Attachment III

Exhibit 1

LOCATIONAL MINIMUM INSTALLED CAPACITY REQUIREMENTS STUDY

COVERING THE NEW YORK BALANCING AUTHORITY AREA
For the 2012 – 2013 Capability Year

NYISO Operating Committee
January 12, 2012

Locational Minimum Installed Capacity Requirements Report

I. Recommendation

This report documents a study conducted by the New York Independent System Operator (NYISO) to determine Locational Minimum Installed Capacity Requirements (LCRs) for the New York City (Zone J) and Long Island (Zone K) Localities for the 2012 - 2013 Capability Year beginning May 1, 2012.

Currently, the New York City (NYC) LCR is eighty-one percent (81%) of the NYC forecast peak load for the 2011 – 2012 Capability Year. The Long Island (LI) LCR is currently one hundred one and a half percent (101.5%) of the Long Island forecast peak load for the 2011 – 2012 Capability Year.

The New York State Reliability Council (NYSRC) in its 2012 Installed Reserve Margin (IRM) study report[1] identified the lowest feasible locational requirements of 83.9% for NYC and 99.2% for LI. The NYISO then determines the actual LCRs taking into consideration changes that have occurred since the NYSRC approved the IRM base case. One of the changes is the completion of the final 2012 ICAP load forecast. Another is the announced retirement of Ravenswood GT 3-4, Sithe Massena, and Beebee Station 13. Lastly, 280 MW of proposed wind additions will not occur by the summer of 2012. These units include; Cody Road, Allegany Wind, Ellenburg II, Ecogen Prattsburg, Stony Creek, and Marble River.

Based on the NYSRC base case for the 2012 – 2013 Capability Year and the changes identified above, the NYISO recommends that the currently effective LCR of 101.5% of the forecast peak load for the Long Island Locality be lowered to 99.0%. Further, the NYISO recommends that the currently effective LCR of 81% of the forecast peak load for the New York City Locality be increased to 83.0%.

II. Updating LCR Values

As its starting point, the NYISO LCR study utilized the statewide Installed Reserve Margin (IRM) study directed by the NYSRC. The IRM study was approved by the NYSRC Executive Committee on December 2, 2011, and is available on the NYSRC web site at www.nysrc.org.

For New York City, there were factors that both increased and decreased its LCR value when compared to the current year's value. Factors that tended to lower the NYC LCR were the additions of Astoria II and the Bayonne Energy Center. These new units have better availabilities than the Zone J's existing fleet. This potential reduction, however, was more than

[1] NYSRC Report titled, "New York Control Area Installed Capacity Requirements for the Period May 2012 Through April 2013", December 2, 2011.

offset by an increase in Equivalent Forced Outage Rates (EFORs) of both NYC generation and the cables surrounding NYC. In addition, the forecast SCR performance for the NYC locality decreased, again putting upward pressure on the NYC LCR.

The factors involved in the decrease in LCR for Long Island from the current year's value are; an increase in the forecast performance of the LI SCR program, and a 1.2 percentage point drop in the load forecast uncertainty model for Long Island. Countering these factors, to a lesser degree, was an increase in the EFOR of the LI generators and the cables entering LI.

The reduction in the LCR values when compared to the IRM study report is due to the following reasons:

- the effect of the final load forecast (used in the LCR study) versus the September forecast used for the IRM study. Generally, as the ratio of downstate to upstate load decreases, the LCRs decrease. The below table shows the reduction in downstate to upstate load ratio due to the final load forecast.

Area	IRM Load (MW) Forecast (9/11)	Final 2012 ICAP Forecast (MW)(12/11)	Decrease
Zone J (NYC)	11,607	11,500	107
Zone K (LI)	5,521	5,526	-5
NYCA	33,335	33,294	41
ROS	16,207	16,268	
Downstate/Upstate ratio	1.057	1.047	

- the additional plant retirements taken into account since the IRM study was performed indicate a loss of poorer performing units. This loss increases the net availability of the fleet of units in the zones in which the retirements occur.

- wind units that were projected to materialize will not be in service before this summer's peak period. Since those units have poorer performance than that of the fleet, the removal of those units from the study database puts a minimal amount of downward pressure on the LCRs (minimal because these wind units are all expected to locate in the upstate zones).

III. Summary of Study

This study and its supporting analysis are based on the unified methodology. A full description of the procedure used for the unified methodology can be found as attachments A and B of the NYSRC's Policy 5-5.[2]

[2] Policy 5-5 can be found on NYSRC.org website under Documents/Policies.

The 2012 IRM study base case indicated that the Loss of Load Expectation (LOLE) criterion of not more than 0.1 days/year can be met with a statewide reserve margin of 16.1% and the lowest feasible locational requirements of 83.9% and 99.2% for NYC and LI, respectively. The NYISO's LCR study then examined the effects of the final ICAP peak load forecast, changes in additions of new resources, and changes in retirements with consideration of the 16.0% IRM provided by the New York State Reliability Council, in order to decide the final LCRs for the localities.

Based on the NYSRC base case for the 2012 – 2013 Capability Year and consideration of the changes identified above, the LOLE criterion of 0.1 days/year is met with a Minimum LCR of 83.0% for the New York City Locality and a Minimum LCR of 99.0% for the Long Island Locality.

Exhibit 2

LOCATIONAL MINIMUM INSTALLED CAPACITY REQUIREMENTS STUDY

COVERING THE NEW YORK BALANCING AUTHORITY AREA
For the 2013 – 2014 Capability Year

NYISO Operating Committee
January 17, 2013

Locational Minimum Installed Capacity Requirements Report

I. Recommendation

This report documents a study conducted by the New York Independent System Operator (NYISO) to determine Locational Minimum Installed Capacity Requirements (LCRs) for the New York City (Zone J) and Long Island (Zone K) Localities for the 2013 - 2014 Capability Year beginning May 1, 2013.

Currently, the New York City (NYC) LCR is eighty-three percent (83%) of the NYC forecast peak load for the 2012 – 2013 Capability Year. The Long Island (LI) LCR is currently ninety-nine percent (99%) of the Long Island forecast peak load for the 2012 – 2013 Capability Year.

The New York State Reliability Council (NYSRC) in its 2013 Installed Reserve Margin (IRM) study report[1] identified the lowest feasible locational requirements of 83.7% for NYC and 102.0% for LI. The NYISO then determines the actual LCRs taking into consideration changes that have occurred since the NYSRC approved the IRM base case. The changes include the completion of the final 2013 ICAP load forecast and the announced retirements of the Danskammer plant, the Carthage Energy unit, the Kensico plant and the Dunkirk #2 unit[2].

Based on the NYSRC base case for the 2013 – 2014 Capability Year and the changes identified above, the NYISO recommends that the currently effective LCR of 99% of the forecast peak load for the Long Island Locality be raised to 105%. Further, the NYISO recommends that the currently effective LCR of 83% of the forecast peak load for the New York City Locality be increased to 86%.

II. Updating LCR Values

As its starting point, the NYISO LCR study utilized the statewide Installed Reserve Margin (IRM) study directed by the NYSRC. The IRM study was approved by the NYSRC Executive Committee on December 7, 2012, and is available on the NYSRC web site at www.nysrc.org.

For New York City, there were factors that both tended to increase and decrease its LCR value when compared to the current year's value. Factors tending to lower the NYC LCR were the addition of the Hudson Transmission Project[3] and the calculation of generating units EFORds with an improved methodology. This reduction trend, however, was outweighed by factors tending to increase the LCR value. These factors include the adoption of fixed SCR values, the slightly higher load forecast uncertainty for NYC, increased EFORds of generation units in

[1] NYSRC Report titled, "New York Control Area Installed Capacity Requirements for the Period May 2013 Through April 2014", December 7, 2012.

[2] Dunkirk 3 and 4 are already retired from the study. Unit 1 remains in service.

[3] The Hudson Transmission Project is modeled without firm capacity contracts and is projected to be available for emergency assistance during the 2013-2014 capability year.

NYC, higher EFORs on the subterranean cables in downstate NY, less assistance provided by the Control Areas surrounding NYC, and the impact of the retirement of Danskammer units.

Long Island also had factors that both tended to increase and decrease its LCR. Factors tending to lower the LI LCR were the addition of the Hudson Transmission Project, a slightly lower load forecast uncertainty for LI, and the calculation of generating units EFORds with an improved methodology. This reduction, however, was more than offset by factors tending to increase the LCR value. These factors include the adoption of fixed SCR values, increased EFORds on the LI generation fleet, higher EFORs on the downstate subterranean cables, less assistance provided by the Control Areas surrounding LI, and the impact of the retirement of the Danskammer units.

When looking at the upward movement of the LCRs with respect to the most recently completed IRM study, the following facts can be observed with their corresponding explanation.

- The retirement of the Danskammer units is the primary factor increasing the LCR values. This is because the Danskammer units are located in Zone G, which provides assistance to both NYC (Zone J) and LI (Zone K). The loss of this large generation source (500 MW) below a key transmission constraint not only has a great impact on the reliability of Zone G, but also significantly influences the reliability situation of NYC and LI due to reduced support to the load center. To compensate for this retirement both the NYC LCR and LI LCR need to be increased.

- The additional plant retirements, other than the Danskammer units, taken into account since the IRM study completion were either in upstate NY (Dunkirk #2 and Carthage Energy unit), or very small in capacity if in downstate NY (Kensico units). Because these retirements remove units with higher EFORds than zones in which they leave, there is some downward pressure on the requirements.

- The final 2013 ICAP load forecast matches the October IRM forecast for New York State. The downstate load however, drops by 85 MW while the upstate load increases by 86 MW. This change is shown in the table below. The reliability benefits of the lower load downstate are equally opposed by the reduction in the upstate's ability, with the now higher load, to assist downstate. For this case, the new load forecast does not affect the LCRs in zones J and K.

Area	**IRM Load Forecast (MW) (10/12)**	**Final 2013 ICAP Forecast (MW) (12/12)**	**Increase (MW)**
Zone J (NYC)	11,532	11,485	-47
Zone K (LI)	5,553	5,515	-38
NYCA	33,278	33,279	1
ROS	16,193	16,279	86

III. Summary of Study

This study and its supporting analysis are based on the unified methodology. A full description of the procedure used for the unified methodology can be found as attachments A, B, and C of the NYSRC's Policy 5-6.[4]

The 2013 IRM study base case indicated that the Loss of Load Expectation (LOLE) criterion of not more than 0.1 days/year can be met with a statewide reserve margin of 17.1% and the lowest feasible locational requirements of 83.7% and 102.0% for NYC and LI, respectively. The NYISO's LCR study then examined the effects of the final ICAP peak load forecast, the changes in retirements, and consideration of the 17.0% IRM established by the New York State Reliability Council, in order to decide the final LCRs for the localities.

Based on the NYSRC base case for the 2013 – 2014 Capability Year and consideration of the changes identified above, the LOLE criterion of 0.1 days/year is met with a Minimum LCR of 86% for the New York City Locality and a Minimum LCR of 105% for the Long Island Locality.

[4] Policy 5-6 can be found on NYSRC.org website under Documents/Policies.

Exhibit 3

LOCATIONAL MINIMUM INSTALLED CAPACITY REQUIREMENTS STUDY

COVERING THE NEW YORK CONTROL AREA
For the 2014 – 2015 Capability Year

NYISO Operating Committee
January 16, 2014

Locational Minimum Installed Capacity Requirements Report

I. Recommendation

This report documents a study conducted by the New York Independent System Operator (NYISO) to determine Locational Minimum Installed Capacity Requirements[1] (LCRs) for the Localities of New York City (Load Zone J), Long Island (Load Zone K), and the new G-J Locality (Load Zones G, H, I, and J) for the 2014 – 2015 Capability Year beginning May 1, 2014.

For the 2013 – 2014 Capability Year, the New York City (NYC) LCR is eighty-six percent (86%) of the NYC forecast peak load, and the Long Island (LI) LCR is one hundred and five percent (105%) of the LI forecast peak load.

The New York State Reliability Council (NYSRC) in its 2014 Installed Reserve Margin (IRM) study report[2] identified the lowest feasible locational requirements of 84.7% for NYC and 106.9% for LI. After that step, the NYISO determines the LCRs taking into consideration changes that have occurred since the NYSRC approved the IRM base case used in IRM study. The only update to the IRM base case is the completion of the final 2014 – 2015 ICAP load forecast.

Based on the NYSRC IRM base case for the 2014 – 2015 Capability Year and the change identified above, the NYISO recommends that the currently effective LCR of 86% of the forecast peak load for the New York City Locality be decreased to 85%. The NYISO also recommends that the currently effective LCR of 105% of the forecast peak load for the Long Island Locality be increased to 107%. The NYISO recommends that the LCR for the G-J Locality be 88%.

II. Updating LCR Values

As its starting point, the NYISO LCR study utilized the IRM study base case directed by the NYSRC. The IRM study and the IRM were approved by the NYSRC Executive Committee on December 6, 2013.

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[1] Capitalized terms not defined herein shall have the meaning set forth in the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff") as revised by the Commission's acceptance of the NYISO's filing to establish a New Capacity Zone and subsequent related filings in Docket Nos. ER12-360 and ER13-1380. *See* New York Independent System Operator, Inc., *Proposed Tariff Revisions to Establish and Recognize a New Capacity Zone and Request for Action on Pending Compliance Filing*, Docket No. ER13-1380-000 (April 30, 2013) (the "April 2013 NCZ Filing") *and* New York Independent System Operator, Inc., *Initial Compliance Filing and Request for Shortened Comment Period and Expedited Action by July 1, 2013*, Docket No. ER12-360-001 (June 19, 2013).

[2] NYSRC 2014 IRM study report ("NYSRC Report") is titled, *New York Control Area Installed Capacity Requirements for the Period May 2014 Through April 2015* (December 6, 2013), and it is available at: <http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.asp>.

For New York City, there are factors that both tend to increase and decrease its LCR value when compared to the 2013 – 2014 Capability Year value. Factors tending to increase the NYC LCR are reduced SCR response and increased Equivalent Demand Forced Outage Rates ("EFORds") of generating units in NYC. This increase trend is outweighed by factors tending to lower the LCR value. These factors include the adoption of a new multiple load shape model, improved transfer capability from the Linden VFT and other topology changes, and more assistance available to NYC from the PJM Interconnection Control Area.

For Long Island, there are factors that both tend to increase and decrease its LCR. The factor tending to lower the LI LCR is the adoption of a new multiple load shape model. This reduction, however, is more than offset by factors tending to increase the LCR value. These factors include reduced SCR response, increased EFORd of the LI generating fleet, and less assistance from ISO-NE Control Area.

The observations described below can be made from the movement of the LCRs with respect to the IRM study base case for the 2014 – 2015 Capability Year.

- The final 2014 – 2015 NYCA ICAP load forecast, used in the LCR study, almost matches the load forecast used in the IRM study. There was only an increase of 10 MW. However, the downstate[3] load increases by 159 MW while the Rest of State[4] load drops by 149 MW. This change is shown in Table 1 below. It indicates more load growth in downstate areas than in upstate areas. This will put more reliability burden on three Localities, all of which are downstate.

Table 1: Change of 2014 Load Forecast

Area	IRM Load Forecast (MW) (10/13)	Final 2014 ICAP Forecast (MW) (12/13)	Increase (MW)
Zone J (NYC)	11,740	11,783	43
Zone K (LI)	5,461	5,496	35
Zones G-J (G-J Locality)	16,167	16,291	124[5]
NYCA	33,656	33,666	10
ROS (Zones A-F)	12,028	11,879	-149

The creation of the G-J Locality does not impact the outcome of using the unified methodology to determine the LCRs of New York City (Load Zone J) and Long Island (Load Zone K). The methodology that the NYISO used to calculate the LCR for the G-J Locality is an extension of

[3] "Downstate" in this report means Load Zones G through K.
[4] The definition of Rest of State (ROS) is revised concurrent with the creation of the G-J Locality. Previously, ROS meant Load Zones A through I. As of January 27, 2014, and as used in this report, ROS means Load Zones A through F.
[5] This G-J Locality MW increase includes the MW increase in Load Zone J.

the existing process, which is the same process used to determine the LCRs for NYC and LI for the 2013 – 2014 and previous Capability Years. The steps to calculate the LCR for the G-J Locality are implemented after the LCRs for the NYC and LI Localities are determined.[6] A brief, general description of this methodology is as follows.

First, ensure the database has been adjusted to arrive at the established statewide IRM and the proposed LCRs for the NYC and LI Localities. Second, lock the capacity in LI at its proposed LCR but return the capacity in NYC to its original value. Third, shift capacity from Load Zones G-J to Load Zones A, C, and D until the NYCA Loss of Load Expectation (LOLE) reaches the target LOLE value. Finally, calculate the capacity-to-load ratio for Load Zones G, H, I, and J collectively, and the resulting value is the LCR for the G-J Locality.

A full description of the process used is available on the NYISO's website.[7] The LCR study and its supporting analysis are based on the unified methodology.

III. Summary of Study

The 2014 – 2015 IRM study base case indicated that the LOLE criterion of not more than 0.1 days/year can be met with a statewide reserve margin of 17.0% and the lowest feasible locational requirements of 84.7% and 106.9% for NYC and LI, respectively. The NYISO's LCR study then examined the effects of the final ICAP peak load forecast, and consideration of the 17.0% IRM established by the NYSRC in order to determine the final LCRs for the Localities.

Based on the NYSRC base case for the 2014 – 2015 Capability Year and consideration of the change identified above, the LOLE criterion of 0.1 days/year is met with a minimum LCR of 85% for the NYC Locality, a minimum LCR of 107% for the LI Locality, and a minimum LCR of 88% for the G-J Locality.

[6] The NYISO has posted the LCR calculation procedure on its website. See next footnote for details.
[7] *Locational Capacity Requirement Calculation Process*, available at: <http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/Reference_Documents/LCR_Calculation_Process/LCR%20Calculation%20Process%2012_13_13.pdf>.

Exhibit 4

LOCATIONAL MINIMUM INSTALLED CAPACITY REQUIREMENTS STUDY

COVERING THE NEW YORK BALANCING AUTHORITY AREA
For the 2015 – 2016 Capability Year

NYISO Operating Committee
January 14, 2015

Accepted - NYISO Operating Committee
January 15, 2015

Locational Minimum Installed Capacity Requirements Report

I. Recommendation

This report documents a study conducted by the New York Independent System Operator (NYISO) to determine Locational Minimum Installed Capacity Requirements (LCRs) for the Localities of New York City (Load Zone J), Long Island (Load Zone K), and the G-J Locality (Load Zones G, H, I, and J) for the 2015 - 2016 Capability Year beginning May 1, 2015.

Currently, for the 2014 – 2015 Capability Year, the New York City (NYC) LCR is eighty-five percent (85.0%) of the NYC forecast peak load and the Long Island (LI) LCR is currently one hundred and seven percent (107.0%) of the Long Island forecast peak load. The G-J Locality requirement is currently eighty-eight percent (88.0%) of the G-J forecast peak load.

The New York State Reliability Council (NYSRC) approved the 2015-2016 Installed Reserve Margin (IRM) at 17.0% on December 5, 2014. The NYISO then determined the LCRs taking into consideration changes that have occurred since the NYSRC approved the IRM base case. After adjusting the model to use the approved IRM, the only change to the database for this analysis is the final 2015 ICAP load forecast shown in the table below.

Area	IRM Load Forecast (MW) (10/2014)	Final 2015 ICAP/LCR Load Forecast (MW) (12/2014)	Change (MW)
Zone J (NYC)	11,990	11,929	-61
Zone K (LI)	5,522	5,539	17
Zones G-J	16,387	16,340	-47
NYCA	33,587	33,567	-20
ROS (Zones A-F)	11,914	11,926	12

Based on the NYSRC base case for the 2015 – 2016 Capability Year and the change identified above, the NYISO's calculations result in decreasing the currently effective LCR of 85.0% of the forecast peak load for the New York City to **83.5%**. The NYISO's calculations also result in decreasing the currently effective LCR of 107.0% of the forecast peak load for the Long Island Locality to **103.5%.** Lastly, the NYISO's calculations result in increasing the currently effective LCR of 88.0% for the G-J Locality to **90.5%.**

II. Updating LCR Values

As its starting point, the NYISO LCR study utilized the statewide Installed Reserve Margin (IRM) study directed by the NYSRC. The IRM study is available on the NYSRC web site[1].

[1] www.nysrc.org

The only adjustment the NYISO has made to the final IRM base case is the inclusion of the final 2015 ICAP/LCR peak load forecast. This forecast updated the October 2014 peak load forecast used in the IRM study. The NYCA system peak had a decrease of 20 MW while Zones J and K had a net 44 MW decrease. These changes in the peak forecast used in the LCR study had only a small impact on the final LCR values.

The LCR analysis is an optimization process for the NYCA system to meet the LOLE reliability criteria by setting minimum requirements for each of the defined localities. As the outcome of the process, the NYC and LI LCRs decreased, while the value for the G-J locality increased, with respect to the most recently completed IRM study and the 2014-2015 LCR values. The following are the dominant factors affecting these results.

1. The return of the Danskammer, Astoria 2 and other units increases the available capacity (total of 975 MW), which improves the system reliability for the transmission constrained areas of the Lower Hudson Valley (G-J Locality), NYC, and LI. The result is a decrease in the LCRs for NYC (-1.5%) and LI Localities (-3.5%) and an increase in the LCR for the G-J Locality (+2.5%).

2. The 2.5% (408 MW) increase in the G-J Locality requirement indicates that 408 MW of the 975 MW of increased available capacity must be located in the G-J Locality to satisfy the locational resource adequacy requirement.

3. Additional assistance to NYC and LI resulted from the inclusion of Annual and Extended PJM Demand Response resources. This increased assistance also decreased the NYC and LI LCR values.

III. Summary of Study

The calculations made in this study, and its supporting analysis, are based on the NYISO process for setting the LCRs, which is posted on the NYISO website[2].

The final 2015 IRM base case maintains the Loss of Load Expectation (LOLE) criterion at not more than 0.1 days/year with a statewide reserve margin of 17.0% and locational requirements of 83.4% and 103.7% for NYC and LI, respectively. The NYISO's LCR study then examined the effects of the final 2015 ICAP/LCR peak load forecast to determine the final LCRs for the three localities.

Based on the NYSRC's final IRM base case for the 2015 – 2016 Capability Year and the NYISO's final 2015 ICAP/LCR peak forecast, the LOLE criterion of 0.1 days/year is met with an LCR of 83.5% for the New York City (Zone J) Locality, an LCR of 103.5% for the Long Island Locality (Zone K), and an LCR of 90.5% for the Zones G-J Locality.

[2] http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

Exhibit 5

LCR Process Review

Dana Walters

Director Economic and Reliability Planning
New York Independent System Operator

LCR Task Force

March 5, 2015
NYISO, Krey Corporate Center

Administrative

- Introductions
- Approach to Meeting
- Provide a starting reference for task force members for consistent understanding of objectives, issues, and processes
  - *Discuss background information*
  - *Discuss expressed concerns with LCR process*
  - *Discuss existing processes*
- Discuss topics for next meeting, but don't discuss specifics of alternatives or solutions at this meeting
- Discuss meeting schedule

Issue Statement

- **Some stakeholders have expressed concerns with the existing Locational Capacity Requirements (LCRs) process because:**
  - ***When load decreases and resources increase, then requirements in G-I may increase***
  - ***If the requirements increase, then Load Serving Entities (LSEs) need to buy more capacity.***
  - ***This seems counter-intuitive when new resources are available to respond to a need.***

Background of Request

- NYISO was asked by the Operating Committee to work with the ICAP WG to take the lead in considering an alternative process to calculate LCRs to address the concerns raised
- NYISO extended to stakeholders an invitation to participate on a LCR Task Force to consider the issue
- NYISO is coordinating the effort to scope the request, consider alternatives and perform analysis of potential viable options, as resources permit

Installed Reserve Margin

- A Power Grid requires Installed Reserve Margin (IRM) to operate its generating fleet and provide customers with reliable service
- There are infinite ways to calculate the LSE obligations to provide for the IRM and LCRs
- In NY, the Transmission Owners (TOs) reached an agreement to balance the obligation for the IRM between the upstate (north of NYC; Zones A-I) LSEs and the downstate LSEs (NYC & LI; Zones J & K)
- Roughly 50% of the peak electrical demand in NY is in Zones A-I and 50% in J & K

Background of Unified Methodology

- **Unified Methodology is a two step process**
  - ***Step 1 (referred to as the Tan 45 method): Develop a curve with varying IRM versus locational requirements in Zones J & K, where all points on the curve will provide a one day in ten year (0.1) Loss of Load Expectation (LOLE)***
  - ***Use a 45 degree line to intersect the curve and provide a 50% balance point***
  - ***Step 1 is administered by NYSRC***
  - ***Step 2 (LCR Method): Starting with the IRM as a reference, determine the locational requirements of Zones J & K and the G-J Locality***
  - ***Step 2 is administered by NYISO***
- **Both steps use the GE Multi-Area Reliability Simulation (MARS) program, which uses a Monte Carlo probabilistic simulation to evaluate the LOLE**

Creation of New G-J Locality

- **NYISO was directed by FERC to create a new Locality based on the outcome of study**
- **NYISO created the G-J Locality**
- **An LCR has to be established for each Locality, so the NYISO developed a process to calculate the G-J requirement without impacting the existing Tan 45 process**

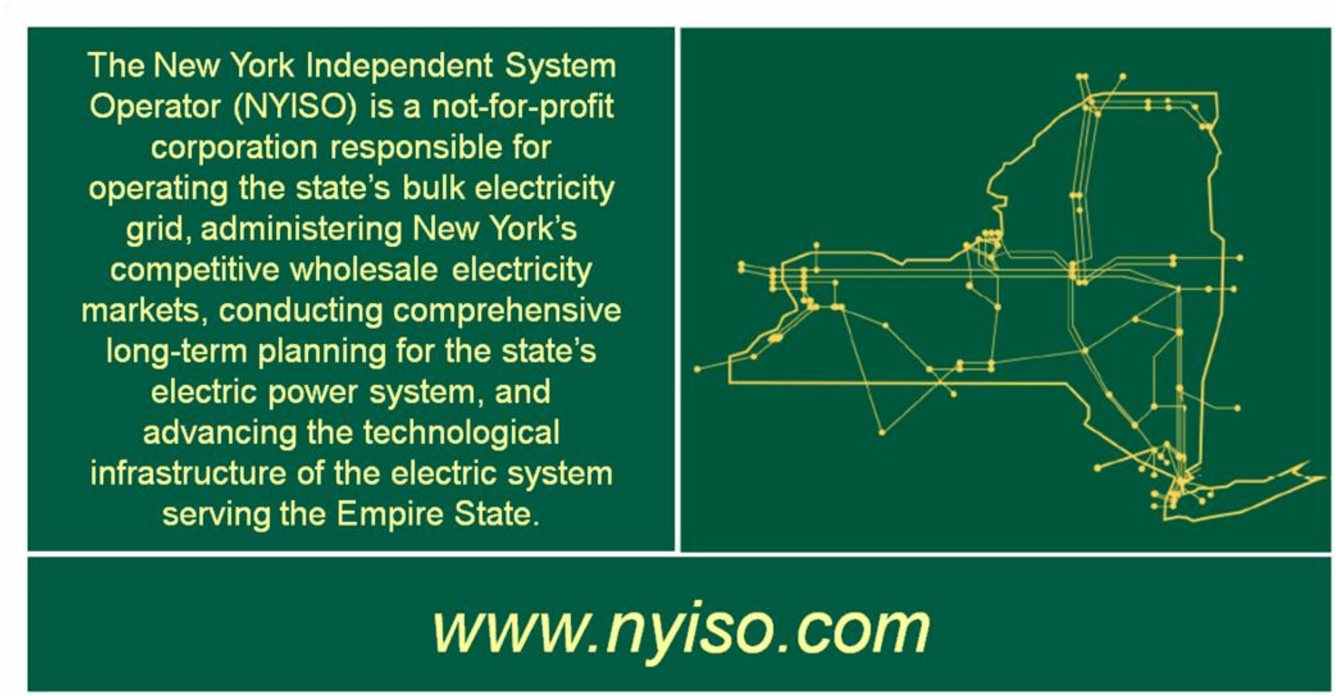

The New York Independent System Operator (NYISO) is a not-for-profit corporation responsible for operating the state's bulk electricity grid, administering New York's competitive wholesale electricity markets, conducting comprehensive long-term planning for the state's electric power system, and advancing the technological infrastructure of the electric system serving the Empire State.
www.nyiso.com

Exhibit 6

Setting of the IRM and LCRs
The Basic Process

Greg Drake

Supervisor – Resource Adequacy

New York Independent System Operator

ICAP WG Task Force for LCR Review

March 5, 2015

NYISO , Rensselaer, NY

Objectives

- Basic understanding of the NYSRC's process for setting the IRM[1]
- Basic understanding of the NYISO's process for setting the LCRs[2]
  - *The LCR process starts with the completed base case database for the IRM.*

1. **To find NYSRC Policy 5-8 go to Documents/Policies at http://www.nysrc.org.**
2. **To find NYISO LCR Calculation Process go to NYISO website at nyiso.com and look under Market Data/ICAP/Reference Documents/LCR_Calculation_Process**

IRM Process - Background

- The IRM study[3] occurs over a calendar year for an upcoming Capability Year (May-April)
- NYISO populates data and performs simulations under guidance of NYSRC's ICS.
- The NYISO is a technical resource for the NYSRC

3. To find present and past IRM reports go to Documents/Reports at http://www.nysrc.org.

IRM Process - Background

- IRM answers the question of how much ICAP is needed to meet the peak load.
- The year is simulated at least 1,000 times to give a Loss of Load Expectation (LOLE).
- Capacity is adjusted so that over the 1,000 iterations, the LOLE comes out to the NYSRC criterion of 0.100 days/year.

IRM Process – Load Inputs

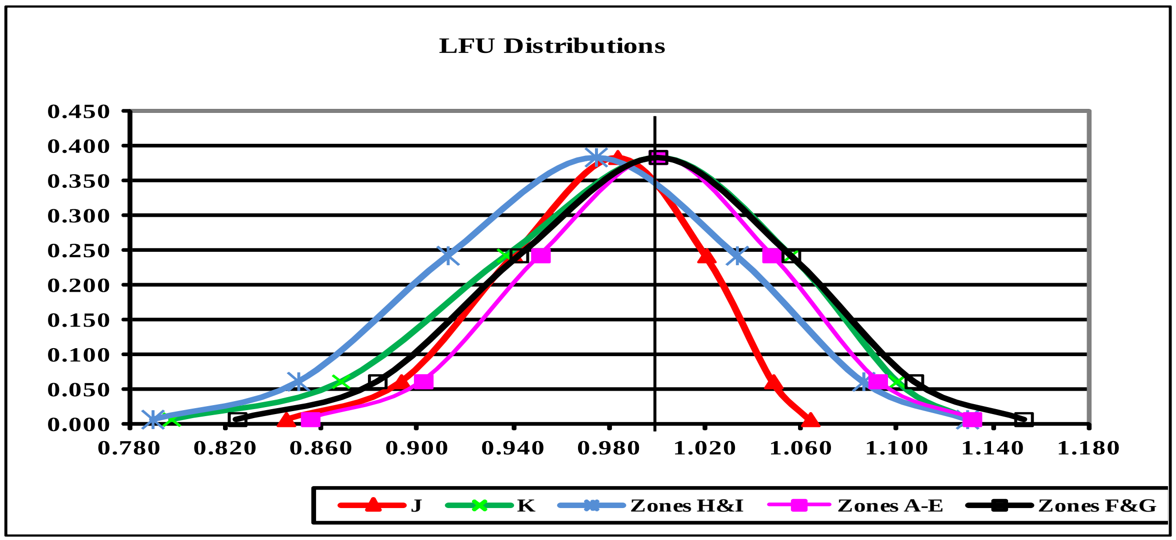
- **The load forecast is based on previous year actual plus forecast growth (TO/NYISO agreement)**
  - *The forecast represents a 50% chance the actual load is higher (50/50 forecast)*
- **Uncertainty of load due to weather is studied.**
  - *Each 1,000 iteration case is run against seven load levels with various probabilities.*
  - *For example, one of the levels could indicate the load if there was only a 6% probability of being above that load (94/6 forecast).*
- **Each load level can have its own historic hourly load shape.**
  - *We currently use 3 shapes.*

Load Forecast Uncertainty

LFU Model

Load Forecast Uncertainty Models

Multiplier	Zones A-E	Zones F&G	Zones H&I	Con Ed (J)	LIPA (K)
0.0062	0.8550	0.8245	0.7893	0.8449	0.7971
0.0606	0.9021	0.8830	0.8500	0.8929	0.8677
0.2417	0.9510	0.9420	0.9123	0.9397	0.9364
0.3830	1.0000	1.0000	0.9741	0.9831	1.0000
0.2417	1.0474	1.0554	1.0329	1.0202	1.0554
0.0606	1.0916	1.1067	1.0856	1.0481	1.0996
0.0062	1.1309	1.1524	1.1289	1.0635	1.1295



IRM Process, Load Inputs-continued

- **Reasons for using different load shapes:**
  - ***Historically, years where the peak was around the 90/10 forecast (higher load level), the hourly load shapes were peaked.***
    - **By peaked, we mean that the number of days whose peaks are near to the peak day were small**
    - **The shapes chosen are based on a conservative year, a peaked year, and a typical year**
- **Even though there are seven load levels, risk (LOLE events) occurs only in the top four bins.**

IRM Process – Capacity Inputs

- **5 years of historical performance is used to predict future availability of thermal and large hydro generators.**
  - ***Wind and solar use one year of production data.***
  - ***Run of river hydro uses a plot of monthly output based on history***
- **The simulation program uses a Monte Carlo methodology to probabilistically generate hourly outage patterns for thermal units for each of the 1,000 iterations.**
- **Special Case Resources (SCRs) are modeled based on registrations and are derated based on tested and historic performance.**

IRM Process – Other Inputs

- **We model interface limits between Zones and between Areas[4] (line and bubble diagram).**
- **Unforced Deliverability Rights (UDR) facilities, to the extent they have not elected to return them for the upcoming Capability Year (i.e., notification to NYISO by August 1) are modeled as contracts.**
  - ***Contract levels on UDRs are considered confidential***
  - ***Any tie capacity left (after contracts) is available for emergency assistance***

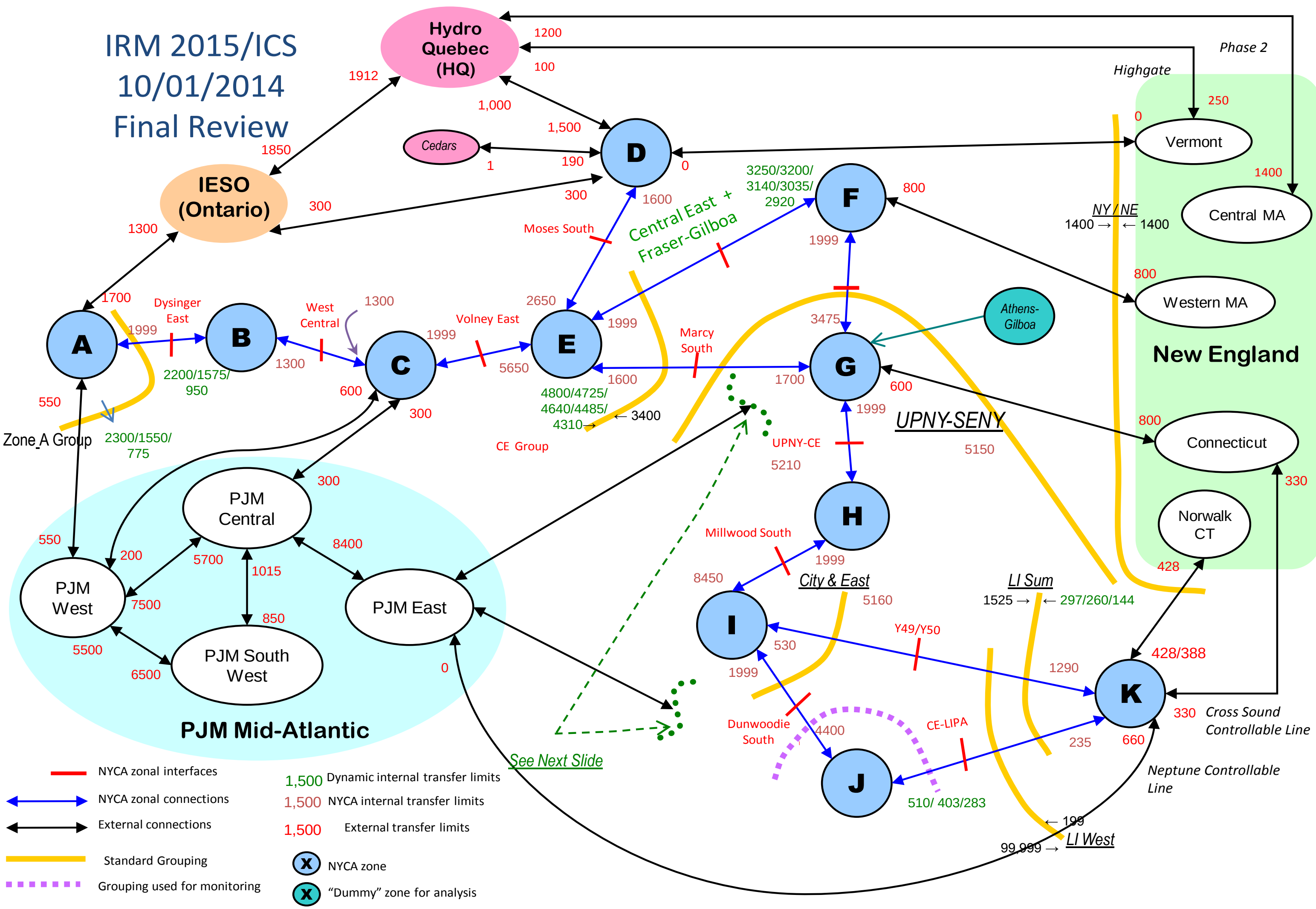
4. Current computing capabilities do not support use of a power flow model in GE MARS.

IRM Process – Other Inputs

- **We model the Emergency Operator Procedures (EOPs) that can be employed during a system emergency.**
  - ***Such as: Voltage reductions, Emergency Demand Response Program (EDRP), Public Appeals, voluntary industrial curtailments, and operating reserves.***
- **Finally, we can ask for emergency assistance from our neighbors.**
  - ***We model neighboring interconnected Control Areas of PJM (classic footprint), New England, Ontario and Quebec***

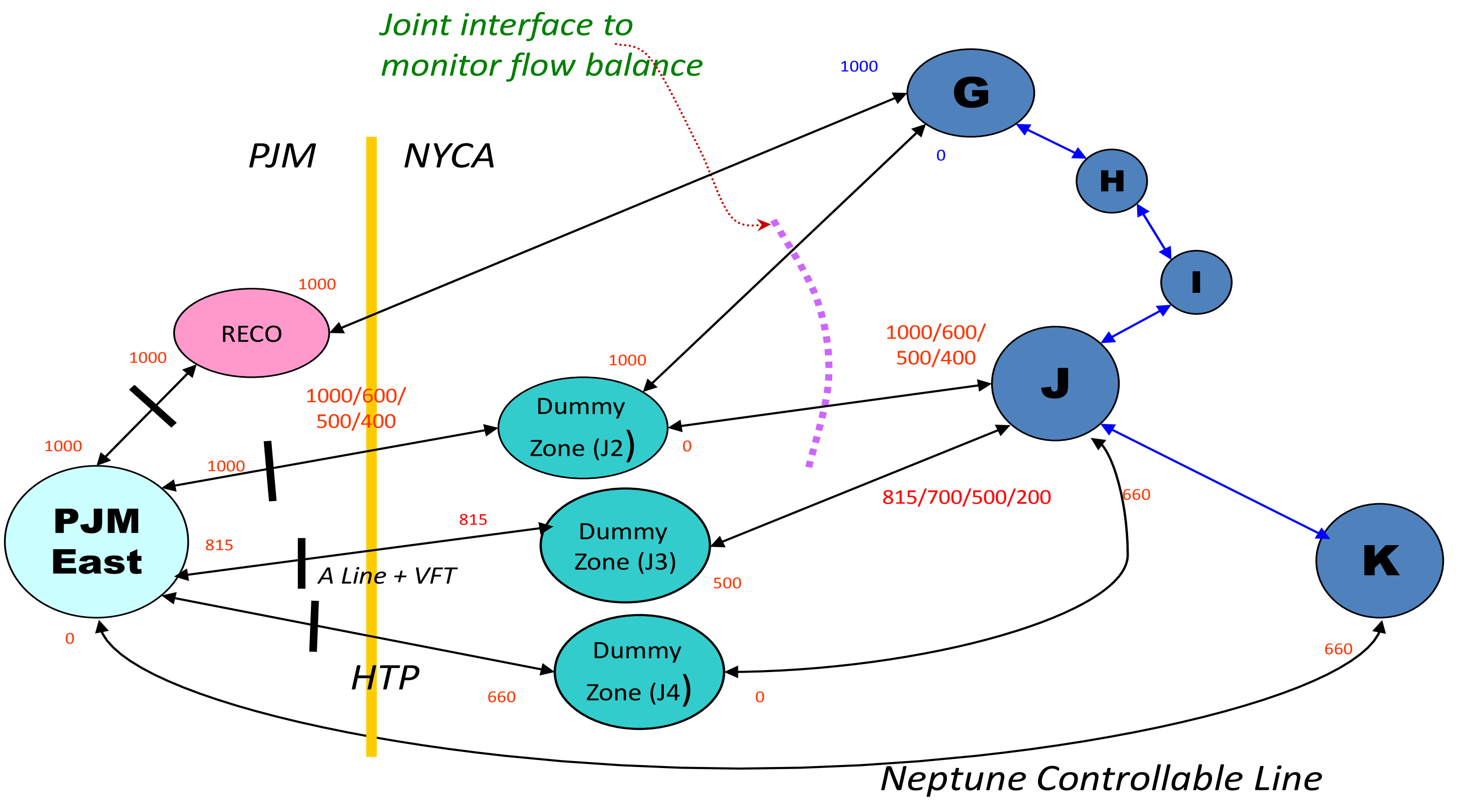
Transmission System Representation for Year 2015 - Summer Emergency Ratings (MW) 6/30/2014

IRM 2015/ICS
10/01/2014
Final Review



Transmission System Representation for Year 2015 - Summer Emergency Ratings (MW)

PJM-SENY MARS Model
6/30/2014



(PJM East to RECO) + (PJM East to J2) + (PJM East to J3) + (PJM East to J4) = 3075 MW

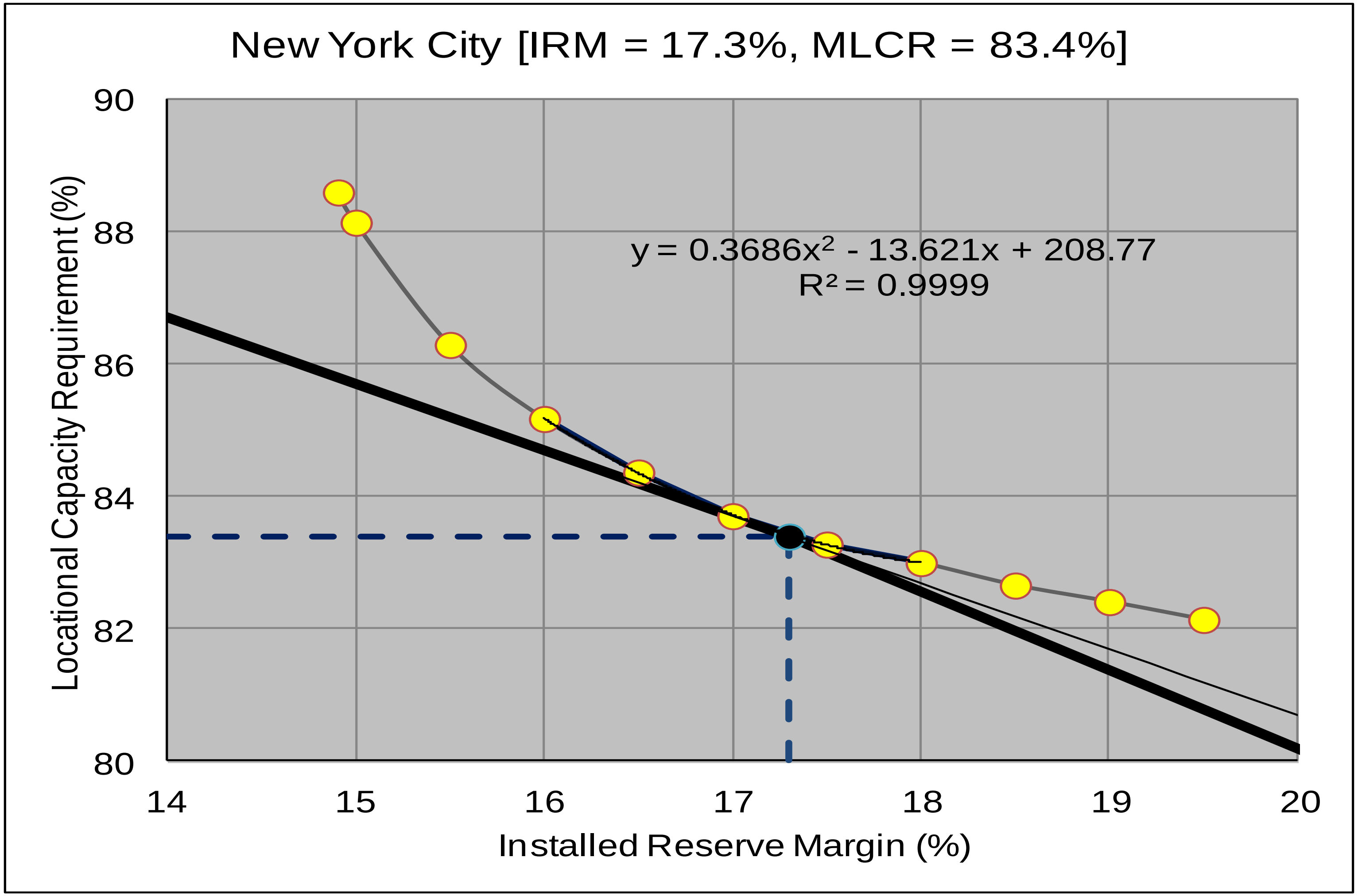
IRM Process – One Curve Point

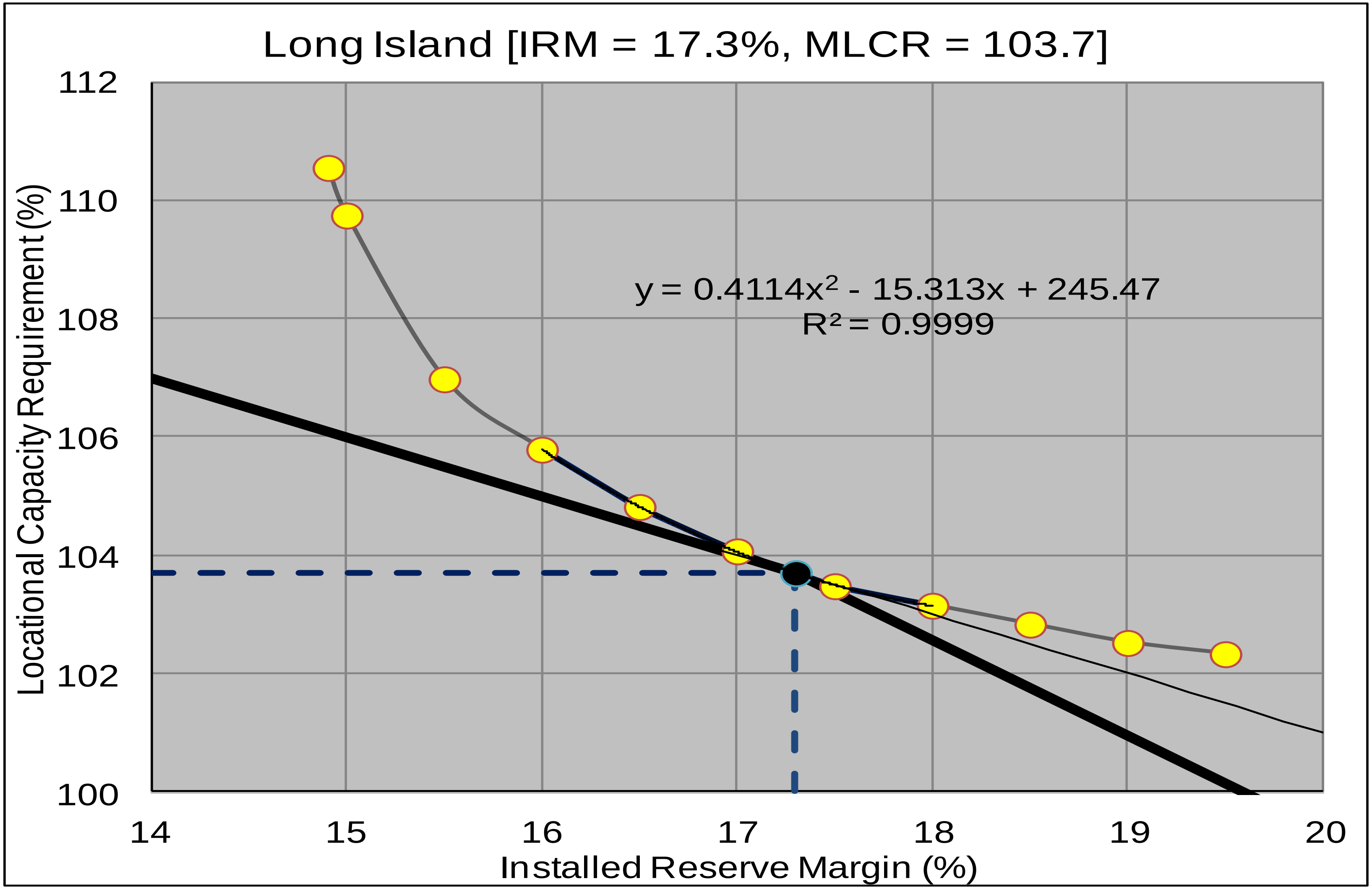
- **If, after utilizing all means possible to meet the peak load, there is still a shortage, a loss of load event is registered.**
- **A single load level LOLE value is the expected loss of load events per year at this level.**
  - ***The final LOLE is arrived at by multiplying each load level probability times its result and adding the seven values.***
- **The model is re-run varying the amount of capacity removed until 0.100 LOLE is met.**
  - ***NYCA currently has excess capacity***

IRM Process – Multiple Curve Points

- Capacity upstate has a different statewide LOLE impact than capacity downstate.
- Where and how the capacity is adjusted affects the final results.
- The IRM-LCR curve (next slide) shows the relationship of the tradeoffs between statewide and J&K locality values (all points are at criteria).
- The NYSRC technical report indicates the IRM at the knee (or tan 45) of the curve.

Figure 3-2 NYCA Locational Requirements vs. Statewide Requirements




Long Island [IRM = 17.3%, MLCR = 103.7]
112
110
108
106
104
102
100
Locational Capacity Requirement (%)
y = 0.4114x² - 15.313x + 245.47
R² = 0.9999
14
15
16
17
18
19
20
Installed Reserve Margin (%)

LCR Process - Background

- The IRM study shows indicative LCR values for Zones J & K. Actual LCR values are found during the LCR study.
  - *The LCR Study starts with the completed IRM database*
- The LCR values must also comply with the LOLE criteria.
- A separate IRM-LCR curve is not created since the IRM value is a fixed input to the LCR study.

