2017 CONSUMER INTEREST LIAISON

ANNUAL REPORT

A Report by the
New York Independent
System Operator

April 2018

The mission of the NYISO, in collaboration with its stakeholders, is to serve the public interest and provide benefit to consumers by:

- Maintaining and enhancing regional reliability
- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policy makers, stakeholders and investors in the power system

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Message from the President and CEO

The past year turned out to be very busy and successful for the NYISO. We completed a record 56 projects with the help and active participation of our stakeholders. Included in these projects were many important market design changes devised to improve the efficiency of our energy and capacity markets.

Major proposed market design changes also require that we keep stakeholders – and especially the end-use sector – aware of the potential impact these proposed market design changes may bring. Some of these proposals included Securing 100+Kv Transmission Facilities in the Market model, On Ramps and Off Ramps with Rules to Create and Eliminate Localities and Alternative Methods of Determining LCRs. We provided a detailed consumer impact analysis on all proposed major market design changes.

Providing detailed consumer impact analyses indicates our continued commitment to making sure all stakeholders, including the end-use sector, are aware of the impacts of proposed major market design changes. Informed stakeholders representing their interests enrich our process, lead to vigorous debate, and help provide outcomes that stem from everyone's active participation.

In 2018, we'll be analyzing topics like harmonizing the state's decarbonization policies with the New York's wholesale market design which includes looking at customer impacts as part of the Integrated Public Policy Task Force (IPPTF). We will also be evaluating our current ancillary services, energy, and capacity markets to determine if they are sufficient to meet the State's goal of achieving 50% renewable energy consumption by 2030. As part of aligning with the New York State Public Service Commission's (PSC) Reforming the Energy Vision (REV), we will further work on providing opportunities for distributed energy resources (DER) to participate in wholesale markets. Additionally, we will work on improving the integration of storage resources into the NYISO wholesale markets. As we work on these major projects, we will analyze the impact of these proposals on our markets and consumers and report our findings to stakeholders.

I look forward to continuing our work together, and hope for another fruitful year.

Brad Jones

President & CEO

Message from the Consumer Interest Liaison

The main objective of this annual report is to provide a summary of the activities undertaken by the NYISO's Consumer Interest Liaison over the past year. During 2017, we completed consumer impact analyses for four major projects and presented them to stakeholders. We also implemented, as part of the Improvement Process of Consumer Impact Analyses, presentations on the methodology to be used for conducting the actual consumer impact. The purpose behind these methodology presentations was to get stakeholder input on the manner in which we would conduct the consumer impact. We made these methodology presentations for three of the four consumer impact analyses conducted during 2017.[1]

The year started with a consumer impact analysis presentation on the proposed enhancements to the NYISO's transmission constraint pricing logic in January 2017. That was followed by a consumer impact analysis for Alternative Methods for Determining Local Capacity Requirements (LCRs) in October 2017. During the presentation, stakeholders requested additional information, which was provided in a second presentation on Alternative LCR Determinations in November 2017.[2] The consumer impact analysis for Securing 100+Kv Transmission Facilities in the Market Model was presented in November 2017. This was soon followed, also in November, by the final consumer impact analysis for 2017 for On Ramps and Off Ramps with Rules to Create and Eliminate Localities.

The period between the first consumer impact analysis in January and the presentations in October/November is when the methodology presentations took place, and when the analyses supporting the presentations were conducted.

In addition to consumer impact analyses, we also work to support the End-Use Sector's participation in NYISO activities. We provide regular information to assist the End-Use Sector, so that its limited resources can be utilized more effectively.

Given the changes taking place in the energy industry, we are expecting a very busy 2018. We discuss these changes towards the end of this report, as well as outlining projects we have identified for analysis in 2018. We are excited to work on these projects, and hope to continue supporting the work of the End-Use Sector in a multitude of ways.

Tariq Niazi

Consumer Interest Liaison

[1] We were unable to present the methodology for Transmission Constraint Pricing as this issue resulted in a waiver request being submitted to FERC that included a commitment by the NYISO to expeditiously resolve the inconsistency between its pricing software and its tariff.

[2] A third consumer impact analysis on Alternative LCR Determinations was presented to stakeholders on February 22 2018. This analysis used the 2018 base case, as compared to the prior analyses that were based on the 2017 base case. We are including this analysis in the 2017 Annual Report as it was an integral part of the Alternative LCR Determination project.

Role of the Consumer Interest Liaison

Since December 1, 1999, the NYISO has been responsible for the reliable and efficient operation of the electrical grid and the associated wholesale markets that serve the New York State consumers. Utilizing a competitive marketplace, the NYISO coordinates the supply of reliable, cost efficient electricity to end users.

While part of the NYISO's mission is to serve the public interest and provide benefits to consumers, it realizes that the complexity of the markets presents challenges for consumers, and groups representing consumers, to participate effectively in the NYISO governance structure. Consumers may lack the resources to thoroughly research and analyze the enormous amount of information available to the market place. To address this limitation, the NYISO took several initiatives to level the playing field and improve the effectiveness of consumer representation in its governance process.

As part of this initiative, the NYISO created the position of Consumer Interest Liaison in 2011 with the responsibility to enhance the effectiveness of the End-Use Sector's ability to more fully participate in the NYISO governance processes. Specifically, the Consumer Interest Liaison's role is to:[3]

- Assist end use consumers in gaining valuable insight into proposed system changes.
- Provide consumers a communication link with the NYISO Board of Directors and senior management.
- Provide consumers with the short term and long term impact of NYISO initiatives and changes.
- Improve the education and outreach with end-use consumers.
- Improve overall transparency of NYISO actions and processes.

In the years following the appointment of the Consumer Interest Liaison, the NYISO devoted numerous resources to improving the participation of end-use consumers. Through several channels of communication and detailed consumer impact analyses, the end-use consumer has a much better ability to understand and participate in NYISO governance decisions.

The Consumer Interest Liaison serves the needs of the end-use consumer by providing multiple services.

Consumer Interest Liaison/Sector Meetings

On an annual basis, the Consumer Interest Liaison meets with each of the stakeholder sectors engaged in the shared governance process to understand relevant issues from each sector's point of view.

[3] In 2011, the NYISO named Tariq Niazi as the Consumer Interest Liaison. Mr. Niazi brought 30 years of experience with him from the New York State Consumer Protection Board (CPB). Mr. Niazi's experience as the former director of the CPB Utility Intervention Unit and Chief Economist uniquely qualifies him to assist New York's electricity consumers in understanding the complexities of the NYISO marketplace.

Projects and consumer impact analyses identified for the current year are presented and discussed. By exploring the viewpoint of each of the sectors participating in the market, the Consumer Interest Liaison is able to obtain a much more complete picture of different aspects of each issue. This input helps the Consumer Interest Liaison to conduct more comprehensive impact analyses that addresses the concerns of all sectors involved. These meetings also help determine the areas where the End-Use Sector members may require more support.

Weekly Summaries

The Consumer Interest Liaison produces a weekly summary of stakeholder meetings and sends it to the end use consumer mailing list. Consumer Interest Liaison personnel attend each stakeholder committee and working group meeting to facilitate accurate summaries of the discussions and deliberations at these meetings. The summaries are provided on a timely basis, in most cases the following week, to keep consumer representatives updated and current on the progress of issues through the governance process. Activity such as filings made to FERC, and Orders to the NYISO from FERC, are included in the weekly summaries to provide additional notice. In addition, the weekly summary highlights relevant notices such as meeting reminders, deadlines for input, and NYISO manual revisions, as well as other topics relevant to effective participation. To see an example of the weekly summary, please see the Appendix. NYISO also posts these summaries on the Consumer Interest Liaison page of the NYISO website.

Monthly End-Use Consumer Conference Calls

Each month the Consumer Interest Liaison conducts a conference call with end-use consumer representatives, including members of the Department of Public Service. Prior to this call, the Consumer Interest Liaison meets with the NYISO Product and Project Management team to review committee and working group schedules for the upcoming months. That information is then reviewed with the end-use consumer representatives. This allows end-use consumer representatives to use the information to track issue progress and milestones. Relevant projects, current issues and training topics also are discussed on the monthly call.

Consumer Inquiries

Due to the complexity of the markets and the evolution that the electrical grid is currently experiencing, End Use Consumers frequently have questions and inquiries requiring explanation by the NYISO. The Consumer Interest Liaison has a responsibility to gather and facilitate clear explanations of these issues to the End Use Consumer representatives. The Consumer Interest Liaison is in a unique position to answer these inquiries directly or seek the assistance of a subject matter expert to clarify issues consumers may face. As part of the Market Structures department, the Consumer Interest Liaison has excellent access to subject matter experts that are working on the current NYISO projects. Inquiries may range from basic committee status updates to in-depth inquiries about the complex concept proposals. Whenever asked, the Consumer Interest Liaison provides the information necessary for End Use Consumer representatives to evaluate their position on critical issues.

Email Reminders

Reliable communication is paramount to effective participation in the NYISO governance process. To this end, the NYISO sends emails through several email databases on a daily basis. To avoid inundating market participants with emails that may be relevant only to specific groups of market participants, the NYISO provides many separate email lists for stakeholders to participate in. The Technical Information Exchange (TIE) email list is the primary list for notices. There are also mailing lists for each committee and working group, as well as several specific mailing lists such as Generator Operators, Demand Response, Main Contacts, etc. The Consumer Interest Liaison participates as a recipient of all these mailing lists and summarizes and resends relevant and pertinent emails to the End Use Consumer email list. Although this acts as a duplicate mailing, it affords end users the security of not missing important information.

Training and Information Sessions

Occasionally, issues arise in the stakeholder process that are extremely complex and/or have the potentially large impact on the markets. In these instances, the Consumer Interest Liaison offers an opportunity to the End-Use Sector for additional information and clarification on these issues to better prepare them for stakeholder discussions.

Through discussions with the End Use Sector, the Consumer Interest Liaison determines if there is a need to provide consumer representatives a more detailed explanation of specific areas of the NYISO markets. By meeting with Subject Matter Experts (SMEs) on NYISO markets, grid operations, and the planning processes, End Use consumer representatives have an opportunity to improve their understanding of current market issues and can be better prepared to more effectively represent their interests.

In July 2017, an end use consumer representative came to the Consumer Interest Liaison with such a request. It seems that in the course of conducting research for their client, they had a number of questions regarding the complex world of Transmission Congestion Contracts (TCCs). TCCs are financial instruments sold through the NYISO marketplace that can be used to hedge costs resulting from transmission system congestion. Primary holders of TCCs are able to hedge congestion costs associated with transmitting one MW of power between the buses specified in the TCCs.[4]

The consumer representative was looking for explanations of several concepts related to TCCs, including; transmission use charges, grandfathered transmission rights, historic fixed price TCCs, congestion charges for lines with multiple owners, distribution of TCC rents and additional questions surrounding transmission on New York Power Authority assets.

The consumer representative and Consumer Interest Liaison agreed that the efficient way for providing clarity to the TCC questions was to arrange an informal training session with the End Use Consumer representatives and SMEs for the TCC product. Based on the NYISO's standard practice, an invitation for a training session was extended to all End Use Consumer stakeholders. In preparation, the representative provided the NYISO with TCC issues for discussion.

On July 19, 2017, several End Use Consumer stakeholders and representation met at the NYISO with the Consumer Interest Liaison and Gregory Williams, Manager of TCC Operations for an instructional session including stakeholder participation. The session provided stakeholders several opportunities to better understand the required details and provided the stakeholders the ability to participate in the governance structure on issues affecting the TCC market in a more informed manner.

[4] A TCC represents the right to collect, or the obligation to pay, the Day-Ahead Market (DAM) Congestion Rents associated with one Megawatt (MW) of transmission between a specified Point of Injection (POI) and specified Point of Withdrawal (POW). The DAM Congestion Rents are determined by the Congestion Component of the DAM Locational Based Marginal Price (LBMP) at the POW of the TCC minus the Congestion Component of the DAM LBMP at the POI of the TCC, for each hour of the Effective Period. TCCs are fully funded. As such, Primary Holders of TCCs always receive (or pay) the full value of Congestion Rents associated with their respective TCCs.

NYISO Governance

Stakeholders, including End Use Consumer representatives, play a significant role in decision making through the NYISO's shared governance process. Stakeholders participate in NYISO's governance through three standing committees: the Management Committee (MC), the Business Issues Committee (BIC), and the Operating Committee (OC). Each of these committees oversees their own working groups, task forces and subcommittees. These committees provide stakeholders the forums to have discussion, debate and vote on issues regarding the administration of the markets, the operation of the New York's bulk power system, and the planning for system reliability, among other topics.

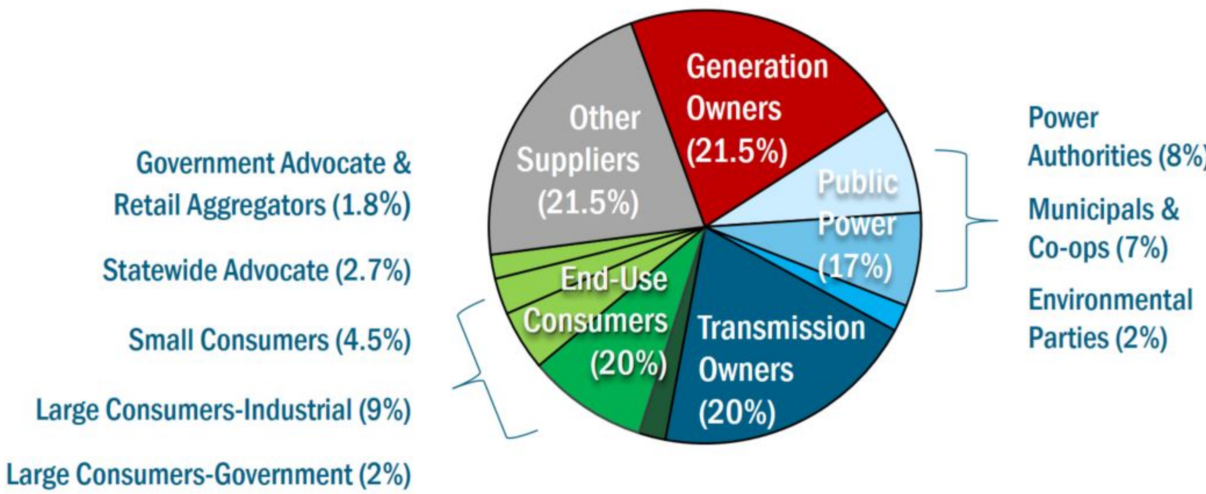
In 2017, the NYISO conducted more than 200 meetings, including monthly sessions of the three standing committees and near-daily meetings of subcommittees, working groups, and task forces.

The NYISO's governing agreements establish specific responsibilities for all three standing stakeholder committees. These committees perform their responsibilities in accordance with their bylaws and in coordination with work performed by NYISO management and staff. Stakeholders are responsible for a range of duties in the shared governance process, including:

- Reviewing and recommending candidates for Board vacancies,
- Developing and reviewing compliance with technical guidelines for the operation of the bulk power system,
- Developing and reviewing enhancements to market design,
- Developing and reviewing system planning reports and
- Reviewing the preparation of and approving the NYISO's annual budget.

The NYISO stakeholders and the NYISO Board of Directors share responsibility for developing and approving proposed changes to the NYISO's governing documents and federally accepted tariffs. The Management Committee must endorse any proposed change to the NYISO's governing documents before they can be approved by the Board of Directors and filed for review by the Federal Energy Regulatory Commission (FERC) under Section 205 of the Federal Power Act. The FERC has noted the collaborative results of the NYISO's shared governance system, stating in 2008, *"The Commission commends NYISO and the stakeholders for working together to resolve many issues…"*

Transmission Owners, Generation Owners, Other Suppliers, End-Use Consumers, and Public Power/Environmental Interests sector representatives vote in the stakeholder committees. Each stakeholder's vote in a committee is a percentage of its sector's allocated voting shares. Actions by the committees require a 58% vote of approval to pass. The voting shares in all three standing committees are allocated among the sectors and subsectors as follows:



In addition to stakeholders with voting rights, entities with significant interests in the NYISO markets may join the shared governance process as non-voting members. Further, staff of the New York State Public Service Commission (PSC) and the Federal Energy Regulatory Commission (FERC) regularly participate in and monitor issues addressed by the NYISO committees.

Consumer Impact Analysis Process

A primary responsibility of the Consumer Interest Liaison is to evaluate the impact of major market design changes on consumers. How a new market rule will impact reliability of the bulk power system, and how a new market rule will impact the competitiveness and efficiency of the market are systematically analyzed using specific criteria.

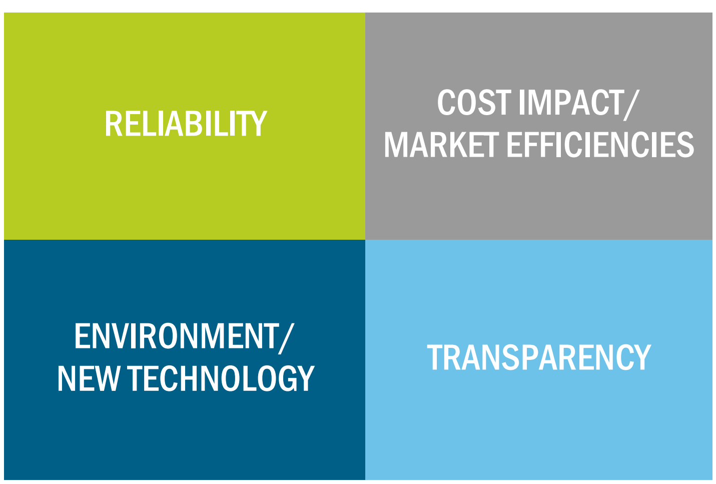
The consumer impact analysis is a formal process for assessing a new market rule, designed to include qualitative and quantitative metrics for each of the areas analyzed. The analysis reviews impacts of new rules under four evaluation areas: Reliability, Cost Impact/Market Efficiencies, Environment/New Technology, and Transparency. Each study area is described below.

The impact on **Reliability** analyzes how a new project improves the reliability of the current system. A project would not be implemented if it caused reliability issues or concerns.

The impact on **Cost Savings/Market Efficiency** analyzes the overall costs and benefits of implementing a project. It also reviews whether the project improves market operations and produces proper price signals to help spur investment.

The impact on **Market Transparency** assesses the extent to which the project will impact the transparency and clarity of market rules.

The impact on the **Environment** reviews how the project may affect the environment, focusing primarily on emission levels.



Projects selected for Consumer Impact Analysis are a subset of all NYISO projects chosen during the annual Budget Project Prioritization Process. The Consumer Impact Analysis list is presented to the stakeholders annually for their input. This occurs during the annual Budget Project Prioritization Process.

The annual Budget Project Prioritization Process typically begins in May and ends in the fourth quarter with the Board of Directors approval of the annual budget. Prior to the Board's approval, NYISO staff and stakeholders discuss the proposed projects and budgetary costs for the year during Budget and Priority Working group meetings. The projects that are included on the Consumer Impact Analysis Project list generally meet one or more of the following analysis guidelines:

- Anticipated net production cost impact of $5 million or more.
- Expected consumer impact from changes in energy or capacity market prices is greater than $50 million per year.
- Incorporates new technology into New York markets for the first time.
- Allows or encourages a new type or category of market product.
- Creates a mechanism for out-of-market payments for reliability.

Consumer Impact Presentations During 2017

- Transmission Constraint Pricing (MIWG – January 31, 2017)
- Methodology for Consumer Impact Analysis: Alternative Methods for Determining LCRs (ICAP – July 25, 2017)
- Consumer Impact Analysis: 2018 Project List (BPWG – July 26, 2017)
- Methodology for Consumer Impact Analysis: Securing 100+kV Transmission Facilities in the Market Model (MIWG – July 31, 2017)
- Consumer Impact Analysis: 2018 Project List (MC – September 27, 2017)
- Methodology for Consumer Impact Analysis: On Ramps and Off Ramps with Rules to Create and Eliminate Localities (ICAP – September 28, 2017)
- Alternative Methods for Determining LCRs (ICAP – October 11, 2017)
- Securing 100+kV Transmission Facilities in the Market Model (MIWG – November 2, 2017)
- On Ramps and Off Ramps with Rules to Create and Eliminate Localities (ICAP – November 6, 2017)
- Additional Analysis: Alternative Methods for Determining LCRs (ICAP –November 6, 2017)

Consumer Impact Analysis: Transmission Constraint Pricing

Background

On October 6, 2016, the NYISO notified market participants of a potential market problem related to the implementation of its graduated Transmission Shortage Cost. At the November 3, 2016 MIWG, the NYISO described that the current software implementing its transmission constraint pricing methodology was not consistent with the applicable tariff provisions. More specifically:

- The NYISO's software did not apply the graduated Transmission Shortage Cost in certain circumstances that were not explicitly described in the tariff.
- The tariff also did not fully describe the manner in which the NYISO's software resolved infeasible transmission constraints.

Also at the November 3, 2016 MIWG, the Market Marketing Unit (MMU) presented an assessment of the transmission constraint pricing implementation and recommended that the NYISO classify the inconsistency issue as a Market Problem. The NYISO concurred with the MMU's recommendation and concluded that the issue is a Market Problem. On January 6, 2017, the NYISO submitted a waiver request to FERC regarding the issue that it declared a Market Problem.

Further, at the November 3, 2016 MIWG, stakeholders requested the NYISO conduct an analysis on minimizing times when constraint relaxation is applied and broadening the use of the graduated Transmission Shortage Cost. In response, the NYISO, at the December 21, 2016 MIWG, presented the results of its analysis based on rerunning 17,658 RTD cases from July 2016 and August 2016.

