-hudson-power-express-provides-update-on-anticipated-full-operation-date/.

[35] *See* Draft 2022 RNA at pages 54 to 56.

continue to change significantly beyond the near-term. As such, more clarification about how RTOs/ISOs intend to improve operational practices beyond the near-term is needed.

Referring to the changing system needs discussed in questions 2 and 3, how does the RTO/ISO expect to alter its operational practices, if at all, in order to successfully manage changing system needs over the next five years and over the next 10 years?

7.1. How does the RTO/ISO expect to meet challenges related to forecasting customer loads and variable energy resource outputs?

7.2. What model improvements, new operational tools, refinements to existing operational practices, or market software enhancements, if any, does the RTO/ISO expect to develop and/or deploy?

A. <u>NYISO Response</u>

1) Forecasting Electric Consumption and Behind-the-Meter Solar Resources

The NYISO has proactively implemented forecasting systems and procedures to address the shifts in electric consumption patterns and is working to expand and supplement these tools as appropriate going forward. Real-time (and Day-Ahead) load forecasts now account for behind-the-meter solar resources, such as roof-top installations and community solar installations. The NYISO currently contracts with multiple vendors to track and forecast behind-the-meter solar capacity and generation within the New York Control Area. Forecasting behind-the-meter solar generation patterns involves using additional weather station data, high resolution satellite data, and sophisticated numerical weather prediction models to forecast clear sky and cloudiness conditions across the state.

The NYISO is also exploring the integration of shorter-term behind-the-meter forecasts (reducing the frequency of forecast updates from one-hour to 15 minutes) to enhance the accuracy and responsiveness of its real-time forecasts. Further development of this system is planned in the future as the number and variety of behind-the-meter distributed resources increases in response to state energy policies.

In parallel, the NYISO is working to develop software systems to track participation of aggregated distributed energy resources (DER) in the NYISO-administered wholesale electric markets. This is critical to ensure that such resources are treated properly in the formulation of real-time and day-ahead load forecasts. DER *not* participating in the wholesale market are treated as retail resources (or load modifiers). Conversely, DER participating in the wholesale markets are treated as wholesale resources. The treatment of wholesale resources as retail resources (and vice-a-versa) in the development of load forecasts for the NYISO's wholesale markets could produce inappropriately low or high load forecasts.

The NYISO is also investing in the development of long-term end-use forecasting models. These models construct system-level forecasts utilizing available data on housing stock, appliance saturations and efficiencies, and commercial square-footage; and are particularly effective in instances when, for example, the historical relationships between consumption and weather and daily load patterns are no longer valid. A situation that is expected to arise in coming years as the building and transportation sectors are further electrified (*e.g.*, expanded adoption of electric heat pumps and light, mid- and heavy-duty electric vehicles). Forecasted load levels and patterns from these long-term models will be leveraged to support the evolution of real-time forecast models as the underlying consumption patterns shift. These end-use forecasting models are also using updated long-term weather trends from recent study work performed by the NYISO. Evolutions in long-term weather patterns due to climate change are expected to alter consumption patterns in the coming decades.

The NYISO is continuing to build out its end use modeling framework (inclusive of electric vehicles, photovoltaics, storage, and other DER) and working toward adoption of hourly load modeling in its long-term forecasts to more accurately forecast the gradual shifting of seasonal load shapes, including the timing of summer and winter peaks.

2) NYISO Operational Tools and Situational Awareness

The NYISO has adopted several operational practices to retain situational awareness as the resource mix on the grid has evolved to include higher penetrations of new technologies, such as renewable generators and energy limited resources. Some of these practices include (1) a daily review of the next seven days for expected weather and storm activity, (2) regular updates on weather that impacts solar generation availability, such as fog, cloud cover, and snow cover, and (3) updates on weather that impacts wind generation availability, such as high winds or icing that can lead to cutout. In addition, the NYISO regularly reviews the forecast accuracy for intermittent resource output to identify potential improvements, and better understand how the relationship between intermittent resource forecasts and actual intermittent resource production impacts system ramp needs.

The NYISO strives to continuously improve its operational practices and has two efforts underway to develop new tools to help the operations personnel manage small resource derates and outages and manage energy availability of limited energy resources. The NYISO Capacity Analysis Commitment Tool ("CACT") and Grid Operations Coordination Portal ("GOCP") will help automate these manual tasks that can take up precious operator attention and time, while retaining the grid reliability that New Yorkers expect.

When NYISO Operators identify hours when additional energy and/or ancillary services are required to meet reliability needs, the CACT will present a list of resources available to be scheduled to operate during these hours. Using the CACT, NYISO Operators will review hours of NYCA-wide or local load zone reliability needs and meet the needs through a combination of scheduling available resources that do not have a Day-Ahead schedule and moving resource schedules from hours of excess generation.

The GOCP tool will be used by DER and HSR (with the potential to expand use to include other resources in the future) to submit outage data via the web without the need to make a phone call to the Transmission Owner or to NYISO operations. The GOCP will enable DER and HSR to report resource outages and derates on a more granular basis. It will enable them to report the need for in-hour derates post market-close, which will make it easier for NYISO to provide feasible schedules to these resources. Finally, the NYISO plans to use the GOCP to enable DER and HSR to update their Operating Reserve Limit—a new metric that will tell the NYISO the quantity of Operating Reserves the DER or HSR can provide and sustain for at least an hour if the Operating Reserves need to be converted to Energy.

4. QUESTION 8

8. Some discussions in the comments and technical conferences noted that while many RTOs/ISOs are creating new E&AS products to incentivize flexibility, existing E&AS market designs might be incentivizing inflexibility. Some discussions specifically referred to uplift payment policies and operational parameters such as economic minimums as creating incentives for inflexibility. Given the importance of E&AS markets incentivizing resource capabilities and performance that help to meet system needs, more information about how future reforms will address possible incentives for inflexibility is needed.

   Beyond the reforms discussed in answering questions 4-7, what other reforms to current RTO/ISO E&AS market rules may be required in the future given the RTO's/ISO's expected changing system needs and shortcomings of current E&AS market designs? Why? For example, are changes to resource eligibility rules for ancillary services or uplift policies expected to be necessary?

A. NYISO Response

As a general rule, the NYISO requires that resources do not reduce or limit their flexibility in the Real-Time Market in order to be eligible for uplift payments, such as the NYISO's bid production cost guarantees ("BPCG") and/or day ahead margin assurance payments ("DAMAP"). A Resource that self-commits is not eligible to receive BPCG unless it is committed Out-of-Merit or via a Supplemental Resource Evaluation to protect local

(Transmission Owner) or NYCA reliability.[36] The NYISO similarly restricts DAMAP payments to Generators that reduce their flexibility in real-time.[37] The NYISO does not currently expect changes to eligibility rules to be required within the ISO-Administered Markets.

5. QUESTION 9

9. Despite the focus of the E&AS technical conferences on E&AS markets, several panelists and commenters expressed support for the continued use and importance of capacity markets and potentially new resource adequacy constructs to satisfy future system needs. Given the focus of the record thus far on potential E&AS market reforms to satisfy operational flexibility needs and other system needs, the Commission would like to give RTOs/ISOs and other commenters the opportunity to comment on other possible reforms beyond E&AS market reforms that should be considered to meet changing system needs.

   For RTOs/ISOs that administer a capacity market, what capacity market reforms, if any, is the RTO/ISO considering to meet expected system needs in the future? For RTOs/ISOs that do not administer a capacity market but rely on a different resource adequacy construct, what reforms, if any, is the RTO/ISO considering to that construct to meet changing system needs?

   9.1. What new capacity accreditation methods, if any, is the RTO/ISO considering for its resource adequacy processes? How will such new capacity accreditation methods help the RTO/ISO satisfy expected changing system needs?

   9.2. What new products that value flexible attributes, if any, should be introduced in resource adequacy constructs, including capacity markets? Would such a change support adequate price signals for the investment and/or retention of resources with the capabilities needed to address emerging needs?

A. NYISO Response

The NYISO administers an Installed Capacity market to procure sufficient resources necessary to meet the resource adequacy obligations established by the New York State Reliability Council ("NYSRC"). As part of the Installed Capacity market, the NYISO runs a prompt spot auction monthly to procure capacity from suppliers to meet the Installed Reserve

---

[36] *See e.g.*, Sections 18.2.1.2 and 18.4.1.2.1 of the NYISO's Market Services Tariff.

[37] *See e.g.*, Section 25.2.2 of the NYISO's Market Services Tariff.

Margin ("IRM") established by the NYSRC and Locality Capacity Requirements ("LCRs") established by the NYISO and all approved by FERC. The prompt Installed Capacity market with proper capacity accreditation mechanisms based on marginal contributions to meeting resource adequacy and sloped demand curves for price determination continues to be an appropriate and extremely efficient way to support resource adequacy requirements.

As part of the NYISO's Comprehensive Mitigation Review filing,[38] the NYISO worked with its stakeholders to overhaul how all resources are valued in the NYISO's Capacity Market. Starting with the NYISO's 2024-2025 Capability Year, which begins May 1st, 2024, all resources participating in the NYISO's Capacity Market will have a capacity accreditation value based upon the marginal reliability value that resources in the same class provide the Resource Adequacy model used to set the Capacity Requirements for upcoming Capability Year. This model is calibrated to the "at criteria" system, with a Loss of Load Expectation of 1 day in 10 years, otherwise known as a 0.1 Loss of Load Expectation. This Loss of Load Expectation is required by the New York State Reliability Council,[39] and is required to be calculated annually to ensure updates to the New York Control Area for load, generation, and transmission are captured and reliability criteria are met. With the enhancement to capacity accreditation for resources being based on the marginal reliability value they provide, as the underlying system evolves, the value of resources will be updated yearly to ensure that the capacity market provides price signals for the resources that are needed to support resource adequacy.

As part of the NYISO's work with stakeholders in implementing these revisions to the

---

[38] *See New York Independent System Operator, Inc.*, 179 FERC ¶ 61,102 (2022) and *New York Independent System Operator, Inc.*, Letter Order, Docket No. ER22-772-000, *et. al.*, (August 10, 2022 (accepting tariff revisions to revise its Unforced Capacity requirement calculations).

[39] NYSRC Reliability Rule A.1: R1 and R1.1, available at https://www.nysrc.org/PDF/Reliability%20Rules%20Manuals/RRC%20Manual%20V46%20final.pdf.

NYISO's capacity accreditation methodology, the NYISO and its stakeholders have identified the need for enhancements and revisions to the resource adequacy models to properly account for changing system conditions. The NYISO has identified several areas for exploration in the near term in its 2022 Master Plan,[40] and will continue to work with stakeholders to enhance the resource adequacy model to more accurately capture factors that can affect resource adequacy.[41] These factors include, but are not limited to, modeling enhancements of units with limited run time, natural gas constraints effects on resources, and refining the treatment of emergency assistance from neighboring area to consider seasonal variations of each region's capability.

As part of the Comprehensive Mitigation Review process discussed above, the NYISO discussed with stakeholders the potential to include other attributes in the Capacity Market, such as attributes for clean, flexible, or storage capability,[42] and decided with stakeholder agreement to instead focus on updating the capacity accreditation methodology for resources to move to a marginal capacity accreditation process. This decision was made in part due to the ability of marginal capacity accreditation to provide effective and efficient market signals to resources based on their operating traits and how they support system reliability. With a marginal capacity accreditation approach to valuing all resources in the capacity market and improvements to the resource adequacy model as the system and risks to grid reliability evolve, the NYISO does not believe that additional products, such as a product focused on flexibility, are needed to incent

---

[40] *See* Draft 2022 Master Plan, Modeling Improvements for Capacity Accreditation and Evolving Resource Adequacy Models, presented at the 9/20/2022 ICAPWG, available at: https://www.nyiso.com/documents/20142/33257202/Draft%202022%20Master%20Plan_Sept%2020%202022.pdf.

[41] *See id.* and NYISO's presentation to the Installed Capacity Working Group on October 19, 2022, Capacity Accreditation, available at https://www.nyiso.com/documents/20142/33857891/02a_10-19-22%20ICAPWG%20Capacity%20Accreditation.pdf/cae2063d-76d6-b4d3-25d5-fadd0c5e1f50.

[42] *See* presentation to the Installed Capacity Working Group on March 25, 2021, Multiple Value Pricing, available at https://www.nyiso.com/documents/20142/20226859/Multiple%20Value%20Pricing%20032521.pdf.

resources needed to meet reliability needs.

Beyond updating the capacity accreditation methodology for all resources, they NYISO has identified potential needs for future revisions to support the energy transition in NY, which is anticipated to move from mainly resource adequacy needs driven by the summer peak loads to a distribution of resource adequacy needs driven by summer peak loads and winter reliability risk due to unavailability of natural gas dependent resources and intermittent renewable resources, such as solar. As identified in the 2022 Master Plan,[43] the NYISO has proposed to examine the existing Capacity Market structure to identify if revisions are necessary to support a shift from resource adequacy needs occurring during summer to growing needs in winter. Additional examinations may be necessary as more investment into the transmission grid is performed, which could alter how locational constraints in the Capacity Market are modeled and solved for.

6. QUESTION 10

10. While this proceeding focused on RTO/ISO markets, several panelists and commenters noted challenges to meeting RTO/ISO system needs that arise from sources beyond the RTO/ISO markets themselves. Panelists and commenters noted potential reforms necessary to address challenges related to coordination between adjacent balancing authorities, coordination between transmission and distribution operations, and inflexibility in the fuel supply of certain resources. Given the lack of record thus far on these challenges and potential reforms, more information is needed to ensure RTOs/ISOs can continue to meet system needs as they evolve in the future and identify and address any obstacles to that objective.