LCR Process – Input Changes

- **The load forecast is updated between the time of the IRM and LCR studies.**
- **Other material changes[5] could also be incorporated.**
  - ***The resulting LCRs could look different than the ones shown in IRM.***

5. Material capability changes are individual changes that would increase or decrease generation, CRIS MW, or transmission transfer capability by 200 MW or greater.

LCR Process – Steps

- **At the established IRM study point:**
  - ***Reset all capacity to Zones J & K. to their 'as found' condition.***
  - ***Shift capacity from Zone J to upstate zones (A, C, and D) until the LOLE criteria is met.***
  - ***Reset the capacity from J and shift from Zone K.***
  - ***Reset the capacity from K and shift from J & K based on ratios found above. <u>This sets the recommendation for the J and K LCRs.</u>***
  - ***Reset J's capacity and freeze K's at the above found LCR level.***
  - ***Shift capacity from G-J. <u>The remaining capacity divided by the G-J peak load is the proposed G-J LCR[6].</u>***

6. The LCR values are rounded to the nearest 0.5% and the LOLE is verified to satisfy LOLE criteria

Numerical Example[7] of LCR Calculations

Setting of Zones J and K LCRs (example)

Zones	MWs Shifted:	J Ratio:	K Ratio:	Starting Capacity	After Shift Capacity	Peak Load Forecast	Margin %
Shift J alone	500			10500	10000	11929	
Shift K alone	400			6000	5600	5539	
		=500/(400+500)	=400/(400+500)				
Ratios found:		0.5555556	0.4444444				
Shift J and K	700						
Final J	388.9	=700*0.56		10500	10111.1	11929	84.8%
Final K	311.1	=700*0.44		6000	5688.9	5539	102.7%

Setting LCRs for the G -J Locality (example)

Zones	MWs Shifted:	J Ratio:	K Ratio:	Starting Capacity	After Shift Capacity	Peak Load Forecast	Margin %
Shift G - J	705			15425	14720	16340	90.1%
Fixed Shift of K:	311.1			6000	5688.9	5539	102.7%

7. All capacity values are in ICAP

Numerical Example[8] of LCR Calculations

After 600 MW Unit Addition in Zone G

Setting of Zones J and K LCRs (example)

Zones	MWs Shifted:	J Ratio:	K Ratio:		Starting Capacity	After Shift Capacity	Peak Load Forecast	Margin %	Initial Case Margin(%)
Shift J alone	*600*				10500	9900	11929		
Shift K alone	*500*				6000	5500	5539		
Ratios found:		0.545455	0.454545						
Shift J and K	*900*								
Final J	490.9				10500	10009.1	11929	83.9%	84.8%
Final K	409.1				6000	5590.9	5539	100.9%	102.7%

Setting LCRs for the G -J Locality (example)

Zones	MWs Shifted:	J Ratio:	K Ratio:		Starting Capacity	After Shift Capacity	Peak Load Forecast	Margin %	
Shift G - J	*905*				***16025***	15120	16340	92.5%	90.1%
Fixed Shift of K:	409.1				6000	5590.9	5539	100.9%	102.7%

8. All capacity values are in ICAP

The New York Independent System Operator (NYISO) is a not-for-profit corporation that began operations in 1999. The NYISO operates New York's bulk electricity grid, administers the state's wholesale electricity markets, and provides comprehensive reliability planning for state's bulk electricity system.

www.nyiso.com

Exhibit 7

LCR Process Review: Next Steps

Dana Walters

Director Economic and Reliability Planning

New York Independent System Operator

LCR Task Force

March 5, 2015

NYISO, Krey Corporate Center

Scope

- **Discuss stakeholder concerns with the current process**
- **Discuss viable options to explore**
  - ***Strictly from the LCR perspective***
  - ***Whether it would be beneficial to involve IRM***

Concerns with changing the LCR process

- If the LCR increases in G-I, but the other Localities and NYCA minimum requirements decrease, stakeholders' views of the change may vary.
- There is only one variable in the LCR process after the application of the Tan 45 process (trade-offs for LSEs south of UPNY/SENY)

Stakeholder Suggestion

- *Suggestion*: As opposed to TAN45 optimizing b/w Zone J vs K and letting G-J "fall out" as a result; TAN45 optimizing b/w Zone K vs G-J and let J "fall out" as a result. In this manner Zone J is partially optimized through G-J.
- *Issue*: We would need to decide how to optimize and what quantities to add/deduct by individual Zone (G, H, I, J). Optimization may not result in minimum requirements for an individual Zone.

Stakeholder Concerns: Inter-relationship with IRM process

- Some possible LCR process revisions might not be possible without the IRM process being changed prior to or concurrent with a change to the LCR process
- Changing the IRM process is a more complicated issue and will raise other issues, most notably the IRM is under the jurisdiction of the NYSRC

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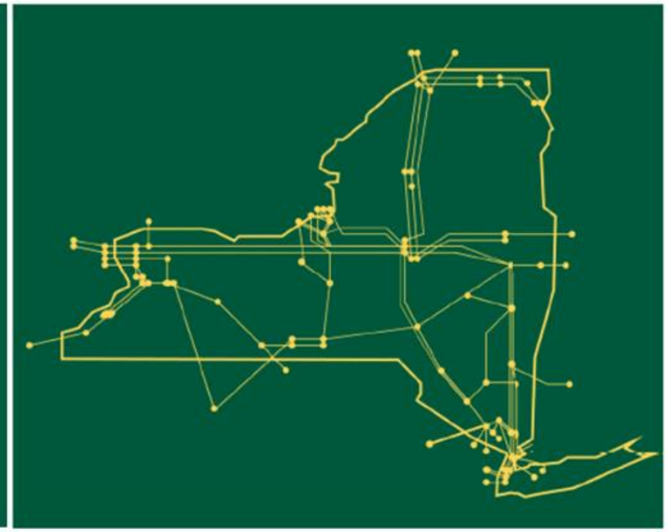

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Exhibit 8

Objective of LCR Methodology Review: Possible Alternatives

Dana Walters

Dir. Reliability and Economic Planning

New York Independent System Operator

LCR Task Force

April 8, 2015

KCC

Current Process

- NYSRC: Determine Installed Reserve Margin (IRM), where the IRM maintains reliability and establishes balance between the upstate and downstate requirements per Policy 5
- NYISO: There are multiple possible approaches to determine the Locational Minimum Installed Capacity Requirements (LCRs)
- The NYISO has been using Policy 5 as a guide for the methodology to establish the LCRs

Possible Alternatives

(Subject to maintaining LOLE of 0.1 and the IRM determined by NYSRC)

- ***Continue with current methodology***
- ***Minimize Cost*: Explore methodologies to set LCRs for J, K and G-J with the objective of minimizing the NYCA-wide capacity procurement costs**
- ***Minimize total MW:* Explore methodologies to set LCRs for J, K and G-J with the objective of minimizing the NYCA-wide MW requirement**
- ***Lowest Possible G-J:* Retain J and K "as found" and determine the minimum G-J**
- ***Other ideas***

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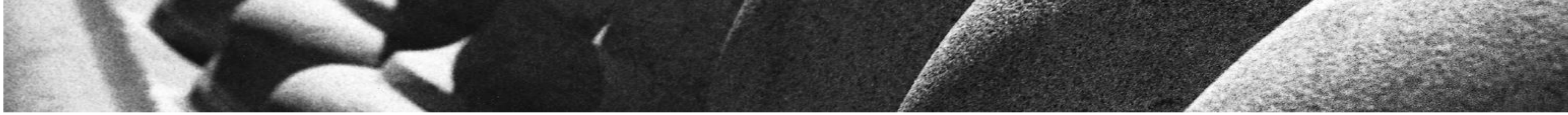
Exhibit 9

G-J Impact Analysis
Presented by
Scott Harvey and Susan Pope
Prepared for New York ISO

January 14, 2016



Topics

- Introduction
- Increase in Zone K LCR Approach
- Bottled Zone K Approach
- Cost Shift Approach
- Appendices

Introduction

The Unified Methodology for setting LCRs was developed in the context of the initial New York ISO capacity market design.

- The Unified Methodology led to some counterintuitive outcomes under the three zone design when capacity shut down in the Zone G, H, I region.
- The introduction of the G-J capacity market zone has corrected some of those anomalies but may introduce new ones as capacity is added in zones G, H and I.
- FTI was asked to evaluate the impact of potential changes in downstate LCR's and capacity market clearing and settlement mechanisms within the context of the Unified Methodology.

Introduction

We examined three potential types of changes in the current design.

- Increasing the Zone K LCR to shift incremental local capacity requirements from Zones G-J to Zone K;
- Accounting for the capacity value of excess Zone K capacity in clearing the G–J capacity market;
- Shifting the cost responsibility for the existing local capacity requirements.

Introduction

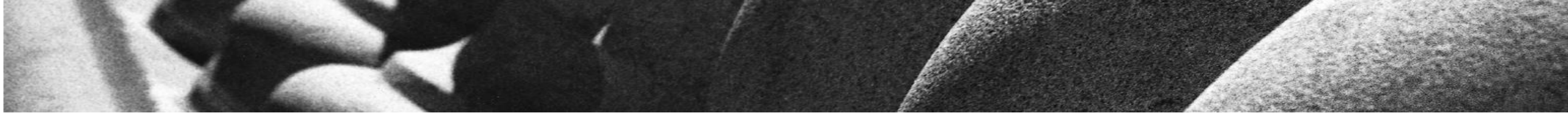
These changes were evaluated with respect to:

- Production cost savings;
- Total wholesale market capacity payments;
- Regional incidence of capacity payments.

Increase in Zone K LCR Overview

The FTI team was asked to estimate the impacts of an increase in the Zone K LCR, accompanied by an offsetting reduction in the G-J LCR.

- The Zone K local capacity requirement was increased by 300.21 megawatts of ICAP (a rough estimate of the limit on exports of power from Zone K), 276.71 megawatts UCAP;
- The G-J local capacity requirement was reduced by 359.48 megawatts of ICAP, 338.74 megawatts of UCAP;
- The intent of this change would be to meet the overall New York capacity requirement more efficiently.



Increase in Zone K LCR — Production Cost Analysis

One way of analyzing the impact of these changes in NYISO LCRs is from the standpoint of changes in production costs.

- Evaluation of the production cost impact of these changes requires measuring the production cost of capacity, which is not straightforward.
- Two possible approaches are to measure the production cost of Zone K and Zone G, H and I capacity based on net CONE or on average clearing prices in the spot auctions.
- Either approach to measuring production costs leads to the conclusion that such a shift in LCRs would be beneficial from a production cost standpoint.

Increase in Zone K LCR — Production Cost Analysis

Net CONE Approach Savings:

338.74 megawatts * $13,170 per month reference price

- 276.71 megawatts * $8,810 per month reference price

= $2,023,391 cost reduction per month

Auction Price Approach Savings:

338.74 megawatts * $6,270 average monthly price [1]

- 276.71 megawatts * $4,200 average monthly price [1]

= $961,718 cost reduction per month

1. January 2015- December 2015 spot auctions

Increase in Zone K LCR — Production Cost Analysis

Neither estimated net CONE nor average auction clearing prices is a perfect measure of capacity production costs, but the fact that both point in the same direction reduces concerns about their individual imperfections.

- Both estimated net CONE and average auction prices in Zone K are reduced by the large energy market returns to building new efficient generation in Zone K.
- This is appropriate because it reflects the substantial production cost savings in the energy market from building new efficient capacity in Zone K.

Increase in Zone K LCR — Consumer Impact

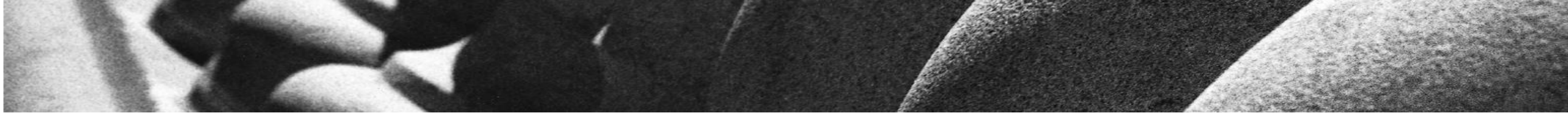
The FTI team was asked to estimate the short-run consumer impact of changes in NYISO downstate LCRs and other design elements of the capacity market spot auction.

- The analysis required estimation of changes in capacity market prices resulting from the potential design changes.
- Estimates of capacity market price changes were based on actual auction data (capacity cleared and demand curve) May 2015-November 2015.
- Estimates for the December 2014–April 2015 period included adjustments for changes to supply for the December 2015-April 2016 period.
- Adjusted LCRs were developed by NYISO.

Increase in Zone K LCR — Consumer Impact

Simulated auction outcomes show that an increase in the Zone K LCR with an offsetting reduction in the G-J LCR would:

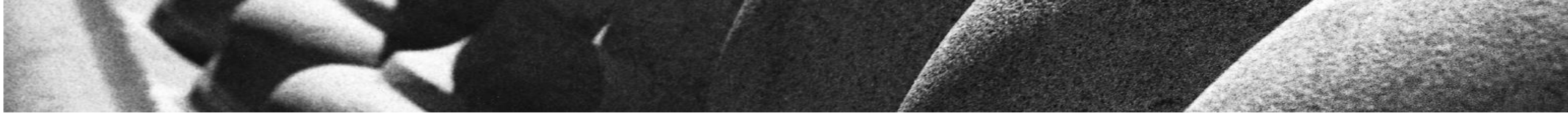
- Raise overall capacity market payments by $69.3 million a year based on the 2015-2016 LCRs.
- Raise overall capacity market payments by $70.5 million a year based on preliminary 2016-2017 LCRs.



Increase in Zone K LCR — Consumer Impact

The likely increase in overall rate payer capacity costs is driven by two structural factors that are not likely to change.

- Zone K load and capacity exceeds Zone GHI load and capacity, so an equal change in capacity prices will have a larger impact on Zone K costs than on GHI costs.
  - May 2015 cleared capacity in GHI was 4,664.60 MW.
  - May 2015 cleared capacity in K was 5,611.20 MW.
- The Zone K demand curve is steeper than the G-J demand curve so a shift of one megawatt of capacity obligation from G-J to Zone K will have a larger impact on the Zone K capacity price.
  - Summer 2015 slope for G–J was $6.30 per MW-month.
  - Summer 2015 slope for Zone K was $9.26 per MW-month.



Increase in Zone K LCR — Consumer Impact

The short-run consumer impact evaluation leads to a different conclusion than the production cost evaluation because of the two factors that drive the outcome of the consumer impact analysis.

- The short-run consumer impact depends on the relative amount of load buying capacity at the Zone K and versus the G-J price, while the production cost comparison does not.
- The short-run consumer impact depends on the change in the clearing price and hence on the relative slope of the Zone K and G-J demand curves, while the production cost comparison does not.

Increase in Zone K LCR — Consumer Impact

FTI evaluated the consumer price and rate impacts of different levels of changes in Zone K and G-J LCRs.

- "Full shift" analyses are based on NYISO's estimates of changes in LCR UCAP requirements under the assumption of 300 MW of ICAP exports from Zone K.
- "Partial shift" analyses were based on one-half of the "full shift" changes to LCR UCAP requirements.
- The partial shift results are not always one-half of the full shift results due to the impacts of price cascading, i.e., floors on the prices in subordinate zones that are set by the prices in larger zones.
  - Zone K costs would increase by $89.8 million to $350.2 million.
  - G-J costs would fall by $69.5 million to $276.2 million.
  - The increase in overall costs would be $20.2 million.

Increase in Zone K LCR — Consumer Impact

The potential for such a shift in the Zone K and G–J LCRs to reduce overall consumer costs increases:

- If, absent the LCR change, the Zone K capacity price set is by the NYCA price, rather than the Zone K demand curve due to cascading; when this occurs, the LCR change will result in a smaller increase in the Zone K capacity price, improving the overall ratepayer impact of the LCR change.
- If, absent the LCR change, the Zone J capacity price would be set by the G-J capacity price, rather than the Zone J demand curve, so that a reduction in the G-J capacity price also reduces the Zone J capacity price, while the Zone J LCR is unchanged.
- If the megawatt reduction in the G-J UCAP requirement is larger than the megawatt increase in the Zone K UCAP requirement.

Increase in Zone K LCR — Regional Incidence

Simulated auction outcomes show that an increase in the Zone K LCR with an offsetting reduction in the G–J LCR would:

- Reduce capacity market payments by Con Ed and O&R rate payers by much more than it would reduce payments by Central Hudson rate payers.
- Raise Zone K capacity market payments by far more than it would reduce payments by Central Hudson rate payers.
- Full shift
  - Increase Zone K costs by $182.3 million to $442.5 million in annual payments.
  - Reduce G-I costs by $90.7 million to $187.4 million in annual payments.
  - Reduce J costs by $22.4 million to $1,308.7 million in annual payments.

Increase in Zone K LCR — Regional Incidence

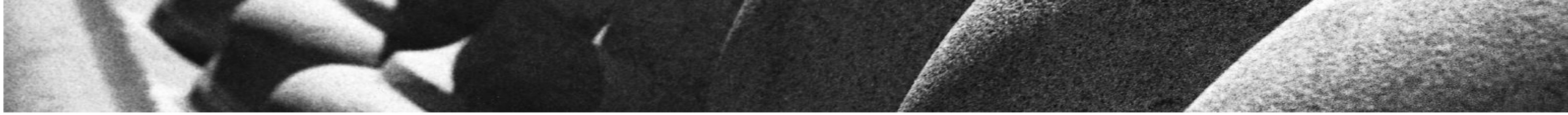
Simulated auction outcomes show that an increase in the Zone K LCR with an offsetting reduction in the G-J LCR would:

- Reduce capacity market payments by G, H I load by $20,557 per megawatt of GHI peak load over the year;
- Raise Zone K capacity market payments by $32,912 per megawatt of Zone K peak load over the year.
- Reduce capacity market payments by J load by $1875 per megawatt of J peak load over the year.

Increase in Zone K LCR Regional Incidence

Basing the analysis on a preliminary version of the LCRs for 2016-2017 (this analysis was completed before the LCRs were finalized) does not materially change the regional pattern of rate impacts.

- Zone K costs increase by $179.2 million to $409.3 million or an increase of $32,364 per megawatt of peak load.
- G-I costs fall by $79.1 million or $17,937 per megawatt of peak load and Zone J costs fall by $29.7 million, or $2488 per megawatt of peak load.



Increase in Zone K LCR — Consumer Impacts

The price impacts calculated are short-run price impacts with auction prices changing to equilibrate supply and demand while holding cleared capacity supply each month at historic levels, adjusted for changes.

- In the long-run, materially lower G-J capacity prices would likely lead to reductions in GHI capacity, partially offsetting the price impact of the LCR reduction for G-J consumers.
- The short-run rate impact on Zone K consumers would be lower than indicated by these calculations because most of the Zone K capacity is purchased under long-term contracts so its cost to consumers would not vary with changes in spot auction clearing prices. In the long-run, however, Zone K load serving entities would have to contract for more capacity and incur higher costs due to a higher Zone K LCR.

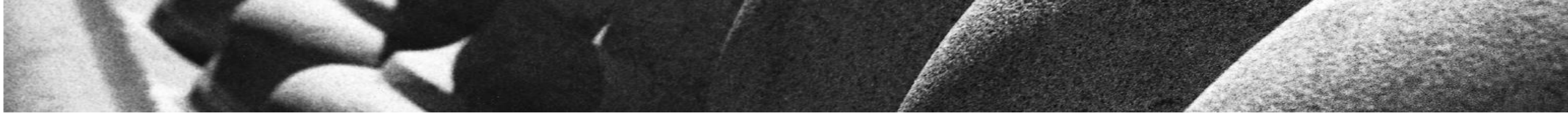
Rate Payer Impact Analysis -- Summary

Scenario	Zone K	Zone J	G-J	Total
2015-2016				
K, G-J - Full	$ 182.3	$ -	$ (113.0)	$ 69.3
K,G-J - Partial	$ 89.8	$ -	$ (69.5)	$ 20.2
2016-2017				
K, G-J - Full	$ 179.3	$ (10.2)	$ (98.6)	$ 70.5
K, G-J - Partial	$ 85.0	$ (10.2)	$ (58.2)	$ 16.5

Note: Due to rounding, row total values reported may not sum to total of row values. Positive values reflect an increase in consumer costs.

Bottled Zone K Approach — Overview

Another approach to adjusting LCRs to address potential anomalies in the capacity market design would be to treat Zone K capacity as within the G-J Zone, but bottled in Zone K by a transfer limit, so that up to a specified number of megawatts of Zone K capacity would count as G-J capacity, with no changes in LCRs.

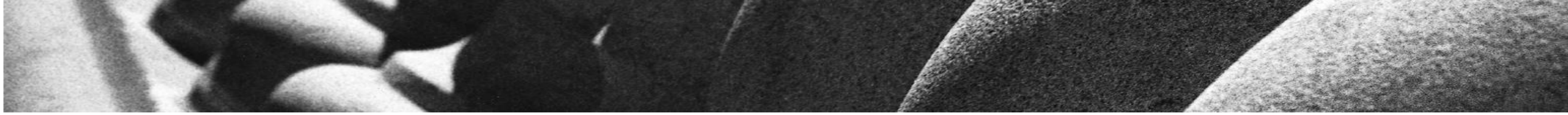


Bottled Zone K Approach Overview

This approach would not change LCRs.

- Some Zone K capacity above the Zone K target would count against the G-J capacity target, i.e. would be included in G-J supply in the spot auction.
- If the excess Zone K supply exceeded the quantity of Zone K capacity allowed to participate in the G-J zone, all Zone K supply would be bottled and settle at the Zone K price.
- If the excess Zone K supply were less than the amount able to participate in the G-J zone, the Zone K clearing price would cascade up to the G-J clearing price.

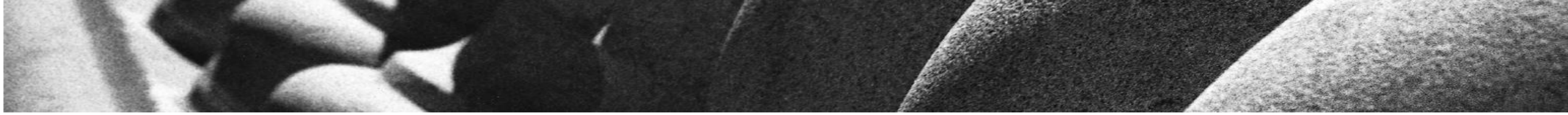
FTI



Bottled Zone K Approach — Production Cost Savings

The bottled Zone K approach will always either produce production cost savings relative to the current design (if there were a surplus of Zone K capacity) or have no impact (if the level of Zone K capacity were below the target quantity).

- Because the bottled Zone K approach would be market based, it would send a price signal that would support efficient outcomes regardless of which regions could provide the lowest cost capacity.



Bottled Zone K Approach — Consumer Impact

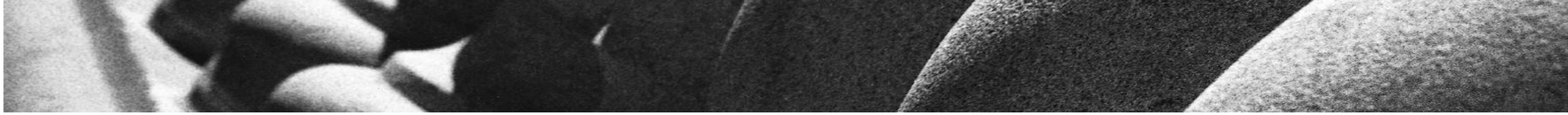
The bottled Zone K approach would have reduced aggregate rate payer costs in every month given the historical excess Zone K supply.

- Overall ratepayer costs would have been reduced by $98.5 million over the 2015-2016 simulated capability year.

Bottled Zone K Approach — Regional Incidence

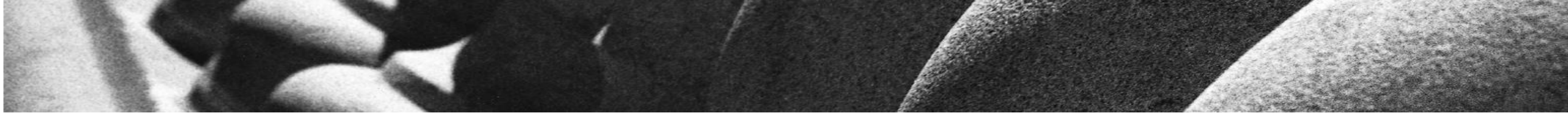
There would be more than one way to allocate capacity market costs to Zone K and G-J consumers under such a design for clearing the Zone K and G–J spot capacity markets.

- One approach would be to simply include the excess Zone K capacity in G-J supply in the spot auction, with the excess Zone K capacity purchased by Zone K load. G–J load would bear no costs for the excess Zone K capacity cleared against the G-J demand curve.
- Another approach would be for G-J load to pay the difference between the G-J spot auction price and the Zone K spot auction price for the excess Zone K capacity, with this payment reducing the capacity market costs of Zone K load.



Bottled Zone K Approach — Regional Incidence

- If the benefit to G-J consumers was shared with Zone K consumers, there would be a benefit to consumers in Zones, G, H, I, J and K.
  - It is estimated that most of the benefit, $77.5 million, or $17,581 per megawatt year of peak load would have flowed to Zone G, H, and I consumers, another $19.5 million would have flowed to Zone J consumers.
  - If the difference between the Zone K and Lower Hudson Valley capacity prices flowed to Zone K consumers, this would have reduced Zone K costs by $1.4 million or $259 per megawatt of peak load.
- If the surplus capacity in Zone K was less than the limit on transfers (300 megawatts in the FTI calculations), the benefit to Zone G-J consumers would be reduced and there would likely be an increased capacity market cost to Zone K consumers.



Cost Allocation

Another consideration in assessments of the long run impact of modifications to LCRs is the impact on cost allocation design.

- Under the current design the higher cost of capacity built in J, K or G-J relative to the cost of NYCA capacity is borne by the rate payers within each region.
- If the NYISO shifts LCRs across regions to minimize overall production costs, the current rules that implicitly allocate capacity cost to the rate payers in the region in which the capacity is located may not be appropriate, perhaps requiring changes in the way capacity costs are allocated across regions.

Cost Shift Approach

Another approach to shifting the rate impact of adding capacity in the new G-J Zone would be to shift a portion of the obligation to buy G-J and NYCA capacity between Zone K load and Zone G-J load, while leaving LCRs unchanged.

- Under this approach, Zone K load would buy some G–J capacity and less rest of state NYCA capacity, and G-J load would buy less G-J capacity and more rest of state NYCA capacity.
- The effect would be to shift some capacity cost from Zones G-J to Zone K; overall consumer capacity costs would not change.
- For example, Zone K load could be obligated to meet 4% of its capacity market obligation with G–J capacity, i.e. 4% out of the 117% would be met with G-J capacity rather than NYCA capacity.

Cost Shift Approach

In our illustrative calculations, a 4% shift would have:

- Increased the capacity costs allocated to Zone K load by $10.5 million (3.3%).
- Reduced the capacity costs allocated to Central Hudson by $2.1 million (2.74%), to Con Ed by $5.5 million (.39%), to NYSEG by $.7 million (.59%) and to O&R by $2.2 million (2.80%), with the benefit allocated to GHI load.
- If the rate benefit were allocated to G-J load, much more of the benefits would have flowed to Con Ed ($8.8 million) and the rate benefits to Central Hudson would have been much lower ($.7 million).

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Summary

	Increase Zone K LCR	Bottled Zone K	Cost Shift from GHI to Zone K
Description	Increase Zone K LCR, decrease G-J LCR	Excess capacity cleared in Zone K included in G-J supply up to limit	Zone K allocated portion of G-J cost and less ROS cost; reverse for G-J
Capacity Production Cost Impact	Substantial decrease, based on net CONE or auction price proxy	Decrease or neutral; gives correct price signal	None
Total Consumer Cost Impact	Estimate substantial short-run increase	Estimate substantial short-run decrease	None
Regional Cost Impact	Increase for Zone K greater than decrease for G-J; impact on CH small, relatively	Decrease for G-J and small reduction for Zone K; possibility of increase in K price	Decrease for G-I depends on whether reduction shared with J; increase for Zone K

Note: These alternatives may warrant a different cost allocation construct.

Appendix – General Methodology

Approach to Capacity Price Estimation

For this study we estimated changes in NYISO capacity prices resulting from hypothetical changes in the demand or supply for capacity in the NYISO spot auctions for each capacity zone for each month of the Summer 2015 and Winter 2015-2016 capability periods.

- The focus was on price changes resulting from shifts in the demand curves for Zone K, G-J capacity due to proposed changes in the LCRs for these zones.
- Capacity supply was assumed to be inelastic in the spot auctions; a few model runs explored sensitivity to changes in the assumed quantity of cleared supply.

The estimated capacity prices with the changes in LCRS, are compared to actual spot prices through November 2015; for the remainder of the 2015-2016 winter period, the comparison is to FTI estimates of clearing prices absent the LCR changes.

Supply Assumptions

- Summer 2015 months and November 2015 use actual cleared capacity.
- Winter 2015-16 months, other than November 2015, use the actual cleared capacity from the corresponding month in the Winter 2014-15 capability period, with the following adjustments:
    - Previous year's quantity is multiplied by the ratio (1-2015 Derate)/(1-2014 Derate)
    - Additional 161.118 UCAP MW added to J, G-J and NYCA (Astoria)
    - Additional 520 MW UCAP added to G-J and NYCA (general missing capacity)
    - 230 MW UCAP subtracted from NYCA (ROS import reduction)

Appendix – K and G-J Changes

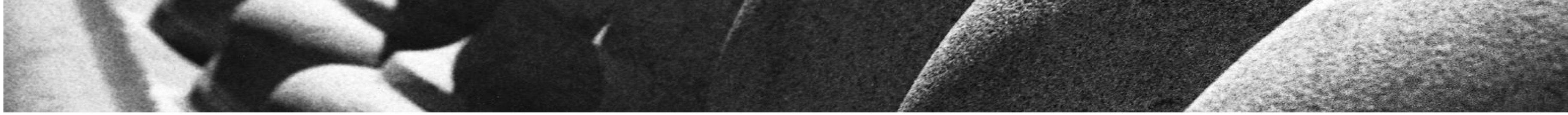
2015-2016 LCRS

LCRs – Actual and Hypothetical 2015-2016

- The NYISO provided estimates of the 2015-2016 LCR changes resulting from adding 300 MW of Zone K ICAP to the Zone K LCR, representing the availability of Zone K exports to satisfy capacity requirements outside of Zone K.
- The summer UCAP quantities calculated for each region for these LCR changes were held constant through each month of the analysis.

LCRs

Zone	2015/2016 LCR	New LCR (Summer)	Resulting UCAP MW Change	New LCR (Winter)
NYCA	117.00%	117.00%	0.00	117.00%
G-J	90.50%	88.30%	-338.74	88.24%
J	83.50%	83.50%	0.00	83.50%
K	103.50%	108.92%	276.71	108.99%



LCR Shift Analysis: K and G-J – Full Shift

Summary Table: Impact of Including 300 MW LI Export in Zone K LCR on Spot Auction Load Payments

Period	Region	Clearing Price ($/kW-Month)	LCR Adjusted Clearing Price ($/kW-Month)	Total Payments by Load $	New Total Payments by Load $	Difference in Load Payments (positive represents increase)
Summer 2015 Capability Period						
May 2015	J	$16.04	$16.04	$154,399,436	$154,399,436	$0
	K	$5.78	$8.37	$32,432,736	$46,965,744	$14,533,008
	GHIJ	$10.93	$8.68	$50,984,078	$40,488,728	-$10,495,350
	ROS	$4.07	$4.07	$75,505,826	$75,505,826	$0
	State Total					***$4,037,658***
June 2015	J	$15.41	$15.41	$149,130,275	$149,130,275	$0
	K	$5.77	$8.36	$32,381,817	$46,917,156	$14,535,339
	GHIJ	$10.56	$8.31	$49,320,480	$38,811,855	-$10,508,625
	ROS	$4.88	$4.88	$88,512,464	$88,512,464	$0
	State Total					***$4,026,714***
July 2015	J	$15.26	$15.26	$147,864,822	$147,864,822	$0
	K	$5.77	$8.35	$32,385,279	$46,866,045	$14,480,766
	GHIJ	$8.36	$6.06	$41,861,864	$30,344,844	-$11,517,020
	ROS	$3.98	$3.98	$72,359,186	$72,359,186	$0
	State Total					***$2,963,746***
Aug. 2015	J	$15.32	$15.32	$148,377,264	$148,377,264	$0
	K	$5.77	$8.36	$32,380,086	$46,914,648	$14,534,562
	GHIJ	$8.32	$6.02	$41,752,256	$30,210,166	-$11,542,090
	ROS	$3.58	$3.58	$65,690,852	$65,690,852	$0
	State Total					***$2,992,472***
Sept. 2015	J	$15.26	$15.26	$147,864,822	$147,864,822	$0
	K	$5.62	$8.21	$31,633,294	$46,211,627	$14,578,333
	GHIJ	$8.28	$5.97	$41,578,848	$29,978,952	-$11,599,896
	ROS	$3.48	$3.48	$63,935,604	$63,935,604	$0
	State Total					***$2,978,437***
Oct. 2015	J	$15.01	$15.01	$145,751,603	$145,751,603	$0
	K	$5.61	$8.20	$31,582,617	$46,163,540	$14,580,923
	GHIJ	$8.13	$5.82	$40,841,868	$29,237,352	-$11,604,516
	ROS	$2.96	$2.96	$54,979,336	$54,979,336	$0
	State Total					***$2,976,407***

Period	Region	Clearing Price ($/kW-Month)	LCR Adjusted Clearing Price ($/kW-Month)	Total Payments by Load $	New Total Payments by Load $	Difference in Load Payments (positive represents increase)
Winter 2015 Capability Period						
Nov. 2015	J	$6.36	$6.36	$63,848,040	$63,848,040	$0
	K	$1.82	$4.68	$10,852,296	$27,905,904	$17,053,608
	GHIJ	$3.46	$0.88	$17,339,444	$4,410,032	-$12,929,412
	ROS	$0.46	$0.46	$8,643,216	$8,643,216	$0
	State Total					***$4,124,196***
Dec. 2015	J	$6.78	$6.78	$67,846,381	$67,846,381	$0
	K	$2.34	$4.52	$13,995,662	$27,034,356	$13,038,694
	GHIJ	$3.51	$2.34	$17,680,268	$11,786,846	-$5,893,423
	ROS	$2.34	$2.34	$42,044,593	$42,044,593	$0
	State Total					***$7,145,271***
Jan. 2016	J	$6.70	$6.70	$67,085,630	$67,085,630	$0
	K	$1.87	$4.73	$11,140,977	$28,180,119	$17,039,141
	GHIJ	$2.49	$1.20	$12,907,555	$6,220,509	-$6,687,047
	ROS	$1.20	$1.20	$21,997,293	$21,997,293	$0
	State Total					***$10,352,095***
Feb. 2016	J	$6.86	$6.86	$68,607,476	$68,607,476	$0
	K	$2.19	$4.45	$13,113,711	$26,646,581	$13,532,870
	GHIJ	$2.95	$2.19	$15,123,604	$11,227,353	-$3,896,250
	ROS	$2.19	$2.19	$39,288,054	$39,288,054	$0
	State Total					***$9,636,620***
Mar. 2016	J	$5.05	$5.05	$51,199,206	$51,199,206	$0
	K	$1.52	$4.39	$9,112,006	$26,316,912	$17,204,906
	GHIJ	$1.63	$0.00	$8,453,533	$0	-$8,453,533
	ROS	$0.00	$0.00	$0	$0	$0
	State Total					***$8,751,374***
April 2016	J	$5.07	$5.07	$51,392,893	$51,392,893	$0
	K	$1.57	$4.44	$9,403,489	$26,593,307	$17,189,818
	GHIJ	$1.52	$0.00	$7,910,154	$0	-$7,910,154
	ROS	$0.00	$0.00	$0	$0	$0
	State Total					***$9,279,664***
May 2015 - April 2016	J			$1,263,367,847	$1,263,367,847	$0
	K			$260,413,970	$442,715,939	$182,301,969
	GHIJ			$345,753,952	$232,716,636	-$113,037,315
	ROS			$532,956,424	$532,956,424	$0
	State Total					***$69,264,653***

Shaded cells indicate months with an increase in rate payer costs. Underlined prices are set by cascading; i.e., they are higher due to a floor price set by a larger region

LCR Shift Analysis: K and G-J - May

TABLE 1: NYISO ICAP and UCAP Calculations
Summer 2015 Demand Curve

Region	Capability Period	Forecasted Peak Load MW	Requirement %	Derating Factor %	ICAP MW Requirement	UCAP MW Requirement	UCAP Effective %
NYCA	Summer 2015	33567.30	117.00%	8.54%	39273.74	35919.76	107.01%
G-J	Summer 2015	16340.00	90.50%	5.77%	14787.70	13934.45	85.28%
J	Summer 2015	11929.40	83.50%	6.92%	9961.05	9271.74	77.72%
K	Summer 2015	5539.00	103.50%	7.83%	5732.87	5283.98	95.40%

TABLE 2: Summer 2015 Demand Curve and Results for May 2015 Spot Auction

Region	Capability Period	UCAP Requirement	Demand Curve Zero Crossing %	UCAP at $0	Reference Price ($/UCAP)	Demand Curve Slope (UCAP $/kW-Month per MW)	Demand Curve Kink Point ($/UCAP)	Demand Curve Kink Point (MW)	Δ Zero Crossing Point and MW Cleared	May 2015 Clearing Price ($/kW-Month)	May 2015 Total MW Cleared
NYCA	Summer 2015	35919.76	112.00%	40230.14	$9.87	-$0.00229	$15.08	33644.48	1776.64	$4.07	38453.50
G-J	Summer 2015	13934.45	115.00%	16024.62	$13.17	-$0.00630	$20.40	12787.00	1734.12	$10.93	14290.50
J	Summer 2015	9271.74	118.00%	10940.66	$20.36	-$0.01220	$28.71	8587.29	1314.76	$16.04	9625.90
K	Summer 2015	5283.98	118.00%	6235.10	$8.81	-$0.00926	$23.15	3735.85	623.90	$5.78	5611.20

TABLE 3: NYISO ICAP and UCAP Calculations with New LCR Percentages for LHV and Zone K
Summer 2015

Region	Capability Period	Forecasted Peak Load MW	Requirement %	Derating Factor %	ICAP MW Requirement	UCAP MW Requirement	UCAP Effective %	Change in ICAP MW Requirement from New LCR	Change in UCAP MW Requirement from New LCR
NYCA	Summer 2015	33567.30	117.00%	8.54%	39273.74	35919.76	107.01%	0.00	0.00
G-J	Summer 2015	16340.00	88.30%	5.77%	14428.22	13595.71	83.21%	-359.48	-338.74
J	Summer 2015	11929.40	83.50%	6.92%	9961.05	9271.74	77.72%	0.00	0.00
K	Summer 2015	5539.00	108.92%	7.83%	6033.08	5560.69	100.39%	300.21	276.71

TABLE 4: Summer 2015 Demand Curve with New LCR Percentages and Imputed Prices for May 2015 Spot Auction
(Impact of Including 300 MW LI Export in Zone K LCR)
Only LHV LCR Reduced

Region	Capability Period	UCAP Requirement	Demand Curve Zero Crossing %	UCAP at $0	Reference Points ($/UCAP)	Demand Curve Slope (UCAP $/kW-Month per MW)	Demand Curve Kink Point ($/UCAP)	Demand Curve Kink Point (MW)	Δ Zero Crossing Point and MW Cleared	Clearing Price Estimate	Clearing Price Estimate (Rounded)	Clearing Price Estimate (Cascaded)	Total MW Cleared
NYCA	Summer 2015	35919.76	112.00%	40230.14	$9.87	-$0.00229	$15.08	33644.48	1776.64	$4.07	$4.07	$4.07	38453.50
G-J	Summer 2015	13595.71	115.00%	15635.07	$13.17	-$0.00646	$20.40	12476.16	1344.57	$8.68	$8.68	$8.68	14290.50
J	Summer 2015	9271.74	118.00%	10940.66	$20.36	-$0.01220	$28.71	8587.29	1314.76	$16.04	$16.04	$16.04	9625.90
K	Summer 2015	5560.69	118.00%	6561.61	$8.81	-$0.00880	$23.15	3931.49	950.41	$8.37	$8.37	$8.37	5611.20

TABLE 5: Estimated Impact on Load Payments for May 2015 Spot Auction -- All Load Capacity Requirements Valued at Spot Price
(Impact of Including 300 MW LI Export in Zone K LCR)
Only LHV LCR Reduced

Region	Capability Period	Total MW Cleared	Actual 2015 Price $/kw-Month	Total Payments by Load $	New Clearing Price Estimate $/kw-Month	New Total Payments by Load $	Difference in Load Payments (positive represents increase)	% Change in Load Payments	Δ Clearing Price $/kW-Month (new - old)
J	Summer 2015	9625.90	$16.04	$154,399,436.00	$16.04	$154,399,436.00	$0.00	0%	$0.00
K	Summer 2015	5611.20	$5.78	$32,432,736.00	$8.37	$46,965,744.00	$14,533,008.00	45%	$2.59
GHIJ	Summer 2015	4664.60	$10.93	$50,984,078.00	$8.68	$40,488,728.00	-$10,495,350.00	-21%	-$2.25
ROS	Summer 2015	18551.80	$4.07	$75,505,826.00	$4.07	$75,505,826.00	$0.00	0%	$0.00
							$4,037,658.00		

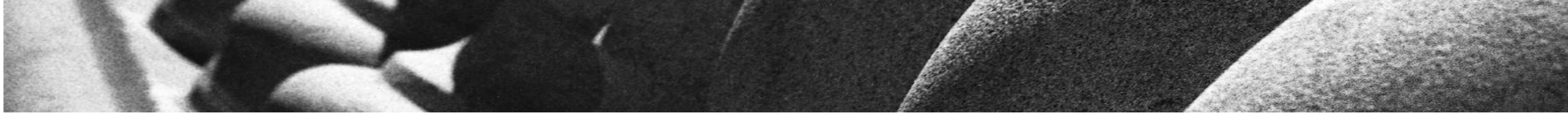
LCR Shift Analysis: K and G-J – Partial Shift

Summary Table: Impact of Including 300 MW LI Export in Zone K LCR on Spot Auction Load Payments

Period	Region	Clearing Price ($/kW-Month)	LCR Adjusted Clearing Price ($/kW-Month)	Total Payments by Load $	New Total Payments by Load $	Difference in Load Payments (positive represents increase)
Summer 2015 Capability Period						
May 2015	J	$16.04	$16.04	$154,399,436	$154,399,436	$0
	K	$5.78	$7.11	$32,432,736	$39,895,632	$7,462,896
	GHIJ	$10.93	$9.82	$50,984,078	$45,806,372	-$5,177,706
	ROS	$4.07	$4.07	$75,505,826	$75,505,826	$0
	State Total					***$2,285,190***
June 2015	J	$15.41	$15.41	$149,130,275	$149,130,275	$0
	K	$5.77	$7.10	$32,381,817	$39,845,910	$7,464,093
	GHIJ	$10.56	$9.45	$49,320,480	$44,136,225	-$5,184,255
	ROS	$4.88	$4.88	$88,512,464	$88,512,464	$0
	State Total					***$2,279,838***
July 2015	J	$15.26	$15.26	$147,864,822	$147,864,822	$0
	K	$5.77	$7.09	$32,385,279	$39,794,043	$7,408,764
	GHIJ	$8.36	$7.23	$41,861,864	$36,203,502	-$5,658,362
	ROS	$3.98	$3.98	$72,359,186	$72,359,186	$0
	State Total					***$1,750,402***
Aug. 2015	J	$15.32	$15.32	$148,377,264	$148,377,264	$0
	K	$5.77	$7.10	$32,380,086	$39,843,780	$7,463,694
	GHIJ	$8.32	$7.18	$41,752,256	$36,031,394	-$5,720,862
	ROS	$3.58	$3.58	$65,690,852	$65,690,852	$0
	State Total					***$1,742,832***
Sept. 2015	J	$15.26	$15.26	$147,864,822	$147,864,822	$0
	K	$5.62	$6.95	$31,633,294	$39,119,465	$7,486,171
	GHIJ	$8.28	$7.13	$41,578,848	$35,804,008	-$5,774,840
	ROS	$3.48	$3.48	$63,935,604	$63,935,604	$0
	State Total					***$1,711,331***
Oct. 2015	J	$15.01	$15.01	$145,751,603	$145,751,603	$0
	K	$5.61	$6.94	$31,582,617	$39,070,118	$7,487,501
	GHIJ	$8.13	$6.99	$40,841,868	$35,114,964	-$5,726,904
	ROS	$2.96	$2.96	$54,979,336	$54,979,336	$0
	State Total					***$1,760,597***

Period	Region	Clearing Price ($/kW-Month)	LCR Adjusted Clearing Price ($/kW-Month)	Total Payments by Load $	New Total Payments by Load $	Difference in Load Payments (positive represents increase)
Winter 2015 Capability Period						
Nov. 2015	J	$6.36	$6.36	$63,848,040	$63,848,040	$0
	K	$1.82	$3.29	$10,852,296	$19,617,612	$8,765,316
	GHIJ	$3.46	$2.19	$17,339,444	$10,974,966	-$6,364,478
	ROS	$0.46	$0.46	$8,643,216	$8,643,216	$0
	State Total					***$2,400,838***
Dec. 2015	J	$6.78	$6.78	$67,846,381	$67,846,381	$0
	K	$2.34	$3.12	$13,995,662	$18,660,883	$4,665,221
	GHIJ	$3.51	$2.34	$17,680,268	$11,786,846	-$5,893,423
	ROS	$2.34	$2.34	$42,044,593	$42,044,593	$0
	State Total					***-$1,228,202***
Jan. 2016	J	$6.70	$6.70	$67,085,630	$67,085,630	$0
	K	$1.87	$3.34	$11,140,977	$19,898,858	$8,757,880
	GHIJ	$2.49	$1.20	$12,907,555	$6,220,509	-$6,687,047
	ROS	$1.20	$1.20	$21,997,293	$21,997,293	$0
	State Total					***$2,070,834***
Feb. 2016	J	$6.86	$6.86	$68,607,476	$68,607,476	$0
	K	$2.19	$3.06	$13,113,711	$18,323,267	$5,209,556
	GHIJ	$2.95	$2.19	$15,123,604	$11,227,353	-$3,896,250
	ROS	$2.19	$2.19	$39,288,054	$39,288,054	$0
	State Total					***$1,313,306***
Mar. 2016	J	$5.05	$5.05	$51,199,206	$51,199,206	$0
	K	$1.52	$2.99	$9,112,006	$17,924,275	$8,812,269
	GHIJ	$1.63	$0.33	$8,453,533	$1,711,451	-$6,742,081
	ROS	$0.00	$0.00	$0	$0	$0
	State Total					***$2,070,188***
April 2016	J	$5.07	$5.07	$51,392,893	$51,392,893	$0
	K	$1.57	$3.04	$9,403,489	$18,208,030	$8,804,541
	GHIJ	$1.52	$0.23	$7,910,154	$1,196,931	-$6,713,223
	ROS	$0.00	$0.00	$0	$0	$0
	State Total					***$2,091,318***
May 2015 - April 2016	J			$1,263,367,847	$1,263,367,847	$0
	K			$260,413,970	$350,201,872	$89,787,902
	GHIJ			$345,753,952	$276,214,521	-$69,539,431
	ROS			$532,956,424	$532,956,424	$0
	State Total					***$20,248,471***

Shaded cells indicate months with an increase in rate payer costs. Underlined prices are set by cascading; i.e., they are higher due to a floor price set by a larger region



Appendix – Zone K and G-J Changes

2016-2017 LCRS (PRELIMINARY VERSION)

LCR Shift Analysis: K and G-J – 2016-2017 LCRs

In this analysis the shifts in local UCAP requirements remain at the levels estimated for the summer of 2015, but the preliminary 2016-2017 LCRs were used as the base.