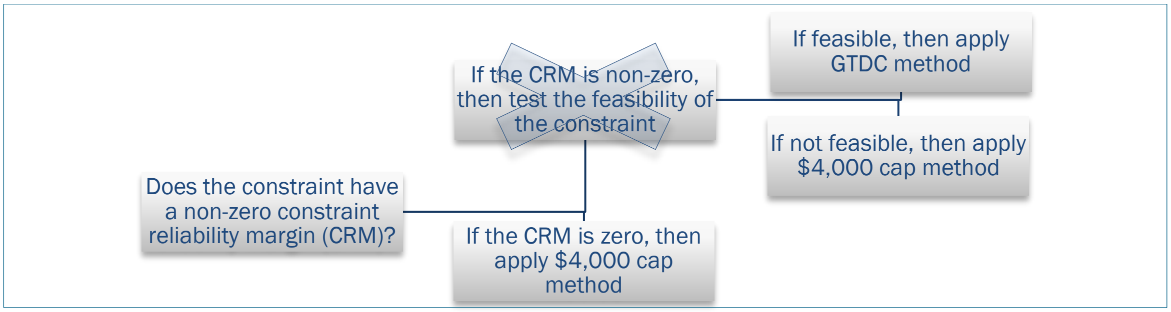
Proposed Transmission Constraint Process

Based on the analysis reviewed at the December 21, 2016 MIWG, the NYISO proposed the following two changes to its current transmission constraint pricing implementation:

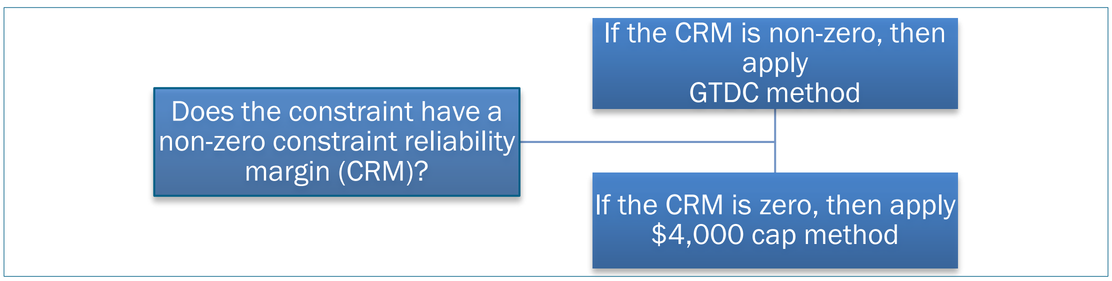
- Apply the graduated Transmission Shortage Cost method to all transmission constraints with a non-zero constraint reliability margin (CRM).
- This proposal would retain the current single $4,000/MWh Shadow Price cap for all transmission Constraints with a zero CRM value.
- Change the second step of the graduated Transmission Shortage Cost from $2,350/MWh to $1,175/MWh.

The diagram below shows the existing process and the transmission constraint process proposed by the NYISO to address the Market Problem.

Existing Process:



Proposed Process for Analysis:



Consumer Impact Analysis Evaluation Areas

The Consumer Impact Analysis computed the Locational Based Marginal Price (LBMP) and consumer cost impact of NYISO's proposal. This evaluation considered the potential impact on all four evaluation areas. The diagram below summarizes these different impacts.

RELIABILITY	COST IMPACT/MARKET EFFICIENCIES
Efficient pricing of transmission constraints impacts resource and Transmission Owner investment decisions which ultimately support grid reliability	The NYISO's proposal is expected to lead to more efficient pricing of transmission constraints relative to the current implementation
ENVIRONMENT/NEW TECHNOLOGY	**TRANSPARENCY**
No direct environmental impact is expected as a result of implementing the NYISO's proposal	Transparency should be enhanced under the NYISO's proposal

Consumer Cost Impact Methodology

The consumer cost impact is based on comparing the current transmission constraint pricing implementation with the proposal introduced by the NYISO. Under the current implementation, the graduated Transmission Shortage Cost is not applied to certain transmission constraints. In addition, the second step of the graduated Transmission Shortage Cost is currently valued at $2,350/MWh.

Under NYISO'S proposal, the graduated Transmission Shortage Cost will apply to all transmission constraints, except for those associated with facilities that have a zero CRM value. A list of transmission facilities and interfaces that have a zero CRM value is posted on the NYISO's website. The single $4,000/MWh Shadow Price cap will continue to apply to transmission constraints associated with these facilities and Interfaces. Additionally, under the NYISO proposal, the second step of the graduated Transmission Shortage Cost will be reduced from $2,350/MWh to $1,175/MWh.

The NYISO updated the tariff to reflect its proposed transmission constraint pricing process including the use of constraint relaxation and treatment of facilities and interfaces with a zero CRM value.

Consumer Cost Impact

Figure 1 below shows the consumer cost impact by zone of applying the NYISO's proposal to data for July 2016 and August 2016:

- Certain intervals on July 7, 2016 and August 23, 2016 for the NYC zone were excluded.
- The results for August 2016 are shown both with and without the scarcity event on August 12, 2016 from HB 13:00 to HB 18:00.

The data below is based on market software reruns for July and August 2016. It shows that consumer costs decreased slightly in both July and August 2016 (without consideration of the intervals when the scarcity pricing rules were in effect) under the NYISO's proposal.

Figure 1: Consumer Cost Impact by Zone

	Cost Delta NYISO Proposal Case minus Baseline Case		
Zone	July	August	August No Scarcity Intervals
CAPITL	($210,356.67)	($3,947.91)	$28,759.10
CENTRL	($213,468.01)	($40,351.95)	$4,253.03
DUNWOD	($223,398.57)	$89,831.55	($60,479.86)
GENESE	($202,794.33)	($29,138.16)	$21,713.27
HUD VL	($322,687.17)	$108,621.26	($83,087.23)
LONGIL	($1,300,209.69)	$13,698,201.25	$346,592.50
MHK VL	($129,013.15)	$19,354.36	$32,290.43
MILLWD	($99,021.13)	$38,856.12	($29,702.32)
N.Y.C.	($5,717,644.92)	($4,435,862.17)	($5,556,728.44)
NORTH	($63,497.05)	$23,934.42	$34,214.59
WEST	($1,626,340.58)	($791,045.76)	($876,390.15)
TOTAL	($10,108,431.28)	$8,678,453.01	($6,138,565.06)

Reliability Impact

The NYISO's proposal is expected to lead to more efficient pricing of transmission constraints relative to the current implementation. Efficient pricing of transmission constraints impacts resource and Transmission Owner investment decisions, which ultimately support grid reliability.

Impact on Transparency

Transparency should be enhanced under the NYISO's proposal.

- A list of transmission facilities and Interfaces that have a zero CRM value has been posted.
- Additional details have been provided to improve understanding of the operation of the NYISO's software and the manner in which infeasible transmission constraints are resolved.
- The clarity of the tariff provisions describing its transmission constraint pricing methodology was also improved.

The NYISO's proposal is also expected to send more appropriate price signals for long-term investment.

Environmental Impact

No direct environmental impact is expected as a result of implementing the NYISO's proposal.

Consumer Impact Analysis: Securing 100+kV Transmission Facilities in the Market Model

Project Objective

The 2015 State of the Market (SOM) report recommended that the NYISO model 100+kV transmission constraints as secured in the Day-Ahead Market (DAM) and Real-Time Markets (RTM). NYISO's objective for this project was to work with its stakeholders on a market design to secure select 100+kV transmission facilities within the market model. As part of the project objective, the NYISO conducted a Consumer Impact Analysis of the NYISO's proposal.

Background

Currently, the NYISO helps Transmission Owners (TOs) manage lower kV constraints through a number of out of market actions, which can lead to situations where market prices are not reflective of all actions required to maintain system reliability.

- The NYISO's Locational Based Marginal Prices (LBMP) do not currently provide the investment signals necessary to incent the construction and maintenance of resources that can efficiently manage the 100+kV constraints.

When the 100+kV transmission facilities are secured in the commitment and dispatch software, as proposed by the NYISO and recommended by the Market Monitoring Unit (MMU), it will both improve overall market efficiency as well as provide better targeted investment signals.

The out of market actions that the NYISO uses to help the TOs manage lower kV constraints are listed below:

- Transaction curtailments
- PAR adjustments
- Out of Merit (OOM) actions
- Day-Ahead Reliability Unit (DARU) commitments
- Supplemental Resource Evaluation (SRE)
- Surrogate interface derates

Benefit of Securing 100+kV Facilities in the Market Solution

Securing 100+kV facilities in the market model will lead to a more efficient solution, reducing the number of out of market actions taken to secure the system. Though this market design is initially expected to cause a slight increase in consumer cost, over time consumers will benefit from improved market signals that reduce long run consumer cost.

Consumer Impact Analysis (IA) Evaluation Areas

This presentation describes the potential impact of NYISO's proposal on all four evaluation areas. The diagram below summaries these impacts.

RELIABILITY Securing 100+kV will maintain future system reliability	**COST IMPACT/MARKET EFFICIENCIES** Possibility of short term increase in consumer costs. Over the long run, improvement in overall market efficiency as well as better targeted investment signals
ENVIRONMENT/NEW TECHNOLOGY More efficient integration of renewable resources is anticipated to have a positive environmental impact	**TRANSPARENCY** Securing 100+kV facilities in the market solution will lead to enhanced price transparency

Cost Impact Methodology – Consumer Impact Analysis

The Consumer Impact Analysis includes:

- Estimate of consumer cost impact based on DA simulation results.
    - The consumer cost measurement uses the delta between LBMPs in Production and both the Baseline Study and a Day-Ahead Reliability Unit (DARU) Study cases, multiplied by the fixed load plus price responsive load that cleared in the DAM.
- Production cost impact estimate based on the results of the DA simulation.
    - Minimizing total production cost given system constraints leads to the lowest long run consumer cost.
- A further review of Historical Power Supplier Guarantee Payments.
    - A review of cost allocation for guarantee payments.

Current Approach

Currently, the majority of the 115kV system is not secured in the market model. Hence, the market software does not schedule resources to prevent normal or contingency overloads on these 115kV transmission facilities. Instead, a number of out-of market-actions are relied upon to secure (prevent overloads) these transmission facilities in DA and RT. For example, Day-Ahead Reliability Unit (DARU) commitments of resources in the DAM are at times relied upon to secure these facilities. DARUs of uneconomic units may depress market prices by displacing units that otherwise reside at the top of the supply stack. Where DAM market prices do not cover DARUed resources' costs, the resources receive make whole payments that result in DA Bid Production Cost Guarantee (BPCG) payments, a type of uplift. Load is unable to hedge exposure to BPCG payments. Similarly, if schedules of units are increased in RT through Out of Market (OOM) actions, these resources are also eligible to collect RT BPCG uplift payments.

Proposed Approach

An alternative to out-of-market actions is to secure the constrained 100+kV facilities in the market solution. This allows the market software to determine the most economical solution to addressing the thermal limits (security) of the transmission facilities. The market software will find a solution that is as efficient or more efficient relative to securing the facility manually.

Assumptions

1. Analysis was conducted for the period of June 24 to July 23, 2016.
2. Hundreds of 100+kV facilities were secured in the simulation.
    - It would not be possible for the NYISO to secure all of these facilities in its production market software.
    - This approach was conservative, as the NYISO's list of facilities for consideration only includes roughly 30 of the 100+kV facilities secured in the simulation.
3. A Constraint Reliability Margin (CRM) of 20MWs was used.
    - The NYISO is considering a reduction in the CRM that applies to lower kV facilities, making the current analysis results conservative.
4. Additionally, constraints in all cases included the current transmission constraint pricing logic.
    - The Constraint Specific Demand Curve effort is likely to establish different transmission pricing for facilities within the simulation.

Consumer Cost Measurement

In order to measure consumer cost, we performed several DA simulations:

1. Production
   - Lower kV facilities not secured within the market software
2. Baseline Study
   - For the baseline study, the majority of 100+kV transmission facilities were secured in the market model to compare this scenario to addressing the transmission constraints through out-of-market actions (Production case) over approximately a one-month period.
   - The thermal constraint on Elbridge-State St. was secured using Milliken as a DARUed unit (as it was designated in Production)
3. "DARU" Study
   - Over the study period, Milliken Units 1&2 were originally reliability committed for 902 hours, as compared to 320 hours (~30%) of economic commitment when the lower kV lines are secured. The 320 hours of economic commitment likely understates the actual operation of the Milliken Units because of the plant's minimum run time requirements
   - Due to recent transmission upgrades, Milliken will rarely be needed as a DARU in the future for 100+kV thermal constraints
     - To demonstrate the efficiency gains of securing facilities within the market software, the NYISO removed the reliability DARU commitment of Milliken Units 1&2 from the Baseline Study to address the thermal constraint on the Elbridge-State St. 115 kV transmission facility.

Consumer Cost Impact

The consumer cost measurement below uses the delta between LBMPs in the Production and the Baseline and DARU Study, multiplied by the fixed load plus price responsive load that cleared in the DAM. Consumer costs increase by $4.2 and $5.6 million respectively, as shown in Figure 2 below. Securing lower kV facilities in the market software reduces uplift and would reduce the increase in consumer costs. DA BPCG paid to Milliken for the 30 days in question totaled roughly $905,000, while RT BPCG totaled roughly $410,000. The Milliken unit uplift would be expected to be reduced, given that Milliken was committed economically significantly less frequently in the DARU study than it was committed for reliability in the production case.

Figure 2: Consumer Cost Measurement

	Production	Baseline Study	DARU Study
Consumer Cost	$539,575,976	$543,785,403	$545,215,735
	Delta from Production	$4,209,427	$5,639,759
	% Delta from Production	0.78%	1.05%
		Delta from Baseline	$1,430,332
		% Delta from Baseline	0.26%

Total System Cost

Minimizing total production cost given system constraints leads to the lowest long-run consumer cost; the impact to total system cost within the DA is used here to draw conclusions about total production cost. Total System Cost is the sum of all costs (production costs) that have cleared the DA market, including virtual load and supply.

Total System Cost increased by 0.05% from Production to the Baseline Study condition. This is primarily driven by the impact of less virtual load clearing, though it is important to note that virtual offers are likely to be different under the NYISO's proposal. Comparing the Baseline Study to the DARU Study condition, Total System Cost decreased by 0.025%.

The DA simulation does not fully capture the benefit of decreased system cost. The NYISO was only able to examine the out-of-market commitment of DARUs within this study; DARUs were committed less frequently, resulting in a lower Total System Cost and a more efficient solution compared to the Baseline Study. If other out-of-market actions could be quantified, an even lower total system cost would be expected.

Once select lower kV facilities are secured in the market model, the avoidance of out-of-market actions is anticipated to decrease total system cost through more import availability, use of individual line constraints in place of interface derates, and possible avoidance of reliability must-run contracts.

Constraint Reliability Margin

The Baseline Study and DARU Study used a CRM of 20 MW for lower kV facilities that were secured. This is conservative, as the NYISO is considering using a lower CRM value for lower kV facilities. To assess the impact of a lower CRM, the Baseline Study was rerun with a CRM of 5 MW for lower kV facilities. The Constraint Specific Demand Curves project will determine whether a lower CRM on 100+kV facilities is appropriate. The current graduated transmission demand curve was applied in Production, and to all of the study cases.

Consumer Cost Impact – Modified CRM

The use of the modified CRM reduces the increase in consumer costs as shown in Table 2 below. Using a CRM of 20 MW resulted in consumer costs increasing by approximately $4.2 million. However, consumer costs increased by only $1.4 million when using a CRM of 5 MW. Reduced Local Reliability Rule uplift, as shown in Figure 3 below, should more than make up for this increased consumer cost:

Figure 3: Reduced Local Reliability Rule uplift

	Production	Baseline Study (20 MW CRM)	Baseline Study (5 MW CRM)
Consumer Cost	$539,575,976	$543,785,403	$540,963,205
	Delta from Production	$4,209,427	$1,387,229
	% Delta from Production	0.78%	0.26%
		Delta from Baseline (20 MW CRM)	($2,822,198)
		% Delta from Baseline (20 MW CRM)	-0.52%

Discussion of Cost to Load Changes (DAM only)

Cost to load decreases slightly in the East, specifically NYC, while increasing in the West. Whether 115kV constraints or 230kV/345 kV constraints are binding varies for each individual day. 115 kV constraints may bind in certain instances in the simulation study cases along with 230 kV/345 kV constraints that were binding in production. This tends to increase the cost to load. On other days within the study cases, a binding 115kV constraint may avoid a 230kV/345kV constraint from binding. In these instances, more power is able to flow across the 230kV/345kV system, which typically decreases cost to load in eastern New York.

Cost Impact Methodology – Real Time

Securing the lower kV system in both the DA and RT markets is expected to significantly reduce the need for RT out–of-market actions. However, it is difficult to accurately identify RT impacts because of the difficulty of removing the impact of out-of-market actions from RT. As an alternative, the NYISO reviewed settlements data to provide an assessment of the DA and RT out-of-market costs, some portion of which may be avoided by securing the lower level facilities.

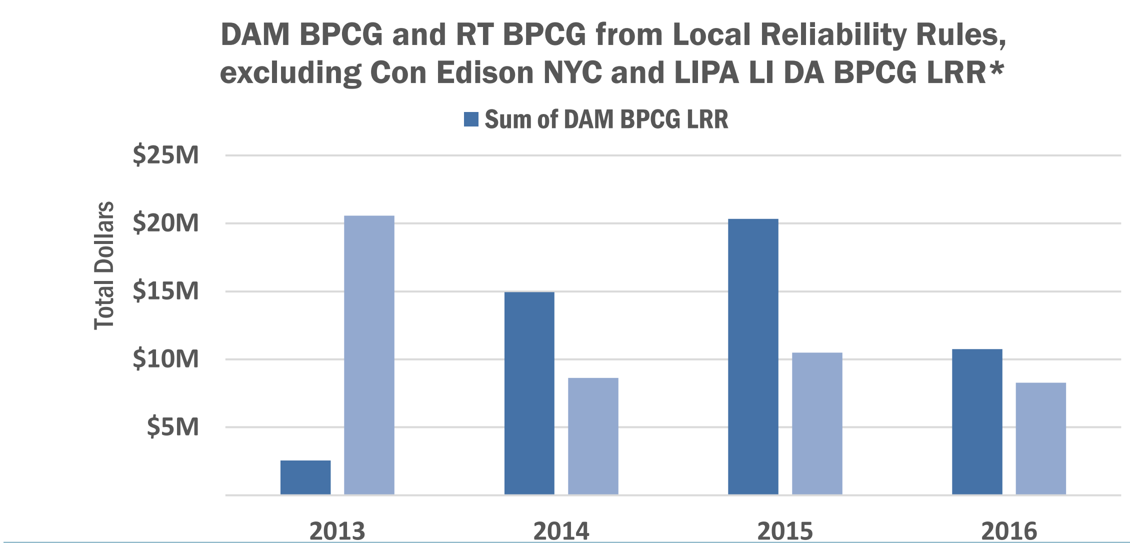
Guarantee Payments

The NYISO proposed that any uplift resulting from securing additional, lower kV facilities in the market model will be allocated statewide. If a local TO requests an out of market action, such as a DARU or OOM, then any uplift paid to a generator as a result of that action will be allocated to the local TO. The NYISO will continue to closely monitor uplift once 100+kV facilities are secured in the market model.

LRR BPCG – Guarantee Payments

The NYISO's proposal will reduce uplift resulting from manual actions to support 100+kV system security. Figure 4 below details uplift attributable to TO actions necessary to support NYSRC Local Reliability Rules. This uplift results from manual TO actions to maintain 100+kV system security, as well as reactive power support. This uplift is charged to LSEs within the TO's district.

Figure 4: Uplift Attributable to TO Actions Necessary to Support NYSRC Local Reliability Rules



Estimated Project Cost

The estimated project cost for implementing the automated mitigation rules described within the NYISO's 100+kV proposal is expected to be a significant software development effort.

Reliability Impact

Securing 100+kV transmission facilities in the market solution should provide better price signals for new investment or maintenance of current resources in areas where it is most needed. This should maintain future system reliability.

Environmental Impact

State policy is promoting increased investment in small and large renewable resources. Providing price signals for new investment is especially important. Software will more efficiently accommodate renewables on a constrained transmission system. More efficient integration of renewable resources is anticipated to have a positive environmental impact.

Impact on Transparency

Securing 100+kV facilities in the market solution will lead to greater price transparency as compared to relying on out-of-market actions to address transmission constraints.

Consumer Impact Analysis: On Ramps & Off Ramps with Rules to Create and Eliminate Localities

Background

Numerous locality elimination working group presentations were made to, and discussed with stakeholders from 2014 to 2017. The Mechanism to Eliminate Capacity Zones (localities) was a 2015 Business Plan Obligation – Market Design Concept. It was also on the Consumer Impact List of Projects for 2015. A Consumer impact analysis on NYISO's 2015 proposal to Eliminate Capacity Zones (localities) was presented to stakeholders at the December 9, 2015 BIC. During 2017, the NYISO started working on a holistic approach with stakeholders for evaluating locality creation and elimination rules as part of the On Ramps and Off Ramps for Zones market design concept project. This consumer impact analysis is based on the approach developed with stakeholder input during 2017.

Project Design Statement for Creation and Elimination of Localities

Develop a robust and transparent process for the creation and elimination of localities-based on reliability principles to ensure locational capacity prices reflect system reliability needs and market conditions.

