2009 Congestion Assessment and Resource Integration Study (CARIS) – Phase 1

Phase 1 - Study Phase

~~2ND~~ 3RD DRAFT REPORT ~~– REDLINE~~

~~September 16~~

October 20, 2009

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Executive Summary

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To be added at a later date.

1. Introduction

The New York Independent System Operator (NYISO) is undertaking a new process pursuant to its ~~tariff~~ Attachment Y of the OATT (Open Access Transmission Tariff, or the Tariff from hereon, to ~~analyze~~assess both historic and projected congestion on the New York ~~Bulk Power System and~~ bulk power system and to estimate the economic benefits of relieving that congestion by ~~adding~~integrating potential projects comprising transmission ~~upgrades~~, generation or demand resources. This new ~~economic planning~~ process is entitled the Congestion Assessment and Resource Integration Study (CARIS). CARIS builds on the NYISO's existing reliability planning process previously known as the Comprehensive Reliability Planning Process (CRPP), and together with the Local Transmission Planning Process (LTPP), ~~these three planning processes comprise~~completes the NYISO's new overall Comprehensive System Planning Process (CSPP). ~~Once~~ The LTPP was developed to be the first step in the CSPP. When the reliability planning process of the CSPP is completed and approved by the NYISO board, the CARIS ~~economic planning process~~ begins, starting from a reliable system as described in the approved Comprehensive Reliability Plan (CRP).

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CARIS consists of two phases~~;~~: Phase 1, ~~called~~ the Study Phase, and Phase 2, ~~called~~ the Project Phase. In Phase 1, the NYISO ~~staff~~, in collaboration with its stakeholders and other interested parties, develops a ten-year projection of congestion, identifies ~~and~~, ranks and groups the most congested elements ~~of~~ on the New York ~~Bulk Power System~~ bulk power system based on the historic and forecasted congestion, and develops the three CARIS studies. Each of the three studies~~. Each study~~ includes~~;~~: i) the development of potential generic solutions to mitigate the identified congestion~~,~~; ii) a benefit/cost assessment of each solution based on NYCA wide production cost savings; ~~and~~ iii) and presentation of additional information on other related congestion metrics to all stakeholders, scenario analyses are then performed on the base case to assess the impact of potential factors to the top three groupings. Phase 1 results are presented in a written report to the NYISO's Electric System Planning Working Group (ESPWG) and the Transmission Planning Advisory Subcommittee (TPAS) for review. ~~In addition, the~~After that review, the draft report is presented to the NYISO's Business Issues Committee (BIC) and the Management Committee (MC) for discussion and action -within the NYISO's Governance process before being submitted to the NYISO Board of Directors (NYISO Board) for approval.

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This document is the NYISO's first CARIS report. It presents the Phase 1 study results and serves the crucial function of providing objective information on the nature of congestion in the New York Control Area (NYCA) that developers can use to decide whether to proceed with transmission upgrades or other resource additions (generation or demand response). This report does not ~~recommend specific transmission upgrades or~~ make any recommendations of any kind and does not favor any type of resource ~~additions.~~ addition or other actions. This process was developed specifically to not interfere with the present NYISO market, and provide information to potential Developers ~~can choose~~to assist them in deciding to invest ~~and build~~ in projects on their own, based on the economics of those projects in the NYISO's markets. Developers may

Formatted: bodytext, Left, Indent: First line: 0 pt also propose economic transmission projects for cost recovery under the NYISO's ~~tariff~~Tariff and proceed through the second phase of CARIS, the Project Phase, which will be conducted by NYISO staff in 2010. For these transmission projects, the NYISO will determine if they qualify as economic projects eligible for cost recovery, as defined by the ~~NYISO tariff~~Tariff. Eligible economic transmission projects that elect to pursue cost recovery under the NYISO's CARIS tariff provisions must be approved by at least 80~~ percent~~% of the weighted vote of ~~the~~ New York's Load Serving Entities (LSEs) that serve loads in those zones that the NYISO identifies as beneficiaries of ~~the~~ transmission projects. The beneficiaries of the ~~project~~ projects will be those load zones ~~who~~that experience net benefits measured over the first ten years from the proposed commercial operation for the project. Developers of economic generation or demand response projects may choose to pursue such projects on a merchant basis or to enter into contracts with ~~load serving entities~~LSEs or other parties~~]~~. CARIS provides ~~the~~additional data and ~~the~~ tools to ~~help~~assist in the development of policy and to provide information to potential developers ~~and policy makers decide whether and how to invest in projects to alleviate congestion in New York.~~ in their investment decisions.

2. Background

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2.1. The Evolution of Planning Processes at the NYISO

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Since its formation in 1999, the NYISO has carried out two primary functions: (1) the reliable operation of New York's bulk power system and (2) the administration of New York's competitive wholesale electricity markets. The restructuring of the New York electric industry from vertically-integrated transmission, generation and distribution companies operating under traditional cost of service regulation to wholesale markets was designed to incent private investment in generation, transmission and other resources ~~and~~ to foster competition. Additionally, this restructuring provided for the shift of the risk ~~of those~~ associated with these investments away from ratepayers to investors operating in economically-efficient~~,~~ and transparent wholesale markets ~~on a level playing field.~~. System planning, therefore, was initially restricted to conducting analyses for ~~developers who sought to add~~entities requesting transmission service which would require transmission upgrades and/or additions under Section 19 and 32 of the NYISO's Open Access Transmission Tariff (OATT~~), which~~). This system also allowed the New York Public Service Commission (NYSPSC) to request studies of transmission upgrades. In addition, NYISO had the responsibility for conducting analyses of any new generation or transmission facilities proposing to interconnect to the New York ~~bulk power system~~ Bulk Power System to determine the necessary system upgrades for compliance with applicable reliability standards.

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The NYISO, in collaboration with its stakeholders, developed a ~~Comprehensive Reliability Planning Process (~~CRPP~~)~~ in 2003-2004 to identify the ~~reliability needs~~Reliability Needs of the bulk power system looking out ten years and seek market-based solutions to the ~~indentified~~ identified Reliability Needs. In December 2004, the FERC approved the CRPP filing, including the addition of a new Attachment Y to the NYISO's OATT, ~~in December 2004,~~ and the NYISO immediately began its implementation in early 2005. ~~-~~The CRPP is a long-range assessment of resource adequacy and transmission reliability over a ~~-~~ten-year planning horizon. It includes the development of a Reliability Needs Assessment ("RNA~~") and a Comprehensive Reliability Plan ("CRP")~~"), an evaluation of proposed solutions, and the development of the CRP to address the identified needs. For each Reliability Need identified in the RNA, the NYISO ~~seeks market-based solutions -- which may include generation, transmission, or demand response resources.~~ contemporaneously requests market-based solutions from the marketplace as well as regulated backstop solutions from the identified Responsible Transmission Owner(s). If no viable market-based solutions are developed in time to satisfy the Reliability Needs, the NYISO ~~identifies the Responsible Transmission Owner(s) to plan and, if necessary,~~will initiate the second step of the solicitation process by requesting alternative regulated responses to ~~implement a regulated backstop solution if no viable market-based solutions are developed in time to satisfy the Reliability Needs.~~Reliability Needs All types of solutions may include generation, transmission, or demand response resources. Once it receives the market-based and regulated backstop proposed solutions, the NYISO assesses these solutions and reports in the CRP whether

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the projects submitted will meet the identified Reliability Needs. If the NYISO deems a Responsible ~~TOs'~~TO's regulated backstop solution ~~is deemed~~ necessary to meet the Reliability Needs ~~by the NYISO~~, then the costs incurred by the Responsible Transmission Owners ~~to plan,develop, and implement~~in planning, developing, and implementing the regulated backstop solutions ~~is~~ are recoverable under the ~~NYISO's tariff~~NYISO Tariff. The principal objective of the CRPP is to maintain reliability by providing an opportunity for ~~investing~~developers to invest in new, market-based projects before triggering a regulated backstop solution. To date, the NYISO has completed four annual cycles of the CRPP. Most recently, the NYISO staff, in collaboration with its stakeholders, developed the 2009 CRP which was approved by the NYISO Board ~~of Directors~~in May, 2009. The Plan identified no ~~reliability needs~~ Reliability Needs through 2018 ~~-~~— provided system conditions do not change ~~-~~— and evaluated the risks that could give rise to ~~reliability needs~~Reliability Needs before that time. The 2009 CRP forms the foundation for this first CARIS study.

In Order No. 890~~,~~ (Order 890), the FERC expanded the planning responsibilities of the NYISO and the New York Transmission ~~owners~~Owners (NYTOs) setting forth nine principles that all planning processes are required to meet. ~~To comply with the FERC Order, the~~The NYISO and the NYTOs submitted a joint compliance filing in December 2007, ~~that~~ which proposed tariff changes creating a three-stage ~~Comprehensive System Planning Process (~~"CSPP~~")~~ which will span a two-year cycle. First, each NYTO conducts a ~~Local Transmission Planning Process (~~LTPP~~)~~ for its respective transmission system and provide the input assumptions ~~-~~and results to interested parties through ~~-~~the NYISO stakeholder process for review and comment. Second, the LTPP provides input into the CRPP, which remains largely unchanged from the process first implemented in 2005. Third, the NYISO conducts the CARIS to a) identify the most constraining elements on the New York bulk power system and study the potential benefits and costs associated with relieving that identified congestion, ~~thus allowing less constrained power to flow to end use customers over the grid,~~ and b) provide that information to stakeholders in order to facilitate the development of solutions to the identified congestion from private developers who, as an alternative to recovering transmission projects costs through contractual obligations/arrangements, can now be eligible for transmission project cost allocation and regulated cost recovery through the ~~NYISO tariff~~Tariff if such project is approved by a supermajority of voting ~~LSE~~ beneficiaries. The NYISO CSPP is illustrated in Figure 2-1 below.

The joint NYISO/NYTO compliance filing was conditionally approved by the FERC on October 18, 2008. The NYISO and the NYTOs have made three subsequent compliance filings, and final approval of the CSPP remains pending at the FERC (Placeholder - FERC Approval). Based on the FERC's conditional approval and the expectation that ~~the transmission~~economic planning proceeds as filed with the FERC, the NYISO and the NYTOs commenced ~~its~~ implementation of CARIS with its stakeholders using the 2009 CRP as the basis.

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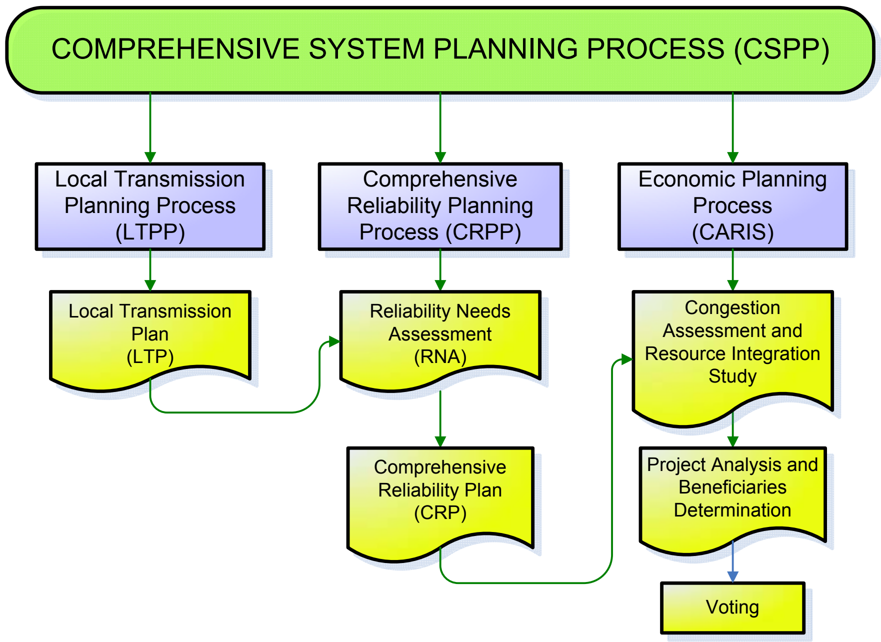

Figure 2-1: NYISO Comprehensive System Planning Process

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2.2. CARIS Process

~~Upon the approval and issuance of the CRP on May 19, 2009~~As directed by FERC Order 890, the NYISO ~~commenced the initial phase of~~ collaborated with its ~~economic planning~~stakeholders through multiple joint ESPWG and TPAS meetings, soliciting inputs and feedback, while developing CARIS procedures, study ~~process, known as~~modeling and assumptions. Further, the procedures were reviewed with the BIC before implementing Phase 1 of CARIS.[1]

The objectives of the CARIS economic planning process are to:

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a. Provide estimates of future congestion on the New York State bulk power transmission facilities ~~BPTFs~~ over the ten-year CSPP planning horizon~~.~~;

b. Identify, through the development of appropriate scenarios, factors that might mitigate or increase congestion;

c. Provide information to market participants, stakeholders and other interested parties on generic solutions to reduce congestion;

d. Provide an opportunity for ~~the~~ developers to propose solutions that may reduce the congestion; and

[1] The CARIS is contained in Sections 11, 12, 13 and 15 of Attachment Y of the NYISO's Open Access Transmission Tariff.[1] The NYISO anticipates that any lessons learned from completion of the first CARIS study will be used to refine and improve the economic planning process.

e. Provide a process for the evaluation and approval of regulated economic transmission projects for cost recovery under the NYISO Tariff.

The 2009 CARIS builds upon and aligns with the CRPP and assumes a baseline reliable system identified in the 2009 CRP for the ten-year study period from 2009 to 2018. ~~The diagram~~Figure 2-2 below presents a graphical depiction of the CARIS process.

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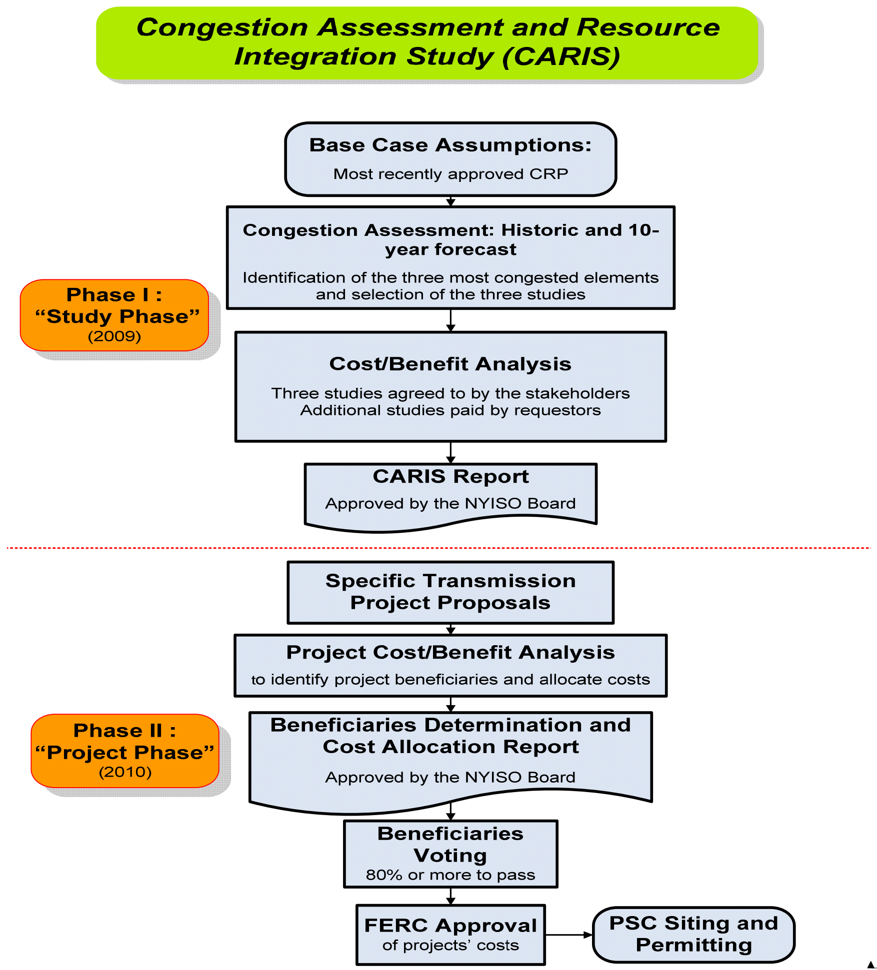

Figure 2-2~~-~~: Overall CARIS ~~process diagram~~Diagram

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2.2.1. Phase 1 - Study Phase

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In Phase 1 of the CARIS process, the NYISO, in collaboration with market participants, identifies the three most congested ~~paths~~elements in the New York ~~BPTS~~bulk power system, determines the three CARIS studies, applies the potential generic solutions to the congestion identified and conducts the ~~cost/~~benefit/cost analysis of the applied potential generic solutions. In ~~identifying the most congested paths, the NYISO performs both the historic and a ten-year forward-looking analysis. In~~ addition, the NYISO also performs scenario analyses with consideration given to load forecast uncertainty, fuel forecast uncertainty, new resources, retirements, emissions changes, environmental proposals and energy efficiency programs.

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~~Each of~~In identifying the most congested elements, the NYISO performs both a five-year historic and a ten-year forward-looking congestion assessment to identify the five most congested elements, and through a relaxation process, develops potential groupings and ranks them based on the highest production cost savings resulting from the relaxation. The top three ranked groups become the subjects of the three CARIS studies. For each of these three studies the NYISO conducts ~~includes~~ a ~~cost/~~benefit/cost analysis of potential generic solutions. All resource types, including generation, transmission and demand response ~~will be~~ are considered on a comparable basis as potential solutions to congestion. The solutions analyzed are not specific projects, but rather represent generic transmission, demand response and/or generation resources placed in key locations on the system to measure their effects on relieving each of the three most congested ~~paths/~~elements. ~~As more fully described in Section 3, the~~ The principal metric for measuring proposed solution benefits for each generic solution is the ~~production cost reduction across the New York Control Area~~change in NYCA wide production costs that would result from each potential solution, expressed as the present value over the ten-year planning horizon. The NYISO also reports data on additional metrics, including estimates of reductions in losses, ~~LBMP (~~changes in Locational Based Marginal Prices (LBMP) load payments, changes in installed capacity costs, ~~ancillary services costs,~~ changes in emissions costs and changes in payments for Transmission Congestion Contracts (TCCs). The TCC payment metric in Phase 1 has been simplified to include congestion rent calculations only and is different from the TCC ~~payment~~revenue metric contained in Phase 2. ~~The~~ CARIS metrics are described in more detail in Section 3.