	2015/2016	Preliminary 2016/2017
G-J	90.50%	90.00%
K	103.50%	102.50%
J	83.50%	81.00%
NYCA	117.00%	117.00%

LCR Shift Analysis: K and G-J – Full Shift –2016-2017 LCRs

Summary Table: Impact of Including 300 MW LI Export in Zone K LCR on Spot Auction Load Payments

Period	Region	Clearing Price ($/kW-Month)	LCR Adjusted Clearing Price ($/kW-Month)	Total Payments by Load $	New Total Payments by Load $	Difference in Load Payments (positive represents increase)
Summer 2015 Capability Period						
May 2015	J	$12.42	$12.42	$119,553,678	$119,553,678	$0
	K	$5.27	$7.91	$29,571,024	$44,384,592	$14,813,568
	GHIJ	$10.43	$8.16	$48,651,778	$38,063,136	-$10,588,642
	ROS	$4.07	$4.07	$75,505,826	$75,505,826	$0
	State Total					*$4,224,926*
June 2015	J	$11.77	$11.77	$113,904,175	$113,904,175	$0
	K	$5.26	$7.90	$29,519,646	$44,335,590	$14,815,944
	GHIJ	$10.06	$7.78	$46,985,230	$36,336,490	-$10,648,740
	ROS	$4.88	$4.88	$88,512,464	$88,512,464	$0
	State Total					*$4,167,204*
July 2015	J	$11.61	$11.61	$112,497,417	$112,497,417	$0
	K	$5.26	$7.89	$29,522,802	$44,284,203	$14,761,401
	GHIJ	$7.85	$5.52	$39,308,090	$27,640,848	-$11,667,242
	ROS	$3.98	$3.98	$72,359,186	$72,359,186	$0
	State Total					*$3,094,159*
Aug. 2015	J	$11.67	$11.67	$113,026,284	$113,026,284	$0
	K	$5.27	$7.90	$29,574,186	$44,333,220	$14,759,034
	GHIJ	$7.81	$5.48	$39,192,923	$27,500,284	-$11,692,639
	ROS	$3.58	$3.58	$65,690,852	$65,690,852	$0
	State Total					*$3,066,395*
Sept. 2015	J	$11.61	$11.61	$112,497,417	$112,497,417	$0
	K	$5.11	$7.75	$28,762,657	$43,622,425	$14,859,768
	GHIJ	$7.76	$5.42	$38,967,616	$27,217,072	-$11,750,544
	ROS	$3.48	$3.48	$63,935,604	$63,935,604	$0
	State Total					*$3,109,224*
Oct. 2015	J	$11.35	$11.35	$110,211,905	$110,211,905	$0
	K	$5.10	$7.74	$28,711,470	$43,573,878	$14,862,408
	GHIJ	$7.62	$5.28	$38,279,832	$26,524,608	-$11,755,224
	ROS	$2.96	$2.96	$54,979,336	$54,979,336	$0
	State Total					*$3,107,184*

Period	Region	Clearing Price ($/kW-Month)	LCR Adjusted Clearing Price ($/kW-Month)	Total Payments by Load $	New Total Payments by Load $	Difference in Load Payments (positive represents increase)
Winter 2015 Capability Period						
Nov. 2015	J	$2.90	$2.27	$29,113,100	$22,788,530	-$6,324,570
	K	$1.27	$4.18	$7,572,756	$24,924,504	$17,351,748
	GHIJ	$2.90	$0.46	$14,533,060	$2,305,244	-$12,227,816
	ROS	$0.46	$0.46	$8,643,216	$8,643,216	$0
	State Total					*-$1,200,638*
Dec. 2015	J	$2.95	$2.71	$29,520,181	$27,118,539	-$2,401,642
	K	$2.34	$4.02	$13,995,662	$24,043,830	$10,048,168
	GHIJ	$2.95	$2.34	$14,859,485	$11,786,846	-$3,072,639
	ROS	$2.34	$2.34	$42,044,593	$42,044,593	$0
	State Total					*$4,573,887*
Jan. 2016	J	$2.63	$2.63	$26,333,613	$26,333,613	$0
	K	$1.32	$4.23	$7,864,219	$25,201,248	$17,337,029
	GHIJ	$1.92	$1.20	$9,952,814	$6,220,509	-$3,732,305
	ROS	$1.20	$1.20	$21,997,293	$21,997,293	$0
	State Total					*$13,604,723*
Feb. 2016	J	$2.79	$2.79	$27,903,040	$27,903,040	$0
	K	$2.19	$3.95	$13,113,711	$23,652,583	$10,538,872
	GHIJ	$2.38	$2.19	$12,201,416	$11,227,353	-$974,063
	ROS	$2.19	$2.19	$39,288,054	$39,288,054	$0
	State Total					*$9,564,810*
Mar. 2016	J	$1.06	$0.92	$10,746,764	$9,327,380	-$1,419,384
	K	$0.96	$3.89	$5,754,951	$23,319,542	$17,564,591
	GHIJ	$1.06	$0.00	$5,497,389	$0	-$5,497,389
	ROS	$0.00	$0.00	$0	$0	$0
	State Total					*$10,647,817*
April 2016	J	$0.95	$0.94	$9,629,832	$9,528,465	-$101,367
	K	$1.01	$3.94	$6,049,378	$23,598,565	$17,549,187
	GHIJ	$0.95	$0.00	$4,943,846	$0	-$4,943,846
	ROS	$0.00	$0.00	$0	$0	$0
	State Total					*$12,503,974*
May 2015 - April 2016	J			$814,937,406	$804,690,443	-$10,246,962
	K			$230,012,462	$409,274,180	$179,261,717
	GHIJ			$313,373,479	$214,822,389	-$98,551,089
	ROS			$532,956,424	$532,956,424	$0
	State Total					*$70,463,665*

Shaded cells indicate months with an increase in rate payer costs. Underlined prices are set by cascading; i.e., they are higher due to a floor price set by a larger region

LCR Shift Analysis: K and G-J – May – 2016-2017 LCRs

TABLE 1: NYISO ICAP and UCAP Calculations
Summer 2016 Demand Curve

Region	Capability Period	Forecasted Peak Load MW	Requirement %	Derating Factor %	ICAP MW Requirement	UCAP MW Requirement	UCAP Effective %
NYCA	Summer 2016	33567.30	117.00%	8.54%	39273.74	35919.76	107.01%
G-J	Summer 2016	16340.00	90.00%	5.77%	14706.00	13857.46	84.81%
J	Summer 2016	11929.40	81.00%	6.92%	9662.81	8994.15	75.39%
K	Summer 2016	5539.00	102.50%	7.83%	5677.48	5232.93	94.47%

TABLE 2: Summer 2016 Demand Curve and Results for May 2015 Spot Auction

Region	Capability Period	UCAP Requirement	Demand Curve Zero Crossing %	UCAP at $0	Reference Price ($/UCAP)	Demand Curve Slope (UCAP $/kW-Month per MW)	Demand Curve Kink Point ($/UCAP)	Demand Curve Kink Point (MW)	Δ Zero Crossing Point and MW Cleared	May 2015 Clearing Price ($/kW-Month)	May 2015 Total MW Cleared
NYCA	Summer 2016	35919.76	112.00%	40230.14	$9.87	-$0.00229	$15.08	33644.48	1776.64	$4.07	38453.50
G-J	Summer 2016	13857.46	115.00%	15936.08	$13.17	-$0.00634	$20.40	12716.35	1645.58	$10.43	14290.50
J	Summer 2016	8994.15	118.00%	10613.09	$20.36	-$0.01258	$28.71	8330.19	987.19	$12.42	9625.90
K	Summer 2016	5232.93	118.00%	6174.86	$8.81	-$0.00935	$23.15	3699.76	563.66	$5.27	5611.20

TABLE 3: NYISO ICAP and UCAP Calculations with New LCR Percentages for LHV and Zone K
Summer 2016

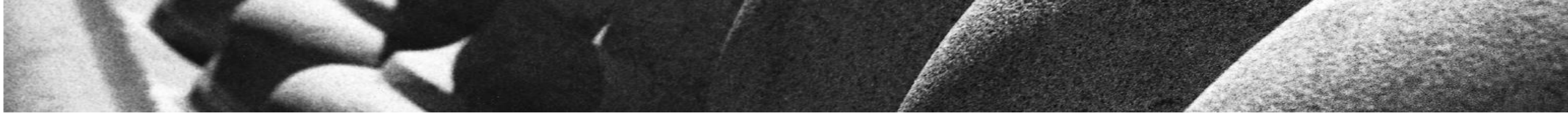
Region	Capability Period	Forecasted Peak Load MW	Requirement %	Derating Factor %	ICAP MW Requirement	UCAP MW Requirement	UCAP Effective %	Change in ICAP MW Requirement from New LCR	Change in UCAP MW Requirement from New LCR
NYCA	Summer 2016	33567.30	117.00%	8.54%	39273.74	35919.76	107.01%	0.00	0.00
G-J	Summer 2016	16340.00	87.80%	5.77%	14346.52	13518.73	82.73%	-359.48	-338.74
J	Summer 2016	11929.40	81.00%	6.92%	9662.81	8994.15	75.39%	0.00	0.00
K	Summer 2016	5539.00	107.92%	7.83%	5977.69	5509.64	99.47%	300.21	276.71

TABLE 4: Summer 2016 Demand Curve with New LCR Percentages and Imputed Prices for May 2015 Spot Auction
(Impact of Including 300 MW LI Export in Zone K LCR)
Only LHV LCR Reduced

Region	Capability Period	UCAP Requirement	Demand Curve Zero Crossing %	UCAP at $0	Reference Points ($/UCAP)	Demand Curve Slope (UCAP $/kW-Month per MW)	Demand Curve Kink Point ($/UCAP)	Demand Curve Kink Point (MW)	Δ Zero Crossing Point and MW Cleared	Clearing Price Estimate	Clearing Price Estimate (Rounded)	Clearing Price Estimate (Cascaded)	Total MW Cleared
NYCA	Summer 2016	35919.76	112.00%	40230.14	$9.87	-$0.00229	$15.08	33644.48	1776.64	$4.07	$4.07	$4.07	38453.50
G-J	Summer 2016	13518.73	115.00%	15546.53	$13.17	-$0.00649	$20.40	12405.51	1256.03	$8.16	$8.16	$8.16	14290.50
J	Summer 2016	8994.15	118.00%	10613.09	$20.36	-$0.01258	$28.71	8330.19	987.19	$12.42	$12.42	$12.42	9625.90
K	Summer 2016	5509.64	118.00%	6501.37	$8.81	-$0.00888	$23.15	3895.39	890.17	$7.91	$7.91	$7.91	5611.20

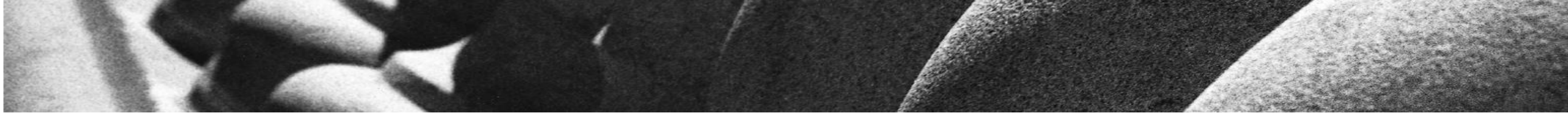
TABLE 5: Estimated Impact on Load Payments for May 2015 Spot Auction -- All Load Capacity Requirements Valued at Spot Price
(Impact of Including 300 MW LI Export in Zone K LCR)
Only LHV LCR Reduced

Region	Capability Period	Total MW Cleared	Actual 2015 Price $/kw-Month	Total Payments by Load $	New Clearing Price Estimate $/kw-Month	New Total Payments by Load $	Difference in Load Payments (positive represents increase)	% Change in Load Payments	Δ Clearing Price $/kW-Month (new - old)
J	Summer 2016	9625.90	$12.42	$119,553,678.00	$12.42	$119,553,678.00	$0.00	0%	$0.00
K	Summer 2016	5611.20	$5.27	$29,571,024.00	$7.91	$44,384,592.00	$14,813,568.00	50%	$2.64
GHIJ	Summer 2016	4664.60	$10.43	$48,651,778.00	$8.16	$38,063,136.00	-$10,588,642.00	-22%	-$2.27
ROS	Summer 2015	18551.80	$4.07	$75,505,826.00	$4.07	$75,505,826.00	$0.00	0%	$0.00
							$4,224,926.00		



Appendix – Bottled K Approach

2015-2016 LCRS



Bottled Zone K Approach

Impact of Additional 300 MW Cleared in Calculating LHV Price

Period	Region	Clearing Price ($/kW-Month)	LCR Adjusted Clearing Price ($/kW-Month)	Total Payments by Load $	Scenario 1: New Total Payments by Load $	Scenario 1: Difference in Load Payments (positive represents increase)	Scenario 2: New Total Payments by Load $	Scenario 2: Difference in Load Payments (positive represents increase)
Summer 2015 Capability Period								
May 2015	J	$16.04	$16.04	$154,399,436	$154,399,436	$0	$154,399,436	$0
	K	$5.78	$5.78	$32,432,736	$32,432,736	$0	$31,454,736	-$978,000
	GHIJ	$10.93	$9.04	$50,984,078	$42,167,984	-$8,816,094	$43,145,984	-$7,838,094
	ROS	$4.07	$4.07	$75,505,826	$75,505,826	$0	$75,505,826	$0
	State Total					***-$8,816,094***		***-$8,816,094***
June 2015	J	$15.41	$15.41	$149,130,275	$149,130,275	$0	$149,130,275	$0
	K	$5.77	$5.77	$32,381,817	$32,381,817	$0	$31,511,817	-$870,000
	GHIJ	$10.56	$8.67	$49,320,480	$40,493,235	-$8,827,245	$41,363,235	-$7,957,245
	ROS	$4.88	$4.88	$88,512,464	$88,512,464	$0	$88,512,464	$0
	State Total					***-$8,827,245***		***-$8,827,245***
July 2015	J	$15.26	$15.26	$147,864,822	$147,864,822	$0	$147,864,822	$0
	K	$5.77	$5.77	$32,385,279	$32,385,279	$0	$32,175,279	-$210,000
	GHIJ	$8.36	$6.47	$41,861,864	$32,397,878	-$9,463,986	$32,607,878	-$9,253,986
	ROS	$3.98	$3.98	$72,359,186	$72,359,186	$0	$72,359,186	$0
	State Total					***-$9,463,986***		***-$9,463,986***
Aug. 2015	J	$15.32	$15.32	$148,377,264	$148,377,264	$0	$148,377,264	$0
	K	$5.77	$5.77	$32,380,086	$32,380,086	$0	$32,182,086	-$198,000
	GHIJ	$8.32	$6.43	$41,752,256	$32,267,669	-$9,484,587	$32,465,669	-$9,286,587
	ROS	$3.58	$3.58	$65,690,852	$65,690,852	$0	$65,690,852	$0
	State Total					***-$9,484,587***		***-$9,484,587***
Sept. 2015	J	$15.26	$15.26	$147,864,822	$147,864,822	$0	$147,864,822	$0
	K	$5.62	$5.62	$31,633,294	$31,633,294	$0	$31,405,294	-$228,000
	GHIJ	$8.28	$6.38	$41,578,848	$32,037,808	-$9,541,040	$32,265,808	-$9,313,040
	ROS	$3.48	$3.48	$63,935,604	$63,935,604	$0	$63,935,604	$0
	State Total					***-$9,541,040***		***-$9,541,040***
Oct. 2015	J	$15.01	$15.01	$145,751,603	$145,751,603	$0	$145,751,603	$0
	K	$5.61	$5.61	$31,582,617	$31,582,617	$0	$31,393,617	-$189,000
	GHIJ	$8.13	$6.24	$40,841,868	$31,347,264	-$9,494,604	$31,536,264	-$9,305,604
	ROS	$2.96	$2.96	$54,979,336	$54,979,336	$0	$54,979,336	$0
	State Total					***-$9,494,604***		***-$9,494,604***

Period	Region	Clearing Price ($/kW-Month)	LCR Adjusted Clearing Price ($/kW-Month)	Total Payments by Load $	Scenario 1: New Total Payments by Load $	Scenario 1: Difference in Load Payments (positive represents increase)	Scenario 2: New Total Payments by Load $	Scenario 2: Difference in Load Payments (positive represents increase)
Winter 2015 Capability Period								
Nov. 2015	J	$6.36	$6.36	$63,848,040	$63,848,040	$0	$63,848,040	$0
	K	$1.82	$1.82	$10,852,296	$10,852,296	$0	$10,960,296	$108,000
	GHIJ	$3.46	$1.46	$17,339,444	$7,316,644	-$10,022,800	$7,208,644	-$10,130,800
	ROS	$0.46	$0.46	$8,643,216	$8,643,216	$0	$8,643,216	$0
	State Total					***-$10,022,800***		***-$10,022,800***
Dec. 2015	J	$6.78	$6.78	$67,846,381	$67,846,381	$0	$67,846,381	$0
	K	$2.34	$2.34	$13,995,662	$13,995,662	$0	$13,995,662	$0
	GHIJ	$3.51	$2.34	$17,680,268	$11,786,846	-$5,893,423	$11,786,846	-$5,893,423
	ROS	$2.34	$2.34	$42,044,593	$42,044,593	$0	$42,044,593	$0
	State Total					***-$5,893,423***		***-$5,893,423***
Jan. 2016	J	$6.70	$6.70	$67,085,630	$67,085,630	$0	$67,085,630	$0
	K	$1.87	$1.87	$11,140,977	$11,140,977	$0	$11,341,977	$201,000
	GHIJ	$2.49	$1.20	$12,907,555	$6,220,509	-$6,687,047	$6,019,509	-$6,888,047
	ROS	$1.20	$1.20	$21,997,293	$21,997,293	$0	$21,997,293	$0
	State Total					***-$6,687,047***		***-$6,687,047***
Feb. 2016	J	$6.86	$6.86	$68,607,476	$68,607,476	$0	$68,607,476	$0
	K	$2.19	$2.19	$13,113,711	$13,113,711	$0	$13,113,711	$0
	GHIJ	$2.95	$2.19	$15,123,604	$11,227,353	-$3,896,250	$11,227,353	-$3,896,250
	ROS	$2.19	$2.19	$39,288,054	$39,288,054	$0	$39,288,054	$0
	State Total					***-$3,896,250***		***-$3,896,250***
Mar. 2016	J	$5.05	$5.05	$51,199,206	$51,199,206	$0	$51,199,206	$0
	K	$1.52	$1.52	$9,112,006	$9,112,006	$0	$9,568,006	$456,000
	GHIJ	$1.63	$0.00	$8,453,533	$0	-$8,453,533	-$456,000	-$8,909,533
	ROS	$0.00	$0.00	$0	$0	$0	$0	$0
	State Total					***-$8,453,533***		***-$8,453,533***
April 2016	J	$5.07	$5.07	$51,392,893	$51,392,893	$0	$51,392,893	$0
	K	$1.57	$1.57	$9,403,489	$9,403,489	$0	$9,874,489	$471,000
	GHIJ	$1.52	$0.00	$7,910,154	$0	-$7,910,154	-$471,000	-$8,381,154
	ROS	$0.00	$0.00	$0	$0	$0	$0	$0
	State Total					***-$7,910,154***		***-$7,910,154***
May 2015 - April 2016	J			$1,263,367,847	$1,263,367,847	$0	$1,263,367,847	$0
	K			$260,413,970	$260,413,970	$0	$258,976,970	-$1,437,000
	GHIJ			$345,753,952	$247,263,189	-$98,490,762	$248,700,189	-$97,053,762
	ROS			$532,956,424	$532,956,424	$0	$532,956,424	$0
	State Total					***-$98,490,762***		***-$98,490,762***

Shaded cells indicate months with an increase in rate payer costs. Underlined prices are set by cascading; i.e., they are higher due to a floor price set by a larger region

Bottled Zone K Approach

TABLE 1: NYISO ICAP and UCAP Calculations

Summer 2015 Demand Curve

Region	Capability Period	Forecasted Peak Load MW	Requirement %	Derating Factor %	ICAP MW Requirement	UCAP MW Requirement	UCAP Effective %
NYCA	Summer 2015	33567.30	117.00%	8.54%	39273.74	35919.76	107.01%
G-J	Summer 2015	16340.00	90.50%	5.77%	14787.70	13934.45	85.28%
J	Summer 2015	11929.40	83.50%	6.92%	9961.05	9271.74	77.72%
K	Summer 2015	5539.00	103.50%	7.83%	5732.87	5283.98	95.40%

TABLE 2: Summer 2015 Demand Curve and Results for May 2015 Spot Auction

Region	Capability Period	UCAP Requirement	Demand Curve Zero Crossing %	UCAP at $0	Reference Price ($/UCAP)	Demand Curve Slope (UCAP $/kW-Month per MW)	Demand Curve Kink Point ($/UCAP)	Demand Curve Kink Point (MW)	Δ Zero Crossing Point and MW Cleared	May 2015 Clearing Price ($/kW-Month)	May 2015 Total MW Cleared	Price Cascaded?
NYCA	Summer 2015	35919.76	112.00%	40230.14	$9.87	-$0.00229	$15.08	33644.48	1776.64	$4.07	38453.50	
G-J	Summer 2015	13934.45	115.00%	16024.62	$13.17	-$0.00630	$20.40	12787.00	1734.12	$10.93	14290.50	NO
J	Summer 2015	9271.74	118.00%	10940.66	$20.36	-$0.01220	$28.71	8587.29	1314.76	$16.04	9625.90	NO
K	Summer 2015	5283.98	118.00%	6235.10	$8.81	-$0.00926	$23.15	3735.85	623.90	$5.78	5611.20	NO

TABLE 3: Zonal Price Calcuations With Additional LHV Cleared MW

May 2015

Region	Capability Period	Forecasted Peak Load MW	Requirement %	Derating Factor %	ICAP MW Requirement	UCAP MW Requirement	UCAP Effective %	May 2015 Excess	May 2015 Total MW Cleared	Change to Cleared MW	Adjusted May 2015 Total MW Cleared	Adjusted Δ Zero Crossing Point and MW Cleared	Adjusted Clearing Price Estimate	Price Cascaded?	Is 300MW constraint binding?
NYCA	Summer 2015	33567.30	117.00%	8.54%	39273.74	35919.76	107.01%	2533.74	38453.50		38453.50	1776.64	$4.07		
G-J	Summer 2015	16340.00	90.50%	5.77%	14787.70	13934.45	85.28%	356.05	14290.50	300.00	14590.50	1434.12	$9.04	NO	YES
J	Summer 2015	11929.40	83.50%	6.92%	9961.05	9271.74	77.72%	354.16	9625.90		9625.90	1314.76	$16.04	NO	
K	Summer 2015	5539.00	103.50%	7.83%	5732.87	5283.98	95.40%	327.22	5611.20		5611.20	623.90	$5.78	NO	

TABLE 5: Estimated Impact on Load Payments for May 2015 Spot Auction -- All Load Capacity Requirements Valued at Spot Price

Impact of Additional 300MW Cleared in Calculating LHV Price

Region	Capability Period	Total MW Cleared	Actual 2015 Price $/kw-Month	Total Payments by Load $	New Clearing Price Estimate $/kw-Month	New Total Payments by Load $ (Scenario 1)	Difference in Load Payments (positive represents increase) (Scenario 1)	Δ Clearing Price $/kW-Month (new - old)	LHV Price - K Price	Load Payments Transferred from LHV to K in Scenario 2	New Total Load Payments $ (Scenario 2)	Difference in Load Payments (positive represents increase) (Scenario 2)
J	Summer 2015	9625.90	$16.04	$154,399,436.00	$16.04	$154,399,436.00	$0.00	$0.00			$154,399,436.00	$0.00
K	Summer 2015	5611.20	$5.78	$32,432,736.00	$5.78	$32,432,736.00	$0.00	$0.00	$3.26	-$978,000.00	$31,454,736.00	-$978,000.00
GHIJ	Summer 2015	4664.60	$10.93	$50,984,078.00	$9.04	$42,167,984.00	-$8,816,094.00	-$1.89	$3.26	$978,000.00	$43,145,984.00	-$7,838,094.00
ROS	Summer 2015	18551.80	$4.07	$75,505,826.00	$4.07	$75,505,826.00	$0.00	$0.00			$75,505,826.00	$0.00
							-$8,816,094.00					-$8,816,094.00

Appendix - Cost Shift Approach

Cost Shift Approach – Benefits to GHI Load

Winter 2015 -2016 Summary of Results : GHI to K Cost Shift

May 2015-April 2016 Summary				
Transmission Owner	Total Cost of Serving Load	Adjusted Total Cost of Serving Load	Change in Cost of Serving Load ($) (Adjusted - Unadjusted)	Change in Cost of Serving Load (%) (Adjusted - Unadjusted)
Central Hudson Gas and Electric	$76,826,429.88	$74,722,148.67	-$2,104,281.21	-2.74%
Consolidated Edison of NY	$1,386,758,066.59	$1,381,294,959.71	-$5,463,106.88	-0.39%
Long Island Power Authority	$317,931,789.61	$328,433,597.00	$10,501,807.39	3.30%
New York Power Authority	$10,933,435.01	$10,933,435.01	$0.00	0.00%
New York State Electric and Gas	$120,476,265.48	$119,760,338.46	-$715,927.02	-0.59%
Niagara Mohawk	$230,894,146.49	$230,894,146.49	$0.00	0.00%
Orange and Rockland Utilities	$81,660,254.41	$79,441,762.14	-$2,218,492.27	-2.72%
Rochester Gas and Electric	$53,737,598.18	$53,737,598.18	$0.00	0.00%
	$2,279,217,985.66	$2,279,217,985.66	$0.00	0.00%

FTI

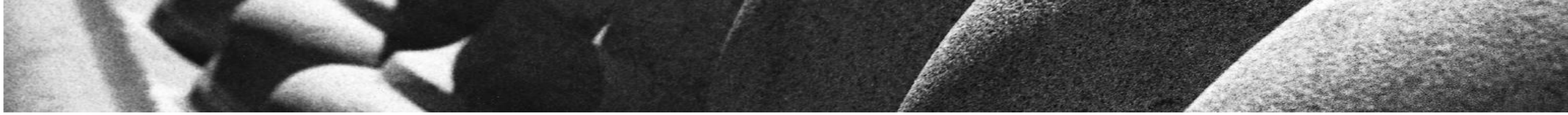
Cost Shift Approach – Benefits all GHIJ Load

Summary of Results : GHIJ to K Cost Shift

May 2015-April 2016 Summary				
Transmission Owner	**Total Cost of Serving Load**	**Adjusted Total Cost of Serving Load**	**Change in Cost of Serving Load ($) (Adjusted - Unadjusted)**	**Change in Cost of Serving Load (%) (Adjusted - Unadjusted)**
Central Hudson Gas and Electric	$76,826,429.88	$76,120,675.01	-$705,754.88	-0.92%
Consolidated Edison of NY	$1,386,758,066.59	$1,377,946,188.96	-$8,811,877.62	-0.64%
Long Island Power Authority	$317,931,789.61	$328,433,597.00	$10,501,807.39	3.30%
New York Power Authority	$10,933,435.01	$10,933,435.01	$0.00	0.00%
New York State Electric and Gas	$120,476,265.48	$120,236,150.71	-$240,114.76	-0.20%
Niagara Mohawk	$230,894,146.49	$230,894,146.49	$0.00	0.00%
Orange and Rockland Utilities	$81,660,254.41	$80,916,194.29	-$744,060.12	-0.91%
Rochester Gas and Electric	$53,737,598.18	$53,737,598.18	$0.00	0.00%
	$2,279,217,985.66	$2,279,217,985.66	$0.00	0.00%

Cost Shift Detail Approach – May 2015

Transmission Owner	Share of Summer 2015 UCAP Requirement	Cleared MW	Clearing Price	Total Cost of Serving Load	Adjusted Proportion of UCAP Requirement	Adjusted Cleared MW	Adjusted Total Cost of Serving Load	Change in Cost of Serving Load (Adjusted - Unadjusted)
G-J								
Central Hudson Gas and Electric	6.72%	960.37	$10.93	$10,496,812.16	6.60%	943.30	$10,310,302.59	-$186,509.57
Consolidated Edison of NY	83.91%	11990.90	$10.93	$131,060,552.59	82.42%	11777.84	$128,731,841.08	-$2,328,711.51
New York State Electric and Gas	2.29%	326.74	$10.93	$3,571,267.66	2.25%	320.93	$3,507,812.63	-$63,455.04
Orange and Rockland Utilities	7.09%	1012.49	$10.93	$11,066,532.59	6.96%	994.50	$10,869,900.11	-$196,632.48
Long Island Power Authority	0.00%	0.00	$10.93	$0.00	1.78%	253.92	$2,775,308.60	$2,775,308.60
TOTAL	**100.00%**	**14290.50**	**$10.93**	**$156,195,165.00**	**100.00%**	**14290.50**	**$156,195,165.00**	**$0.00**
K								
Long Island Power Authority	100.00%	5565.93	$5.78	$32,171,067.61	100.00%	5565.93	$32,171,067.61	$0.00
TOTAL	**100.00%**	**5565.93**	**$5.78**	**$32,171,067.61**	**100.00%**	**5565.93**	**$32,171,067.61**	**$0.00**
J								
Consolidated Edison of NY	100.00%	9625.90	$16.04	$154,399,436.00	100.00%	9625.90	$154,399,436.00	$0.00
TOTAL	**100.00%**	**9625.90**	**$16.04**	**$154,399,436.00**	**100.00%**	**9625.90**	**$154,399,436.00**	**$0.00**
GHI								
Central Hudson Gas and Electric	20.59%	960.37	$10.93	$10,496,812.16	20.22%	943.30	$10,310,302.59	-$186,509.57
Consolidated Edison of NY	50.70%	2365.00	$10.93	$25,849,465.59	46.13%	2151.94	$23,520,754.08	-$2,328,711.51
New York State Electric and Gas	7.00%	326.74	$10.93	$3,571,267.66	6.88%	320.93	$3,507,812.63	-$63,455.04
Orange and Rockland Utilities	21.71%	1012.49	$10.93	$11,066,532.59	21.32%	994.50	$10,869,900.11	-$196,632.48
Long Island Power Authority	0.00%	0.00	$10.93	$0.00	5.44%	253.92	$2,775,308.60	$2,775,308.60
TOTAL	**100.00%**	**4664.60**	**$10.93**	**$50,984,078.00**	**100.00%**	**4664.60**	**$50,984,078.00**	**$0.00**
ROS								
Central Hudson Gas and Electric	1.51%	280.97	$4.07	$1,143,533.17	1.60%	298.03	$1,212,983.67	$69,450.50
Consolidated Edison of NY	20.49%	3809.87	$4.07	$15,506,157.66	21.63%	4022.92	$16,373,299.09	$867,141.43
Long Island Power Authority	4.20%	781.99	$4.07	$3,182,685.93	2.84%	528.07	$2,149,245.31	-$1,033,440.62
New York Power Authority	2.01%	373.22	$4.07	$1,519,025.11	2.01%	373.22	$1,519,025.11	$0.00
New York State Electric and Gas	17.83%	3315.93	$4.07	$13,495,816.22	17.86%	3321.73	$13,519,444.94	$23,628.73
Niagara Mohawk	42.38%	7881.83	$4.07	$32,079,031.60	42.38%	7881.83	$32,079,031.60	$0.00
Orange and Rockland Utilities	1.71%	318.88	$4.07	$1,297,854.89	1.81%	336.87	$1,371,074.86	$73,219.96
Rochester Gas and Electric	9.86%	1834.39	$4.07	$7,465,975.80	9.86%	1834.39	$7,465,975.80	$0.00
TOTAL	**100.00%**	**18597.07**	**$4.07**	**$75,690,080.38**	**100.00%**	**18597.07**	**$75,690,080.38**	**$0.00**
NYCA								
Central Hudson Gas and Electric	3.23%	1241.33		$11,640,345.33	3.23%	1241.33	$11,523,286.26	-$117,059.07
Consolidated Edison of NY	41.09%	15800.77		$195,755,059.25	41.09%	15800.77	$194,293,489.17	-$1,461,570.08
Long Island Power Authority	16.51%	6347.92		$35,353,753.55	16.51%	6347.92	$37,095,621.52	$1,741,867.98
New York Power Authority	0.97%	373.22		$1,519,025.11	0.97%	373.22	$1,519,025.11	$0.00
New York State Electric and Gas	9.47%	3642.67		$17,067,083.88	9.47%	3642.67	$17,027,257.57	-$39,826.31
Niagara Mohawk	20.50%	7881.83		$32,079,031.60	20.50%	7881.83	$32,079,031.60	$0.00
Orange and Rockland Utilities	3.46%	1331.37		$12,364,387.48	3.46%	1331.37	$12,240,974.96	-$123,412.52
Rochester Gas and Electric	4.77%	1834.39		$7,465,975.80	4.77%	1834.39	$7,465,975.80	$0.00
TOTAL	**100.00%**	**38453.50**	**$4.07**	**$313,244,662.00**	**100.00%**	**38453.50**	**$313,244,662.00**	**$0.00**



FTI – Compass Lexecon Electricity Practice

Joseph Cavicchi	Jcavicchi@compasslexecon.com	617-520-4251
Bert Conly	Bert.Conly@fticonsulting.com	214-397-1604
Scott Davido	Scott.Davido@fticonsulting.com	832-667-5124
Scott Harvey	Scott.Harvey@fticonsulting.com	617-747-1864
William Hogan	William_Hogan@harvard.edu	617-495-1317
Joseph Kalt	Jkalt@compasslexecon.com	617-520-0200
Susan Pope	Susan.Pope@fticonsulting.com	617-747-1860
Ellen Smith	Ellen.Smith@fticonsulting.com	617-747-1871
Jeffrey Tranen	Jtranen@compasslexecon.com	212-249-6569
Kevin Wellenius	Kevin.Wellenius@fticonsulting.com	207-495-2999
	Papers at lmpmarketdesign.com	

Exhibit 10

Alternative Methods for Determining LCRs

Michael DeSocio

Senior Manager, Market Design

LCR Task Force

January 14, 2016

Krey Conference Center, NYISO

Background

- NYISO has been considering possible approaches that can be implemented in the near term to ameliorate concerns raised by Central Hudson regarding the methodology the NYISO uses to establish the Locational Minimum Installed Capacity Requirements (LCRs).

- Given the analysis to date, the NYISO has been unable to find a cost effective approach that could be implemented in the near term

Approach Forward

- **The NYISO is currently investigating the various approaches recommended by Potomac Economics in the 2014 State of the Market Report (*See 2014 SOM Page 63*) to develop a comprehensive approach to determining LCRs for any Locality**
  - ***The NYISO will not be attempting to change the IRM methodology itself so that we can develop a solution expeditiously***
- **There are two significant aspects to making any changes to the determination of LCRs**
  1. ***Developing a methodology for determining LCRs based on minimizing total NYCA capacity costs while maintaining minimum reliability criteria***
  2. ***Allocating capacity costs fairly to LSEs***

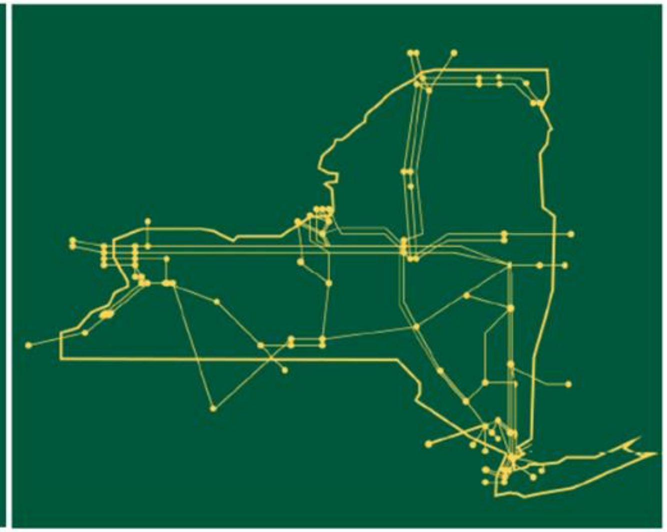
Approach Forward

- The NYISO will be working with its stakeholders to develop a fair and reasonable approach for determining LCRs and determining the associated cost allocation methodology
- The NYISO, with the help of expert consultants, will be analyzing the various variables that impact the problem over the next few months
- Stakeholder discussions will be held in the Installed Capacity Working Group meetings and are expected to begin in Q2 2016

Next Steps

- **January 14, 2016 LCR Task Force**
  - ***Kick off Alternative Method Effort***
- **April – June 2016 ICAP Working Groups**
  - ***Develop and Review Alternative Method***
  - ***Develop associated tariff revisions***
- **July 2016 BIC, OC and MC Meetings**
  - ***Discussion and Vote on Alternative Method***
- **Determine internal process and software changes**
- **If possible, incorporate Alternative Method into the process for determining 2017 LCRs**

The New York Independent System Operator (NYISO) is a not-for-profit corporation responsible for operating the state's bulk electricity grid, administering New York's competitive wholesale electricity markets, conducting comprehensive long-term planning for the state's electric power system, and advancing the technological infrastructure of the electric system serving the Empire State.



www.nyiso.com

Exhibit 11

Alternative Methods for Determining LCRs Update

Bob Logan

Senior Market Design Specialist

ICAPWG

March 24, 2016

Krey Conference Center, NYISO

Background

- **NYISO had been considering possible approaches that can be implemented in the near term to ameliorate concerns raised in discussions with stakeholders regarding the methodology the NYISO uses to establish the Locational Minimum Installed Capacity Requirements (LCRs).**

Approach Forward

- **The NYISO is currently investigating the various approaches based on those recommended by Potomac Economics in the 2014 State of the Market Report (*See 2014 SOM Page 63*) to develop a comprehensive approach to determining LCRs for any Locality**
  - ***The NYISO is considering an approach that does not require a change the IRM methodology, so that it can be implemented expeditiously***
- **There are two significant aspects to making any changes to the determination of LCRs**
  1. ***Developing a methodology for determining LCRs based on minimizing total NYCA capacity costs while maintaining minimum reliability criteria***
  2. ***Allocating capacity costs fairly to LSEs***

Approach Forward

- The NYISO will be working with its stakeholders to develop a fair and reasonable approach for determining LCRs, which would include determining the associated cost allocation methodology
- The NYISO, with the help of expert consultants, will be analyzing the various variables that impact the issue over the next few months
- Stakeholder discussions will be held in joint LCR Task Force and Installed Capacity Working Group meetings and are expected to begin in Q2 2016

Status Update

- **The NYISO has engaged GE to assist in developing a mechanism to determine LCRs**
  - ***GE proposes to develop a tool that will iterate between minimizing cost of capacity supply using an LP optimization and achieving 0.1 LOLE using the traditional MARS tool***
  - ***Timeline for GE to complete the product design, test and provide analysis is approximately 3-4 months***

GE Tool Objectives

- **Least cost distribution of capacity resources amongst NYCA localities**
- **A robust, stable and replicable process**

GE Methodology – 4 Steps

1. Capacity would be removed from Load Zones west of Total East with excess capaxity until the Capability Year's IRMis met.
2. Capacity would be removed from each Locality until the current Capability Year's LCRs, are met.
3. The MW of each Locality's ICAP Demand Curve proxy unit would be added to each Locality. In the current configuration this would mean adding an approximately 220 MW simple cycle combustion turbine to Zones J and K the unit added to J would satisfy the addition of capacity to both New York City and the G-J Locality and removing 220 MW from west of Total East. This represents the Demand Curve level of excess , and will provide the reference LOLE for the cost minimization.
4. An automated cost minimization would be performed, iteratively shifting capacity from each Locality and in to the zones withexcess in ROS west of Total East until reaching an LOLE less than or equal to the reference LOLE at the least overall cost of capacity

Cost Minimization

Minimize:

$$Cost\ of\ Capacity\ Procurement = \sum_x Q_x \cdot P_x(Q_x) + \sum_y Q_y \cdot P_y\left(Q_y + \sum_z Q_z\right) + \left[(Reserve\ Margin \cdot NYCA\ Coincident\ Peak) - \left(\sum_x Q_x + \sum_y Q_y\right)\right] \cdot P_{NYCA}(Q_{NYCA})$$

Subject to: $LOLE \leq 0.1$

Where:

X= single Load Zone Localities
Y= Locality with multiple Load Zones
Z=Localities contained within another Locality

$$Q_x = LCR_x \cdot Area_x\ Non\ Coincident\ Peak$$

$$Q_y = \left(\begin{matrix} LCR_y \cdot Locality_z \\ Coicident\ Peak \end{matrix}\right) - \sum_z \begin{matrix} LCR_z \cdot Area_z \\ Non\ Coincident\ Peak \end{matrix}$$

$$P_x(Q_x),\ P_y\left(Q_y + \sum_z Q_z\right),\ P_{NYCA}(Q_{NYCA}) = Net\ CONE\ or\ other\ Cost\ Elasticity\ Function$$

Potential Concerns

The NYISO is still evaluating the following potential concerns with the outlined approach:

- Shifting too much capacity into K
- Shifting too much capacity out of J
- Aligning the MARS model with operating characteristics of system
  - *I. e., If 12,000 MW located on LI, then NYISO could not operate the grid*

Next Steps

- March – June Internal Design & Review
  - *Develop the model, test, review results*
- June – August 2016 ICAP Working Groups
  - *Develop and Review Alternative Method*
  - *Develop associated tariff revisions*
- September 2016 BIC, OC and MC Meetings
  - *Discussion and Vote on Alternative Method*
- Determine internal process and software changes
- If possible, incorporate Alternative Method into the process for determining 2017 LCRs
- The NYISO will consider input received during today's meeting
- Stakeholders can also provide additional comments in writing to deckels@nyiso.com

The New York Independent System Operator (NYISO) is a not-for-profit corporation responsible for operating the state's bulk electricity grid, administering New York's competitive wholesale electricity markets, conducting comprehensive long-term planning for the state's electric power system, and advancing the technological infrastructure of the electric system serving the Empire State.

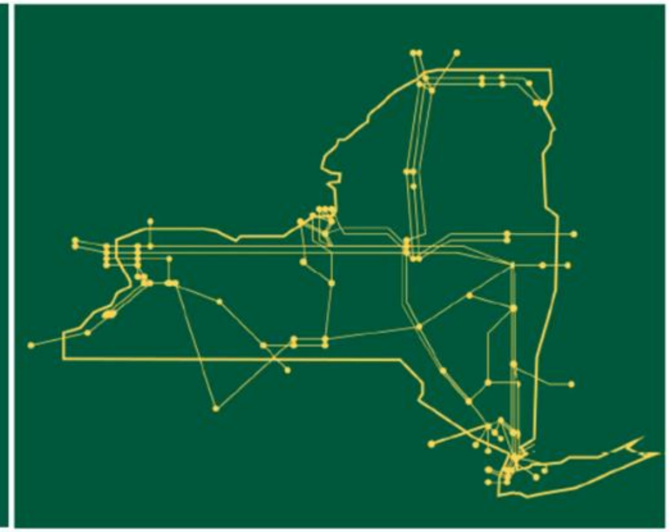


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Exhibit 12

ALTERNATIVES FOR DETERMINING LCRS

PROJECT OBJECTIVES AND UPDATE

AUGUST 23, 2016

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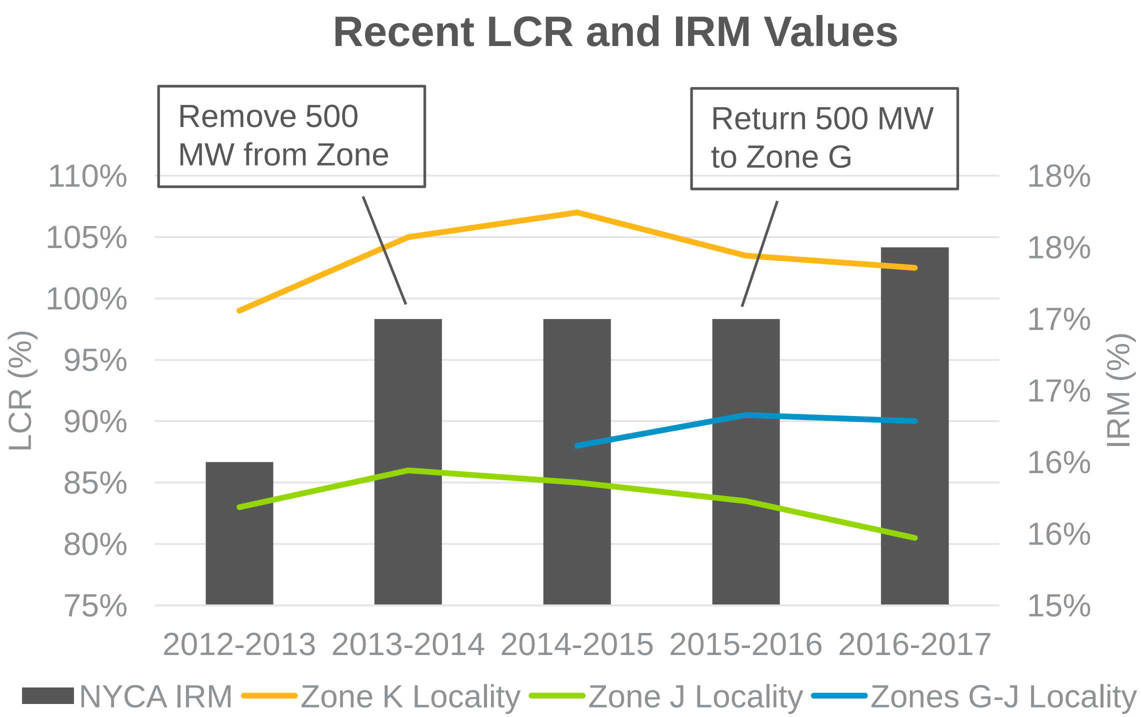
PROJECT PURPOSE & BACKGROUND

LCR methodology not seen as transparent or least cost, and results have been counterintuitive, according to some stakeholders



Source: NYISO LCR Reports

"Setting IRM/LCRs such that the capacity demand curves reflect the marginal reliability value of additional capacity in each locality would provide incentives for more efficient investment, which would lower overall capacity costs." ~Market Monitoring Unit recommendation in 2014 SOM report

PROJECT OBJECTIVES

- Explore alternative methods for calculating LCRs to
  - Improve transparency and market certainty
  - Reduce costs
  - Maintain reliability
- As part of this process, we will explore options with existing method for calculating IRM as well as alternative methods that solve for IRM and LCR simultaneously, working with NYSRC on any potential implications for IRM methodology
- We will also investigate the current state of the MARS model and database to highlight other areas where the methodology or data can be improved that are directly related to the LCR results

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PROJECT TASKS & TENTATIVE SCHEDULE

Task Description	Tentative Schedule
Task 1: Initial Analysis - Compare options that simultaneously solve for LCRs for all 3 Localities to optimize least cost of capacity procurement - Explore options with fixed IRM and co-optimizing IRM and LCRs simultaneously - Explore limitations of MARS model - Stress test methodologies and model	August - September
Task 2: Methodology Proposal Development - Scenarios on 2016 IRM case	September - October
Task 3: Presentation of Draft Proposed Methodology - Results of analysis and comparison to current methodology - Present to ICAPWG, NYSRC-ICS	October
Task 4: Stakeholder Feedback and Iterations	October - November
Task 5: Final Findings	December

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CURRENT STATUS: TASK 1

- Optimizer Tool installed and being tested
  - Iterative wrapper that works with MARS model to minimize cost of capacity procurement where LOLE is 0.1
- Initial test results appear reasonable and stable, testing ongoing, including:
  - Adding/removing capacity in different load zones
  - 2016 IRM case, and will re-run with 2017 IRM case
  - Using current DCR net cone values and proposed 2017 net cone values
  - Other assumptions exploring include MARS interface topology, treatment of emergency assistance, shifting methodology
- What other cases would you the stakeholders like to see run to test that the results are robust, transparent, replicable, and provide a reliable result?
- Next presentation will include initial results, and is tentatively set for the end of September

CONTACTS

AMANVIR CHAHAL
Associate Director
202.481.7319
amanvir.chahal@navigant.com

MAGGIE SHOBER
Managing Consultant
202.481.8684
maggie.shober@navigant.com

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Exhibit 13

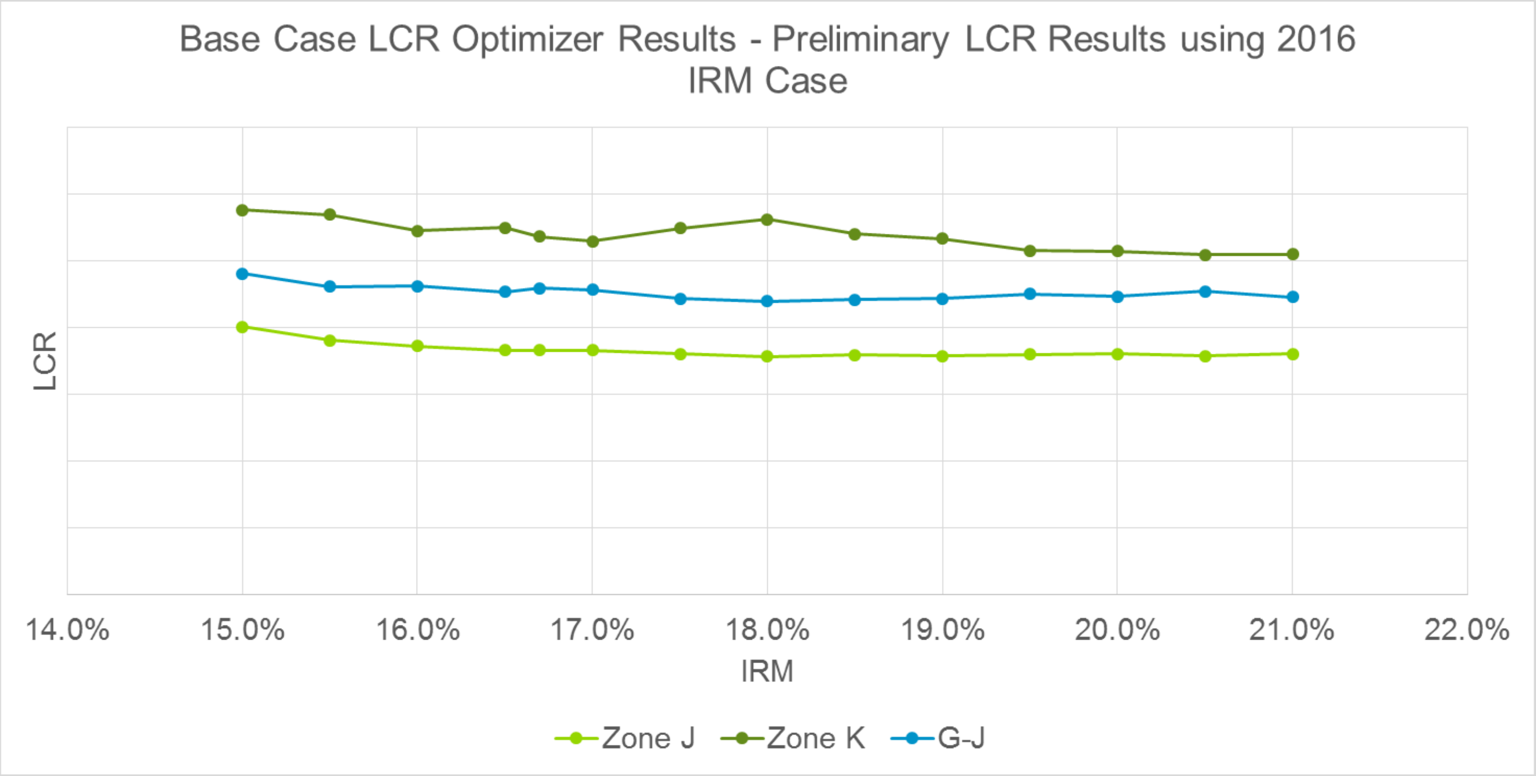
ALTERNATIVES FOR DETERMINING LCRS

PROJECT UPDATE AND INITIAL RESULTS

SEPTEMBER 28, 2016

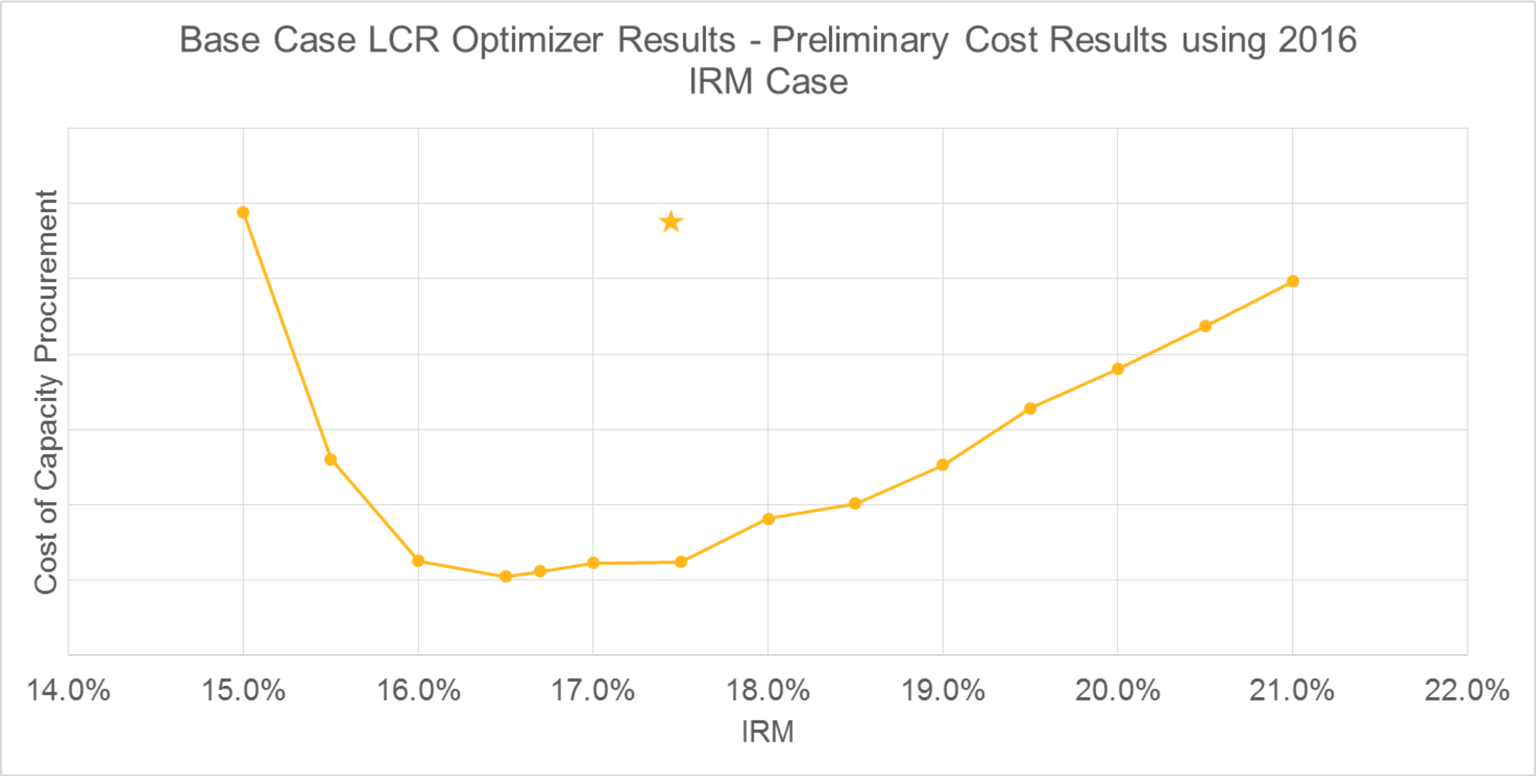
INITIAL RESULTS – COMPARISON WITH 2016 IRM STUDY