NYISO Proposal for Creating and Eliminating Localities

Align Create & Eliminate Rules with Reliability Planning Process:

- Use accepted and familiar reliability planning approach.
- Use established planning cases from the existing Reliability Planning Processes.
- Focus primarily on transmission capability between LBMP zones.
- Use transmission security and/or resource adequacy.

Benefits of Establishing Rules to Create and Eliminate Zones

Establishing rules to create and eliminate localities when necessary avoids burdening consumers with unneeded costs. New localities should be created when necessary to avoid the potential costs of delayed creation. The rules should also provide for a way to eliminate localities when no longer needed in order to avoid unnecessary cost to consumers. Finally, avoid premature elimination by establishing a reasonable target threshold level for elimination.

Consumer Impact Analysis (IA) Evaluation Areas

Present the potential impact on all four evaluation areas:

RELIABILITY	COST IMPACT/MARKET EFFICIENCIES
A delay in creating a Locality or a premature elimination of a Locality could lead to early retirements and the lack of new investment. Hence, creating the potential for inadequate capacity to serve load in the region.	A well designed elimination rule that avoids toggling and premature Locality elimination would avoid adverse economic impacts on consumers. The timely creation of the Locality would potentially have a positive economic impact.
ENVIRONMENT/NEW TECHNOLOGY	**TRANSPARENCY**
No negative environmental impacts expected	No negative impacts

Potential Impact on Costs

Evaluate cost impact/savings to consumers of:

- Premature elimination of localities
- Timely creation of localities
- Keeping localities in place longer than needed
- The impact of uncertainty on Demand Curve reset peaking plant amortization

Elimination of Localities

Eliminating a locality prematurely would potentially result in not providing the correct price signal for siting new generation or retaining and investing in existing generation. Additionally, it could lead to early retirements and a potential for inadequate capacity within the locality. To illustrate the short-term impact of premature elimination, we assume that 500/1000 MW will retire and compute the impact on capacity prices and costs. For the long-term impact, we assume that in addition to retirements, some new generation that was expected to come online, will no longer come into service due to inadequate prices.

Short-Term Impact

Figure 5 below shows the short-term (2017/2018) impacts of eliminating the G-J Locality prematurely. For illustration, it was assumed that 500/1000 MW would retire if we eliminate the locality. For the 500 MW retirement case, NYCA-wide capacity costs increase as the increase in costs to ROS (A-I), Zone K and NYC are more than the costs savings from eliminating the locality. The adverse economic impact on NYCA is approximately $91 million.

For the 1000 MW retirement case, NYCA-wide capacity costs again increase as the increase in costs to ROS (A-I), Zone K and NYC are more than the costs savings from eliminating the locality. The adverse economic impact on NYCA is approximately $860 million.

A well-designed elimination rule that avoids toggling and premature locality elimination would potentially avoid $91 million in additional adverse economic impacts on consumers assuming 500 MW would have retired if the zone had been prematurely eliminated and $860 million if 1000 MW had retired.

The last set of columns on the right side of Figure 5 assumes no retirements even after the locality is eliminated. Given the price separation between the localities, that is not a realistic scenario.

Figure 5: Locality Elimination – Short Run

Short Run Capacity Cost Impacts with Current LCR Methodology 2017/18 (In millions)															
Capacity Area	Summer Price	Winter Price	With G-J Locality (Base Case)	Summer Price	Winter Price	G-J Locality Eliminated 500MW Retired J = 83 K = 103.8	Change in Capacity Area Cost	Summer Price	Winter Price	G-J Locality Eliminated 1000MW Retired J = 85.3 K = 104.9	Change in Capacity Area Cost	Summer Price	Winter Price	G-J Locality Eliminated No Retirements No LCR Change (This scenario is not realistic)	Change in Capacity Area Cost
ROS	$2.6	$0.0	$277.3	$3.80	$0.76	$605.5	$328.2	$5.03	$1.89	$905.3	$628.0	$2.58	$0.01	$347.6	$70.3
G-J	$10.0	$4.0	$387.2			$0.0	-$387.2			$0.0	-$387.2			$0.0	$387.2
J	$10.2	$4.0	$841.5	$12.31	$3.98	$968.1	$126.6	$15.48	$7.35	$1,364.9	$523.4	$10.15	$1.68	$697.4	-$144.0
K	$6.4	$0.33	$235.5	$6.67	$0.76	$259.8	$24.3	$7.53	$1.89	$331.6	$96.1	$6.43	$0.33	$235.5	$0.0
TOTAL			$1,742			$1,833	$91			$2,602	$860			$1,281	-$461

Long-Term Impact

Figure 6 shows the long-term (2021/2022) impacts of eliminating the G-J Locality. For illustration, it was assumed that in addition to 1000 MW retiring, 750 MW of new generation does not come into service as prices are too low because of locality elimination. The first scenario (columns 5-8), assumes that as a result of Locality elimination 1000 MW retire from G-J Locality. 250 MW are also assumed to enter Zone F as the NYCA prices increase with the elimination of the G-J Locality. NYCA-wide capacity costs increase as the increase in costs for ROS (A-I), Zone K and NYC are more than the costs savings from eliminating the zone. The NYCA-wide adverse economic impact is approximately $211 million.

The second scenario (columns 9-12) assumes that in addition to 1000 MW retiring, 750 MW of new expected generation does not come into service. NYCA-wide costs again increase as the increase in costs for ROS (A-I), Zone K and NYC are more than the costs savings from eliminating the zone. The NYCA-wide adverse economic impact in this scenario is approximately $1.2 billion.

Once again, a well-designed elimination rule that avoids premature elimination would potentially avoid additional adverse economic impacts on consumers.

Figure 6: Locality Elimination – Long Run

Long Run Capacity Cost Impacts with Current LCR Methodology 2021/22 (In millions)											
Capacity Area	Summer Price	Winter Price	With G-J Locality (Base Case)	Summer Price	Winter Price	G-J Locality Eliminated 1000MW Retired G New Entry 250MW F J = 82.1 K = 103.5	Change in Capacity Area Cost	Summer Price	Winter Price	G-J Locality Eliminated No New Entry G 1000MW Retired G New Entry 250 F J = 85.1 K = 104.7	Change in Capacity Area Cost
ROS	$0.27	$0.01	$30.0	$2.29	$0.01	$308.7	$278.6	$4.31	$0.94	$689.9	$659.9
G-J	$8.79	$2.72	$370.6			$0.0	-$370.6			$0.0	-$370.6
J	$11.36	$2.72	$833.4	$13.68	$4.60	$1,086.9	$253.5	$18.22	$9.43	$1,655.4	$822.0
K	$1.17	$0.01	$41.0	$2.60	$0.01	$90.7	$49.7	$4.31	$0.94	$184.5	$143.6
TOTAL			$1,275			$1,486	$211			$2,530	$1,255

Timely Creation of New Localities

The timely creation of a new locality would potentially result in providing the correct price signal for siting new generation or retaining and investing in existing generation. Additionally, it would also avoid early retirements and a potential for inadequate capacity within the locality. To illustrate the potential benefit of timely creation, it was assumed that there is no G-J Locality (base case) as shown in Figure 7 on the first set of columns starting from the left of Figure 7. The total annual cost of the capacity market in the base case with no G-J Locality is $1,281 million.

The second set of columns assumes that 500 MW retire in the G-J Locality as a result of inadequate prices and compute the impact on capacity prices and total capacity costs. Total cost of capacity rises to $1,833 million.

The third set of columns assumes that 1000 MW retire and the total capacity cost increases to $2,602 million.

The final set of columns show the creation of the G-J Locality and the impact on capacity prices and costs without any retirements. The total cost of the capacity market is $1,742.

The timely creation of the locality would potentially have a positive economic impact on consumers of $91 million ($1,833-1,742) assuming 500 MW would have retired if the locality had not been created and $860 million if 1000 MW ($2,602-1,742) had retired.

Figure 7: Timely Locality Creation

Short Run Capacity Cost Impacts with Current LCR Methodology 2017/ 18 (In millions)															
Capacity Area	Summer Price	Winter Price	2017/18 (Base Case)	Summer Price	Winter Price	500MW Retired J = 83 K = 103.8	Change in Capacity Cost	Summer Price	Winter Price	1000MW Retired J = 85.3 K = 104.9	Change in Capacity Cost	Summer Price	Winter Price	With New Locality No Retirements	Change in Capacity Cost
ROS	$2.58	$0.01	**$347.6**	$3.80	$0.76	**$605.5**	$257.9	$5.03	$1.89	**$905.3**	$557.7	$2.58	$0.01	**$277.3**	-$70.3
G-J						**$0.0**	$0.0			**$0.0**	$0.0	$9.95	$3.97	**$387.2**	$387.2
J	$10.15	$1.68	**$697.4**	$12.31	$3.98	**$968.1**	$270.6	$15.48	$7.35	**$1,364.9**	$667.4	$10.15	$3.97	**$841.5**	$144.0
K	$6.43	$0.33	**$235.5**	$6.67	$0.76	**$259.8**	$24.3	$7.53	$1.89	**$331.6**	$96.1	$6.43	$0.33	**$235.5**	$0.0
TOTAL			**$1,281**			**$1,833**	**$553**			**$2,602**	**$1,321**			**$1,742**	**$461**

Additional Cost Impacts

Keeping Locality in place longer than needed

For illustration, it was assumed that transmission and/or other changes have led to a situation where the conditions for locality elimination may have been met and a locality is no longer needed. In such a situation, keeping a locality in place when no longer needed could potentially have cost impacts on consumers if prices do not fully converge. For illustration, Figure 8 shows the cost impact of prices not fully converging for different levels of assumed price separation between the G-J Locality and NYCA. On the X-axis, we show the amount of UCAP MW. The Y-axis shows different levels of price separation between the G-J Locality and NYCA. For example, if the price separation is $1 and the incremental G-I MW are 4500, the total impact would be $54 million. Similarly, a $2 price separation would increase the cost to consumers to $108 million.

Figure 8: Impact of Price Separation Between Capacity Areas

G, H, I Incremental UCAP MW Difference (in millions)									
Price Differential	3000	3500	4000	4500	5000	5500	6000	6500	7000
$0.25	$9.00	$10.50	$12.00	$13.50	$15.00	$16.50	$18.00	$19.50	$21.00
$0.50	$18.00	$21.00	$24.00	$27.00	$30.00	$33.00	$36.00	$39.00	$42.00
$0.75	$27.00	$31.50	$36.00	$40.50	$45.00	$49.50	$54.00	$58.50	$63.00
$1.00	$36.00	$42.00	$48.00	$54.00	$60.00	$66.00	$72.00	$78.00	$84.00
$1.25	$45.00	$52.50	$60.00	$67.50	$75.00	$82.50	$90.00	$97.50	$105.00
$1.50	$54.00	$63.00	$72.00	$81.00	$90.00	$99.00	$108.00	$117.00	$126.00
$1.75	$63.00	$73.50	$84.00	$94.50	$105.00	$115.50	$126.00	$136.50	$147.00
$2.00	$72.00	$84.00	$96.00	$108.00	$120.00	$132.00	$144.00	$156.00	$168.00

Demand Curve Reset Peaking Plant Amortization

Some stakeholders suggested that the option of locality elimination will lead to additional risk and that may impact the net CONE of the peaking plant used to establish the ICAP Demand curve. Figure 9 shows different levels of potential impact on reference prices for G-J and the resultant impact on capacity costs.

Figure 9: Potential Impact on Peaking Plant Amortization

Length of Term	Factor	Reference Price	Total Capacity Cost	Total Cost Difference
G-J Unadjusted	Base	$14.84	$1,741.5	
10yr G-J then NYCA	15%	$17.07	$1,912.6	$171.1
7yr G-J then NYCA	25%	$18.55	$2,035.0	$293.5
5yr G-J then NYCA	50%	$22.26	$2,338.4	$596.9
3yr G-J then NYCA	75%	$25.97	$2,642.7	$901.1

Reliability Impacts

A delay in creating a locality or a premature elimination of a locality could lead to early retirements and the lack of new investment. Hence, creating the potential for inadequate capacity to serve load in the region.

Environmental Impacts

No negative environmental impacts expected.

Impacts on Transparency

No negative impacts.

Consumer Impact Analysis: Alternative Methods for Determining LCRs

Project Objective for Determining Alternative LCRs

Evaluate an alternative methodology for determining Locality Capacity Requirements (LCRs) based on economic optimization that minimizes the cost of satisfying planning requirements:

- Identify LCRs that provide the least cost distribution of capacity resources amongst New York Control Area (NYCA) localities while keeping Loss of Load Expectation (LOLE)<0.1.

Background

The NYISO started this project by first establishing guiding principles to evaluate the alternative LCR methodology (least cost, stable, robust, predictable). Next, the proof of concept phase demonstrated how the alternative LCR methodology performs in relation to the guiding principles. This was followed by Phase 2, which focused on refining the methodology to ensure that optimization is based on sound market and engineering principles. Phase 3 focused on simulating market situations to demonstrate the performance of the alternative methodology.

Consumer Impact Analysis (IA) Evaluation Areas

Present the potential impact of all four evaluation areas. The diagram below summaries these impacts:

RELIABILITY	COST IMPACT/MARKET EFFICIENCIES
Stable and predictable market signals resulting from the optimized LCR methodology lead to more efficient decisions in expanding and retiring assets, hence improving reliability.	In the short & intermediate term, consumer cost reduced in the majority of cases. In the long term, Consumer savings are smaller since the difference in the quantity of capacity purchased for each Locality is minimal between the current LCR methodology and the optimized methodology while the price stays relatively stable.
ENVIRONMENT/NEW TECHNOLOGY	**TRANSPARENCY**
No change expected.	Stable LCRs enhance transparency as market response to changes in generation and/or reference prices become more predictable.

Cost Impact Methodology

The impact analysis compares the cost impacts on consumers in each of the three localities (zones J, K, G-J) and NYCA of the alternative LCR methodology with the current methodology for the, short term, intermediate, and long term. The cost impact analysis utilized the results produced after all refinements were incorporated into the methodology (*i.e.*, final methodology). The 2017/2018 Capability Year LCR base case was solved to an LOLE of 0.1 days/year while using the NYCA Minimum Installed Capacity Requirement (IRM).

Consumer Impact Assumptions

Load

- Equivalent to the peak load in the MARS case

Reference Point

- Current values, except when sensitivity assumed a change in Net CONE

Derating Factor

- Historical values

Supply

- **Short Term**: Current generation with assumed values for imports, exports, unsold, and unoffered based on historical levels.
- **Intermediate Term**: Same as short term except with the removal or addition of the generation assumed in the sensitivity.
- **Level of Excess**: Supply level is equal to the LCR/IRM plus the assumed level of excess defined in the Demand Curve Reset.
- **Historical Percentage Excess**: Supply level is equal to the historic excess defined as a percentage of excess above the requirement observed within the last 3 Capability Years in each of the different localities.

Short Term Cost Impact Methodology

The short-term impact compares the cost of applying the current methodology and the alternative methodology to the 2017/2018 Capability Year LCR base case:

- The short-run impact analysis assumes no changes to generation and transmission

Figure 10: Short Term Cost Methodology

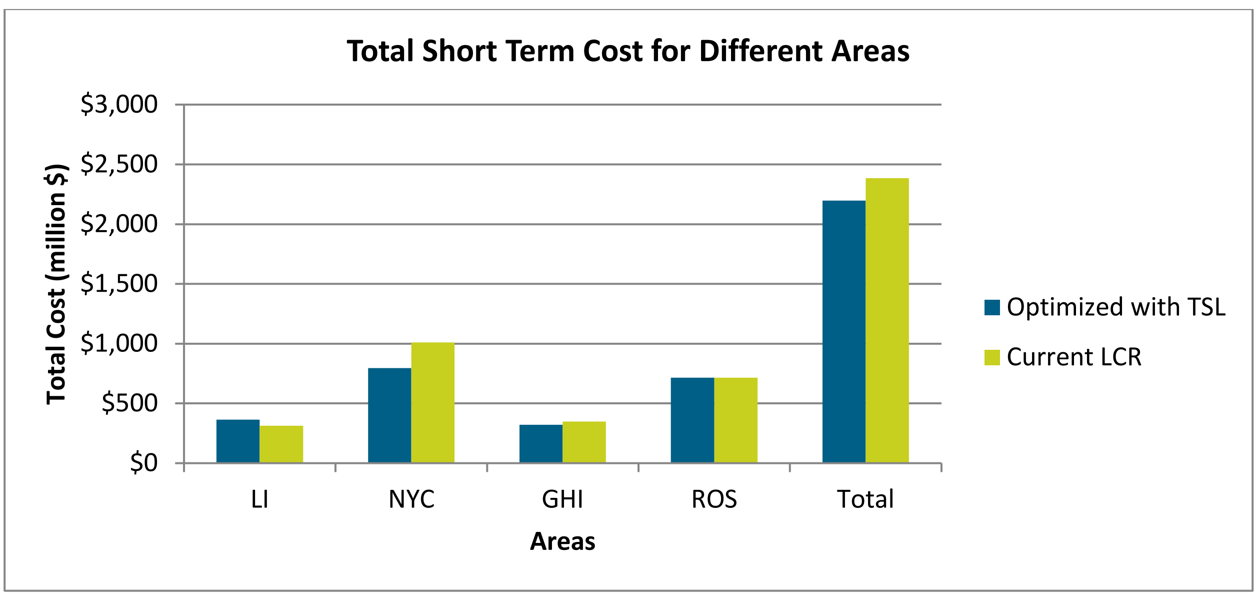
Scenario	Optimized Costs ($)			Current LCR Methodology Costs ($)		
	As found	At Level of Excess	At Generic Excess level	As found	At Level of Excess	At Generic Excess level
Base Case						
+500 MW in G						
-500 MW in G						

Difference in cost is short run impact (as found system and assumes no changes)

Short Term Consumer Impacts

Based on the sensitivity conducted, as shown below in Figure 11 below, total NYCA consumer cost is reduced by approximately $188 million in the short run.

Figure 11: Total Short Term Cost for Different Areas



Intermediate Cost Impact Methodology

The intermediate impact compares the cost of applying the current LCR methodology with the alternative methodology as generation and transmission resources change. This analysis assumes the only change to the system is the change used to perform the sensitivity case. For example, the cost impact of a +500 MW Zone J sensitivity case would keep all assumptions constant except for the addition of 500 MW to Zone J.

The intermediate impact was performed on a sub-set of simple sensitivity cases along with a set of sensitivities that include multiple changes to the system. Sensitivities were also performed for changes in net CONE.

Figure 12: Intermediate Cost Impact Methodology

Scenario	Optimized Costs ($)			Current LCR Methodology Costs ($)		
	As found	At Level of Excess	At Generic Excess level	As found	At Level of Excess	At Generic Excess level
Base Case						
+500 MW in G						
-500 MW in G						

Difference in cost is intermediate impact (as found system with an addition and subtraction of 500 MW to G)

Intermediate Term Consumer Impacts

Based on the sensitivities conducted, as shown below in Figures 13, 14, and 15, total NYCA capacity costs in the intermediate term are reduced in the majority of cases. The only cases that do not result in savings occur when the current LCR methodology results in a Zone J LCR lower than the Transmission Security Floor used in the optimization. The intermediate impact was performed on a sub-set of simple sensitivity cases (Figure 13) along with a set of sensitivities that include multiple changes to the system (Figure 14). Sensitivities were also performed for changes in net CONE (Figure 14).