Upon completion of the Phase 1 analysis, the results of the analysis are presented to stakeholders in a written report. The report provides interested parties with a wide range of information, including a discussion of its assumptions, inputs, and methodology ~~and analytical results,~~ to assist them in identifying and developing actual solutions to transmission congestion.

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~~Upon completion of the analysis, a~~ A draft CARIS report ~~is~~is first submitted to the ~~Electric System Planning Working Group (~~ESPWG~~)~~ and the ~~Transmission Planning Advisory Subcommittee (~~TPAS~~)~~ for review and comment. Following completion of that review, the draft CARIS report is sent to the ~~Business Issues Committee (~~BIC~~)~~ and the ~~Management Committee (~~MC~~)~~ for discussion and action. Thereafter, the draft CARIS, with BIC and MC input, is forwarded to the NYISO Board for review and action. The draft CARIS is also provided to the Independent Market Advisor ~~(Placeholder – FERC Approval)~~ for review and consideration. The

Board may approve the CARIS report as submitted or propose modifications on its own motion for further consideration. Upon approval by the Board, the NYISO issues the CARIS report and posts it on its website.

In addition to the three CARIS studies, stakeholders may also request additional studies of system congestion at their own expense. Requests may be made at any time, and studies will be conducted as the NYISO's resources allow. The NYISO posts all requests for studies on its website. The specific process for requesting, conducting and paying for additional studies is set forth in Section 1.1.2 of the Initial CARIS Manual~~ for CARIS.~~.[2] Other information on additional studies, including the form to request additional studies, ~~are~~is posted on the NYISO website~~:~~ ~~http://www.nyiso.com/public/services/planning/caris.jsp~~

. No results of any additional studies are included in this report.

2.2.2. Phase 2 – Project Phase

Phase 2 of the CARIS is conducted after the approval of ~~this~~ the Phase 1 report by the NYISO Board. In Phase 2 the developers of potential transmission projects that have an estimated capital cost in excess of $~~25M~~25 million to alleviate congestion may seek regulated cost recovery through the ~~NYISO's tariff~~NYISO Tariff. Such developers must submit their projects to the NYISO for analysis of benefits and costs (project's benefit/cost analysis) at any time prior to the input phase (Phase 1) of the next CARIS cycle, in accordance with the cost allocation principles and methodologies contained in ~~OATT, Attachment Y.~~ Tariff. Projects are eligible for cost recovery if they would produce net savings based upon a comparison of the NYCA-wide production cost savings with the annual total revenue requirements for the project~~–~~; both computed over the first ten years following the projected in-service date of the facility. The costs for the benefit/cost analysis will be supplied by the developer of the project and expressed as the net present value of the annual total revenue requirement for the project, reasonably allocated over the first ten ~~year~~ years from the proposed commercial operation of the project.

Beneficiaries determined by the NYISO will be ~~Load Serving Entities (~~LSEs~~)~~ in load zones that economically benefit from the project, and cost allocation among them will be based upon their relative economic benefit. The beneficiary determination for cost allocation purposes will be based upon ~~Load Serving Entities'~~LSEs' relative LBMP load savings. The aggregate LBMP load savings, for all zones that experience a reduction in LBMP, will be measured and compared on a net (reduced by TCC payments and bilateral contracts) present value basis with the project's revenue requirements over the first ten years of a project's life measured from its expected in~~-~~-service date. LBMP load savings are calculated first on a zonal basis and are then allocated to each LSE in a zone according to the ratio of its load to all load in the zone - both expressed in MWh.

In addition to the NYCA-wide production cost savings metric, the NYISO will also ~~use~~ provide additional metrics, for information purposes only, to estimate the potential benefits of the proposed project and to allow LSEs to consider other metrics when evaluating or comparing

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[2] http://www.nyiso.com/public/webdocs/services/planning/initial_caris_manual_bic_approved/CARISmanual.pdf.

potential projects. These additional metrics will include estimates of reductions in losses, changes in LBMP load payments, changes in generator payments, changes in Installed Capacity (ICAP) costs, ~~ancillary services costs,~~ changes in emissions costs, ~~losses and TCCs payments. The TCC payment~~and changes in TCC revenues. The TCC revenue metric that will be used in Phase 2 of the CARIS process is different from the TCC payment metric used in ~~Phase1~~Phase 1. In Phase 2, the TCC ~~payment~~revenue metric will measure reductions in estimated TCC revenues and allocation of congestion rents to the TOs~~.~~ (for more detail on this metric see Section 3.3.2 of this report and the Initial CARIS Manual ~~for CARIS~~, Section 15.4b).

The NYISO will also analyze and present additional information by conducting ~~a~~ scenario ~~analysis~~analyses, where appropriate, regarding future uncertainties, such as possible changes in load forecasts, fuel prices and environmental regulations, as well as other qualitative impacts, such as improved system operations, other environmental impacts, and integration of renewable resources. Although this data may assist and influence how a ~~benefitting~~benefiting LSE votes on a project, they will not be used for purposes of cost allocation.

The NYISO will provide its ~~cost/~~benefit/cost analysis and beneficiary determination for particular projects to the ESPWG for comment. Following that review, the NYISO ~~cost/~~benefit/cost analysis and beneficiary determination will be forwarded to the BIC and ~~to the~~ MC ~~for discussion and action.~~ .[3] After the MC vote, the ~~costs/~~benefit/cost analysis and beneficiary determination will be forwarded to the NYISO Board of Directors for review and approval. ~~The beneficiary determination will be provided to the BIC and the MC for review and comment, but not approval. Thereafter the beneficiary determination will be forwarded to the Board of Directors for review and approval.~~

After the project ~~cost/~~benefit/cost and beneficiary determinations are approved by the NYISO Board ~~of Directors~~ and posted on the NYISO's website, the project will be brought to the BIC meeting for a vote by the identified LSEs, utilizing the economic planning process voting procedure (see the Initial CARIS Manual, Appendix F), on whether the project is approved for cost allocation. The specific provisions for cost allocation are set forth in the ~~tariff,~~Tariff which also calls for the NYISO to establish procedures to determine the specific list of voting entities for each proposed project. That procedure and procedures for conducting a vote for projects in ~~phase~~ Phase 2 of CARIS are under development at the ESPWG and are not the subject of this report. In order for a project to be approved for cost recovery, the ~~tariff~~Tariff states that "eighty (80) percent or more of the actual votes cast on a weighted basis must be cast in favor of implementing the project." If the project meets the required vote in favor of implementing the project, and the project is implemented, all beneficiaries, including those voting "no," will pay their proportional share of the cost of the project through the NYISO Tariff. This process does not relieve the developer of the responsibility to file with FERC for approval of the project costs and with the appropriate state authorities to obtain siting approval for the project.

[3] The NYISO benefit/cost analysis will be forwarded to the BIC and to the MC for discussion and action. The beneficiary determination will be provided to the BIC and the MC for review and comment, but not approval.

2.3. –2009 CARIS Collaborative Process

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———As directed by FERC Order 890, the NYISO has encouraged all interested parties, including Market Participants, stakeholders, regulatory agencies and policy makers to participate in the CARIS process. As a result of this collaborative process, CARIS procedures and methodologies have been developed as set forth in the Initial CARIS Manual~~. ~~, Appendix F.

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The NYISO began ~~preparing~~preparations to implement CARIS after it filed its joint December 2007 compliance filing with the TOs. Modeling tools and assumptions were discussed with stakeholders at ESPWG throughout 2008. During the final stages of the 2009 CRP process, the NYISO worked with the NYTOs and all interested parties at the ESPWG to establish the procedures for implementing CARIS as called for in the ~~tariff~~Tariff. To date, NYISO has drafted and obtained approval of the BIC for all of the procedures needed for completing the Phase 1 CARIS Report. These procedures are set forth in Appendix F of the Initial CARIS Manual~~ for CARIS that is posted under Planning on the NYISO website (see Apendix F). ~~.

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The NYISO collaborated with its stakeholders through multiple joint ESPWG and TPAS meetings, soliciting inputs and feedback, while developing CARIS procedures, study modeling and assumptions. Further, the procedures were reviewed with the BIC before implementing Phase 1 of CARIS. [4] The ESPWG and TPAS completed their review of the CARIS report on ……date, and the NYISO staff forwarded the report to the ~~Indepenedent~~Independent Market Advisor for his comments. On ------ date, the BIC reviewed the CARIS report and recommended that the MC recommend that the NYISO Board of Directors approve the report. On ----- date, the MC reviewed the CARIS report and recommended that the Board approve it. Subsequent to MC approval, the NYISO forwarded the draft CARIS to the NYISO Board ~~of Directors~~ for review and approval.

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It is important to point out that CARIS estimates of future congestion are forecasts and may be different than actual future congestion. The CARIS studies are based upon the 2009 CRP base case which was developed in mid 2008 and includes assumptions about the NYCA system and load growth which were reasonable during that time frame. The base case, however, does not include recent developments such as the load forecast reductions caused by the current economic downturn. Further, CARIS simulations are based upon a limited set of long term assumptions about the utilization of grid resources throughout the 10-year planning horizon which are subject to change. The costs used for the benefit/cost ratios developed for generic projects are representative of the average cost for a broad range of projects representative of the generic solution type and are intended for illustrative purposes within the CARIS Phase 1 only. For example, the CARIS studies do not assess reliability impacts associated with generic solutions and therefore the corresponding interconnection costs are not included in benefit/cost ratios for generic solutions.

[4] The NYISO anticipates that any ~~lessens~~lessons learned ~~review after completing~~from completion of the first CARIS study will be used to refine and improve the economic planning process.

2.4. Relationship of CARIS to other Planning Processes

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Numerous electric system planning processes have taken root at the national, state, and local level simultaneous to the expansion of the NYISO's electric system planning functions. In the American Reinvestment and Recovery Act, Congress encouraged broader transmission system planning to upgrade aging facilities and expand transmission capability to move power between regions in the United States and Canada, such as for delivering renewable energy resources from resource rich areas to urban load centers. To implement this initiative, the U~~.~~S~~.~~ Department of Energy (DOE) has made funding available for interconnection-wide planning under ~~an FOA (~~a Funding Opportunity Announcement (FOA) issued on June 15, 2009. The NYISO is participating in the formation of the Eastern Interconnection Planning Collaborative (EIPC) to conduct transmission planning studies for the Eastern United States and Canada. ~~The~~ On September 14, 2009, the EIPC ~~will seek~~applied to ~~avail itself of~~ the DOE for a grant ~~funding for~~ to fund this endeavor. (Placeholder for what will happen before we post the final report

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Regionally, the NYISO ~~continue~~continues to participate in the Northeast Coordinated System Planning Protocol (NCSPP). The NYISO, ISO New England (ISO-NE), Independent Electricity System Operator of Ontario (IESO), and PJM Interconnection LLC (PJM) executed the regional planning protocol in December 2004 to provide a vehicle to enhance coordination of planning in the northeastern United States, with the participation of Canadian planning authorities. The collaborative released a Northeast Coordinated System Plan (NCSP) in 2006 and in 2009 to address ~~reliability needs~~Reliability Needs among regions and seams issues among ISO and Regional Transmission Organization (RTO) markets. The 2009 NCSP is posted on the NYISO's website at http://www.nyiso.com/public/webdocs/services/planning/ipsac/NCSP03-27-09.pdf.

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At the ~~State~~ state level, the Governor of New York re-established a State Energy Planning Board (SEPB) by Executive Order in April 2008. The NYISO has actively participated in the SEPB working group, filing comments, submitting white papers on timely topics, and conducting reliability modeling for ~~the Plan's~~ a bulk power system assessment. The SEPB ~~release~~released a draft State Energy Plan (SEP) in August 2009, and the NYISO will submit further input during the 60-day public comment period. ~~Rendering~~Pending the completion of ~~State Energy Plan~~the SEP in the fall of 2009, the ~~Public Service Commission~~NYSPSC has held Phase 3 of its Electric Resource Planning (ERP) proceeding in abeyance. The ERP proceeding will expand upon and implement SEPB policy initiatives, such as state support for renewable resources, demand response and energy efficiency.

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With input from the NYISO, the ~~New York~~ NYTOs are conducting the New York State Transmission Assessment and Reliability Study (STARS). STARS is a joint study of the state's bulk power system over a 20-year planning horizon to help meet future electric needs, support the growth of renewable energy sources, and ensure the reliability of the power system. Its aim is to develop a thorough assessment of the transmission system and suggest long-range plans for coordinated infrastructure investment in the state's power system. Because the bulk power system is owned by separate entities, yet interconnected, the STARS will examine the types of investments, including smart grid applications, needed to meet the long-term needs of the entire ~~state~~control area to complement studies currently being performed by the New York Independent System Operator (NYISO).

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Finally, at the municipal level, the City of New York created a City Energy Planning Board (CEPB) as part of Plan NYC. The ~~Board~~CEPB is designed to provide a coordinated vision in providing for the future energy needs of New York City considering supply and demand while addressing cost, reliability and environmental impacts. The City has retained CRA International to conduct a Master Electrical Transmission Plan for ~~New York~~ the City, a long-term study of the City's energy needs and policy initiatives that will affect NYISO's planning processes. The New York City Economic Development Corporation released the results of this analysis in June 2009.

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It is anticipated that specific projects which may result from any of the above initiatives will be analyzed under the ~~NYISOs~~ NYISO's interconnection and planning processes~~—~~, including CARIS~~–~~, if funding under the ~~NYISO's tariff~~NYISO Tariff is requested for an economic transmission project~~— as applicable."~~.

3. CARIS Methodology and Metrics

~~One of the first steps in developing the methodology for conducting CARIS was to choose a production cost simulation tool to forecast congestion. NYISO, in conjunction with the ESPWG, chose to use a long term commercially available software package rather than attempting to adapt the same tool as used for the historic congestion analysis into a forecasting model. . The tool used for historic congestion analysis is PROBE, developed by PowerGEM LLC.~~

3.1. CARIS Methodology

For the purposes of conducting the ten-year forward looking CARIS analysis, ~~two production cost simulation tools were utilized; GridView and MAPS. GridView was developed by ABB and MAPS was developed by General Electric Company. Both production cost simulation tools are widely accepted in the industry and both give comparable results. As a result,~~ the NYISO ~~and ESPWG have decided to utilize both simulation tools for the first cycle of the CARIS process.~~

~~**1.1Model Overview (GridView/MAPS, PROBE)**~~

~~Production cost simulation software is the primary analytical tool utilized in the CARIS process. Production-cost-simulation tools seek to minimize the cost of dispatching a static fleet of generation assets to serve a deterministic forecast of (typically hourly) loads.[5] In general terms Production cost simulations calculate the hourly production cost of supply resources under security constrained transmission network and area market conditions.~~

~~To estimate the cost of transmission congestion, procedures and protocols were developed by the NYISO for utilizing the above simulation models. The fundamental idea is to calculate what the day-ahead hourly clearing prices would be if there were **no** transmission constraints, using the same data and calculation approach as the NYISO's Security Constrained Unit Commitment software (SCUC). The congestion cost is then calculated as the difference between the constrained transmission system and the unconstrained transmission system. Annual congestion cost is the sum of daily costs.~~

~~**1.1.1Grid View and MAPS**~~

~~As noted above, in conducting the CARIS analysis the NYISO utilized both GridView and MAPS as the production cost simulation software. Both tools mimic the operation of the NYISO day ahead electricity market by performing security constrained unit commitment and economic dispatch of the generation by monitoring transmission system flows under both normal and contingency conditions. This enables calculation of hourly production costs in light of the~~

~~[5] Kahn 1955~~

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~~constraints imposed by the transmission system on the economic dispatch of generation. Both programs feature the following:~~

- ~~Detailed representation of the large scale transmission network. The transmission system is modeled in terms of individual transmission lines, interfaces (which are groupings of lines), phase-angle regulators (PARs), and HVDC lines. Both software model voltage and stability considerations through operating nomograms that define how these limits can change hourly as a function of loads, generation, and flows elsewhere on the system.~~
- ~~Detailed generation model for thermal, hydro, pumped storage, wind, solar etc. Generation system data capabilities include multi-step cost curves based on heat rates, emission costs, fuel costs, unit cycling capabilities,The generation units, along with chronological hourly load profiles, are assigned to individual buses on the system. Hourly load profiles are adjusted to meet peak and energy forecasts input to the model on a monthly or annual basis. Information on hourly loads at each bus in the system is required to calculate electrical flows on the transmission system. This is specified by assigning one or a combination of several hourly load profiles to each load bus.~~
- ~~Co-optimization of energy and ancillary services~~
- ~~Post contingency analysis for any given hour dispatch~~

~~i.PROBE - PoRtfolio Ownership and Bid Evaluation~~

~~PROBE, developed by PowerGEM LLC, is the day-ahead market simulation tool which was utilized by the NYISO as an analysis tool to conduct the NYISO's historic congestion analysis. The results of this historic congestion analysis, expressed as a change in production costs, generator payments, load payments and congestion, have been reported on a quarterly basis on the NYISO's website since 2003. The results of PROBE analysis were also used in the benchmarking process of GridView and MAPS.~~

~~PROBE provides market simulation by using a LP-based Security Constrained Economic Dispatch (SCED) and Security Constrained Unit Commitment (SCUC) engine. PROBE uses actual submitted generator parameters, hourly bids and network status (including transmission outages) used by the NYISO to clear the day-ahead market. The tool performs a simulation for the market "as it was", and then removes all transmission constraints (other constraints such as generator ramp rates and minimum run times are still enforced). Unit commitment and dispatch are then recalculated for this unconstrained scenario with no changes in bids from those actually submitted. The constrained and unconstrained results are compared to derive the change in bid production costs, load payments and generation payments. All calculations represent all market segments such as energy, start-up, and ancillary services bids for generators, import/export bids, virtual bids, and fixed and price-capped demand bids.~~

~~In contrast to other Planning-type software products, PROBE is designed to reproduce the day-ahead market clearing calculation as closely as possible. To accomplish this, PROBE was customized to model ISO's market rules, including rules regarding co-optimization of energy and ancillary services, mitigation, marginal losses, and other custom market rules.~~

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~~*The major difference between the CARIS tools (GView/MAPS) simulation and PROBE simulation is in the following: the CARIS tools in the CARIS model do not simulate: a) fixed and price-capped load; b) virtual load and generation; b) transmission outages; c) co-optimization with ancillary services; and c) production costs based on mitigated bids. Production cost simulation in GridView and MAPS is based on heat rates instead.*~~