- Initial results using the MARS "LCR Optimizer" show stable LCRs as the IRM varies
- Optimizing for IRM and LCRs simultaneously result in IRM of 16.7%



INITIAL RESULTS – COMPARISON WITH 2016 IRM STUDY

- Cost of capacity procurement is lower than Tan45 method
  - Dots show fixed IRM runs, co-optimized IRM is at 16.7%
  - Star shows cost of capacity procurement under 2016 Tan45 method



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INITIAL RESULTS – ADDITIONAL OBSERVATIONS

- The sensitivity of the results to the number of MARS replications was tested, with negligible impact observed

- Zone K and the G-J Locality have a notable range in which they can fall on the total LCR chart without much movement in the total cost to procure capacity

- Additional runs using objective functions beyond limiting the cost to procure capacity may need to be explored

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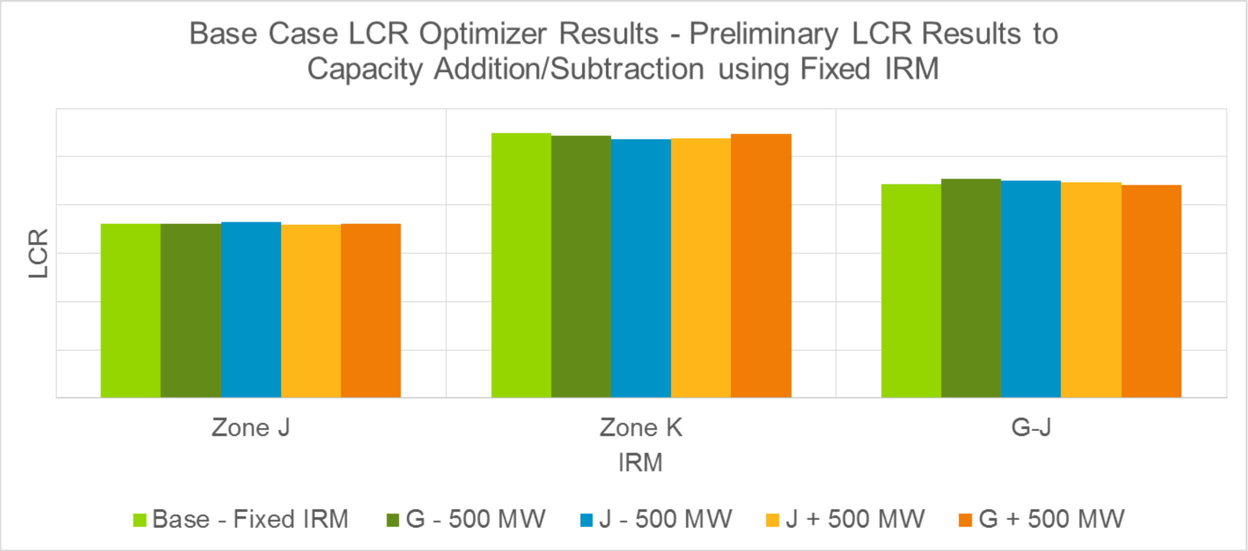
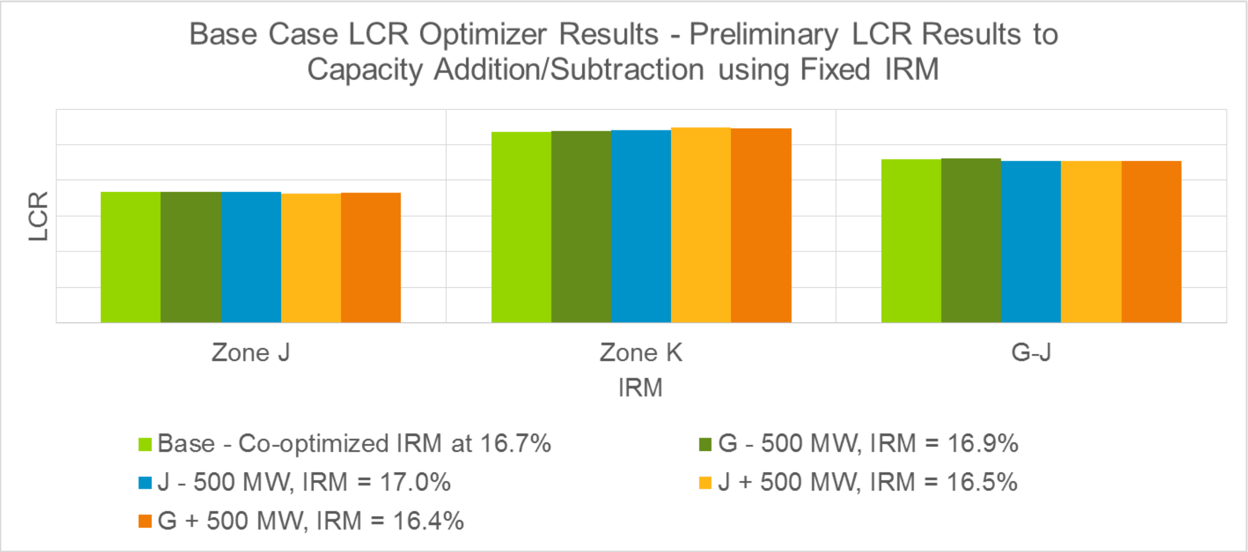
ADDING/SUBTRACTING CAPACITY WITH FIXED IRM

- With a fixed IRM at 17.5%
  - Adding 500 MW to Zone J decreases the LCRs in Zones J and K, increases the LCR in the G-J Locality
  - Adding 500 MW to Zone G decreases the Zone K and the G-J Locality LCRs
  - Removing 500 MW from Zone J increases the LCRs in Zone~~s~~ J and the G-J Locality, decreases LCR in Zone K
  - Removing 500 MW from Zone G increases LCR in the G-J Locality, decreases LCR in Zone K



ADDING/SUBTRACTING CAPACITY WITH CO-OPTIMIZED IRM

- Co-optimizing the IRM adds stability to the results
  - Adding 500 MW to Zone J decreases the IRM and the LCRs in Zones J and the G-J Locality, increases the LCR in Zone K
  - Adding 500 MW to Zone G decreases the IRM and the LCRs in all Localities
  - Removing 500 MW from Zone J increases the IRM and LCRs in Zones J and K, decreasing the LCR in the G-J Locality
  - Removing 500 MW from Zone G increases the IRM and the LCRs in Zones K and the G-J Locality



ADDITIONAL CASES

- Cases currently running:
  - Limited emergency assistance, based on the initial NYISO draft emergency assistance whitepaper proposal
    - NYISO draft is being discussed with ICS in relation to the development of a potential IRM sensitivity run
  - Sensitivity to elasticity of Demand Curve net cost of new entry
  - Lower amount of capacity deliverable into SENY based on interface constraints

- Any additional sensitivities that stakeholders would be interested in need to be submitted as soon as possible and no later than October 3

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PROJECT TASKS & TENTATIVE SCHEDULE

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CONTACTS

AMANVIR CHAHAL
Associate Director
202.481.7319
amanvir.chahal@navigant.com

MAGGIE SHOBER
Associate Director
202.481.8684
maggie.shober@navigant.com

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Exhibit 14

ALTERNATIVES FOR DETERMINING LCRS

PROJECT UPDATE AND RESULTS

OCTOBER 27, 2016

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METHODOLOGY

- Methodology proposes to identify LCRs to provide a least cost distribution of capacity resources amongst NYCA localities
- GE developed a linear program that works with MARS to minimize the cost of capacity procurement while maintaining a LOLE of 0.1 by iteratively spawning MARS runs as the constraint function of proposed problem formulation
- Problem function:
  - Minimize: $Cost\ of\ Capacity\ Procurement = \sum_x Q_x \times P_x + \sum_y Q_y \times P_y + [(Reserve\ Margin \times Pool\ Coincident\ Peak) - (\sum_x Q_x + \sum_y Q_y)] \times P_{ROP}$
  - Subject to: LOLE ≤ 0.1
  - Where:
    - x = Single Area Localities
    - y = Nested Localities
    - z = Single Localities contained within a Nested Locality
    - ROP = Rest of Pool
    - Q_x = LCR_x x $Area_x$ Non Coincident Peak
    - Q_y = (LCR_y x Nested $Locality_z$ Coincident Peak) - $\sum_z$ LCR_z x $Area_z$ Non Coincident Peak
    - P_x, P_y, P_{ROP} = Net CONE or other cost elasticity

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PROJECT OBJECTIVE AND STATUS

- Work with stakeholders to explore the potential to develop a fair and reasonable approach for determining LCRs
- The methodology presented here is different from the Tan45
- The NYISO acknowledges that the current Services Tariff provides that the NYISO is to "determine the amount of Unforced Capacity that must be sited within the NYCA, and within each Locality, and the amount of Unforced Capacity that may be procured from areas External to the NYCA, in a manner consistent with the Reliability Rules"
- This project is exploratory, there are no proposals on the table at the moment

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COST OBJECTIVE

- The Tan45 method minimizes the amount of capacity needed to keep LOLE ≤ 0.1
- The methodology used here minimizes the cost of capacity procurement while keeping LOLE ≤ 0.1
- The cost of capacity procurement is based on net CONE elasticity curves
  - Net CONE elasticity curves = Net CONE +/- 6% LOE

COMPARISON OF SHIFTING METHODS

Current LCR Process (Tan 45)

- Set J and K capacity to their ‘as found’ condition
- Shift capacity from J to zones west of Central-East that have excess capacity until LOLE of 0.1 is violated
- Reset J to ‘as found’ and shift capacity from K to those same zones until LOLE criteria is violated
- Reset K to ‘as found’ and shift from J&K based on their ratios from above two steps
  - This sets the recommendation for the J and K LCRs
- Reset J to ‘as found,’ keep K at the LCR level, and shift capacity from G-J until the LOLE is violated
  - This sets the LCR for the G-J Locality

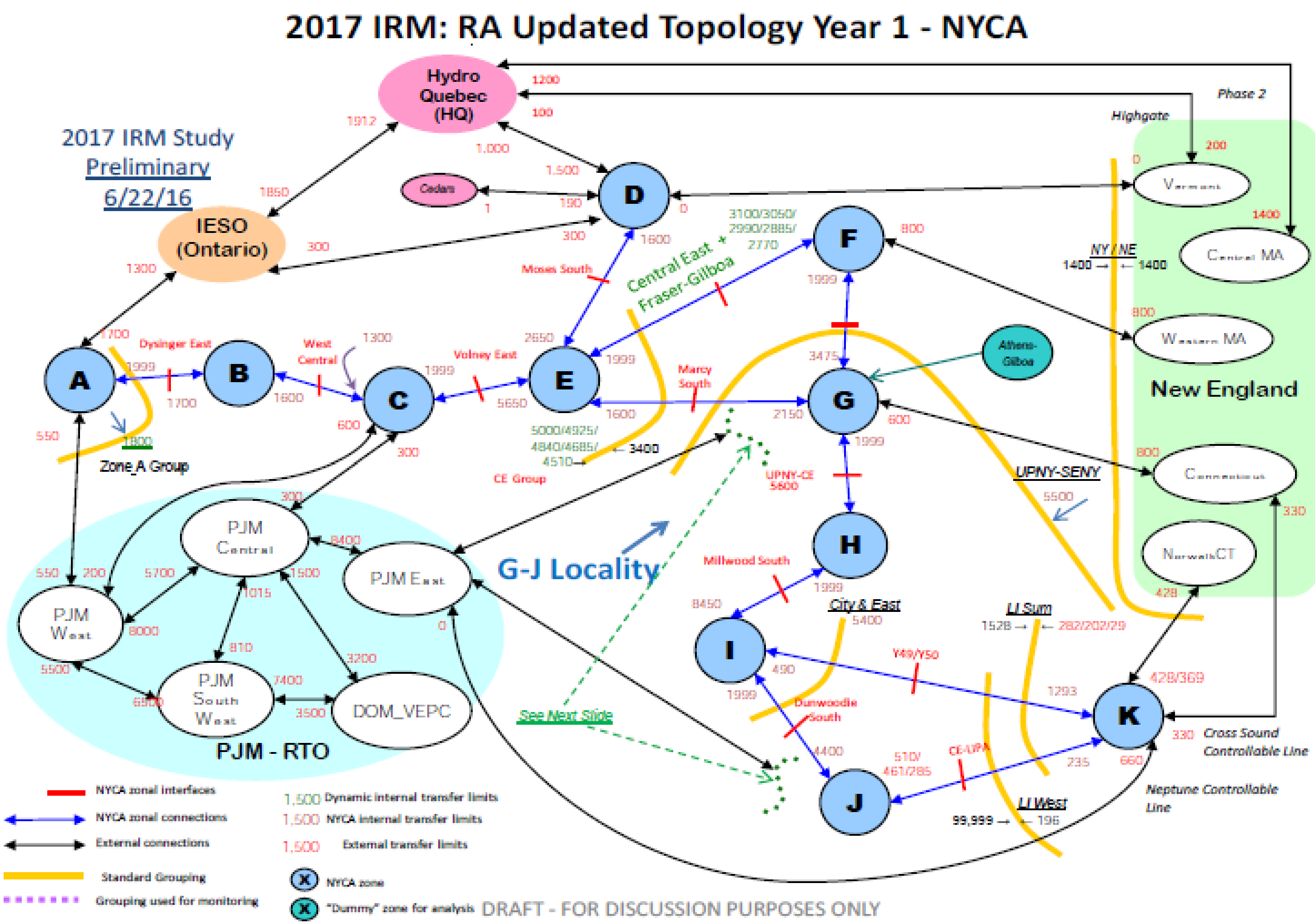
GE MARS Optimizer Tool

- GE developed a python based wrapper around the GE-MARS software to iteratively spawn MARS runs as the constraint function of proposed problem formulation
  - This process shifts capacity from all three localities (J, K, and G-J) simultaneously with the goal of achieving the minimum cost to procure capacity while maintaining a 0.1 LOLE
- This process is repeated until the user specified stopping criteria is met, or a maximum number of iterations have been run
- The current method shifts to zones west of Central-East that have excess capacity, though this can be changed in the future

ASSUMPTIONS

- The preliminary runs use assumptions that might be considered by the NYSRC for the 2017 IRM base case.
- Assumptions include:
  - October 2016 peak Load forecast
  - Generation capacity from 2016 Goldbook
    - 0 MW new non-wind
    - 67.5 MW project related re-ratings
    - 185.4 MW retirements or mothballs
    - 221.1 MW wind capacity additions
  - Interface limits based on 2016: Operating Study, Operations Engineering Voltage Studies, Comprehensive Reliability Plan, and additional analysis including interregional planning initiatives
    - Image on next slide
    - See white paper on Emergency Assistance from August 30, 2016 NYSRC ICS meeting for further detail on interface limit assumptions

INTERFACE LIMITS



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PROJECT TASKS & UPDATED SCHEDULE

Task Description	Tentative Schedule
Task 1: Initial Analysis - Compare options that simultaneously solve for LCRs for all 3 Localities to optimize least cost of capacity procurement - Explore options with fixed IRM and co-optimizing IRM and LCRs simultaneously - Explore limitations of MARS model - Stress test methodologies and model	August - October
Task 2: Methodology Development - Scenarios on 2016 & 2017 IRM cases	September - November
Task 3: Presentation of Draft Methodology - Results of analysis and comparison to current methodology - Present to ICAP, NYSRC-ICS	October - November
Task 4: Stakeholder Feedback and Iterations	October - December
Task 5: Final Findings	December - January

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CONTACTS

AMANVIR CHAHAL
Associate Director
202.481.7319
amanvir.chahal@navigant.com

MAGGIE SHOBER
Associate Director
202.481.8684
maggie.shober@navigant.com

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Exhibit 15

ALTERNATIVES FOR DETERMINING LCRS

PROJECT UPDATE AND RESULTS

NOVEMBER 9, 2016

NAVIGANT

PROJECT OBJECTIVE AND STATUS

- Work with stakeholders to explore the potential to develop a fair and reasonable approach for determining LCRs
- The methodology presented here is different from the Tan45
- The NYISO acknowledges that the current Services Tariff provides that the NYISO is to "determine the amount of Unforced Capacity that must be sited within the NYCA, and within each Locality, and the amount of Unforced Capacity that may be procured from areas External to the NYCA, in a manner consistent with the Reliability Rules"
- This project is exploratory, there are no proposals on the table at the moment

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METHODOLOGY

- Methodology proposes to identify LCRs to provide a least cost distribution of capacity resources amongst NYCA localities
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- Problem function:
  - Minimize: $Cost\ of\ Capacity\ Procurement = \sum_x Q_x \times P_x + \sum_y Q_y \times P_y + [(Reserve\ Margin \times Pool\ Coincident\ Peak) - (\sum_x Q_x + \sum_y Q_y)] \times P_{ROP}$
  - Subject to: LOLE ≤ 0.1
  - Where:
    - x = Single Area Localities
    - y = Nested Localities
    - z = Single Localities contained within a Nested Locality
    - ROP = Rest of Pool
    - Q_x = LCR_x x $Area_x$ Non Coincident Peak
    - Q_y = (LCR_y x Nested $Locality_z$ Coincident Peak) - $\sum_z LCR_z$ x $Area_z$ Non Coincident Peak
    - P_x, P_y, P_{ROP} = Net CONE cost elasticity curve

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COST OBJECTIVE AND NET CONE ELASTICITY CURVES

- The methodology used here minimizes the cost of capacity procurement while keeping LOLE ≤ 0.1
- The cost of capacity procurement is based on net CONE elasticity curves
- Net CONE elasticity curves are derived from level of excess (LOE) calculations during the demand curve reset process
  - Shape of Net CONE elasticity curves from 2013 – 2016 DCR, which were calculated using Net CONE +/- 6% LOE
  - 5-point curve for each Locality, centered around net CONE value from 2017 DCR

SHIFTING METHOD

- This process shifts capacity from all three Localities (J, K, and G-J) simultaneously
- This process is repeated until the user specified stopping criteria is met, or a maximum number of iterations have been run
  - Iteration is the number of times the Optimization tool runs MARS
  - Replication is the number of random draws each MARS iteration uses to come up with a solution
    - Usually a fixed number – we use the same number as the IRM calculation
  - For example: each run of the Optimization tool runs 40 iterations of MARS, so 40 x 2,000 = 80,000 total MARS replications
  - Sensitivity tests confirmed our results
    - Showed no impact on results from additional replications

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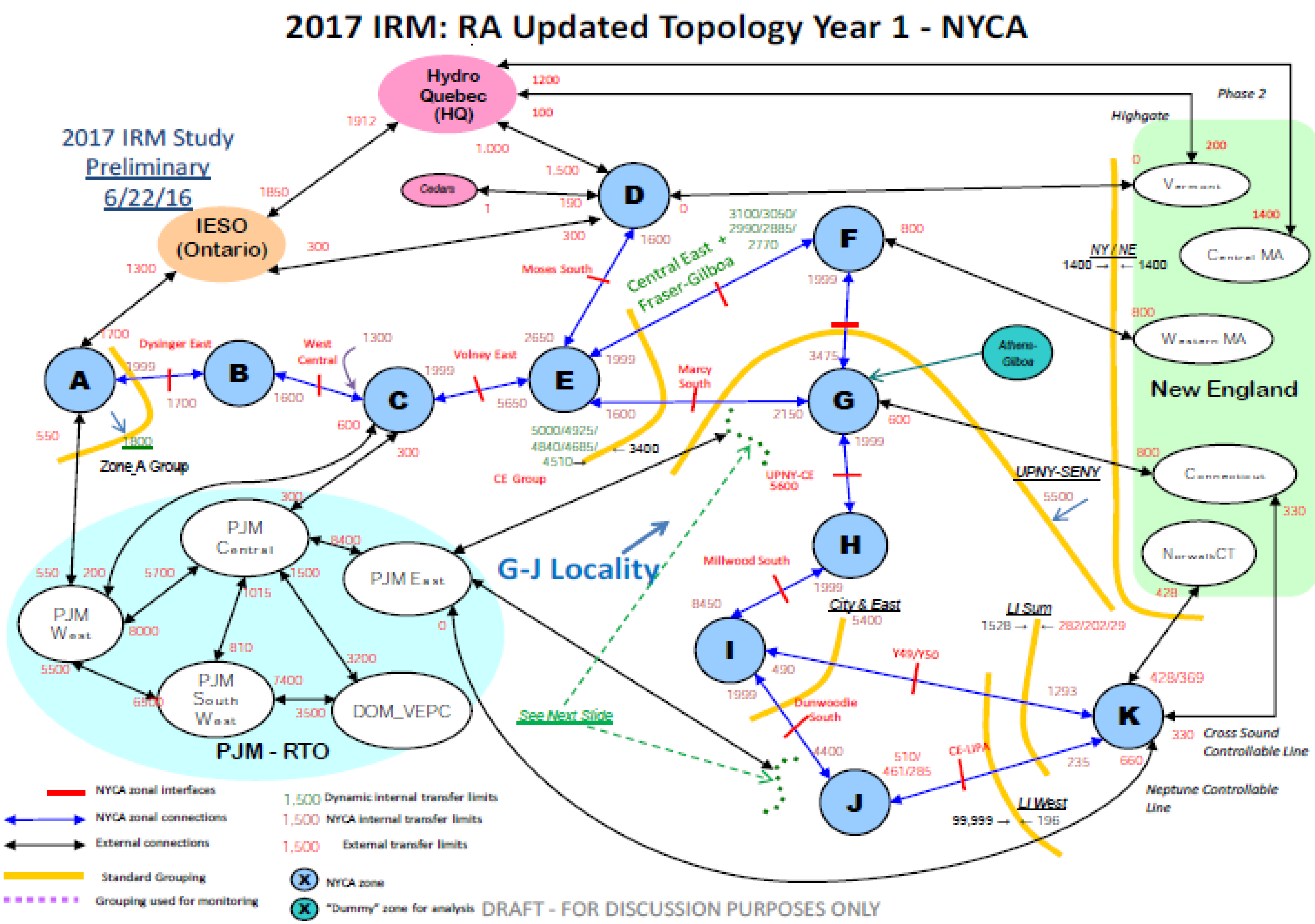
ASSUMPTIONS

- The preliminary runs rely on the first preliminary draft 2017 IRM base case
- Assumptions include:
  - October 2016 peak Load forecast
  - Generation capacity from 2016 Goldbook
    - 0 MW new non-wind
    - 67.5 MW project related re-ratings (additional CRIS)
    - 185.4 MW retirements or mothballs
    - 221.1 MW wind capacity additions
  - Interface limits based on 2016: Operating Study, Operations Engineering Voltage Studies, Comprehensive Reliability Plan, and additional analysis including interregional planning initiatives
    - Image on next slide
    - For additional information on interface limit assumptions, see the initial draft white paper on Emergency Assistance, being discussed with NYSRC ICS in relation to the development of a potential IRM sensitivity run

INTERFACE LIMITS



BASE CASE RESULTS

Case	IRM	Zone J LCR	Zone K LCR	G-J Locality LCR
Fixed IRM	18.3%	79.2%	105.2%	91.7%
Optimized IRM	16.9%	82.3%	105.4%	93.9%

- The values in the table above are not the values identified by the NYSRC or its committees in studying the 2017 IRM, and are presented here solely for purposes of advancing the discussion regarding alternative LCR methodologies
- Results from two base case runs: one with a fixed IRM, and one allowing the IRM to be optimized along with the LCRs
- We are seeking discussion and suggestions from the ICAP Working Group

PROJECT TASKS & UPDATED SCHEDULE

Task Description	Tentative Schedule
Task 1: Initial Analysis - Compare options that simultaneously solve for LCRs for all 3 Localities to optimize least cost of capacity procurement - Explore options with fixed IRM and co-optimizing IRM and LCRs simultaneously - Explore limitations of MARS model - Stress test methodologies and model	August - October
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Exhibit 16

ALTERNATIVES FOR DETERMINING LCRS

PROJECT UPDATE AND RESULTS

DECEMBER 15, 2016

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AGENDA

- Project objective
- Methodology
- Assumptions
- Results
- Insights & next steps

PROJECT OVERVIEW

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PROJECT OBJECTIVE AND GUIDING PRINCIPLES

- Work with stakeholders to explore the potential to develop a fair and reasonable approach for determining LCRs
- The methodology presented here is different from the Tan45
- This is exploratory, there are no proposals on the table at the moment

Guiding Principles

Efficient allocation of capacity	• Cost effective • Proper investment incentive • Maintains reliability
Transparent and predictable	• Simple, stable, robust • Predictability

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METHODOLOGY

METHODOLOGY OVERVIEW

- The overall problem function is to minimize the cost of capacity subject to LOLE
- The methodology proposes to identify LCRs to provide a least cost distribution of capacity resources amongst NYCA Localities based on the net CONE in each Locality
  - Net CONE is discussed on the following slide
- This process is done by a tool developed by GE that wraps around MARS and linearly varies the LCR's to converge upon a solution satisfying the stopping criteria designated by the user
  - We have been using a stopping criteria of a change in total cost of < 0.1%

METHODOLOGY: NET CONE ELASTICITY CURVES

- The cost of capacity procurement is based on net CONE elasticity curves
- Development of net CONE curves is based on a model developed during the 2013 Demand Curve reset process and updated for the 2016 Demand Curve net CONE values
- The model developed 5-point curves at:
  - Base LCR/IRM
  - +/- 3% LCR/IRM
  - +/- 6% LCR/IRM

Methodology

- Adjust curves from Demand Curve reset model to current LCR and net CONE values
- Adjustment performed using percent change on a MW basis for Gross CONE
- Adjusted for net EAS

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METHODOLOGY: LOLE AT LEVEL OF EXCESS

- To align the assumptions used in the LCR optimizer tool with those from the Demand Curve, based on input from the MMU we are considering using the LOLE at the level of excess (LOE) in the optimization process
- Net CONE values are calculated at the level of excess, and not at the 100% requirement point
  - The 100% requirement point is further up the Demand Curve than the net CONE, but this is the point that corresponds with 0.1 LOLE
  - The level of excess represents the net CONE, however, this corresponds with an LOLE less than 0.1
- This new methodology would solve for the level of excess LOLE and then remove the additional capacity between the 100% LCR requirement and the LOE to determine both the final LCR's and verify that the reliability criteria of an LOLE <= 0.1 is still met

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EXPORT CONSTRAINED ZONE K PROPOSAL

- The "Export Constrained Zone K approach" proposes to treat Zone K capacity as within the G-J Locality up to a specified limit based on the transfer limit out of Zone K
- This approach would not change LCRs but would change cost allocation
  - If excess capacity in Zone K exceeds the limit, all Zone K supply would settle at the Zone K price
  - If excess capacity in Zone K is less than the limit, the Zone K clearing price would move up the Demand Curve to the G-J clearing price
- Because the Optimizer Tool is a change in the methodology for developing the LCRs and not a change in the methodology for cost allocation, the two cannot be directly compared
- An Export Constrained Zone K approach has been presented by the MMU as an alternative to the current cost allocation method

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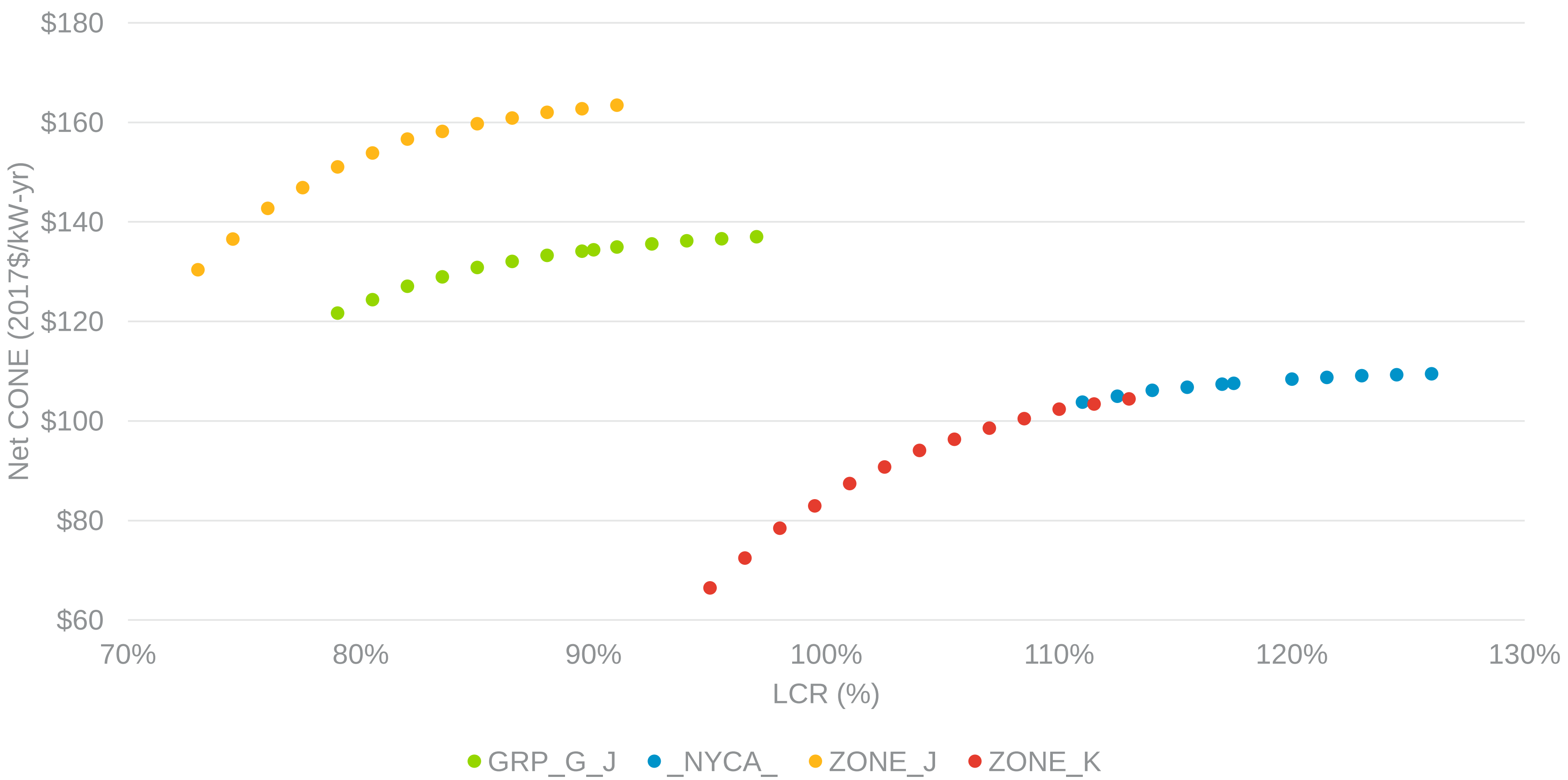
ASSUMPTIONS

ASSUMPTIONS

- The preliminary runs rely the final 2017 IRM base case
- Some key assumptions from this case include:
  - Update to final 2016 peak load forecast
  - Use most recent five year (2011-2016) forced and partial outage rates
  - Update generating capacity based on 2016 Gold Book
  - Remove PSEG wheel
- A more detailed description of the assumptions included in the 2017 IRM Base Case can be found in the New York Control Area Installed Capacity Requirement Technical Report 2016-2017(1).

1) http://nysrc.org/pdf/Reports/2016%20IRM%20Tech%20Study%20Report%20Final%2012-15-15.pdf

NET CONE ELASTICITY CURVES



Data table in the appendix

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RESULTS

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METRICS

- The following metrics will be used to present results from the optimizer tool and compare to the Tan45 unified method
- It is important to understand that the savings in the cost of capacity procurement is different from savings seen in the capacity market
  - Cost of capacity procurement savings are calculated at the reference point using net CONE
  - Market costs are the capacity purchased in the auctions at market clearing prices

Quantitative
- Cost of capacity procurement
- Stability when adding/subtracting generation

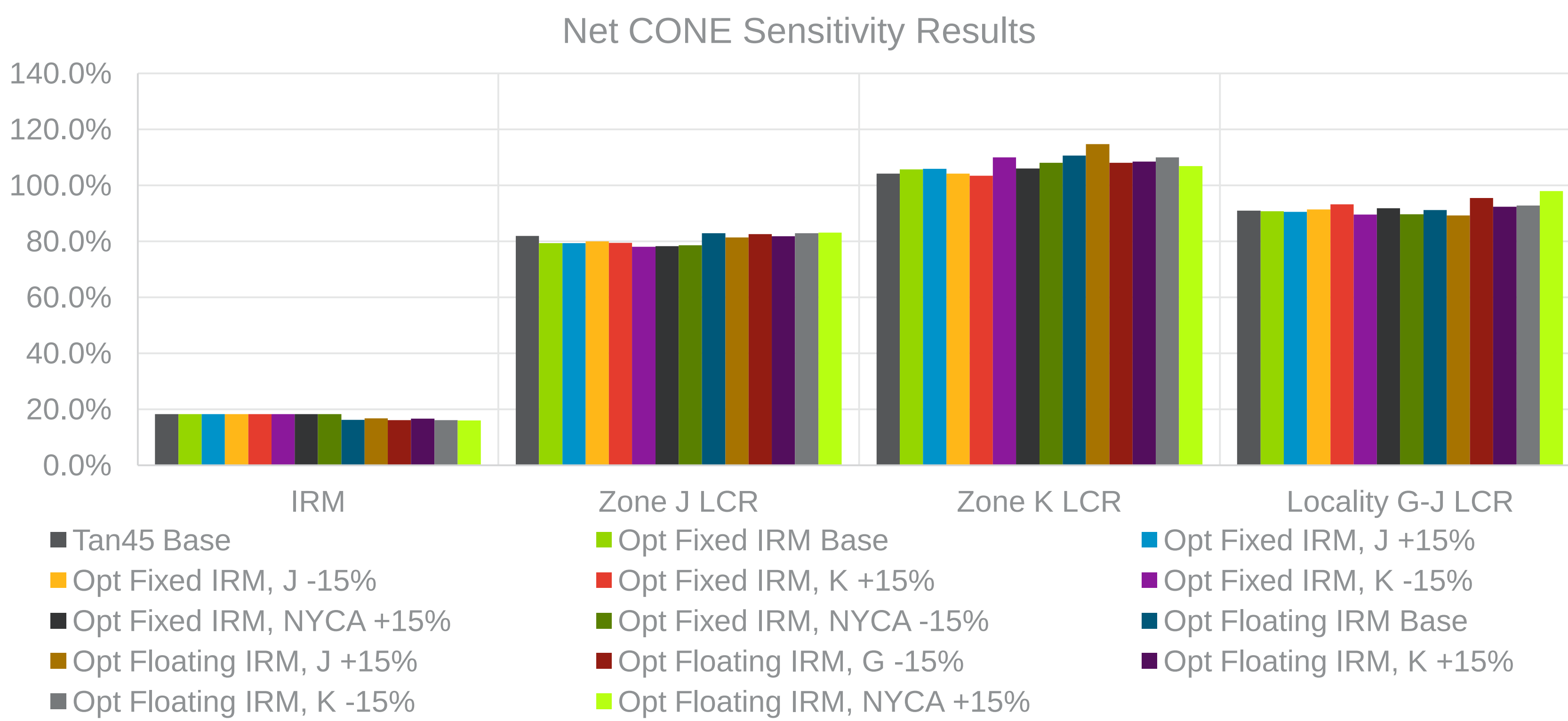
Qualitative
- Briefly explainable results in response to changes in assumptions
- Consumer impact

BASE CASE RESULTS

- Due to technical difficulties, base case results were not available in time for this presentation

OPTIMIZER TOOL'S SENSITIVITY TO NET CONE CURVES

Note: These sensitivities were run on a previous base case, so are shown compared to the Unified Method and base Optimizer results.



Data table in the appendix

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OPTIMIZER TOOL'S SENSITIVITY TO NET CONE CURVES

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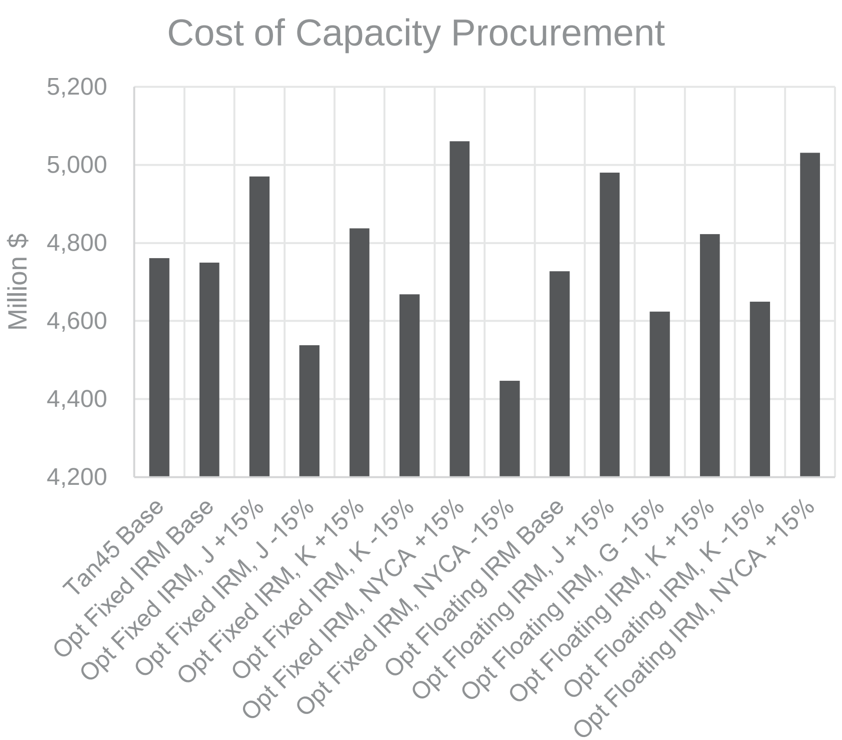

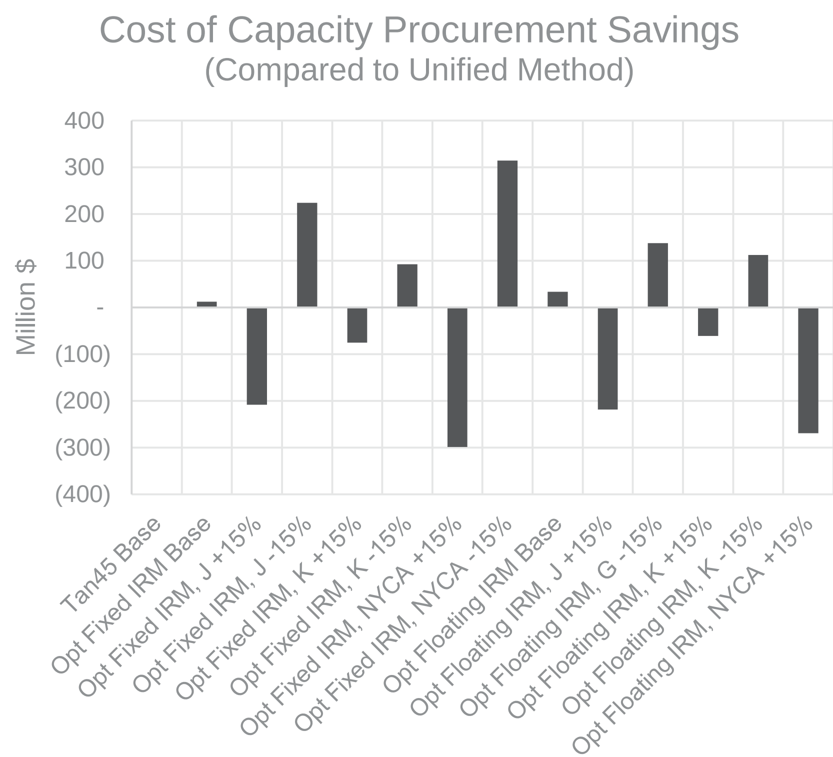

Data table in the appendix

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INSIGHTS & NEXT STEPS

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ADDITIONAL INSIGHTS INTO CURRENT METHODOLOGY

Throughout this process, there have been items within the current methodology that have shed light on the results

- In the unified method (Tan 45 + final LCRs), a ratio is set between J & K based on the relative LOLE impact of capacity in each region, then this ratio is used to shift capacity when determining the G-J LCR
  - The J to K ratio will vary based on the starting conditions, *i.e.*, the amount of capacity in each Locality
  - Therefore the LCRs will change if the starting capacity in a Locality is changed
- EFORd impacts have far reaching consequences on LCRs
  - For example generation additions/retirements with different EFORd than the Locality EFORd
  - This is due to the fact that shifting from a Locality is done in ratio of their respective UCAP
- Removing/Shifting from/into zones with excess may need to be evaluated
  - No sensitivities have been performed around this metric, but it has been brought up on numerous occasions to adjust which ROS zones are the recipients of the downstate shifting to determine LCRs

NEXT STEPS

- Perform sensitivities using both 0.1 and LOE values for LOLE
  - +/- generation in each locality
  - Changes in EFORd
  - Changes in net CONE curves
  - Changes in load
  - Changes in emergency assistance
  - Changes in internal NYCA interface limits
  - If time, look into sensitivities around the following:
    - Shifting method
    - Objective function
    - Market clearing prices
- Reporting of findings

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UPDATE ON SCHEDULE

- In 2017, the NYISO will evaluate what has been done to date and set a new project plan and schedule for next steps on this issue

CONTACTS

AMANVIR CHAHAL
Associate Director
202.481.7319
amanvir.chahal@navigant.com

MAGGIE SHOBER
Associate Director
202.481.8684
maggie.shober@navigant.com

APPENDIX: TABLE OF NET CONE VALUES

LCR Point	NYCA
111.0%	$103.79
112.5%	$104.98
114.0%	$106.17
115.5%	$106.78
117.0%	$107.40
117.5%	$107.57
120.0%	$108.42
121.5%	$108.76
123.0%	$109.11
124.5%	$109.29
126.0%	$109.48

LCR Point	G-J Locality
79.0%	$121.68
80.5%	$124.38
82.0%	$127.08
83.5%	$128.96
85.0%	$130.85
86.5%	$132.07
88.0%	$133.28
89.5%	$134.12
90.0%	$134.40
91.0%	$134.96
92.5%	$135.58
94.0%	$136.21
95.5%	$136.62
97.0%	$137.02

LCR Point	Zone J
73.0%	$130.39
74.5%	$136.56
76.0%	$142.73
77.5%	$146.89
79.0%	$151.06
80.5%	$153.85
82.0%	$156.64
83.5%	$158.19
85.0%	$159.73
86.5%	$160.88
88.0%	$162.02
89.5%	$162.74
91.0%	$163.46

LCR Point	Zone K
95.0%	$66.47
96.5%	$72.46
98.0%	$78.46
99.5%	$82.95
101.0%	$87.43
102.5%	$90.76
104.0%	$94.09
105.5%	$96.33
107.0%	$98.56
108.5%	$100.47
110.0%	$102.38
111.5%	$103.41
113.0%	$104.44

APPENDIX: TABLE OF NET CONE SENSITIVITY RESULTS

	IRM	Zone J LCR	Zone K LCR	Locality G-J LCR	Cost of Capacity Procurement (Million $)	Cost of Capacity Procurement Savings (Million $)
Tan45 Base	18.3%	81.9%	104.2%	91.0%	$4,761.20	-
Opt Fixed IRM Base	18.3%	79.3%	105.7%	90.7%	$4,749.30	11.90
Opt Fixed IRM, J +15%	18.3%	79.3%	105.9%	90.5%	$4,969.90	(208.70)
Opt Fixed IRM, J -15%	18.3%	80.0%	104.2%	91.4%	$4,537.60	223.60
Opt Fixed IRM, K +15%	18.3%	79.4%	103.4%	93.2%	$4,837.00	(75.80)
Opt Fixed IRM, K -15%	18.3%	78.0%	110.0%	89.5%	$4,668.60	92.60
Opt Fixed IRM, NYCA +15%	18.3%	78.3%	106.0%	91.8%	$5,060.30	(299.10)
Opt Fixed IRM, NYCA -15%	18.3%	78.6%	108.1%	89.7%	$4,447.00	314.20
Opt Floating IRM Base	16.2%	82.9%	110.6%	91.2%	$4,727.50	33.70
Opt Floating IRM, J +15%	16.8%	81.4%	114.7%	89.2%	$4,979.90	(218.70)
Opt Floating IRM, G -15%	16.1%	82.6%	108.0%	95.5%	$4,623.70	137.50
Opt Floating IRM, K +15%	16.6%	81.8%	108.5%	92.3%	$4,822.30	(61.10)
Opt Floating IRM, K -15%	16.1%	82.9%	110.0%	92.8%	$4,649.30	111.90
Opt Floating IRM, NYCA +15%	16.0%	83.1%	106.9%	97.9%	$5,030.90	(269.70)

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Exhibit 17

Alternative Methods for Determining LCRs

Zachary Stines
Associate Market Design Specialist
New York Independent System Operator

Installed Capacity Working Group
February 15, 2017
NYISO

Outline

I. Recap of 2016 Effort
   I. *Current Process*
   II. *Market Guiding Principles for Design*
   III. *Optimization*
II. 2017 Plan
   I. *Phases*
III. Current Status
   I. *Net CONE*
   II. *Preliminary Results*

Recap of 2016 Effort

- Reviewed current method
- Defined market guiding principles for the design of a new methodology to determine LCRs
- GE developed a tool utilizing optimization techniques and MARS software
- Preliminary results affirmed the tool functions as designed

Current Method: Numerical Example

- **2 Locality Example (support provided by larger system)**
- **Distinct Localities (not overlapping or wholly within one another)**

	Locality 1	**Locality 2**
Load (MW)	**10,000**	**5,000**
Capacity (MW)	**9,000**	**5,600**
Shiftable Surplus (MW)	**1,000**	**500**
Surplus Area 1/Area 2 Ratio	1,000/500 = **2:1**	
Total Joint Shiftable Surplus (MW)	**1,200**	
Joint Shiftable Surplus (MW)	2:1*1,200 = **800**	1:2*1,200 = **400**
Capacity Requirement (MW)	9,000-800 = **8,200**	5,600-400 = **5,200**
Capacity Requirement	8,200/10,000 = **82.0%**	5,200/5,000 = **104.0%**

Current Method: Numerical Example

- **500 MW capacity addition in Locality 1**

	Locality 1 + 500MW	Locality 2
Load (MW)	**10,000**	**5,000**
Capacity (MW)	9,000+500 = **9,500**	**5,600**
Shiftable Surplus (MW)	**1,500**	**500**
Surplus Area 1/Area 2 Ratio	1,500/500 = **3:1**	
Total Joint Shiftable Surplus (MW)	**1,700**	
Joint Shiftable Surplus (MW)	3:1*1,700 = **1,275**	1:3*1,700 = 425
Capacity Requirement (MW)	9,500-1,275 = **8,225**	5,600-425 = **5,175**
Capacity Requirement	8,225/10,000 = **82.3%**	5,175/5,000 = **103.5%**
Δ Capacity Requirement	82.3-82.0 = ↑ **0.3%**	103.5-104.0 = ↓ **0.5%**

Current Method: Numerical Example

- **2 Locality Example (support provided by larger system)**
- **Locality 1 is wholly within in Locality 2**

	Locality 1	Locality 2
Load (MW)	**10,000**	**16,000**
Capacity (MW)	**9,000**	**15,000**
Area 1/Nested Area Capacity Ratio	9,000/15,000 = **0.600**	
Total Joint Shiftable Surplus (MW)	**1,500**	
Joint Shiftable Surplus (MW)	0.600*1,500 = **900**	1,500-900 = **600**
Capacity Requirement (MW)		15,000-1,500 = **13,500**
Capacity Requirement		13,500/16,000 = **84.4%**

Current Method: Numerical Example

- **500 MW capacity addition in Area 2**

	Locality 1	Locality 2 + 500 MW
Load (MW)	**10,000**	**16,000**
Capacity (MW)	**9,000**	**15,500**
Area 1/Nested Area Capacity Ratio	9,000/15,500 = **0.581**	
Total Joint Shiftable Surplus (MW)	**1,650** (limited by Area 1)	
Max Joint Shiftable Surplus (MW)	0.581*1,650 = **959**	1,650-959 = **691**
Capacity Requirement (MW)		15,500-1,650 = **13,850**
Capacity Requirement		13,850/16,000 = **86.6%**
Δ Capacity Requirement		86.6-84.4 = ↑ **2.2%**

Market Guiding Principles

Design Statement:

Develop a robust, transparent, and intuitive (predictive) process for developing proper capacity requirements that maintain reliability while producing a lower cost solution

Efficient allocation of capacity

- **Maintains reliability**
- **Cost effective**
- **Proper investment incentives**

Transparent and predictable

- **Simple, stable, robust**
- **Predictable**

Least Cost Optimization

- **Minimize total cost of capacity at the reliability criterion (LOLE ≤ 0.1)**
- **Cost defined by Unit Net CONE used to develop each ICAP Demand Curve~~s~~**
- **Uses Linear Approximation as computational method**
  - ***Iterative process between Linear Program wrapper and MARS that approximates the objective function and constraint to find least cost***

2017 Project Development

Stage	Objective	Specific Topics:
Proof of Concept	Demonstrate alternative methodology in relation to guiding principles (*i.e.*, least cost, stability, robust, predictability)	Generation +/- Unit net CONE +/- Load +/- EFORd +/-
Refine Methodology	Modify the alternative method to ensure that all aspects have a purpose and are being performed as a result of sound market and engineering principles	Unit net CONE curves Potential Bounds Emergency assistance assumptions Modeling methodology
Market Simulations	Simulate realistic market situations to demonstrate performance of methodology	Changes in resources Topological changes Locality configurations
Defining Process	Develop a process for the methodology that ensures guiding principles are being achieved over time	Develop process of method Process timeline Transition methods
Demonstrating Market Benefits	Demonstrate the methodology results in market benefits and resolve any issues that arise from its implementation	Consumer impact Multiyear simulation Cost allocation
Final Market Design	Summarize all findings and develop a final market design for implementation	Develop final market design

Phase 1: Proof of Concept

- **Objective:**
  - *Demonstrate alternative methodology that achieve guiding principle*
- **Tasks:**
  - *Perform simple sensitivities:*
    - **Generation +/-**
    - **Unit Net CONE +/-**
    - **Load +/-**
    - **EFORd +/-**

Phase 2: Refine Methodology

- **Objective:**
  - ***Refine the alternative methodology so all aspects have a purpose and are being performed consistent with sound market and engineering principles***
- **Tasks:**
  - ***Investigate:***
    - **Objective function and inputs (*e.g.*, Unit Net CONE)**
    - **Alterations in emergency assistance**
    - **Potential Bounds (e.g. transmission security limits)**
    - **Modeling methodology (e.g. EFORd, shifts, UCAP, ICAP)**
  - ***Develop:***
    - **Rational and support for all aspects of methodology**