Figure 13: Total Intermediate Term Cost for the NYCA (Changes in Generation)

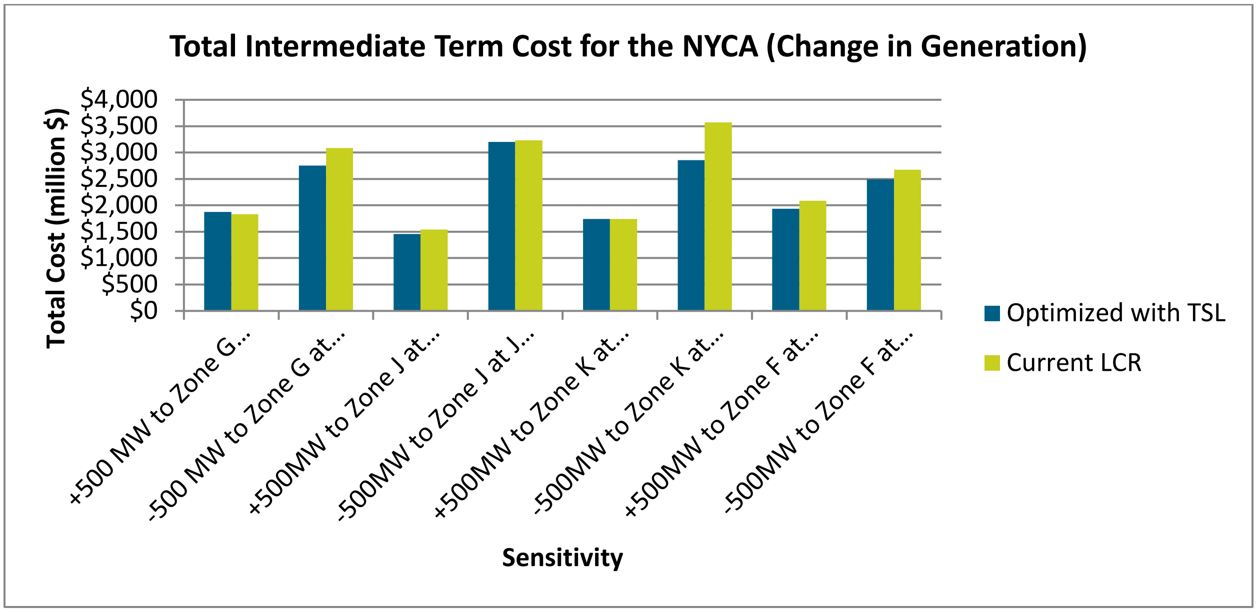


Figure 14: Total Intermediate Term Cost for NYCA (Multiple Changes in Generation)

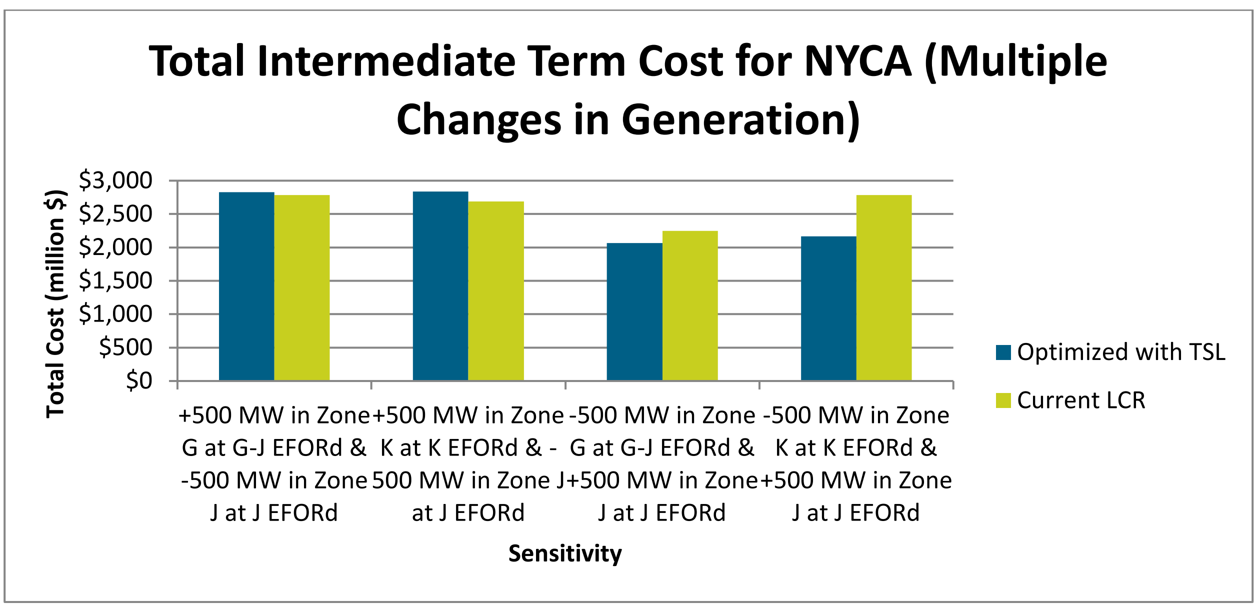
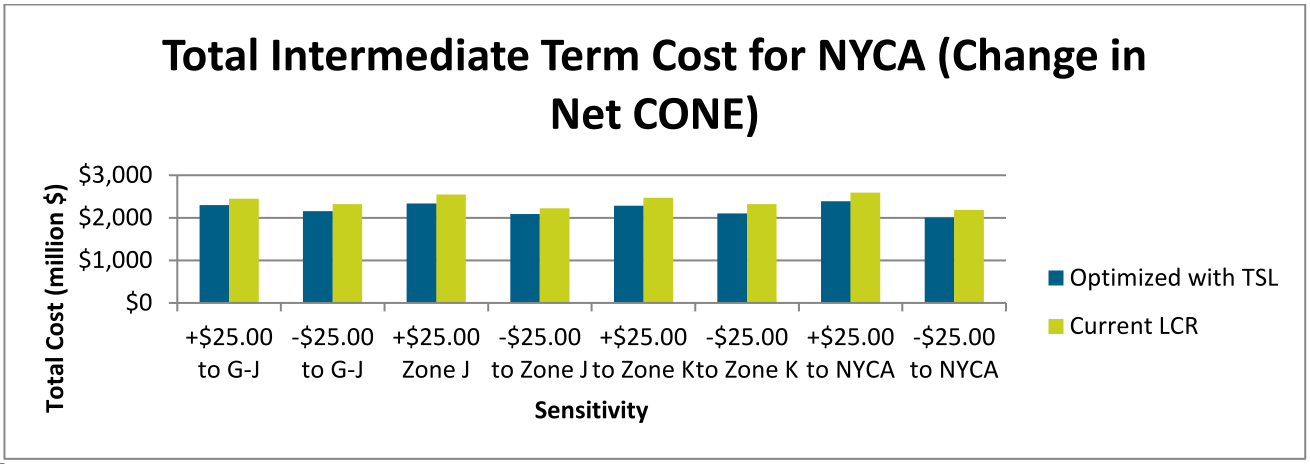


Figure 15: Total Intermediate Term Cost for NYCA (Changes in Net CONE)



While the graphs above (Figures 13, 14, and 15) show the total NYCA capacity cost in the intermediate term under both the current and optimized LCR methodology based on changes to generation and net CONE, Figures 16, 17, and 18 below show the change in these costs between the current and optimized LCR methodology. Additionally, the figures also break down the cost delta between the two LCR methodologies for each Locality. The average benefit from the Optimized LCR methodology with TSL compared to the Current LCR methodology is approximately $164 million as shown in Figure 18.

Figure 16: Short & Intermediate Term Capacity Cost from Current LCR to Optimized with TSL (Changes in Generation)

Sensitivity	Δ Short & Intermediate Term Capacity Cost from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$52	-$215	-$26	$0	-$188
+500 MW to Zone G at G-J EFORd	$126	$53	-$139	$0	$39
-500 MW to Zone G at G-J EFORd	$17	-$383	$37	$0	-$329
+500MW to Zone J at J EFORd	$97	-$135	-$43	$0	-$82
-500MW to Zone J at J EFORd	$3	-$37	-$1	$0	-$34
+500MW to Zone K at K EFORd	$0	$5	-$6	$0	-$2
-500MW to Zone K at K EFORd	$177	-$716	-$176	$0	-$715
+500MW to Zone F at F EFORd	$84	-$158	-$74	$0	-$149
-500MW to Zone F at F EFORd	$67	-$222	-$27	$0	-$182

Figure 17: Short & Intermediate Term Capacity Cost from Current LCR to Optimized with TSL (Changes in Net CONE)

Sensitivity	Δ Short & Intermediate Term Capacity Cost from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$96	$113	-$111	$0	$99
+$25.00 to G-J	$156	-$215	-$89	$0	-$148
-$25.00 to G-J	-$15	-$205	$53	$0	-$167
+$25.00 Zone J	$76	-$249	-$39	$0	-$212
-$25.00 to Zone J	$52	-$157	-$26	$0	-$131
+$25.00 to Zone K	$10	-$215	$14	$0	-$191
-$25.00 to Zone K	$41	-$215	-$41	$0	-$215
+$25.00 to NYCA	$5	-$215	$10	$0	-$200
-$25.00 to NYCA	$75	-$215	-$48	$0	-$187
+500 MW in Zone G & -500 MW in Zone J	$81	$156	-$192	$0	$44
+500 MW in Zone K & -500 MW in Zone J	$0	$122	$25	$0	$147
-500 MW in Zone G & +500 MW in Zone J	$49	-$243	$9	$0	-$185
-500 MW in Zone K & +500 MW in Zone J	$196	-$649	-$162	$0	-$616

Figure 18: Short & Intermediate Term Cost of Capacity from Current LCR to Optimized with TSL (Statistical)

Sensitivity	Δ Short & Intermediate Term Cost of Capacity from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Minimum	-$15	-$716	-$192	$0	-$715
25th Percentile	$12	-$220	-$86	$0	-$197
Average	$66	-$182	-$48	$0	-$164
75th Percentile	$93	-$61	$7	$0	-$46
Maximum	$196	$156	$53	$0	$147

Long Term Cost Impact Methodology

The long-term cost impact compares the cost of the current LCR methodology with the alternative methodology at long-run equilibrium. Two different versions of long-run equilibrium were used, as defined below:

- The long-run equilibrium was modeled at the Level of Excess condition (defined in the Demand Curve reset).
- Historic excess defined as a percentage of excess above the requirement observed within the last three capability years in each of the different localities.

Consumer Costs at Level of Excess (LOE)

Figure 19: Consumer Costs at LOE Methodology

Scenario	Optimized Costs ($)			Current LCR Methodology Costs ($)		
	As found	At Level of Excess	At Generic Excess level	As found	At Level of Excess	At Generic Excess level
Base Case						
+500 MW in G						
-500 MW in G						

Difference in cost is long term impact (at LOE)

Long Term Consumer Impacts at Level of Excess

Based on the sensitivities conducted, as shown below in Figures 20, 21, and 22, total long term NYCA consumer cost at the LOE is reduced in all cases except one. The only case that did not result in savings occurs when the current LCR methodology results in a Zone J LCR lower than the Transmission Security Floor used in the optimization. Consumer savings in the long term are smaller than the short-term savings since the difference in the quantity of capacity purchased for each Locality is minimal between the current LCR methodology and the optimization while the price stays relatively stable.

Figure 20: Total Long Term Cost at LOE for Different Areas

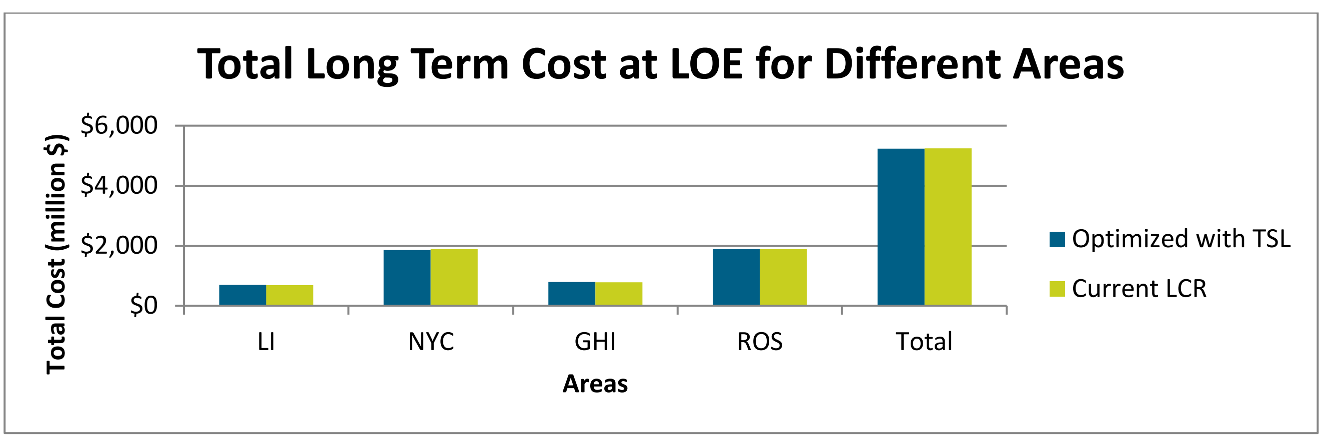


Figure 21: Total Long Term Cost at LOE for the NYCA (Change in Generation)

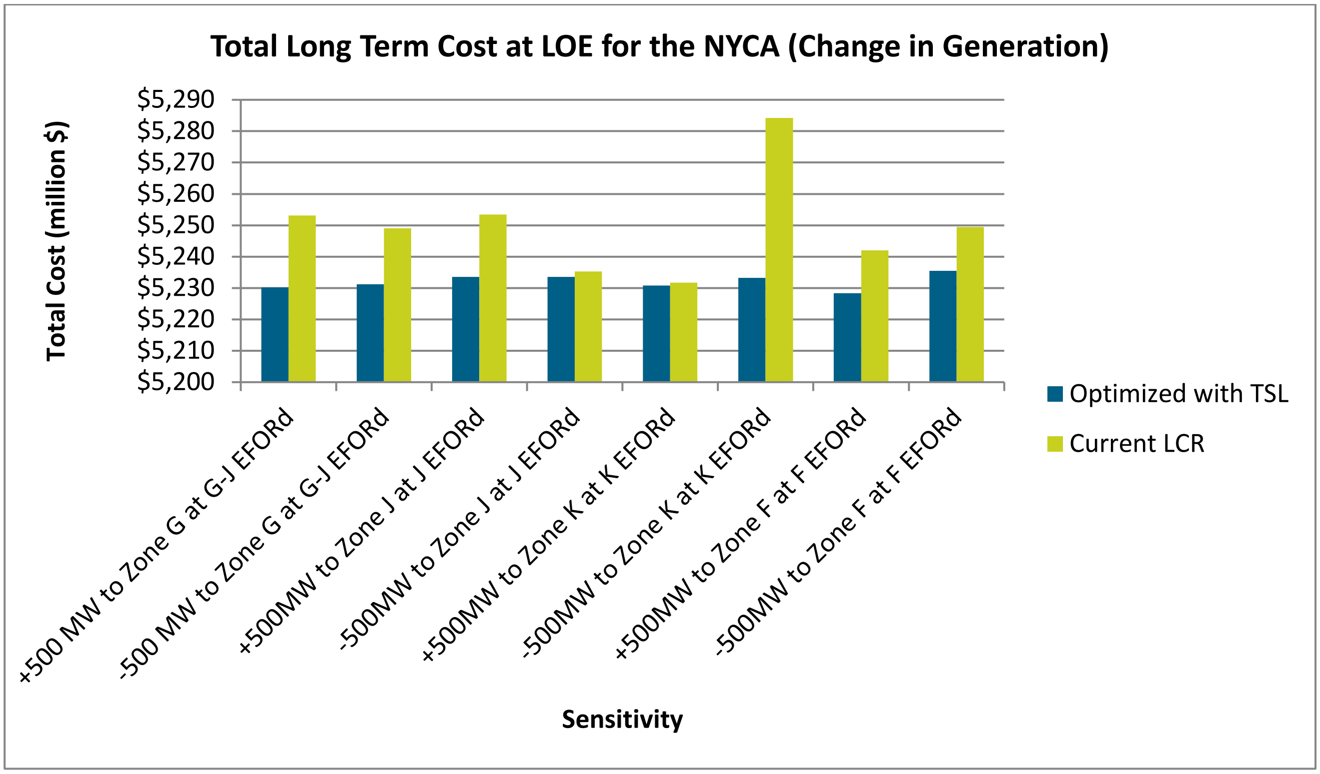


Figure 22: Total Long Term Cost at LOE for NYCA (Multiple Changes in Generation)

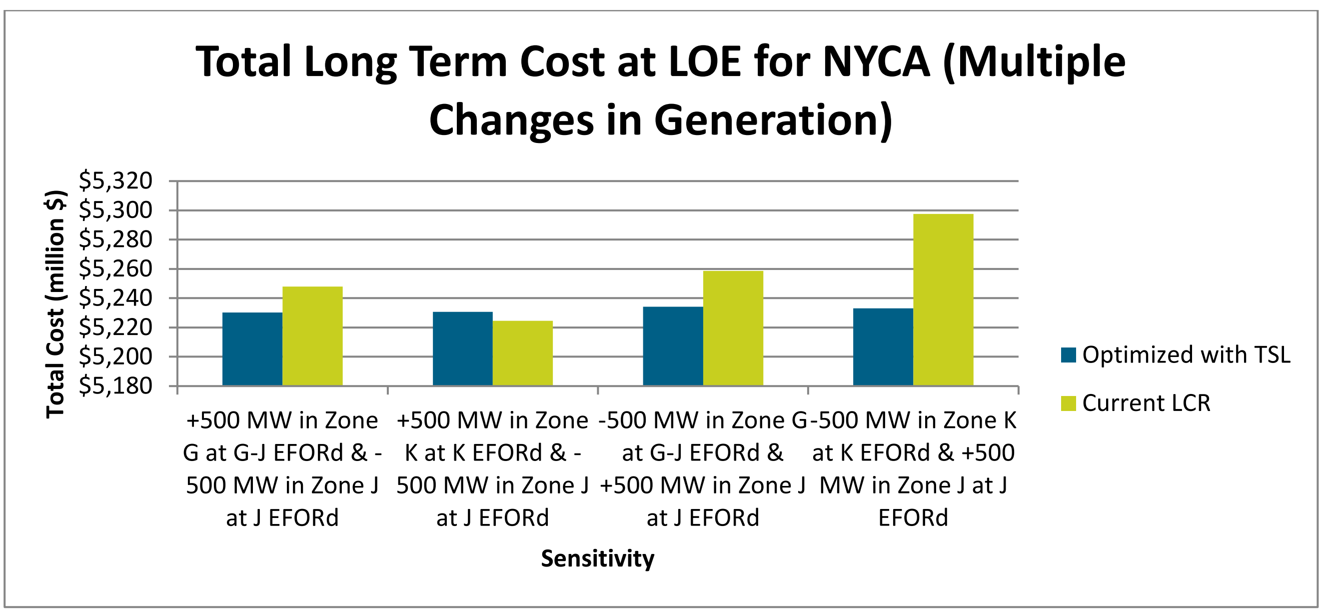
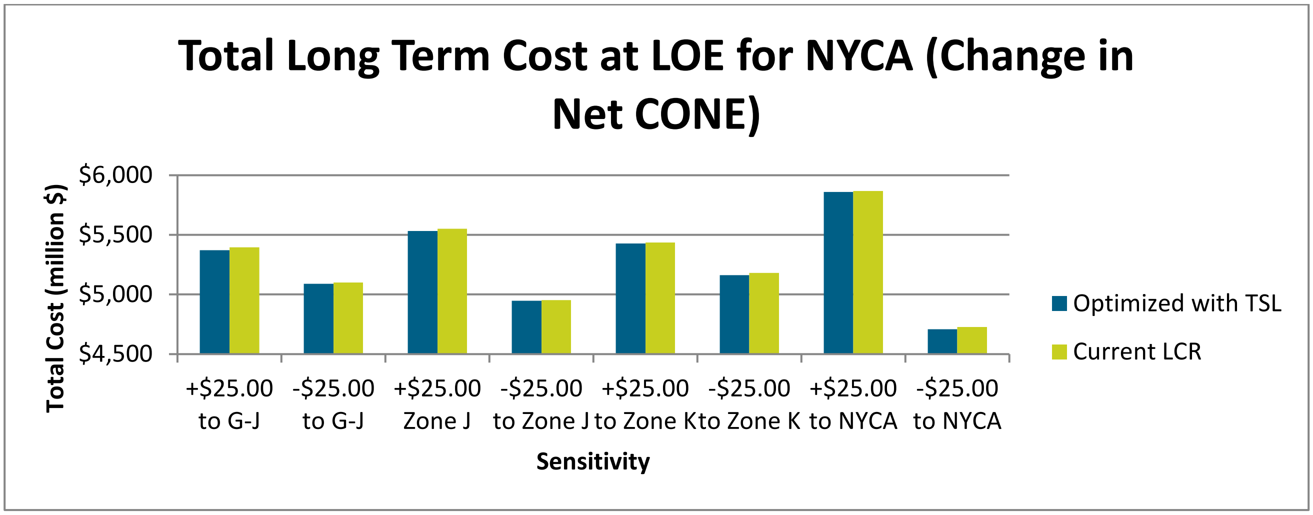


Figure 23: Total Long Term Cost at LOE for NYCA (Change in Net CONE)



While the graphs above (Figures 20, 21, 22, and 23) show the total NYCA long term capacity cost at LOE under both the current and optimized LCR methodology based on changes to generation and net CONE, Figures 24, 25, and 26 below show the change in these costs between the current and optimized LCR methodology. Additionally, the tables also break down the cost delta between the two LCR methodologies for each locality. The average benefit from the Optimized LCR methodology with TSL compared to the Current LCR methodology is approximately $18 million as shown in Figure 26.

Figure 24: Capacity Cost at LOE from Current LCR to Optimized with TSL (Changes to Generation)

Sensitivity	Δ Capacity Cost at LOE from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$8	-$32	$7	$5	-$12
+500 MW to Zone G at G-J EFORd	$18	$8	-$90	$41	-$23
-500 MW to Zone G at G-J EFORd	$3	-$88	$78	-$11	-$18
+500MW to Zone J at J EFORd	$14	-$46	$2	$11	-$20
-500MW to Zone J at J EFORd	$1	-$6	$4	$0	-$2
+500MW to Zone K at K EFORd	$1	$1	-$3	$1	-$1
-500MW to Zone K at K EFORd	$30	-$112	$0	$32	-$51
+500MW to Zone F at F EFORd	$12	-$23	-$12	$10	-$14
-500MW to Zone F at F EFORd	$11	-$36	$5	$6	-$14

Figure 25: Capacity Cost at LOE from Current LCR to Optimized with TSL (Changes to Net CONE)

Sensitivity	Δ Capacity Cost at LOE from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$16	-$20	-$153	$78	-$40
+$25.00 to G-J	$23	-$32	-$31	$15	-$24
-$25.00 to G-J	-$2	-$32	$38	-$14	-$10
+$25.00 Zone J	$11	-$36	-$3	$9	-$19
-$25.00 to Zone J	$8	-$24	$7	$5	-$4
+$25.00 to Zone K	$1	-$32	$28	-$4	-$7
-$25.00 to Zone K	$8	-$32	-$5	$9	-$19
+$25.00 to NYCA	$1	-$32	$28	-$5	-$8
-$25.00 to NYCA	$11	-$32	-$3	$6	-$17
+500 MW in Zone G & -500 MW in Zone J	$12	-$24	-$94	$40	-$18
+500 MW in Zone K & -500 MW in Zone J	-$9	$19	-$5	$1	$6
-500 MW in Zone G & +500 MW in Zone J	$7	-$110	$89	-$10	-$25
-500 MW in Zone K & +500 MW in Zone J	$33	-$138	-$2	$43	-$64

Figure 26: Cost of Capacity at LOE from Current LCR to Optimized with TSL (Statistical)

Sensitivity	Δ Cost of Capacity at LOE from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Minimum	-$9	-$138	-$153	-$14	-$64
25th Percentile	$2	-$36	-$5	$0	-$22
Average	$10	-$35	-$5	$12	-$18
75th Percentile	$14	-$10	$7	$14	-$8
Maximum	$33	$24	$89	$78	$6

Consumer Costs at Historic Percentage Excess

Figure 27: Consumer Costs at Historic Percentage Excess Methodology

Scenario	Optimized Costs ($)			Current LCR Methodology Costs ($)		
	As found	At Level of Excess	At Generic Excess level	As found	At Level of Excess	At Generic Excess level
Base Case						
+500 MW in G						
-500 MW in G						

Difference in cost is long term impact (at generic excess)

Long Term Consumer Cost Impacts at Historic Excess

Based on the sensitivities conducted, as shown in Figures 28, 29, 30, and 31 total long term NYCA consumer cost at historic excess is reduced in the majority of cases. The only cases that do not result in savings occur when the current LCR methodology results in a Zone J LCR lower than the Transmission Security Floor used in the optimization.