    What reforms beyond those to the RTO's/ISO's tariff(s) does the RTO/ISO believe might be needed to address expected changing system needs?

    10.1. What reforms to reliability requirements, such as reforms to NERC standards, might be necessary?

    10.2. What reforms to policies for coordinating operations with adjacent balancing authority areas in both RTO/ISO and non-RTO/ISO regions might be necessary?

[43] *See* Draft 2022 Master Plan, Winter Reliability Capacity Enhancements, presented at the Installed Capacity Working Group meeting on September 20, 2022, available at: https://www.nyiso.com/documents/20142/33257202/Draft%202022%20Master%20Plan_Sept%2020%202022.pdf.

10.3. What actions should the Commission consider taking to encourage coordination between the electricity transmission and distribution system operators in order to address challenges arising from limited visibility into distribution-connected resources?

10.4. What reforms to other services within the Commission's jurisdiction, such as natural gas transportation services, should the Commission consider in order to improve operational flexibility in the fuel supply?

A. NYISO Response

While the NYISO's Day-Ahead Market scheduling process works efficiently with natural gas nomination opportunities, enhancements to the natural gas scheduling process could provide electric generators with increased flexibility that will be necessary to support electric system reliability under the changing generation and load conditions discussed throughout this report.

Additional nomination opportunities over weekends and holidays would more efficiently support electric generation.[44] Generators would be able to procure gas that aligns closer to their electric generation needs, which could vary dramatically over a two- or three-day weekend, or the five-day period around the Thanksgiving holiday. Forecasting electric generation and corresponding natural gas needs several days in advance increases uncertainty today and will prove more difficult in the future with higher penetration of intermittent generation.

The NYISO is planning for the eventual deactivation of natural gas-fired electric generators in response to public policy in New York State. However, natural gas-fueled generators will be required to maintain electric system reliability until sufficient new resources with similar operating attributes are developed and connected to the electric system. Flexible natural gas nominations will be critical to balance the intermittency of wind and solar resources until new flexible clean technologies are developed and deployed consistent with New York State's CLCPA mandates.

---

[44] *See Comments of the ISO/RTO Council*, Docket No. RM14-2-000 (November 25, 2014).

The NYISO encourages consideration of the following potential improvements:

1. Aligning natural gas nomination scheduling requirements more closely with actual deliveries (*i.e.*, permit hourly gas nominations).
2. Shortening the time commitments associated with natural gas deliveries (*i.e.*, hourly gas nominations), particularly when actual temperatures deviate from forecasts.
3. Development of non-traditional gas market products and a secondary market for the resale of unused gas that are responsive to changing electric market system needs (*e.g.*, the ability to start or ramp-up natural gas fired generation to address wind lulls, or the ramp-down of solar production on summer afternoons).
4. Hardening/winterization of natural gas infrastructure and designation/identification of critical interdependent facilities (natural gas and other fuel supply infrastructure, communication infrastructure, etc.).

With the increasing number of intermittent electricity resources being installed and increasing variability in electric load, natural gas-fired power plants will be called on to utilize their fast start and quick ramping capability to respond and serve as a backstop to maintain the reliability of the power grid. As a result, pipelines will be asked to deliver large volumes of natural gas on short notice, a major shift from the traditional model of supplying natural gas to industrial and local distribution markets. The potential improvements proposed here by the NYISO would increase market opportunities for natural gas producers and pipelines and increase flexibility for electric generators.

7. QUESTION 11

11. While the questions in this order have asked about a five-year and 10-year time horizon, what activities, if any, is the RTO/ISO undertaking to consider changing system needs that could materialize beyond the 10-year time horizon?

A. NYISO Response

In 2021, the NYISO revised its Economic Planning process to extend the economic planning study scope from 10 years to 20 years.[45] This adjustment was made in recognition of

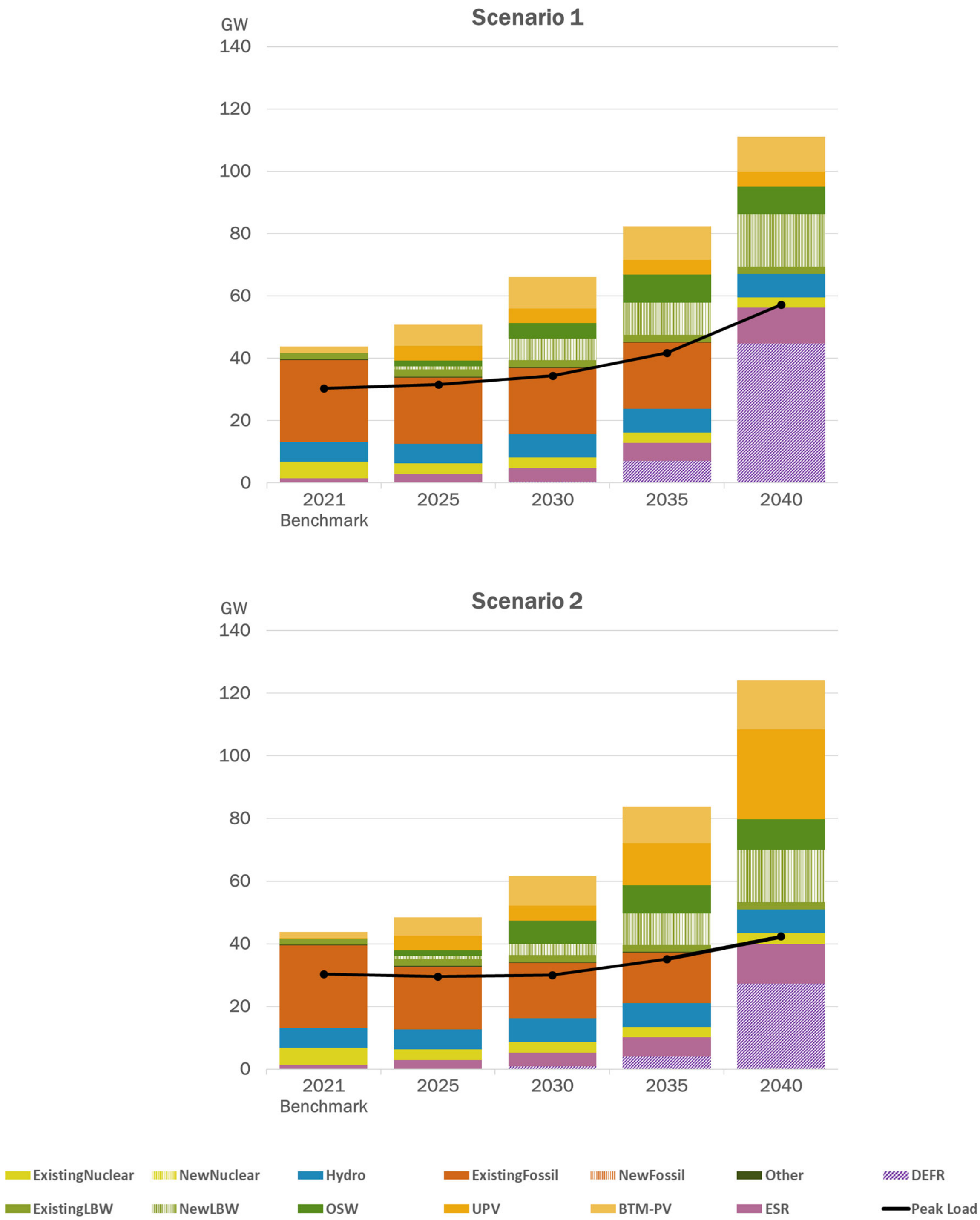
[45] *See New York Independent System Operator, Inc.*, 175 FERC ¶ 61,010 (2021).

the state policy mandates that set milestones in the 2030 and 2040 timeframe.[46] The NYISO recently published its *2021-2040 System & Resource Outlook* (the Outlook), a new NYISO report that follows the revised economic planning process and includes an examination of the level of electrical system investment necessary to achieve New York State's climate policy requirements. Developed in collaboration with stakeholders and state agencies, the Outlook uses several scenarios to identify potential pathways for transmission and supply investments that will support a reliable transition of the electric grid towards achieving state policy. Going forward, the Outlook will be updated every two years as part of the NYISO's economic planning process.

In addition to the study timeframe extension, new tools and methods were introduced to enable the evaluation of changing system needs. For example, a capacity expansion model is now being used in the Outlook and is critical to projecting the various pathways to achieve policy objectives through 2040. Several of the future scenarios are then evaluated in production cost and flexibility/reserve models to identify operational, economic, reserve, and other needs.

[46] *See,* New York Climate Leadership and Community Protection Act (CLCPA), NY State Senate Bill S6599, 2019-06-18.

Figure 5: New York Installed Capacity Generation Resource Mix Scenarios[47]



The 2021 RNA included a reliability evaluation of one of the policy scenarios developed

[47] *See*, The Outlook at pages 46 to 49.

in the 2021-2040 System & Resource Outlook to determine LOLE performance under a scenario where policy objectives are achieved.

Additionally, since the CLCPA was enacted in 2019, the NYISO has taken several other steps to better understand the reliability, operational, and market implications of such a transformation in the resource mix operating within the state between now and 2040. In late 2019, the NYISO released a report outlining *Reliability and Market Considerations for a Grid in Transition*,[48] its "Grid in Transition report" and a look at the anticipated long-term load impact.[49] In 2020, based on the considerations described in its Grid in Transition report, the NYISO released two important studies, *New York's Evolution to a Zero Emission Power System*[50] and *Climate Change Impact and Resilience Study*.[51] These studies helped inform the NYISO and its stakeholders about the operational, reliability and investment implications of transitioning to a carbon free grid by 2040. The Grid in Transition report and following studies continue to frame the NYISO's approach to evolving its market design, including the NYISO's consideration of enhancements to the energy and ancillary services markets.

The three reports highlight potential issues that, if not addressed early, could lead to poor investment decisions or, worse, reliability issues. Some of the potential issues identified by the reports include:

- The variability of output from wind and solar resources presents a fundamental challenge to balancing supply with electricity demand, while the growth of behind-the-meter supply will increase the variability of demand on the system, making load more dynamic than it is today;

---

[48] *See* Grid in Transition report.

[49] *See New York ISO Climate Change Impact Study: Phase 1: Long-Term Load Impact.*

[50] *See Evolution to a Zero Emission Power System* study.

[51] *See Climate Change Impact and Resilience Study* Official Phase 2 report.

- Battery storage resources help to fill-in short term reductions in renewable resources output, but extended periods of low- or zero-renewable output rapidly deplete the short duration storage capabilities of existing battery technologies;
- Dispatchable, emission-free resources with longer duration energy output capabilities are needed to balance renewable intermittency on the system; and
- Climate change will impact meteorological conditions and cause events that introduce additional reliability risks.

8. QUESTION 12

12. If RTO/ISO market design changes beyond the RTO/ISO's planned E&AS market reforms discussed in answering questions 4-7 are necessary to manage expected changes in system needs, how can the Commission best assist RTOs/ISOs and their stakeholders in reforming their markets in the future?

A. NYISO Response

The NYISO's responses in this submittal have detailed robust tools for identifying the operational services needed to maintain grid reliability as New York transitions to the clean energy electric system envisioned in state policies. The Energy and Ancillary Services design initiatives detailed in this submittal are informed by vigorous market design and economic studies and robust planning analyses. These efforts, undertaken with thorough engagement with stakeholders, support the market reform initiatives underway and inform a continuous re-evaluation of system conditions for additional future market enhancements.

The NYISO's shared governance process has a proven track record of developing innovative market design enhancements that support reliability, enhance market efficiency, and reduce barriers to entry for the new clean energy resources entering service in response to state policies. An example a recent shared governance experience is the Comprehensive Mitigation Review ("CMR") proposal. This innovative proposal, addressing long-standing concerns with the impacts of buyer-side market mitigation rules on state policy objectives, as well as proposing needed enhancements to capacity accreditation rules, was the product of an extensive shared governance process that resulted in approval by more than 80% of NYISO stakeholders. The CMR proposal was approved with strong backing across all five stakeholder sectors, including unanimous support from New York State entities, New York City, municipal interests and the New York Transmission Owners, and significant support from both existing capacity suppliers and consumer interests. The NYISO's independent market monitor also played a major role in developing the CMR proposal. The Commission accepted the proposal in May 2022.

The NYISO encourages the Commission to allow each ISO/RTO, and the NYISO specifically, to work within its respective stakeholder processes to develop the improvements needed to continue running efficient wholesale electricity markets and to maintain electric system reliability as we transition to the grid of the future.

The Commission should not impose a uniform approach on all ISOs/RTOs. Each ISO/RTO relies on a different mix of generation resources and must consider vastly different public policies from the state or states within its region. The characteristics of each ISO's/RTO's commitment, dispatch, and settlement processes should inform how each ISO/RTO moves forward with potential market improvements. The Commission has recognized that ISOs and RTOs do not (and need not) have identical software or market rules for their markets and power systems to produce compatible results.[52] The Commission has also recognized that the practical ability of each ISO or RTO to implement software changes, including the potential costs of making those changes, often justifies allowing ISOs/RTOs to comply with Commission mandates in ways that accommodate regional differences rather than insisting on "one-size fits

[52] *See, e.g., New York Independent System Operator, Inc.*, 142 FERC ¶ 61,202 at PP 24-26 (2013) ("NYISO's compliance obligation does not require NYISO to redesign its market. [footnote omitted]. This would be particularly unnecessary here where, as NYISO points out, it would be costly and economically inefficient to do so.")

all" solutions.[53]

The NYISO, as well as other ISOs/RTOs around the country, have robust stakeholder-driven processes that identify priorities and the projects required to support region-specific priorities. The NYISO encourages the Commission to allow these processes to anticipate the changes that will be needed in their region and to develop the market rules and projects that will address the changing system needs and resource models.