~~1.2Modeling Validation~~

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~~1.2.1Database Verification~~

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~~To help ensure that the CARIS analyses produced accurate results, the NYISO conducted a two-stage data and modeling verification process. This involved a review of all input data and many of the program parameters on two separate occasions, prior to the development of the base case analyses. The verification process was conducted by NYISO System and Resource Planning staff under the direction of a team leader.~~

~~The following topics were examined as part of data verification:~~

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- ~~forecasts of hourly load data for NYISO zones and external areas;~~
- ~~hourly import and export schedules;~~
- ~~transmission system losses;~~
- ~~transmission interface transfer limits, contingencies & nomograms;~~
- ~~generator incremental heat rates and emissions rates;~~
- ~~modeling of combined cycle units;~~
- ~~fuel price forecasts;~~
- ~~modeling of pumped storage & hydro units; and~~
- ~~geographical location of generators by size and type.~~

~~The verification process involved a direct comparison of data contained in the Gridview and MAPS models with the primary data sources from which those inputs were derived. Where modeling choices were made, as in the case of incremental heat rates and combined cycle units, parameters were selected that most closely represented actual unit characteristics.~~

~~In several cases, discrepancies were noted by the data verification team. A log of discrepancies was kept and after the first stage of data verification, the log was presented for review and discussion with the CARIS team. The CARIS team was then directed to remedy the discrepancies in data or modeling choices made. These changes were accomplished before the development of the base case scenarios.~~

~~Once the base case scenarios were developed, reviewed, and confirmed, the Gridview and MAPS input files used to generate those results were saved as reference cases from which all future scenarios were developed. This was done to ensure that all subsequent scenarios were all performed from the same set of standard conditions.~~

~~After the development of the base case scenarios, a second stage of data verification was performed, similar to the first. This was to confirm that no significant elements of the data inputs or modeling~~ , in conjunction with ESPWG, developed a production costing model database. The details and assumptions ~~had been made subsequent to the development of the base case analyses.~~

~~(Datatabse conversion certification – Ram, Andrea)~~

~~**1.2.2Model Verification/Back Cast**~~

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~~**Generation Comparison**~~

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~~The objective of the back casting process was to compare the CARIS database results to actual system data to confirm the validity of the model. The CARIS~~ in developing this database ~~model simulations were benchmarked against January through April 2009 actual generation and fuel mix for selected New York City stations. The stations selected were those that report generation and fuel use in EIA f923~~were discussed at various ESPWG meetings and are summarized in Appendix C. The database was used in two production cost simulation software tools: ABB's GridView and GE's Market Analysis and Portfolio Simulation (MAPS), which are widely accepted in the industry. For benchmarking purposes, both tools are being utilized, and appear to give comparable results. For the purposes of this report, Grid View results are presented. Moving,forward, the NYISO will maintain the common database for both tools.

~~As shown in Tables 1 and 2, general overall agreement on total production and fuel mix is achieved. However, some significant differences in specific units were seen. A sensitivity case was then run to account for actual transmission line outages and the outage of Ravenswood 3 for four months. As shown in Table 1,. this resulted in better alignment of specific units except for Linden Cogen due to its EIA reporting.~~

~~Table 1 - 2009 In- City Back Cast~~

Jan - April 2009 Actual						
Facility Name	FO2	RFO	KER	NG	WO	Grand Total
Arthur Kill Generating Station		0	0	215,920		215,920
Astoria Energy	28,380			982,634		1,011,014
Astoria Gas Turbines			4,387	7,748		12,135
Astoria Generating Station		136,792		330,972		467,764
Brooklyn Navy Yard Cogeneration	2,635			568,240		570,875
Charles Poletti		76,693		413,334		490,027
East River	0	39,563		775,794		815,357
Gowanus Gas Turbines Generating	4,435	0	0	955		5,390
Linden Cogen Plant	2,578			1,659,797	67,491	1,729,866
Narrows Gas Turbines Generating	16,701		0	7,469		24,170
Poletti 500MW CC	0		19,919	791,248		811,167
Ravenswood	0	39,757	11,041	735,385		786,183
	54,729	292,806	35,347	6,489,495	67,491	6,939,868

Jan - April 2009 T25						
Plant Name	FO2	FO6	KER	NG		Grand Total
Arthur Kill Generating Station				344,915		344,915
Astoria Energy				948,670		948,670
Astoria Gas Turbines	245		0	11,732		11,978
Astoria Generating Station		0		1,685,187		1,685,187
Brooklyn Navy Yard Cogeneration				50,310		50,310
Charles Poletti		0		454,211		454,211
East River		0		118,290		118,290
Gowanus Gas Turbines Generating	6,254			212,827		219,081
Linden Cogen Plant				1,079,165		1,079,165
Narrows Gas Turbines Generating			0	117,898		117,898
Poletti 500MW CC				854,514		854,514
Ravenswood		465,617	0	1,128,636		1,594,253
	6,500	465,617	0	7,006,356		7,478,472

~~Table 2 - 2009 In In- City Back Cast Sensitivity Case~~

Jan - April 2009 Actual						
Facility Name	FO2	RFO	KER	NG	WO	Grand Total
Arthur Kill Generating Station		0	0	215,920		215,920
Astoria Energy	28,380			982,634		1,011,014
Astoria Gas Turbines			4,387	7,748		12,135
Astoria Generating Station		136,792		330,972		467,764
Brooklyn Navy Yard Cogeneration	2,635			568,240		570,875
Charles Poletti		76,693		413,334		490,027
East River	0	39,563		775,794		815,357
Gowanus Gas Turbines Generating	4,435	0	0	955		5,390
Linden Cogen Plant	2,578			1,659,797	67,491	1,729,866
Narrows Gas Turbines Generating	16,701		0	7,469		24,170
Poletti 500MW CC	0		19,919	791,248		811,167
Ravenswood	0	39,757	11,041	735,385		786,183
	54,729	292,806	35,347	6,489,495	67,491	6,939,868
Jan - April 2009 T25AR1Q1						
Plant Name	FO2	FO6	KER	NG		Grand Total
Arthur Kill Generating Station				96,888		96,888
Astoria Energy				983,721		983,721
Astoria Gas Turbines	828		0	36,082		36,910
Astoria Generating Station				266,727		266,727
Brooklyn Navy Yard Cogeneration				588,297		588,297
Charles Poletti		0		638,390		638,390
East River		0		237,676		237,676
Gowanus Gas Turbines Generating	14,546			309,543		324,088
Linden Cogen Plant				1,107,935		1,107,935
Narrows Gas Turbines Generating			0	177,509		177,509
Poletti 500MW CC				876,491		876,491
Ravenswood		0	0	1,270,951		1,270,951
	15,374	0	0	6,590,408		6,605,783

~~Congestion Comparison~~

~~To validate projected CARIS congestion values, the NYISO compared the first quarter of 2009 CARIS congestion data to actual PROBE first quarter of 2009 congestion data. The comparison has shown that the CARIS base case modeling results are reasonably aligned with PROBE once adjusted for externals, virtuals and Central East limit at 2400. CARIS base case modeling results~~

~~would be further aligned with PROBE if all transmission outages were considered. (e.g. Laden-Buch and Buch-Millwood throughout March~~

~~**1.3CARIS Metrics**~~

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~~In conducting the CARIS Study Phase, the NYISO performs~~ For historic congestion analysis, the Portfolio Ownership and Bid Evaluation (PROBE) production cost simulation tool, developed by PowerGEM LCC, has been used in the last six years to perform the NYISO historic congestion analysis. PROBE utilizes the actual NYISO Day-Ahead Market (DAM) data to emulate the actual SCUC operation. Unlike in GridView and MAPS simulation, PROBE simulates virtual bidding and transmission outages, and calculates production costs based on generation mitigated bids. While those additional attributes are important in capturing the real congestion values for the past events, it is nearly impossible to model them with certainty in projecting future transmission congestion. Therefore, it has been decided that these attributes are ignored in the ten-year forward looking CARIS analysis. For more detail on each simulation tool see Appendix D.

The methodology for conducting the CARIS was vetted with ESPWG and incorporated in the Initial CARIS Manual.

3.2. CARIS Metrics

One of the key metrics in the CARIS analysis is the transmission congestion in terms of demand dollar ($Demand) congestion. The demand dollar congestion values are calculated by multiplying zonal load with a transmission constraint's shadow price and zone's shift factor (SF) on that constraint. This definition is consistent with the definition that has been used for the reporting of historic congestion for the past six years.

In conducting Phase 1 of the CARIS process, the NYISO performed an assessment of historic and projected future congestion, ~~identifies~~identified the top three congested elements, and ~~conducts~~ conducted benefit/cost analysis of each type of generic potential solution ~~-~~— transmission, generation and demand response/energy efficiency ~~-~~— to the identified congestion ~~identified. This.~~ The CARIS analysis ~~applies benefit/cost~~reports various metrics that were developed with NYISO stakeholders at the ESPWG to measure the cost impacts of congestion and the benefits of its mitigation. The principal benefit metric for ~~the~~ CARIS analysis is NYCA-wide production cost reduction that would result from each of nine generic potential solutions. Additional benefit metrics were analyzed as well and the results are presented in this report for information purposes only. ~~Metrics shall include estimates of reduction in losses, LBMP load costs, generator payments, ICAP costs, Ancillary Services costs, emission costs, and TCC payments.~~ All ~~the quantities, except ICAP, will be the result of the forward looking production cost simulation for the ten-year planning period. The additional~~ benefit metrics ~~will be~~ were determined by measuring the difference between the forecasted CARIS base case system value and a forecasted system value when ~~the~~ each potential generic solution ~~is~~ was added. The discount rate ~~to be~~ used for the present value analysis ~~shall be~~ was the current weighted average cost of capital for the ~~NY Transmission owners~~NYTOs.

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3.2.1. Principal Benefit Metric[6]

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~~Section 11.3.d of Attachment Y of the OATT specifies that the~~ The principal benefit metric for the CARIS analysis ~~will be~~is the present value of the NYCA~~-~~-wide production cost ~~cost~~ reduction that would result from implementation of ~~each~~nine potential generic ~~solution~~congestion mitigation solutions.

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3.2.2. Additional Benefit Metrics[7]

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~~Also taken from Section 11.3.d, the~~ The additional benefits, which are provided for information purposes only[8], include estimates of reduction in losses, LBMP load costs, generator payments, ICAP costs, Ancillary Services costs, emission costs, and TCC payments. All the quantities, except ICAP, will be the result of the forward looking production cost simulation for the ten-year planning period. The NYISO, in collaboration with the ESPWG, determined the methodology and models needed to develop and implement these additional metrics requirements, which are described below and detailed in the Initial CARIS Manual.

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Reduction in Losses ~~-~~– This metric calculates the change in marginal losses payments. Losses payments are based upon the loss component of the zonal LBMP load payments.

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LBMP Load Costs ~~-~~– This metric measures the change in total load payments and unhedged load payments. Total load payments ~~includes~~ include the LBMP payments (energy, congestion and losses) paid by electricity demand (forecasted load, exports, and wheeling). Exports will be consistent with the input assumptions for each neighboring control area. Unhedged load payments represent total load payments minus the TCC payments.

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Generator Payments ~~-~~– This metric measures the change in generation payments and includes the LBMP payments (energy, congestion, losses), and ancillary services payments made to electricity suppliers. ~~Thus, generator~~ Ancillary Services costs include payments for regulation services and operating reserves, including 10 minutes synchronous, 10 minutes non-synchronous and 30 minutes non-synchronous. Generator payments are calculated as the sum of the LBMP payments and ancillary services

[6] Section 11.3.d of the Tariff specifies that the principal benefit metric for the CARIS analysis.
[7] Section 11.3.d of the Tariff specifies the additional metrics. The additional metrics allow LSEs to consider other parameters when evaluating or comparing potential projects.
~~[8]~~

payments to generators and imports. Imports will be consistent with the input assumptions for each neighboring control area.

ICAP Costs ~~–~~ – The measurement of this metric is highly dependent on the rules and procedures guiding the calculation of the installed reserve margin (IRM) and locational capacity requirement (LCR), both for the next capability period and future capability periods. Therefore, for the first CARIS cycle only ~~for the first CARIS cycle~~, the NYISO will use the MW impact methodology ~~described below. For the future CARIS cycles, the NYISO will develop a methodology to reflect potential changes in ICAP costs separate from~~ .[9] For more detail on this ~~temporary approach set forth below. The temporary approach is not meant to set precedence for the more fully developed ICAP cost methodology applicable to future CARIS cycles.~~

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~~*The MW impact methodology:*~~

~~1. Determine the base system LOLE for the horizon year (e.g. 2018 LOLE 0.02).~~

~~2. Add a potential generic solution to congestion identified.~~

~~3. Calculate the LOLE for the system with the potential generic solution added.~~

~~4. If the LOLE is lower that the base system, reduce generation in all NYCA zones proportionally regardless of type of generic solution until the base system LOLE is reached. The amount of reduced generation is reported as the NYCA MW impact.~~

~~**Ancillary Services Costs** - This~~ metric ~~measures the change in Ancillary Services costs, which include payments for Regulation Services and Operating Reserves, including 10 Minute Synchronous, 10 Minute Non-synchronous and 30 Minute Non-synchronous.~~see the Initial CARIS Manual.

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Emission Costs ~~-~~ – This metric measures the change in the total cost of emission allowances for CO_2, ~~NOx~~NO_X, and SO_2, emissions on a zonal basis. Total emission costs are a component of the production cost curve. Emission costs are the product of forecasted total emissions and forecasted allowance prices.

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TCC Payments

[9] For the future CARIS cycles, the NYISO will develop a methodology to reflect potential changes in ICAP costs separate from this temporary approach which is not meant to set precedence for the more fully developed ICAP cost methodology applicable to future CARIS cycles.

– The TCC payment metric is calculated differently for Phase 1 and for Phase 2 of the CARIS process~~.~~:

~~4.~~For Phase 1~~ TCC payments:~~

- ~~The TCC Payment metric set forth below will be used for purposes of Phase 1 of~~, the ~~CARIS process and will not be used in the Projects Phase for regulated economic transmission project cost allocation under Section 15.4. This~~ TCC payment metric ~~will measure~~measures the change in total congestion rents collected in the day-ahead market. Congestion rents ~~shall be~~ are calculated as the product of the Congestion Component of the Day-Ahead LBMP in each Load Zone or Proxy Generator Bus and the withdrawals scheduled in each hour at that Load Zone or Proxy Generator Bus, minus the product of the Congestion Component of the Day-Ahead LBMP at each Generator Bus or Proxy Generator Bus and the injections scheduled in each hour at that Generator bus or Proxy Generator Bus, summed over all locations and hours.

~~5.~~For Phase 2, the TCC ~~payments:~~

- payment metric referred to as TCC Revenues is used for the purposes of Phase 2 regulated economic transmission project cost allocation under Section 15.4 of the Tariff. The TCC ~~Payment~~revenue metric ~~set forth below will be used for purposes of Phase 2 of the CARIS process and will not be used in Phase 1 of the CARIS process. The TCC payment metric in Phase 2~~ will measure net reductions in TCC ~~revenues~~Revenues and will reflect the forecasted impact of the project on TCC auction revenues and day-ahead residual congestion rents allocated to load in each zone, excluding the congestion rents that accrue to any ~~Incremental~~ incremental TCCs that may be made feasible as a result of this project. This impact will include forecasts of: ~~(~~1) the total impact of that project on the Transmission Service Charge offset applicable to loads in each zone (which may vary for loads in a given zone that are in different Transmission Districts); ~~(~~2) the total impact of that project on the NYPA Transmission Adjustment Charge offset applicable to loads in that zone; and ~~(~~3) the total impact of that project on payments made to LSEs serving load in that zone that hold Grandfathered Rights or Grandfathered TCCs, to the extent that these have not been taken into account in the calculation of item ~~(~~1~~)~~ above. Calculations of net reductions in TCC revenues are detailed in ~~a~~the Initial CARIS Manual~~ for CARIS.~~.

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4. Baseline System Assumptions and Methodology

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The implementation of the CARIS process requires the gathering, assembling, and coordination of a significant amount of data, in addition to that already developed for the reliability planning processes. In accordance with ~~Attachment Y of~~ the ~~NYISO OATT~~Tariff, the starting point ~~for~~in conducting CARIS analysis is the NYISO's ~~current 2009~~most currently approved CRP. ~~This~~The 2009 CARIS analysis begins with the ~~Base Case~~ base case input assumptions provided in the 2009 CRP~~. No changes have been made in these Base Case assumptions. The CARIS process~~ and aligns with the ~~NYISO's~~ 10-year reliability planning horizon for the 2009 CRP. ~~The OATT requires that the CARIS process assume that the NYCA bulk power system meets the applicable reliability criteria for the entire ten-year planning horizon studied in the CRP, 2019-2018. The 2009 CRP concluded that there were no reliability needs through 2018.~~

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4.1. Major System Assumptions

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It is important to note that there are no substantive changes in ~~Base Case~~ base case input assumptions from the 2009 CRP except for those prescribed in section 1.1.3 of the Initial CARIS ~~procedure manual; *Inclusion of Market-Based Solutions (MBS) and Reliability Backstop Solutions (RBS) in CARIS Base Case; Scaling Back MBS* [10] .~~Manual.[11] This step resulted in no change in the system model~~.~~

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from the 2009 CRP. Appendix C ~~lists all of the input assumption data and~~ includes a detailed description of the ~~rationale for each. Below are descriptions of key data sources and~~ assumptions~~. The data was~~ utilized in the CARIS analysis developed ~~based on the OATT and~~ in collaboration with stakeholders. The ~~study system and~~key assumptions are ~~based on the 2009 RNA/CRP~~presented below:

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~~1.4~~Power ~~Flow Data Used in the CARIS Model~~

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~~CARIS uses the network topology, system impedance and transmission line ratings that were developed from the 2009 CRP power flows. The following power~~ flow ~~cases developed for the CARIS from the 2008 FERC 715 filing base cases:~~

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- ~~Summer 2009 Peak Load~~
- ~~Summer 2013 Peak Load~~
- ~~Winter 2013/2014 Peak Load~~
- ~~Summer 2018 Peak Load~~

~~[10] While the system topology and resource additions are the same as in the 2009 CRP, additional data inputs were needed for the CARIS studies since the CRP studies employed transmission and resource adequacy analyses while the CARIS uses production cost analysis requiring additional inputs~~

[11] While the system topology and resource additions are the same as in the 2009 CRP, additional data inputs were needed for the CARIS studies since the CRP studies employed transmission and resource adequacy analyses while the CARIS uses production cost analysis requiring additional inputs

1. ~~For the intermediate years between 2010 to 2017, the~~ models - CARIS uses the same power flow ~~cases were based on data provided in the FERC 715 2013 Summer Peak Load case. PJM system changes~~ base cases utilized in the 2009 CRP.