Figure 28: Total Long Term Cost at Historic Excess for Different Areas

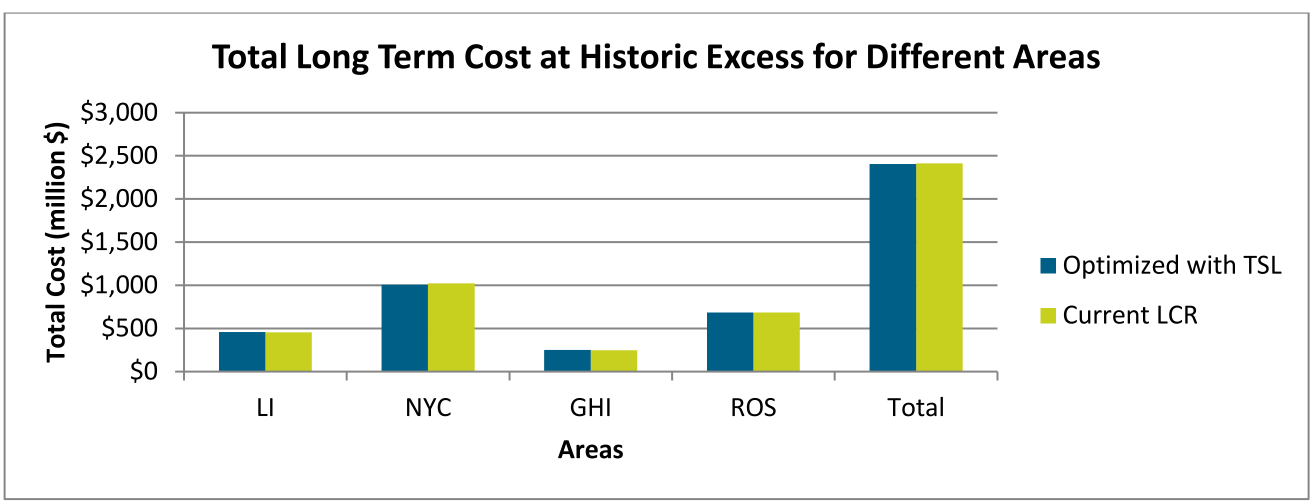


Figure 29: Total Long Term Cost at Historic Excess for the NYCA (Change in Generation)

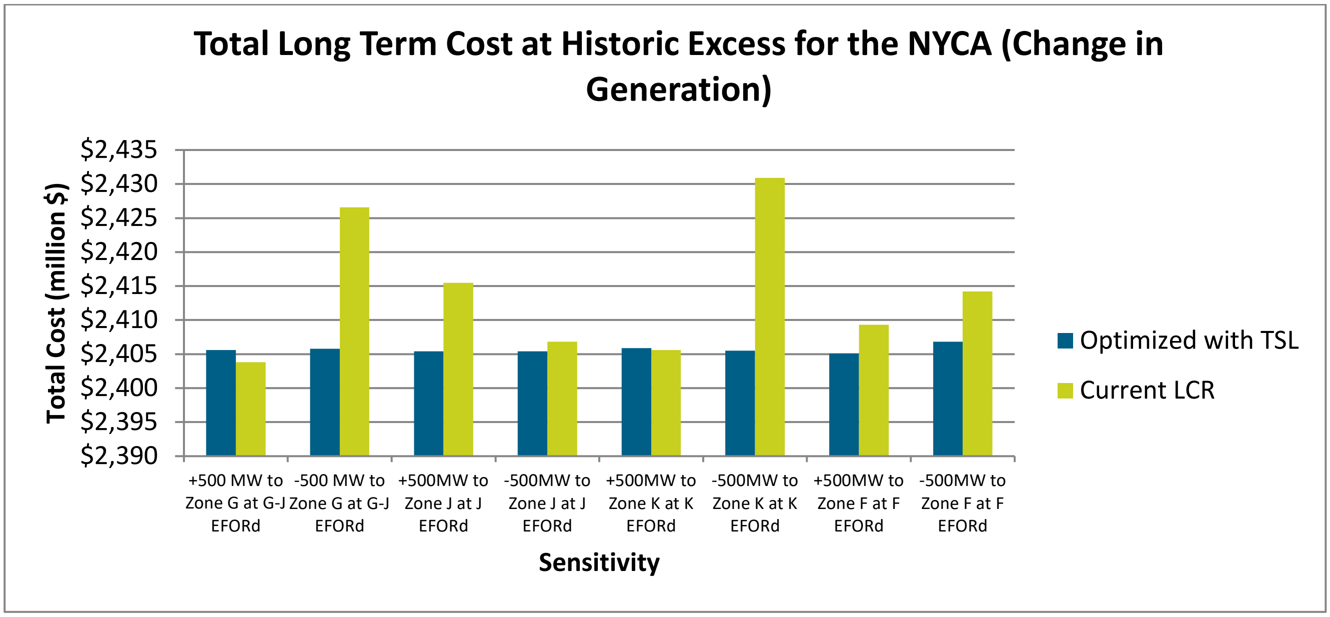


Figure 30: Total Long Term Cost at Historic Excess for NYCA (Multiple Changes in Generation)

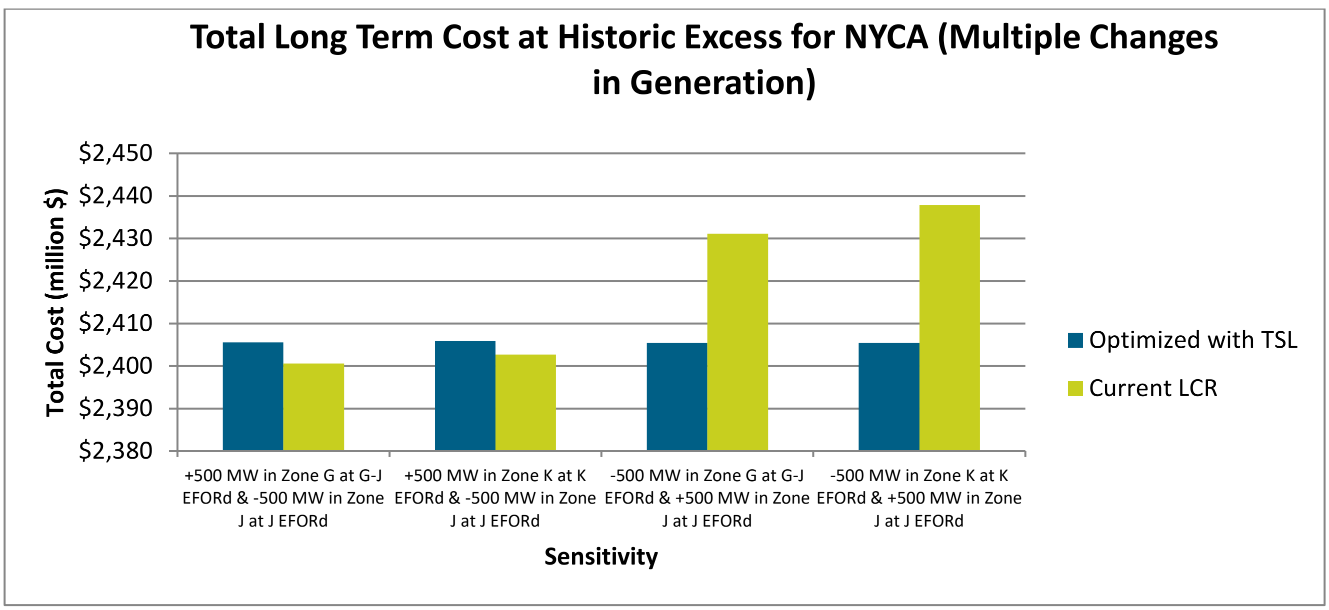
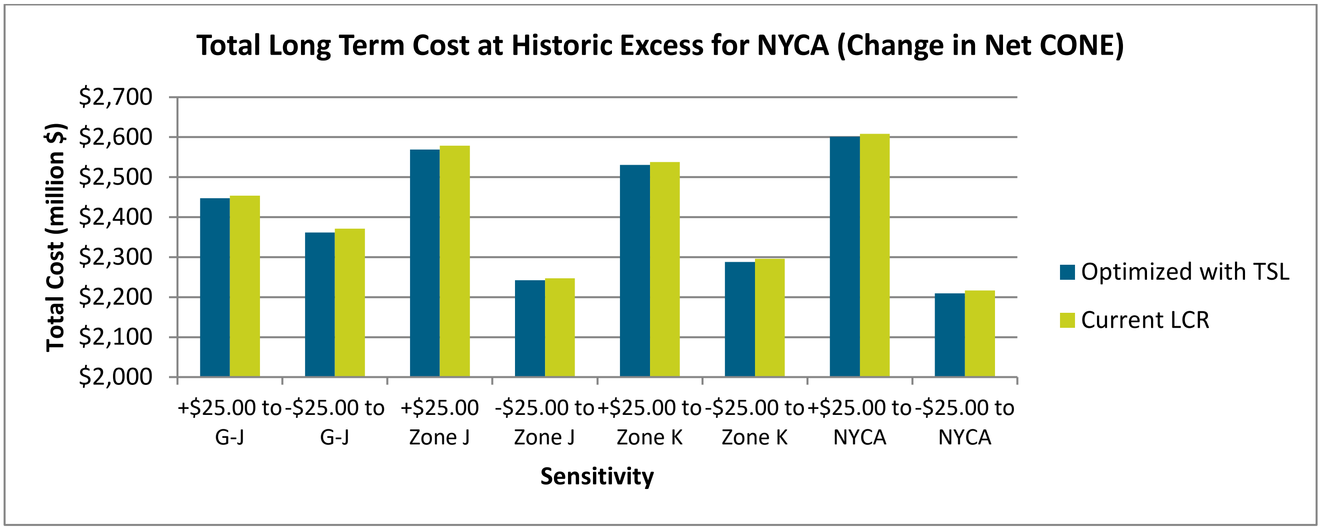


Figure 31: Total Long Term Cost at Historic Excess for NYCA (Change in Net CONE)



As discussed above, Figures 28, 29, 30, and 31 show the total NYCA long-term capacity cost at historic excess under both the current and optimized LCR methodology based on changes to generation and net CONE. Figures 32, 33, and 34, on the other hand, show the change in these costs between the current and optimized LCR methodology. Additionally, the tables also break down the cost delta between the two LCR methodologies for each locality. The average benefit from the optimized LCR methodology with TSL compared to the current LCR methodology is approximately $8 million as shown in Figure 34.

Figure 32: Capacity Cost at Historic Excess from Current LCR to Optimized with TSL (Changes in Generation)

Sensitivity	Δ Capacity Cost at Historic Excess from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$4	-$15	$2	$2	-$7
+500 MW to Zone G at G-J EFORd	$10	$4	-$27	$16	$2
-500 MW to Zone G at G-J EFORd	$1	-$42	$24	-$4	-$21
+500MW to Zone J at J EFORd	$7	-$22	$1	$4	-$10
-500MW to Zone J at J EFORd	$0	-$3	-$1	$0	-$1
+500MW to Zone K at K EFORd	$0	$0	-$1	$1	$0
-500MW to Zone K at K EFORd	$16	-$54	-$1	$12	-$25
+500MW to Zone F at F EFORd	$7	-$11	-$3	$4	-$4
-500MW to Zone F at F EFORd	$6	-$17	$2	$2	-$7

Figure 33: Capacity Cost at Historic Excess from Current LCR to Optimized with TSL (Changes in Net CONE)

Sensitivity	Δ Capacity Cost at Historic Excess from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$8	$10	-$47	$30	$1
+$25.00 to G-J	$12	-$15	-$9	$6	-$6
-$25.00 to G-J	-$1	-$15	$12	-$5	-$10
+$25.00 Zone J	$6	-$18	-$1	$3	-$9
-$25.00 to Zone J	$4	-$13	$2	$2	-$5
+$25.00 to Zone K	$1	-$15	$9	-$2	-$7
-$25.00 to Zone K	$5	-$15	-$1	$4	-$8
+$25.00 to NYCA	$1	-$15	$9	-$2	-$8
-$25.00 to NYCA	$6	-$15	-$1	$2	-$7
+500 MW in Zone G & -500 MW in Zone J	$6	$12	-$28	$15	$5
+500 MW in Zone K & -500 MW in Zone J	-$5	$9	-$2	$0	$3
-500 MW in Zone G & +500 MW in Zone J	$4	-$53	$27	-$4	-$26
-500 MW in Zone K & +500 MW in Zone J	$17	-$66	$0	$17	-$32

Figure 34: Cost of Capacity at Historic Excess from Current LCR to Optimized with TSL (Statistical)

Sensitivity	Δ Cost of Capacity at Historic Excess from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Minimum	-$5	-$66	-$47	-$5	-$32
25th Percentile	$1	-$17	-$2	$0	-$9
Average	$5	-$17	-$1	$5	-$8
75th Percentile	$7	-$5	$2	$5	-$2
Maximum	$17	$12	$27	$30	$5

Additional Factors

Stability of LCRs

Figures 35 and 36 show changes in LCRs as generation changes under the optimized and current methodology, respectively. Similarly, Figure 37 shows the range of change in LCRs in both percentage terms and MWs as generation changes. The optimization methodology clearly results in an increase in stability as generation changes occur within the system.

Figure 35: Optimized LCRs with TSL for Changes in Generation

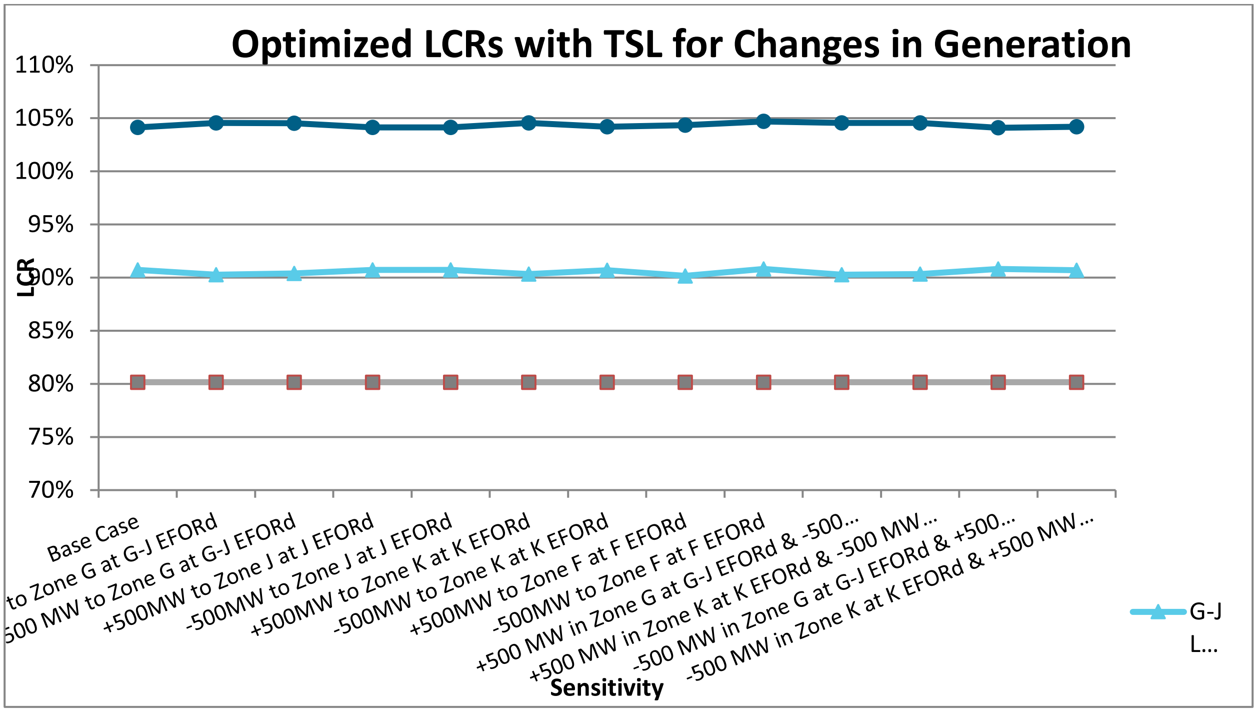


Figure 36: Current LCRs Methodology for Changes in Generation

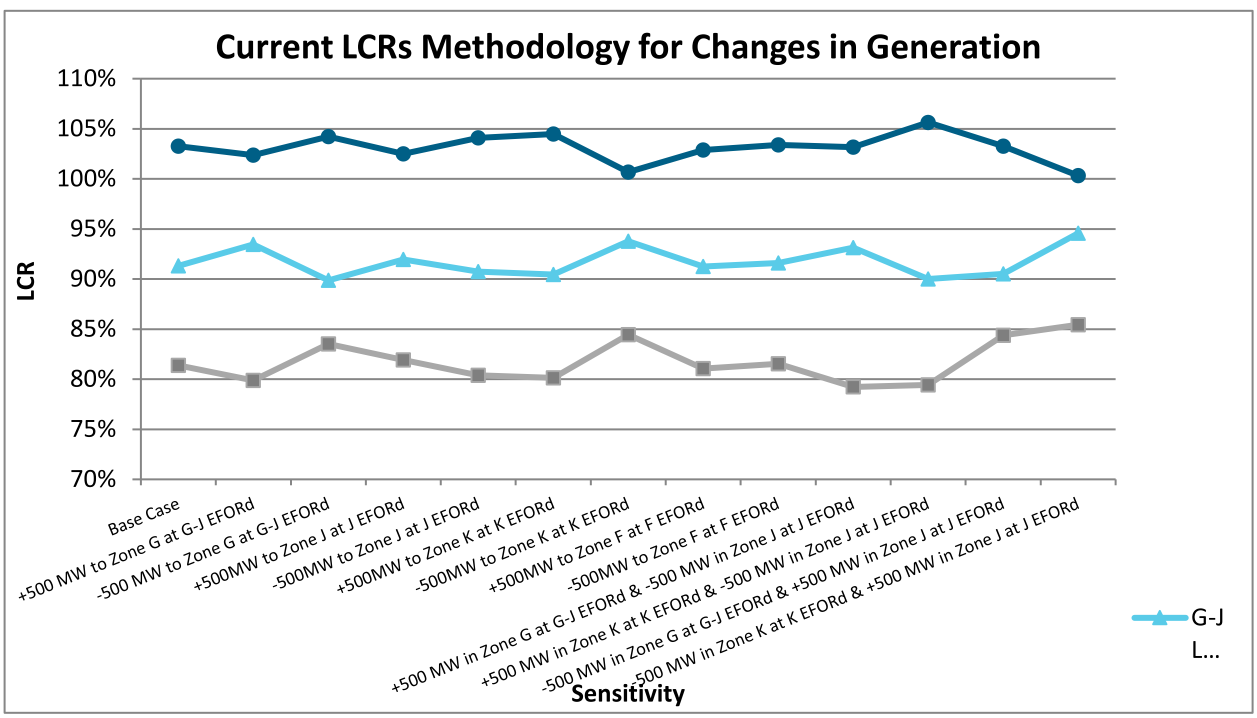


Figure 37: Total MW Changes in Percentage and MW

Methodology	Range of LCRs		
	Zone K	Zone J	G-J
Current LCR Methodology	5.3%	6.2%	4.7%
Optimized with TSL	0.6%	0.0%	0.7%

Methodology	Range of LCRs		
	Zone K	Zone J	G-J
Current LCR Methodology	289 MW	725 MW	756 MW
Optimized with TSL	32 MW	0 MW	104 MW

Reliability Impact

The alternate LCR methodology results in more stable and efficient LCRs than the current LCR methodology. The increase in stability should improve market signals. Stable and predictable market signals will lead to more efficient decisions in expanding and retiring assets, hence improving reliability. Transmission Security Limits (TSL) further improve reliability.

Environmental Impact

No change expected.

Impact on Transparency

More stable LCRs should enhance transparency as market response to changes in generation and/or reference prices will be more predictable than under the current LCR methodology.

Appendix for Alternative Methods for Determining LCRs

The Consumer Impact Analysis for Alternative Methods for Determining LCRs was presented to stakeholder at the October 11, 2017 ICAP meeting. During the presentation, some stakeholders requested additional information related to the consumer impact. This appendix provides the additional consumer impact information in response to stakeholder requests.