Phase 3: Market Simulations

- **Objective:**
  - ***Simulate realistic market situations to demonstrate the application of methodology***
- **Tasks:**
  - ***Perform more complex sensitivities:***
    - **Substantial changes in resources**
    - **Locality configurations**
    - **Topological changes (*e.g.*, AC Transmission)**

Phase 4: Defining Process

- **Objective:**
  - ***Develop a process by which to confirm over time that the methodology will achieve the guiding principles***
- **Tasks:**
  - ***Investigate:***
    - **Process timeline**
    - **Transition methods**

Phase 5: Demonstrating Market Benefits

- **Objective:**
  - ***Demonstrate that the methodology provides value to the market by achieving the guiding principles and resolve any issues that arise from its implementation***
- **Tasks:**
  - ***Investigate:***
    - **Market and consumer impacts**
    - **Cost allocation**
  - ***Perform multiyear simulation***

Phase 6: Final Market Design

- **Objective:**
  - ***Summarize all findings and develop a final market design for implementation***
- **Tasks:**
  - ***Summarize:***
    - **All supporting analysis**
  - ***Final NYISO recommendation***

Phase 1: Current Status

- Developed 2017 project outline
- Monthly action item at NYSRC-ICS
- Updated optimizer Unit Net CONE curves with the generator used to develop the ICAP Demand Curves accepted in January 2017
- 2017 Final IRM Base Case

Unit Net CONE Curves

- Used to generate a representation of capacity supply curve
- The curves utilized in 2016 for this LCR-evaluation effort were based on both ICAP Demand Curves accepted in 2014 and 2017
- Curves have been updated with information from newly accepted ICAP Demand Curves
  - *Generates corresponding Unit Net CONE values at different LCRs and NYCA minimum installed capacity requirements*
- Overall values were similar to those previously used in 2016
- Will be evaluated in greater detail in Phase 2

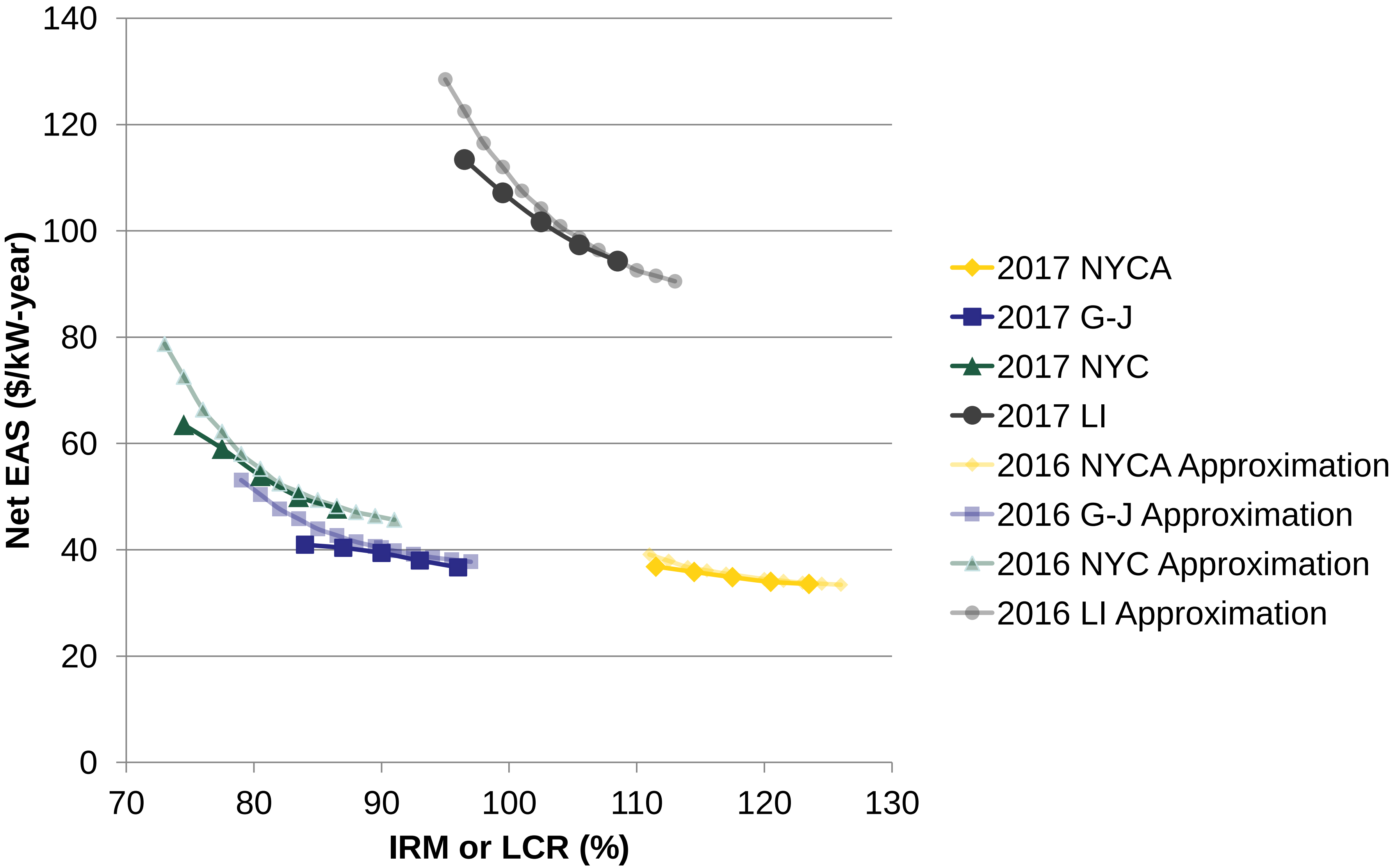
Developing Unit Net CONE Curves

- **Energy curves were developed in the 2013 Demand Curve reset**
  - ***Evaluated E&AS revenues assuming different installed levels of capacity (i.e., LCR and IRM)***
- **The shape of these curves was used as an approximation when developing curves in 2016**
- **The shapes were then scaled to the values associated with the 2016 Demand Curve reset**

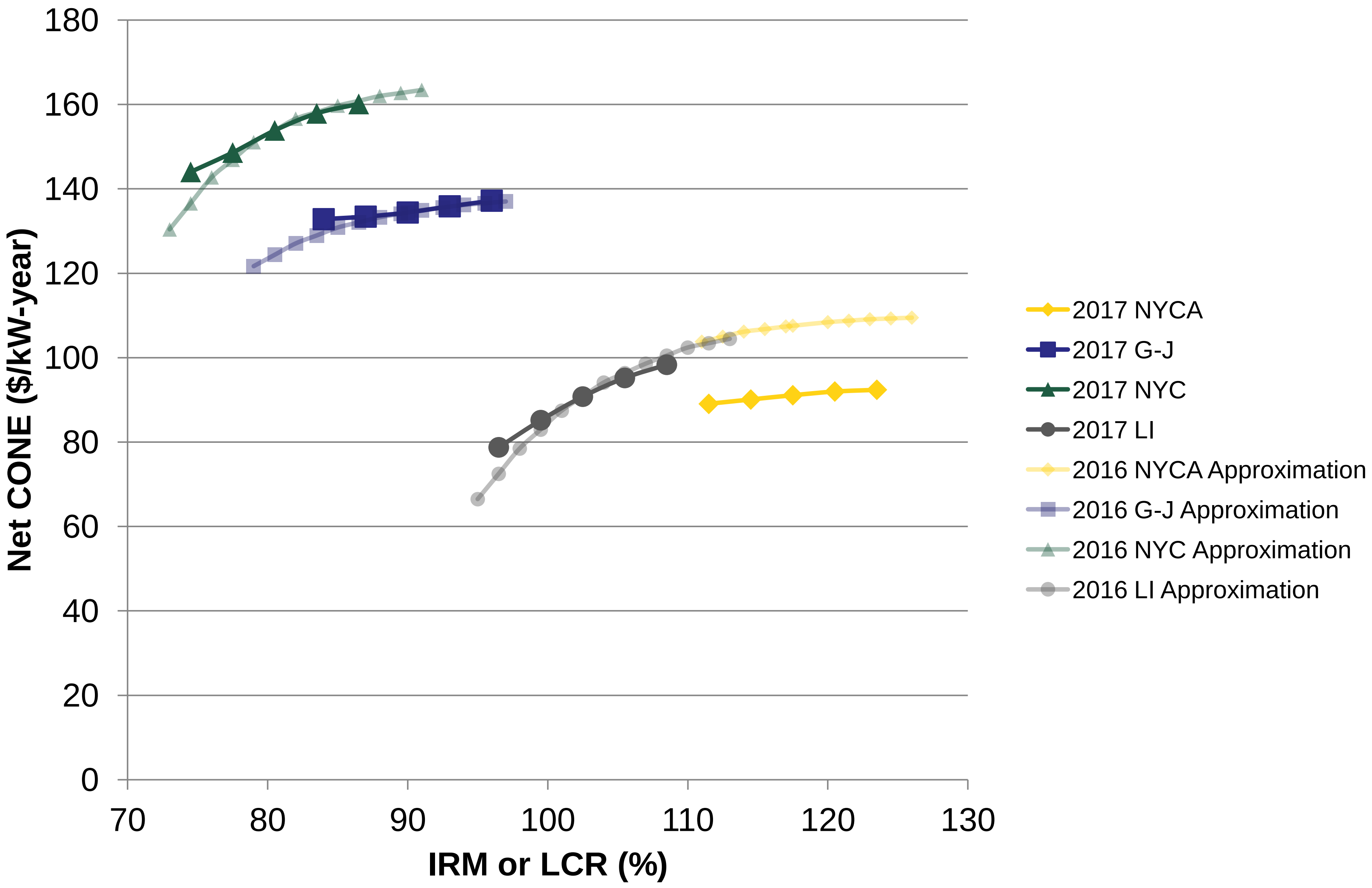
Developing Unit Net CONE Curves

- In 2017, GE performed MAPS runs under different levels of Installed capacity (i.e., LCRs and IRM)
- These runs were utilized to develop Level of Excess-Adjustment Factors (LOE-AFs) at each different level of Installed capacity
- Different LOE-AFs were then used to generate final Net EAS for peaking unit in same manner as 2016 Demand Curve reset
- Resulting Net EAS was used to create final Unit Net CONE values
- These Unit Net CONE values create final curves

Unit Net EAS Revenue



Unit Net CONE Curves



Next Steps

- **Complete Phase 1 by presenting simple sensitivities**
  - ***Net CONE +/-***
  - ***Load +/-***
  - ***EFORd +/-***
- **Begin Phase 2 analysis**
  - ***Objective function inputs (i.e., Unit Net CONE)***
  - ***Alterations in emergency assistance***
  - ***Modeling methodology (e.g., EFORd, shifts, UCAP vs. ICAP)***

Next Steps

- The NYISO will consider input received during today's ICAP Working Group meeting and at NYSRC-ICS meetings
- Any additional comments sent to deckels@nyiso.com will be considered
- The NYISO will return to a future ICAPWG meeting to discuss its progress and adjustments to the plan based on comments or results

The mission of the New York Independent System Operator, 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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Exhibit 18

Alternative Methods for Determining LCRs

Zachary Stines
Associate Market Design Specialist
New York Independent System Operator

Installed Capacity Working Group
April 4, 2017
NYISO

Outline

I. 2017 Commitment
II. Resource Limitations
III. Base Case
IV. Next Sensitivities
V. Phase 2: Refining Methodology
    I. *Transmission Security*
    II. *Continuing Phase 2*
VI. Timeline

2017 Commitment

- **NYISO will evaluate and propose an alternative methodology for determining LCRs based on economic optimization**
  - ***This methodology will utilize the final NYSRC approved IRM***
- **2017 objective is not aimed at proposing an alternative methodology for developing the IRM**
  - ***Results including optimization of IRM will be presented for informational purposes only***
- **Based on the current timeline, it is unlikely any recommendation this year would lead to a change in the methodology used for determining 2018 LCRs**

Resource Constraints

- NYISO is utilizing GE to provide MARS analysis for:
  - *Locational Exchange Factor (LEF)*
  - *Alternative Methods for Determining LCRs*
- The limited resources have been focused on the Locational Exchange Factor project due to its time-sensitive nature
- This redistribution of resources has delayed the progress of this project

2017 Base Case

Scenario	GHIJ	J	K	Solution Cost (million $)
Tan45	91.5%	81.5%	103.5%	$4,414
Optimized Base Case	92.2%	78.1%	104.5%	$4,371

- **Base Case results in same LOLE (i.e., 0.1) with a lower cost of capacity**
- **The capacity cost is based on Unit Net CONE cost curves developed with GE in 2017**
- **The solution cost shown above is the long-term equilibrium**

Phase 1: Sensitivities

- Currently working with GE to evaluate and analyze the performance of the optimizer tool with respect to simple sensitivities (e.g., generation additions)
- These results were not ready at the time of this posting and will be provided at a future date

Phase 2: Transmission Security

- Evaluate the incorporation of additional transmission security constraints into the LCR optimization
- Seek to ensure NYSRC Transmission System Planning Performance Requirements and NYC System Operations local criteria are not violated
- Develop LCR floors that would account for transmission security reliability requirements
- Work with Planning and Operations to evaluate appropriate limits for the LCR floors for purposes of this analysis

Transmission Security

- LCR floors would be incorporated as a constraint within the optimization
- Optimization would result in LCRs that are the maximum of either the value associated with resource adequacy or the LCR floor
- Similar concept is utilized by ISO-NE
  - *Local Sourcing Requirements (LSR) is the local requirement for import constrained zones*
  - *It is the maximum value of either the Local Resource Adequacy Requirements (LRA) and the Transmission Security Analysis (TSA)*

Continuing Phase 2

- **Evaluating Cost Curves**
  - ***Understand effects of changes in CONE (using DCR peaking plant) on optimization results***
  - ***Develop methodology***
- **Shifting methods**
  - ***Develop greater understanding for how capacity is shifted using the optimization methodology***

2017 Project Development

Stage	Objective	Specific Topics:
Proof of Concept	Demonstrate alternative methodology in relation to guiding principles (*i.e.*, least cost, stability, robust, predictability)	Generation +/- Unit net CONE +/- Load +/- EFORd +/-
Refine Methodology	Modify the alternative method to ensure that all aspects have a purpose and are being performed as a result of sound market and engineering principles	Unit net CONE curves Potential Bounds Emergency assistance assumptions Modeling methodology
Market Simulations	Simulate realistic market situations to demonstrate performance of methodology	Changes in resources Topological changes Locality configurations
Defining Process	Develop a process for the methodology that ensures guiding principles are being achieved over time	Develop process of method Process timeline Transition methods
Demonstrating Market Benefits	Demonstrate the methodology results in market benefits and resolve any issues that arise from its implementation	LOLE Criterion Consumer impact Multiyear simulation Cost allocation
Final Market Design	Summarize all findings and develop a final market design for implementation	Develop final market design

Next Steps

- The NYISO will consider input received during today's ICAP Working Group meeting
- Any additional comments sent to deckels@nyiso.com will be considered
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- ***Planning the power system for the future***
- ***Providing factual information to policy makers, stakeholders and investors in the power system***

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Exhibit 19

Alternative Methods for Determining LCRs

Zachary Stines
Associate Market Design Specialist

Installed Capacity Working Group

May 11, 2017, NYISO

Agenda

- **Phase 1: Proof of Concept**
  - Updates to the Optimization
  - Initial Sensitivities Results
- **Phase 2: Refining Methodology**
  - Transmission Security
  - Cost curves
- **Next Steps**
  - 2017 Project Development
- **Questions**

Phase 1: Proof of Concept

Updates to Optimization

- Altered formulation of LOLE constraint within optimization tool
  - Linear versus Log-Linear
- Reset solver with a smaller initial step size after a low initial tolerance has been met

Updates Impact on Optimized Base Case

Scenario	Zone J LCR (%)	Zone K LCR (%)	G-J LCR (%)	Cost (million)
Optimized Base Case (Old)	78.1	104.5	92.2	$4,370.8
Optimized Base Case (Updated)	77.5	107.0	91.0	$4,366.4
Δ in Base Cases	**0.6**	**-2.5**	**1.2**	**$4.4**

- Updated Base Case results in a lower cost, but slightly different LCRs for the localities

Initial Sensitivities

- **Entry/exit of Capacity**
  - Capacity addition/subtraction in Zone GHIJ
  - Capacity addition/subtraction in Zone J
  - Capacity addition/subtraction in Zone K
  - Capacity addition/subtraction in Rest of State
  - Capacity addition/subtraction in G with Lower Bound on Zone J
- **Changes in Net CONE**
  - Increase and decrease GHIJ Net CONE
  - Increase and decrease Zone J Net CONE
  - Increase and decrease Zone K Net CONE
  - Increase and decrease NYCA Net CONE
  - Increase in all Locality Net CONE
- **Changes in Transmission Capability**
  - Increase UPNY-SENY

Methodologies used in Sensitivities

- **Optimization Methodology**
  - Uses GE Optimization tool and NYISO final 2017-2018 Capability Year LCR base case
  - Optimized the 3 Localities' LCRs while maintaining the 2017 NYSRC approved IRM of 18% subject to a LOLE constraint of 0.1 Days/year
- **Current LCR Methodology**
  - Uses NYISO LCR Calculation Process[1]
  - Not a full Unified Method (i.e., Tan45)
  - Maintains the NYSRC approved IRM of 18%
  - Used to provide a simple comparison

[1] This process is available at <http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/Reference_Documents/LCR_Calculation_Process/LCR%20Calculation%20Process%2012_13_13.pdf>.

Current LCR Methodology Base Case

- The NYISO final 2017-2018 Capability Year LCR base case was solved to a LOLE of 0.1 days/year with the NYSRC approved IRM of 18.0%
- The resulting base case will allow for a direct comparison with the optimized methodology and the simplified current LCR methodology

Scenario	Zone J LCR (%)	Zone K LCR (%)	G-J LCR (%)	Cost (million)
Base Case (Current LCR)	81.4	103.2	91.3	$4,407.7

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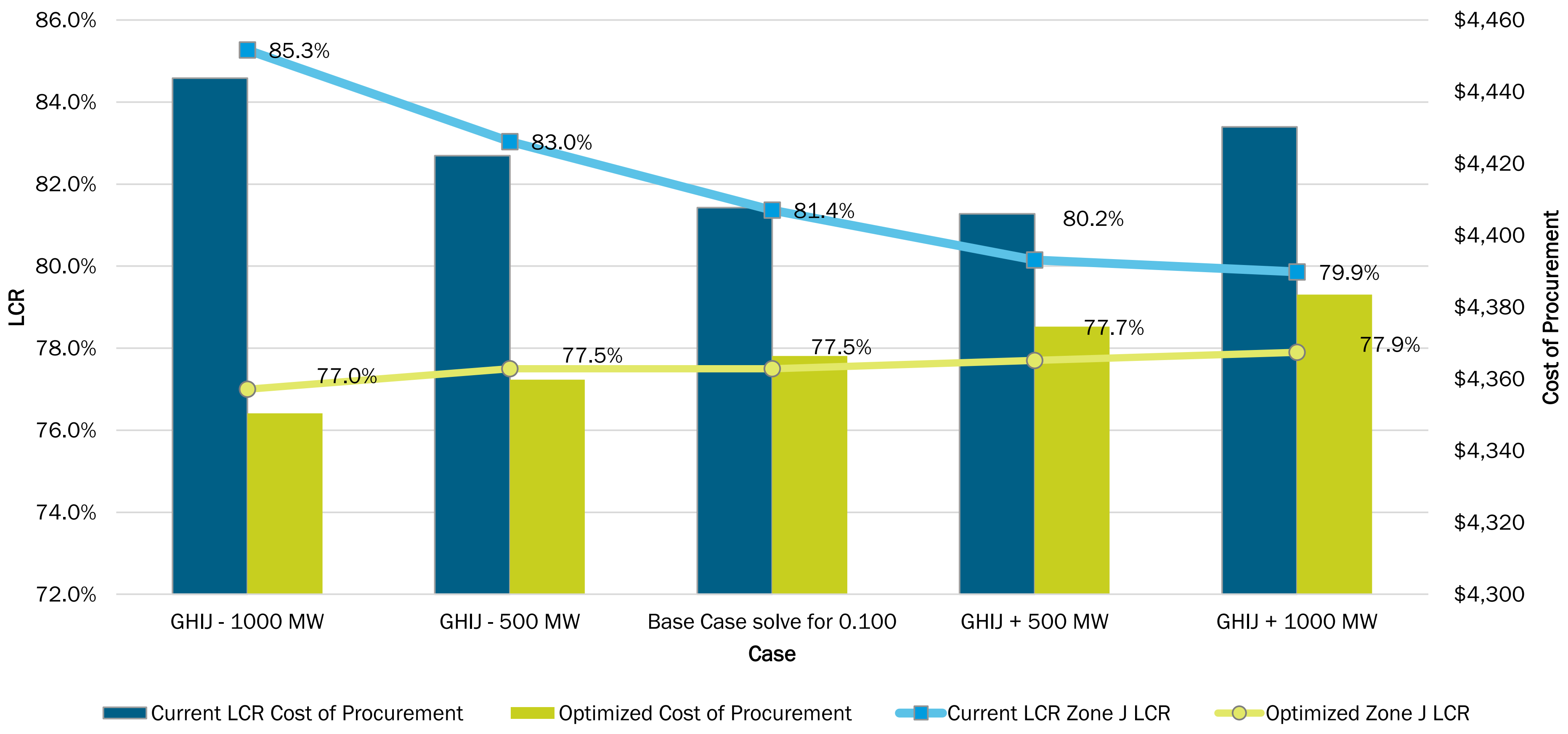
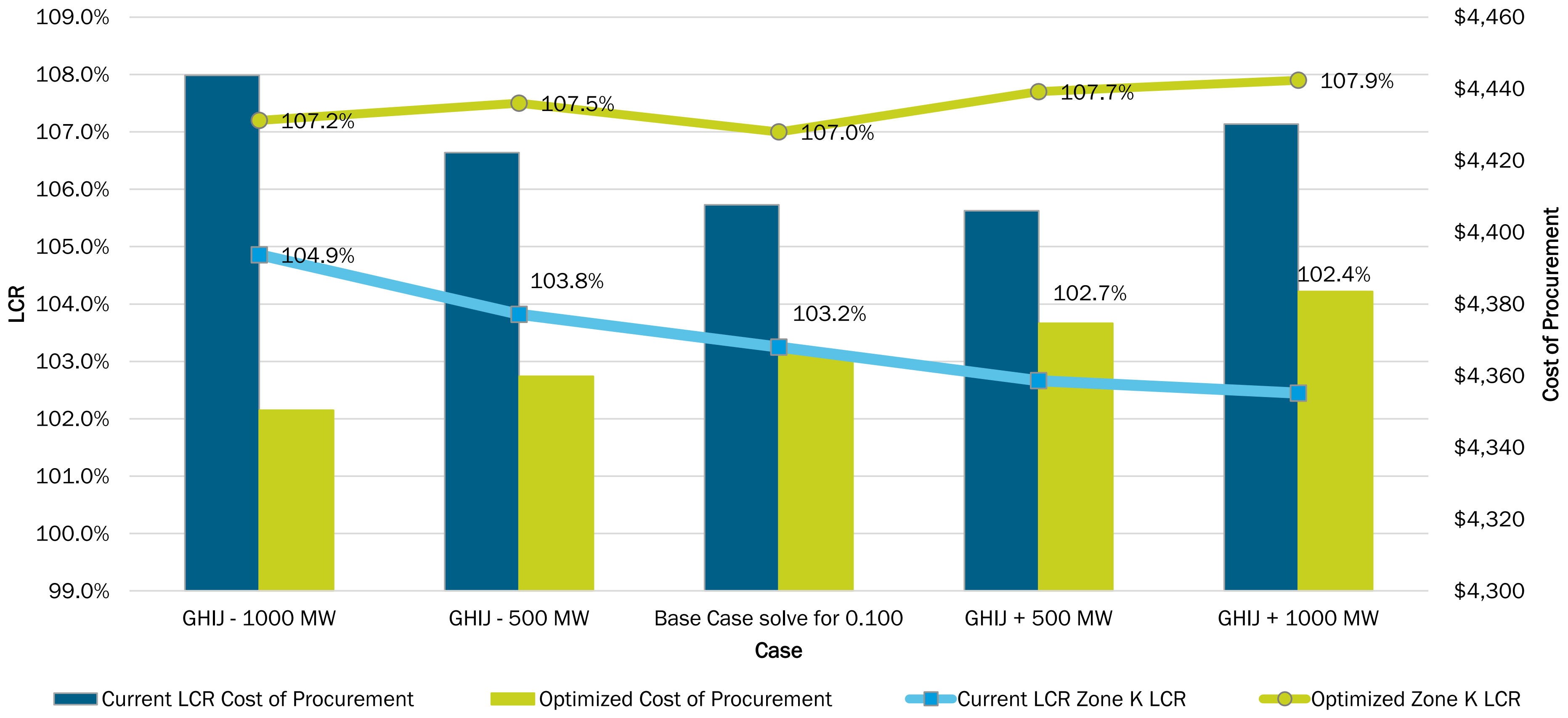
Changes in Capacity Sensitivities