2. Load and capacity forecast was taken from the 2009 RNA/CRP. It represents the 2008 Gold Book econometric forecast adjusted for approximately 30% of the entire Energy Efficiency Portfolio Standard (EEPS) goals. The 2009 load forecast impacted by the recession was not used in the load model.

3. Transmission and constraint model utilizes a bulk power system representation comprising the entire Eastern Interconnection, including the United States and Canadian Provinces east of the Rocky Mountains, excluding Texas. The model uses the 2009 RNA/CRP transfer limits and system upgrades/additions. External transactions between NYCA and its neighboring control areas are modeled as the interchange flow between the load (export) and generator (import) proxy busses. Transmission outages were not modeled ~~in PJM's 2012 RTEP Study and NYISO system changes described in the 2009 CRP Study required changes such as additional generators and transmission lines to these power flow cases to capture the sequencing of these additional resources. The FERC 715 2018 Summer Peak Load case and NYISO system changes described in the 2009 CRP Study were used to develop the 2018 power flow case. The winter transmission line ratings from the FERC 715 Winter 2013/2014 Peak Load case was used for all years assessed in the CARIS.~~. Refer to Appendix D for details.

4. Production cost model utilizes the most economic security constrained dispatch of generation resources to serve the load subject to the constraints given in the model. To develop the production cost curves, unit heat rates, fuel forecasts and emission costs forecast were developed based on public domain information. The CO_2 emission cost forecast does not include Federal CO_2 policy. The model includes the planned maintenance generation outages, but not forced outages.

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Notwithstanding the other major inputs listed in other sections that can have significant impact on the congestion projection, are the known events that have impacts on the simulation outcome, as summarized in Table 4-1.

Table 4-1: Timeline of Major Events

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Caithness Installed	Empire Generator Installed	M29 Cable Installed		Susquehanna-Roseland Line Installed	SWCT Transmission Reinforcement Installed				New Power Flow Case
	Linden VFT Installed	Athens SPS Ends		West Central Interface Decreased from 1770 MW to 1425 MW		Estimated load and resource balances in neighboring areas	Estimated load and resource balances in neighboring areas	Estimated load and resource balances in neighboring areas	Estimated load and resource balances in neighboring areas
	Poletti Retired								
	New Power Flow								
	Increased Fuel Price								

Note: The contract between New Athens Generation Company and National Grid specifically calls for the removal of the Athens SPS at the end of 2010 unless a permanent physical reinforcement has been identified. There appears to be no intention to extend the operation of the current Athens SPS after 2010.

4.2. Load and Capacity Forecast

The load and capacity forecast used in the CARIS baseline system, provided in

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Table 4-3Table 4-2, was taken directly from the 2009 RNA/CRP. There were no changes made to the load forecast or the resource mix in the CARIS as compared to the 2009 CRP.

As reported in the CRP, the 2008 Gold Book forecasts for peak load and energy demand were modified to account for the impacts of programs such as the Energy Efficiency ~~Portfoilio Standards~~Portfolio Standard (EEPS) and Special Case Resources (SCRs) to reflect achievement of approximately 30% of the entire EEPS goal and increased SCR levels experienced in the market~~.~~.[12]

Table ~~4.1~~4-2: RNA Study Case Load and Resource Table with Updated TO Plans[13]

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Peak Load										
NYCA	**34,059**	**34,269**	**34,462**	**34,586**	**34,725**	**34,905**	**35,029**	**35,258**	**35,430**	**35,658**
Zone J	12,127	12,257	12,361	12,452	12,537	12,627	12,683	12,787	12,879	12,980
Zone K	5,386	5,395	5,403	5,403	5,377	5,370	5,358	5,374	5,354	5,383
Resources										
NYCA										
“Capacity”	39,992	39,657	40,496	40,496	40,502	40,452	40,452	40,452	40,452	40,452
“SCR”	2,084	2,084	2,084	2,084	2,084	2,084	2,084	2,084	2,084	2,084
Total	**42,077**	**41,741**	**42,580**	**42,580**	**42,586**	**42,536**	**42,536**	**42,536**	**42,536**	**42,536**
Res./Load Ratio	123.5%	121.8%	123.6%	123.1%	122.6%	121.9%	121.4%	120.6%	120.1%	119.3%
Zone J										
“Capacity”	10,097	9,206	9,206	9,206	9,206	9,206	9,206	9,206	9,206	9,206
“SCR”	622	622	622	622	622	622	622	622	622	622
Total	**10,719**	**9,828**	**9,828**	**9,828**	**9,828**	**9,828**	**9,828**	**9,828**	**9,828**	**9,828**
Res./Load Ratio	88.4%	80.2%	79.5%	78.9%	78.4%	77.83%	77.49%	76.86%	76.31%	75.71%
Zone K										
“Capacity”	5,938	6,368	6,368	6,368	6,368	6,368	6,368	6,368	6,368	6,368
“SCR”	216	216	216	216	216	216	216	216	216	216
Total	**6,154**	**6,584**	**6,584**	**6,584**	**6,584**	**6,584**	**6,584**	**6,584**	**6,584**	**6,584**
Res./Load Ratio	114.3%	122.0%	121.9%	121.9%	122.4%	122.61%	122.88%	122.52%	122.98%	122.31%

4.3. Transmission Model

The CARIS production cost analysis utilizes a bulk power system representation comprising the entire Eastern Interconnection, which is defined roughly as the bulk electric network ~~-~~in the ~~US states~~United States and Canadian Provinces ~~west~~east of the Rocky Mountains, excluding Texas. A detailed representation of this network, with equivalents for the

[12] “SCR” values reflect projected August 2009 ICAP capability period values held constant over the ten-year Study Period.

[13] New York Control Area (NYCA) "Capacity" values include resources internal to New York, Additions, Reratings, Retirements, Purchases and Sales, and UDRs with firm capacity. Zone K "Capacity" values include UDRs with firm capacity. Wind generation values include full nameplate capacity.

“SCR” values reflect projected August 2009 ICAP capability period values held constant over the ten-year Study Period. [13]New York Control Area (NYCA) "Capacity" values include resources internal to New York, additions, reratings, retirements, purchases and sales, and UDRs [WHAT DOES THIS MEAN – DEFINE] with firm capacity. Zone K "Capacity" values include UDRs with firm capacity. Wind generation values include full nameplate capacity.

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WECC and Texas is developed in the NERC Multi-area Modeling Working Group (MMWG) process. Figure 4-1Figure 4-1 below illustrates the electric grid represented in the CARIS model comprising the Eastern Interconnection regions and Balancing Authorities. The CARIS model includes a full active representation for ~~New York Control Area (~~the NYCA~~)~~, ISO~~ New England (ISONE), Independent Electricity System Operator (~~-NE, IESO~~)~~, and PJM ~~Interconnection LLC (PJM) ~~(PJM Classic, ~~AP, ~~Allegheny Power System (APS), American Electric Power System (AEP~~,~~), Commonwealth Edison Company (CE~~,~~), Duquesne Light Company (DLCO~~,~~), Dayton Power and Light (DAY) and Virginia Power (VP)) for both the network model and the a production cost model. A proxy bus is used to model Hydro Quebec (HQ) to NYISO ~~&~~and ISO-NE. Transmission- only models are represented for Michigan Electric Coordinated Systems (MECS~~,~~), First Energy Corporation (FE~~,~~), Southwest Power Pool (SPP), MAR, Northern Indiana Public Service Company (NIPS~~,~~), Ohio Valley Electric Corporation (OVEC~~,~~), Tennessee Valley Authority (TVA~~,~~), Florida Reliability Coordinating Council (FRCC), SERC Reliability Corporation (SERC), and equivalences for the Electric Reliability Council of Texas (ERCOT), and the WECC. For purposes of the CARIS report, the model is discussed in two parts: the NYCA system representation and the system representations for the external control areas.

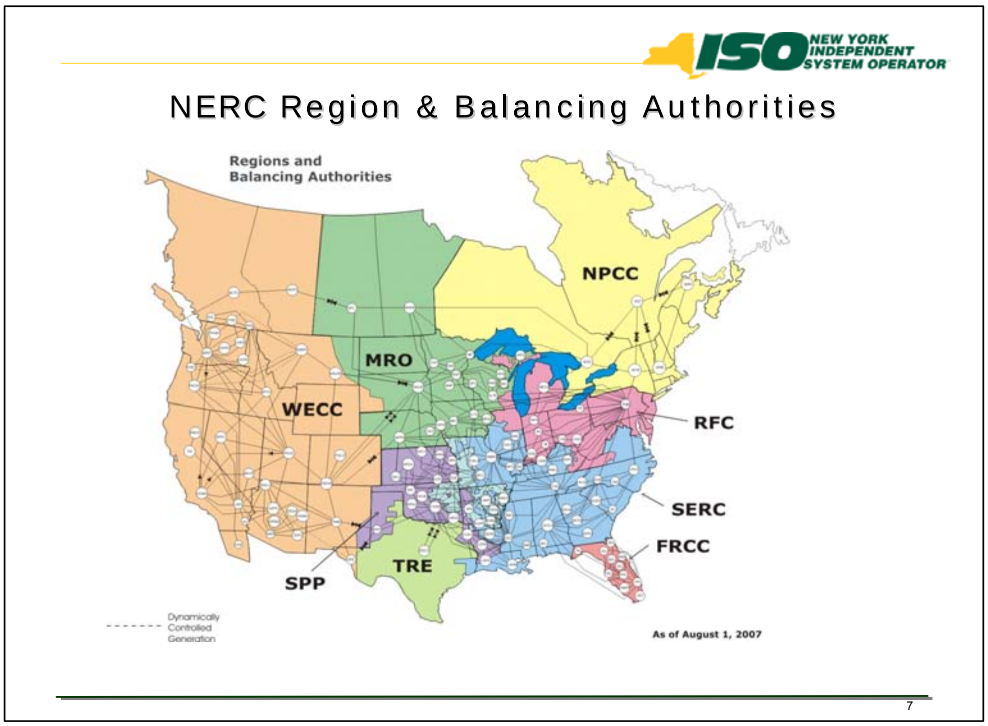

Figure 4-1: ~~Represented Area~~All Areas Modeled in CARIS (Excluding WECC & TRE)

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1.1.1 New York Control Area Model

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Figure 4-2 below displays the bulk power system for NYCA, which is generally facilities 230 kV and above, but does include certain 138 kV facilities and a very small number of 115 kV facilities. The balance of the facilities 138 kV and lower are considered non-bulk or sub-transmission facilities. The figure also displays key transmission interfaces for New York.

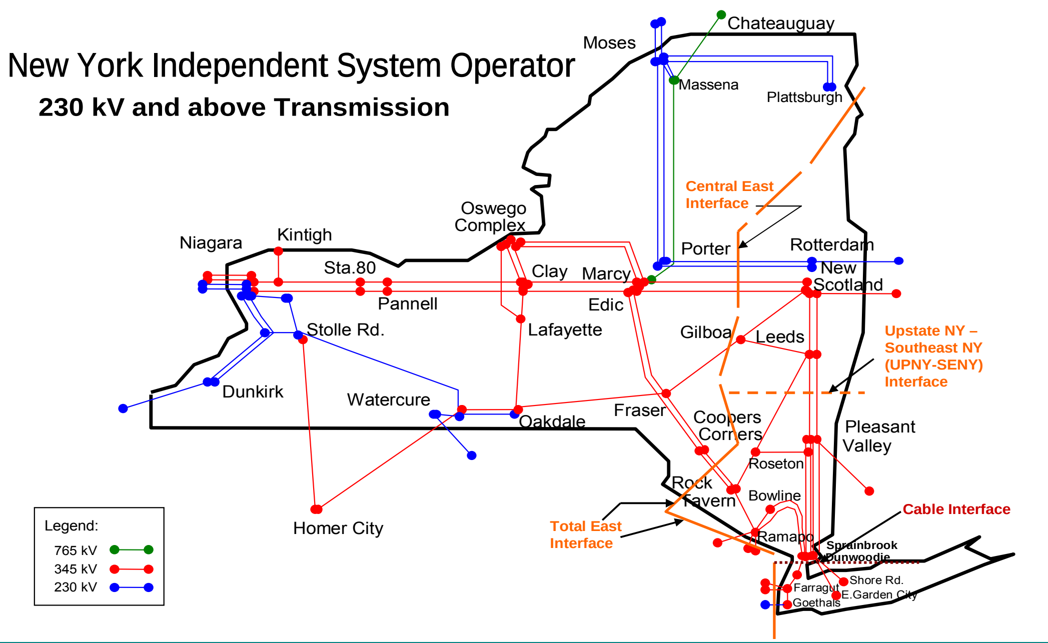

Figure 4-2: NYISO 230 kV and above Transmission Map

1.1.2 New York Control Area Upgrades & Resource Additions

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The highlights of year on year model changes are as follows:

a. Caithness Long Island – new 320MW, Combined Cycle, LIPA, Suffolk, NY, Commercial Operation - 4/2009;
b. BesiCorp – new 660MW, Combined Cycle, National Grid, Rensselear, NY, proposed Commercial Operation 2/2010;
c. Polleti - 890.7MW, retirement expected 2/2010;
d. M29 – 345kV transmission line from an existing station in Yonkers NY to a new substation in NYC, expected in-service date 2011

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4.3.1. New York Control Area Transfer ~~limits~~Limits

In the resource adequacy analysis for the 2009 RNA, interface transfer limits were assumed to be constant from the end of the first five years throughout the second five-year period. The assumed interface transfer limits were confirmed during the CRP evaluation of the baseline system. For the resource adequacy analysis of the RNA/CRP, emergency criteria transfer limits are employed in the GE-MARS software model, while the transfer limits for the CARIS study are based upon normal criteria transfer limits. For voltage and stability based limits, the normal and emergency limits are assumed to be the same. The normal voltage transfer limits for critical NYCA transmission interfaces in the CARIS were taken from the RNA, ~~,~~ and the CRP with some exceptions as indicated in

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Table 4-3Table 4-3 below.

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Table 4-3: - Transmission System ~~Base Case~~ Normal Voltage Transfer Limits for Key Interfaces (in MW)

Interface	2009 CARIS Study				
	2009	**2010**	**2011**	**2012**	**2013**
WEST CENTRAL-~~OP~~Open	1770	1770	1770	1770	1425
CENTRAL EAST	2600	2600	2600	2600	2600
CONED – LILCO	2166	2166	2166	2166	2166
UPNY-ConEd	5000	5000	5000	5000	5000
Dunwoodie (I) to NYCity (J)	4000	4075	4400	4400	4400
Dunwoodie (I) to Long Island (J)	1217	1265	1265	1265	1265
Spr/Dunwoodie So~~. OP~~uth	5315	5290	5365	5365	5365

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Note: Central East and UPNY-ConEd were ~~modified from the~~ modeled differently than the RNA/CRP values~~.~~[14]

Normal thermal interface transfer limits for the CARIS study are not directly utilized ~~as~~**from** the ~~monitored element and contingencies, which set the limit, are modeled directly. The CARIS constraint data consist of approximately 2000 monitored bulk power transmission elements, contingencies, and nomograms to model the transmission constraints limiting the economic dispatch of the system.~~

~~The CARIS thermal transfer limit data was initially developed by performing~~ thermal transfer analysis **performed** using the **Power Technologies Inc. Power System Simulator for Engineering (**PSS/E**)** MUST **software** application ~~using~~**which uses** the transmission planning set of ~~normal~~**design** criteria contingencies. ~~MUST identifies~~**Instead, CARIS uses** the most limiting monitored line and contingency sets which ~~h~~**MUST identified** as the most ~~impact on~~ **limiting constraint to the** NYCA ~~Cross-State~~**cross-state** transmission interfaces~~. The planning models utilize a set of monitored lines and contingencies and were then compared with monitored lines and contingency sets used in the NYISO SCUC analysis~~ **to determine thermal transfer limits as the load and generation is varied throughout the annual simulations**. The resulting monitored lines and contingency sets used in the CARIS do~~es~~ not include lines which have less than a **five** 5~~%~~ **percent** impact on the NYCA ~~Cross-State~~**cross-state** transmission interfaces**,** or **the lines that** only impact local 115-138 kV transmission or sub-transmission constraints. **Error! Not a valid bookmark self-reference.** lists the monitored lines and

[14] Central East was not modeled explicitly in the RNA/CRP but was modeled with the Fraser - Gilboa circuit. UPNY/ConEd was modeled with a nomogram in the RNA/CRP whereby two 300 MW reductions from 5300 MW were applied depending upon the generation availability and load in SENY. This was simplified to one value of 5000 MW for CARIS.

contingency elements that set the NYCA Cross-State transmission interfaces thermal limits from the Summer 2009 Operating Study. Many studies were done similar to this and those monitored lines and contingencies were added to this CARIS database.

Table 4-4 - Transmission System Base Case Normal Thermal Transfer Limiting Element and Contingencies for Cross-State Transmission Interfaces

Limiting Element	Rating		Limiting Contingency	
Niagara – Rochester (NR2) 345kV	@LTE	1501 MW	L/O	AES/Somerset – Rochester (SR-1) 345kV
Stolle Rd – Meyer (67) 230kV	@NOR	430 MW	L/O	Pre-Contingency loading
Leeds – Pleasant Valley (92) 345kV	@LTE	1538 MW	L/O	Athens – Pleasant Valley (91) 345kV
Mott Haven - Rainey 345kV (Q11)	@SCUC	765 MW	L/O	Mott Haven - Rainey 345 kV (Q12)
Dunwoodie – Shore Rd. (Y50) 345kV	@NOR	653 MW*	L/O	Pre-contingency Loading
Fraser – Coopers Corners (33) 345kV	@LTE	1404 MW	L/O	Double-circuit Tower 31&41 Marcy – Coopers Corners (UCC2-41) 345kV Porter – Rotterdam (31) 230kV
Fraser – Coopers Corners (33) 345kV	@NOR	1207 MW		Pre-Contingency Loading

1.1.3 External Areas

The external areas immediately adjacent to around the NYCA are also modeled at full representation except for Hydro Quebec. Those areas include ISONE, IESO, PJM (PJM Classic, AP, AEP, CE, DLCO, DAY and VP). Since HQ is asynchronously tied to the bulk system, proxy buses representing the direct ties from HQ to NYISO and HQ to ISONE are modeled. External areas surrounding the above areas only model the transmission system to capture the impact of loopflows.