Stakeholders requested the following additional information:

- The October 11, 2017 presentation provided the difference (delta) between the cost of the current and the cost of the optimized LCR methodology for total capacity that cleared in each Locality (Cost of Capacity).
    - Stakeholders wanted to see each Locality's total cost responsibility up to their IRM requirement.
    - Additionally, stakeholders wanted to see the total costs (not just the delta) for each Locality between the current and optimized LCR methodologies.

Stakeholders also requested the historical percentage used in the long term consumer impact analysis

The tables that follow provide the additional information requested by stakeholders:

- Short term consumer impact (assumes no changes in generation and/or transmission).
- Intermediate term consumer impact (generation and transmission resources change).
- Long term cost impact:
    - Long-run equilibrium modelled at the Level of Excess condition (defined in the Demand Curve reset).
    - Historic excess defined as a percentage of excess above the requirement (observed in the last 3 Capability Years in each of the different localities).

The consumer costs shown in the tables for both the current LCRs and optimized LCRs with the Transmission Security Limit (TSL) are based on the full IRM responsibility of each Locality.

The cost of capacity shown in the tables for both the current LCRs and optimized LCRs with the Transmission Security Limit (TSL) are based on the individual Locality requirement and total capacity that cleared in each Locality.

Additionally, the tables that follow show the delta between consumer costs and cost of capacity for the current and optimized LCRs for the different sensitivities for each Locality.

Total Capacity Cost

Current LCR Methodology (Short and Intermediate Capacity Cost)

Sensitivity	Short & Intermediate Term Capacity Cost for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$313	$1,011	$348	$714	$2,385
+500 MW to Zone G at G-J EFORd	$262	$744	$333	$494	$1,833
-500 MW to Zone G at G-J EFORd	$368	$1,380	$404	$934	$3,085
+500MW to Zone J at J EFORd	$268	$548	$234	$490	$1,540
-500MW to Zone J at J EFORd	$361	$1,421	$514	$938	$3,234
+500MW to Zone K at K EFORd	$175	$792	$284	$491	$1,741
-500MW to Zone K at K EFORd	$577	$1,530	$529	$938	$3,574
+500MW to Zone F at F EFORd	$291	$955	$344	$495	$2,085
-500MW to Zone F at F EFORd	$328	$1,038	$386	$921	$2,673

Sensitivity	Short & Intermediate Term Capacity Cost for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$248	$683	$303	$714	$1,949
+$25.00 to G-J	$313	$1,011	$413	$714	$2,450
-$25.00 to G-J	$313	$1,011	$285	$714	$2,323
+$25.00 Zone J	$313	$1,174	$348	$714	$2,549
-$25.00 to Zone J	$313	$847	$348	$714	$2,221
+$25.00 to Zone K	$399	$1,011	$348	$714	$2,472
-$25.00 to Zone K	$246	$1,011	$348	$714	$2,318
+$25.00 to NYCA	$318	$1,011	$352	$911	$2,592
-$25.00 to NYCA	$313	$1,011	$348	$518	$2,190
+500 MW in Zone G & -500 MW in Zone J	$307	$1,229	$530	$718	$2,784
+500 MW in Zone K & -500 MW in Zone J	$255	$1,262	$460	$714	$2,690
-500 MW in Zone G & +500 MW in Zone J	$312	$940	$284	$712	$2,249
-500 MW in Zone K & +500 MW in Zone J	$559	$1,126	$384	$714	$2,783

Current LCR Methodology (Capacity Cost at LOE)

Sensitivity	Capacity Cost at LOE for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$689	$1,887	$782	$1,888	$5,245
+500 MW to Zone G at G-J EFORd	$682	$1,847	$867	$1,857	$5,253
-500 MW to Zone G at G-J EFORd	$697	$1,943	$702	$1,907	$5,249
+500MW to Zone J at J EFORd	$683	$1,901	$788	$1,882	$5,253
-500MW to Zone J at J EFORd	$696	$1,861	$785	$1,893	$5,235
+500MW to Zone K at K EFORd	$700	$1,854	$783	$1,895	$5,232
-500MW to Zone K at K EFORd	$668	$1,967	$789	$1,861	$5,284
+500MW to Zone F at F EFORd	$686	$1,878	$787	$1,891	$5,242
-500MW to Zone F at F EFORd	$691	$1,891	$786	$1,882	$5,250

Sensitivity	Capacity Cost at LOE for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$678	$1,835	$790	$1,915	$5,217
+$25.00 to G-J	$689	$1,891	$927	$1,888	$5,396
-$25.00 to G-J	$689	$1,887	$636	$1,888	$5,100
+$25.00 Zone J	$689	$2,193	$782	$1,888	$5,551
-$25.00 to Zone J	$689	$1,594	$782	$1,888	$4,952
+$25.00 to Zone K	$879	$1,887	$782	$1,888	$5,435
-$25.00 to Zone K	$624	$1,887	$782	$1,888	$5,180
+$25.00 to NYCA	$795	$1,887	$782	$2,405	$5,869
-$25.00 to NYCA	$689	$1,887	$782	$1,370	$4,727
+500 MW in Zone G & -500 MW in Zone J	$689	$1,831	$871	$1,858	$5,248
+500 MW in Zone K & -500 MW in Zone J	$709	$1,836	$784	$1,896	$5,225
-500 MW in Zone G & +500 MW in Zone J	$689	$1,965	$703	$1,901	$5,259
-500 MW in Zone K & +500 MW in Zone J	$665	$1,993	$790	$1,850	$5,298

Current LCR Methodology (Capacity Cost at Historic Excess)

Sensitivity	Capacity Cost at Historic Excess for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$456	$1,023	$249	$685	$2,412
+500 MW to Zone G at G-J EFORd	$452	$1,004	$275	$673	$2,404
-500 MW to Zone G at G-J EFORd	$461	$1,050	$225	$692	$2,427
+500MW to Zone J at J EFORd	$453	$1,030	$251	$682	$2,416
-500MW to Zone J at J EFORd	$460	$1,010	$250	$687	$2,407
+500MW to Zone K at K EFORd	$462	$1,007	$249	$687	$2,406
-500MW to Zone K at K EFORd	$445	$1,061	$251	$674	$2,431
+500MW to Zone F at F EFORd	$455	$1,019	$250	$686	$2,409
-500MW to Zone F at F EFORd	$457	$1,025	$250	$682	$2,414

Sensitivity	Capacity Cost at Historic Excess for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$451	$998	$252	$695	$2,395
+$25.00 to G-J	$456	$1,023	$290	$685	$2,454
-$25.00 to G-J	$456	$1,023	$208	$685	$2,371
+$25.00 Zone J	$456	$1,189	$249	$685	$2,578
-$25.00 to Zone J	$456	$857	$249	$685	$2,247
+$25.00 to Zone K	$582	$1,023	$249	$685	$2,538
-$25.00 to Zone K	$340	$1,023	$249	$685	$2,296
+$25.00 to NYCA	$456	$1,023	$257	$873	$2,609
-$25.00 to NYCA	$456	$1,023	$241	$497	$2,217
+500 MW in Zone G & -500 MW in Zone J	$456	$996	$276	$673	$2,401
+500 MW in Zone K & -500 MW in Zone J	$467	$998	$250	$688	$2,403
-500 MW in Zone G & +500 MW in Zone J	$456	$1,060	$225	$690	$2,431
-500 MW in Zone K & +500 MW in Zone J	$443	$1,074	$251	$670	$2,438

Optimized Methodology with TSL (Short and Intermediate Capacity Cost)

Sensitivity	Short & Intermediate Term Capacity Cost for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$365	$796	$322	$714	$2,197
+500 MW to Zone G at G-J EFORd	$388	$796	$194	$494	$1,872
-500 MW to Zone G at G-J EFORd	$386	$997	$441	$934	$2,756
+500MW to Zone J at J EFORd	$365	$412	$191	$490	$1,458
-500MW to Zone J at J EFORd	$365	$1,384	$512	$938	$3,199
+500MW to Zone K at K EFORd	$175	$796	$277	$491	$1,740
-500MW to Zone K at K EFORd	$754	$814	$353	$938	$2,859
+500MW to Zone F at F EFORd	$375	$796	$270	$495	$1,936
-500MW to Zone F at F EFORd	$395	$816	$359	$921	$2,491

Sensitivity	Short & Intermediate Term Capacity Cost for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$344	$796	$193	$714	$2,047
+$25.00 to G-J	$469	$796	$323	$714	$2,302
-$25.00 to G-J	$298	$806	$338	$714	$2,156
+$25.00 Zone J	$388	$925	$309	$714	$2,337
-$25.00 to Zone J	$365	$690	$322	$714	$2,090
+$25.00 to Zone K	$409	$796	$362	$714	$2,281
-$25.00 to Zone K	$287	$796	$307	$714	$2,104
+$25.00 to NYCA	$323	$796	$363	$911	$2,393
-$25.00 to NYCA	$388	$796	$300	$518	$2,003
+500 MW in Zone G & -500 MW in Zone J	$388	$1,384	$338	$718	$2,828
+500 MW in Zone K & -500 MW in Zone J	$255	$1,384	$485	$714	$2,838
-500 MW in Zone G & +500 MW in Zone J	$362	$697	$293	$712	$2,064
-500 MW in Zone K & +500 MW in Zone J	$754	$477	$222	$714	$2,167

Optimized Methodology with TSL (Capacity Cost at LOE)

Sensitivity	Capacity Cost at LOE for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$697	$1,855	$789	$1,893	$5,234
+500 MW to Zone G at G-J EFORd	$700	$1,855	$777	$1,898	$5,230
-500 MW to Zone G at G-J EFORd	$700	$1,855	$781	$1,896	$5,231
+500MW to Zone J at J EFORd	$697	$1,855	$789	$1,893	$5,234
-500MW to Zone J at J EFORd	$697	$1,855	$789	$1,893	$5,234
+500MW to Zone K at K EFORd	$700	$1,855	$779	$1,897	$5,231
-500MW to Zone K at K EFORd	$697	$1,855	$788	$1,893	$5,233
+500MW to Zone F at F EFORd	$698	$1,855	$775	$1,901	$5,228
-500MW to Zone F at F EFORd	$701	$1,855	$792	$1,888	$5,236

Sensitivity	Capacity Cost at LOE for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$694	$1,855	$636	$1,992	$5,177
+$25.00 to G-J	$712	$1,859	$896	$1,903	$5,371
-$25.00 to G-J	$687	$1,855	$675	$1,874	$5,091
+$25.00 Zone J	$700	$2,156	$779	$1,897	$5,532
-$25.00 to Zone J	$697	$1,569	$789	$1,893	$4,948
+$25.00 to Zone K	$880	$1,855	$809	$1,884	$5,429
-$25.00 to Zone K	$632	$1,855	$777	$1,897	$5,161
+$25.00 to NYCA	$796	$1,855	$810	$2,400	$5,861
-$25.00 to NYCA	$700	$1,855	$779	$1,376	$4,710
+500 MW in Zone G & -500 MW in Zone J	$700	$1,855	$777	$1,898	$5,230
+500 MW in Zone K & -500 MW in Zone J	$700	$1,855	$779	$1,897	$5,231
-500 MW in Zone G & +500 MW in Zone J	$696	$1,855	$792	$1,891	$5,234
-500 MW in Zone K & +500 MW in Zone J	$697	$1,855	$788	$1,893	$5,233

Optimized Methodology with TSL (Capacity Cost at Historic Excess)

Sensitivity	Capacity Cost at Historic Excess for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$460	$1,007	$251	$687	$2,405
+500 MW to Zone G at G-J EFORd	$462	$1,007	$248	$688	$2,406
-500 MW to Zone G at G-J EFORd	$462	$1,007	$249	$688	$2,406
+500MW to Zone J at J EFORd	$460	$1,007	$251	$687	$2,405
-500MW to Zone J at J EFORd	$460	$1,007	$251	$687	$2,405
+500MW to Zone K at K EFORd	$462	$1,007	$248	$688	$2,406
-500MW to Zone K at K EFORd	$461	$1,007	$251	$687	$2,406
+500MW to Zone F at F EFORd	$461	$1,007	$247	$690	$2,405
-500MW to Zone F at F EFORd	$463	$1,007	$252	$685	$2,407

Sensitivity	Capacity Cost at Historic Excess for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$459	$1,007	$205	$725	$2,396
+$25.00 to G-J	$469	$1,007	$281	$691	$2,448
-$25.00 to G-J	$455	$1,007	$220	$679	$2,362
+$25.00 Zone J	$462	$1,171	$248	$688	$2,569
-$25.00 to Zone J	$460	$844	$251	$687	$2,242
+$25.00 to Zone K	$583	$1,007	$258	$683	$2,531
-$25.00 to Zone K	$344	$1,007	$248	$688	$2,288
+$25.00 to NYCA	$457	$1,007	$266	$871	$2,601
-$25.00 to NYCA	$462	$1,007	$241	$499	$2,209
+500 MW in Zone G & -500 MW in Zone J	$462	$1,007	$248	$688	$2,406
+500 MW in Zone K & -500 MW in Zone J	$462	$1,007	$248	$688	$2,406
-500 MW in Zone G & +500 MW in Zone J	$460	$1,007	$252	$686	$2,406
-500 MW in Zone K & +500 MW in Zone J	$461	$1,007	$251	$687	$2,406

Total Consumer Cost

Current LCR Methodology (Short and Intermediate Consumer Cost)

Sensitivity	Short & Intermediate Term Consumer Cost for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$328	$1,182	$333	$542	$2,385
+500 MW to Zone G at G-J EFORd	$274	$890	$290	$379	$1,833
-500 MW to Zone G at G-J EFORd	$384	$1,580	$420	$701	$3,085
+500MW to Zone J at J EFORd	$280	$654	$230	$376	$1,540
-500MW to Zone J at J EFORd	$378	$1,677	$474	$704	$3,234
+500MW to Zone K at K EFORd	$175	$922	$269	$376	$1,741
-500MW to Zone K at K EFORd	$617	$1,759	$494	$704	$3,574
+500MW to Zone F at F EFORd	$303	$1,094	$318	$369	$2,084
-500MW to Zone F at F EFORd	$344	$1,243	$375	$711	$2,673

Sensitivity	Short & Intermediate Term Consumer Cost for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$263	$847	$296	$542	$1,949
+$25.00 to G-J	$328	$1,193	$387	$542	$2,450
-$25.00 to G-J	$328	$1,172	$281	$542	$2,323
+$25.00 Zone J	$328	$1,346	$333	$542	$2,549
-$25.00 to Zone J	$328	$1,018	$333	$542	$2,221
+$25.00 to Zone K	$414	$1,182	$333	$542	$2,471
-$25.00 to Zone K	$261	$1,182	$333	$542	$2,318
+$25.00 to NYCA	$338	$1,214	$349	$691	$2,592
-$25.00 to NYCA	$324	$1,151	$322	$394	$2,190
+500 MW in Zone G & -500 MW in Zone J	$322	$1,469	$447	$545	$2,784
+500 MW in Zone K & -500 MW in Zone J	$252	$1,478	$419	$542	$2,690
-500 MW in Zone G & +500 MW in Zone J	$328	$1,076	$305	$540	$2,249
-500 MW in Zone K & +500 MW in Zone J	$592	$1,280	$368	$542	$2,783

Current LCR Methodology (Consumer Cost at LOE)

Sensitivity	Consumer Cost at LOE for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$732	$2,315	$761	$1,437	$5,245
+500 MW to Zone G at G-J EFORd	$730	$2,318	$768	$1,437	$5,253
-500 MW to Zone G at G-J EFORd	$735	$2,321	$756	$1,437	$5,249
+500MW to Zone J at J EFORd	$731	$2,323	$763	$1,437	$5,253
-500MW to Zone J at J EFORd	$735	$2,305	$759	$1,437	$5,235
+500MW to Zone K at K EFORd	$736	$2,301	$758	$1,437	$5,232
-500MW to Zone K at K EFORd	$726	$2,353	$769	$1,437	$5,284
+500MW to Zone F at F EFORd	$732	$2,313	$761	$1,437	$5,242
-500MW to Zone F at F EFORd	$733	$2,318	$762	$1,437	$5,250

Sensitivity	Consumer Cost at LOE for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$729	$2,294	$757	$1,437	$5,217
+$25.00 to G-J	$732	$2,344	$882	$1,437	$5,396
-$25.00 to G-J	$732	$2,290	$640	$1,437	$5,100
+$25.00 Zone J	$732	$2,621	$761	$1,437	$5,551
-$25.00 to Zone J	$732	$2,022	$761	$1,437	$4,952
+$25.00 to Zone K	$922	$2,315	$761	$1,437	$5,435
-$25.00 to Zone K	$667	$2,315	$761	$1,437	$5,180
+$25.00 to NYCA	$850	$2,396	$791	$1,831	$5,868
-$25.00 to NYCA	$721	$2,234	$730	$1,043	$4,727
+500 MW in Zone G & -500 MW in Zone J	$732	$2,312	$767	$1,437	$5,248
+500 MW in Zone K & -500 MW in Zone J	$739	$2,293	$756	$1,437	$5,225
-500 MW in Zone G & +500 MW in Zone J	$732	$2,331	$758	$1,437	$5,259
-500 MW in Zone K & +500 MW in Zone J	$725	$2,364	$771	$1,437	$5,298

Current LCR Methodology (Consumer Cost at Historic Excess)

Sensitivity	Consumer Cost at Historic Excess for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$474	$1,171	$237	$531	$2,412
+500 MW to Zone G at G-J EFORd	$472	$1,163	$238	$531	$2,404
-500 MW to Zone G at G-J EFORd	$476	$1,184	$237	$531	$2,427
+500MW to Zone J at J EFORd	$472	$1,175	$237	$531	$2,415
-500MW to Zone J at J EFORd	$476	$1,164	$237	$531	$2,407
+500MW to Zone K at K EFORd	$476	$1,162	$237	$531	$2,406
-500MW to Zone K at K EFORd	$468	$1,194	$238	$531	$2,431
+500MW to Zone F at F EFORd	$473	$1,169	$237	$531	$2,409
-500MW to Zone F at F EFORd	$474	$1,172	$237	$531	$2,414

Sensitivity	Consumer Cost at Historic Excess for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$471	$1,156	$237	$531	$2,395
+$25.00 to G-J	$474	$1,179	$270	$531	$2,454
-$25.00 to G-J	$474	$1,163	$204	$531	$2,371
+$25.00 Zone J	$474	$1,337	$237	$531	$2,578
-$25.00 to Zone J	$474	$1,005	$237	$531	$2,247
+$25.00 to Zone K	$599	$1,171	$237	$531	$2,538
-$25.00 to Zone K	$357	$1,171	$237	$531	$2,296
+$25.00 to NYCA	$479	$1,200	$254	$676	$2,609
-$25.00 to NYCA	$469	$1,142	$221	$385	$2,217
+500 MW in Zone G & -500 MW in Zone J	$474	$1,159	$238	$531	$2,401
+500 MW in Zone K & -500 MW in Zone J	$479	$1,156	$237	$531	$2,403
-500 MW in Zone G & +500 MW in Zone J	$474	$1,190	$237	$531	$2,431
-500 MW in Zone K & +500 MW in Zone J	$467	$1,201	$239	$531	$2,438

Optimized Methodology with TSL (Short and Intermediate Consumer Cost)

Sensitivity	Short & Intermediate Term Consumer Cost for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$380	$963	$312	$542	$2,197
+500 MW to Zone G at G-J EFORd	$400	$912	$181	$379	$1,872
-500 MW to Zone G at G-J EFORd	$402	$1,201	$452	$701	$2,756
+500MW to Zone J at J EFORd	$377	$512	$193	$376	$1,458
-500MW to Zone J at J EFORd	$381	$1,641	$473	$704	$3,199
+500MW to Zone K at K EFORd	$175	$925	$263	$376	$1,740
-500MW to Zone K at K EFORd	$794	$1,013	$348	$704	$2,859
+500MW to Zone F at F EFORd	$387	$923	$257	$369	$1,936
-500MW to Zone F at F EFORd	$411	$1,017	$352	$711	$2,491

Sensitivity	Short & Intermediate Term Consumer Cost for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$360	$942	$204	$542	$2,047
+$25.00 to G-J	$484	$963	$313	$542	$2,302
-$25.00 to G-J	$313	$976	$325	$542	$2,156
+$25.00 Zone J	$404	$1,090	$301	$542	$2,337
-$25.00 to Zone J	$380	$857	$312	$542	$2,090
+$25.00 to Zone K	$424	$970	$345	$542	$2,281
-$25.00 to Zone K	$302	$961	$299	$542	$2,104
+$25.00 to NYCA	$342	$1,001	$357	$691	$2,393
-$25.00 to NYCA	$399	$928	$282	$394	$2,003
+500 MW in Zone G & -500 MW in Zone J	$403	$1,579	$301	$545	$2,828
+500 MW in Zone K & -500 MW in Zone J	$252	$1,605	$439	$542	$2,838
-500 MW in Zone G & +500 MW in Zone J	$377	$833	$313	$540	$2,064
-500 MW in Zone K & +500 MW in Zone J	$788	$608	$229	$542	$2,167

Optimized Methodology with TSL (Consumer Cost at LOE)

Sensitivity	Consumer Cost at LOE for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$735	$2,303	$759	$1,437	$5,234
+500 MW to Zone G at G-J EFORd	$736	$2,300	$758	$1,437	$5,230
-500 MW to Zone G at G-J EFORd	$736	$2,301	$758	$1,437	$5,231
+500MW to Zone J at J EFORd	$735	$2,303	$759	$1,437	$5,234
-500MW to Zone J at J EFORd	$735	$2,303	$759	$1,437	$5,234
+500MW to Zone K at K EFORd	$736	$2,300	$758	$1,437	$5,231
-500MW to Zone K at K EFORd	$735	$2,302	$759	$1,437	$5,233
+500MW to Zone F at F EFORd	$735	$2,299	$757	$1,437	$5,228
-500MW to Zone F at F EFORd	$736	$2,303	$759	$1,437	$5,235