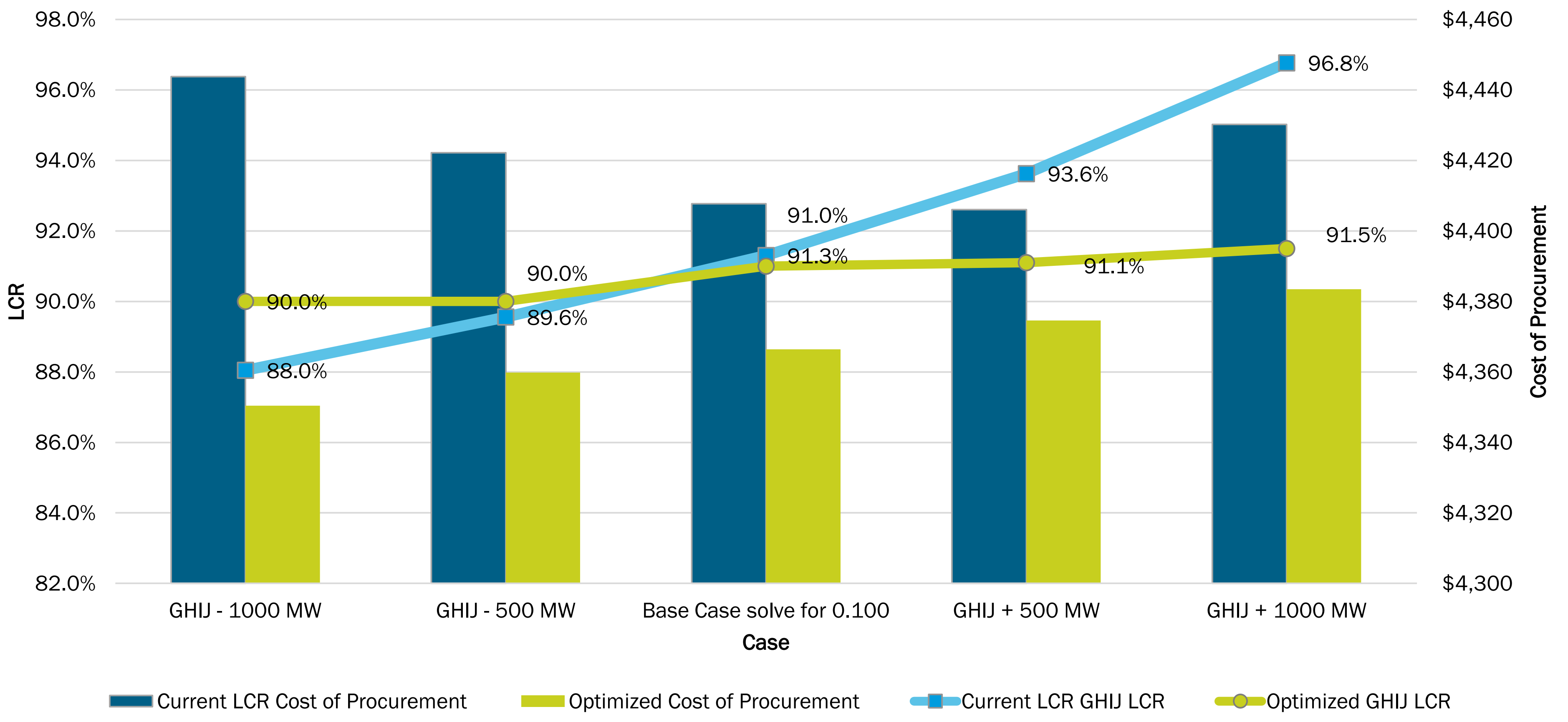
Changes to Capacity in GHIJ: Zone J LCR



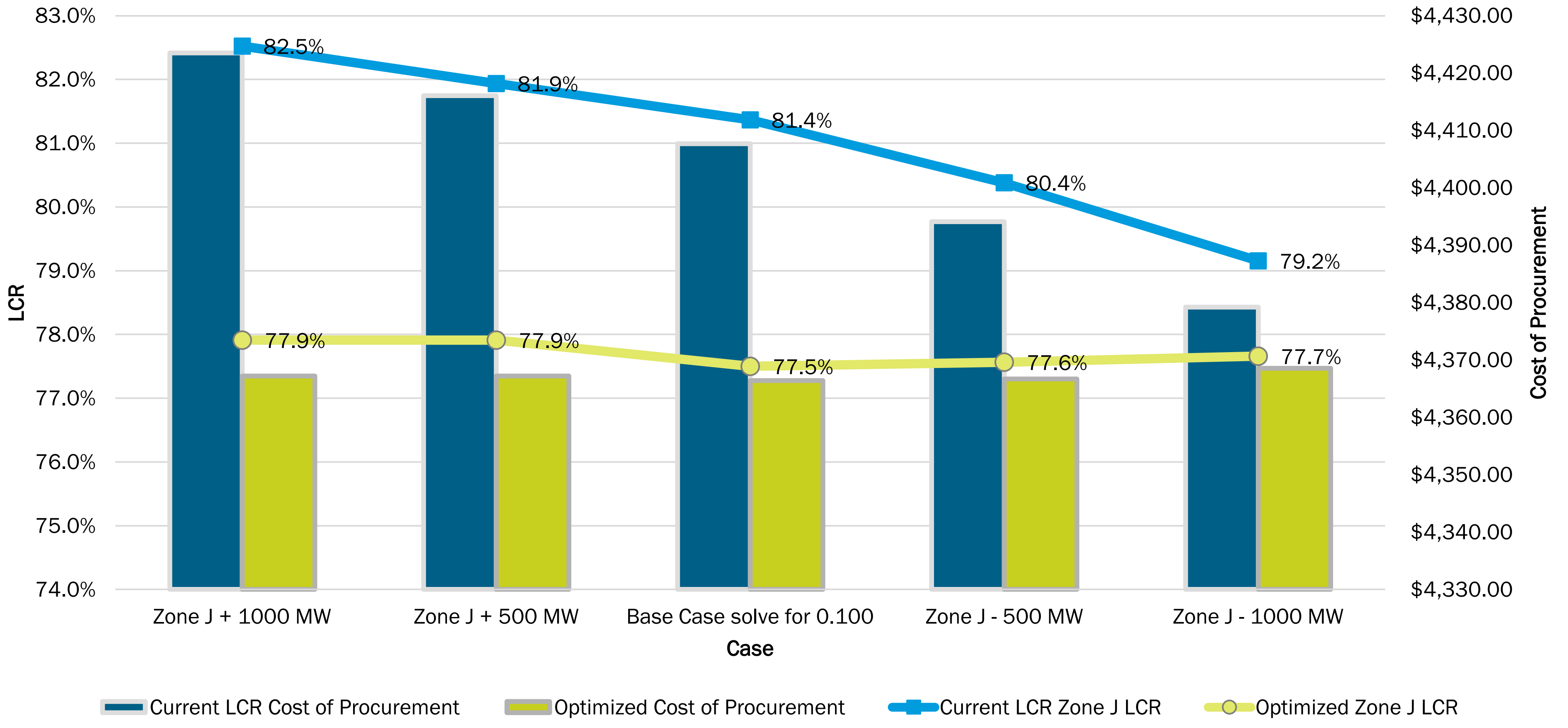
Changes to Capacity in GHIJ: Zone K LCR



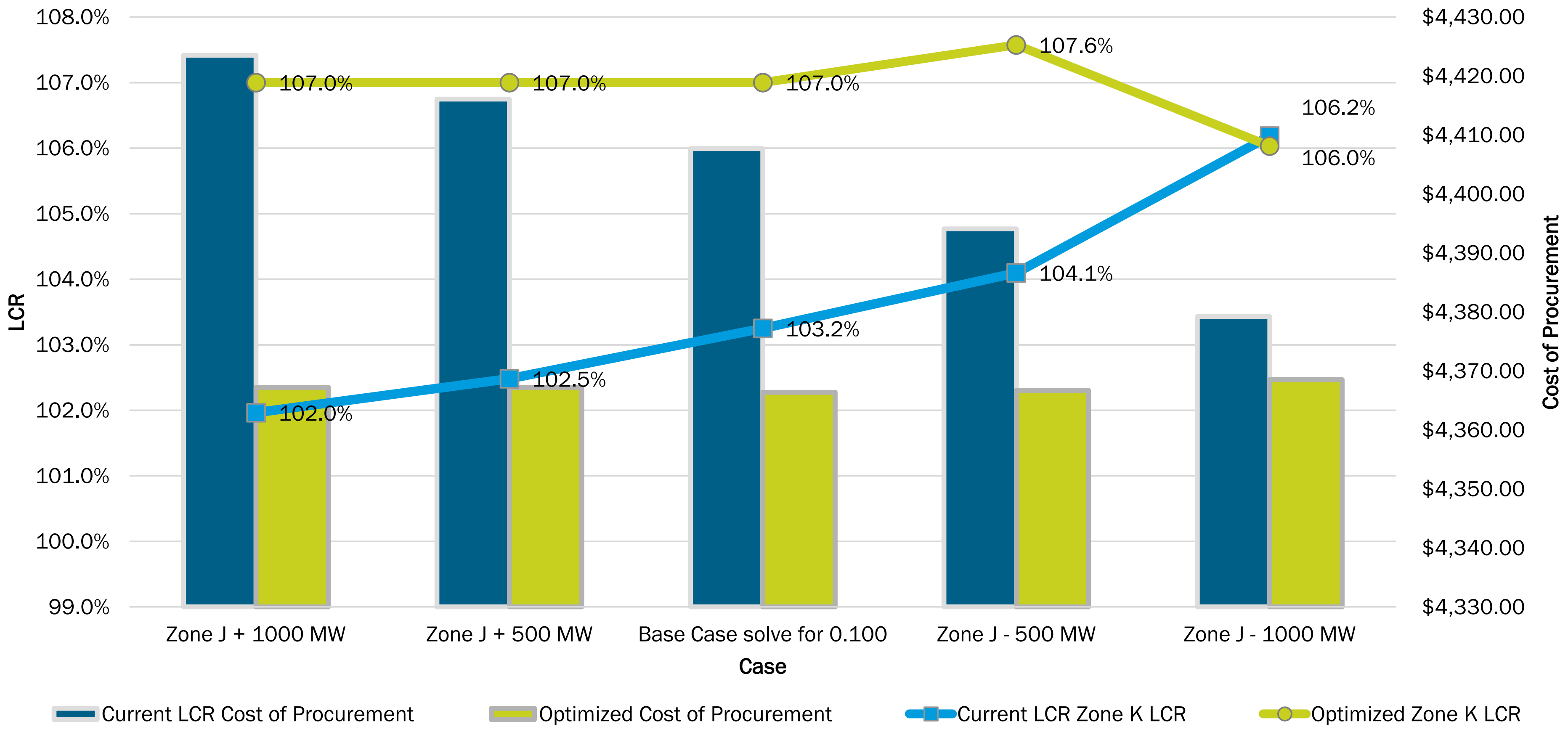
Changes to Capacity in GHIJ: GHIJ LCR



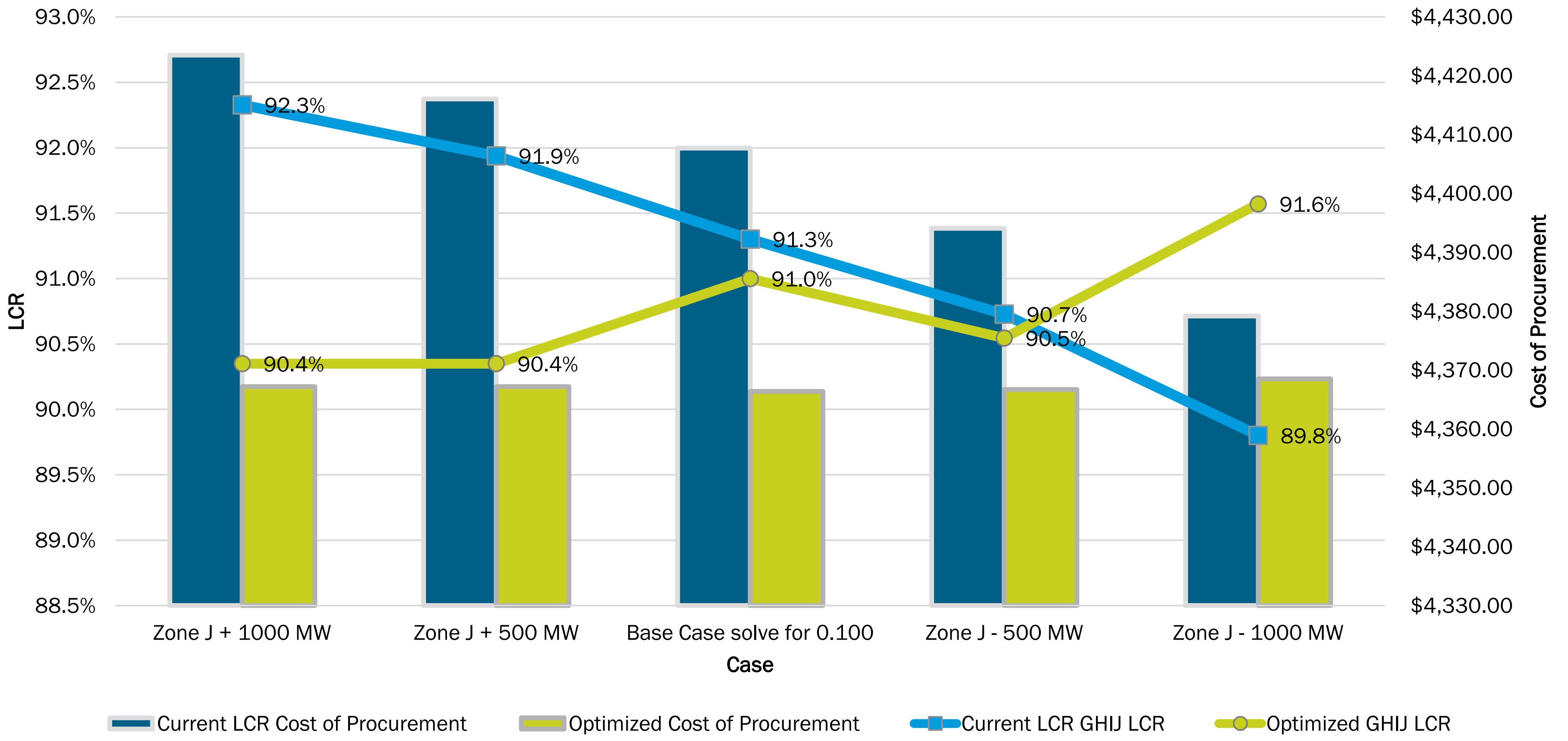
Changes to Capacity in J: Zone J LCR



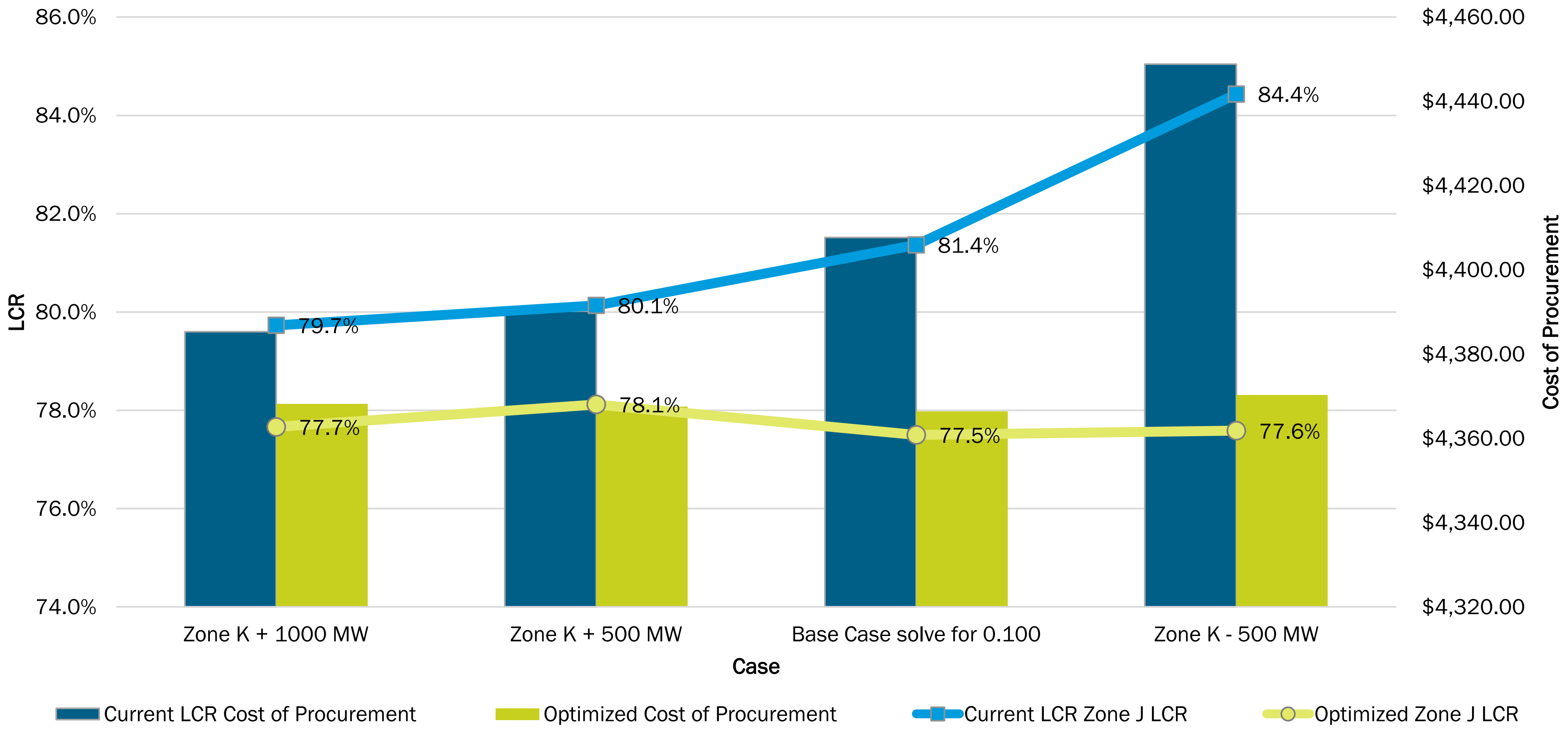
Changes to Capacity in J: Zone K LCR



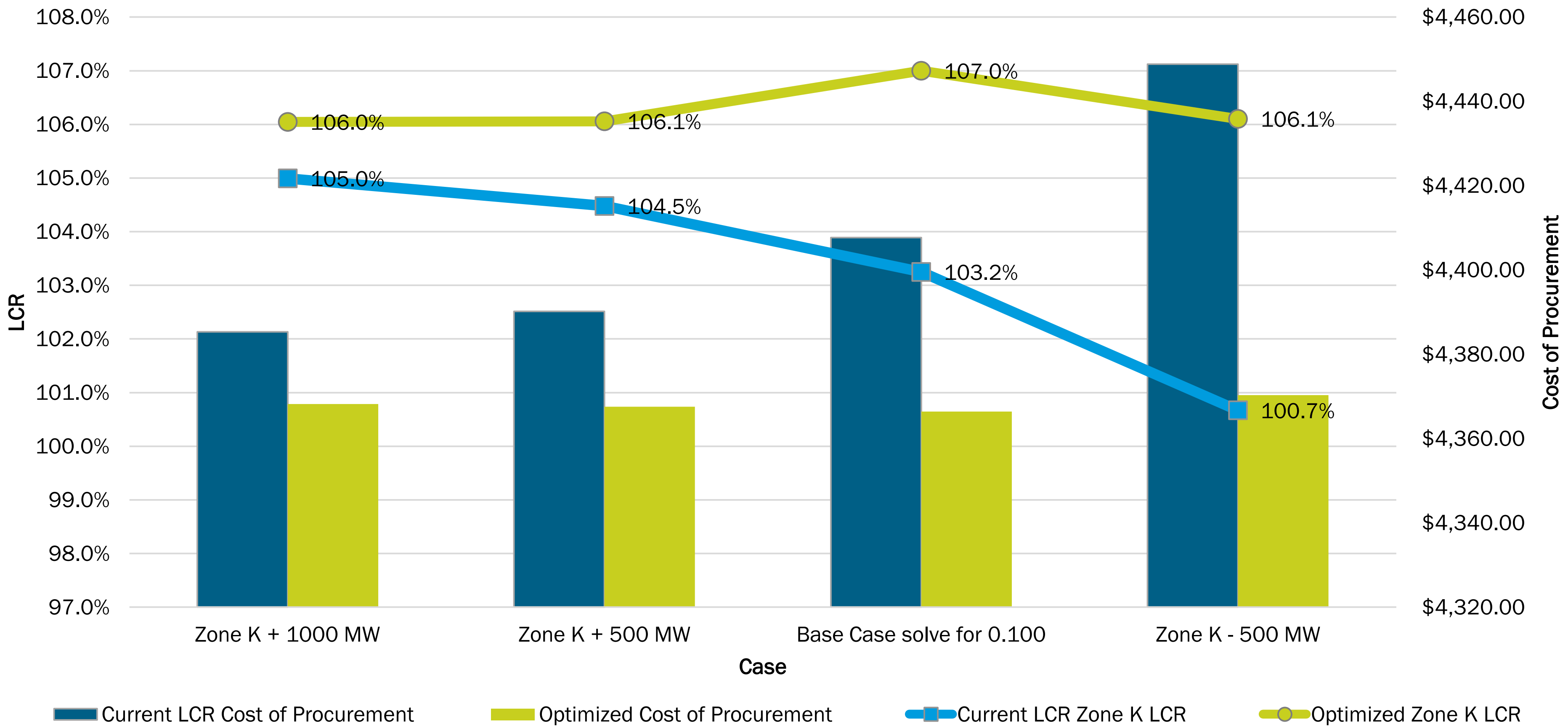
Changes to Capacity in J: GHIJ LCR



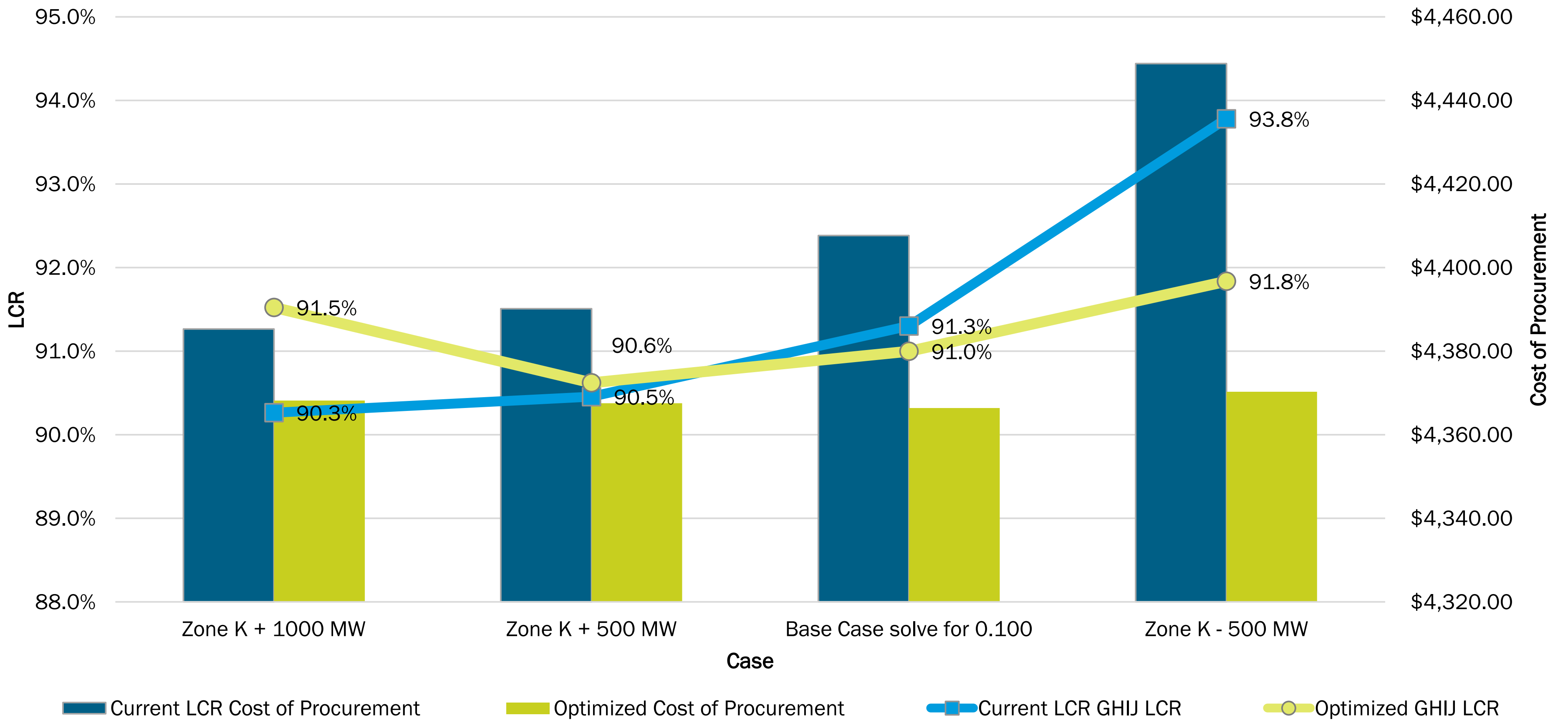
Changes to Capacity in K: Zone J LCR



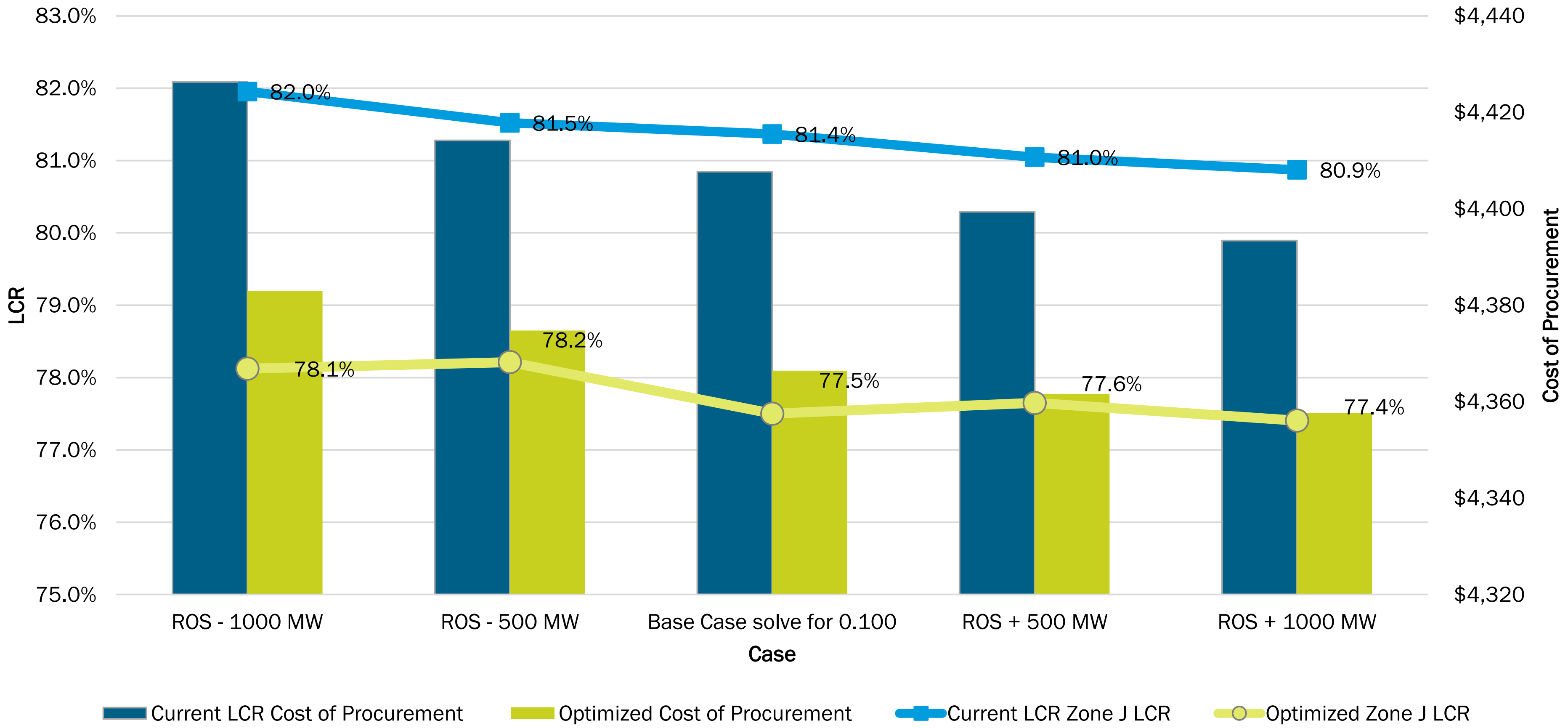
Changes to Capacity in K: Zone K LCR



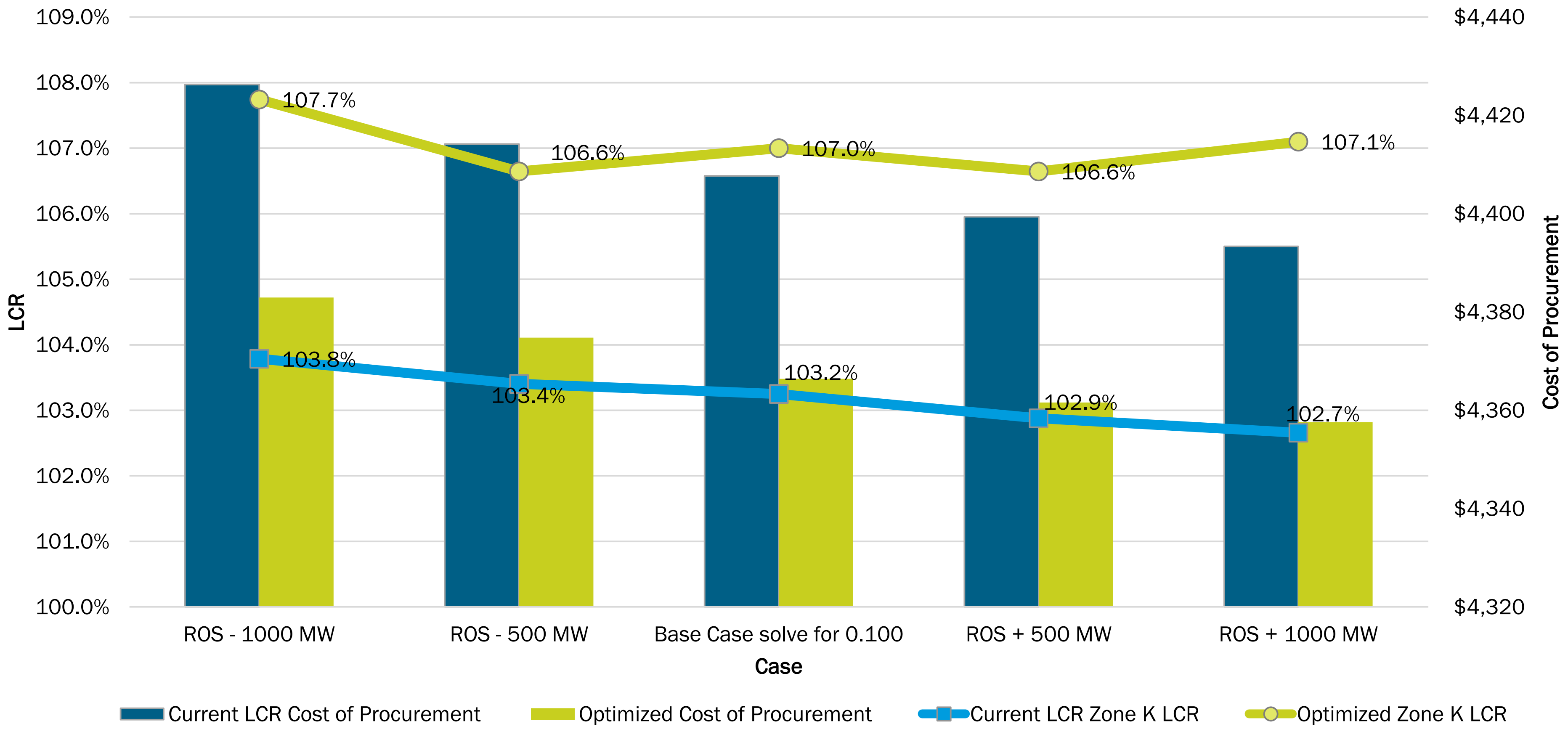
Changes to Capacity in K: GHIJ LCR



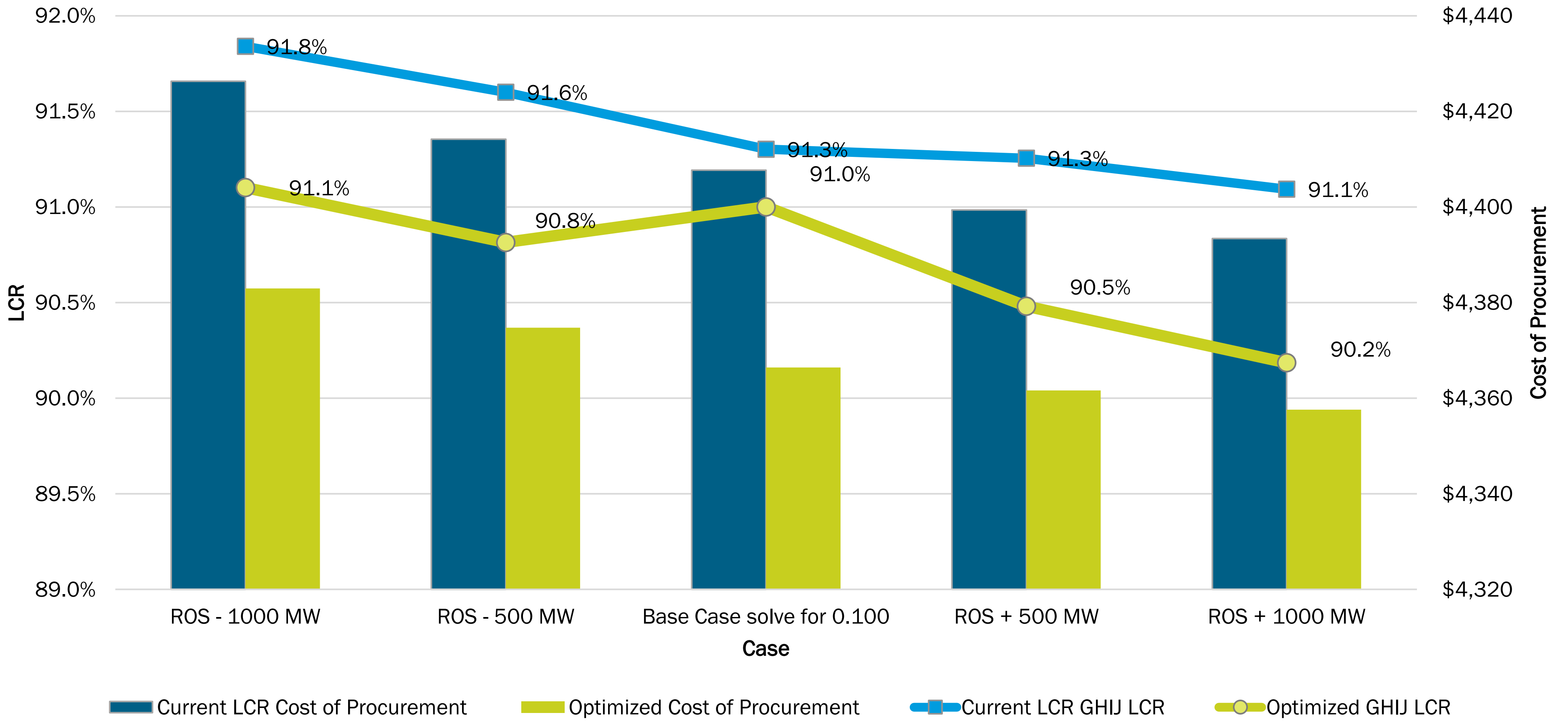
Changes to Capacity in ROS: Zone J LCR



Changes to Capacity in ROS: Zone K LCR



Changes to Capacity in ROS: GHIJ LCR



Changes in Capacity: Comparative Results

Scenario	Δ Optimized LCR from Optimized Base Case (%)			Δ Current LCR case from Current LCR Base Case (%)		
	Zone J	Zone K	G-J	Zone J	Zone K	G-J
+500 MW in GHIJ	0.2	0.7	0.1	-1.3	-0.5	2.3
- 500 MW in GHIJ	0.0	0.5	-1.0	1.6	0.6	-1.7
+500 MW in J	0.4	0.0	-0.6	0.5	-0.7	0.6
-500 MW in J	0.1	0.6	-0.5	-1.0	0.9	-0.6
+500 MW in K	0.6	-0.9	-0.4	-1.3	1.3	-0.8
-500 MW in K	0.1	-0.9	0.8	3.0	-2.5	2.5
+500 MW in ROS	0.1	-0.4	-0.5	-0.4	-0.3	-0.0
-500 MW in ROS	0.7	-0.4	-0.2	0.1	0.2	0.3
Average Absolute Δ from Base	**0.3**	**0.6**	**0.5**	**1.2**	**0.9**	**1.1**

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Changes in Capacity: Comparative Results

Scenario	Δ Optimized LCR from Optimized Base Case (%)			Δ Current LCR case from Current LCR Base Case (%)		
	Zone J	Zone K	G-J	Zone J	Zone K	G-J
+1000 MW in GHIJ	0.4	0.9	0.5	-1.5	-0.8	5.5
- 1000 MW in GHIJ	-0.5	0.2	-1.0	3.9	1.7	-3.3
+1000 MW in J	0.4	0.0	-0.6	1.1	-1.2	1.0
-1000 MW in J	0.2	-1.0	0.6	-2.2	3.0	-1.5
+1000 MW in K	0.2	-1.0	0.5	-1.7	1.8	-1.0
+1000 MW in ROS	-0.1	0.1	-0.8	-0.5	-0.5	-0.2
-1000 MW in ROS	0.6	0.7	0.1	0.6	0.6	0.5
Average Absolute Δ from Base	**0.3**	**0.6**	**0.6**	**1.6**	**1.4**	**1.9**

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Changes in Capacity: Cost Comparison

Scenario	Current LCR Methodology Cost (million)	Optimized LCR Methodology Cost (million)	Δ Cost (million)
Base Case	$4,407.7	$4,366.4	$41.3
GHIJ + 500 MW	$4,406.0	$4,374.6	$31.4
GHIJ - 500 MW	$4,422.2	$4,359.8	$62.4
Zone J + 500 MW	$4,416.0	$4,367.2	$48.9
Zone J - 500 MW	$4,394.1	$4,366.7	$27.4
Zone K + 500 MW	$4,390.2	$4,367.6	$22.6
Zone K - 500 MW	$4,448.8	$4,370.3	$78.5
ROS + 500 MW	$4,399.4	$4,361.6	$37.7
ROS - 500 MW	$4,414.2	$4,374.8	$39.4

- Cost presented is the solution cost from the optimization objective function
- The objective function represents the cost of capacity procurement at the given requirement

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Changes in Capacity: Cost Comparison

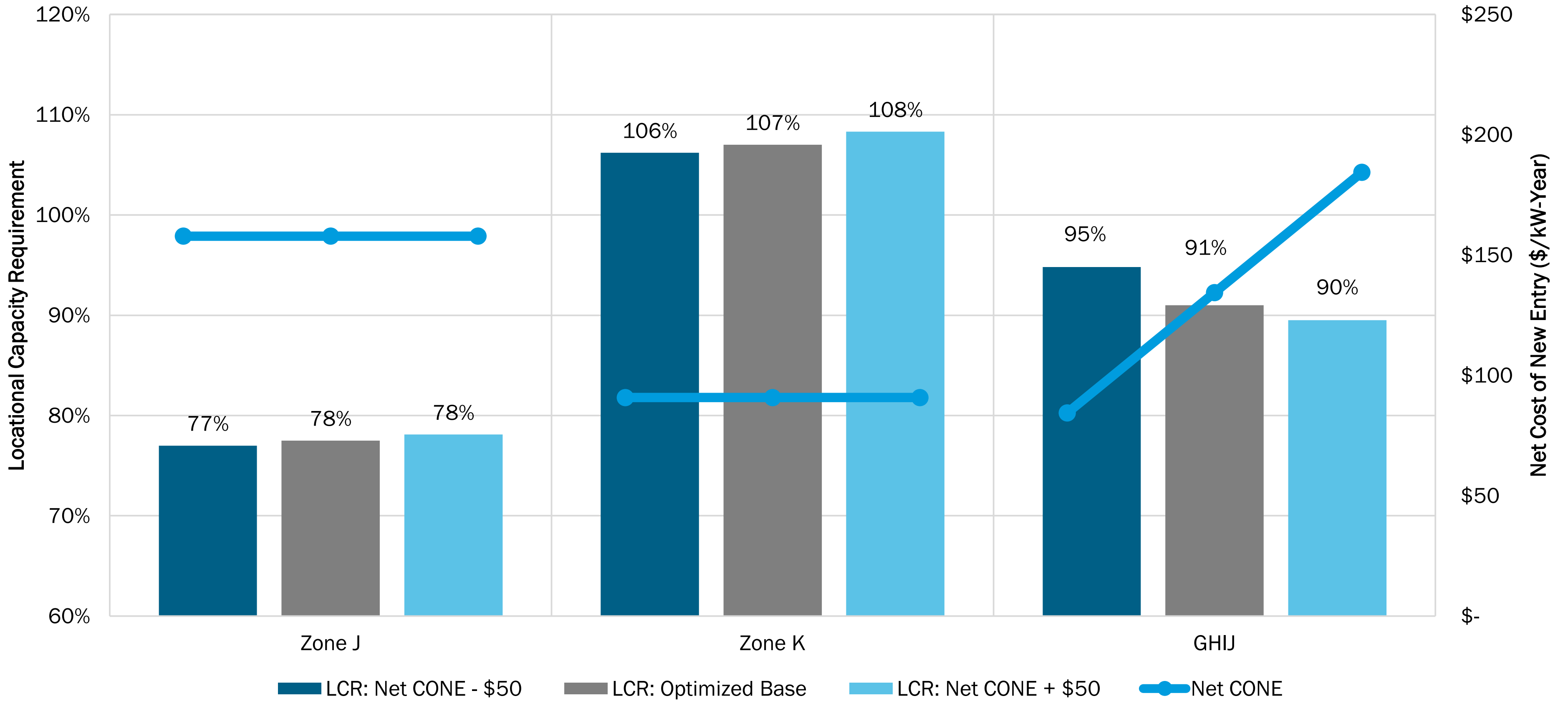
Scenario	Current LCR Methodology Cost (million)	Optimized LCR Methodology Cost (million)	Δ Cost (million)
Base Case	$4,407.7	$4,366.4	$41.3
GHIJ + 1000 MW	$4,430.2	$4,383.5	$46.7
GHIJ - 1000 MW	$4,443.8	$4,350.4	$93.4
Zone J + 1000 MW	$4,423.5	$4,367.2	$56.3
Zone J - 1000 MW	$4,379.2	$4,368.5	$10.7
Zone K + 1000 MW	$4,385.3	$4,368.2	$17.1
ROS + 1000 MW	$4,393.4	$4,357.6	$35.8
ROS - 1000 MW	$4,426.3	$4,383.0	$43.3

Changes in Capacity: Conclusions

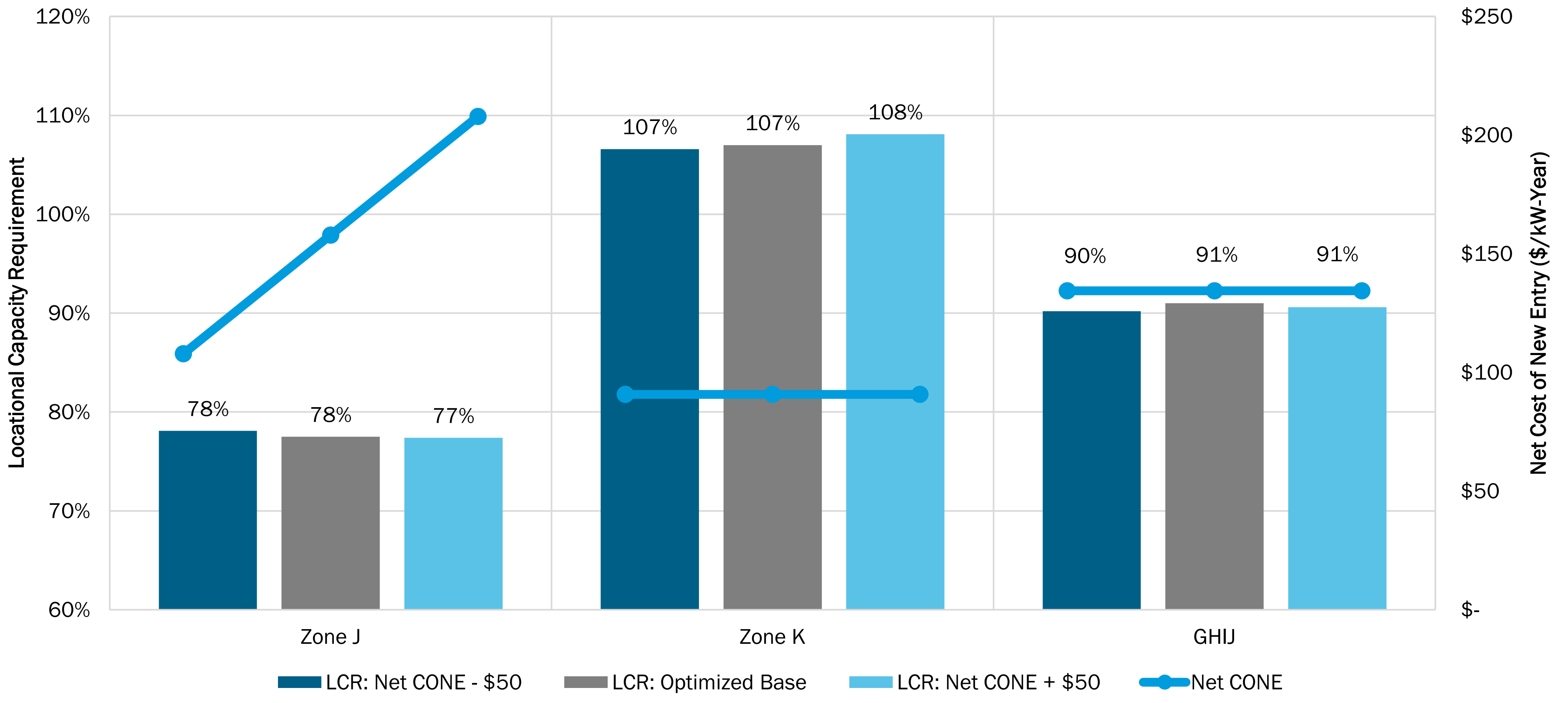
- The optimized methodology reduces volatility in comparison to the current LCR methodology when there are changes in capacity
- Secondary effects observed in the optimization will be investigated in Phase 2

Changes in Net CONE Sensitivities

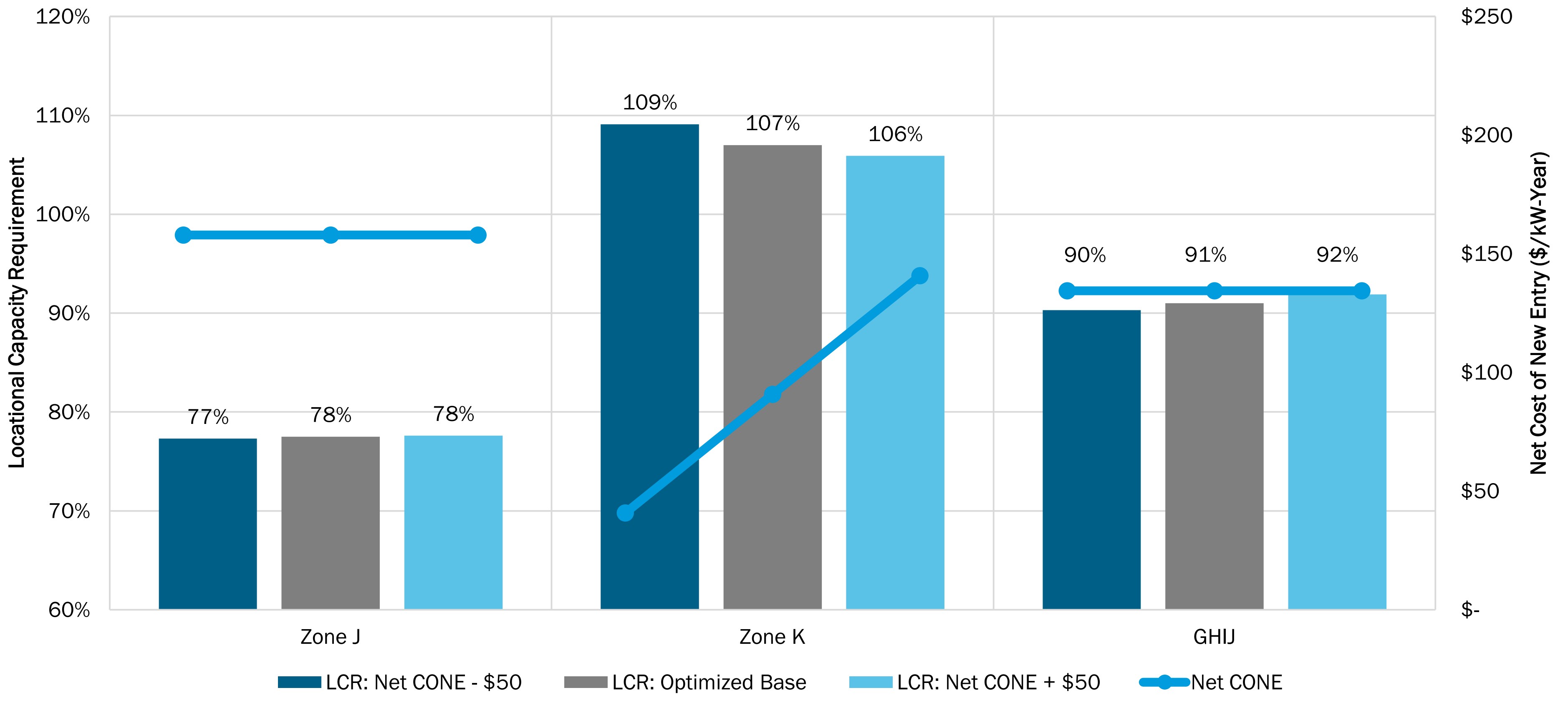
Net CONE Curves: +/- $50 GHIJ



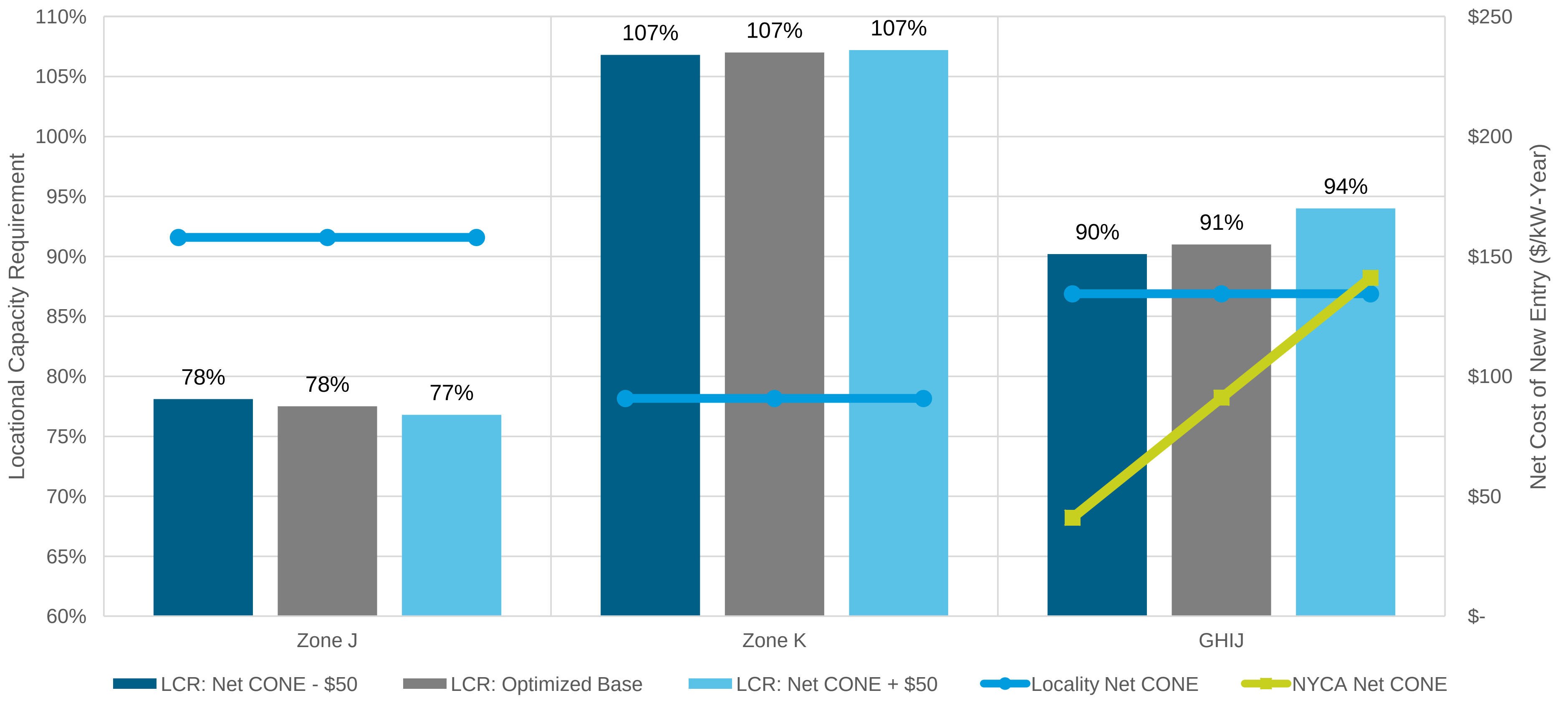
Net CONE Curves: +/- $50 Zone J



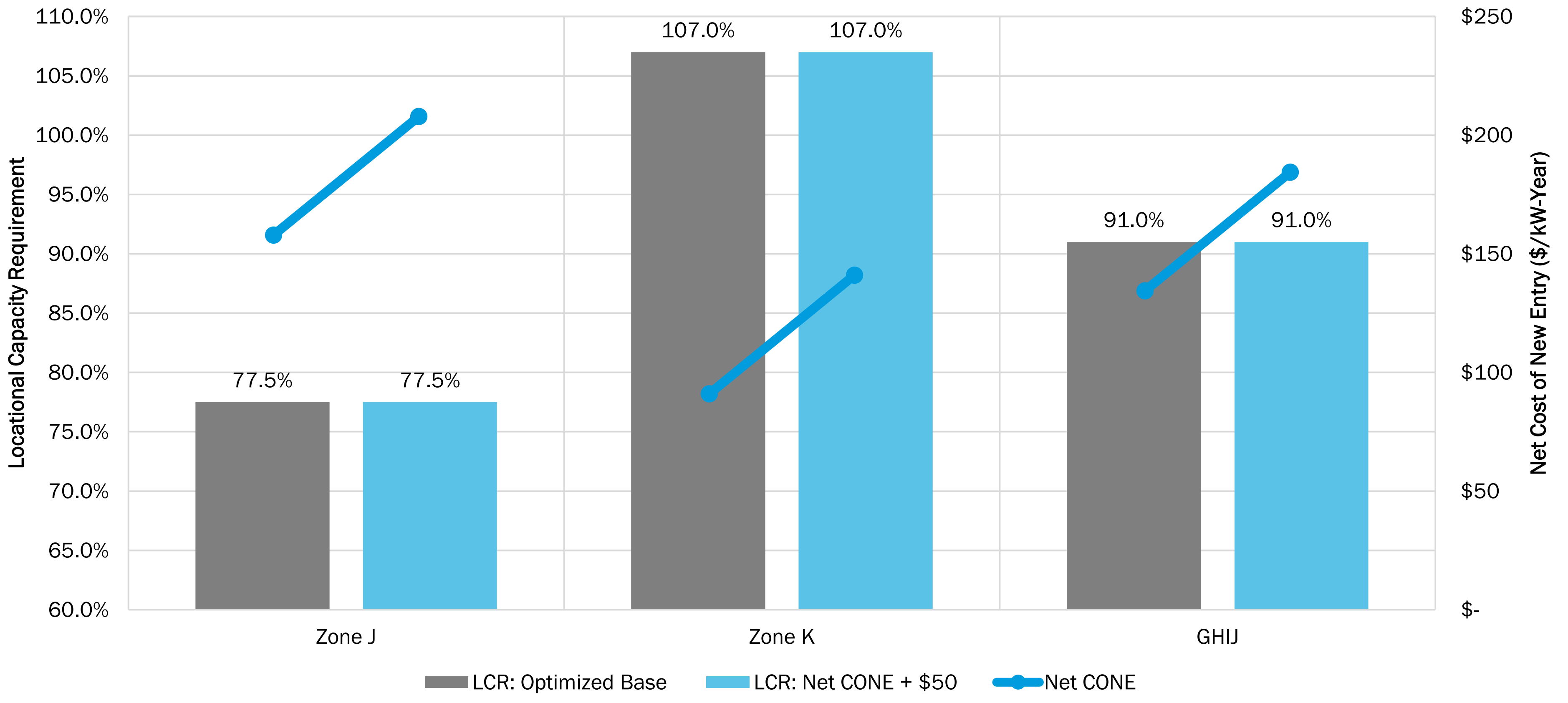
Net CONE Curves: +/- $50 Zone K



Net CONE Curves: +/- $50 NYCA



Net CONE Curves: +$50 All Zones



Changes in Net CONE: Cost Comparison

Scenario	Current LCR Methodology Cost (million)	Optimized LCR Methodology Cost (million)	Δ Cost (million)
Base Case	$4,413.7	$4,366.4	$47.3
GHIJ Net CONE + $50	$5,148.5	$5,090.3	$58.2
GHIJ Net CONE - $50	$4,154.4	$4,079.8	$74.6
Zone J Net CONE + $50	$4,889.3	$4,818.7	$70.6
Zone J Net CONE - $50	$3,938.1	$3,911.8	$26.3
Zone K Net CONE + $50	$5,170.1	$5,109.2	$60.9
Zone K Net CONE - $50	$4,132.8	$4,073.7	$59.1
NYCA Net CONE + $50	$5,831.1	$5,747.2	$83.9
NYCA Net CONE - $50	$3,471.9	$3,424.9	$47.0
All Net CONE + $50	$6,371.2	$6,323.9	$47.3

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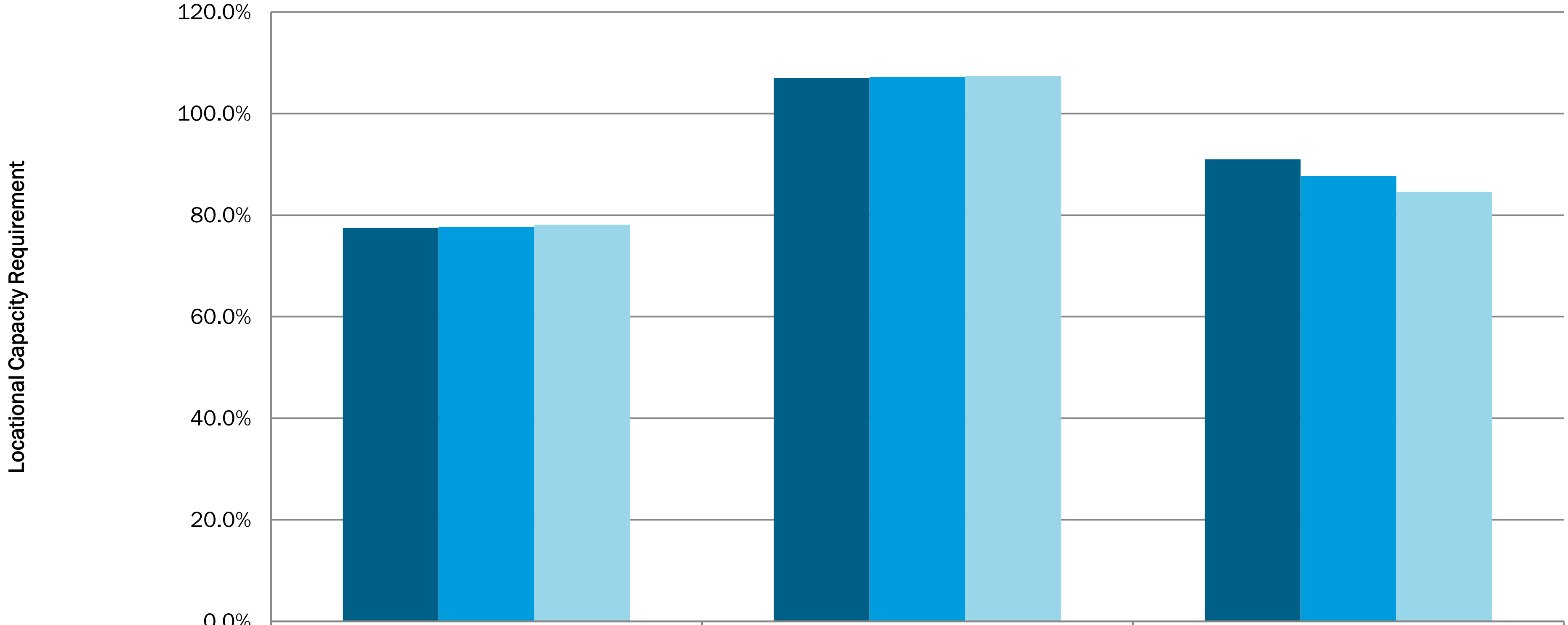
Changes in Net CONE: Conclusions

- The sensitivities tested extreme changes (i.e., between 30% and 55% change in Net CONE)
- The optimized LCR responded intuitively to the changes in Net CONE (i.e., increase in Net CONE in most instances causes a reduction in LCR)
- The Net CONE can have an impact on the final optimized LCRs
- This places an emphasis on developing robust methodology for determining the cost curves

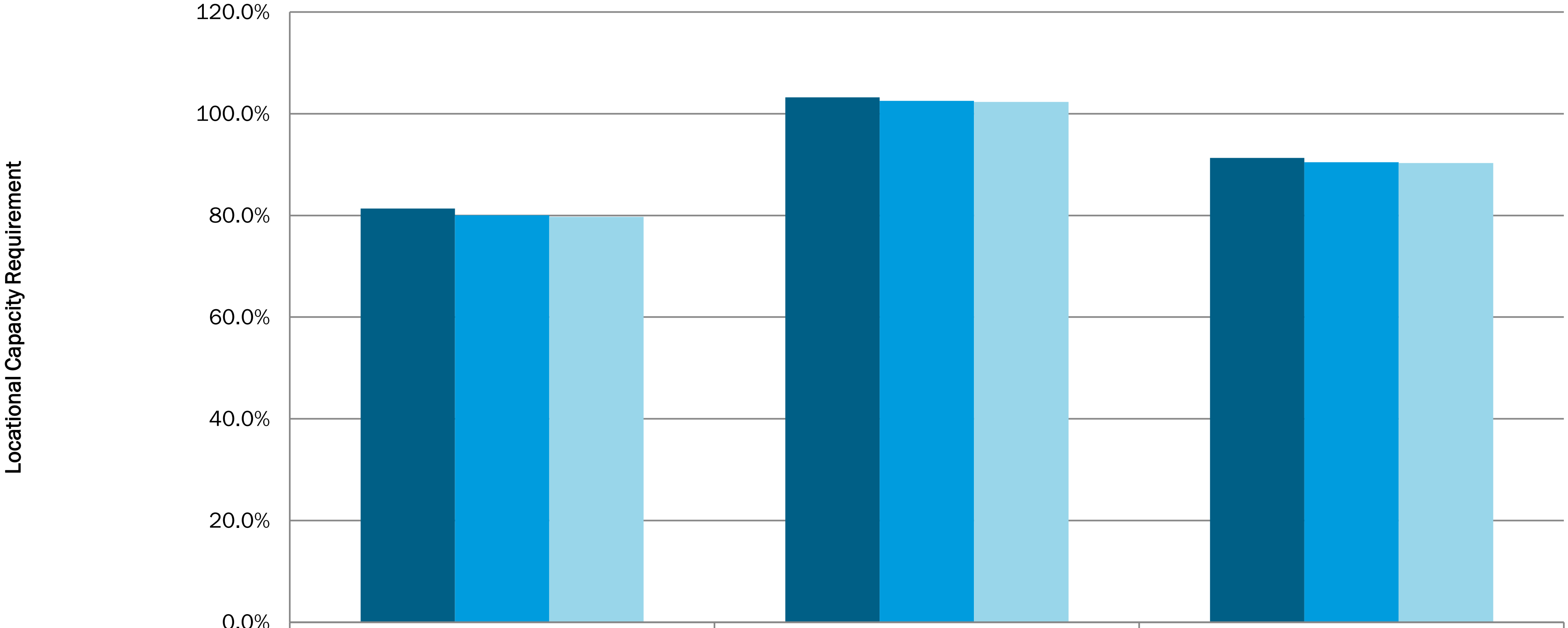
Changes in Transmission Sensitivities

Changes in Transmission: Optimized Methodology



	Zone J LCR	Zone K LCR	GHIJ LCR
Base Case	77.5%	107.0%	91.0%
UPNY-SENY + 500 MW	77.7%	107.2%	87.7%
UPNY-SENY + 1000 MW	78.1%	107.4%	84.6%

Changes in Transmission: Current Methodology



	Zone J LCR	Zone K LCR	GHIJ LCR
Base Case solve for 0.100	81.4%	103.2%	91.3%
UPNY-SENY + 500 MW	80.0%	102.5%	90.5%
UPNY-SENY + 1000 MW	79.7%	102.3%	90.3%

Changes in Transmission: Conclusions of Simple Analysis

- There are limitations to this simple analysis since changes in UPNY-SENY transmission would likely result in a change in the IRM
- The conclusions based on the simple analysis presently are:
  - UPNY-SENY reduces amount of optimal capacity required in GHIJ, but does not impact the amount for Zone J
  - The Zone J LCR is minimized to its optimal level in the Base Case (as a result of constraints south of UPNY-SENY)
  - Future sensitivity will seek to confirm that the optimal Zone J LCR is dependent on the downstream constraints by increasing Dunwoodie South limit to observe if the optimal Zone J LCR decreases

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Phase 1: Conclusions and Next Steps

- Perform sensitivities to assist in the understanding of any secondary effects observed in changes in generation sensitivities
- Work to potentially refine methodology to address these secondary effects
- Develop a robust methodology for determining cost curves that minimizes volatility
- Run a full Tan45 process for a few specific sensitivities to increase the understanding of how the current process and optimization responds
- While cost savings are only 1-2%, the process has numerous other benefits
  - Stability, more robust, intuitive, etc.

Phase 2: Refining Methodology

Transmission Security

- The NYISO continues to work to develop values for the lower bounds
- Sensitivities were performed to show how the optimization could incorporate lower bounds
  - Incorporated an arbitrary lower bound for Zone J of 80%

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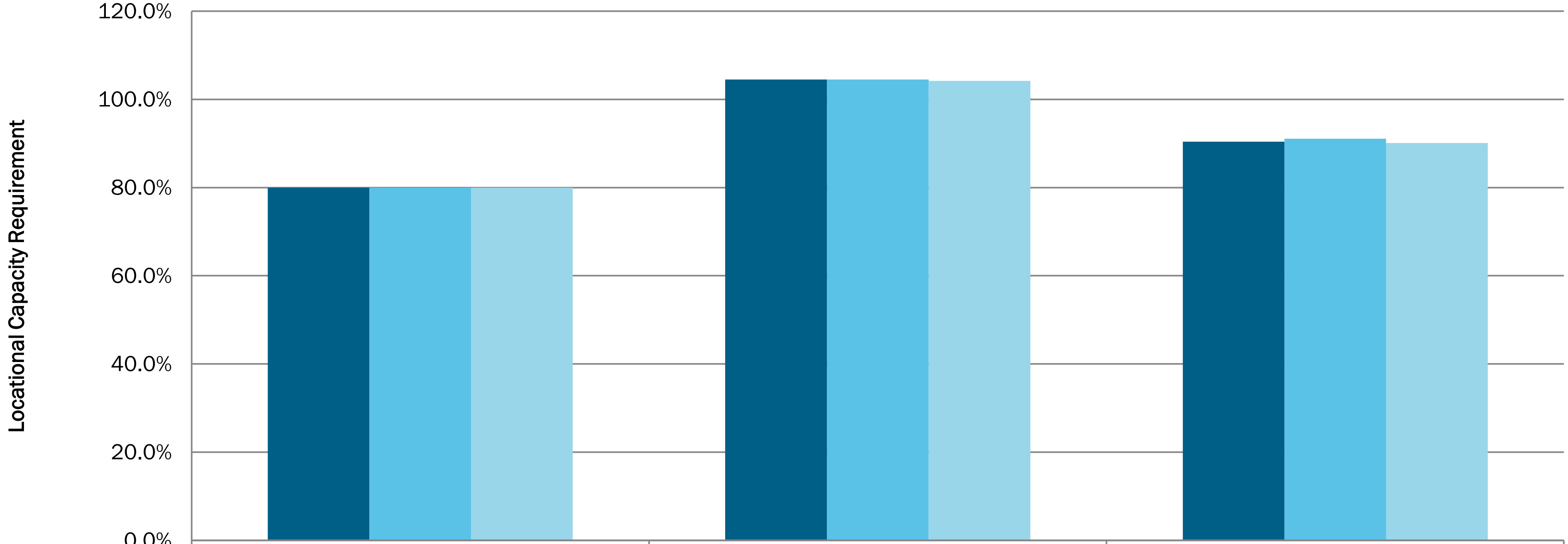
Changes in Generation: Optimized Methodology with Lower Bound



	Zone J LCR	Zone K LCR	GHIJ LCR
Base Case LB J	80.0%	104.5%	90.4%
GHIJ + 500 MW	80.0%	104.5%	91.1%
GHIJ - 500 MW	80.0%	104.2%	90.1%

Lower Bound Comparison of Costs

Scenario	Optimized LCR with Lower Bound Cost (million)	Current LCR Methodology Cost (million)	Δ Cost (million)
Base Case	$4,387.7	$4,407.7	$20.00
+500 MW in GHIJ	$4,394.6	$4,406.0	$11.40
-500 MW in GHIJ	$4,381.7	$4,422.2	$40.50

Lower Bound Conclusions

- The optimization with a lower bound still results in a lower cost when compared to the current methodology
- The optimization still reduces volatility when a lower bound is incorporated

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Cost Curves

- Phase 1 simple sensitivities only investigated how the magnitude of the cost curves impact the optimization
- Phase 2 will perform analysis and sensitivities to:
  - Investigate the impact of cost curves' shape on optimization
  - Develop a robust methodology for generating the curves
  - Seek to reduce any unnecessary volatility from cost curves

Next Steps

Next Steps

- The NYISO will consider input received during today's ICAP Working Group meeting
- Any additional comments sent to deckels@nyiso.com will be considered
- The NYISO will return to a future ICAPWG meeting to discuss its progress and adjustments to the plan after considering comments or results

2017 Project Development

Stage	Objective	Specific Topics:
Proof of Concept	Demonstrate alternative methodology in relation to guiding principles (*i.e.*, least cost, stability, robust, predictability)	Generation +/- Unit net CONE +/- Transmission +/-
Refine Methodology	Modify the alternative method to ensure that all aspects have a purpose and are being performed as a result of sound market and engineering principles	Unit net CONE curves Potential Bounds Modeling methodology
Market Simulations	Simulate realistic market situations to demonstrate performance of methodology	Changes in resources Topological changes Locality configurations
Defining Process	Develop a process for the methodology that ensures guiding principles are being achieved over time	Develop process of method Process timeline Transition methods
Demonstrating Market Benefits	Demonstrate the methodology results in market benefits and resolve any issues that arise from its implementation	LOLE Criterion Consumer impact Multiyear simulation Cost allocation
Final Market Design	Summarize all findings and develop a final market design for implementation	Develop final market design

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Questions?