Table 4-5 illustrates the external transmission limits used in the CARIS Study.

Table 4-5 - External Area Transmission Transfer Limits

Area	Interface	2009	2010	2011	2012	2013	2014
IESO	IMO EXPORT	2500	2500	2500	2500	2500	2500
IESO	IMO-MISO	1	1	1	1	1	1
IESO	IMO-NYISO	2000	2000	2000	2000	2000	2000
ISONE	Boston	4900	4900	4900	4900	4900	4900
ISONE	Connecticut-Export	2200	2200	2200	2200	2200	3600
ISONE	East-West (NE-NY)	2100	2100	2100	2100	2100	2100
ISONE	ISO-NE EXPORT	4000	4000	4000	4000	4000	4000
ISONE	ISONE-NYISO	1400	1400	1400	1400	1400	1400

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ISONE	LI – ISONE	450	450	450	450	450	450
ISONE	ME – NH	1400	1400	1400	1400	1400	1500
ISONE	NB – NEPOOL	500	500	500	500	500	500
ISONE	North – South	2700	2700	2700	2700	2700	2700
ISONE	Norwalk-Stamford	1300	1300	1300	1300	1300	1300
ISONE	Orrington South	1050	1050	1050	1050	1050	1050
ISONE	SEMA	1450	1450	1450	1450	1450	1450
ISONE	SEMA/RI	2200	2200	2200	2200	2200	2200
ISONE	South West CT	2350	2350	2350	2350	2350	3650
ISONE	Surowiec South	1150	1150	1150	1150	1150	1150
NYISO	NYISO-HQ	1050	1050	1050	1050	1050	1050
NYISO	NYISO-IESO	2500	2500	2500	2500	2500	2500
NYISO	NYISO-PJM	2500	2500	2500	2500	2500	2500
PJM	APSOUTH	3250	3250	3250	3250	3250	3250
PJM	Central Interface	5200	5200	5200	5200	5200	5200
PJM	Eastern Interface	7000	7000	7000	7000	7000	7000
PJM	PJM East – NYISO	2500	2500	2500	2500	2500	2500
PJM	PJM EXPORT	6000	6000	6000	6000	6000	6000
PJM	PJM West – NYISO	2000	2000	2000	2000	2000	2000
PJM	PJM_Extension Export	1500	1500	1500	1500	1500	1500
PJM	PJM_HomerCty	531	531	531	531	531	531
PJM	PJM-VAP	500	500	500	500	500	500
PJM	Western Interface	6250	6250	6250	6250	6250	6250

1.1.4 External Area Model

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Two major transmission additions in the PJM area are included in the base cases. The first was the TrAIL Line (which is located in PJM and is scheduled to go commercial in 2010; and the second is the Susquehanna-Roseland 500kV addition which is located in PJM and is scheduled to go commercial in 2013.

1.1.5 Loop Flows

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The phenomenon of loop flow has been widely studied and its impact on transmission line loading is well documented and understood.

Neighboring transmission systems are usually tightly connected together, and this can cause loop flow, or unscheduled flows occurring on a neighboring system. These unscheduled flows can have a component resulting when one system is transferring power across its own system and a second component resulting from transactions between systems.

A second component of loop flow is caused by electric transactions that are scheduled from one specific location to another without regard to the actual flow of energy. Loop flow results from the effect of those unscheduled flows.

The first type of loop flow was captured in the CARIS databases simply by expanding the simulations to include the hourly dispatch of generation and load in the NYISO and its neighboring control areas RFC, ISONE, Ontario Hydro and Hydro Quebec (HQ modeled as Proxy bus). Expanding the simulation to include the NYISO neighboring markets allows for more accurate flow calculations on NYISO transmission lines by taking into account the impact of the neighboring systems' load and generation on NYISO transmission lines. This approach is also consistent with the NYISO's DAM (SCUC) methodology.

The second component of loop flow, which is caused by unscheduled flows, was modeled in the CARIS databases by setting nomograms to certain levels on the Lake Erie clockwise/counterclockwise flows.

1.1.6 Hurdle Rates and Interchange Models

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Hurdle rates set the conditions in which economy interchange can be transacted between neighboring market/control areas. It represents a minimum savings level that needs to be achieved before energy will flow across the interchange. Hurdle rates serve two purposes in the CARIS model. First, they are used when preparing the Base Case to help calibrate the production-cost simulation so that it replicates a historical pattern of generation dispatch. Second, they are used to find a different (and usually lower-cost) combination of generation resources to meet loads aggregated from the base case.

Two independent hurdle rates are used in the CARIS base case, one for the commitment and a separate one for the dispatch. The commitment hurdle rate sets the level that a unit commitment change will be made and the dispatch hurdle rate sets a level that will allow economic dispatch to be changed to allow scheduled energy to flow between market areas. Hurdle rates are held constant throughout the 2010-2018 study period.

Hurdle Rates on several closed and open interfaces were used to model regional power imports, exports and wheel through transactions, Table 4-6. These hurdle rates are acceptable practice in conducting multi-pool production cost simulations and they are used to represent several phenomena such as complex market pricing at the boundary busses, cost mark-ups and market inefficiency. The Hurdle Rates values in the CARIS databases are also consistent with previous NYISO and consultant studies and are considered standard industry practice. In addition, the annual NYISO imports are consistent with historic import levels confirming that NYISO's hurdle rate assumptions are reasonable.

Table 4-6 - Hurdle Rates utilized in the CARIS simulations

Interface	Unit Commitment - $/MWH		Economic Dispatch - $/MWH	
	Imports	Exports	Imports	Exports
NYISO AC	1000	1000	6	6
ISONE AC	1000	1000	8	3
PJM AC	1000	1000	8	8
Ontario Hydro	1000	1000	6	6

Lake Erie Loop Flow	1000	1000		
…				

While no firm power transactions were specifically modeled, the NYISO DC tie-lines (Neptune and CSC) were excluded from the interfaces and therefore flows on those facilities were not subject to hurdle rates. It should be noted that the flow on the CSC line was allowed to reverse direction (i.e. flow toward ISONE) but the Neptune flows was restricted to 660 MW into Long Island and reverse flow toward PJM was not allowed to occur in the simulation because exports from NYCA to PJM are not presently allowed on Neptune line. Exclusion of the DC tie-lines from the interfaces was necessary to capture their historic scheduled flows (*e.g.*, 90% loading factor on Neptune) and thus how they are expected to be operated in the future.

1.2 Production Cost Model

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Production costing models require input data to develop cost curves for the resources that the model will commit and dispatch to serve the load subject to the constraints given the model. This section will discuss how the "production cost data" for these resources were identified and quantified. The model simulations are driven by incremental cost of production of generators. The incremental cost of generation is product of the incremental heat rate times the sum of fuel cost, emissions cost, and variable operation and maintenance expenses. Section 4.4.1 reviews how heat rate information was developed for the NYCA generation fleet. Section 4.4.2 reviews the development of emission allowance forecasts. Section 4.4.3 reviews the development of the fuel forecast.

1.2.1 Heat Rates

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Fuel costs represent the largest incremental expense for fossil fueled generating units. Fuel costs are the product of fuel prices and incremental heat rates. Thus it is critically important to the quality of the results of CARIS that individual generating unit heat rates used in the simulations be an accurate representation of reality. Individual unit heat rates are important competitive information and thus are not widely available from generator owners. Both of the simulation models have databases that represent the model providers' best estimates of heat rates. When the heat rates from the two models were compared it was apparent that significant differences existed.

In order to gain additional insight as to which, if either, dataset was an accurate representation of actual unit performance, publicly available information reporting heat input was matched with net generator production from NYISO market data to calculate hourly heat rates for 2008. One vendor has substituted a dataset for which the NYISO did not have a direct license agreement thus removing that data set from further consideration. Unit heat input data is available from the USEPA's Clean Air Market Data. This data set was then used to calculate unit heat rates and incremental heat rates across each units operating range through the use of regression analysis techniques. First, second, and third order polynomials developed. Generally, third order polynomials resulted in the best fit. A small number of data points were eliminated for a few units to improve curve fit. The eliminated data could be the result of errors in reporting or represent limited operation within a specific hour. These calculated heat rates were then compared to the remaining simulation model data for each fossil fueled unit in NYCA and one heat rate curve was selected for each unit.

Consideration was given to using this approach across all of the units in the simulation, however, the relative smaller impact of heat rate inaccuracies for non-NYCA units and the shear magnitude of the effort to correct heat rates for all units in the simulation lead to the conclusion that vendor supplied heat rate information should be used for all non-NYCA units.

Both simulation models employ power points which are points in the units operating range where specific data such as heat rate is tied to the power point. In general there are minimum and maximum points where the unit can be simulated to operate on a sustained basis. There may also be additional intermediary points. Each of these points was tied to a point on the heat rate curve and the incremental heat rate was determined.

A review of the actual operating performance of NYCA units revealed that the vendor supplied data sets did not accurately capture the point of minimum operation for units that have emission control systems that are sensitive to flue gas exit temperatures for the control of NOx emissions. The minimum operating points for units with these permit conditions were increased to reflect these operating limits.

Heat Rates of marginal units in all zones display the expected seasonal patterns with summer months having the highest values. Also, there is a progression by which the monthly averages are the lowest in Zone A and the further east a zone is located, the higher the implied heat rate is. The relative magnitudes across zones are consistent with the differences in the generation fuel-mixes as depicted in Figure 4-3.

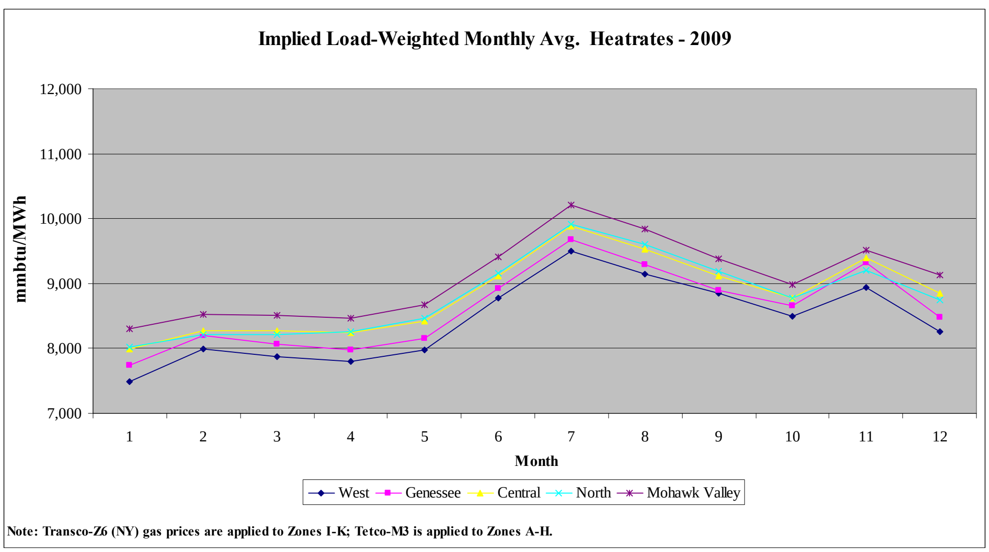

Figure 4-3 - Load-weighted monthly average heat rates for Upstate NY

In all zones, Figure 4-4, the implied heat rates for all downstate zones display the expected seasonal patterns. The heat rates of Marginal units are highest for Millwood (Zone H), Hudson Valley (Zone G), and Long Island (Zone K). With respect to zones G and J, the difference in assumed gas prices explains the relative parity during non-winter months and the divergence during the winter months.

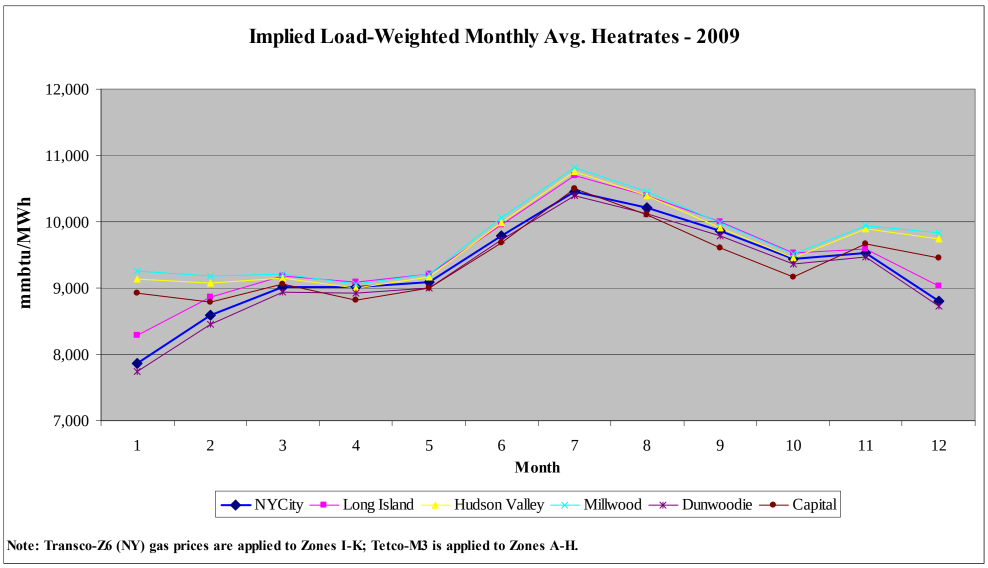

Figure 4-4 - Load-weighted monthly average heat rates for downstate NY

1.2.2 Emission Cost Forecast

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The costs of emission allowances are an increasing proportion of production costs. Currently all NYCA fossil fueled generators greater than 25 mw and most generators in surrounding states are required to hold allowances in amounts equal to their emissions of SO_2, NO_X, and CO_2. There are exchanges for trading allowances and futures contracts for allowances. The Chicago Climate Futures Exchange offers standardized and cleared futures and options contracts on emission allowances and other environmental products. The emission allowance price forecasts were created by using future contract values on May 15, 2009. Extrapolations were made for years where futures contracts were not traded. The simulations were based on the assumption that all fossil generators are required to have emission allowances equal to their respective emissions.

Emission costs are the product of emission rate and emission allowance costs. Annual emission rates were used in the simulations. The annual emission rates in terms of #/mmBTU are available from the USEPA CAMD (California Micro Devices Corporation). Since the emission rate determined above is an average emission rate, the same rate was used across the operating range.

Figure 4-5 shows the Emission Allowance Forecast by year in $/Ton.

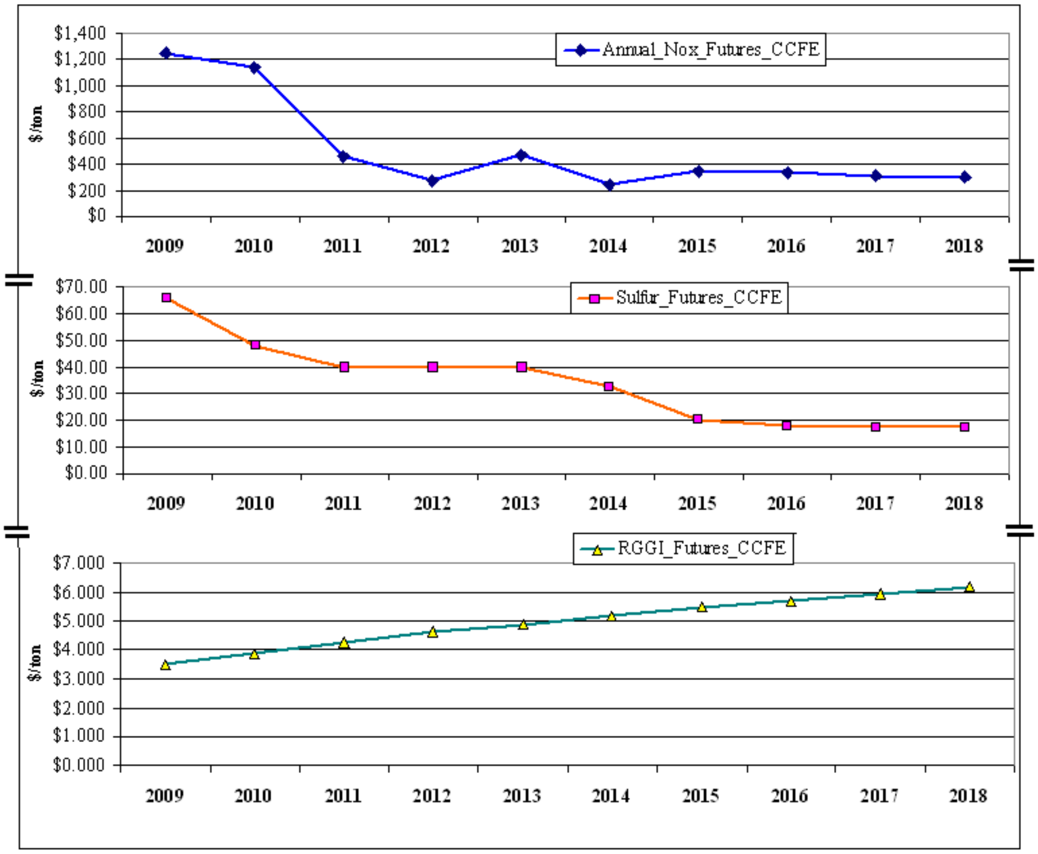

Figure 4-5 - Emission Allowance Forecast

With respect to the RGGI Futures, the data from Chicago Climate Futures Exchange (CCFE) was available only through 2012. The implied trend was extrapolated to cover the 2013-2018 period.

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4.4. Fuel Forecasts

4.4.1. CARIS Base Annual Forecast

The starting~~-~~ point for preparing the fuel~~-~~ price forecasts for CARIS is ~~EIA's (~~the US Energy Information ~~Administration – www.eia.doe.gov)~~Administration's (EIA)[15] current national long-term forecast of delivered fuel-prices that is released each spring as part of the Annual Energy Outlook (AEO).