Sensitivity	Consumer Cost at LOE for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$734	$2,266	$740	$1,437	$5,177
+$25.00 to G-J	$740	$2,321	$873	$1,437	$5,371
-$25.00 to G-J	$732	$2,280	$642	$1,437	$5,090
+$25.00 Zone J	$736	$2,602	$758	$1,437	$5,532
-$25.00 to Zone J	$735	$2,017	$759	$1,437	$4,948
+$25.00 to Zone K	$923	$2,308	$761	$1,437	$5,429
-$25.00 to Zone K	$667	$2,300	$757	$1,437	$5,161
+$25.00 to NYCA	$850	$2,388	$792	$1,831	$5,861
-$25.00 to NYCA	$726	$2,216	$726	$1,043	$4,710
+500 MW in Zone G & -500 MW in Zone J	$736	$2,300	$758	$1,437	$5,230
+500 MW in Zone K & -500 MW in Zone J	$736	$2,300	$758	$1,437	$5,231
-500 MW in Zone G & +500 MW in Zone J	$735	$2,303	$759	$1,437	$5,234
-500 MW in Zone K & +500 MW in Zone J	$735	$2,302	$759	$1,437	$5,233

Optimized Methodology with TSL (Consumer Cost at Historic Excess)

Sensitivity	Consumer Cost at Historic Excess for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$476	$1,162	$237	$531	$2,405
+500 MW to Zone G at G-J EFORd	$477	$1,162	$237	$531	$2,406
-500 MW to Zone G at G-J EFORd	$477	$1,162	$237	$531	$2,406
+500MW to Zone J at J EFORd	$476	$1,162	$237	$531	$2,405
-500MW to Zone J at J EFORd	$476	$1,162	$237	$531	$2,405
+500MW to Zone K at K EFORd	$477	$1,162	$237	$531	$2,406
-500MW to Zone K at K EFORd	$476	$1,162	$237	$531	$2,406
+500MW to Zone F at F EFORd	$476	$1,162	$237	$531	$2,405
-500MW to Zone F at F EFORd	$477	$1,162	$237	$531	$2,407

Sensitivity	Consumer Cost at Historic Excess for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$475	$1,156	$235	$531	$2,396
+$25.00 to G-J	$480	$1,168	$269	$531	$2,448
-$25.00 to G-J	$473	$1,154	$204	$531	$2,362
+$25.00 Zone J	$477	$1,325	$237	$531	$2,569
-$25.00 to Zone J	$476	$999	$237	$531	$2,243
+$25.00 to Zone K	$600	$1,163	$237	$531	$2,531
-$25.00 to Zone K	$359	$1,162	$237	$531	$2,288
+$25.00 to NYCA	$479	$1,192	$254	$676	$2,601
-$25.00 to NYCA	$473	$1,132	$220	$385	$2,209
+500 MW in Zone G & -500 MW in Zone J	$477	$1,162	$237	$531	$2,406
+500 MW in Zone K & -500 MW in Zone J	$477	$1,162	$237	$531	$2,406
-500 MW in Zone G & +500 MW in Zone J	$476	$1,162	$237	$531	$2,405
-500 MW in Zone K & +500 MW in Zone J	$476	$1,162	$237	$531	$2,406

Historic Percentages Used in the Long Term

	Historic Percentages Used in the Long Term			
	LI	NYC	G-J	NYCA
Summer	7.80%	6.81%	8.10%	5.06%
Winter	10.58%	13.22%	14.70%	10.94%

Consumer Impact Analysis Using the 2018 Base case: Alternative Methods for Determining LCRs

Background/Overview

The initial Consumer Impact Analysis for Alternative Methods for Determining LCRs was presented to stakeholders at the October 11, 2017 ICAPWG meeting. During that presentation, some stakeholders requested additional information from the November 6, 2017 ICAPWG meeting. Both of these presentations used the 2017 base case.

At the February 6, 2018 ICAPWG meeting, the NYISO presented updated LCRs based on the 2018 base case. During the February 14 BIC meeting, some stakeholders requested that the consumer impact analysis be updated using the 2018 base case, since the prior analyses were based on the 2017 base case. This presentation updates the Consumer Impact Analysis based on the 2018 base case.

Changes from the 2017 to the 2018 Base Case

As discussed at the February 6, 2018 ICAP meeting, the 2018 base case required more capacity in southeast New York to meet the reliability criteria of LOLE (<0.1 days/year than the 2017 base case required). This was observed using both the current and optimized LCR methodologies. The increase from 2017 to 2018 were mainly a result of the following:

- Increase in Load Forecast Uncertainty in Zones J and K
- Changes in Interface Limits
- Increased EFORd on underground transmission cables and UDRs

The following changes also occurred between 2017 and 2018, and were incorporated into the analysis:

- Increase in Demand Curve Net CONE cost curves
- Updated Transmission Security LCR Floors

Figure 38: 2017 and 2018 LCR Percentages

	Approved LCRs			Optimized LCRs		
	G-J	J	K	G-J	J	K
2017	91.5%	81.5%	103.5%	90.7%	80.2%	104.2%
2018	94.5%	80.5%	103.5%	90.8%	79.7%	107.5%

While both the current and optimized methodology required an increase in southeast New York capacity from 2017 to 2018, the optimized methodology was able to achieve a solution that minimizes this increase in capacity while also reducing total statewide cost, as shown in Figure 39.

Figure 39: 2017 and 2018 LCRs (MW)

	Approved LCRs (MW)			Optimized LCRs (MW)		
	G-J	J	K	G-J	J	K
2017	14,696.1	9,511.1	5,617.0	14,569.8	9,354.7	5,652.5
2018	15,042.5	9,288.9	5,605.6	14,432.0	9,198.2	5,856.1
Δ Locality MW	346.4	-222.2	-11.5	-137.9	-156.5	203.6
Δ Southeast New York MW	334.9			65.7		

Cost Impact Analysis

The tables that follow provide the Consumer Impact Analysis based on the 2018 base case. The impact analysis follows the following format:

- Short term consumer impact assumes no changes in generation from the 2017 Consumer Impact Analysis
- Long term cost impact
    - Long-run equilibrium modelled at the Level of Excess condition (defined in the Demand Curve reset).
    - Historic excess defined as a percentage of excess above the requirement (observed in the last three Capability Years in each of the different localities).

This analysis looks only at the base case both in the short and long run. Sensitivities around changes in generation, transmission and net CONE would require MARs runs.

The cost of capacity shown in the tables for both the current LCRs and optimized LCRs with the updated Transmission Security Limit (TSL) are based on the individual Locality requirement and total capacity that cleared in each Locality. Additionally, the tables that follow show the delta between the cost of capacity for the current and optimized LCRs.

Assumptions for the analysis

- 2018 load forecast
- 2018 approved and optimized LCRs
- 2018 Reference prices
- 2017 Supply assumptions used for the Consumer Impact Analysis presented on November 6, 2017 ICAPWG meeting

2018 Total Cost of Capacity

The costs presented below assume that all capacity is purchased at the spot market auction clearing price, and therefore could differ from observed costs if capacity was purchased through other methods (*i.e.*, bilateral contracts or self-supply). The cost of capacity presented is for the 2018 Capability Year, and provides a hypothetical outcome based on the described assumptions and using the optimization methodology. This analysis was based on the 2018 load forecast, projected 2018 reference prices, 2018 approved LCRs, and optimized LCRs – while utilizing the 2017 supply assumptions from the Consumer Impact Analysis presented at the ICAPWG on November 6, 2017.

Figure 40: 2018 Short Term Cost

Methodology	2018 Short Term Cost of Capacity (million $)				
	LI	NYC	GHI	ROS	Total
Current Methodology	$303	$1,179	$576	$649	$2,706
Optimized Methodology	$553	$668	$308	$649	$2,178
Delta	$251	-$511	-$268	$0	-$528

Given the slope of the demand curve, approximately 200 MW of additional capacity, load reduction, or a combination of additions and reductions in Long Island could return the Long Island cost back to that observed under the current method (i.e., about $303 MM), all else equal.

This analysis was based on the 2018 load forecast, 2018 reference prices, 2018 approved and optimized LCRs – while utilizing the 2017 supply assumptions from the Consumer Impact Analysis presented at the ICAPWG on November 6, 2017.

Figure 41: 2018 Long Term Cost at LOE

Methodology	2018 Long Term Cost of Capacity at LOE (million $)				
	LI	NYC	GHI	ROS	Total
Current Methodology	$765	$2,061	$972	$2,017	$5,815
Optimized Methodology	$802	$2,037	$880	$2,060	$5,780
Delta	$37	-$23	-$91	$43	-$35

This analysis was based on the 2018 load forecast, 2018 reference prices, 2018 approved and optimized LCRs while utilizing the 2017 supply assumptions from the Consumer Impact Analysis presented at the ICAPWG meeting on November 6, 2017

Figure 42: 2018 Long Term Cost at Historic Excess

Methodology	2018 Long Term Cost of Capacity at Historic Excess (million $)				
	LI	NYC	GHI	ROS	Total
Current Methodology	$383	$1,121	$521	$551	$2,576
Optimized Methodology	$398	$1,109	$473	$562	$2,542
Delta	$15	-$11	-$48	$11	-$34

This analysis was based on the 2018 load forecast, 2018 reference prices, 2018 approved and optimized LCRs while utilizing the 2017 supply assumptions from the Consumer Impact Analysis presented at the ICAPWG meeting on November 6, 2017

Figure 43: 2017 Short Term Cost

Methodology	2017 Short Term Cost of Capacity (million $)*				
	LI	NYC	GHI	ROS	Total
Current Methodology	$313	$1,011	$348	$714	$2,385
Optimized Methodology	$365	$796	$322	$714	$2,197
Delta	$52	-$215	-$26	$0	-$189

These results were presented for the Consumer Impact Analysis at the November 6, 2017 ICAPWG meeting.

Figure 44: 2017 Long Term Cost at LOE

Methodology	2017 Long Term Cost of Capacity at LOE (million $)*				
	LI	NYC	GHI	ROS	Total
Current Methodology	$689	$1,887	$782	$1,888	$5,245
Optimized Methodology	$697	$1,855	$789	$1,893	$5,234
Delta	$8	-$32	$7	$5	-$12

These results were presented for the Consumer Impact Analysis at the November 6, 2017 ICAPWG meeting

Figure 45: 2017 Long Term Cost at Historic Excess

Methodology	2017 Long Term Cost of Capacity at Historic Excess (million $)*				
	LI	NYC	GHI	ROS	Total
Current Methodology	$344	$1,023	$418	$514	$2,299
Optimized Methodology	$347	$1,007	$423	$516	$2,293
Delta	$3	-$15	$5	$1	-$6

These results were presented for the Consumer Impact Analysis at the November 6, 2017 ICAPWG meeting

Consumer Impact Analyses: 2018 Project List

Analysis Guidelines

In selecting projects for conducting Consumer Impact Analyses, the NYISO uses the following general guidelines:

- Anticipated net production cost impact of $5 million or more per year.
- Expected consumer impact from changes in energy or capacity market prices is greater than $50 million per year.
- Incorporates new technology into NY Markets for first time.
- Allows or encourages a new type or category of market product.
- Creates a mechanism for out-of-market payments for reliability.

In addition to using the analysis guidelines listed above, the NYISO also considers the following:

- FERC directives (compliance filings) where the NYISO has implementation flexibility.
- Emerging stakeholder issues.

2018 Proposed Projects for Consumer Impact Analysis

- BSM Repowering
- DER Participation Model
- Energy Storage Integration and Optimization
- Constraint Specific Transmission Demand Curves
- Integrating Public Policy

BSM Repowering

Description: A focused BSM repowering exemption may be appropriate in order to revise market rules so that they do not discourage or prevent replacements, while adequately protecting the integrity of the wholesale markets. This project would seek to evaluate and develop a proposal for a buyer-side mitigation exemption that specifically addresses the concerns with replacement (repowered) generation projects and encourages private investment.

Benefit: A specially-tailored BSM evaluation process may be able to reduce the potential for over-mitigation of repowering projects.

Screen: Emergent stakeholder issue.

DER Participation Model

Description: The NYISO released its *Distributed Energy Resource (DER) Roadmap* in February 2017, as a first step to enhancing its market rules for DER participation in the NYISO's energy, ancillary services, and capacity markets. The NYISO is also currently evaluating potential modifications to its existing Demand Response programs as part of this effort. This project will include the design of DER performance obligations, metering and telemetry requirements, baseline and performance measurement and verification rules, resource modeling, and the development of an understanding of how to balance the simultaneous participation of DER in retail-level programs, as well as the NYISO's wholesale markets.

Expected Benefit: Provide opportunities for Distributed Energy Resource Participation in Wholesale Markets. Alignment with NYS PSC's REV initiative.

Screen: Allows or encourages a new type or category of market product.

Energy Storage Integration and Optimization

Description: The NYISO would more fully develop the energy storage participation model, associated market rules, and tariff language. Additionally, the NYISO would consider ways to improve the optimization of energy storage resources on a least cost basis by leveraging Energy Storage Resources' flexibility through more sophisticated energy constraint modeling.

Expected Benefit: Improve modeling of resources that can inject and withdraw energy from the grid in response to NYISO dispatch signals. Increase market efficiency through more economic utilization of storage resources

Screen: Incorporates new technology into NYISO markets for first time

Constraint Specific Transmission Demand Curves

Description: Some transmission shortages are still resolved by relaxation instead of by setting prices through use of a transmission demand curve. This project would study replacing the NYISO's current transmission constraint pricing methodology with multiple transmission demand curves that can vary according to the importance, severity, and/or duration of the transmission constraint violation.

Expected Benefit: More efficient pricing of transmission constraints should potentially result in reduced price volatility and more efficient resource scheduling

Screen: Emergent stakeholder issues

Integrating Public Policy

Description: This project will continue the vetting of wholesale market concepts with stakeholders to harmonize the State's de-carbonization goals with the wholesale energy and capacity market design. The effort will include consideration of market design changes as well as market products for energy and capacity markets that support viable and efficient wholesale markets for maintaining needed existing and incenting new resources necessary to sustain reliable grid operations over the long run. As part of the evaluation, a comprehensive review of the impacts that may result from a major incremental influx of renewable energy resources and associated market design changes to account for these impacts will be studied. This effort will also include, as necessary, responding to actions taken by FERC in its State Public Policy Proceeding

Expected Benefit: Harmonize state de-carbonization policies with New York's wholesale market design. Evolve wholesale market incentives to maintain grid reliability.

Screen: Significant Market Design Concept

Key 2018 Electrical Industry Initiatives

The Consumer Interest Liaison supports the end use sector by, among other things, providing information necessary to keep current with the ever-changing electricity market and facilitating informed decisions on relevant issues. As the NYISO market rules change, new products become available, and new technology affects the markets, the Consumer Interest Liaison will continue to inform consumers of these changes. As we enter 2018, we find that technology and innovation are bringing substantial change to the energy landscape. Harmonizing NYS Public Policy and energy markets, energy storage, and distributed energy production are just a few of the areas that will have a large effect on New York's grid. Listed below are some areas of interest that the NYISO is currently addressing and the Consumer Interest Liaison office is closely monitoring for possible future analysis emerging from these areas of interest.

CES/Integrating Public Policy

The 2015 State Energy Plan (SEP) stated that 50% of all electricity used in New York be generated by renewable resources by 2030 (commonly referred to as the "50-by-30 goal") Governor Andrew Cuomo directed the New York State Department of Public Service (DPS) to convert SEP targets to mandated requirements. In the following year, the New York State Public Service Commission (PSC) issued an Order Adopting a Clean Energy Standard. (CES).

As part of the CES Order, the PSC adopted the SEP's 50-by-30 goal as part of the approach to reduce statewide greenhouse gas emissions 40% from 1990 levels by 2040. As a mechanism to meet that objective, the CES Order establishes a mechanism through which load serving entities in the State support new renewable resources and at-risk nuclear generators. The mechanisms through which support are provided to these resources are the procurement of Renewable Energy Credits (RECs) and Zero Emission Credits (ZECs).[5]

The CES Order applies to all customers in New York, including those served by the State's distribution utilities, competitive energy supply companies (ESCOs, i.e., entities that serve end use load), New York State power authorities, and those served directly by the wholesale energy markets. Existing resources and energy efficiency investments apply toward the 50-by-30 goal.

Higher renewable resource penetration will affect how the NY power system performs, how market participants behave, and market outcomes. In order to continue to meet its responsibilities, the NYISO must prepare for and adapt to the increased level of renewable resources. The NYISO's market solution tools are uniquely equipped to explore what could happen if the renewable resource mix changes in response to State energy policy.

The NYISO used its market software, beginning in 2016, to model the energy markets based on the additional renewable generation the CES contemplates in the New York Control Area (NYCA). A full unit commitment and dispatch simulated both the Day-Ahead Market (DAM) and the Real-Time Market (RTM) based on New York's bulk power system (NY Power System) and 2016 market conditions, augmented with additional renewable resources. The analysis evaluated how the 2016 NY Power System might perform with additional renewable resources. The NYISO did not make speculative assumptions about future retirements or transmission upgrades and the NYISO applied current wholesale market products and rules as of 2016.

The results of the energy market study were unsurprising. Energy prices were persistently negative in the western part of the state and low across the rest of the state. The market study selected existing resources less often to provide energy. New, incremental renewable in front of the meter and behind the meter resources, modeled as virtual supply, displaced the currently connected resources. Units dispatched down included conventional hydroelectric, combined-cycle, fossil fuel steam turbine and

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[5] Above CES/IPP text is taken directly from "Integrating Public Policy: A Wholesale Market Assessment of the Impact of 50% Renewable Generation http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2017-12-20/2017%20Market%20Assessment%20with%2050%20percent%20Renewables,%20Report.pdf

[3] The Energy to Lead, 2015 New York State Energy Plan.

[4] Staff White Paper on Clean Energy Standard, New York State Department of Public Service, January 25, 2016.

[5] State of New York Public Service Commission Case Nos. 15-E-0302 and 16-E-0270, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Order Adopting a Clean Energy Standard (issued August 1, 2016) (CES Order).

[6] The CES Order states at p. 27, "b. Non-Jurisdictional Entities: Staff states that NYPA and LIPA are expected to adopt renewable and non-emitting energy targets that are proportional to their load. This includes municipal utilities and rural cooperatives that obtain their full requirements from NYPA. The CES obligation of jurisdictional entities would be calculated under the assumption that NYPA and LIPA are adopting their proportional shares of the statewide goals."

existing wind resources. While all existing resources were committed less frequently to provide energy, some received additional commitments for ancillary services. Transmission limits, high intermittent resource production, and low net load also contributed to renewable curtailments[6]. A full report was produced on this effort in December 2017.

Operating characteristics such as availability, flexibility, and willingness to cycle are important to long-term grid stability and will need to be financially rewarded. If the NYISO does not appropriately compensate suppliers for these characteristics, the wholesale markets may not provide adequate incentives for the necessary resources to manage future reliability needs. Market design concepts that could address these concerns are under evaluation. Further analysis and concept proposals will be forthcoming in 2018. As these new products and services are prioritized for development, the Consumer Interest Liaison will monitor the development and keep consumers informed on the impending impacts to the marketplace.

Carbon Pricing/ Integrating Public Policy

At the request of stakeholders, the NYISO commissioned The Brattle Group in August 2016 to explore whether and how New York State environmental policies may be pursued within the existing wholesale market structure. In developing its analysis, Brattle received valuable input from the NYISO, the New York Department of Public Service (DPS), and stakeholders. The report is intended to provide a first step in a discussion on how to harmonize state policy and wholesale markets in New York.

Harmonizing state goals and the operation of wholesale electricity markets could leverage market forces to more efficiently meet both state goals and traditional electric system goals of providing affordable, reliable supply. One way to harmonize wholesale electricity markets with decarbonization goals is through carbon pricing. Higher carbon prices would incentivize competition from low-cost sources of carbon abatement and consequently reduce the total economic cost of meeting New York's decarbonization goals. Carbon pricing would invite a broader, more competitive range of solutions than targeted procurements under the CES alone.[7]

In October 2017, the NYISO and DPS began jointly facilitating the Integrating Public Policy Task Force (IPPTF) to investigate the topics and timelines to further explore options to incorporate the cost of carbon dioxide into wholesale energy markets with the goal of contributing to achieving New York State's public

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[6] The NYISO has a Comprehensive System Planning Process, which includes a Public Policy Planning process. A full description of how Public Policy Transmission is identified and developed in New York can be found in the NYISO's Public Policy Transmission Planning Process Manual. (NYISO n.d.)

[7] Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Pricing_Carbon_into_NYISOs_Wholesale_Energy_Market.pdf?_cldee=c2xlbW1lQG55aXNvLmNvbQ%3d%3d&recipientid=contact-6f64b57d2e27e5119404005056810dcf-30441601d79f4a2f9afded8de3b57476&esid=b19eeb95-c17e-e711-9435-005056815c52

policies, while providing the greatest benefits at the least cost to consumers and appropriate price signals to incentivize investment and maintain grid reliability.[8]

The New York Independent System Operator (NYISO) / New York State joint staff team[9] intends to present a carbon dioxide pricing proposal by December 2018. Alternatively, the NYISO / New York State joint staff team will present a detailed schedule by the end of December 2018 leading to a firm proposal date in early 2019 unless the NYISO / New York State joint staff team concludes that a viable proposal is not achievable and notifies the IPPTF.[10]

The office of the Consumer Interest Liaison will closely monitor the progress of the IPPTF and evaluate potential impacts to consumers.