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- 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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Appendix

Changes in Capacity: 500 MW

Scenario	Optimized LCR (%)			Current LCR Methodology (%)			Optimized Cost (million)	Current LCR Cost (million)
	Zone J	Zone K	G-J	Zone J	Zone K	G-J		
Base Case	77.5	107.0	91.0	81.4	103.2	91.3	$4,366.4	$4,407.7
+500 MW in G	77.7	107.7	91.1	80.2	102.7	93.6	$4,374.6	$4,406.0
- 500 MW in G	77.5	107.5	90.0	83.0	103.8	89.6	$4,359.8	$4,422.2
+500 MW in J	77.9	107.0	90.4	81.9	102.5	91.9	$4,367.2	$4,416.1
-500 MW in J	77.6	107.6	90.5	80.4	104.1	90.7	$4,366.7	$4,394.1
+500 MW in K	78.1	106.1	90.6	80.1	104.5	90.5	$4,367.6	$4,390.2
-500 MW in K	77.6	106.1	91.8	84.4	100.7	93.8	$4,370.3	$4,448.8
+500 MW in ROS	77.6	106.6	90.5	81.0	102.9	91.3	$4,361.6	$4,399.4
-500 MW in ROS	78.2	106.6	90.8	81.5	103.4	91.6	$4,374.8	$4,414.2

Changes in Capacity: 1000 MW

Scenario	Optimized LCR (%)			Current LCR Methodology (%)			Optimized Cost (million)	Current LCR Cost (million)
	Zone J	Zone K	G-J	Zone J	Zone K	G-J		
Base Case	77.5	107.0	91.0	81.4	103.2	91.3	$4,366.4	$4,407.7
+1000 MW in G	77.9	107.9	91.5	79.9	102.4	96.8	$4,383.5	$4,430.2
- 1000 MW in G	77.0	107.2	90.0	85.3	104.9	88.0	$4,350.4	$4,443.8
+1000 MW in J	77.9	107.0	90.4	82.5	102.0	92.3	$4,367.2	$4,423.5
-1000 MW in J	77.7	106.0	91.6	79.2	106.2	89.8	$4,368.5	$4,379.2
+1000 MW in K	77.7	106.0	91.5	79.7	105.0	90.3	$4,368.2	$4,385.3
+1000 MW in ROS	77.4	107.1	90.2	80.9	102.7	91.1	$4,357.6	$4,393.4
-1000 MW in ROS	78.1	107.7	91.1	82.0	103.8	91.8	$4,383.0	$4,426.3

Changes in Net CONE

Scenario	Optimized LCR (%)			Current LCR Methodology (%)			Optimized Cost (million)	Current LCR Cost (million)
	Zone J	Zone K	G-J	Zone J	Zone K	G-J		
Base Case	77.5	107.0	91.0	81.5	103.5	91.5	$4,366.4	$4,413.7
+$50 GHIJ	78.1	108.3	89.5	81.5	103.5	91.5	$5,090.3	$5,148.5
-$50 GHIJ	77.0	106.2	94.8	81.5	103.5	91.5	$4,079.8	$4,154.4
+$50 Zone J	77.4	108.1	90.6	81.5	103.5	91.5	$4,818.7	$4,889.3
-$50 Zone J	78.1	106.6	90.2	81.5	103.5	91.5	$3,911.8	$3,938.1
+$50 Zone K	77.6	105.9	91.9	81.5	103.5	91.5	$5,109.2	$5,170.1
-$50 Zone K	77.3	109.1	90.3	81.5	103.5	91.5	$4,073.7	$4,132.8
+$50 NYCA	76.8	107.2	94.0	81.5	103.5	91.5	$5,747.2	$5,831.1
-$50 NYCA	78.1	106.8	90.2	81.5	103.5	91.5	$3,424.9	$3,471.9
+$50 All Zones	77.5	107.0	91.0	81.5	103.5	91.5	$6,323.9	$6,371.2

Changes in Transmission

Scenario	Optimized LCR (%)			Current LCR Methodology (%)			Optimized Cost (million)	Current LCR Cost (million)
	Zone J	Zone K	G-J	Zone J	Zone K	G-J		
Base Case	77.5	107.0	91.0	81.4	103.2	91.3	$4,366.4	$4,413.7
UPNY-SENY+500 MW	77.7	107.2	87.7	80.0	102.5	90.5	$4,342.1	$4,369.9
UPNY-SENY+1000 MW	78.1	107.4	84.6	79.7	102.3	90.3	$4,325.6	$4,362.4

Exhibit 20

Alternative Methods for Determining LCRs

Zachary Stines

Associate Market Design Specialist

Installed Capacity Working Group

June 1, 2017, NYISO

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Agenda

- **Phase 2: Refining the Methodology**
  - Follow-up from Phase 1
  - Cost curves
- **Phase 3: Market Simulations**
- **Next Steps**
- **Questions**

Phase 2: Refining the Methodology

Phase 2: Refining Methodology

- **Follow-up on Phase 1**
  - Seek to analyze and understand questions raised in Phase 1 and not yet addressed
- **Cost curves**
  - Seek to evaluate and understand how the cost curve shape impacts the optimization
  - Identify candidate cost curve methods and shapes

Phase 1 Follow-up

Phase 1 Follow-up

- **Following the May 11th ICAPWG, GE:**
  - Finished remaining Phase 1 sensitivities
  - Reran specific cases in which the results had appeared to be potentially anomalous
  - Performed new sensitivities aimed at answering certain questions raised in Phase 1 (e.g., increase in transmission capability of Dunwoodie South)
  - Perform a complete Tan45 on select sensitivities

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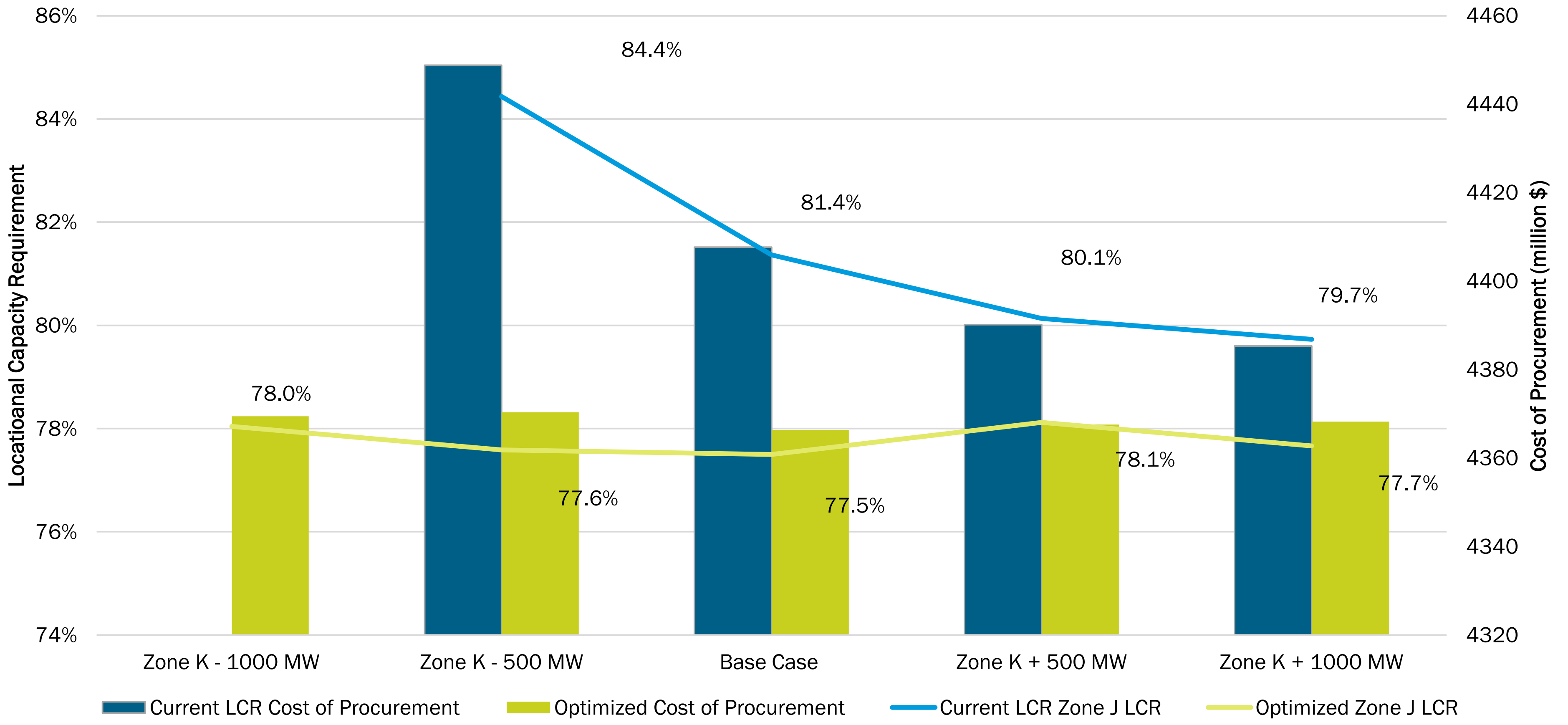
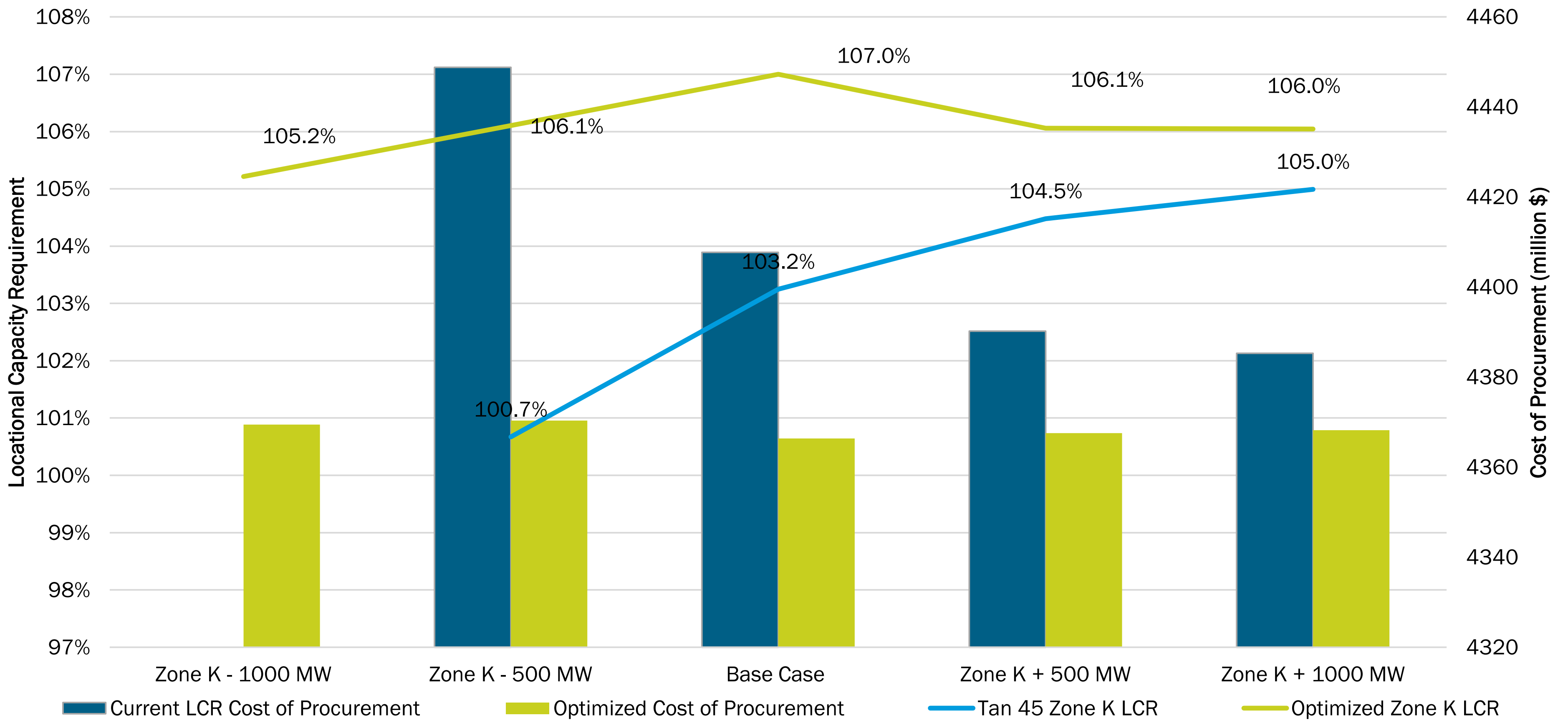
Finished Results: Zone K

- -1000 MW in Zone K case was finished since the May 11th ICAPWG presentation

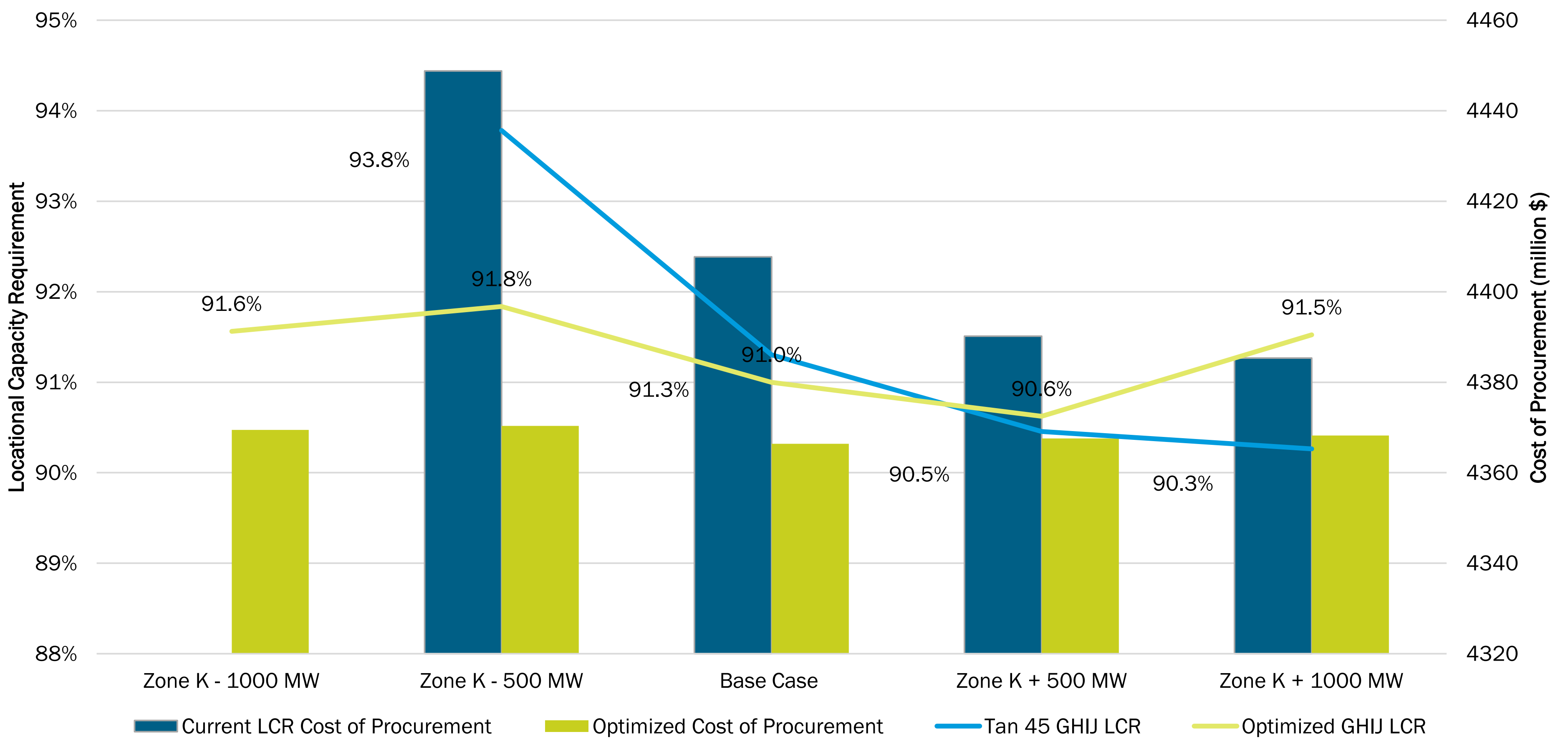
Changes to Zone K Capacity: Zone J LCR



Changes in Zone K Capacity: Zone K LCR



Changes in Zone K Capacity: GHIJ LCR



Increase in Transmission Capability

- Phase 1 sensitivity showed that increasing the transmission capability of UPNY-SENY reduced the optimal amount of capacity required in GHIJ, yet minimally impacted Zone J
- It was hypothesized that Zone J LCR is minimized to its optimal level as a result of constraints south of UPNY-SENY
- Two new sensitivities sought to test this:
  - Dunwoodie South +1000 MW
  - UPNY-SENY +1000MW & Dunwoodie South +1000MW

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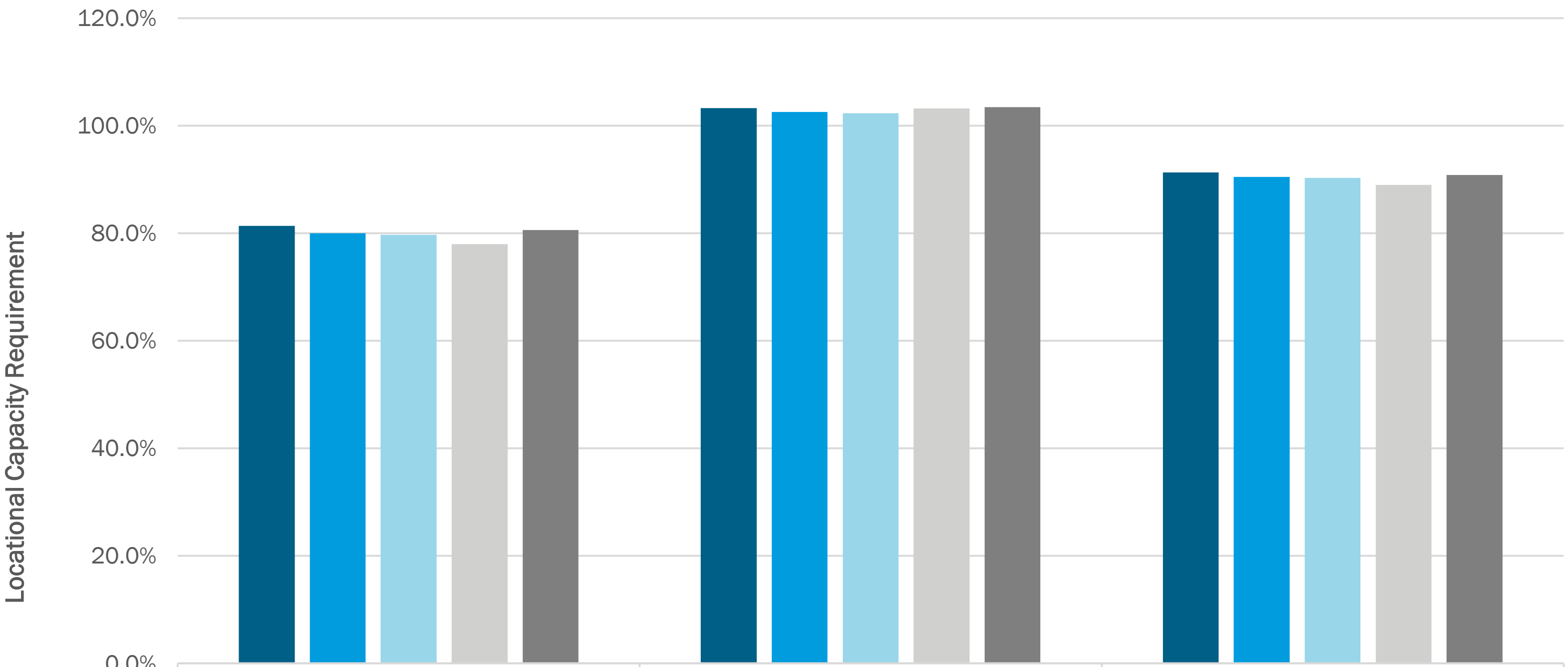
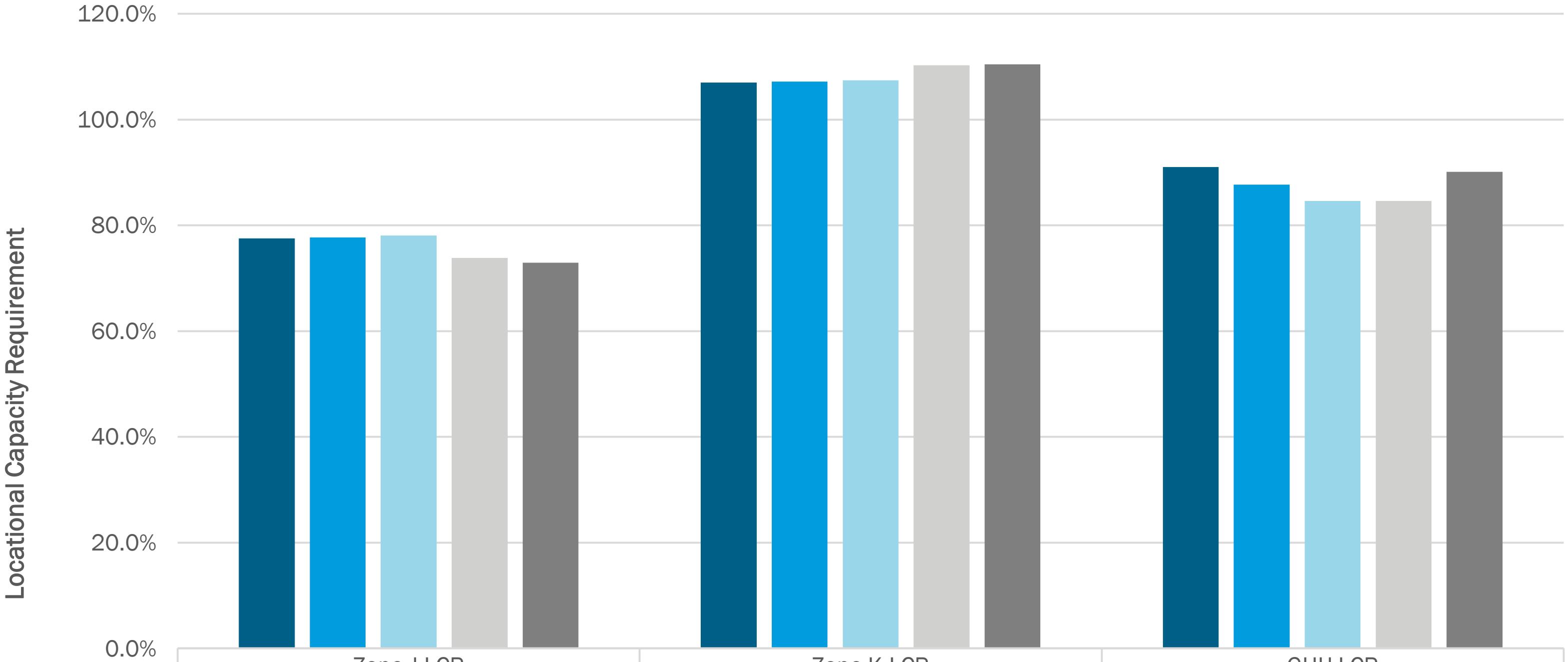
Changes in Transmission: Current LCR Methodology



	Zone J LCR	Zone K LCR	GHIJ LCR
Base Case solve for 0.100	81.4%	103.2%	91.3%
UPNY-SENY + 500 MW	80.0%	102.5%	90.5%
UPNY-SENY + 1000 MW	79.7%	102.3%	90.3%
Dunwoodie South, UPNY-SENY +1000 MW	78.0%	103.2%	89.0%
Dunwoodie South +1000 MW	80.6%	103.4%	90.8%

Changes in Transmission: Optimization Methodology



	Zone J LCR	Zone K LCR	GHIJ LCR
Base Case solve for 0.100	77.5%	107.0%	91.0%
UPNY-SENY + 500 MW	77.7%	107.2%	87.7%
UPNY-SENY + 1000 MW	78.1%	107.4%	84.6%
Dunwoodie South, UPNY-SENY +1000 MW	73.8%	110.3%	84.6%
Dunwoodie South +1000 MW	72.9%	110.4%	90.1%

Changes in Transmission Sensitivities Conclusions

- The optimization limits Zone J capacity requirement subject to the constraints south of UPNY-SENY
- Transmission changes can have an impact on the tradeoffs between capacity within each Locality
  - Increase in Dunwoody South capability results in the optimal requirements for Zone K to increase while Zone J decreases

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Complete Tan45

- Based upon stakeholder input, the following sensitivities were initialized using a complete Tan45
  - Changes in capacity within G-J locality
  - Increase in the transmission capability of UPNY-SENY

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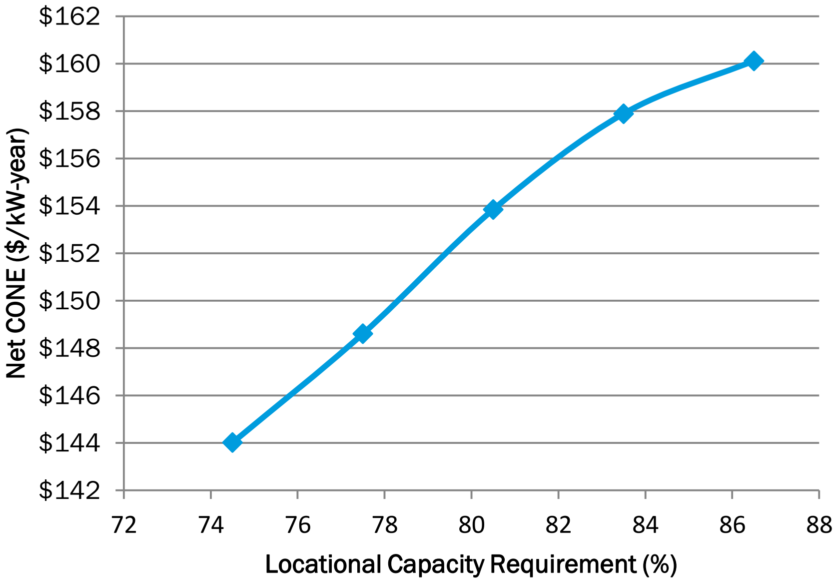
Cost Curves

What defines the cost curves?

- These curves define the cost used within the optimization of each Locality
- They are a function of the Locality's Minimum Installed Capacity Requirement



Which cost to use?

- **Net CONE**
  - Net cost of new entry ("CONE") for the Demand Curve peaking unit
- **Reference Point Price**
  - The price on the Demand Curve at 100 % of the requirement and is a function of the Net CONE and level of excess
- **Gross CONE**
  - Total cost of new entry; i.e., without netting any revenues

What is the shape of the curve?

- **6 point Cost Curves (currently being used in optimization)**
  - Developed using GE MAPS in a process comparable to that used in the Demand Curve reset
  - Evaluate Net EAS at -6%, -3%, +3%, and +6% to develop curve
- **Single value**
  - Could potentially develop a single cost for the capacity that is not dependent on the quantity of Installed Capacity
- **Other relationships (e.g., linear, 3-point, etc.)**

Different Cost Curves being Evaluated

- **Single value**
  - Net CONE
  - Gross CONE
  - Reference point price
- **6 point cost curve**
  - Net CONE curves based on MAPS
  - Reference point price

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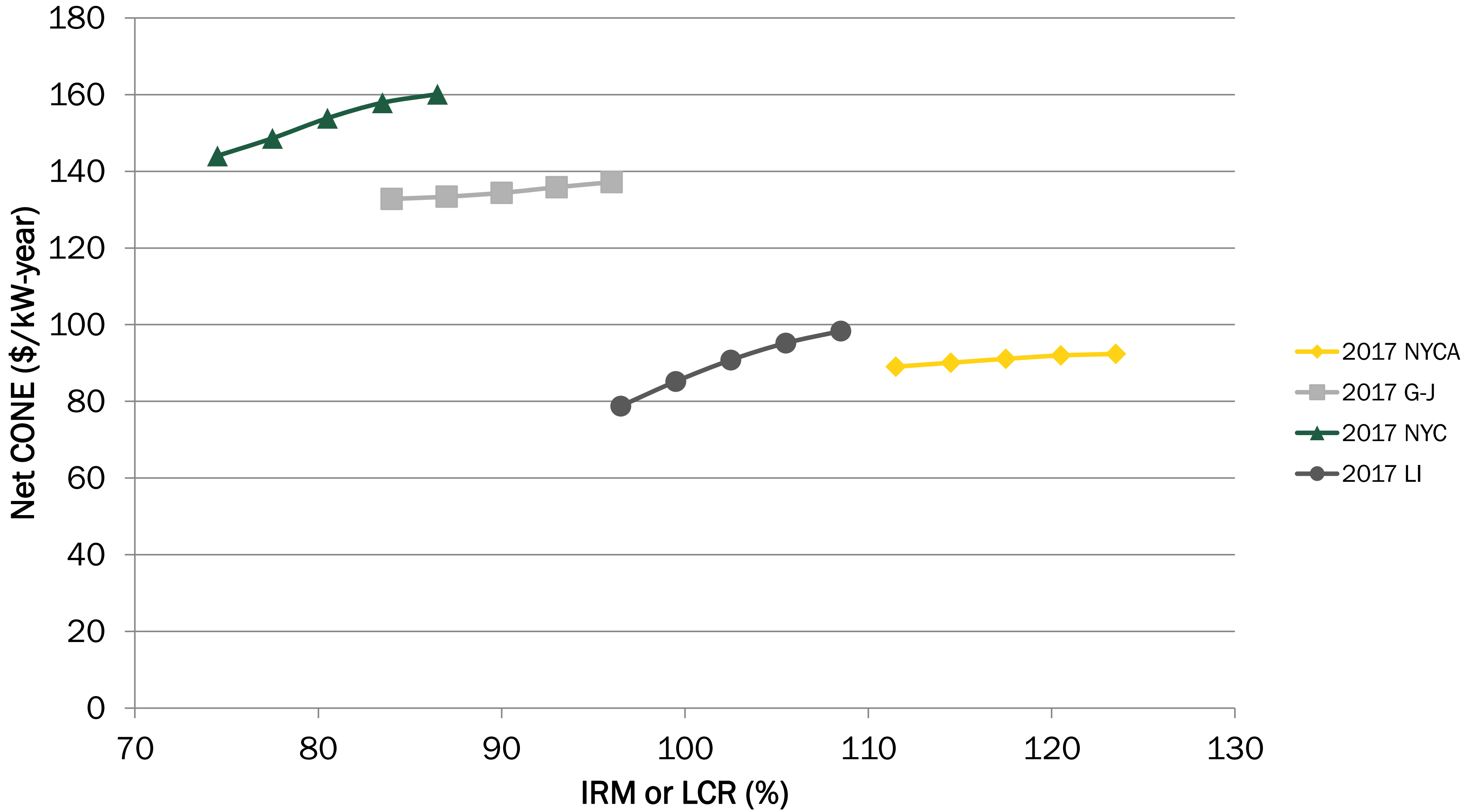

180
160
140
120
100
80
60
40
20
0
Net CONE ($/kW-year)
70
80
90
100
110
120
130
IRM or LCR (%)
2017 NYCA
2017 G-J
2017 NYC
2017 LI

How often will these cost curves change?

- Periodicity of cost curve
  - Understand the impacts of the cost curve periodicity
  - Annually updated or fixed for a set number of years?
- Time horizon used to develop cost curve
  - How many years should be evaluated to determine the cost curves?
  - 1 year, 3 years, >3 years, etc.

Next Steps

Phase 3: Market Simulations

- **Goal:** Simulate realistic market situations to demonstrate performance of methodology
  - Evaluate how the process would be performed with full Tan45 followed by optimization
  - Perform sensitivities that are expected to transpire within the coming years (e.g., capacity entry, capacity exit, transmission builds, etc.)

Consumer Impact

- Consumer impact analysis will be provided for this project
- Methodology of the analysis will be provided and presented this summer
- Final analysis will be presented in the fall

Other Next Steps

- The NYISO will consider input received during today's ICAP Working Group meeting
- Additional comments sent to deckels@nyiso.com will be considered
- The NYISO will return to a future ICAPWG meeting to discuss its progress and adjustments to the plan after considering comments or results

2017 Project Development

Stage	Objective	Specific Topics:
Proof of Concept	Demonstrate alternative methodology in relation to guiding principles (*i.e.*, least cost, stability, robust, predictability)	Generation +/- Unit net CONE +/- Transmission +/-
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Questions?

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Exhibit 21

Alternative Methods for Determining LCRs

Zachary Stines
Associate Market Design Specialist

Installed Capacity Working Group

June 29, 2017, NYISO

NEW YORK INDEPENDENT SYSTEM OPERATOR

Agenda

- **Phase 2: Refining the Methodology**
  - Transmission Security
  - Complete Tan45
  - Cost Curve Sensitivities
  - Aligning Cost and Requirements
- **Next Steps**
  - Phase 3: Market Simulations
  - Consumer Impact
- **Questions**

Phase 2: Refining the Methodology

Phase 2: Refining Methodology

- **Transmission Security**
- **Complete Tan45**
  - Perform full Tan45 analysis on select sensitivities
- **Cost curves**
  - Seek to evaluate and understand how the cost curve shape impacts the optimization
  - Identify candidate cost curve methods and shapes
- **Align the cost assumptions and the optimized requirements**

Transmission Security

Transmission Security

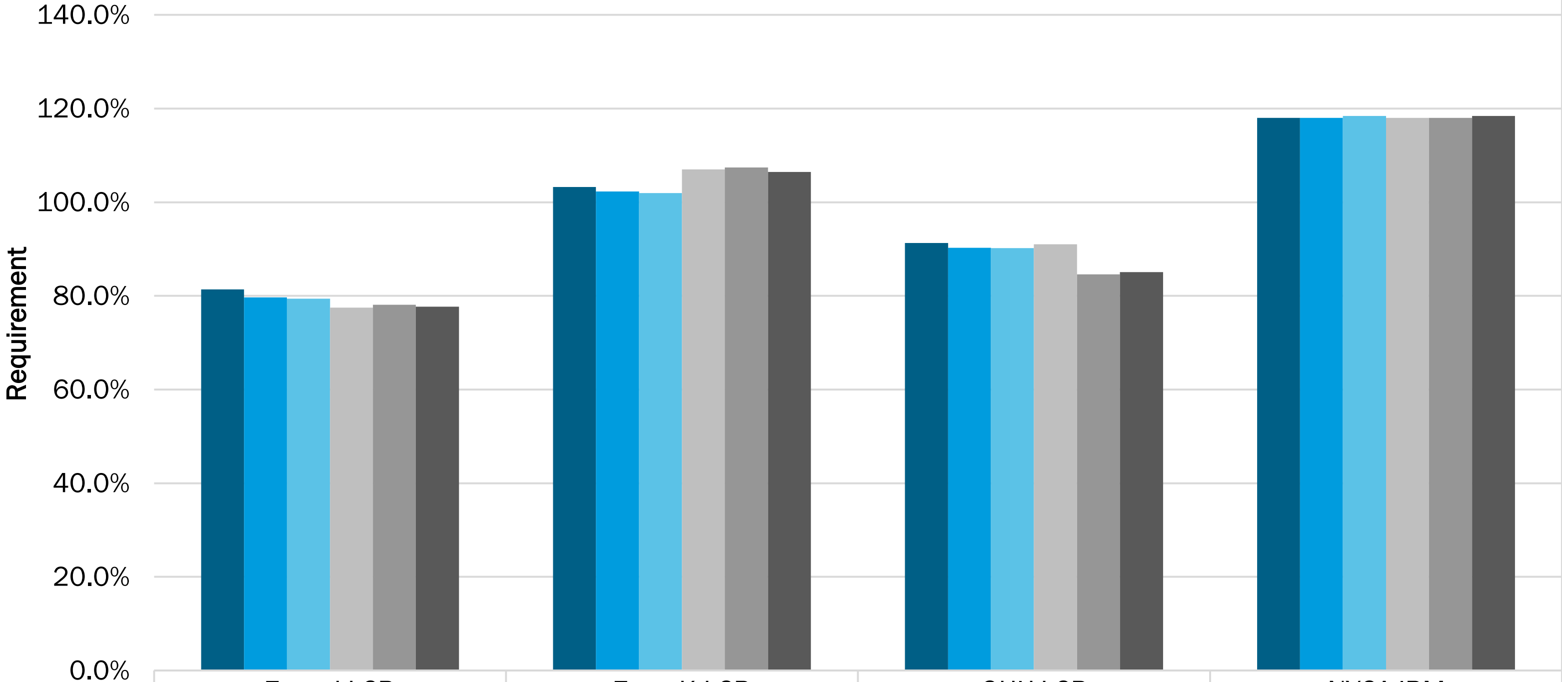
- NYISO is still working to develop transmission security limits for the Localities to use in the analysis
- The transmission security limits will be incorporated into the optimization
- Discussion on this process and analysis will be provided at future meetings

Complete Tan45

Complete Tan45 – UPNY-SENY 1000 MW

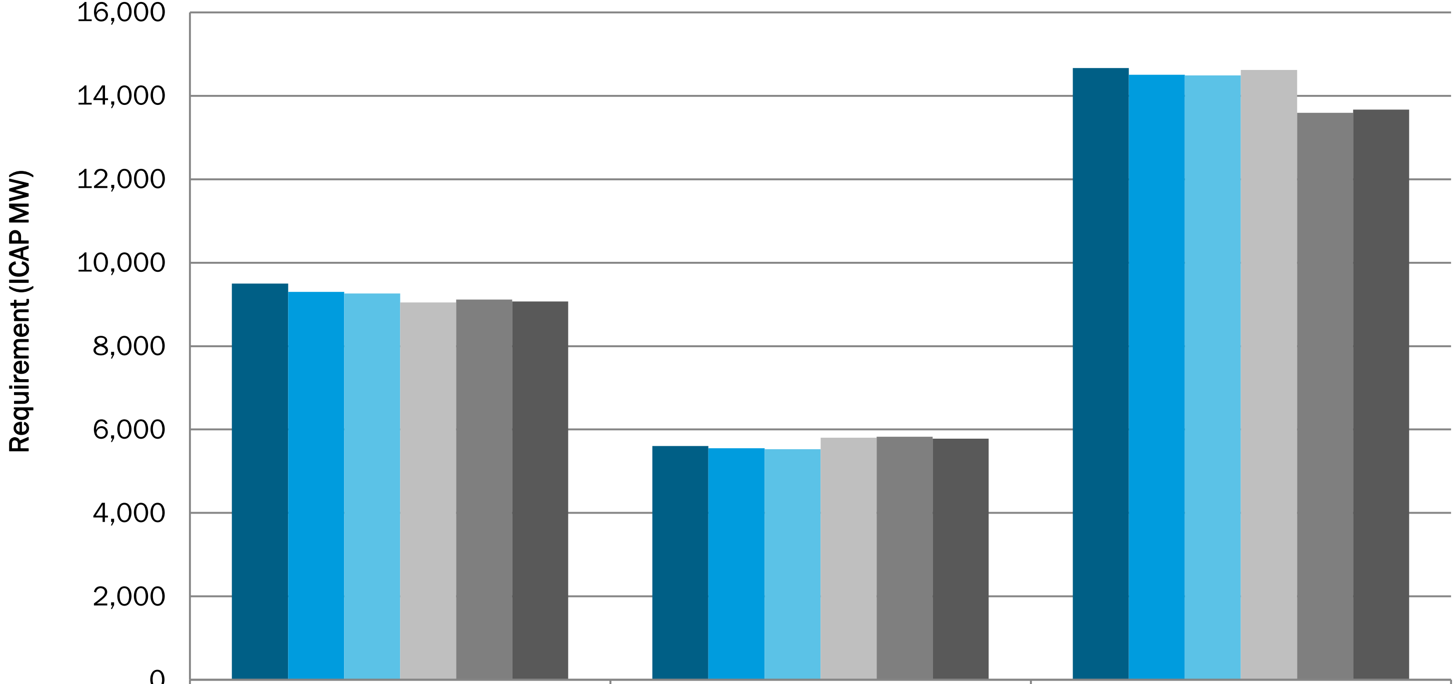
- **GE performed a complete Tan45 on sensitivity case with 1000 MW increase in transfer capability on UPNY-SENY**
- **It resulted in an IRM of 18.4%**
  - GE is currently investigating the reason for the increase in the IRM

Increase UPNY-SENY Capability Results (% Requirements)



	Zone J LCR	Zone K LCR	GHIJ LCR	NYCA IRM
Currrent LCR: Base Case	81.4%	103.2%	91.3%	118.0%
Current LCR: UPNY-SENY +1000 MW	79.7%	102.3%	90.3%	118.0%
Tan45: UPNY-SENY +1000 MW	79.4%	101.9%	90.2%	118.4%
Optimized: Base Case	77.5%	107.0%	91.0%	118.0%
Optimized: UPNY-SENY +1000 MW	78.1%	107.4%	84.6%	118.0%
Optimized: 18.4% IRM UPNY-SENY +1000 MW	77.7%	106.5%	85.1%	118.4%

Increase UPNY-SENY Capability Results (ICAP MW Requirements)

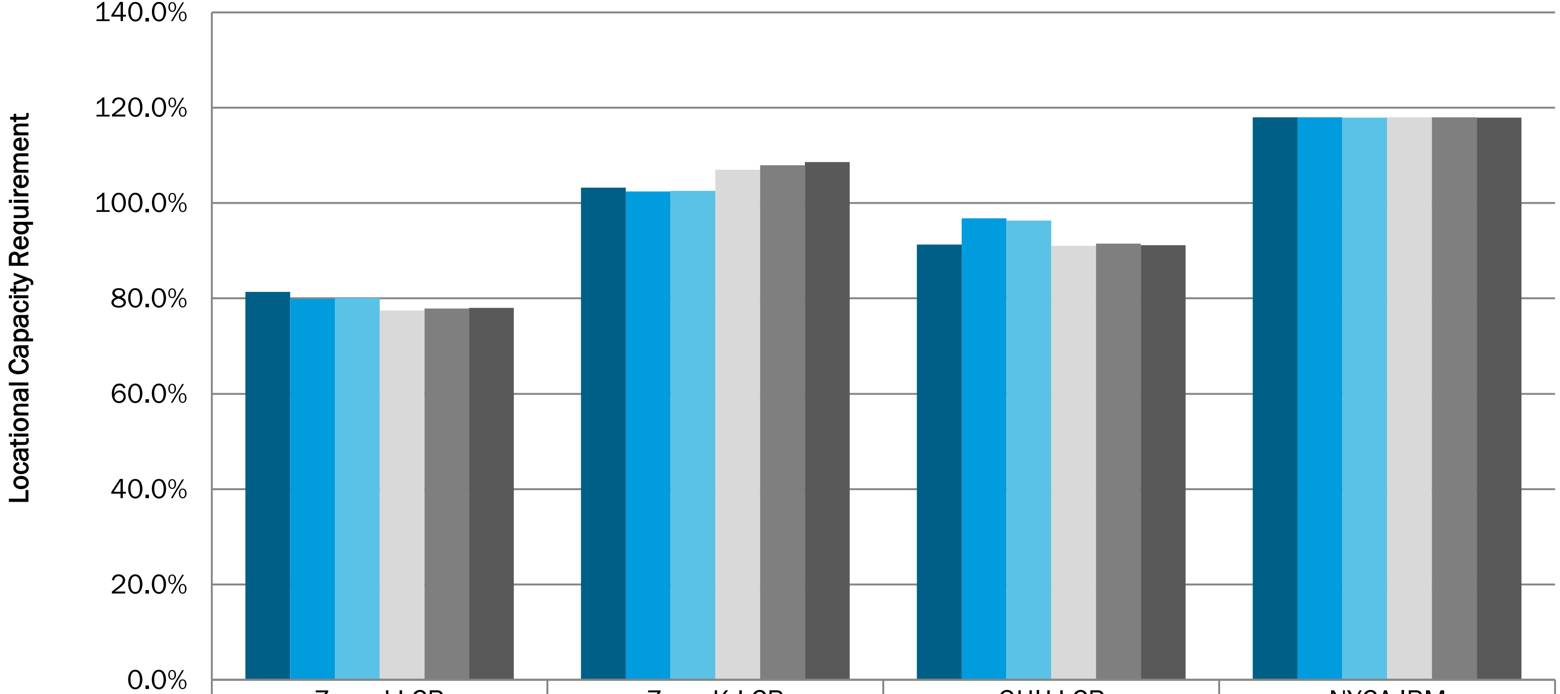


	Zone J	Zone K	GHIJ
Current LCR: Base Case	9,495	5,603	14,664
Current LCR: UPNY-SENY +1000 MW	9,301	5,552	14,503
Tan45: UPNY-SENY +1000 MW	9,263	5,532	14,484
Optimized: Base Case	9,044	5,807	14,616
Optimized: UPNY-SENY +1000 MW	9,114	5,829	13,588
Optimized: 18.4% IRM UPNY-SENY +1000 MW	9,070	5,779	13,668

Complete Tan45 –Capacity Addition to G-J

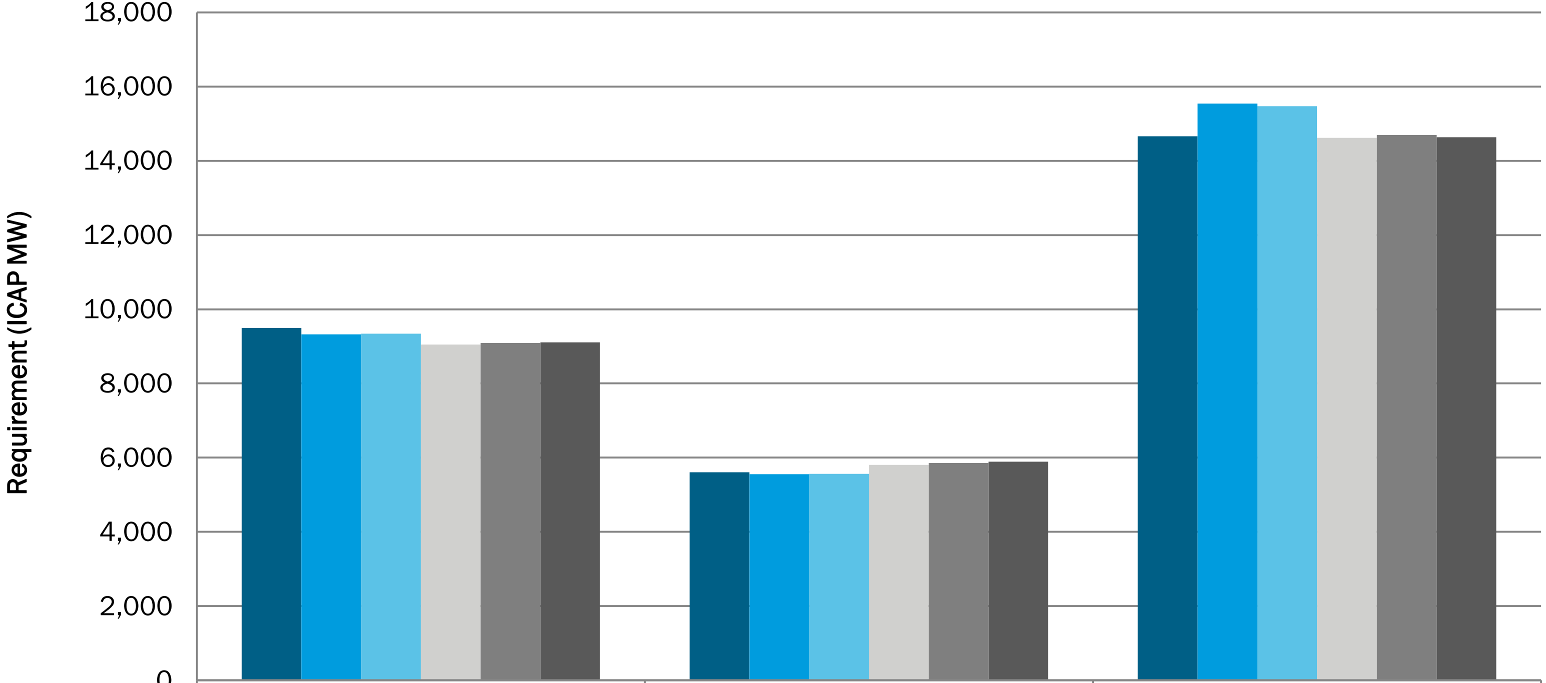
- GE performed a complete Tan45 on sensitivity with 1000 MW capacity addition to Zone G
- It resulted in an IRM of 17.9%
- This IRM was used in the optimization

Capacity Addition to G-J Results (% Requirements)



	Zone J LCR	Zone K LCR	GHIJ LCR	NYCA IRM
Current LCR: Base Case	81.4%	103.2%	91.3%	118.0%
Current LCR: GHIJ +1000 MW	79.9%	102.4%	96.8%	118.0%
Tan45: GHIJ +1000 MW	80.1%	102.6%	96.3%	117.9%
Optimized: Base Case	77.5%	107.0%	91.0%	118.0%
Optimized: GHIJ +1000 MW	77.9%	107.9%	91.5%	118.0%
Optimized: 17.9% IRM GHIJ +1000 MW	78.0%	108.6%	91.1%	117.9%

Capacity Addition to G-J Results (ICAP MW Requirements)



	Zone J	Zone K	GHIJ
Current LCR: Base Case	9,495	5,603	14,664
Current LCR: GHIJ +1000 MW	9,320	5,560	15,542
Tan45: GHIJ +1000 MW	9,344	5,568	15,468
Optimized: Base Case	9,044	5,807	14,616
Optimized: GHIJ +1000 MW	9,091	5,856	14,696
Optimized: 17.9% IRM GHIJ +1000 MW	9,106	5,893	14,638

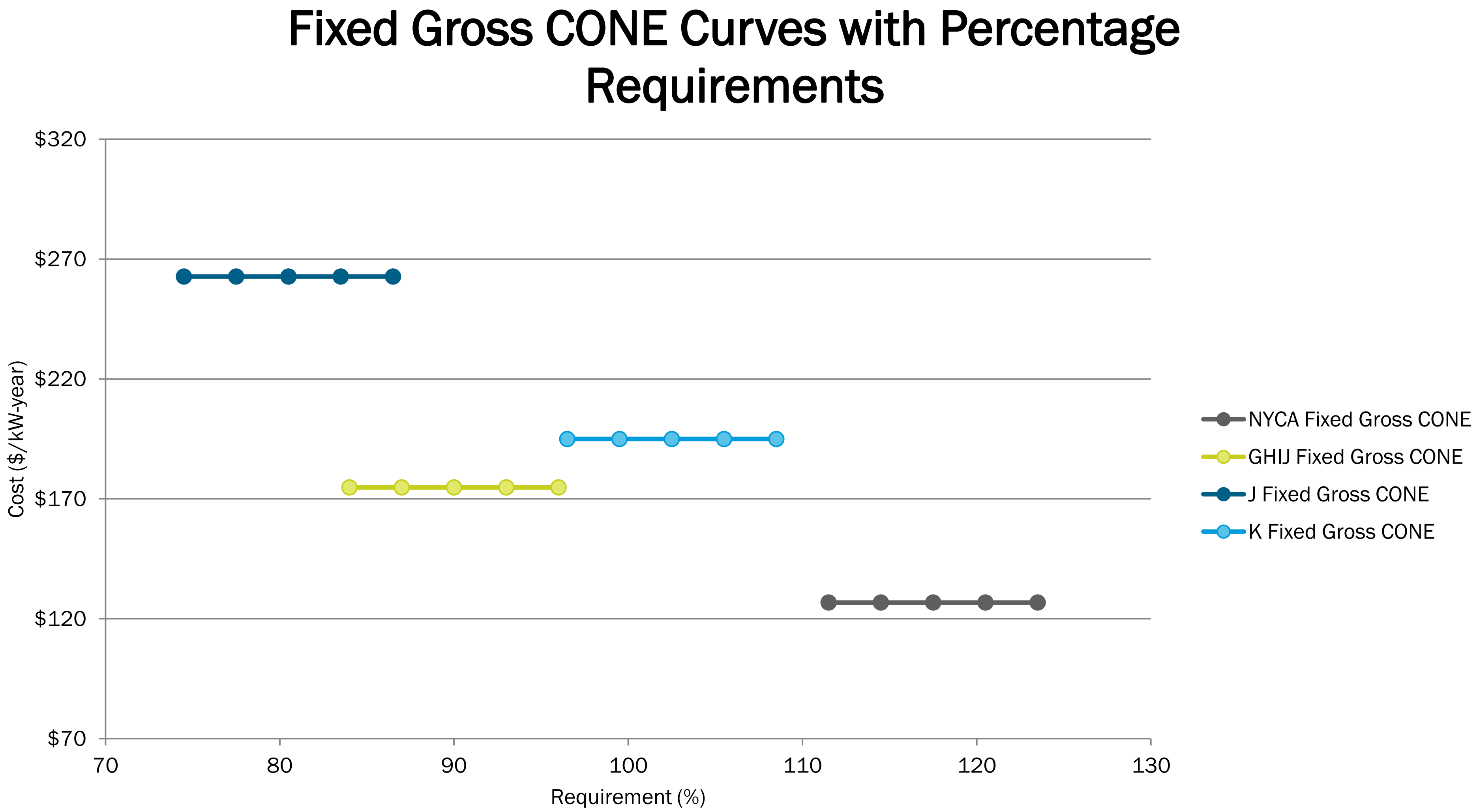
Complete Tan45 Conclusions

- Simplified analysis was reasonable approximation
- Still observing stability in the optimization method relative to the current process
- Decreasing IRM requires the optimal Locality requirements to increase
  - Specific increases in the LCRs observed in the sensitivities are being investigated further