The figures in this forecast are in real dollars~~,~~ (i.e~~.~~., indexed relative to a base year~~; e.g. 2007~~). Forecasted time-series of the GDP ~~Deflator~~deflator published by EIA, as part of the AEO, is used to inflate the *real* values to *nominal* values. ~~This shall serve as the base annual~~

4.4.2. New York Fuel Forecast

In developing the New York's fuel forecast, adjustments were made to the EIA's fuel forecast ~~series.~~

~~**Adjustments**~~ to reflect ~~**Bases**~~bases for fuel prices in New York

. A key source of data for estimating the relative differences or 'basis' for fuel prices in New York are the Monthly Utility and non-Utility Fuel Receipts and Fuel Quality Data reports based on information collected through Form EIA-423 (2000-2007) and EIA-923 (2008 onwards).[16] The base annual forecast series are then subjected to an adjustment to reflect the New York 'basis' relative to the national prices as follows:

Natural Gas (Figure 4-6 & Figure 4-7Figures 4-2 and 4-3):

A historical analysis of EIA's national AEO forecasts of delivered fuel-prices suggests that they are around 5% higher than Henry Hub prices. Any basis for New York, then, is assessed against 105% of Henry Hub price forecasts. The natural gas price for zones I through K is the Transco Zone 6 (NY) and the proxy for the remainder of NYISO zones is the Tetco-M3 trading price. Analysis of historical prices reveals that, relative to 105% of Henry Hub prices, on average, the basis for Transco Zone 6 (NY) is around 13% and for Tetco-M3 it is 5.5%. (The 7.5

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[15] www.eia.doe.gov

[16] Prior to 2008, this data was submitted via FERC Form 423. 2008 onwards, the same data are collected on Schedule 2 of the new Form EIA-923. See http://www.eia.doe.gov/cneaf/electricity/page/ferc423.html

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percentage-point differential is consistent with the sum of historical difference between the two prices and the applicable taxes in the New York City area.)

Fuel Oils (Figure 4-6 & Figure 4-7Figures 4-2 and 4-3):

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Based on reports drawn from EIA-423 for the years 2002-2007, prices of both distillate and residual oils are about 15% cheaper in New York as compared to the U~~.~~S~~.~~ average price. Since the overwhelming bulk of oil-based generation is situated in Zones J and K, the basis for the Downstate zones is -15%. To allow for additional transportation charges, the basis for the Upstate zones is -10%.

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Coal (Figure 4-6 & Figure 4-7Figures 4-2 and 4-3):

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The data for Bituminous Coal in EIA-423 was used to calculate a common basis for all NYISO zones. Prices in New York are, on average, 15% higher than in the U~~.S.~~nited States as a whole.

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Uranium (Figure 4-6 & Figure 4-7Figures 4-2 and 4-3):

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It is assumed that the ~~same~~same fuel price applies to all nuclear generators in the U~~.S~~nited States.

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4.4.3. Seasonality and Volatility

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All average monthly fuel~~-~~ prices, with the exception of uranium, display somewhat predictable patterns of fluctuations over a given 12-month period. In order to capture such seasonality, NYISO estimated seasonal-factors using standard statistical methods.[17] The multiplicative factors were applied to the annual forecasts to yield forecasts of average monthly prices.

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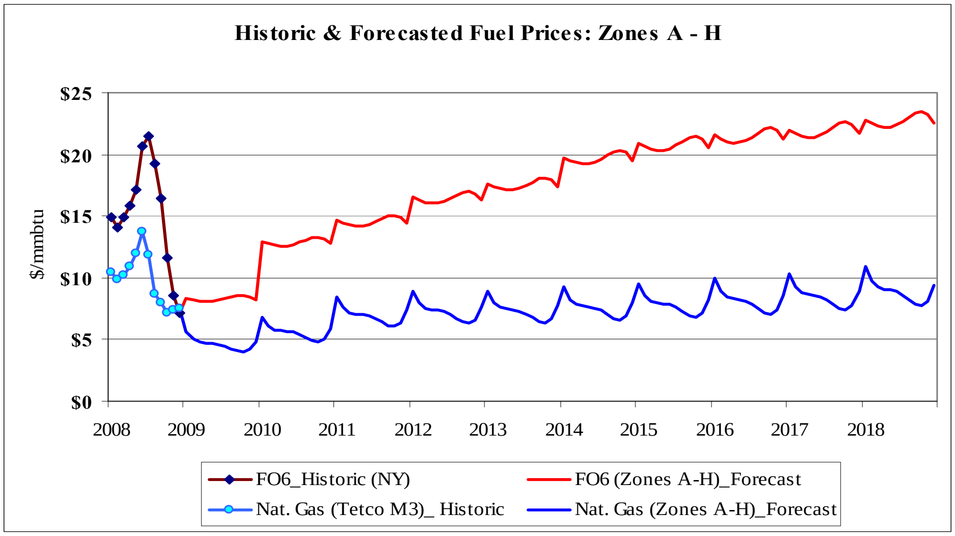
[17] This is a two-step process: First, using multi-year time-series, deviations around a time-varying trend (e.g. a centered 12-month moving average or a Hodrick-Prescott Filtered trend) were calculated; second, a 4-degree polynomial trend was fitted to the estimated seasonal factors.



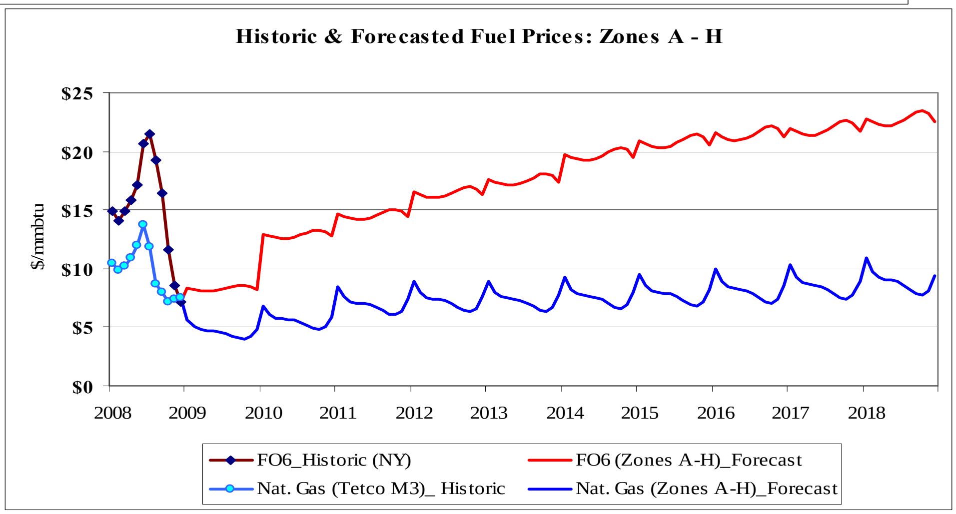


Figure 4-6–: Historic and forecasted fuel prices for Zones A-H

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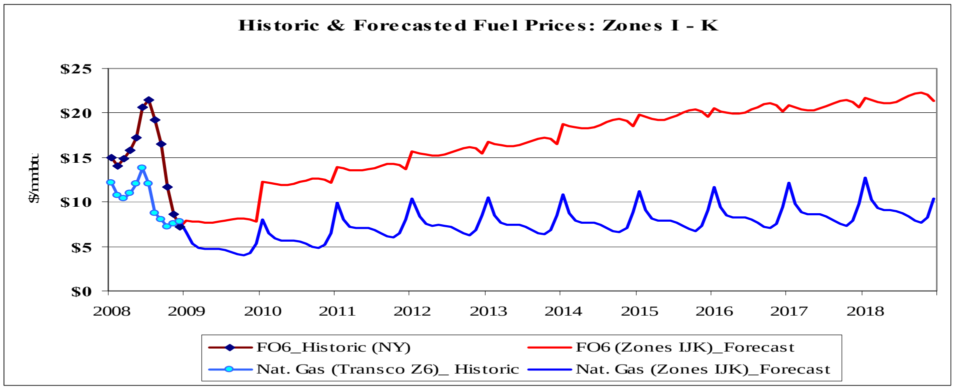

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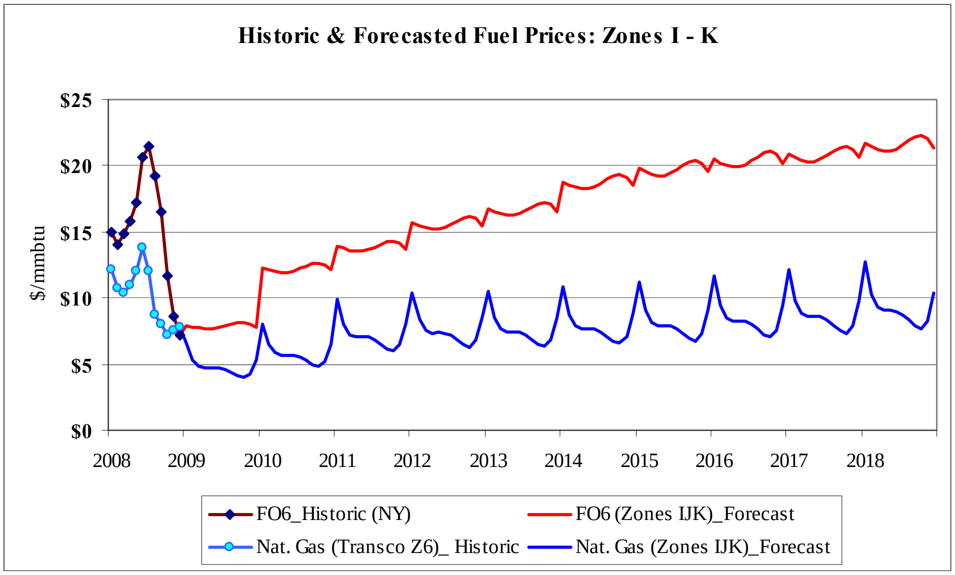

Figure 4-7~~-~~: Historic and forecasted fuel prices for Zones I-K

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The seasonalized time-series ~~represent~~represents the forecasted trend of average monthly prices~~,~~ (i.e~~.~~., a trend). However, in order to facilitate simulation studies to explore scenarios with higher/lower prices, the NYISO developed volatility-factors to capture typical intra-month variability of prices. These factors were the typical monthly standard deviation of daily prices, based on historical data. For natural gas and fuel-oils, this monthly volatility factor equals the average standard deviation of daily prices. In the case of coal, only monthly average prices are available; therefore, the corresponding factor is the standard deviation of average monthly prices. ~~(~~This approximation is reasonable because coal prices exhibit relatively muted volatility, as compared to natural gas, and fuel oils~~)~~.

4.4.4. External Areas Fuel Forecast

The fuel forecasts for the three external areas, Figure 4-8 **and** Figure 4-9 **were developed as follows:**

This procedure outlines the process of developing monthly fuel-price forecasts for three adjacent control areas – ISO-NE, PJM, and IESO~~.~~

, were also developed. The starting point was the base-line annual forecasts of each fuel for New York~~[18]~~ ~~.~~.[19] The annual averages and the seasonal factors for each external control area were estimated as follows: For ISO-NE and PJM, information obtained from EIA Form 423 (EIA-423) was used to calculate the basis relative to figures for New York, and for IESO the basis was based on data from a recent publication.[20]

Table 4-7: ,

Table 4-8: ,

Table 4-9, &

~~[18] These forecasts were, in turn, based on EIA's current national long-term forecast of delivered fuel-prices.~~

[19] These forecasts were, in turn, based on EIA's current national long-term forecast of delivered fuel-prices.

[20] Ontario Wholesale Electricity Market Price Forecast For the Period May 1, 2008 through October 31, 2009, Presented to Ontario Energy Board, April 11, 2008 by Navigant Consulting Inc., Toronto, Ontario.

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Table 4-10Tables 4-5, 4-6, 4-7 and 4-8 below outline the assumptions that went into the fuel-price forecasts for each external control area.

Table 4-7–: ISO—-New England Assumptions

	Annual Average	Monthly Factor
Natural Gas	Same as the price for Zones I – K	Same as the factor for Zones I – K
FO2	120% of the price for New York	Same as the factor for New York
FO6	115% of the price for New York	Same as the factor for New York
Coal	125% of the price for New York	Same as the factor for New York

Table 4-8–: PJM—-East Assumptions

	Annual Average	Monthly Factor
Natural Gas	Same as the price for Zones A – H	90% of the factor for Zones A – H in Jan.; 95% in Feb., and 100% for other months
FO2	125% of the price for Zones A – H	Same as the factor for New York
FO6	113% of the price for Zones A – H	Same as the factor for New York
Coal	97% of the price for Zones A – H	Same as the factor for New York

Table 4-9–: PJM—-West Assumptions

	Annual Average	Monthly Factor
Natural Gas	Same as the price for Zones A – H	88% of the factor for Zones A –- H
FO2	125% of the price for Zones A – H	Same as the factor for New York
FO6	113% of the price for Zones A – H	Same as the factor for New York
Coal	82% of the price for Zones A – H	Same as the factor for New York

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Table 4-10–: IESO Assumptions

	Annual Average	Monthly Factor
Natural Gas	84% of the price for Zones A – H; rest of the months the same as the price for Zones A – H	90% of the factor for Zones A – H
FO2	Same as the EIA national forecast	Same as the factor for New York
FO6	Same as the EIA national forecast	Same as the factor for New York
Coal	120% of the price for New York	Same as the factor for New York

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4.5. Emission Cost Forecast

The costs of emission allowances are an increasing portion of generators' production costs. Currently all NYCA fossil fueled generators greater than 25 MW and most generators in surrounding states are required to hold allowances in amounts equal to their emissions of SO_2, NO_X, and CO_2. There are exchanges for trading allowances and futures contracts for allowances. The Chicago Climate Futures Exchange (CCFE) offers standardized and cleared futures and options contracts on emission allowances and other environmental products. The emission allowance price forecasts were created by using future contract values on May 15, 2009. Extrapolations were made for years where futures contracts were not traded. The simulations were based on the assumption that all fossil generators are required to have emission allowances equal to their respective emissions.

Emission costs are the product of emission rate and emission allowance costs. Annual emission rates were used in the simulations. The annual emission rates in terms of #/mmBTU are available from the EPA's Clean Air Markets Division (CAMD). Since the emission rate determined above is an average emission rate, the same rate was used across the operating range.

Figure 4-4 shows the emission allowance forecast by year in $/Ton.

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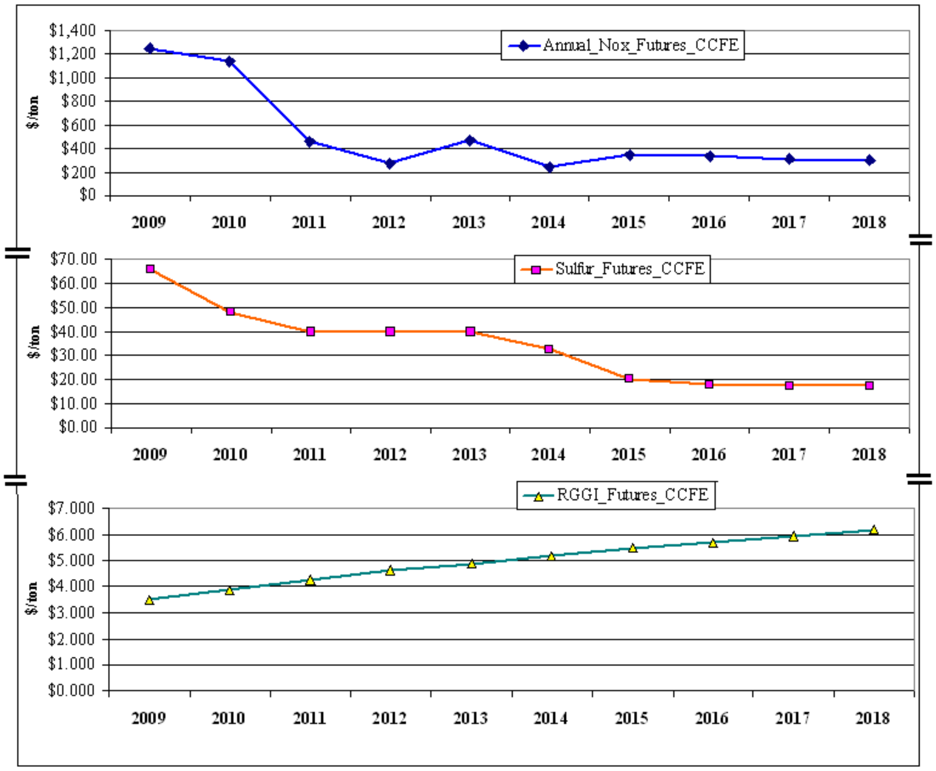

Figure 4-8 - *Forecasted oil fuel prices for ISONE, PJM, & Ontario*

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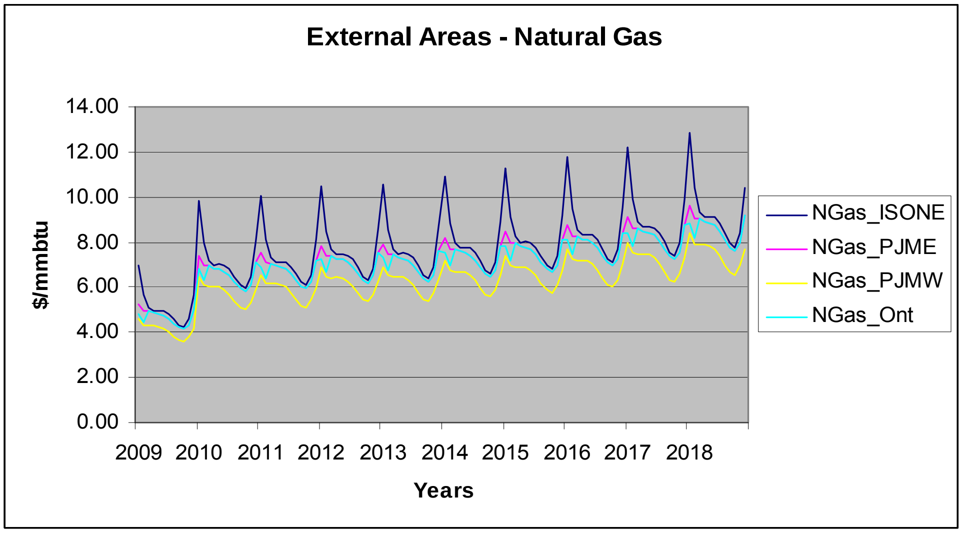

Figure 4-9 - Forecasted natural gas prices for ISONE, PJM, & Ontario

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1.2.3 Fuel Switching

Fuel switching capability is widespread within NYCA. Thirty seven percent of the 2009 NYCA generating capacity, or 14,470 MW, has the ability to burn either oil or gas. There are two reasons that generating facilities would exercise the capability to burn oil: the first reason is that oil would be the economic fuel of choice, the second reason would be to satisfy reliability rules. Historically significant quantities of oil have been used. (Wes will provide a table)

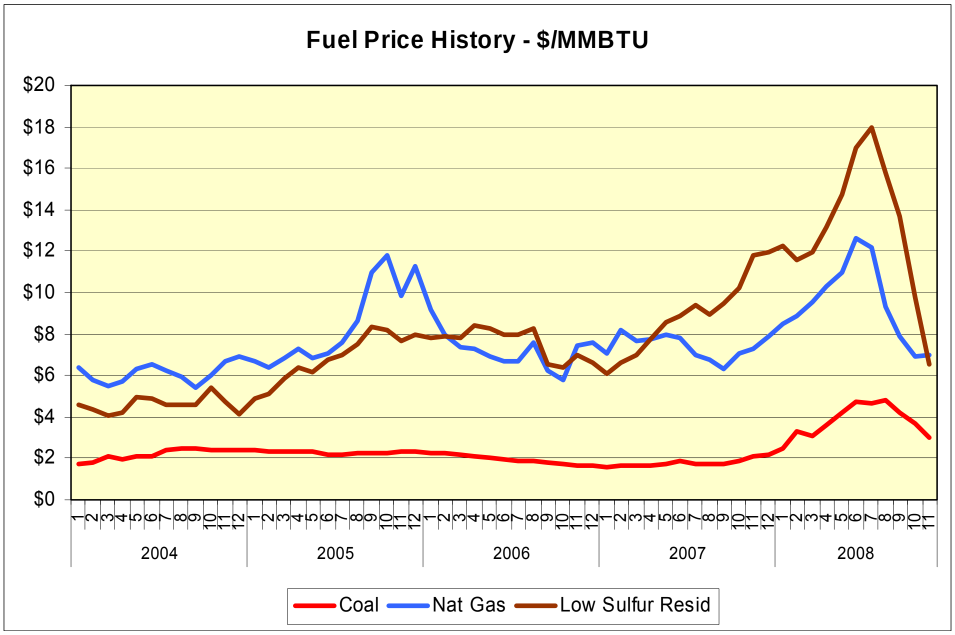

Figure 4-10 - Historical fuel prices of coal, natural gas, and low sulfur coal

Both simulation models can select the economic fuel based on monthly production costs for units with duel fuel capability. For the planning horizon, the fuel price forecast does not show that low sulfur residual fuel oil will be an economic choice on a monthly basis.