II. The NYISO's Responses to Commissioner Christie's Additional Questions

In addition to the questions that the Commission instructed the NYISO to address, Commissioner Christie posed five additional questions to the ISOs and RTOs. The NYISO has addressed most or all of Commissioner Christie's questions in its responses above. The NYISO was most intrigued by Commissioner Christie's question #3 that asked:

> Is it appropriate to continue to use LMP in energy and capacity markets? Does the continued use of LMP threaten reliability as the generation mix changes? Does the use of LMP ensure that consumers get the benefit of low clearing prices? Is there a better pricing model than LMP in RTO/ISO markets to achieve reliability and fairness to consumers?

The NYISO's response is an emphatic "yes." It is appropriate for ISOs and RTOs to continue to use Locational Marginal Pricing ("LMP") in energy markets, and to co-optimize the scheduling of related ancillary services products, including regulation service and operating reserves. The NYISO is not aware of any other pricing model that would be equal to or superior to the LMP market methodologies employed in ISO/RTO markets to maintain reliability while producing fair wholesale electric market prices for consumers.

To more completely respond to Commissioner Christie's question, the NYISO commissioned noted economists Dr. Scott Harvey and Dr. William Hogan to prepare a paper that

---

[53] *Id*. *See also, New York Independent System Operator, Inc.*, 133 FERC ¶ 61,246 at P 25 (2010).

explains the development and benefits of LMP pricing, and compares the benefits of using LMP to other recognized market models. Doctors Harvey and Hogan conclude that LMP provides the flexibility and capabilities that ISOs and RTOs will need to:

(a) provide efficient incentives for storage resources to charge and discharge;

(b) send a pricing signal that behind-the-meter generation and other resources that the ISOs and RTOs do *not* directly dispatch can respond to;

(c) produce operationally feasible, financially binding, day-ahead schedules;

(d) provide locational incentives that signal where generation is needed, where load should locate, and where storage devices can be deployed to greatest effect;

(e) supports efficient and competitive entry to provide balancing service by enabling forward hedging and forward contracts that recognize locational prices;

(f) is flexible enough to accommodate new market dispatch designs and evolving environmental rules and subsidies; and

(g) permits mitigation measures to be focused on sellers with the ability to profitably exercise locational market power.

Their paper titled *Locational Marginal Prices and Electricity Markets* is included as Attachment A to this Report.

III. Conclusion

The NYISO submits this Report to inform the Commission's consideration of whether further action is appropriate. While the grid of the future poses various challenges, the NYISO is working with its stakeholders to undertake numerous initiatives, described above, to prepare its wholesale markets for the massive changes that are anticipated. The NYISO and its stakeholders have many energy and ancillary service market initiatives planned and underway that are or will be important for maintaining reliable electric service, supporting a smooth transition to meet New York's CLCPA requirements, and supporting related energy and environmental goals.

Rather than instructing changes that assume each ISO and RTO faces similar problems, the NYISO respectfully requests that the Commission allow each ISO or RTO to devise modifications to its energy and ancillary service markets that best meet that region's operational needs. The NYISO does not support a "one size fits all" solution, or the imposition of a uniform set of requirements on all ISOs and RTOs.

Respectfully submitted,

NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.

By: */s/ James H. Sweeney*
Alex M. Schnell
Assistant General Counsel,
Registered Corporate Counsel
James Sweeney
Senior Attorney

October 18, 2022

Attachment A

Locational Marginal Prices and Electricity Markets

Scott Harvey and William Hogan [1]

October 17, 2022

"…it is time to put the all-important question of the continued use of locational marginal pricing (LMP) in these market constructs on the table for serious scrutiny and discussion."[2]

I. Introduction

In the absence of a monopoly, electricity markets allow market participants to make choices about their real-time generation and power consumption, as well as injections and withdrawals from storage. The real-time price of power plays a major role in making these choices. Prices that are too high or too low distort real-time choices as well as associated expectations for long-run scheduling and investment decisions. Both economic theory and extensive practical experience demonstrate why the real-time locational marginal price (LMP) is the only real-time pricing system that supports an efficient wholesale electricity market. The Federal Energy Regulatory Commission (FERC) has wisely supported the development of LMP markets. The critical role for LMP was true in the past, is true today, and will be true and more important with the anticipated changing resources mix.

Locational marginal pricing has two important characteristics.[3] First, the prices are calculated from the system operator's actual operational security constrained economic dispatch solution for balancing load and generation. LMP prices support balanced supply and demand at each location and account for market participant bids and offers, the physical constraints of the transmission system and physical constraints on resource operation such as upper operating limits, and ramp rates. Second, LMP settlements are based on market clearing prices, as opposed to the pay-as-bid pricing designs used to determine constrained-on and -off payments in non-LMP pricing systems.[4]

---

1 William W Hogan is the Raymond Plank Research Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University. Scott Harvey is a consultant with FTI Consulting and a member of the California ISO/Western EIM Market Surveillance Committee. The preparation of this paper was supported by the New York ISO. Michael DeSocio and Alex Schnell of the New York ISO, and Jason Mann and Martina Lindovska of FTI Consulting LLP, provided valuable comments, but the views represented here are not necessarily attributable to any of those mentioned and any remaining errors are solely the responsibility of the authors. A full disclaimer of the author's past and current consulting relationships is provided in an endnote.

2 Commissioner Mark Christie, Concurring Opinion, "Modernizing Wholesale Electricity Market Design," Federal Energy Regulatory Commission, Docket No.AD21-10-000, April 21,2022.

3 The framework here is the generic economic dispatch model for congested power flows and abstracts from related issues associated with ancillary services and commitment decisions. See (Schweppe et al., 1988). For an introduction to locational marginal pricing see (Hogan, 1998). For the more general case, see (Gribik et al., 2007) and (Andrianesis et al., 2022).

4 Constrained-up and -down payments compensate resources that would otherwise lose money if they followed their dispatch instructions. Constrained-off payments are conceptually the difference between the clearing price and the offer of the resource. Constrained-on payments are similarly conceptually the difference

A crucial element of LMP pricing is that it settles all resource injections and withdrawals at the same location at the same point in time at the same market clearing spot price. This is a fundamental feature of LMP pricing because LMP pricing is intended to provide prices that are consistent with least cost dispatch instruction and that reflect the cost of meeting load at each location at each point in time. The only alternatives to settling all injections and withdrawals of dispatchable resources at market clearing prices would be designs based on command and control or based on constrained-on and -off payments with pay-as-bid designs. As discussed further below, the market clearing price signal plays an important role in assuring that the injection and withdrawal decisions of distributed resources that are not dispatched by the system operator will support, rather than undermine, transmission grid reliability.

Recognize that the LMP price is only used to settle transactions in independent system operator (ISO) and regional transmission organization (RTO) spot markets. Market participants can enter into forward contracts, bilateral or exchange traded, that settle at prices other than the spot price. LMP spot prices that are the same for all resources and loads at a particular location are an essential underpinning of these forward contracts. Buyers and sellers could not contract forward efficiently if the seller would face a different spot price than a buyer at the same location.[5]

The inquiry from Commissioner Christie references a white paper that raises many issues for ISOs and RTOs given the changing nature of the electricity system over the clean energy transition.[6] These issues go beyond the LMP pricing model, and some are beyond the scope of the present paper. The main point here is that the offered criticisms of LMP are misplaced. While the authors of the white paper criticize ISOs for paying "all suppliers a single clearing price because they assume they can treat MWs of capacity and MWs of energy like commodities," this is precisely what LMP markets do not assume nor do.

In LMP markets, prices can vary by location at each interconnection point (node) on the transmission system and by time in five-minute increments. Power produced at locations where incremental supply cannot be dispatched to meet load due to transmission constraints will be paid a low price, while in non-LMP markets it is often paid the same price as generation that can be dispatched.[7] In LMP markets power produced when net demand is low will not be paid the same price as generation that is produced when net demand is high. In an LMP market, resources that cannot vary their output to produce more power when net load and prices are high or to produce less when net load and prices are low will receive lower average prices than resources that are dispatchable. Hence, in an LMP market fast ramping resources will earn larger margins than slow ramping units at the same location because they will produce more power when prices are high and less when prices are low. In an LMP market, power

between the offer of the resource and the clearing price. Individual system operators may not report these payments consistent with these definitions and there can be offer caps and floors affecting the payments.

[5] As discussed below, auctions of financial transmission rights allow suppliers and consumers (or their load serving entity) at different locations to enter into forward contracts, either bilateral or exchange traded contracts at trading hubs, without incurring congestion risk. No mechanism that we are familiar with has been developed that allows resources that are paid less than the spot price to enter into hedging contracts with loads.

[6] (Clark & Duane, 2021).

[7] See the discussion of constrained-off payments below.

consumers that can reduce their consumption when prices are high and increase consumption when prices are low will pay lower average prices than power consumers that continue to consume at high levels when prices are very high. Moreover, power intensive consumers that have choice in where they locate their operations can locate where prices are typically low due to transmission congestion. All of these outcomes in an LMP market raise social welfare by reducing consumption whose value is less than the cost of meeting that demand and increasing consumption that can be met a cost lower than its value.

Some of the asserted complaints about pricing are not related to price designs, but relate to the structure of subsidy designs for renewable resources, particularly wind and solar resources.[8] The underlying concern is that the subsidy designs in place were set up with the expectation of much lower energy prices than currently prevail, with the consequence that the subsidies are perceived by some to be too high at current energy price levels.

Whatever the merits of this concern, the critique of LMP is unsupported. First, these subsidy contracts and tax incentives were not put in place by ISOs or RTOs, they were put in place by state and federal governments and their regulatory agencies. While ISOs can and should attempt to inform the decisions of these state and federal entities regarding subsidy designs, it is not appropriate or even feasible for ISOs to undo these subsidy designs by reducing the spot prices paid for power produced by particular resources.

Second, any suggestion that ISOs and RTOs need to somehow reduce the payments to renewable resources in order to avoid excessive payments and consumer costs ignores the reality that LMP pricing is used to coordinate a day-ahead and/or real-time spot market in several large regions in which most (MISO) or virtually all (SPP and Western EIM) LSEs are regulated or public utilities. Moreover, within PJM and ISO New England there are individual states in which load is served by regulated or public utilities, and even in states with retail competition there are many public utilities that serve their load at cost-based rates.

There are no windfall profits on renewable generation owned by these regulated or public utilities, the higher revenues attributable to subsidies typically just reduce the cost of serving their load. It would make no sense to require these utilities to sell their renewable output at less than the market price at the same time that they must buy power to cover their load at the market price. Moreover, the revenues received by any renewable generation resources these utilities have contracted to buy power from will be determined by those contracts, not ISO pricing designs.

Furthermore, in states with retail competition, many retailers contract forward for power to lock in the cost of serving the retail loads they have, in turn, contracted to serve. Some of these forward contracts will be with renewable producers that may therefore not receive the benefits of high power prices, because they have already sold their power through the forward contract. For all of these reasons, it

[8] Duane and Fisher (2022) p. 9 "causing consumers to pay more for wind and solar electricity than they should."

does not make sense for ISOs and RTOs to distort market prices in order to reduce payments to renewable resources to offset what some commentators think are excessive subsidies to renewable producers.

If there is a concern with excessive revenues for future subsidized projects, that concern can be addressed by how the subsidies are structured. Furthermore, efforts by governments or regulators to price discriminate among suppliers, and pay each supplier just what is needed to elicit supply, inevitably result in shortages, market inefficiency and eventually inflated consumer costs. The US suffered the impacts of these types of designs in the natural gas industry and the crude oil and refining industry in the 1960s and 1970s. The abandonment of these policies and a shift to deregulated markets with market clearing pricing were important regulatory reforms of the 1980s that have served the country well over the following 30 plus years.[9]

Output related tax subsidies, procurement contracts that pay a positive price for output delivered at a location and time when the price is negative, and Investment Tax Credit designs that impose large penalties on batteries that charge with power withdrawn from the transmission grid, reduce market efficiency. But these choices are unrelated to LMP markets and outside the control of ISOs and RTOs. LMP markets make the best of these policy decisions from the perspective of reliably meeting load at least cost. In the context of environmental policy, it is noteworthy that LMP pricing has shown over the past 20 years that it is able to accommodate a wide variety of state and federal environmental policies. These include emission allowance costs for NO_X and SO_X and now for greenhouse gases, RECs,

---

[9] There is a long history of attempts to apply non-uniform prices in the oil and gas industries. Wellhead regulation of natural gas was introduced in the 1950s and by the winter of 1977-78 had produced a supply shortage of regulated, interstate gas, a shortage that resulted in gas consumers "freezing in the dark." This situation led to the Natural Gas Policy Act (NGPA) which among other things eliminated the agency responsible for the wellhead regulation policy (the Federal Power Commission) and created FERC. The NGPA introduced a simplified, but still non-uniform, price regulation design. This design had broken down by 1983, leading to pipeline special marketing programs, the Maryland Peoples counsel case, Order 436, Order 636 and the end of price regulation of natural gas. See among many sources discussing this history, Breyer and MacAvoy (1974); MacAvoy & Pindyck (1975) and Bradley (1996.)