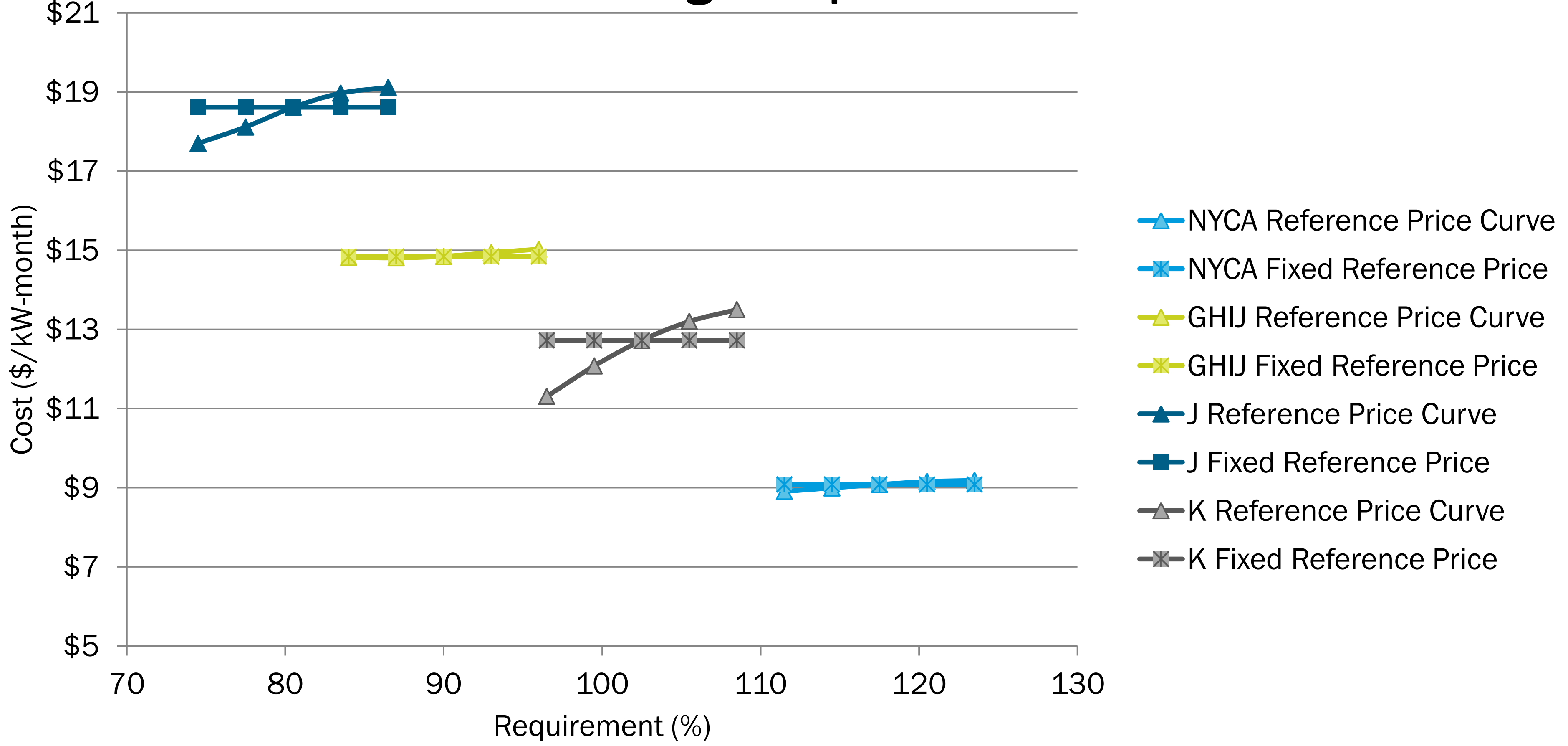
Cost Curve Sensitivities

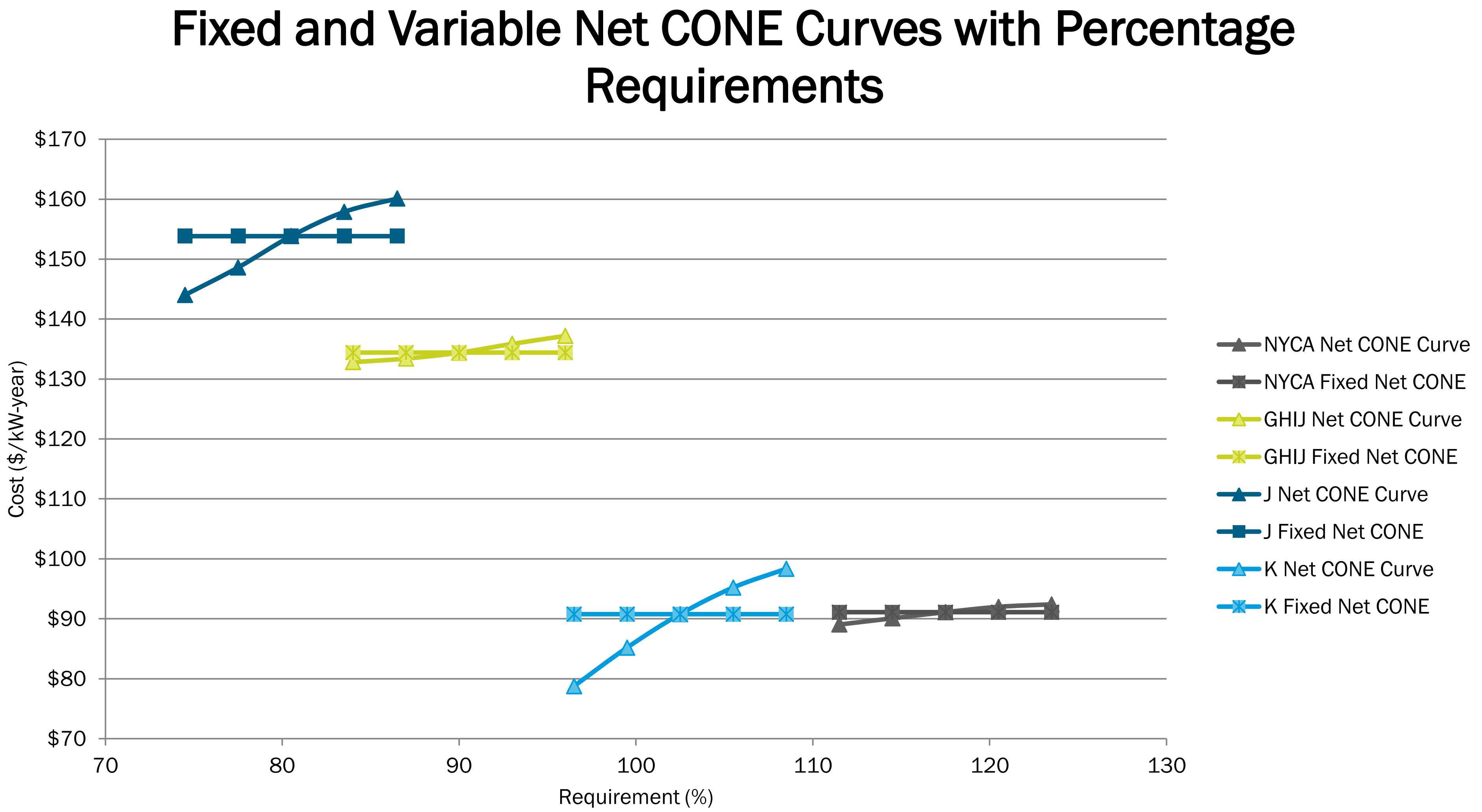
Sensitivities

- **Net CONE**
  - Fixed Value
  - 5 point curve
  - 5 point curve (doubled slope)
- **Reference Price**
  - Fixed Value
  - 5 point Curve
- **Gross CONE**
  - Single Value


Fixed Gross CONE Curves with Percentage Requirements
$320
$270
$220
$170
$120
$70
Cost ($/kW-year)
70
80
90
100
110
120
130
Requirement (%)
NYCA Fixed Gross CONE
GHIJ Fixed Gross CONE
J Fixed Gross CONE
K Fixed Gross CONE

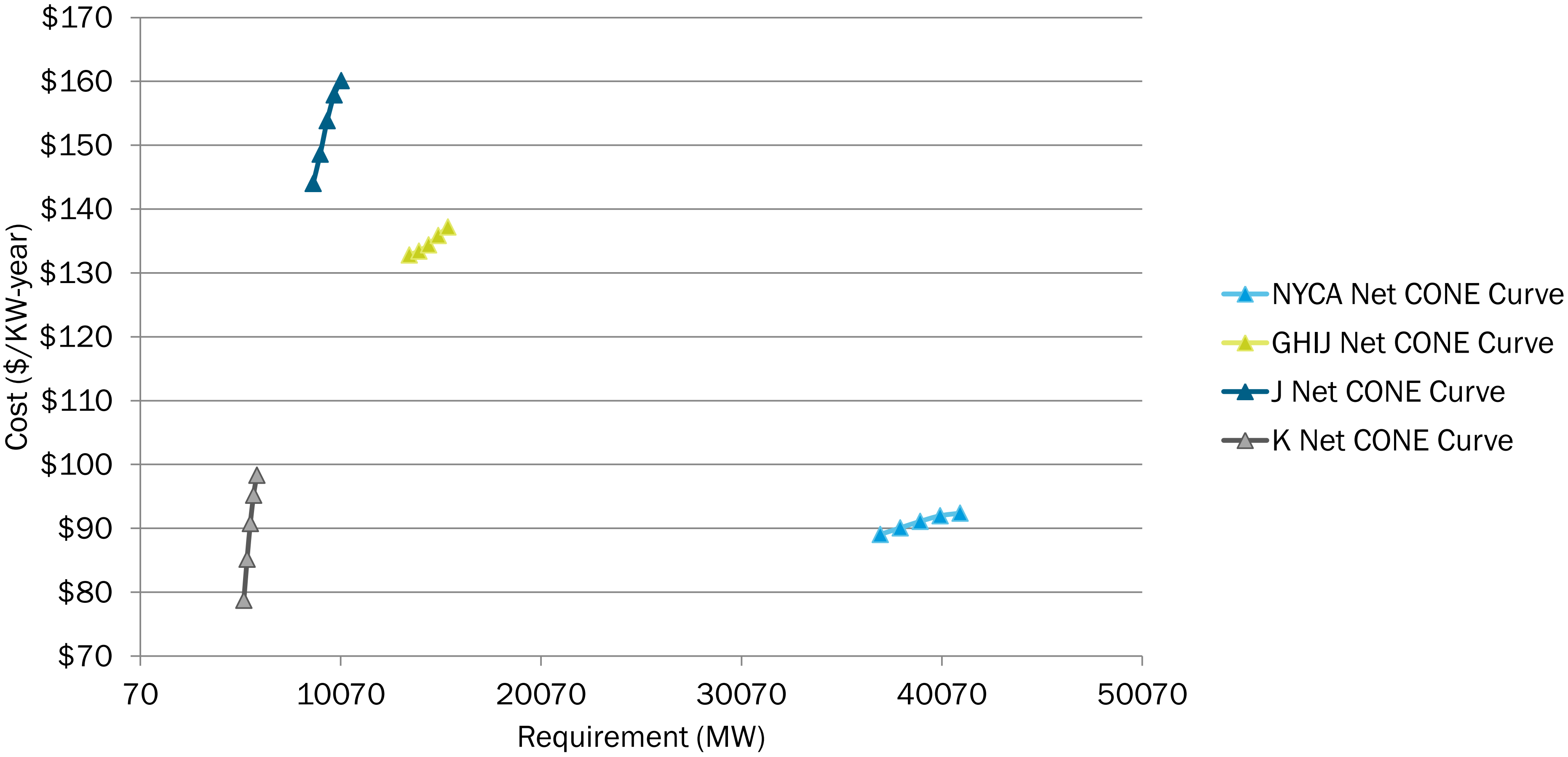
Fixed and Variable Reference Price Curve with Percentage Requirements



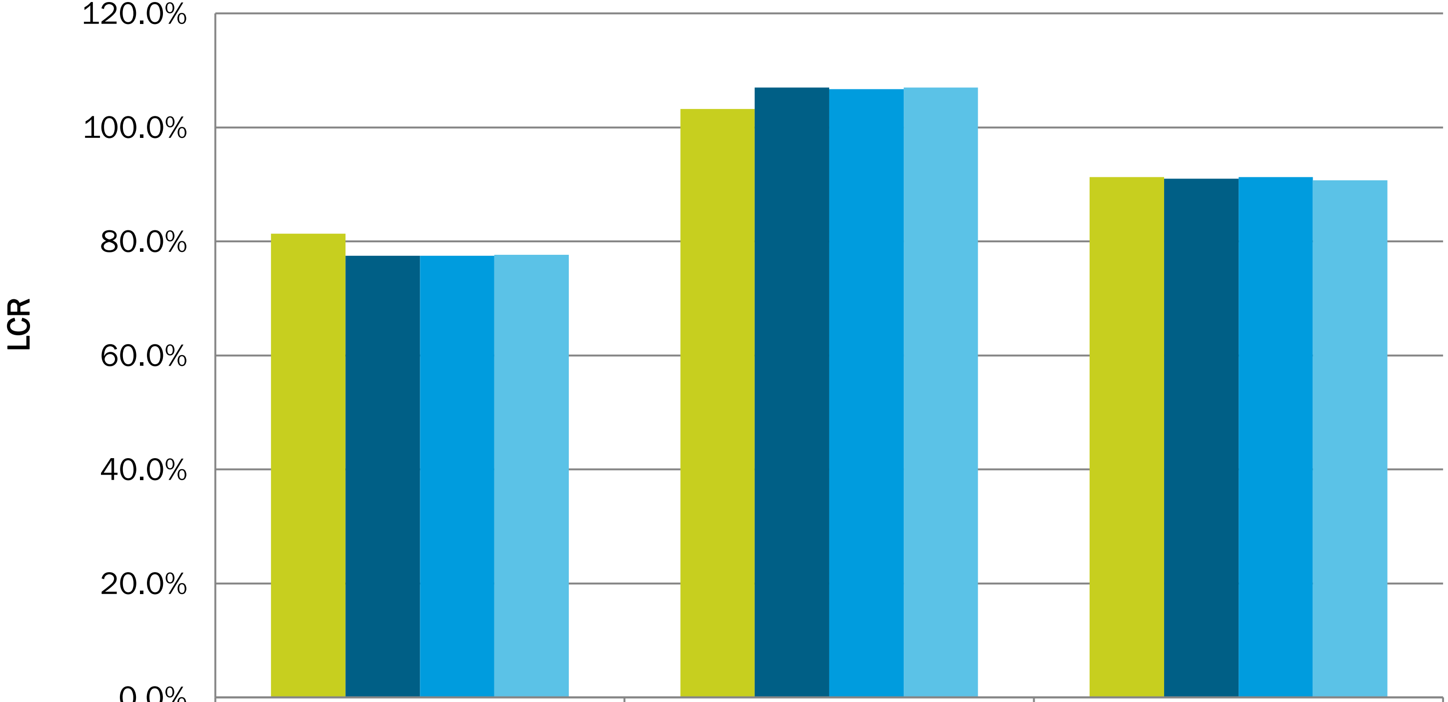


Fixed and Variable Net CONE Curves with Percentage Requirements
$170
$160
$150
$140
$130
$120
$110
$100
$90
$80
$70
Cost ($/kW-year)
70
80
90
100
110
120
130
Requirement (%)
NYCA Net CONE Curve
NYCA Fixed Net CONE
GHIJ Net CONE Curve
GHIJ Fixed Net CONE
J Net CONE Curve
J Fixed Net CONE
K Net CONE Curve
K Fixed Net CONE

Variable Net CONE Curve with Megawatt Requirements

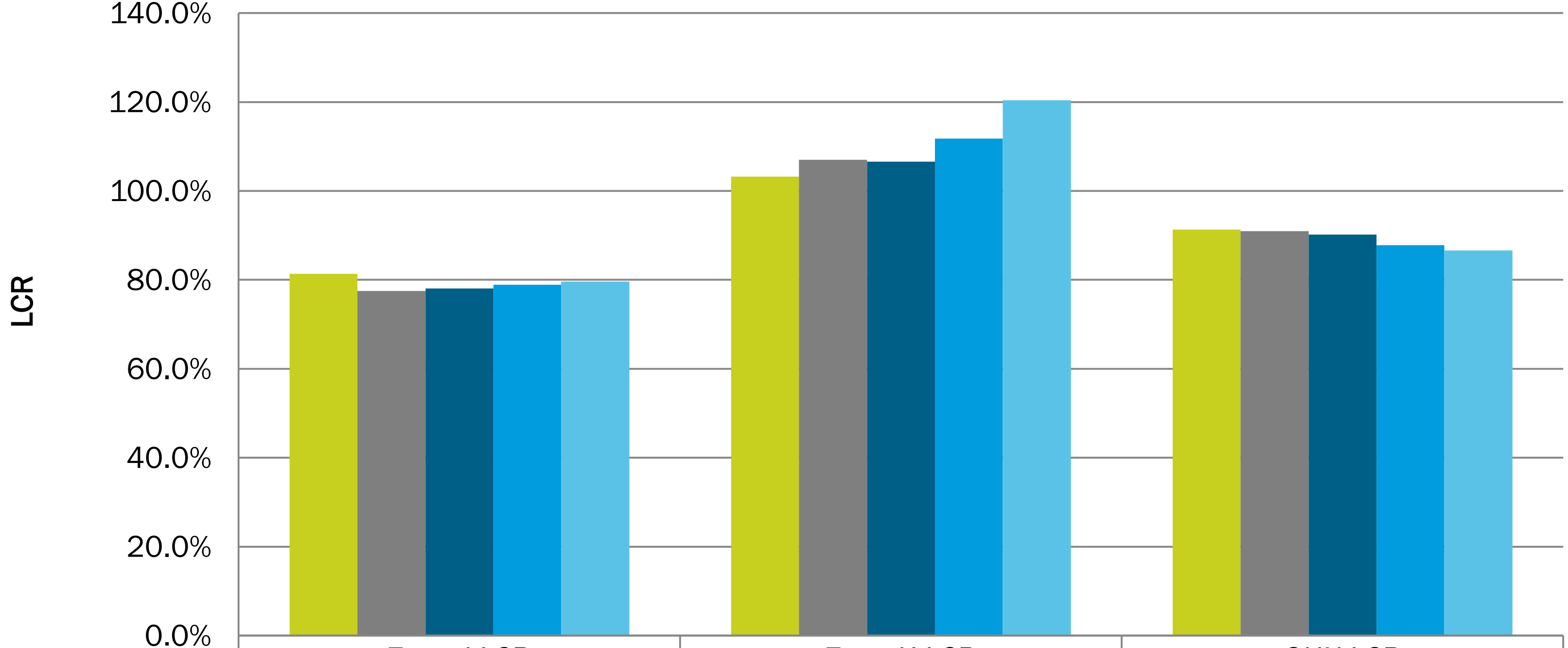


Variable Cost Curves Sensitivities



	Zone J LCR	Zone K LCR	GHIJ LCR
Current LCR: Base Case	81.4%	103.2%	91.3%
Optimized: Net CONE Curve	77.5%	107.0%	91.0%
Optimized: Net CONE Curve (Double Slope)	77.5%	106.7%	91.3%
Optimized: Reference Price Curve	77.7%	107.0%	90.8%

Fixed Cost Curve Sensitivities



	Zone J LCR	Zone K LCR	GHIJ LCR
Current LCR: Base Case	81.4%	103.2%	91.3%
Optimized: Net CONE Curve	77.5%	107.0%	91.0%
Optimized: Fixed Gross CONE	78.1%	106.6%	90.2%
Optimized: Fixed Reference Price	78.9%	111.8%	87.8%
Optimized: Fixed Net CONE	79.6%	120.4%	86.6%

Shape of the Cost Curve

- Single value cost curves are simple, but are an over simplification of reality. Therefore, they can result in counter-intuitive results
- Elasticity is needed to adequately reflect system conditions
- Therefore, elasticity is valuable in the development of the net CONE curves

Reference Price

- Calculated based on a number of factors:
  - Net CONE at the level of excess (LOE) condition
  - Seasonal changes in capacity supply
- Does not represent marginal cost of providing capacity at requirement
- More reflective of willingness to pay for capacity at requirement
- Originally used in sensitivities to understand potential impact of LOE, but determined to not be the appropriate method for the purpose of the analysis

Gross CONE

- Represents total investment cost to build new generation
- The generator is able to sell multiple products (i.e., energy, capacity, ancillary services) providing multiple revenue streams
- Gross CONE does not reflect the marginal cost of providing capacity

Net CONE

- Levelized embedded costs of a peaking plant net of energy and ancillary services revenues
- Represents the marginal cost of providing capacity
- Same formulation used to establish the ICAP Demand Curves

Aligning Cost and Requirements

Current Objective Function

$$\mathit{Cost\ of\ Capacity\ Procurement} = \sum_x Q_x \cdot P_x(Q_x) + \sum_y Q_y \cdot P_y\left(Q_y + \sum_z Q_z\right) + \left[(\mathit{Reserve\ Margin} \cdot \mathit{Pool\ Coincident\ Peak}) - \left(\sum_x Q_x + \sum_y Q_y\right)\right] \cdot P_{ROP}(Q_{Pool})$$

X = Single Load Zone that is a Locality (i.e., Zone J and Zone K)

Y = Locality minus any Single Load Zone Locality located within it (i.e., GHI)

Z = Single Locality located within a larger Locality (i.e., Zone J)

ROP = Rest of Pool (i.e., Rest of State)

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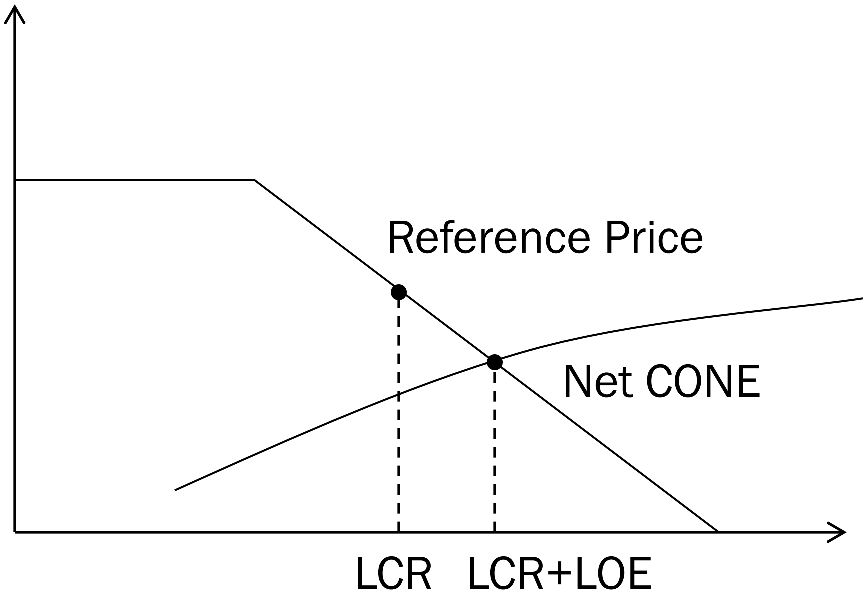
Current Objective Function

- Capacity quantity of each Locality used in the objective function corresponds to 100% of the Locality's requirement
- Prices (i.e., net CONE) used in the objective function corresponds to the LOE condition

Aligning Cost with Requirements

- Need to ensure there is alignment between the capacity requirements (quantity) being optimized and the cost (price) being assumed when calculating total cost



Methods for Aligning

- Alter Objective Function
  - Alters the quantity in the objective function, but not the decision variables (i.e., LCRs)
- Alter Cost Curve
  - Alters the prices in the objective function
- Alter the Optimal Requirements
  - Alters the decision variables to be the optimal quantity of capacity at the LOE condition

Altering Objective Function

- Alters the quantity used in the objective function by adding the quantity of capacity associated with the LOE condition
- Does not alter the decision variables (i.e., LCRs) or the cost curves
- Seeks to minimize cost of procuring capacity at the LOE condition
  - For example:

$$\text{Total Cost} = (Q_{\text{LCR}} + Q_{\text{Peaking Unit}})(P_{\text{Net CONE at LOE}})$$

Altering Cost Curve

- Evaluate the net CONE of capacity at the requirement rather than the LOE condition
- Optimize the requirements using the new net CONE curves
- Only alters the prices used in the objective function
  - For example:

$$\text{Total Cost} = (Q_{LCR})(P_{\text{Net CONE at LCR}})$$

Altering the Optimal Requirements

- Optimize the quantity of capacity needed at the LOE condition subject the LOLE constraint at the LOE
- LOLE at the LOE was determined to be 0.072 days/year
- Final LCRs would be determined by removing the capacity associated with the LOE from the optimal quantities

Next Steps

Phase 2: Refine Methodology

- Return to ICAPWG with more results from sensitivities to inform discussion on methodology
- Develop final methodology to be used in future Phases

Phase 3: Market Simulations

- **Goal:** Simulate additional market situations to demonstrate performance of methodology
  - Perform sensitivities with multiple changes to the system
  - Evaluate how the process would be performed with full Tan45 followed by optimization

Consumer Impact

- Consumer impact analysis will be provided for this project
- Methodology of the analysis will be provided and presented at an upcoming ICAPWG meeting
- Final analysis will be presented thereafter

Other Next Steps

- The NYISO will consider input received during today's ICAP Working Group meeting
- Additional comments sent to deckels@nyiso.com will be considered
- The NYISO will return to a future ICAPWG meeting to discuss its progress and adjustments to the plan after considering comments or results

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2017 Project Development

Stage	Objective	Specific Topics:
Proof of Concept	Demonstrate alternative methodology in relation to guiding principles (*i.e.*, least cost, stability, robust, predictability)	Generation +/- Unit net CONE +/- Transmission +/-
Refine Methodology	Modify the alternative method to ensure that all aspects have a purpose and are being performed as a result of sound market and engineering principles	Unit net CONE curves Potential Bounds Modeling methodology
Market Simulations	Simulate realistic market situations to demonstrate performance of methodology	Changes in resources Topological changes Locality configurations
Defining Process	Develop a process for the methodology that ensures guiding principles are being achieved over time	Develop process of method Process timeline Transition methods
Demonstrating Market Benefits	Demonstrate the methodology results in market benefits and resolve any issues that arise from its implementation	LOLE Criterion Consumer impact Multiyear simulation Cost allocation
Final Market Design	Summarize all findings and develop a final market design for implementation	Develop final market design

Questions?

The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefits 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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Exhibit 22

Methodology for Consumer Impact Analysis: Alternative Methods for Determining LCRs

Tariq N. Niazi
Senior Manager, Consumer Interest Liaison

Installed Capacity Working Group

July 25, 2017

DRAFT – FOR DISCUSSION PURPOSES ONLY

Agenda

- Project Objective
- Background
- Consumer Impact Methodology
- Feedback
- Next Steps

Project Objective for Determining Alternative LCRs

- Evaluate an alternative methodology for determining 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 NYCA Localities while keeping LOLE<0.1

Background

- The NYISO started this project by first establishing guiding principles (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 is focusing on refining the methodology to ensure that optimization is based on sound market and engineering principles
- Phase 3 will focus on simulating market situations to demonstrate the performance of the alternative methodology

Consumer Impact Analysis (IA) Evaluation Areas

- Present the potential impact on all four evaluation areas

RELIABILITY	COST IMPACT/ MARKET EFFICIENCIES
ENVIRONMENT/ NEW TECHNOLOGY	TRANSPARENCY

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Cost Impact Methodology

- The impact analysis will compare the cost impacts on the three Localities (J, K, G-J) of the alternative LCR methodology with the current methodology for the, short term, intermediate, and long term
- The base case and the sensitivity cases referenced herein are the same as those presented to stakeholders
  - The impact analysis will utilize the results produced after all refinements have been incorporated into the methodology (*i.e.*, final methodology)
- The 2017/2018 Capability Year LCR base case will be solved to an LOLE of 0.1 days/year while using the NYCA Minimum Installed Capacity Requirement
- Both quantitative and qualitative analysis will be discussed

Short term Cost Impact Methodology

- The short term impact will compare 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 will assume no changes to the generation and transmission

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)

Intermediate Cost Impact Methodology

- **The intermediate impact will compare the cost of applying the current LCR methodology with the alternative methodology as generation and transmission resources change**
  - This analysis will assume 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 will be performed on a sub-set of simple sensitivity cases (*e.g.*, sensitivities provided at the May 11, 2017 ICAPWG) along with a set of sensitivities that include multiple changes to the system**

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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)

Long term Cost Impact Methodology

- **The long term impact will compare the cost of the current LCR methodology with the alternative methodology at long-run equilibrium**
  - The long-run equilibrium will be modeled at the Level of Excess condition and also at a set of generic excess levels
    - The generic excess level will be based on historic excess experienced in the different Localities

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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

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

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Other Factors to be Considered

- **Stability**
  - Discuss how the alternative LCR methodology affects the stability of the LCRs and its impacts on consumers
- **Intuitive response to system changes**
  - Discuss how the alternative methodology affects the predictability of the LCRs to system changes and its impacts on consumers

Other Impacts

- **Evaluate other impacts:**
  - Reliability Impact
  - Environmental Impact
  - Impact on Transparency

Next Steps

- Communicate any changes to the consumer impact analysis methodology in response to stakeholder feedback
- Present the results of the consumer impact analysis in the September/October timeframe

Feedback?

- Email additional feedback to:
- deckels@nyiso.com

Questions?

We are here to help. Let us know if we can add anything.

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- Maintaining and enhancing regional reliability
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- Planning the power system for the future
- Providing factual information to policy makers, stakeholders and investors in the power system

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Exhibit 23

Alternative Methods for Determining LCRs

Zachary Stines
Associate Market Design Specialist

Installed Capacity Working Group

July 25, 2017, NYISO

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Agenda

- **Phase 2: Refining the Methodology**
  - Aligning Cost and Requirements
  - Transmission Security
- **Next Steps**
  - Phase 2: Final Refined Methodology
  - Phase 3: Market Simulations
- **Questions**

Phase 2: Refining the Methodology

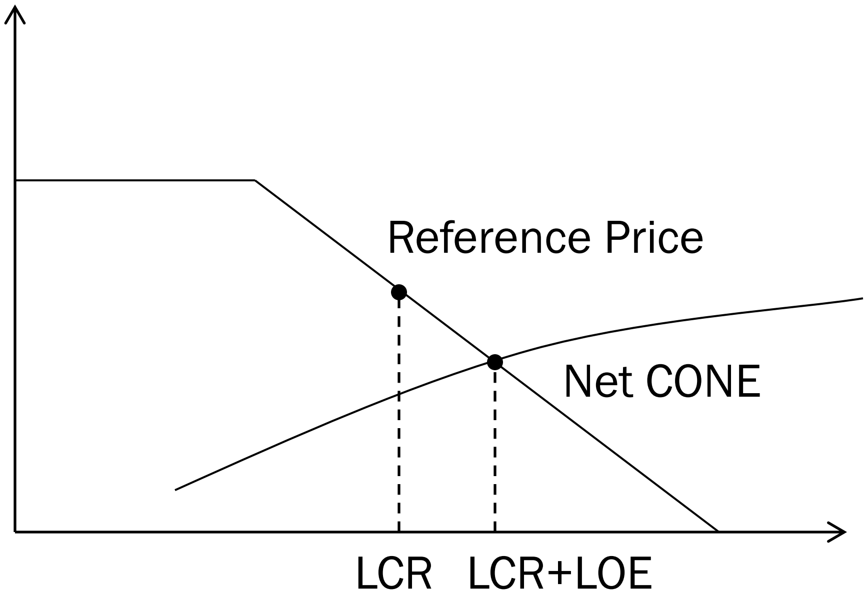
Phase 2: Refining Methodology

- Align the cost assumptions and the optimized requirements
  - Final methodology
- Transmission Security
  - Preliminary methodology

Aligning Cost and Requirements

Aligning Cost with Requirements

- Need to ensure there is alignment between the capacity requirements (quantity) being optimized and the cost (price) being assumed when calculating total cost



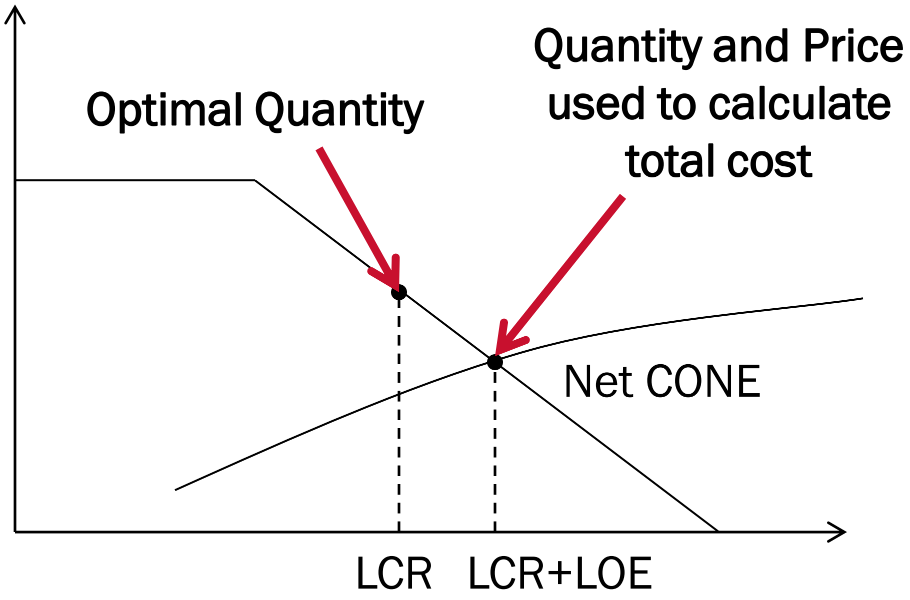
*Note: LOE = level of excess

Methods for Aligning

- **Alter Objective Function**
  - Alters the quantities in the objective function, but not the decision variables (*i.e.*, LCRs)
- **Alter Cost Curve**
  - Alters the prices in the objective function
- **Alter the Optimal Requirements**
  - Alters the decision variables to be the optimal quantity of capacity at the LOE condition

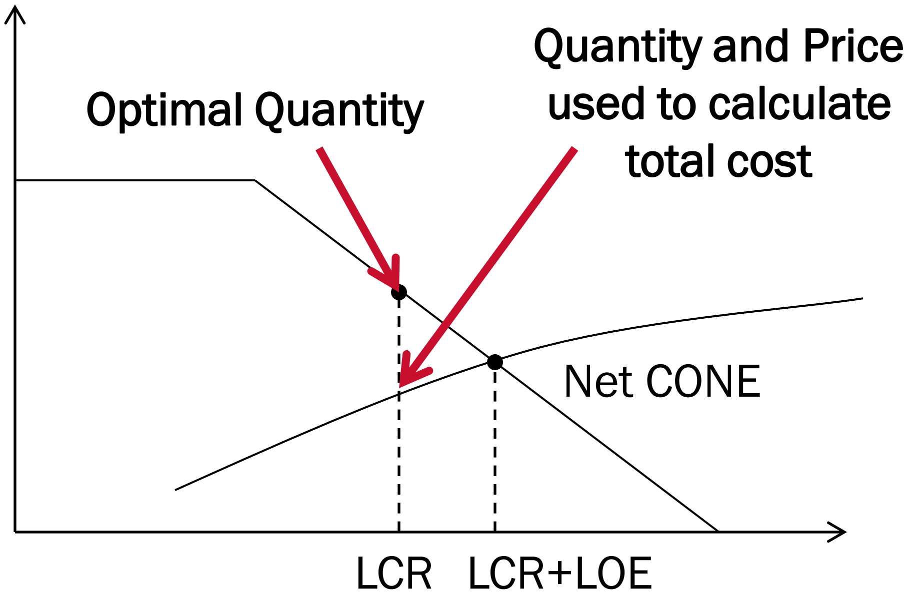
Altered Objective Function Method

- Alters the objective function to minimize cost of procuring capacity at the LOE condition
- Decision variable remains LCRs
- Minimized cost at LOE



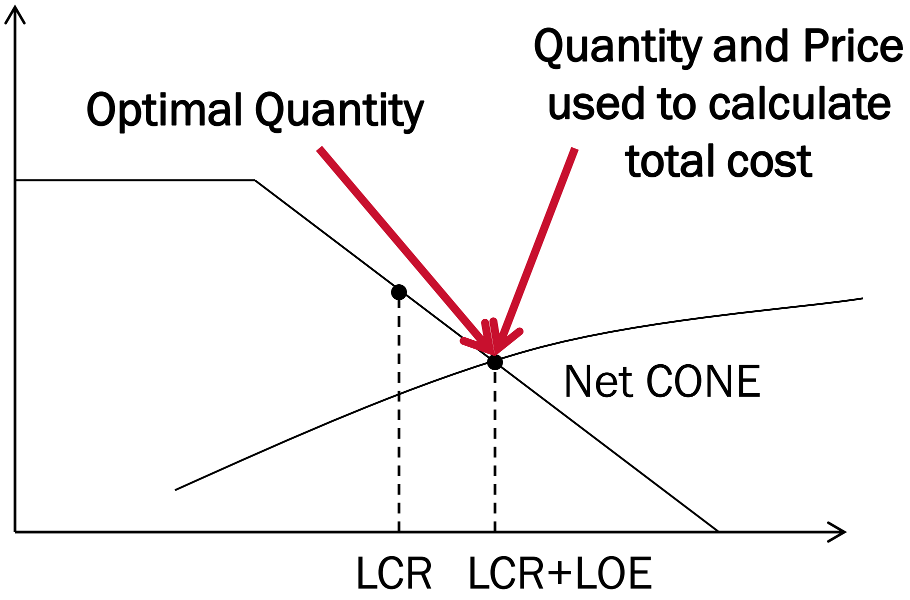
Altering Cost Curve Results

- Used Net CONE curves that were evaluated at 100% of the requirement rather than the Level of Excess
- Decision variable remains LCRs
- Minimizes cost at the LCRs rather than the LOE



Altering the Optimal Requirements

- Optimize the quantity of capacity needed at the LOE condition subject the LOLE constraint at the LOE
- LCRs calculated by removing capacity associated with the LOE
- Final LCRs result in LOLE of 0.099 days/year



Altering Objective Function

Scenario	Zone J LCR	Zone K LCR	G-J LCR
Current LCR Methodology	81.4%	103.2%	91.3%
Optimized Methodology	77.5%	107.0%	91.0%
Refined Optimized Methodology (Altered Objective function)			
Refined Optimized Methodology (Aligned Cost Curve)	78.2%	105.6%	90.9%
Refined Optimized Methodology (Optimal capacity at LOE condition)	78.9%	105.3%	91.5%

*Note: Results for the Refined Optimized Methodology (Altered Objective Function) are still being evaluated and will be provided at a future ICAPWG

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Altering Objective Function

Scenario	Zone J LCR	Zone K LCR	G-J LCR
Current LCR Methodology	9,495 MW	5,603 MW	14,664 MW
Optimized Methodology	9,044 MW	5,807 MW	14,616 MW
Refined Optimized Methodology (Altered Objective function)			
Refined Optimized Methodology (Aligned Cost Curve)	9,126 MW	5731 MW	14,600 MW
Refined Optimized Methodology (Optimal capacity at LOE condition)	9,208 MW	5715 MW	14,696 MW

*Note: Results for the Refined Optimized Methodology (Altered Objective Function) are still being evaluated and will be provided at a future ICAPWG

Transmission Security

Transmission Security

- NYISO is still working to develop transmission security limits for the Localities
- Evaluation of the impact of the transmission security limits on the optimization will be provided at future meetings
- Discussion on this process and analysis will be provided at future meetings

Next Steps

Phase 2: Refine Methodology

- Final methodology based on this evaluation and stakeholders' input
- Present evaluation of transmission security

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Phase 3: Market Simulations

- **Goal:** Simulate additional market scenarios to demonstrate performance of methodology
  - Perform sensitivities with multiple changes to the system
  - Evaluate how the process would be performed with full Tan45 followed by optimization

Other Next Steps

- The NYISO will consider input received during today's ICAP Working Group meeting
- Additional comments sent to deckels@nyiso.com will be considered
- The NYISO will return to a future ICAPWG meeting to discuss its progress and adjustments to the plan after considering comments and results

2017 Project Development

Stage	Objective	Specific Topics:
Proof of Concept	Demonstrate alternative methodology in relation to guiding principles (*i.e.*, least cost, stability, robust, predictability)	Generation +/- Unit net CONE +/- Transmission +/-
Refine Methodology	Modify the alternative method to ensure that all aspects have a purpose and are being performed as a result of sound market and engineering principles	Unit net CONE curves Potential Bounds Modeling methodology
Market Simulations	Simulate realistic market situations to demonstrate performance of methodology	Changes in resources Topological changes Locality configurations
Defining Process	Develop a process for the methodology that ensures guiding principles are being achieved over time	Develop process of method Process timeline Transition methods
Demonstrating Market Benefits	Demonstrate the methodology results in market benefits and resolve any issues that arise from its implementation	Consumer impact Multiyear simulation Cost allocation
Final Market Design	Summarize all findings and develop a final market design for implementation	Develop final market design

Questions?

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Exhibit 24

Alternative Methods for Determining LCRs

Zachary Stines

Associate Market Design Specialist

Installed Capacity Working Group

August 22, 2017 - REVISED August 21, 2017 ,NYISO

THIS PPT UPDATES THE PPT POSTED FOR THE AUGUST 22, ICAPWG MEETING.

The update is to:

•Table column header on Slide 21

NEW YORK INDEPENDENT SYSTEM OPERATOR

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Agenda

- **Phase 2: Refining the Methodology**
  - Aligning Cost and Requirements Final Results and Proposal
  - Transmission Security
- **Next Steps**
  - Phase 3: Market Simulations
  - BIC Vote
  - 2018 Project Scope
- **Questions**

Phase 2: Refining the Methodology

Phase 2: Refining Methodology

- **Align the cost assumptions and the optimized requirements**
  - Final results and proposed methodology
- **Transmission Security**
  - Preliminary methodology and result

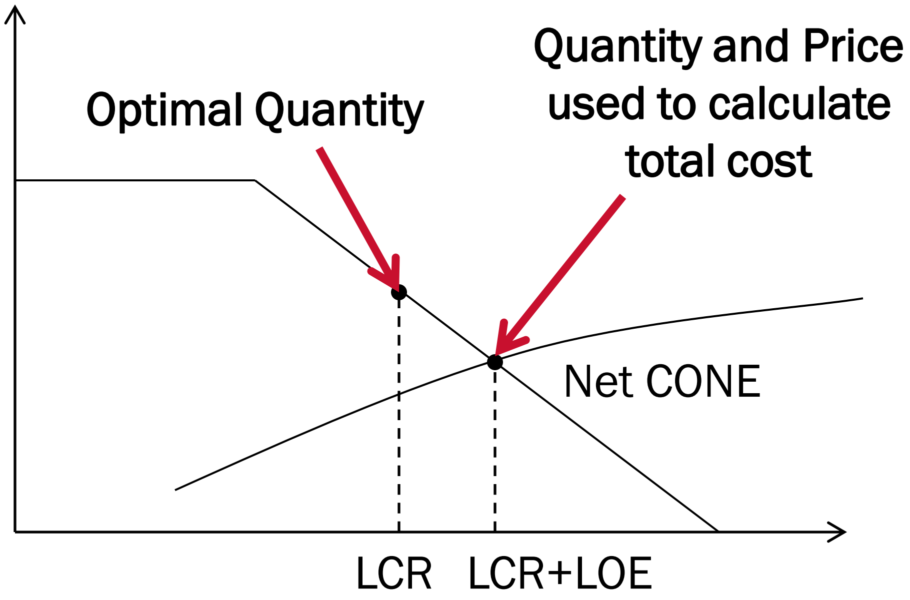
Aligning Cost and Requirements Results

Methods for Aligning

- **Alter Objective Function**
  - Alters the quantities in the objective function, but not the decision variables (*i.e.*, LCRs)
- **Alter Cost Curve**
  - Alters the prices in the objective function
- **Alter the Optimal Requirements**
  - Alters the decision variables to be the optimal quantity of capacity at the level of excess (“LOE”) condition

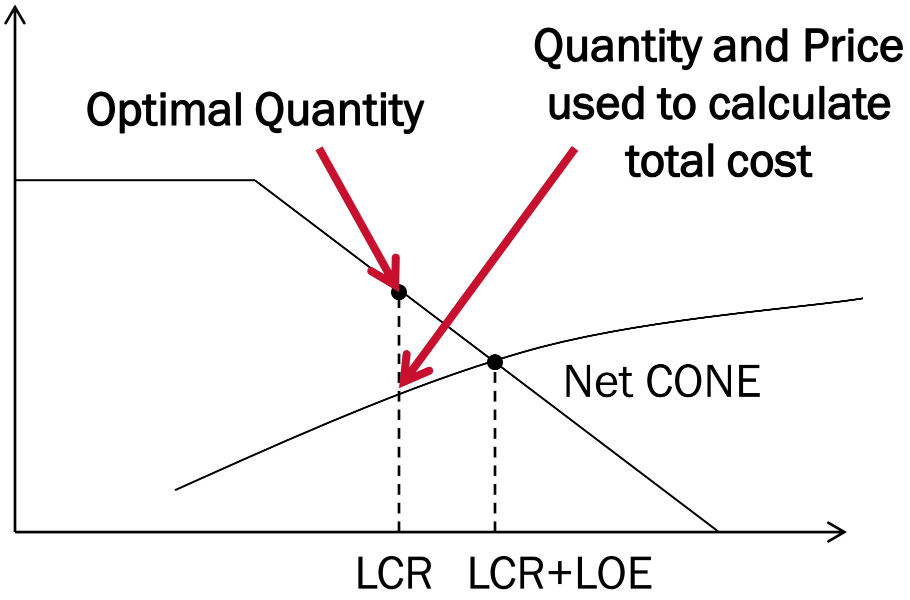
Altered Objective Function Methodology

- Alters the objective function to minimize cost of procuring capacity at the LOE condition
- Decision variable remains LCRs
- Minimized cost at LOE



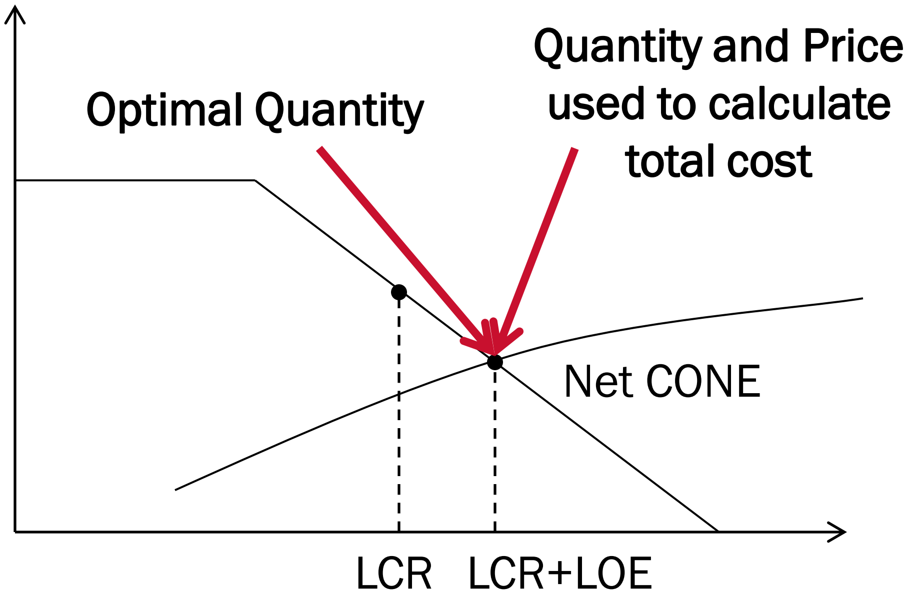
Altering Cost Curve Results

- Used Net CONE curves that were evaluated at 100% of the requirement rather than the Level of Excess
- Decision variable remains LCRs
- Minimizes cost at the LCRs rather than the LOE



Altering the Optimal Requirements

- Optimize the quantity of capacity needed at the LOE condition subject the LOLE constraint at the LOE
- LCRs calculated by removing the capacity at the LOE
- Final LCRs result in LOLE of 0.099 days/year



Aligning Cost and Requirements Results

Scenario	Zone J LCR	Zone K LCR	G-J LCR
Current LCR Methodology	81.4%	103.2%	91.3%
Optimized Methodology	77.5%	107.0%	91.0%
Refined Optimized Methodology (Altered Objective function)	78.0%	105.3%	91.5%
Refined Optimized Methodology (Aligned Cost Curve)	78.2%	105.6%	90.9%
Refined Optimized Methodology (Optimal capacity at LOE condition)	78.9%	105.3%	91.5%

Aligning Cost and Requirements Results

Scenario	Zone J LCR	Zone K LCR	G-J LCR
Current LCR Methodology	9,495 MW	5,603 MW	14,664 MW
Optimized Methodology	9,044 MW	5,807 MW	14,616 MW
Refined Optimized Methodology (Altered Objective function)	9,102 MW	5,715 MW	14,696 MW
Refined Optimized Methodology (Aligned Cost Curve)	9,126 MW	5,731 MW	14,600 MW
Refined Optimized Methodology (Optimal capacity at LOE condition)	9,208 MW	5,715 MW	14,696 MW

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Methodology Proposal

Aligning Cost and Requirements Methodology Proposal

- Based upon the analysis conducted, the NYISO proposes that the "Alter Objective Function" methodology be used
- This methodology optimizes the LCRs to minimize the cost of capacity assuming the quantity and price at the LOE condition

Reasons for Proposal

- This methodology achieves the objective of aligning the cost and requirements while avoiding suboptimal outcomes identified with the other methodologies
- Alter Cost curve
  - Utilization of cost that is not market based
- Alter the Optimal Requirement
  - Potential for the LOLE at the LOE to change based on the base case
  - When the base case is changed, risk of not meeting LOLE or achieving greater than LOLE is introduced due to need to remove the capacity associated with the LOE from the optimized quantity of capacity

Final Base Case

- The proposed refinement will be used in the final methodology and final base case

Scenario	Zone J LCR	Zone K LCR	G-J LCR
Current LCR Methodology	81.4%	103.2%	91.3%
Preliminary Optimized Base Case	77.5%	107.0%	91.0%
Final Optimized Base Case (Altered Objective function)	78.0%	105.3%	91.5%

Final Base Case

Scenario	Zone J LCR	Zone K LCR	G-J LCR
Current LCR Methodology	9,495 MW	5,603 MW	14,664 MW
Preliminary Optimized Base Case	9,044 MW	5,807 MW	14,616 MW
Final Optimized Base Case (Altered Objective function)	9,102 MW	5,715 MW	14,696 MW

Transmission Security

Transmission Security Methodology

- N-1-1 analysis was conducted to determine the transmission security import limits into each Locality
- These import limits were used to determine the minimum UCAP required for each Locality
- This minimum UCAP requirement was then converted into ICAP using the 5-year zonal EFORd utilized in the MARS model

Example Calculation

Transmission Security Requirements	Formula	Zone X
Load Forecast (MW)	[A] = Given	12,000
Transmission Security Import Limit (MW)	[B] = Given	1,500
Transmission Security UCAP Requirement (MW)	[C] = [A]-[B]	10,500
Transmission Security UCAP Requirement (%)	[D] = [C]/[A]	87.5%
5 Year EFORd (%)	[E] = Given	8.0%
Transmission Security ICAP Requirement (MW)	[F] = [D]/(1-[E])	11,413
Transmission Security LCR Floor (%)	[G] = [F]/[A]	**95.1%**

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Preliminary Transmission Security LCR Floor

Transmission Security Requirements	G-J	Zone J	Zone K
Load Forecast (MW)	16,061	11,670	5,427
Transmission Security Import Limit (MW)	3,250	3,250	400
Transmission Security UCAP Requirement (MW)	12,811	8,420	5,027
Transmission Security UCAP Requirement (%)	79.76%	72.15%	92.63%
5 Year EFORd (%)	10.50%	9.99%	10.06%
Transmission Security ICAP Requirement (MW)	14,314	9,355	5,589
Transmission Security LCR Floor (%)	**89.12%**	**80.16%**	**102.99%**

*Values are preliminary and subject to change

Preliminary Transmission Security LCR Floors

	Zone J LCR	G-J LCR	Zone K LCR
Preliminary Transmission Security LCR Floors	80.16%	89.12%	102.99%

- **These values are preliminary and subject to change**
- **These preliminary floors will be incorporated into the optimization and presented at a future ICAPWG meeting**
- **Final base case will be presented both with and without transmission security limits for information purposes**
  - The final base case incorporating these limits will be presented at a future ICAPWG meeting

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Next Steps

Stage 3: Market Simulations

- **Goal:** Simulate additional market scenarios to demonstrate performance of final methodology
  - Perform sensitivities with multiple changes to the system
  - Evaluate how the process would be performed with full Tan45 followed by optimization

BIC Vote

- **Bring complete market design to BIC for vote by end of 2017**
  - Milestone confirming stakeholder support with the market design and methodology as it has developed in the 2017 project
  - The vote will be used by the NYISO to efficiently allocate resources
    - Tariff development will be undertaken only if proposal has broad stakeholder support
    - Will determine if the 2018 Alternative Methods for LCRs will continue as currently defined

2018 Project Scope

- Review existing Tariff language and Draft Tariff language to reflect new methodology as necessary
  - Take to BIC and MC for action
- File revised Tariff language with FERC
- Revise LCR methodology documentation and any manual revisions required
- Develop internal process for implementation
- Address any administrative issues (ongoing)

Other Next Steps

- The NYISO will consider input received during today's ICAP Working Group meeting
- Additional comments sent to deckels@nyiso.com will be considered
- The NYISO will return to a future ICAPWG meeting to discuss its progress and adjustments to the plan after considering comments and results

2017 Project Development

Stage	Objective	Specific Topics:
Proof of Concept	Demonstrate alternative methodology in relation to guiding principles (*i.e.*, least cost, stability, robust, predictability)	Generation +/- Unit net CONE +/- Transmission +/-
Refine Methodology	Modify the alternative method to ensure that all aspects have a purpose and are being performed as a result of sound market and engineering principles	Unit net CONE curves Potential Bounds Modeling methodology
Market Simulations	Simulate realistic market situations to demonstrate performance of methodology	Changes in resources Topological changes Locality configurations
Defining Process	Develop a process for the methodology that ensures guiding principles are being achieved over time	Develop process of method Process timeline Transition methods
Demonstrating Market Benefits	Demonstrate the methodology results in market benefits and resolve any issues that arise from its implementation	Consumer impact Multiyear simulation Cost allocation
Final Market Design	Summarize all findings and develop a final market design for implementation	Develop final market design

NEW YORK INDEPENDENT SYSTEM OPERATOR

Questions?

The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefits 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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