DER Market Concept Design

Technological advancements and public policies, particularly the New York State Public Service Commission's (PSC) Reforming the Energy Vision (REV), are encouraging greater adoption of distributed energy resources (DER) to meet consumer energy needs as well as system needs. DER offer the potential to make load more dynamic and responsive to wholesale market price signals, potentially improving overall system efficiencies.

In August 2016, the NYISO released a draft of the *Distributed Energy Resources (DER) Roadmap* for New York's Wholesale Electricity Markets. The *DER Roadmap* is a plan for the next 3-5 years for integration of DER and evolution of existing Demand Response (DR) programs. The *DER Roadmap* is an effort in progress to:

- Integrate DER into Energy, Ancillary Services, and Capacity markets
- Align with goals of NYS REV
- Develop appropriate DER measurement and verification methods
- Align payments with performance

The NYISO continued the effort to develop DER integration throughout 2017. A Pilot Program for DER was launched in November 2017 to allow potential DER market participants to demonstrate their capabilities to provide existing market products and meet relevant performance requirements. DER Pilot Projects can engage and exercise their DER technologies and solutions in a simulated NYISO dispatch

[8] IPPTF Work Plan Draft http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg_ipptf/meeting_materials/2018-01-08/Work%20Plan%20DRAFT%2012272017.pdf

[9] The NYISO/New York State joint staff team is comprised of New York Independent System Operation, New York Department of Public Service and New York State Energy Research and Development Authority staff.

[10] IPPTF Work Plan Draft http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg_ipptf/meeting_materials/2018-01-08/Work%20Plan%20DRAFT%2012272017.pdf

environment.

A DER Market Design Proposal was presented in December 2017 outlining the proposed market design to integrate DER with the NYISO markets.

A Meter Data Study was performed in 2017 to inform the NYISO on issues identified in the Meter Policies track in the NYISO's *DER Roadmap*.

The DER Participation Model will be the subject of Consumer Impact Analysis for 2018. The Consumer Interest Liaison will continue to monitor the progress of this effort and as the project is more clearly defined, present the impact analysis at the appropriate time.

Energy Storage

Energy Storage Resources (ESRs) will provide significant system and market benefits to the NYISO-administered wholesale markets over the coming decades. To realize those benefits the NYISO will need to reduce barriers to entry for those resources. As indicated in The State of Storage: Energy Storage Resources in New York's Wholesale Electricity Markets, the NYISO has begun a multi-year effort to develop a new participation model specifically for ESRs that provide greater opportunity for ESRs to participate in the wholesale markets. The first phase of this multi-year effort, the Energy Storage Integration project, will establish participation rules for ESRs in the NYISO's Energy, Ancillary Service, and Capacity markets. It is anticipated that the market rule and software changes necessary to implement the Energy Storage Integration project will be completed in 2020.[11]

This comprehensive Market Design Concept Proposal was developed with the help of stakeholders throughout 2017, and explains the NYISO's proposals related to: (i) minimum eligibility requirements, (ii) aggregation eligibility requirements, (iii) registration and offer parameters, (iv) scheduling logic, (v) settlements logic, and (vi) mitigation framework.

The report also identified market design topics that will be discussed further in 2018, such as Energy market mitigation rules, Capacity market obligations, additional Ancillary Services provisions, and guidelines for the simultaneous participation in NYISO-administered wholesale markets and a retail-level program or market ("dual participation").

Energy Storage Integration and Optimization will be the subject of Consumer Impact Analysis for 2018. The Consumer Interest Liaison will continue to monitor the progress of this effort and as the project is more clearly defined, present the impact analysis at the appropriate time.

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[11]Energy Storage Integration: Market Design Concept proposal
http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2017-12-20/2017%20ESR%20Market%20Design%20Concept%20Proposal.pdf

Transmission

A cleaner, greener, integrated grid to serve New York requires a modernized, upgraded, and expanded transmission system to enable the new resource mix of a changing energy landscape in New York. Upgraded transmission capability is vital to meeting public policy goals and efficiently moving power to address regional power needs. (*Power Trends 2017*, pg. 11)

Over 80% of New York's high-voltage transmission lines went into service before 1980. Of the state's more than 11,000 circuit-miles of transmission lines, nearly 4,700 circuit-miles will require replacement within the next 30 years, at an estimated cost of $25 billion. (*Power Trends 2017*, pg. 44)

The downstate region (New York City, Long Island, and the Hudson Valley (Zones F-K) annually uses 66% of the state's electric energy. Yet, that region's power plants generate only 53% of the electricity produced in the state.

With regard to the regional variations in periods of highest demand for electricity, 72% of New York's peak power demand occurs downstate (Zones F-K). Power plants in this region, however, which typically use higher-cost fuel supplies because of more stringent environmental requirements, are capable of supplying only 63% of New York's electricity needs during peak periods. (*Power Trends 2017*, pg. 45)

Transmission projects that fulfill public policy requirements will be eligible for cost recovery through the NYISO's tariff — if they are selected by the NYISO as the more efficient or cost-effective transmission solution to the need identified by the New York State PSC. Under provisions of the NYISO tariff, the New York State PSC reviews and identifies the public policies (including existing federal, state or local law or regulation, or a new legal requirement that the PSC establishes after public notice and comment under the state law). Once the New York State PSC determines the Public Policy Transmission Needs, the NYISO solicits transmission and other types of projects, performs planning studies, and selects the transmission projects that will meet those needs in a more efficient or cost-effective manner.

In July 2015, the New York State PSC issued an order that identified relieving congestion in the state's western region as a Public Policy Transmission Need, known as the Western New York Public Policy Need. The Commission determined that reducing transmission congestion in the region could achieve significant environmental, economic and reliability benefits throughout the state.

In a decision that will support New York's goal of maximizing the flow of energy from renewable resources in the region, the New York Independent System Operator's (NYISO) Board of Directors selected a proposal on October 17, 2017 from NextEra Energy Transmission New York (NextEra) to address the public policy need for new transmission in Western New York. (NYISO Press Release, 10/17/2017)

In December 2015, the New York State PSC advanced its AC transmission proceeding to a competitive process managed by the NYISO by identifying a Public Policy Transmission Need to relieve congestion on the UPNY-SENY and Central East interfaces, which run from central New York, through the Capital Region to the Lower Hudson Valley. The Commission action limited the new transmission lines to replacing and upgrading existing lines within existing rights-of-way, which is intended to reduce or eliminate adverse environmental, landowner, and economic impacts.

In April 2016, developers submitted 15 transmission projects and one non-transmission project in response to NYISO's solicitation of proposed solutions. Following a stakeholder review and comment period, the NYISO issued the AC Transmission Public Policy Transmission Need Viability and Sufficiency Assessment. Out of the 16 proposed projects, the NYISO identified 13 viable and sufficient projects, and filed its assessment with the PSC. On January 24, 2017, following consideration of public comments, the PSC issued an order confirming the AC Transmission Needs and determined that the NYISO should proceed with its public policy process. (*Power Trends 2017*, pg. 42)

As 2017 closed, the NYISO was conducting the evaluation of Developer proposed solutions and anticipates selecting a proposed solution for the AC Transmission Public Policy Transmission Need in 2018.

Appendix

Process Improvements in the Communication of Consumer Impact Analyses

Background

During the last quarter of 2014 and continuing into the first quarter of 2015, the NYISO received extensive feedback on the manner in which it communicates and conducts its Consumer Impact Analyses. Some of this feedback came at the October 30, 2014, Market Issues Working Group (MIWG) meeting during the presentation of the Comprehensive Shortage Pricing Consumer Impact Analysis. Additional feedback was received at the December 17, 2014, Management Committee meeting during the presentation of the Comprehensive Shortage Pricing proposal. Seeing as 2017 was the first full year for the implementation of these process changes, we felt it was important to include this in the appendix for 2017.

To obtain additional feedback, the Consumer Interest Liaison met with representatives of all sectors in small group discussions. These meetings took place in January and February 2015:

- January 14: Generator and Other Supplier
- January 28: TO and Public Power
- February 10: DR and Environmental Interests
- February 12: End-Use Sector

The Consumer Interest Liaison also had a meeting on February 5, 2015, with the Department of Public Service (DPS) staff to get their feedback.

Response to Stakeholder Feedback

Based on feedback from stakeholders, the NYISO proposed a number of changes/additions to the manner in which Consumer Impact Analyses (CIA) are conducted and presented. The focus was on actionable suggestions while also taking note of other comments.

Proposed Changes

The Consumer Interest Liaison will continue to maintain its independence in conducting and presenting CIAs

Provide stakeholders a preliminary indication at the outset of a market design initiative whether a project is expected to have a major consumer impact to exceed $50 million per year.

Present to stakeholders a description of the methodology to be used for CIAs before conducting the impact analysis:

- CIA presentations will provide greater detail on how estimates are computed
- With the exception of confidential information, MPs would have information required to reproduce (duplicate) results
- *Present to stakeholders the final CIA at least 30 days prior to submission of the market design initiative to BIC, OC and/or MC for approval*

Present CIAs as a total package rather than just a focus on numbers:

- The analysis to include, in detail, the reasons why a project is being undertaken
- List the benefits of the project
- Attempt to estimate the impact of major market design changes over both the short-term and long-term, if warranted
- The presentation will attempt to account for countervailing conditions and opinions from other parties and differing assumptions

CIAs to clearly state all the assumptions underlying the impact analysis:

- Emphasize that the values presented are strictly estimates based on the assumptions used in the analysis
- The time frame over which the estimates are computed to be clearly defined, e.g., estimates are based on an identified snapshot in time
- The major driver(s) of the impact would be highlighted in the final analysis
- Impact estimates to be presented as a range

The process of conducting and presenting CIAs to be incorporated into the 2016 project schedule from the outset.

Evaluate alternative implementation options for stakeholder consideration:

- Present the alternative of not doing a project and the associated consequences
- Utilize scenario analysis in reporting the results of CIAs when relevant

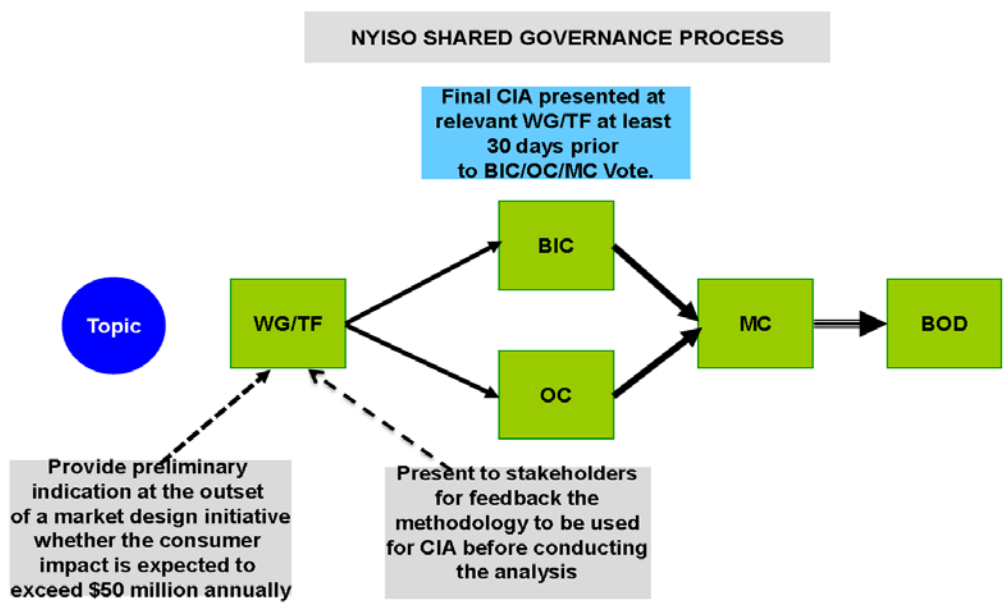
Impact of Suggested Changes on Project Schedule

The suggested changes will have a significant impact on both the work load and the project schedule. The first column in Figure 24 shows the current timeline for completing a typical consumer impact analysis and the deliverables. The second column shows both the lengthening of the project schedule and the increase in the number of deliverable items.

Impact on Project Schedule

	Current Process	Proposed Process
May		BPWG: Present Project Candidate List to MPs
June		Internal: Identify Projects for CIA
July		MIWG: Present CIA Topics and Initial Estimate
August		
September		
October	Internal: Identify Projects For CIA	
November	MIWG: Present Project List to MPS	
December		
January	Internal: Perform Consumer Impact Analysis	MIWG: Present CIA Methodology
February		Internal: Perform Consumer Impact Analysis
March		
April		
May		
June		
July	MIWG: Present CIA Findings	
August	BIC/OC: Project Approval Vote	
September	MC: Project Approval Vote	MIWG: Present CIA 30 Days Prior to BIC/OC
Ocotber		
November		BIC/OC: Project Approval Vote
December		MC: Project Approval Vote

Consumer Impact Analysis - Process Map



NEW YORK INDEPENDENT SYSTEM OPERATOR

NYISO Consumer Interest Liaison Weekly Summary

January 8 – January 12, 2018

Notices:

- *The **monthly Generator Status Update document** has been posted on the NYISO's website. The posting is located in the Generator Status Update folder under the Planning Documents & Resources section at the following link: **Generator Status Update***
- *Based on Stakeholder feedback, the **Integrating Public Policy Wholesale Market Assessment of the Impact of 50% Renewable Generation** study, presentation and the supplemental appendix 6 - Hydro-Quebec Transactions have been updated and reposted at this link. **Material***
- *With technology and rapid change transforming the energy industry and placing new demands on the electric grid, the New York Independent System Operator (NYISO) today **released a multi-year strategic plan focused on addressing these new dynamics with precision and innovation**. The **2018-2022 Strategic Plan** provides a clear vision on the way forward as industry transformation and public policy goals are redefining the power system and competitive wholesale markets. Working in close coordination with Market Participants, Stakeholders, policy makers and regulators, the NYISO remains committed to being a leader in reliability, market design and technological innovation. **Press Release***
- *Please use the link below to access the NYISO's stakeholder summary for the upcoming week.*
  NYISO Stakeholder Summary

Meeting Summaries:

Wednesday, January 10, 2018
Joint Installed Capacity/Market Issues/Electric System Planning Working Group
Alternative Method for Determining LCRs
Zachary Stines of the NYISO provided an update to the Alternative Method for Determining Locational Capacity Requirements (LCRs) project. Mr. Stines explained that the NYISO is recommending that the uncollared Net Cost of New Entry (CONE) be used in the LCR optimization process. Although the NYISO calculates the uncollared cost, it applies a limit (collar) to the amount of adjustment on the Demand Curve Reference Price developed through the annual update process. Mr. Stines noted that the NYISO has determined that the use of the uncollared Net CONE sends the efficient investment signals to the market. In response to stakeholder requests, the NYISO agreed to provide additional, specific sensitivities that would compute the results of both the collared and uncollared Net CONE. The NYISO explained that the timeline to implement the project is a Summer 2019 deployment. The NYISO will provide tariff language on the proposal prior to a scheduled BIC vote on February 14, 2018. To see the complete presentation please go to:
http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2018-01-10/ICAPWG_1-10-18_AlternativeMethodsforLCRs_Final.pdf

Securing 100+kV Transmission Facilities in the Market Model
Ethan Avallone of the NYISO presented the process to identify and evaluate facilities that should be modeled as secured in the Business Management System (BMS) Day-Ahead Market and Real-Time Market models. Mr. Avallone detailed the criteria to be used in determining which facilities will be secured in the market model. To efficiently communicate each facility status, the NYISO will include an additional column within Attachment A of the Outage Scheduling Manual to indicate that a given facility is secured within the market models. A listing of the facilities to be evaluated was provided. Stakeholders requested that an explanation be provided for each facility on the listing that is not selected to be secured in the market models. A timeline was provided for the process, with facilities added prior to the EMS/BMS deployment scheduled to begin Q2 2018. The remaining facilities will be added following the EMS/BMS deployment in 2019. To see Mr. Avallone's complete presentation, please go to: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2018-01-10/100+kV%20Jan%20MIWG%20FINAL.pdf

Market Assessment for Accommodating Public Policy: Stakeholder Feedback
Ethan Avallone of the NYISO provided stakeholders an opportunity to share additional feedback on the Integrating Public Policy report. The NYISO has addressed stakeholder feedback from the December 20, 2017 MIWG meeting. The NYISO will present market design ideas recommended for further development at the February 2, 2018 MIWG meeting. A timeline of the process was provided for stakeholders showing analysis and discussion dates and a Market Design Concept Proposal with a presentation of the IPP Master Plan, anticipated for June 2018. To see Mr. Avallone's complete presentation, please go to:
http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2018-01-10/vIPP%20Jan%2010%202018.pdf

NYISO Proposed On/Off Ramp Methodology

Mark Younger of Hudson Energy Economics presented a proposal stating that the Alternative Methodology to Determine Locational Capacity Requirements (LCRs) project precludes the need to develop an Off Ramp for Capacity Localities rule. The NYISO will respond to the proposal at the next scheduled ICAPWG meeting.

RMR: Changes on Rehearing to Anti-toggling Provisions
Lorenzo Seirup of the NYISO presented the NYISO's proposed response to the November 16, 2017 FERC directive for a further compliance filing to address certain aspects of the NYISO's second Reliability Must Run compliance filing. Specifically, FERC ordered the NYISO to:

- *revise the requirement to repay above-market revenues to require repayment of only the above-market revenues that exceed an RMR generator's going-forward costs for RMR service, and to allow RMR generators that accepted an APR to retain their availability and performance incentives;*
- *revise the repayment periods for capital expenditures and above-market revenues to require repayment of either in the shorter of 36 months or twice the duration of the applicable RMR agreement; and*
- *make two technical corrections suggested by the NYTOs*

The NYISO has revised the language and submitted the compliance filing to FERC for approval. To see Mr. Seirup's presentation, please go to:
http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2018-01-10/2nd%20Compliance%20FIling%20presentation%202018-01-10%20ICAPWG.pdf

Planning-Related RMR Compliance Revisions
Carl Patka of the NYISO provided two tariff language clarifications required by FERC compliance directives. In Directive #1, the Commission directed the NYISO to clarify that a Developer may also propose "generation RMR alternatives to a reliability need that are not market-based, or that involve generators that are currently mothballed or in an ICAP ineligible forced outage." The NYISO will consider all generator options that Developers present to it as temporary solutions, including acceleration or increased capacity of new generation. In Directive #2, the Commission directed the NYISO to clarify in its tariff that "NYISO will exclude RMR generators and Interim Service Providers from its reliability needs assessment base case, and will include permanent transmission RMR alternatives." The NYISO is submitting the revision as follows:
"the ISO shall not include in the RNA Base Case an Interim Service Provider, an RMR Generator, or any other interim ~~non-RMR~~ Generator Deactivation Solution selected by the ISO pursuant to Attachment FF of the ISO OATT; *provided, further,* the ISO will include in the RNA Base Case a permanent transmission ~~non-RMR~~ Generator Deactivation Solution selected by the ISO pursuant to Attachment FF of the ISO OATT if it meets the base case inclusion requirements in the ISO Procedures." The NYISO will make its compliance filing on January 16, 2018. To see the NYISO presentation, please go to:
http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2018-01-10/Planning_RMR_ICAP_Jan10.pdf

New Business
Steve Gill of the NYISO announced that the NYISO has approved Joule Energy Services as a Small Customer Aggregation in the NYISO markets. The next step is to review and approve Joule Energy Services data for market participation.

Friday, January 12, 2018
Electric System Planning Working Group
2017 CARIS 1 Preliminary Solution Results
Timothy Duffy of the NYISO presented the preliminary solution results for the 2017 Congestion Assessment and Resource Integration Study (CARIS 1). A timeline for the complete study was provided for stakeholders with an anticipated approval by the Board of Directors in April 2018. Mr. Duffy presented the three Studies identified in the process:

- *Central East-Edic-Marcy*
- *Central East-Pleasant Valley*
- *Central East*

The additional scenarios for analysis were detailed:

- *Central East-Pleasant Valley corridor under "System Resource Shift" scenario*
    - *Achievement of "50 by 30" by 2026 (Solar, on-shore and off-shore wind)*
    - *Retirement of NYCA Coal units*
    - *Retirement of IP2 and 3 units*
- *Central East interface with Edic-Marcy constraints resolved*
- *Provides additional data to stakeholders on the potential production cost savings and the cost effectiveness of solutions under those assumptions.*

Mr. Duffy provided the preliminary solutions, associated costs for transmission, generation, demand response and energy efficiency, and production costs savings each study/solution combination for stakeholder discussion. To see the complete discussion as presented by Mr. Duffy, please go to: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2018-01-12/2017_CARIS_I_Solution_Summary.pdf

FERC Filing

January 12, 2018
NYISO compliance filing of an annual report on Demand Side Management Programs

January 11, 2018
NYISO filing of a motion to intervene and comments in support of the NYSRC filing of an 18.2% Installed Reserve Margin for the 2018-2019 Capability Year

FERC Orders

January 12, 2018
FERC Order granting NYISO's January 4, 2018 request for temporary limited waiver of Sections 21.4 and 21.5.1 of its Services Tariff to enable NYISO to consider incremental energy and minimum generation offers that exceed $1,000/MWh

Filings and Orders:

http://www.nyiso.com/public/markets_operations/documents/tariffviewer/index.jsp

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