The market based uniform pricing of natural gas, has worked for well over 30 years now, through a gas glut, through high prices during late 2000 through early 2001, then low prices until 2003, then high prices through 2010, then low prices, through the outbreak and now with high prices in 2022, but high gas prices today are due to shortages in the world market while the US is a gas exporter.

There was a similar effort in the 1970s to discriminate in the pricing of "old oil," "new oil", high cost oil, and imported oil, with a related system of price controls on refined products. The regulation of refined product prices was intended to pass through the benefits of price capped domestic oil to consumers but actually served to subsidize the consumption of imported oil and refined products and to raise refined product prices. See among many sources discussing these polices and their impact Deacon (1978), Kalt (1981) Harvey & Roush (1981), Glasner (1985), Argwhal and Deacon (1985) Bradley (1996) and Rogers (2003).

production tax credits and investment tax credits. ISOs and RTOs did not develop these policies, but LMP markets accommodate them.

The mistaken focus on LMP pricing and markets in the context of environmental subsidy designs is highlighted by the discussion in a recent white paper[10] of proposals to replace the single clearing price in Great Britain. The Great Britain electricity market is not (yet) an LMP market. The current Great Britain market design clears day-ahead based on the fiction of a single pool wide price (it does not utilize LMP pricing) and utilizes a real-time balancing market that is not based on a least cost dispatch, restricts participation and settles on pay-as-bid, rather than market clearing prices. As a result of this design, not only do British power consumers pay high prices for power as a result of high gas prices, but they must also make high payments for power that is not produced (charges for constrained-off payments) under the current non-LMP design.

Returning to the focus of the benefits of LMP pricing with the evolving resource mix over the energy transition, we view the core benefits that need to be preserved as:

- Providing an efficient, transparent price signal for storage resources, behind the meter generation, price responsive loads and behind the meter networks, enabling these resources to support transmission grid reliability during stressed system conditions rather than undermining it;
- Enabling operationally feasible, financially binding, day-ahead market schedules that posture the system to meet expected system conditions, schedule the resources needed to balance net load during unexpected conditions, and incent resources to be available to cover their schedules in real-time;
- Providing efficient locational incentives that not only reduce consumer costs but also support transmission grid reliability by providing efficient incentives for the locational and supply of storage and ramping capability;
- Avoiding the consumer cost of constrained-off payments, associated with single and zonal price market designs;
- Supporting efficient and competitive entry to provide balancing by enabling forward hedging at locational prices that reflect transmission congestion and enable sale of exchange traded forward contracts supported by balancing capability;
- Having the ability to accommodate new concepts in dispatch design and the continued evolution of environmental rules and subsidies, including designs which reduce subsidies as market prices rise; and
- Ensuring the ability of LMP pricing designs to accommodate market power mitigation designs that are focused on sellers with the ability to profitably exercise locational market power without confounding market power with pay-as-bid incentives.

10 Duane & Fisher 2022 p. 8

We begin in section II with a review of the factors that drove the implementation of LMP in US markets over the period 1996 through 2014. In section III we shift to a review of the benefits of LMP markets with the evolving resource mix from around 2014 to the distant future.

II. Overview of LMP Development

LMP pricing is typically associated with market-based pricing where prices are determined employing offer prices submitted by market participants based on their assessment of their incremental costs, rather than by offer prices based on administrative measures of incremental cost.[11] While LMP is used in many markets with retail competition (ERCOT, NYISO, PJM and ISO NE), LMP pricing can also be used for settlements among regulated and public utilities participating in a coordinated regional dispatch. In fact, LMP pricing is currently used in the US in regions in which most load is served by regulated or public vertically integrated utilities such as the Southwest Power Pool (often referred to as SPP), the Western Energy Imbalance Market (EIM) and MISO.

A fundamental driver for the implementation of LMP pricing was the development of decentralized markets coordinated by a system operator responsible for managing transmission congestion and avoiding transmission overloads. This role was traditionally filled by the control room of a vertically integrated utility that was able to use command-and-control to dispatch to balance generation and load while avoiding system overloads. Command-and-control dispatch was also used in tight power pools such as the New York Power Pool (predecessor to NYISO) and PJM in combination with what was known as "split-savings" pricing.[12] Command and control was workable within the power pools when the out-of-merit dispatch costs were small, the participants were in principle prohibited from exploiting the inefficient pricing, and the participating regulated utilities were able to recover their costs in their regulated retail rates.

The workability of command-and-control dispatch within the tight power pools came under pressure in the 1990s. Increases in gas prices created larger transmission congestion costs, along with the potential, or sometimes certain, inability of some utilities to recover any additional costs in retail rates, rates which were already under pressure from high costs (associated with out of market qualifying facility costs such

---

11 However, LMP pricing can be utilized in combination with cost-based offers as it was in PJM from April 1, 1998 to April 1, 1999. Beginning April 1, 1999, market-based offers were used for the dispatch in unconstrained regions and to manage congestion on the three main voltage constraints within PJM. Cost-based bids continued to be submitted and used to manage congestion on local transmission constraints that had not been deemed competitive. The PJM market power mitigation design has evolved tremendously over time and is not discussed in detail here as that would be a substantial paper in itself. See PJM Market Monitoring Unit, 2004 State of the market report, March 8, 2005 pp. 19, 63-67 for a review of the early design.

12 At a conceptual level, split savings designs calculate the savings from the actual dispatch compared to each company's hypothetical individual "own load" dispatch and then distributes the savings according to a formula that splits the savings. The time granularity used for this calculation can vary from system to system and there is often enormous complexity involved in accounting for a variety of factors including bilateral transactions. These designs historically created arbitrage opportunities and incented trading outside the pool. See Thomson, (1995).

as those due to the New York 6 cent law, or other factors).[13] The legacy split-savings pool pricing mechanisms would clearly be unworkable in a decentralized market with unregulated participants, providing a further driver for the development of LMP pricing designs by the member systems of the New York Power Pool and the PJM supporting companies.

While most U.S. ISOs and RTOs employ LMP to settle both the real-time dispatch and their day-ahead market, LMP pricing can be implemented solely in real-time for settlements without the implementation of an ISO coordinated day-ahead market.[14] Although LMP can and has been implemented solely for real-time settlements, a major benefit of LMP pricing is that it enables the implementation of an operationally feasible day-ahead market, as discussed in greater detail below.

Organized markets with LMP designs are essential in supporting forward hedging arrangements and enabling exchange traded financial contracts that can settle against the spot price, with congestion hedged through financial transmission rights (FTRs). Point-to-point transmission rights are essential to support long-term contracting between load and generation. From the earliest days of electricity market reform, continuing until now, there is no feasible system of transmission rights other than FTRs that operate in connection with LMP market design. Nothing other than the LMP/FTR combination works in theory to support efficient participation in economic dispatch in a decentralized market, while efficiently managing congestion and supporting forward contracting between resources and power consumers at different locations. We also know from 20 years of experience that nothing else works in practice in a market setting.

III. LMP Benefits with 1995-2014 market conditions and resource mix

LMP pricing was developed and initially implemented in the 1990s, and has provided important benefits when used under those conditions and resource mix. The primary benefit was that LMP pricing was consistent with, and supported economic dispatch, and did this without the need for constrained-on and -off payments. Eliminating the need for constrained-off payments eliminated an important driver for the imposition of entry barriers in non-LMP markets. An important benefit that has been realized over time is that LMP supports the implementation of operationally feasible day-ahead market. In addition, LMP pricing has been able to accommodate the implementation of sophisticated market power mitigation designs. Moreover, commodity trading exchanges have evolved with the development of

---

13 The authors began working on the development of LMP pricing systems with the member systems of the New York Power Pool and some PJM utilities prior to the issuance of order 888.

14 This was the case in PJM from April 1, 1998 to June 1, 2000 and was also the case in the Southwest Power Pool from 2007 to 2014. LMP pricing has also been used for real-time settlements in the Western EIM since 2014, with discussions of the prospective implementation of a day-ahead market across some or all of the Western EIM footprint continuing. The day-ahead market for the Western EIM is referred to as EDAM, extended day-ahead market. Documents relating to its design can be found at https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market

LMP markets by developing a wide variety of exchange traded hedging products for LMP based electricity markets.[15]

1. LMP is consistent with, and supports, centralized economic dispatch

Open Access and nondiscrimination, combined with efficient operation of the transmission system, requires LMP. LMP is the only pricing system that supports the efficient dispatch because LMP prices are calculated based on the marginal conditions in the dispatch. Any pricing system that sets prices that are inconsistent with the real-time dispatch necessarily requires discriminatory pricing, limits on access, constrained-on and –off payments, or reliance on command and control to maintain reliability

Many early, and sometimes continuing, electricity market design debates include a claim that there is or should be a single market-clearing price for the entire market, or at least that the effect of transmission congestion could be limited to a few large pricing zones that would be able to represent the major effect of transmission congestion. This was and is an appealing argument as it seems much simpler to have a single liquid market that covers a large proportion of total power production.

However, the claimed simplicity turned out to be a mirage. It is often asserted that locational pricing is not needed because there will not be material congestion, but this assertion has turned out to be untrue again and again in actual system operation. Transmission constraints are ubiquitous, with impacts that can sometimes be counterintuitive.[16] The true locational marginal cost of meeting load can be both higher and lower than the marginal costs of any of the operating generators due to interactions that require redispatch of multiple generators (some up, some down) to meet a marginal increment of load at a particular location.

Furthermore, in circumstances in which there is no transmission congestion, LMP would result in essentially a single market-clearing price. Under these conditions, LMP would capture the purported benefits of a single price or zonal system. Hence, single or zonal pricing models differ from the LMP model only under conditions of congestion where the single and zonal pricing models require reliance on command and control or constrained-on and –off payments to work.

At the opposite extreme are the market models that attempt to differentiate power flows as multiple products with separate pricing and allocation rules for each. However, a core fact of the well-recognized requirement for instantaneous power flow balancing is that, at a particular moment and location, power flows are indistinguishable. In other words, power at a point in time and place is a commodity. It does not matter how it was produced, in fact it is meaningless to ask which resource produced the power consumed at a particular location at a particular moment in time. The LMP model defines the market-clearing prices for this building-block commodity.

---

15 See ICE https://www.theice.com/products/Futures-Options/Energy/Electricity and Nodal Exchange, contract specifications at https://www.nodalexchange.com/regulation/nodal-exchange-regulation/participant-agreement-and-rulebook/

16 These conditions are well understood by system operators, and have been explained and illustrated for interested market participants willing to ask.

While it is sometimes asserted that locational pricing creates local market power, this is not the case. Locational market power is not reduced by declaring that prices will be the same across artificially large zones. Locational market power still exists, it would just be exercised in a different manner. The expected liquidity of a large zone is a mirage because the commodities being traded at different locations are not really the same. Power at different locations or produced and consumed at different points in time is not homogenous. Incremental load within transmission constrained regions cannot be met with generation located outside the constrained region. In the end, someone picks up the cost of a market that assumes power is fungible locationally when it is not, often through socializing the cost across loads. This fiction often results in single price markets that lack effective mechanisms to identify and mitigate the exercise of locational market power in the balancing market.

While managing transmission congestion by defining generator pricing zones may seem to be a workable middle ground, it typically creates even more problems than a single market price design.[17] Moreover, when conditions mandate a change in a zonal definition, history shows that there is no workable way to adjust zonal definitions on an ongoing basis. The only stable design is one that goes all the way to LMP with a possible unique real-time price for every location. In theory and in practice, LMP is the truly simple system.

2. LMP avoids need for constrained-on and-off payments to manage congestion

Vertically integrated utilities do not need to use LMP pricing to support their economic dispatch to meet load, as the system operator of the vertically integrated utility is sending dispatch instructions to employees who have no economic incentive to depart from those instructions. However, command-and-control does not work in a market-based system, as requiring generators to operate at prices that do not cover their costs is not sustainable. Non-locational pricing systems inherently create situations in which the price is too high or too low to make the efficient dispatch profitable for some generators. The zonal price will exceed the incremental cost of generators in the constrained-down region who would find it profitable to operate when they need to be dispatched down. At the same time, the zonal price can be too low relative to the incremental cost of generators in the constrained-up region who would find it unprofitable to operate when they are dispatched up.[18]

---

17 In particular, if the zones are used to dispatch generation, the zonal design can result in unmanageable congestion, unused transmission capacity, and uneconomic dispatch because of the fictions underlying the zonal definition. There is an extensive, detailed discussion of these issues in the 2009 ERCOT market report. See Potomac Economics Ltd, "2009 State of the Market Report for the ERCOT Wholesale Electricity Market, "pp. 76-90. A similar discussion of these issues with data for prior years can be found in earlier state of the market reports. ERCOT implemented a nodal LMP design at the end of 2010.

18 Supply exceeds demand (including exports) at the clearing price inside a constrained-down region in a single price market. Some low-cost generators in constrained-down regions are therefore directed to reduce their output below the amount offered at the clearing price in order to avoid transmission overloads. Conversely, supply (including imports) exceeds demand within constrained-up regions in a single price market. Some high-cost generators are therefore directed to increase their output above the amount offered at the clearing price in order to balance load and generation.