The New York Reliability Council has established rules for the reliable operation of the New York Bulk Power System. Two of those rules guard against the loss of electric load because of the loss of gas supply. Rule I-R3 states "The New York State Bulk Power System shall be operated so that the loss of a single gas facility does not result in the loss of electric load within the New York City zone. Rule I-R5 similarly states, The New York State Bulk Power System shall be operated so that the loss of a single gas facility will not result in the uncontrolled loss of electricity within the Long Island zone. To satisfy these criteria, annual studies are performed that update the configurations of the electricity and gas systems and simulate the loss of a various gas supply facilities. The loss of these gas facilities leads to the loss of some generating units. This loss becomes critical because it may result in voltage collapse when load levels are high enough. Therefore, criteria are set up whereby certain units that are capable of doing so are required to switch to minimum oil so that in the event of the worst gas system contingency these units stay on-line at minimum generation levels and support system voltage. This MW deficiency must be made up first though the increased use of imports until oil burning units are able to ramp up their output over a longer timeframe. Some new combined cycle gas turbine units in these zones have the ability to "switch-on-the-fly" from gas-burn to oil-burn with a limited loss of output that can be quickly recovered. However, there is the risk that this live switching may not be successful and the unit may trip. Therefore, in many cases, such units are required to switch to burning oil at lower load levels so there is the ability of recovering from an unsuccessful switching. As the fleet in these zones has seen a shift to increased use of combined cycle units with switch–on-the-fly capability, the amount of oil used in steam units to satisfy minimum oil burn criteria has decreased. In order to simulate the use of oil in steam units to satisfy these reliability criteria, Northport 4 # is forced oil operation only in Summer, and Ravenswood #3 is up to its minimum load levels. For operation at higher load levels the models then simulate these units as duel fuel units that selected the economic fuel.

1.2.4 Generation Maintenance

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Planned maintenance outages duration was developed based upon historic 2007 and 2008 maintenance schedules -- FERC FORM 714 2007-2008. The planned outage schedules were initially specified by the program and manually modified so that the total capacity outage for each month and zone is consistent with historic levels.

The unforced outage duration was based upon the data specified in the 2009 CRP. The unforced outage duration was then added to the planned outage schedule was modified to include the unforced outage duration.

1.3 Generic Solution Cost Matrix

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1.3.1 Methodology

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: Emission Allowance Forecast

With respect to the carbon emission futures under the Regional Greenhouse Gas Initiative (RGGI), the data from the CCFE was available only through 2012. The implied trend was extrapolated to cover the 2013-2018 period.

4.6. Potential Generic Solutions

Generic solutions ~~were~~ are evaluated by NYISO ~~staff~~ for each identified congested element or grouping utilizing each resource type ~~-~~– generation, transmission, and demand response ~~-~~– as required in Section 11.3~~c of Attachment Y~~ of the ~~OATT.~~Tariff. The development of the generic solutions ~~and their~~ representative ~~cost were~~ costs are accomplished by ~~using a cost matrix methodology.~~consultants experienced with NYISO's market and systems and with stakeholder input.[21]. This methodology was based on utilizing typical MW block size generic solutions, a standard set of assumptions, and an order of magnitude costs for each resource type. ~~The block sizes, assumptions and cost estimates for each resource type were vetted through the stakeholder process at the ESPWG meetings.~~

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[21] NERA/Sargent & Landy, Quanta Services, and Brattle Group were retained to provide the initial cost assessment for the generation, transmission and demand response solutions.

It should be noted that the estimates included in the Potential Generic Solution Cost Matrix should not be utilized for purposes outside of the CARIS process. These estimates should not be assumed as reflective or predictive of actual projects or imply that facilities can necessarily be built for these generic order of magnitude solution estimates.

4.6.1. Resource Block Sizes

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Typical resource block sizes ~~were~~are developed for each resource type based on the following guidelines:

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- Block size would be reflective of a typical size built for the specific resource type and geographic location

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- Block size is to be small enough to be additive with reasonable step changes

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- Blocks sizes are in comparable proportions between the resource types

The block sizes selected for each resource type are ~~as follows:~~presented in Table 4-9 through Table 4-11.

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Table 4-11~~-~~: Transmission Block Sizes

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Location	Line System Voltage (kV)	Block Ampacity (Amp)	Block Capacity (MVA)
Zone A-J	345	1673	1000
Zone K	138	2092	500

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Note: ~~138~~138 kV was selected for Zone K due to the limited number of ~~345~~345 kV substations located within this Zone. The block capacity was reduced accordingly to be reflective of the typical line size for this voltage class.

Table 4-12~~-~~: Generation Block Sizes

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Plant Location	Plant Block Size Capacity (MW)
Zone A-K	250

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Table 4-13~~–~~: Demand Response Block Sizes

Location	Demand Response Block Size (MW)	Portfolio Type
Zone A-K	100	Energy Efficiency
Zone A-K	100	Demand Response

4.6.2. Guidelines and Assumptions for Generic Solutions

Developing cost estimates for these resource types ~~are~~ is very dependent on many different parameters and site specific situations. ~~Therefore, a set of assumptions that address the following items were developed for each resource type:~~A detailed list of assumptions utilized for each resource is included in the Potential Generic Solution Cost Matrix, in Appendix C.

The following guidelines and assumptions are used to select the potential generic solution and determine their cost:

Transmission Resource

- The generic transmission solution consists of a new transmission line interconnected to the system upstream and downstream of the grouped congested elements being studied.
- The generic transmission line terminates at the nearest existing substations of the grouped congested elements.
- If there is more than one substation located near the grouped congested elements which meets the required criteria, then the two substations that have the shortest distance between the two are selected.
- The cost of the Transmission solution would be affected by the following:

1. type of construction (~~i.e.~~typical conventional overhead or underground)
2. voltage and ampacity capability
3. substation interconnection
4. rights of way
5. permitting
6. system upgrade facilities
7. order of magnitude cost estimate

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Generation Resource

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- The generic generation solution consists of the construction of a new combined cycle generating plant connecting downstream from the grouped congested elements being studied.
- The generic generation solution terminates at the nearest existing substation of the grouped congested elements.
- If there is more than one substation located near the grouped congested elements which meets the required criteria, the substation that has the highest relative shift factor is selected.
- The cost of the Generation solution would be affected by the following:

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1. type of plant
2. length, type, voltage and ampacity of generator lead
3. substation interconnection
4. length of gas line
5. rights of way
6. permitting
7. system upgrade facilities
8. order of magnitude cost estimate

Demand Response

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~~1.zonal locations~~

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- ~~energy efficiency/~~The generic demand response solution is modeled as a reduction in load within the zone where the most downstream grouped congested element is terminated.

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- The on-peak demand is assumed to be concentrated in the top 60-100 highest load hours.
- The demand response installed in a zone is limited to less than 10% of the peak zonal load. If the "block" demand response exceeds 10% of the peak zonal load, it is prorated based on peak load between the selected zone and the next downstream zone.
- The cost of the Demand Response solution would be affected by the following:

1. zonal locations
2. energy efficiency (available 8760 hours/year)/ demand response
3. utility demand side management filings
4. order of magnitude cost estimate

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~~A detailed list of assumptions utilized for each resource is included in the Potential Generic Solution Cost Matrix included in Appendix C.~~

4.6.3. Order of Magnitude Unit Pricing

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Order of magnitude unit pricing cost estimates were developed based on the block sizes and assumptions for each resource type. The NYISO utilized engineering consultants to develop order of magnitude cost estimates based on their experience in the industry and similar existing projects or programs currently being considered within ~~NY.~~New York. The order of magnitude cost estimates took into account the cost differences between geographical areas within ~~NY.~~New York. Three sets of costs were developed that are reflective of the differences in labor, land and permitting costs between Upstate, Downstate and Long Island. The order of magnitude unit pricing for the following elements, listed in Table 4-11, were developed for the three resource types[22] and for each geographical area~~:~~.

~~Transmission Generation Demand Response~~
~~Transmission Line Cost per Mile Plant Costs Energy Efficiency Programs~~
~~Substation Terminal Costs Generator Lead Cost per Mile Demand Response Programs~~
~~System Upgrade Facilities Substation Terminal Costs~~
~~System Upgrade Facilities~~
~~Gas Line Cost per Mile~~
~~Gas Regulator Station~~

Table 4-14: Order of Magnitude Unit Pricing Elements

Transmission	**Generation**	**Demand Response**
Transmission Line Cost per Mile	Plant Costs	Energy Efficiency Programs
Substation Terminal Costs	Generator Lead Cost per Mile	Demand Response Programs
System Upgrade Facilities	Substation Terminal Costs	
	System Upgrade Facilities	
	Gas Line Cost per Mile	
	Gas Regulator Station	

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All costs were reviewed by the Transmission Owners and ~~Market Participants~~stakeholders through the stakeholder process. As part of this process, ranges for the cost for each element were developed in order to address the wide variability that can occur in a project due to such items as permitting, right of way constraints, and existing system conditions. The resulting order of magnitude unit pricing levels are included in the Potential Generic Solution Cost Matrix in Appendix C. ~~It should be noted that due to the limited data available the Demand Response resource type costs were based on New York utility EEPS filings for their Demand Side Management programs which consider the potential market value and not actual costs to build or implement DSM.The NYISO will consider developing a customer installed cost~~

[22] For this CARIS cycle Demand Resource costs considered potential market value and not actual costs to build or implement DSM. In the next CARIS cycle the actual cost estimates will be considered for Demand Response solutions.

~~approach in future CARIS analysis so that cost estimates for all resource types will be predicting actual cost to implement such a project.~~

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4.6.4. Application of Order of Magnitude Cost Estimates

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Upon selection of the three congestion areas to be studied and their potential solutions, the order of magnitude ~~cost estimates will be~~ unit pricing element are utilized to develop order of magnitude generic solution costs for inclusion in the benefit to cost ratio analysis. If ~~upon a cursory review of~~ the location for the potential solution identifies unusual complexities, a contingency factor will be applied to the costs included in the matrix. These complexities may include but are not limited to right of way restrictions, terrain and/or permitting difficulties.

~~1.4.1Disclaimers~~

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~~Estimates included in the Potential Generic Solution Cost Matrix should not be utilized for purposes outside of the CARIS process. These estimates should not be assumed as reflective or predictive of actual projects or imply that facilities can necessarily be built for these generic order of magnitude solution estimates.~~

5. 2009 CARIS Analyses – Study Phase

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~~The results in this chapter are preliminary and subject to change (need to update)~~This section presents the results of Phase 1, the Study Phase, of the CARIS process. Specific economic projects are not considered in this phase. They will be subsequently studied in Phase 2, the Project Phase, of the CARIS process. The results are presented below and described in more detail in Appendix E. The process steps include:1) congestion assessment; 2) ranking of congested elements; 3) selection of three studies; 4) potential generic solutions application; 5) benefit/cost analysis; and 6) scenario analysis.

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The Study Phase of the CARIS process begins with the development of a ten-year projection of future congestion costs resulting from NYCA system facilities. This projection is combined with the past five years of historic congestion to identify and rank significant and recurring congestion. Based on this ranking, the top five congested elements are identified, and a grouping process is implemented to develop the three studies comprising CARIS. Potential solutions to these most congested groupings are then assessed, and the benefit/cost ratios are presented based on generic solution costs and forecasted production cost savings. Scenario analyses are also conducted to determine the impact of uncertainties on the projection of congestion.

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5.1. Congestion Assessment

~~This section presents the results of the first, or study phase, of the CARIS process. Details of this process are presented in Appendix E. The results of the process steps in Phase 1 are presented below.~~

~~The study phase begins with the development of a ten year projection of future congestion costs impacting the NYCA system. This projection is combined with the past five years of historic congestion to identify and rank significant and recurring congestion. Based on this ranking, the top five congested elements are identified, and a grouping process is implemented to develop the three studies comprising CARIS. Potential solutions to these most congested groupings are assessed and benefit cost ratios based on project costs and production cost savings as well as additional metrics are provided to identify other potential cost savings associated with additional metrics are presented. Scenario analysis is conducted to determine the impact of uncertainties on the projection of congestion and development of the metrics that may increase or decrease the calculation of benefits.~~

Congestion assessment is performed both from a historical and future perspective and is done separately. The results are presented in the following two sections of this chapter..

In order to assess and identify the most congested elements, both positive and negative congestion on constrained elements is taken into consideration. The concept of positive versus negative congestion is based on how the congestion relates to the reference point. New York uses the Marcy bus as its reference point. In the absence of losses, any location with LBMP greater than the Marcy LBMP has positive congestion, and this means that more expensive generators, most often downstate, are required to serve load at such location, compared to the load at Marcy due to system constraints. Any location with LBMP below reference LBMP has negative congestion. This typically happens due to transmission constraints in generator pockets when lower cost generation cannot be delivered in full to the New York grid, or when all available relatively inexpensive imports cannot be fully delivered.

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5.1.1. Historic Congestion

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Historic congestion assessment ~~as depicted in Table 5-1 below~~ has been ~~ongoing~~ conducted at the NYISO for the last six years~~. Metrics~~ with metrics and procedures ~~were~~ developed with the ESPWG and approved by the NYISO Operating Committee. Four congestion metrics were developed to assess historic congestion: Bid-Production Cost (BPCG) as the primary metric, Load Payments metric, Generator Payments metric, and Congestion Payment metric. The results of the ~~assessment~~ historic congestion analysis are posted on the NYISO website quarterly. The NYISO uses PROBE production cost simulation tool to generate historical results, which, unlike the CARIS forecasted results, include, among others, the impact of virtual bidding and actual transmission outages on congestion. This is explained in more detail further in the text and in Appendix D.

Table 5-1 below summarizes the impact of historic congestion on BPC, unhedged congestion payments, generator payments, and load payments over the past six years, including zones both internal and external to NYCA. The results represent the change in metrics' values between a constrained system and a system in which all constraints are relieved. When all the constraints were relieved, BPC and congestion payments resulted in positive savings, while generator payments and load payments resulted in negative savings for the majority of studied historic years. More information on historic congestion metrics and how they are calculated is included in Appendix E.

Table 5-1 - Historic Congestion Assessment

YEAR	PROBE DAM bid based(1) million$			
	Load Payment	**Generator Payment**	**Production Cost(2)**	**Congestion**
2004	10,059	8,615	N/A	831
2005	15,314	13,153	N/A	1,382
2006	11,969	10,241	N/A	1,541
2007	12,831	10,840	N/A	1,451
2008	15,485	12,178	N/A	2,540

(1) Source: Historic Congestion Reporting

(2) N/A represent absolute values of bid production costs which were not reported as this number can be negative due to a preponderance of negative market bids (Nuclear Units and other Bilaterals)

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1.3.2 Projected Congestion

A projection of future congestion, Table 5-2, is developed from analysis conducted with a production cost model that employs security-constrained unit commitment and economic dispatch and utilizes the CARIS base case developed as part of the CARIS process implemented with full ESPWG participation.

Congestion associated with the constraints modeled is defined as $demand congestion that has been used for the reporting of the historic congestion for the past six years. This differs from the classical "congestion rent" definition.: PROBE NYCA System Congestion Impact - Mitigated Bids ($ in Millions), 2003-2008

Total NYCA Congestion Impact - Mitigated Bids ($ Millions), 2003 - 2008

Year	BPC ($mil.) (mitigated)	Unhedged Congestion Payments* ($ mil.)	Generator Payments ($ mil.)	Unhedged Load Payments* ($mil.)
2003	85	293	-136	-136
2004	72	316	-181	-181
2005	113	685	-71	-71
2006	118	921	59	59
2007	130	806	-107	-107
2008	243	1,525	-417	-417

* The values do not include TCC hedge.

Figure 5-1 below illustrates a cumulative effect of bid production costs savings over the past six years.