These inconsistencies between prices and dispatch instructions in single or zonal pricing designs create a need for a mechanism to incent or require generators to follow dispatch instructions. Single or zonal price market systems typically rely upon constrained-on and-off payments to incent dispatchable resources to operate consistent with system operator instructions. The constrained-on payments that go to generators whose incremental costs exceed the single price do not necessarily inflate consumer costs relative to an LMP market, as consumers would pay higher prices for this constrained-on output in an LMP market as well. However, in practice these single or zonal pricing designs may inflate the cost of congestion management if the real-time dispatch is not a full least cost dispatch in which all resources can participate, but is instead a balancing market with limited participation, pay-as-bid pricing, and a dispatch that differs from a contingency constrained least cost dispatch.[19]

A fundamental problem with non-LMP markets from the standpoint of consumer costs is the further need to make constrained-off payments to generators that must be dispatched below the level that would be profitable based on the single or zonal price in order to avoid transmission system overloads. These constrained-off payments do not contribute to meeting load and inherently serve to increase consumer costs, even with cost-based bidding by suppliers. The constrained-off payment is generally calculated as the difference between the non-LMP price and the resource incremental offer price. The constrained-off payment therefore increases as the offer price falls. The potential for inflated consumer costs is increased under market-based pricing in which resources that expect to be constrained-off, and have some degree of market power in reducing output within a generation pocket, can submit artificially low offer prices and thereby inflate the constrained-off payments they receive.[20] This was referred to as

[19] See, for example, the discussion of "nodal price chasing" in Ontario Energy Board, Market Surveillance Panel, Monitoring Report on the IESO-Administered Electricity Markets, for the period from May 2017-October 2017, December 2019, pp. 21-25; and Ontario Energy Board, Market Surveillance Panel Report 36, March 2022, pp. 25-26.

[20] It is noteworthy that these suppliers would not possess market power in the usual sense of being able to raise prices by withholding output. They could lack even the slightest ability to profitably raise prices by raising their offer prices, yet be able to raise constrained-off payments by lowering their offer prices without facing any competition in relieving congestion if they are a major source of the flows that create the congestion. This situation can also arise in LMP markets when there are deratings of the transmission system between the day-ahead market and the real-time dispatch but it happens every day in non-LMP markets with constrained-off payments.

the INC/DEC game in the original CAISO market (1998-2009).[21] Essentially the same problem appeared in the Texas ERCOT market and was among the factors leading to the subsequent LMP reform.[22]

The Ontario Independent Electricity System Operator (IESO) has also had issues with inflated constrained-off payments under its current non-LMP design. These excess costs have been discussed extensively by the Market Surveillance Panel.[23] A noteworthy source of excess costs has been constrained-off payments to import schedules.[24] The Ontario IESO has also limited constrained-off payments by implementing an offer price floor for wind in September 2013, requiring that 90% of wind resource output be dispatched off at $-3/MWh and the rest at -$15/MWh.[25] We regularly see situations in LMP based markets in the US in which intermittent resources are dispatched off economically at low or negative prices at some locations on the grid while prices are high at other locations. Under a non-LMP pricing design, these situations would either lead to extremely large constrained-off payments or lead to the implementation of price floors and command and control management of intermittent resource output.

While the excess costs associated with constrained-off payments are undesirable for a number of reasons, these payments are necessary in market-based non-locational pricing systems to avoid transmission system overloads. The experience with PJM's 1997 market implementation is instructive. The single-zone market was developed by Enron and Philadelphia Electric Company (PECO). FERC required PJM to implement this design in preference to the LMP system offered by the remaining supporting utilities. The design called for a single pool price across the whole system and allowed for

---

21 See for example, Opinion of the ISO Department of Market Analysis, December 20, 1999 regarding "the DEC Game," the discussion of the "DEC Game" in California ISO;" CAISO filing letter for Amendment 42, ER02-922-000, January 31, 2002 pp. 8-12; 2002 Annual Report on Market Issues and Performance," April 2003, pp. 8-7 to 8-8 the discussion of Palo Verde Negative Decremental bidding in California ISO, California ISO, Amendment to Comprehensive Market Design Proposal, Docket No. ER-02-1656 and EL01-68, July 22, 2003 p.29-30; "2003 Annual Report on Market Issues and Performance," p. 7-2. California ISO "2004 Annual Report on Market Issues and Performance, April 2005, pp. 6-14 to 6-15; California ISO, Department of Market Monitoring, 2005 Annual Report, Market Issues and Performance, April 2006 pp.6-1 to 6-5; California ISO, Department of Market Monitoring, 2006 Annual Report, Market Issues and Performance, April 2007 pp.6-1 to 6-5..

22 See, for example, Potomac Economics Ltd, 2009 State of the Market Report for the ERCOT Electricity Markets, July 2010 pp. 99-102.

23 See for example, Ontario Energy Board, Market Surveillance Panel, Monitoring Report 32, July 16, 2020 pp. 19-21; Ontario Energy Board, Market Surveillance Panel, "Congestion Payments in Ontario's Wholesale Electricity market: An Argument for Market Reform," December 2016.Ontario Energy Board, Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets, May 2010 to October 2010, February 2011, pp.70- 73, 108-110 Ontario Energy Board, Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets, November 2010 to April 2011, November 2011 pp. 134-137.

24 Ontario Energy Board, Market Surveillance Panel, "Congestion Payments in Ontario's Wholesale Electricity market: An Argument for Market Reform," December 2016. In particular see the discussion of constrained-on and-off payments to imports pp. 35-36; 44-45; and 49-50. Ontario Energy Board, Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets, May 2010 to October 2010, February 2011, pp. 72-73.

25 See SE-91 [http://www.ieso.ca/Documents/consult/se91/se91-20101104-Renewable_Integration-Stakeholder_Plan.pdf (esmap.org)](http://www.ieso.ca/Documents/consult/se91/se91-20101104-Renewable_Integration-Stakeholder_Plan.pdf) and Stakeholder Engagement Prereading, "Negative pricing," February 13, 2020.

constrained-on payments, but did not provide for constrained-off payments.[26] Hence, if transmission congestion developed, generators that were dispatched down to manage congestion had to forgo production that would have been paid the pool price, despite having much lower offer prices and costs. At the same time, resources that were dispatched, or self-scheduled, or non-firm imports that were willing to buy through congestion under the terms of the tariff, were paid a price for their output that was much higher than their offers.

When transmission congestion developed on a predictable basis in June 1997 following implementation of this single price market, these economics induced a downward death spiral in self-scheduling by an increasing number of resources in western PJM.[27] This design had the consequence that utilities that did not self-schedule, or could not self-schedule their resources because of the terms of joint unit agreements, were required to purchase power at prices far above the cost of the resources that were dispatched off in favor of self-scheduled generation and non-firm imports willing to "buy through" congestion.[28]

The prospect of being unable to manage congestion and avoid overloads on the eastern interface caused PJM to make a unilateral filing at FERC at 4:59 p.m. on Friday June 27, 1997 with an effective date of 5 p.m. on June 28, 1997, that eliminated the ability of non-firm import transactions to effectively self-schedule, allowing PJM to curtail these transactions on a non-economic basis when they contributed to congestion on the transmission system.[29] These changes temporarily enabled PJM to manage congestion within the Enron-PECO pricing design for a while, but by August 22, 1997 PJM market participants had identified market rules that allowed them to circumvent the June 27 curtailment rules. The resulting loss of PJM's ability to manage congestion within its economic dispatch culminated in PJM using the declaration of a minimum generation emergency on August 22 to allow it to curtail transactions on a non-market basis.[30] PJM subsequently changed its operating procedures to not

---

[26] See FERC February 28, 1997 order in Dockets Nos. OA97-262-000 and ER97-1083-000, pp. 4-5 "We hereby inform PJM that it should implement, subject to refund and further order as noted above, the PECO Energy congestion pricing proposal."

[27] See, for example, PJM filing Docket No. ER97-3463-000 June 27, 1997, at p. 5. "Two out of four companies on the west side of the east/west operating constraint have begun such self-scheduling since the beginning of June and a third western company has indicated its intent to do so." See also William Hogan, Strengths and Weaknesses of the PJM Market Model, p. 9.

[28] See PJM filing Docket No. ER97-3463-000, June 27, 1997 at p.6.

[29] See PJM filing Docket No. ER97-3463-000 June 27, 1997. The filing noted regarding the self-scheduling that "It also results in reliability concerns because more generating units are being self-scheduled, thus excluding themselves from redispatch. PJM thus has fewer units under its immediate control, and this reduces PJM flexibility in responding to operating conditions that occur on the PJM system.
…. Although this situation has not yet threatened PJM's reliability, it created the potential for serious problems. For example, recent instances have occurred where generators on the reduce side of PJM's constraint have not been following PJM's orders during redispatch operations due to the economic disincentives to reduce their generation." Filing letter P. 5. These changes were approved by FERC on July 18, 1997 with an effective date of June 28, 1997, see 80 FERC ¶61,069.

[30] PJM posted the following explanation of the events on August 22, 1997 with the minutes of its August 27, 1997 Market Operations Committee Meeting.

accept new non-firm or secondary service transmission schedules that would require re-dispatching generation, effective October 1, 1998, thereby undoing Open Access.

Based on this experience, in late 1997 FERC approved a shift to an LMP market design,[31] and PJM implemented a cost-based economic dispatch with locational marginal prices that applied to load and generation at each location on April 1, 1998. In 1999, FERC approved a revised "Market Based" pricing approach where generator engineering cost estimates would be replaced by market bids and offers for most market participants. Similarly, FERC approved an LMP design for NYISO in 1999[32] and the process of implementing LMP markets continued to include all the organized markets.

While PJM did not have constrained-off payments for imports into the constrained-down west region in 1997, imports into constrained-down regions have proved to be a challenge for other ISOs with non-LMP markets. For example, the IESO has encountered challenges with imports from Minnesota (MISO) and Manitoba into the constrained-down northwest region.[33] Similarly, Great Britain has encountered issues with imports from Norway when Northern England is constrained-down. System operators with non-LMP pricing systems face poor choices in managing imports into constrained-down regions in which the single market settlement price may greatly exceed the incremental dispatch offer. If they make constrained-off payments based on import offers, import suppliers can submit lower priced offers that utilize the full import capability of the transmission system, knowing that they will be constrained-down and receive constrained-off payments for not producing power. Conversely, if import suppliers cannot be dispatched down in exchange for constrained-off payments, imports may displace lower cost zero emission output. These situations do not arise in an LMP market as the price in the constrained-down region is consistent with the dispatch, and low priced import supply offers into a constrained-down region are paid an appropriately low market clearing price.

"Approximately 11:00 PJM had dispatched all units in Central and Western PJM down to their economic minimum cost. No further units remained in the central or west to control the transfer limit. Additional generation in the East was still required. No generation in the central or west had been scheduled by PJM. All generation operating in these areas was self-scheduled by the owning company.
At 11:21 PJM issues a minimum generation declaration for western and central PJM.
At 11:21 -11:30 PJM polled all companies affected by the minimum generation declaration to determine if any generation changes were anticipated. No generation changes were reported.
At 11:30 PJM started curtailing spot market transactions from the west that were bid in a price of zero. Approximately 1200 MW of energy was bid in at zero. Curtailments were made based on the timestamp of when the bids were received. The initial curtailment was for 574 MW to start at 11:45"
PJM System Operations Overview August 22, 1997.

[31] November 25, 1997 FERC order in dockets Nos. ER97-3189 and EC97-38.

[32] See January 27, 1999 FERC Order dockets Nos. ER97-1523, OA97-470, and ER97-4234, 86 FERC ¶61,062

[33] Ontario Energy Board, Market Surveillance Panel, "Congestion Payments in Ontario's Wholesale Electricity market: An Argument for Market Reform," December 2016 pp. 49-50; Ontario Energy Board, Market Surveillance Panel, "Monitoring Report on the IESO-Administered Electricity Markets, May 2010 to October 2010, February 2011, pp.72- 73.

3. LMP allows implementation of financially binding, operationally feasible, day-ahead markets.

Operationally feasible, financially binding, day-ahead market schedules were desirable in the 1990s because they ensured that slow starting units that would be needed to meet load would be committed. Operationally feasible and financially binding day-ahead markets had been implemented in NYISO, PJM, ISO New England and MISO by 2005. The CAISO and Ontario IESO tried to develop designs for operationally feasible, financially binding day-ahead markets for their 1998 and 2002 market designs. Their goal was to create market designs which would support financially binding schedules for resources that would need to be dispatched up out of merit in real-time and receive constrained-on payments. However, the CAISO and IESO were unable to develop a workable design based on their single and zonal price market designs that would not have resulted in excess consumer costs absent LMP pricing in real-time.[34]

The CAISO explained the importance of an operationally feasible day-ahead market in its July 22, 2003 MDO2 filing, observing that:

> Because the CAISO's congestion management system does not model intra-zonal transmission constraints and accepts schedules from SCs that are not physically feasible, the CAISO has no effective process for managing intra-zonal congestion in the forward market. As a result, instead of managing intra-zonal congestion the same way the CAISO manages inter-zonal congestion, i.e. by ensuring that schedules cannot cause congestion, the CAISO has been forced to accept forward schedules that create congestion and attempt to manage such intra-zonal congestion in real-time. This is a difficult and burdensome process that demands a disproportionate share of grid operators' time, forces them to scramble in Real-Time to keep the grid running reliably, and impinges on their other responsibilities.[35]

One core problem in developing operationally feasible day-ahead markets on congested transmission systems based on a single or zonal price (such as those of CAISO and the IESO) is that without LMP prices in real-time that would be used to settle deviations between day-ahead market schedules and real-time supply, resources scheduled out of merit in an operationally feasible day-ahead market could fail to perform and settle their imbalance at a system or zonal price that would be lower than their payment in the day-ahead market. A second core problem in single or zonal pricing designs was that not only would a non-LMP day-ahead market do nothing to reduce the magnitude of constrained-off payments, it would likely increase them by providing more opportunity for resources to enter into phantom day-ahead market positions that would be constrained-off in real-time. These phantom schedules would not only

[34] See Ontario IESO, "Day-ahead Market Evolution Preliminary Assessment," May 5, 2008; Michael Cadwalader, Scott Harvey and Susan Pope, "Comments on the Evaluation of an Unconstrained Price Day-Ahead Market Compared to an Enhanced Day-Ahead Commitment Process," prepared for the IESO, September 3, 2008.

[35] California ISO, Amendment to Comprehensive Market Design Proposal, Docket No. ER-02-1656 and EL01-68, July 22, 2003, p.28. Footnote 30 outlines the operating challenges described by James McIntosh, director of grid operations. "SCs" are scheduling coordinators in California ISO terminology, the entities responsible for interactions with the CAISO for load, supply, or both.

increase the constrained-off payments borne by power consumers, they would further depress the unconstrained day-ahead price relative to the actual cost of meeting load in constrained-up regions in real-time. These phantom schedules would provide little or no benefit for forward scheduling of needed generation or imports that would be out-of-merit at the single day-ahead market price, while potentially increasing the scheduling of uneconomic exports in the day-ahead market that would be constrained-off in real-time.

In another example of the operational challenges created by non-LMP pricing designs, European day-ahead markets are not operationally feasible and require the system operator to not only balance the system for unexpected events in real-time but also to re-balance the system to compensate for infeasible day-ahead schedules on a pretty much continuous basis. The pressure for reform of these markets continues in addition to dealing with the challenges created by the war in Ukraine.

The lack of an operationally feasible day-ahead market can create operating challenges under normal market conditions, but these challenges can turn into serious reliability issues under stressed system conditions such as those prevailing in the CAISO during May and June 2000. The reliability risks also rise as the magnitude of the differences between the day-ahead market schedules and the resources actually needed to balance load and generation increase. Balancing the electric system in real-time when there are substantial unexpected events that cause real-time conditions to change is always challenging, but LMP enables operationally feasible, and financially binding, day-ahead markets that help minimize these problems.

4. LMP avoids the need for the ISO to impose rules that limit entry of new resources in order to attempt to limit the magnitude of constrained-off payments

The potential for high constrained-off payments to generation located in constrained-down regions provides a rationale for ISOs to impose restrictions on entry in constrained regions in order to reduce magnitude of the required payments for not producing power. However, these restrictions on entry not only deter inefficient entry incented by constrained-off payments, they can also create barriers to the entry of new efficient, low emitting generation that would replace high cost, high emission generation. For example, this was the case in ISO New England's system impact study procedures that Bucksport and Champion (potential entrants into the New England electricity market) noted in their complaint. Bucksport and Champion observed that these system impact studies "assume that all existing and new generation must be fully integrated with load, such that any generator located anywhere in NEPOOL must be able to serve load anywhere in NEPOOL," "assume the most extreme operating conditions that are inconsistent with industry standards and, therefore, assume that any constraint on the system can only be remedied through the construction of transmission upgrades," "assumes that all projects in the queue ahead of that project studied will be built, the SIS necessarily produces inaccurate results" and finally "grandfather preferential rights of existing generators and 'goldplates' the NEPOOL transmission system."[36] The relevant elements of the Champion Bucksport complaint were granted and NEPOOL's proposed changes to its interconnection study rules were rejected by FERC in 1998.[37]

In addition, generation that may be constrained-down in low load conditions may be needed to meet load in high load conditions. It is noteworthy that the debate over the amendment 19 "NewGen" restrictions in California took place in 1999, just before the well-known California electricity market crisis. The final FERC order rejecting the proposed "ACCM" rules that would have limited entry by either requiring transmission upgrades or the application of discriminatory settlement and dispatch rules to any new generator that created congestion in any interconnection study scenario was issued at the end of January 2000,[38] shortly before it became apparent to everyone in the west that the real problem in CAISO was not too much generation receiving constrained-off payments, but too little generation to meet load over the summer of 2000.

An indirect way of limiting entry in order to contain the level of constrained-off payments would be to introduce transmission access charges for generators, with charges that are high in the constrained-down region and low or even negative in constrained-up regions. Great Britain introduced this type of access charge in the 1990s which has evolved into the current "TNUOS" charges. A detailed discussion of the British TNUOS design is well outside the scope of this overview, but we note that the original transmission access charges, and now TNUOS charges, have failed to manage the huge rise in constrained-off payments over the past decade.[39]

Moreover, the entire concept of using transmission access charges to manage interconnection was developed more than 20 years ago in the context of investments in thermal generation. It will become increasing unworkable with the evolving decentralized resource mix. In today's world transmission access charges are useless in managing the congestion created by intermittent resources whose full output is needed to meet load at some times of day or under some conditions, but whose full output cannot be delivered to load or stored at times of very high intermittent resource output. Today it is not enough to deter inefficient investment in constrained-down locations, the electricity market design must be able to efficiently manage the unavoidable transmission congestion associated with varying levels of intermittent resource output over the day or year.

Similarly, transmission access charges will not discourage inefficient investments in behind the meter generation by power consumers in constrained-down regions who pay an inflated uniform price.

---

[36] See Complaint of Champion International Corporation and Bucksport Energy LLC, EL98-69-000, August 7, 1998 p. 5. The complaint also raised issues regarding NEPOOL governance and study queues.

[37] See ISO New England filing in Docket ER98-3853, July 22, 1998 at 14-15 and 18-19; FERC order in Docket ER98-3853-000 85FERC ¶61,141. See also the Bucksport order in EL98-69-000, 85FERC ¶61,142 October 29, 1998, and the Champion/Bucksport Complaint in Docket EL8-69-000, August 7, 1998.

[38] See CAISO June 23, 1999 filing letter, Docket No, ER99-3339-000, January 31, 2000, FERC order, 90 FERC ¶61,086. January 31, 2000 and Scott Harvey and William Hogan, "Comments on the California ISO's New Gen Policy," July 27, 1999.

[39] See FTI, "Operation market design: Dispatch and Location, preread for National Grid ESO workshop on January 17, 2022," slide 14 historical constraint costs.

Transmission access charges are not suited to providing a signal that discourages investment in additional intermittent resources, most of whose output would be constrained-off, while at the same time encouraging retention of, or investment in, dispatchable resources at the same location that could operate when wind and solar output is low. Designs based on using transmission access charges to reduce uneconomic entry and limit constrained-off payments also do not readily send an efficient signal for investment in, and operation of, energy storage resources in constrained-down regions. While these energy storage resources could offer injection schedules that might need to be constrained-off, under an LMP market design the storage resources could store energy if the LMP price at their location was low, and thereby reduce the need to constrain off other resources.

5. Market power mitigation

Because LMP pricing sets market-clearing prices, sellers do not have to bid the market clearing price in order to be paid the market clearing price, that is, the same price received by other sellers at the same location. The ability of sellers to offer supply at their incremental cost and be paid the market clearing price at their location facilitates the identification of the potential exercise of market power and enables the application of market power mitigation designs, without artificially suppressing prices.[40] This is impossible in non-locational price designs with pay-as-bid balancing mechanism where sellers have to bid the market clearing price in order to be paid the market clearing price; that is, in order to be paid the same price as other suppliers dispatched in the balancing market to meet load at the same location. Even low-cost suppliers have an incentive to offer supply at the expected market clearing price in pay-as-bid market designs, making it very difficult to identify anomalous offers or to apply market power mitigation designs. In addition, if even small producers that do not possess market power have an incentive to submit offers based on the expected market price, the scope of mitigation will expand beyond large suppliers to become pay as ISO estimated cost bidding and compensation.

Moreover, with the implementation of reserve shortage pricing within LMP pricing designs, as in NYISO, MISO, PJM, ERCOT, ISO New England and SPP, prices can reach high levels during emergency conditions without the need for any seller to submit high offer prices. While the CAISO does not have a reserve shortage pricing design in its day-ahead market or in real-time, following the August 2020 blackout rules have been implemented to ensure that prices are set at appropriate levels when the CAISO finds it necessary to take the step of "arming" load for shedding in order to meet its mandatory WECC reserve requirements, with the armed load replacing non-spinning reserves that are dispatched to balance load and generation [41]

[40] We will not go into the details of market mitigation designs in LMP markets. However, these designs apply mitigation based on "reference prices" or "default energy bids" when triggered by congestion. Even when mitigation is applied, all resources are paid the market clearing price, which could be set by a mitigated offer, the offer of a resource not subject to mitigation, or a reserve shortage or transmission penalty price.

[41] See CAISO filing letter in Docket ER21-1536, March 26, 2021, pp. 32-36; California ISO, Market Enhancements for Summer 2021 Readiness, Draft Final Proposal, February 18, 2021 pp. 33-36.

6. Market liquidity

As LMP based markets have been implemented and developed over the past 20 years, forward markets have evolved in parallel, with LMP enabling the develop of exchange traded financial hedges.[42] LMP provides much greater liquidity in forward markets for generation located within constrained areas. Market participants can monetize their locational value in forward markets by selling power at trading hubs and buying counterflow FTRs from their location to the trading hub, realizing the value of the congestion management they provide in the forward market, or they can sell their output at a hub in a constrained-up region.

There is, on the other hand, no market mechanism for resources in constrained-up regions to sell forward in balancing markets in non-LMP systems because they can only sell their output at its actual value in the pay-as-bid balancing market, and only near real-time. Non-LMP prices provide inappropriately high liquidity for resources that cannot be dispatched to meet load,[43] while providing poor liquidity for resources in constrained-up regions that can be dispatched to meet load, but can only sell their power at its actual value in the real-time balancing market. There is no forward market for constrained-on payments in non-LMP market designs. Hence there is no market mechanism for generation located in constrained-up regions to lock in the value of their generation in forward contracts. Instead, they must realize the value of their asset day by day in a pay-as-bid market for constrained-on generation.

Hence, non-LMP markets are backwards in terms of liquidity, providing liquidity in forward markets for assets that cannot be dispatched to meet load, while providing no liquidity for generation located where it is needed to balance net load in real-time but unable to realize the balancing market value of their asset in forward contracts. This design greatly favors incumbent generation in the constrained-on region which does not have to compete in forward markets with new entrants, as the entrants cannot enter into forward contracts at balancing market prices, and the incumbents would be able to reduce their balancing market offers if entry were to occur. In LMP markets, on the other hand, entrants have the ability to sell power forward at prices that reflect expected balancing market prices, either through bilateral contracts or exchange traded contracts, locking in returns before they enter the market.

IV. LMP and the Evolving Resource Mix 2016-2050

In this section we turn to the role of LMP with the evolving resource mix in the US over the past 7-8 years and the prospective benefits of using LMP pricing to support the energy transition in the US and around the world over the next 10, 20 and 30 years. The transmission congestion that was a recurrent

---

[42] The huge number of financial hedges of various sorts traded in power market hubs on ICE and Nodal Exchange is an excellent illustration of this development.

[43] Constrained-off payments enable resources whose output cannot be dispatched to sell power forward at the same price as generation that can be dispatched to meet load.

pattern on the US and Ontario transmission systems over the period 1997 to 2014 is likely to be even more chronic as the resource mix evolves towards greater reliance on intermittent resources. There will inevitably be transmission congestion when intermittent resource output is unusually high. It will never be economic to expand the transmission grid to accommodate output levels that only occur sporadically, or only for a short time each day. The need for a pricing system that efficiently manages congestion will likely become more, not less, important in coming years.

As highlighted in the introduction, the core benefits of LMP with the evolving resource mix over the next 30 years will be an extension of its benefits over the past 20 years.

1. LMP market clearing price provides an efficient price signal consistent with market conditions for storage resources and for price responsive off dispatch resources

With the evolution of the resource mix and the development of distributed generation, storage and price responsive loads it is becoming increasingly important that LMP prices are used to provide an efficient price signal that energy storage and off-dispatch behind the meter resources can respond to in a manner that supports, rather than undermines, grid reliability.

This is particularly important for resources such as storage that need to optimize their output over time, charging when prices and the actual cost of power are low and injecting power when prices and the actual cost of power are higher. It is hard to imagine how storage resources could effectively compete, or realize their full potential economic value in balancing net load, in a pay-as-bid balancing market that lacks a transparent price signal, such as the real-time LMP price, to guide storage and injection decisions. This would be the case both for storage resources located in low price constrained-down regions and those located in high price constrained-up areas. In a pay-as-bid balancing market, storage resources would have to guess how low prices would be in order to submit low bids to buy at low prices and guess how high to offer in order to sell at the same price as other suppliers. If storage resources submitted bids that were too low with the hope of buying at the bid price, they could not charge, while if they submitted bids high enough to ensure they charged, they could have to pay higher prices than the cost of generation, artificially reducing the value of storage.

Conversely storage in constrained-up areas could submit offers low enough to ensure they were dispatched for balancing but would then not be paid the true market price, that is, they would not be paid the same price received by marginal resources dispatched in the balancing market to meet load at the same location. However, if they bid higher to try to be paid the market price, they would risk not being dispatched if their estimate of the market prices was slightly too high. Any pay-as-bid design based on the guessing games described above will hinder the use of storage to support an energy transition.

Moreover, single or zonal price systems will typically understate the value of ramping capability, whether provided by hydro generation, gas generation or storage resources. A single or zonal price will inherently understate the value of ramp because the non-locational prices will reflect ramping capability that is not available to balance net load in the actual dispatch because of transmission constraints.[44]

LMP markets incent and allow all resources, and all types of resources, to participate in economic dispatch to provide balancing, rather than restricting participation in the balancing market to a subset of the available resources as is the case in European balancing markets. In particular, non-LMP systems do not send a price signal that incents behind the meter resources to adjust their output in a way that balances the system. Indeed, when there is transmission congestion, non-LMP pricing systems will often incent behind the meter resources to operate in a manner that contributes to increasing local imbalances because they will operate based on the single or zonal price, rather than responding to the LMP price at their location. This role of LMP markets of supporting the broadest possible participation in balancing markets, and supporting the efficient participation of behind the meter generation, price responsive loads and price responsive network injections and withdrawals, will become more important as the level of intermittent resource output rises, and as the resource mix evolves to include more distributed resources that will respond to price signals but will not receive dispatch instructions from the system operator.[45]

The pay-as-bid pricing designs used by non-LMP balancing markets in Great Britain and the EU favor large incumbents, disadvantage both entrants and new technologies, and likely facilitate the exercise of market power by reducing the margins of small competitors. While there have been, and are, efforts to reform these designs, a large part of this discrimination is inherent in the non-locational pay-as-bid design of the balancing markets.

As we explain below, in pay-as-bid balancing markets there is no forward market in which generators and consumers in constrained regions can buy and sell forward contracts. Generators in constrained-up regions that are dispatched up in the balancing market are not paid the market clearing price and consumers whose load must be met in the balancing market do not pay the market clearing price.

2. LMP avoids need for constrained-off payments and reduces emissions

LMP pricing avoids undue payments to thermal generation that is not needed to meet load and which add emissions when operated at minimum load in order to receive constrained-off payments. LMP pricing also avoids undue payments to intermittent resources that have output profiles over the day or year that result in a significant portion of their potential output being constrained-off.

The documented experience of failure with zonal markets in the U.S. is complemented by the stunning and growing magnitude of constrained-off and on payments in Great Britain and in European zonal

---

[44] Illustrative calculations based on the Ontario 5 minute single price and the underlying nodal price indicate that the single design reduced the profitability of faster ramping capacity by about 2/3 over 2012 for a hypothetical resource in the constrained-up region, southeastern Ontario. See Scott Harvey, "Review of the Efficiency of the Hourly Ontario Energy Price," prepared for the IESO, July 8, 2013 pp. 139-140.

[45] Conversely, limiting participation in balancing markets will benefit the incumbent resources that currently provide balancing by reducing competition.

markets that have created their own set of demands for market reform. Under non-LMP market designs, not only do consumers pay high prices for energy when it is expensive, they make high payments for suppliers in constrained-down regions to not produce under the single price designs.

3. LMP supports an efficient locational price signal

The benefits from an LMP pricing design in providing an efficient price signal applies to locating new zero emission resources, locating new storage resources, and incenting existing thermal resources to remain in operation, exit or upgrade depending on their location, capabilities, and economics.

a. Renewables

There is a growing list of assertions that the fundamental nature of renewable energy, often referred to as zero-marginal cost generation, must necessarily eliminate the need for economic dispatch and lead to a collapse of market-clearing pricing models such as the LMP system. A modest effort examining this claim reveals that the argument is simply without foundation.[46]

The implied basis of the claim is that prices will often be zero and therefore will not be sufficient to support generation investment or demand response. The claim is often that this is a self-evident fact and, therefore, we need to move beyond current electricity market designs. However, zero cost resources are not always on the margin. The Western EIM region has a high proportion of zero emission resources, but the real-time LMP prices typically are not zero. In fact, they are often far above zero. Moreover, it is not apparent that LMP prices will be zero when the energy transition is complete, because the cost of storing and withdrawing energy is not zero, the cost of pondage hydro will not be zero, the price at which price responsive loads would be willing to reduce consumption will not be zero, and the cost of hydrogen generation will not be zero. We cannot accurately foresee the resource mix that will be used to achieve net zero emission goals, but we think it fanciful to suggest that it will be achieved with prices that are always zero with no congestion.

While the results of dispatch, ancillary service provision, and so on, will certainly change with a changing resource mix, the underlying fundamentals of balancing the transmission system will remain. Even with the prospective changes in the resource mix in the U.S. and Western Europe, the price of power will not always be zero everywhere. Non–zero, and potentially quite high prices, will be needed to balance net load when intermittent resource output is low, with some of that balancing likely provided by reductions in consumption that will not occur at low prices. When intermittent resource output is very high, prices will also be needed to balance net load, perhaps in part by incenting storage both by utility scale resources and perhaps in part by decentralized devices such as the batteries of electric cars. This will be incented by appropriate locational prices. The system operator will use economic and technical inputs to coordinate a reliable economic dispatch in both situations. The associated LMP prices may be more volatile, consistent with the change in the resource mix, although the increase in volatility will be reduced as the amount of storage and price responsive load on the grid increases. But these changes

---

46 For example, see Hogan 2022.

will not eliminate the need for LMP prices that support the economic dispatch. The basic operational design of LMP markets works for all levels of marginal cost, whether high or low.

LMP incents resources to locate where they will be constrained-down less often, especially during high priced hours. States and utilities with programs subsidizing renewable resources can make use of LMP pricing to structure subsidies for low emission resources that are settled at a trading hub.[47] These designs can provide an energy price hedge for renewables, by settling the subsidy at the trading hub, rather than the generator location, but leave the consequences of siting generation in bad locations on the project, rather than shifting these costs onto power consumers as would be the case with constrained-off payments.[48] Although this has typically not been the case in the U.S., subsidy contracts could be structured as two-way contracts-for-differences which require payments by the project when the market price exceeds the contract strike price.[49] This type of contract assign avoids the potential for higher than intended subsidy payments when energy payments are high, but conversely provides a higher subsidy when prices are lower than expected. In an LMP market, subsidy contracts can also be structured so that the subsidy goes to zero if the LMP price at the trading hub is zero. LMP enables these design choices. However, subsidy design is in the hands of governments and regulators, not ISOs or RTOs.

LMP also incents developers to build resources when transmission is available, or soon will be available, to support increased output, as the resource does not generate revenues if it is put in service prior to the time there is sufficient transmission to deliver resource output to market. However, non-LMP pricing systems based on constrained-off payments incent project developers to build generation potentially years before sufficient transmission will be available to deliver the output of that generation to load, as the resource operator will receive constrained-off payments as a reward for building generation that cannot be dispatched, while consumers bear the cost of paying for resources whose output cannot be dispatched to meet load or to reduce emissions.[50]

b. Storage

In addition to shifting power production from periods with low prices to those with high prices, an important role of storage resources can be to provide ramp up and down to balance variations in

47 See for example the Clean Path New York contract which settles a contract for differences against at a fixed average of the zone J price over the day. This design provides higher total compensation to the project if it delivers more of the renewable power in high priced hours and at locations with prices closer to the overall zone J price., see article 4 at https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-e-0302&CaseSearch=Search, November 30, 2021.

48 The project operator would have the option of hedging congestion risk by purchasing an FTR from the project location to the trading hub.

49 Some subsidy contracts in Great Britain are structured this way and have required payments by projects at the current high price levels. https://www.lowcarboncontracts.uk/news/announcement/reconciliation-of-q4-2021-payments-sees-cfd-portfolio-paying-back-to-electricity-suppliers

50 The connect and manage policies in Great Britain are a conspicuous example of such a failure.

intermittent resource output. The value of ramp for balancing is typically materially understated by single price markets which maintain the fiction that all of the ramping capability on the system is available to balance net load at each location. If this were the case, there would be less need for batteries to provide ramp, but it is a fiction and a single price can greatly understate the true locational value of ramp and storage. This mispricing of ramp and storage in single clearing price markets in turn would require additional subsides to try to correct for the mispricing. Since there is no straightforward way to correct for this mispricing other than implementing an LMP market, the structure of subsidies to compensate for the under valuation of ramping capability has the likely outcome of introducing additional distortions.

LMP prices reflect the impact of transmission constraints which can greatly impact the value of ramp. The value of ramp is often low in single price markets because there is enough ramping capability across the regional or national grid to manage variations in net load. However, this ramping capability is often not actually available to balance net load because it is behind transmission constraints. Because dynamic LMP prices value power at a specific location and during a specific 5-minute interval they accurately value ramping capability at each location on the grid in each dispatch interval. This is important as it will incent storage resources to locate where storage has the most value given locational pricing patterns over the day. Storage resources could optimally be located on the constrained-down or constrained-up side of transmission constraints, depending on when the constraint is binding. LMP pricing incents storage resource operators to optimize their resource characteristics based on location and the pattern of prices over the day at that location.

c. Residual thermal generation for balancing

LMP price signal will incent balancing resources to remain in operation at the locations where they provide the most value to consumers for balancing because prices will be higher at those locations during the time periods when the output of the resources is needed, while incenting the retirement of thermal resources whose operation is no longer needed. This is not the case with non-LMP pricing designs where constrained-off payments can incent the continued operation of resources that have little value in meeting load or in providing balancing.

4. LMP allows and supports financially binding and operationally feasible day-ahead markets

With evolving resource mixes in the US, as well is in Canada, Australia, Great Britain and the EU, there will be greater operational pressure and less ability to accommodate non-LMP designs that inherently yield infeasible forward schedules. These operationally infeasible forward schedules cannot be used to balance load and generation in real-time even under expected system conditions. Moreover, reliance on infeasible forward schedules will magnify operating challenges when system conditions differ from those that were expected.

In the 1990s and 2000s operators had to manage the impact of generation and transmission forced outages that could radically change system conditions in a short period of time. These operational surprises were managed with contingency constrained economic dispatch and operating reserves that allowed the system operator to maintain reliability during those unanticipated events.

System operators still need to manage the transmission system and maintain reserves to maintain reliability following transmission and generation outages, but the pace at which system operators must manage variations in net load will potentially accelerate as the resource mix evolves. An illustrative example of this accelerated pace is that on August 15, 2020 the CAISO went from having adequate reserves, to declaring a stage 2 emergency, to shedding load in 12 minutes.[51] With operating conditions changing on an accelerated time-line in the future, there will be no room for market designs that place the system operator in a deep hole at the beginning of every operating day by starting with day-ahead market schedules that are not operationally feasible, even if there are no surprises. The conclusion we draw is that it is no longer operationally workable for system operators to rely on market designs that produce forward schedules that are inconsistent with expected market conditions.

Being able to implement an operationally feasible, and financially binding, day-ahead market was not only an important benefit of implementing on LMP market for the CAISO as discussed above, this was also an important consideration for the IESO in deciding to implement LMP for the 2020s and beyond.[52] An important driver for operationally feasible day-ahead markets in the 1990s and 2000s was the need to commit slow starting gas generating units day-ahead, so they would be available in real-time. While that need may be far less important in the 2020s and 2030s, operationally feasible day-ahead markets also provide a framework for financial schedules for price responsive load, which will need to make some decisions well before real-time; for behind the meter networks that need to take actions prior to real-time; and for other resources, such as cascade hydro systems, that may need to take costly actions day-ahead; and for storage resources to lock in margins over the day with financially binding schedules. Financially binding and operationally feasible day-ahead market schedules also provide the system operator with expected operating plans and incent the supplier to be able to operate to its schedule when needed, and to increase or reduce output relative to that schedule as dispatched based on real-time LMP prices.

5. LMP has shown itself to be flexible and able to accommodate evolving dispatch designs

Over the past 20 years LMP has accommodated a number of changes in dispatch design, all of which have readily been implemented within the overarching LMP market designs. These innovations include:

- Ramp dispatch (CAISO, Western EIM, and MISO)
- Fast start/fixed block/extended-LMP pricing (NYISO, MISO, PJM, ISO New England, SPP)
- Co-optimization of energy and ancillary services in real-time (NYISO, MISO, SPP and to some extent ISO NE and PJM)

---

51 California ISO, California Public Utilities Commission, California Energy Commission, “Root Cause Analysis Mid-August 2020 Extreme Heat Wave,” January 13, 2021 p. 30.

52 IESO, Market Renewal Program: Introduction to Day Ahead Market, October 11, 2017, pp. 2-9.

- Co-optimization of energy and ancillary service schedules in the day-ahead market (all U.S. ISOs)
- Reserve shortage pricing NYISO, MISO, PJM, ISO NE, PJM, SPP and ERCOT
- Multiple interval optimization (CAISO, Western EIM and NYISO)
- 15 minute pricing and settlements as well as 5 minute pricing (CAISO, Western EIM)
- Transmission overload pricing (NYISO, CAISO, MISO, SPP, and ERCOT.

We have focused in this paper on economic dispatch and LMP pricing, but there has also been an evolution and innovation of financial transmission right auction design to meet the evolving needs of market participants. These changes include implementation of:

- On- and off-peak FTRs
- Balance of period auctions (PJM, MISO, NYISO and ISO New England)
- Future year auctions (PJM, ERCOT and NYISO)
- Transmission outage performance incentives (NYISO)

Moreover, there are additional innovations on the horizon which can also be readily implemented within an LMP framework

- State of Charge based storage offers and dispatch (CAISO)
- Financially binding, operationally feasible, intra-day markets

It is not clear how state of charge-based bidding could even be workable in pay-as-bid balancing markets that require participants to bid the market price in order to be paid the same market price that the marginal supplier is paid. This is another example of how pay-as-bid balancing mechanisms are wedded to the past. Pay-as-bid designs are always inefficient and discriminatory but they are particularly unsuited to managing the output of the evolving resource mix and a transmission grid that may rely to a significant extent on distributed resources for balancing.

Similarly, it would not be possible to introduce operationally feasible and financially binding intra-day market without LMP for much the same reason that operationally feasible day-ahead markets are not workable in single clearing price markets.

Finally, we noted above the potential benefits in subsidy design from the use utilities and states are making of LMP pricing in the structure of subsidy contracts for low or zero emission resources to incent efficient locational and operating decisions by structuring the subsidies as a CFD settling at a trading hub or zonal price.

V. Conclusion

LMP pricing puts US markets in a better position to accommodate rising levels of intermittent output than would be the case with single or zonal pricing designs. Moreover, one underlying concern of commentators with LMP markets is with the level of payments to renewable resources when energy prices are high. As we have pointed out above, the level of these payments is an outcome of state and federal policies, not ISO and RTO pricing designs. Moreover, the ability of LMP markets to obviate the need for constrained-off payments to manage congestion is particularly important when market clearing prices are high due to high fuel costs as is the case today both in the US, and around much of the world, and these "payments to not produce" would also rise.

There are still huge operational and market challenges in accommodating higher levels of intermittent output while maintaining historical levels of reliability, but LMP pricing contributes to achieving this goal. Market designs based on command and control, constrained-on and-off payments and pay-as-bid balancing mechanisms will at best hinder achieving these goals, if not make it impossible without adverse impacts on reliability. Critical operational benefits of LMP market designs in maintaining reliability with the evolving resource mix include:

- An efficient, transparent price signal for storage resources, behind the meter generation, price responsive loads and behind the meter networks, enabling these resources to support grid reliability during stressed system conditions rather than undermining it;
- Operationally feasible, financially binding, day-ahead market schedules that posture the system to meet expected system conditions, schedule the resources needed to balance net load during unexpected conditions, and incent resources to be available to cover their schedules in real-time.
- Efficient locational incentives that not only reduce consumer costs but also support transmission grid reliability by providing efficient incentives for the locational supply of storage and ramping capability;
- Avoiding the consumer cost of constrained-off payments, associated with single and zonal price market designs;
- Supporting efficient and competitive entry to provide balancing by enabling forward hedging at locational prices that reflect transmission congestion and enable sale of exchange traded forward contracts supported by balancing capability;
- The ability to accommodate new concepts in dispatch design and the continued evolution of environmental rules and subsidies, including possible improved designs which reduce subsidies as market prices rise; and
- The ability of LMP pricing designs to accommodate market power mitigation designs that are focused on sellers with the ability to profitably exercise locational market power without confounding market power with pay-as-bid incentives.

References

Andrianesis, P., Bertsekas, D., Caramanis, M. C., & Hogan, W. W. (2022). Computation of convex hull prices in electricity markets with non-convexities using dantzig-wolfe decomposition. *IEEE Transactions on Power Systems*, *37*(4). https://arxiv.org/pdf/2012.13331.pdf

Argwal, V and Deacon R. "Price controls, price dispersion and the supply of refined petroleum products; Energy Economics October 1985

Bradley, R. Oil, Gas and Government Volumes I and II, 1996, Rowman & Littlefield.

Breyer, S and MacAvoy, P; Energy Regulation by the Federal Power Commission, 1974, Brookings Institution.

Bushnell, J. B., Harvey, S. M., Hobbs, B. F., & Oren, S. S. (2013). Opinion on Initial Implementation of the Energy Imbalance Market and Related Market Design Changes, CAISO Market Surveillance Committee. https://www.caiso.com/Documents/Feb28_2014_TariffAmendment_EnergyImbalanceMarket_ER14-1386-000.pdf

California ISO, California Public Utilities Commission, California Energy Commission, "Root Cause Analysis Mid-August 2020 Extreme Heat Wave," January 13, 2021 http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf#search=Root%20cause

California ISO, 2002 Annual Report on Market Issues and Performance, April 2003.

California ISO, 2004 Annual Report on Market Issues and Performance, April 2005.

California ISO, Department of Market Monitoring, 2005 Annual Report, Market Issues and Performance, April 2006.

California ISO, Department of Market Monitoring, 2006 Annual Report, Market Issues and Performance, April 2007.

Clark, T., & Duane, V. (2021). *Stretched to the Breaking Point: RTOs and the Clean Energy Transition* (Issue July). https://www.wbklaw.com/wp-content/uploads/2021/07/Wholesale-Electricity-Markets-White-Paper-07.08.21.pdf

Deacon, R. "An Economic Analysis of Gasoline Price Controls," Natural Resources Journal ,October 1978

Duane, D and Fisher, T, "Can we Afford a Single Clearing Price Electricity Market," August 2022 https://elcon.org/can-we-afford-a-single-clearing-price-electricity-market/

Glasner, D. Politics Prices and Petroleum, 1985, Ballinger Publishing Company.

Gribik, P. R., Hogan, W. W., & Pope, S. L. (2007). *Market-Clearing Electricity Prices and Energy Uplift*. https://scholar.harvard.edu/whogan/files/gribik_hogan_pope_price_uplift_123107.pdf

Harvey, S & Roush, C. Petroleum Procue Price Regulation, Output, Efficiency and Competitive Effects, February 1981, Government Printing Office.

Harvey, S "Review of the Efficiency of the Hourly Ontario Energy Price," prepared for the IESO, July 8, 2013

Harvey, S. and Hogan, W, "Comments on the California ISO's New Gen Policy," July 27, 1999.

Harvey, S. M., Hogan, W. W., & Pope, S. L. (1997). Transmission Capacity Reservations and Transmission Congestion Contracts. Center for Business and Government, Harvard University. http://www.hks.harvard.edu/fs/whogan/tccoptr3.pdf

Hogan, W. W. (1995). To Pool or Not to Pool: A Distracting Debate. Public Utilities Fortnightly, January 1. https://www.fortnightly.com/fortnightly/1995/01/pool-or-not-pool-distracting-debate

Hogan, W. W. (2002). Electricity market restructuring: Reforms of reforms. Journal of Regulatory Economics, 21(1). https://link.springer.com/article/10.1023/A:1013682825693

Hogan, W. W. (2021). Strengths and Weaknesses of the PJM Market Model. In Handbook on the Economics of Electricity (Invited Chapter 7: forthcoming). https://scholar.harvard.edu/whogan/files/hogan_chapter_7_handbook_on_the_economics_of_electricity_112619r.pdf

Hogan, W. W. (2022). Electricity Market Design and Zero-Marginal Cost Generation. Current Sustainable/Renewable Energy Reports, 0123456789. https://doi.org/10.1007/s40518-021-00200-9

Hogan, W. W. (1998). *Competitive Electricity Market Design: A Wholesale Primer*. https://scholar.harvard.edu/whogan/files/empr1298.pdf

Kalt, J. The Economics and Politics of Oil Price Regualtion Federal policy in the Post-Embargo Era, 1981, The MIT Press.

MacAvoy, P and Pindyck, R. Price Controls and the Natural Gas Shortage, 1975, American Enterprise Institute

Ontario Energy Board, Market Surveillance Panel, “Congestion Payments in Ontario’s Wholesale Electricity market: An Argument for Market Reform,” December 2016, https://www.oeb.ca/ontarios-energy-sector/market-surveillance-panel/panel-reports

Ontario Energy Board, Market Surveillance Panel, “Monitoring Report on the IESO-Administered Electricity Markets, May 2010 to October 2010, February 2011,

Ontario Energy Board, Market Surveillance Panel, “Monitoring Report on the IESO-Administered Electricity Markets, November 2010 to April 2011, November 2011

Ontario Energy Board, Market Surveillance Panel, “Monitoring Report on the IESO-Administered Electricity Markets, May 2010 to October 2010, February 2011

Ontario Energy Board, Market Surveillance Panel, Monitoring Report on the IESO-Administered Electricity Markets, for the period from May 2017-October 2017, December 2019;

Ontario Energy Board, Market Surveillance Panel ,Report 32, July 16, 2020

Ontario Energy Board, Market Surveillance Panel ,Report 36, March 2022

Potomac Economics Ltd, “2009 State of the Market Report for the ERCOT Wholesale Electricity Market,” July 2010, https://www.potomaceconomics.com/document-library/?filtermarket=ERCOT

PJM Market Monitoring Unit, 2004 State of the market report, March 8, 2005

Rogers, R. "The Effect fo the Energy Policy and Conservation Act (EPCA) Regulation on Petroleum Product Prices, 19767-1981", Energy Journal Vol 24 #2 2003.

Schweppe, F. C., Caramanis, M. C., Tabors, R. D., & Bohn, R. E. (1988). *Spot pricing of electricity*. Kluwer Academic Publishers. http://books.google.com/books?id=Sg5zRPWrZ_gC&pg=PA265&lpg=PA265&dq=spot+pricing+of+electricity+schweppe&source=bl&ots=1MIUfKBjBk&sig=FXe_GSyf_V_fcIuTmUtH7mKO_PM&hl=en&ei=Ovg7Tt66DO2x0AH50aGNCg&sa=X&oi=book_result&ct=result&resnum=3&ved=0CDYQ6AEwAg#v=onep

Thomson, R. G. (1995). The electric power industry: deregulation and market structure (No. 95-004WP; Issue June). https://dspace.mit.edu/bitstream/handle/1721.1/50182/35719387.pdf?sequence=1

EndNote

William W. Hogan is the Raymond Plank Research Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University. Scott Harvey is a consultant with FTI Consulting and a member of the California ISO/Western EIM Market Surveillance Committee. This paper draws on research for the Harvard Electricity Policy Group and for the Harvard-Japan Project on Energy and the Environment. The authors are or has been consultants on electric market reform and transmission issues for Allegheny Electric Global Market, American Electric Power, American National Power, Aquila, AQUIND Limited, Atlantic Wind Connection, Australian Energy Market Operator, Australian Gas Light Company, Avista Corporation, Avista Utilities, Avista Energy, Barclays Bank PLC, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, California Independent Energy Producers Association, California Independent System Operator/Western EIM, , California Suppliers Group, Calpine Corporation, CAM Energy, Canadian Imperial Bank of Commerce, Centerpoint Energy, Central Maine Power Company, Chubu Electric Power Company, Citigroup, City Power Marketing LLC, Cobalt Capital Management LLC, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, COMPETE Coalition, Conectiv, Constellation Energy, Constellation Energy Commodities Group, Constellation Power Source, Coral Power, Credit First Suisse Boston, DC Energy, Detroit Edison Company, Deutsche Bank, Deutsche Bank Energy Trading LLC, Duquesne Light Company, Dyon LLC, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Authority New Zealand, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, Energy Endeavors LP, Energy Security Board Australia, Exelon, Financial Marketers Coalition, FirstEnergy Corporation, FTI Consulting, GenOn Energy, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., GDF SUEZ Energy Resources NA, Great Bay Energy LLC, GWF Energy, Independent Energy Producers Assn, ISO New England, Israel Public Utility Authority-Electricity, Koch Energy Trading, Inc., JP Morgan, LECG LLC, Longview Power, Lubbock Power and Light, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, MIT Grid Study, Monterey Enterprises LLC, MPS Merchant Services, Inc. (f/k/a Aquila Power Corporation), JP Morgan Ventures Energy Corp., Morgan Stanley Capital Group, Morrison & Foerster LLP, National Grid ESO, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ofgem, Ontario Attorney General, Ontario IMO and IESO, Ontario Ministries of Energy and Infrastructure, Pepco, Pinpoint Power, PJM Office of Interconnection, PJM Power Provider (P3) Group, Powerex Corp., Powhatan Energy Fund LLC, PPL Corporation, PPL Montana LLC, PPL EnergyPlus LLC, Public Service Company of Colorado, Public Service Electric & Gas Company, Public Service New Mexico, PSEG Companies, Red Wolf Energy Trading, Reliant Energy, Rhode Island Public Utilities Commission, Round Rock Energy LP, San Diego Gas & Electric Company, Secretaría de Energía (SENER, Mexico), Sempra Energy, SESCO LLC, Shell Energy North America (U.S.) L.P., SPP, Texas Genco, Texas Utilities Co, Tokyo Electric Power Company, Toronto Dominion Bank, Total Gas & Power North America, Transalta, TransAlta Energy Marketing (California), TransAlta Energy Marketing (U.S.) Inc., Transcanada, TransCanada Energy LTD., TransÉnergie, Transpower of New Zealand, Tucson Electric Power, Twin Cities Power LLC, U.S. Department of State, Vitol Inc., Westbrook Power, Western Power Trading Forum, Williams Energy Group, Wisconsin Electric Power Company, and XO Energy. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author. (Related papers can be found on the web at www.whogan.com).

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding in accordance with the requirements of Rule 2010 of the Rules of Practice and Procedure, 18 C.F.R. §385.2010.

Dated at Rensselaer, NY this 18th day of October 2022.

/s/ Kerry J. Maerki

Kerry J. Maerki
New York Independent System Operator, Inc.
10 Krey Blvd.
Rensselaer, NY 12144
(518) 356-6222