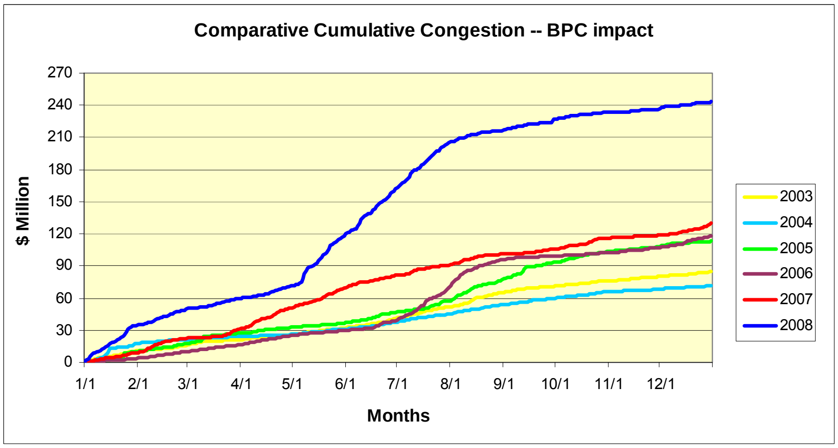

Figure 5-1: PROBE Cumulative BPC Impact

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Historic congestion values by zone are presented in Table 5-2 indicating the highest congestion in New York City and Long Island. Total NYCA congestion (TCC hedge is included) in 2008 nearly doubled in comparison to 2007, mostly due to high fuel prices in 2008.

Table 5-2 : Historic Congestion by Zone 2004-2008

Historic Congestion $Demand Payment ($ in Millions)

Zone	2004.0	2005.0	2006.0	2007.0	2008.0
West	-0.7	-4.9	0.9	-14.1	-25.2
Genessee	0.5	-1.3	1.6	-14.0	-9.4
Central	0.5	-1.2	3.5	9.4	18.4
North	0.0	-1.1	-0.2	-0.3	-1.8
Mohawk Valley	0.1	-0.3	2.1	4.6	9.8
Capital	7.5	19.3	27.2	73.8	143.4
Hudson Valley	4.9	19.9	54.4	86.9	175.5
Millwood	2.7	11.8	26.7	30.8	78.0
Dunwoodie	4.4	23.6	44.1	56.1	124.4
NYCity	581.8	808.7	672.9	700.0	1402.7
Long Island	229.5	508.0	708.2	517.9	624.4
NYCA Total	**831.2**	**1,382.3**	**1,541.5**	**1,451.1**	**2,540.3**

Historic Congestion Source: PROBE DAM quarterly reports
DAM data include Virtual bidding and Transmission planned outages

Table 5-3 below lists historic congestion values for top constraints from 2004 to 2008. Based on the positive congestion values, the top three congested constraints are Central East, Leeds-Pleasant-Valley, and Dunwoodie Shore Road.

Table 5-3: Historic Congestion by Constraint ($ in Millions) 2004-2008

Constraint	2004	2005	2006	2007	2008	Total
CENTRAL EAST - VC	52	102	187	571	1,199	2,112
PLSNTVLY 345 LEEDS 345 1	27	182	452	435	667	1,763
DUNWODIE 345 SHORE_RD 345 1	152	348	492	260	187	1,439
MOTTHAVN 345 RAINEY 345 2	0	0	0	43	272	315
RAINEY 138 VERNON 138 1	5	84	21	19	81	210
WEST CENTRAL	(0)	(0)	(2)	(51)	(55)	(108)
E179THST 138 HELLTP_W 138 1	(9)	(18)	(10)	(12)	(34)	(83)

* Ranking is based on absolute values.

5.1.2. Projected Congestion

A projection of future congestion is reported as demand dollar ($Demand) congestion. Congestion forecasts resulting from the simulation are highly dependent upon many long-term assumptions. The CARIS model utilizes input assumptions listed in Appendix C.

When comparing historical congestion values to projected congestion values, one must bear in mind that there are significant differences in assumptions used by the PROBE and CARIS tools. The CARIS tools did not simulate the following: a) virtual bidding; b) transmission outages; c) fixed load and price-capped load; d) generation and demand bid price; e) Bid Production Cost Guarantee payments (BPCG); and f) co-optimization with ancillary services. Another factor when comparing historic and future congestion values is the fuel prices. Projected fuel prices for 2009 are much lower that 2008 fuel prices.

The relative values of congestion shown in Table 5-4 indicate that the majority of the projected congestion is in the downstate zones.

Table 5-4: Projection of Future Congestion 2009-2018 (nominal $ in Millions)

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~~YEAR~~	~~CARIS Metrics - DAM bid based[1] million$~~				~~NYCA Actual GWh~~		
	~~Load Payment~~	~~Generator Payment~~	~~Production Cost[2]~~	~~Congestion~~	~~Demand~~	~~Generation~~	~~Interchange~~
-	~~PROJECTED~~				~~PROJECTED~~		
~~2009~~	~~7,409~~	~~6,772~~	~~4,206~~	~~118~~	~~168,128~~	~~158,034~~	~~10,094~~
~~2010~~	~~9,817~~	~~8,714~~	~~5,159~~	~~119~~	~~169,747~~	~~155,017~~	~~14,730~~
~~2011~~	~~10,046~~	~~8,894~~	~~5,309~~	~~128~~	~~170,954~~	~~155,679~~	~~15,274~~
~~2012~~	~~10,520~~	~~9,269~~	~~5,578~~	~~140~~	~~171,927~~	~~155,939~~	~~15,988~~
~~2013~~	~~10,760~~	~~9,471~~	~~5,739~~	~~94~~	~~173,156~~	~~156,723~~	~~16,433~~
~~2014~~	~~11,343~~	~~10,000~~	~~6,074~~	~~99~~	~~174,800~~	~~158,246~~	~~16,553~~
~~2015~~	~~11,786~~	~~10,333~~	~~6,361~~	~~113~~	~~176,177~~	~~158,513~~	~~17,664~~
~~2016~~	~~12,369~~	~~10,779~~	~~6,678~~	~~134~~	~~178,250~~	~~159,559~~	~~18,691~~
~~2017~~	~~12,910~~	~~11,222~~	~~7,041~~	~~154~~	~~179,283~~	~~160,061~~	~~19,222~~
~~2018~~	~~13,618~~	~~11,638~~	~~7,190~~	~~186~~	~~180,427~~	~~158,571~~	~~21,856~~

~~(1)~~ ~~Source: Annual Congestion Report~~

(2) ~~Market Reports reports Bid Production Cost values, which are negative numbers caused by a high number of negative market bids (Nuclear Units and other Bilaterals)~~

Area	2,009	2,010	2,011	2,012	2,013	2,014	2,015	2,016	2,017	2,018
West	(5)	(13)	(12)	(14)	(34)	(33)	(36)	(41)	(45)	(57)
Genessee	(3)	(3)	(3)	(4)	(23)	(21)	(22)	(25)	(29)	(37)
Central	1	1	1	1	(0)	(0)	(2)	(2)	(1)	1
North	0	1	1	1	0	0	0	1	1	1
Mohawk Valley	1	1	2	2	1	1	1	2	2	2
Capital	5	15	14	18	13	13	15	19	23	23
Hudson Valley	8	20	35	38	33	33	35	39	43	50
Millwood	3	6	11	12	11	10	11	12	13	15
Dunwoodie	6	14	26	28	24	24	26	28	30	36
NYCity	87	209	271	300	278	292	326	375	410	426
Long Island	27	69	98	106	93	91	97	106	116	132
NYISO Total	130	319	443	488	397	410	452	514	563	593

Table 5-5 lists the future top most congested elements: Leeds-Pleasant Valley, Central East, West Central, Astoria West, Mott Haven-Rainy and Dunwoodie Shore Road.

Table 5-5: Projection of Future Congestion 2009-2018 (nominal $ in Millions)

Constraints	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
LEEDS-PLEASANT VALLEY 345 KV	35.12	68.87	229.8	245.05	219.98	217.07	214.79	227.77	235.75	292.82	1,987.01
CENTRAL EAST	26.84	92.59	79.9	102.69	66.98	62.32	74.66	97.01	125.63	117.9	846.51
MOTT HAVEN-RAINEY 345 KV	1.44	15.38	2.01	3.52	5.51	7.96	9.72	12.88	15	23.52	96.94
DUNWOODIE-SHORRD 345	4.26	15.69	7.57	7.23	6.73	6.31	6.44	7	8.12	8.5	77.86
WEST CENTRAL-OP	-0.02	-2.85	-3.3	-4.51	-52.62	-48.09	-46	-54.48	-63.6	-86.5	-361.97
ASTORIAW138-HG5 138	-2.45	-9.26	-12.01	-10.51	-11.29	-12.45	-13.2	-14.71	-14.52	-16.93	-114.89

Note: Allowance for diminishing congestion in the future years in the approved ranking procedure directs the selection of West Central as the third ranked element.

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5.2. Ranking of Congested Elements

The identified congested elements from the ten-~~-~~year projection of congestion are lined up with the past five years of identified historic congested elements to develop fifteen years of $Demand congestion statistics for each identified constraint. The fifteen years of statistics are analyzed to identify recurring congestion or the mitigation of congestion from future system changes incorporated into the base CARIS system. Ranking of the identified constraints is initialy based ~~first~~ on the highest ~~Present Value of~~ present value of congestion over the fifteen years ~~in the first year~~ of the study ~~and after the additional assessment of the top five~~.

Table 5-6 lists the ranked elements ~~is conducted, the final ranking of the elements is performed which is~~ based on the highest ~~change in production costs.~~

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~~In order to assess and identify the most congested elements,~~present value of congestion over the fifteen years of the study, including both positive and negative congestion ~~on~~

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~~constrained elements was taken into consideration. The concept of positive vs. negative congestion is based on how the congestion relates to the reference point. New York uses the Marcy bus as its reference point, which is mostly an unconstrained location as power typically flows from the West to East and toward "downstate" in New York, and congestion generally occurs on constraints such as Central East or other downstate constraints. In the absence of losses, any location with LBMP greater than the Marcy LBMP has positive congestion, and this means that more expensive generators, most often downstate, are required to serve load at such location compared to the load at Marcy due to system constraints. Any location with LBMP below reference LBMP has negative congestion. This typically happens due to transmission constraints in generator pockets when lower cost generation can't be delivered in full to the NY grid, or when all available relatively inexpensive imports can't be fully delivered.~~ . Dunwoodie-Shore Road and Mott Haven-Rainey's historic congestion diminishes in the future with the addition of the Caithness plant and the planned installation of the M29 Cable. Dunwoodie-Shore Road congestion declined substantially in 2007 when Neptune cable came into service. The top five elements are evaluated in the next step for selection of the three studies.

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Table 5-6: Ranked Elements Based on the Highest Present Value of Congestion Over the Fifteen Years Aggregate

	Present Value of Congestion in $ mm		
Element	**Historic**	**Future**	**Aggregate**
LEEDS-PLEASANT VALLEY 345 KV	$ 2,063	$ 1,307	$ 3,370
CENTRAL EAST	$ 2,442	$ 567	$ 3,009
WEST CENTRAL-OP	$ (120)	$ (230)	$ (350)
DUNWOODIE-SHORE ROAD 345 KV	$ 1,770	$ 59	$ 1,829
MOTT HAVEN-RAINEY 345 KV Q12	$ 341	$ 66	$ 407
ASTORIA W 138-HELLGATE5 138	$ 50	$ (78)	$ (28)

The frequency of actual and projected congestion is shown in Table 5-7 below. The table presents the actual number of congested hours by constraint, from 2007 through August 2009, and projected number of congested hours, from 2009 through 2018. Based on the projected values, the most congested constraint in terms of frequency is Dunwoodie-Shore Road, followed Athens Pleasant Valley, West Central, Central East, and Mott Haven Rainey respectively.

Table 5-7: Number of Congested Hours by Constraint

# of Congested Hours	Actual			CARIS Base Case Projected									
Constraint	**2007**	**2008**	**2009**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
CENTRAL EAST	3,189	5,182	3,351	1,001	1,643	1,392	1,527	1,099	1,020	1,115	1,188	1,326	1,249
ATHENS_PLTVLLEY	1,494	1,013	661	681	860	2,289	2,381	2,154	2,148	2,087	2,123	2,017	2,094
NY MTHAVN-RAINY	1,354	671	1,184	536	1,333	483	652	789	883	925	1,019	1,193	1,562
DUNWOODIE_SHORRD	245	25	1,064	2,797	3,484	2,527	2,366	2,224	2,171	2,014	2,048	2,074	2,129
WEST CENTRAL-OP	1,943	2,120	278	5	277	318	403	2,618	2,366	2,160	2,257	2,356	2,745

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5.3. Selection of Three Studies

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~~From the table and ranking results discussed in section 5.1.3,~~ Selection of the three CARIS studies is a two-step process in which the top five ranked constraints are identified ~~as primary~~and utilized for further assessment in order to identify potential for grouping of ~~these primaries with other~~ constraints ~~that would comprise~~. Resultant grouping of elements for each of the top five ranked constraints is utilized to determine the three studies.

In the first step ~~of ranking the congested elements~~, the five congested elements with the highest present value ranking ~~shall be~~ are utilized for further assessment under the CARIS process ~~for that cycle. This~~, as explained in the previous step 5.2. In the second step, this assessment ~~will be~~ is accomplished in multiple iterations to include additional elements that appear as limiting when each of the top ~~three~~five congested elements are relaxed. ~~In the second step of ranking, the~~ The assessed element groupings ~~will be~~ are then ranked based upon the highest change in production cost. The three ranked groupings with the largest change in production cost ~~will then be~~ are selected as the three CARIS studies. The three CARIS studies, as shown in

- In order to identify additional elements that may have a significant impact on congestion, each primary element being studied will be relieved independently of each other for a mid and horizon year (2013 and 2017) Table 5-8
- The primary element's constraint is relieved by replacing its limit with 9999.
- The resultant new list of top congested elements from the two year analysis will be reviewed to determine if any additional elements that are electrically adjacent to the primary element have become congested. A congested element will be considered electrically adjacent if it is connected within one bus away from the primary element's bus.
- If a new electrically adjacent element is revealed in the top five most congested element listing, a grouped analysis will be completed which relieves both the primary and the new adjacent element.

If multiple additional electrically adjacent elements are revealed in the top five most congested elements listing, then a grouped analysis will be performed on each independently. The grouping with the highest improvement in production cost savings will be selected as the study grouping.

Table 5-8 - Congestion Results when the Top Three Congested Elements are Relaxed

No additional electrically adjacent congested elements were found for Central East or Leeds- PV. Upon relieving the Dunwoodie to Shore Rd. line, the Dunwoodie to Long Island Interface became congested. Therefore, this interface with be grouped with the Dunwoodie-Shore Rd. line for determining a potential solution.

Table 5-9: include Leeds - Pleasant Valley, Central East, and West Central. The detailed discussion on the ranking process is presented in Appendix E.

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- In order to identify additional elements that may have a significant impact on congestion, each primary element being studied will be relieved independently of each other for a mid and horizon year (2013 and 2017) Table 5-8
- The primary element's constraint is relieved by replacing its limit with 9999.
- The resultant new list of top congested elements from the two year analysis will be reviewed to determine if any additional elements that are electrically adjacent to the primary element have become congested. A congested element will be considered electrically adjacent if it is connected within one bus away from the primary element's bus.
- If a new electrically adjacent element is revealed in the top five most congested element listing, a grouped analysis will be completed which relieves both the primary and the new adjacent element.

If multiple additional electrically adjacent elements are revealed in the top five most congested elements listing, then a grouped analysis will be performed on each independently. The grouping with the highest improvement in production cost savings will be selected as the study grouping.

Table 5-8 - Congestion Results when the Top Three Congested Elements are Relaxed

	2013				2017			
Congested Contraint	**Base**	**Central East Relaxed**	**Leeds-PV Relaxed**	**Dunwoodie-Shore Rd. Relaxed**	**Base**	**Central East Relaxed**	**Leeds-PV Relaxed**	**Dunwoodie-Shore Rd. Relaxed**
CENTRAL EAST	35.14	0.00	38.76	34.11	86.47	0.00	91.49	92.32
ATHENS_PLTVLLEY_345_ PLTVLLEY_LEEDS 3_2	38.52	39.52	0.00	39.35	44.15	47.27	0.00	46.97
HMPHRBR_DVNPT_345_ DUNWODIE_SHORE RD_1	12.59	12.32	13.50	0.00	11.69	11.18	12.71	0.00
DUNWOODIE_SHORRD_345_ DUNWODIE_ SHORE RD_1	17.38	17.37	19.01	0.00	14.76	15.04	16.40	0.00
LIPA Cable	5.08	5.16	5.66	4.41	4.78	4.93	5.33	4.01
NYCLP Greenwood	1.43	1.46	1.96	1.36	2.19	2.26	2.59	2.07
Ontario North-NYISO	(7.83)	(7.94)	(8.03)	(7.78)	(7.89)	(8.29)	(8.13)	(7.87)
PJM_LINDEN GOETHALS	(9.62)	(9.64)	(9.96)	(9.54)	(9.77)	(9.68)	(9.83)	(9.68)
WEST CENTRAL-OP	(24.85)	(30.11)	(28.10)	(25.25)	(34.13)	(41.91)	(36.25)	(32.63)
Dunwoodie (I) to Long Island (K)				27.72				24.57
NYCA Total	**94.00**	**53.12**	**52.45**	**90.91**	**154.00**	**59.87**	**109.21**	**160.09**

No additional electrically adjacent congested elements were found for Central East or Leeds- PV. Upon relieving the Dunwoodie to Shore Rd. line, the Dunwoodie to Long Island Interface became congested. Therefore, this interface with be grouped with the Dunwoodie-Shore Rd. line for determining a potential solution.

Table 5-9: Top Three CARIS Studies (nominal $ in Millions)

Constraints	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
LEEDS-PLEASANT VALLEY 345 KV	35.12	68.87	229.8	245.05	219.98	217.07	214.79	227.77	235.75	292.82	1,987.01
CENTRAL EAST	26.84	92.59	79.9	102.69	66.98	62.32	74.66	97.01	125.63	117.9	846.51
WEST CENTRAL-OP	-0.02	-2.85	-3.3	-4.51	-52.62	-48.09	-46	-54.48	-63.6	-86.5	-361.97

The location of the top three congested groupings, along with their base present value congestion payment, is presented in Figure 5-2.

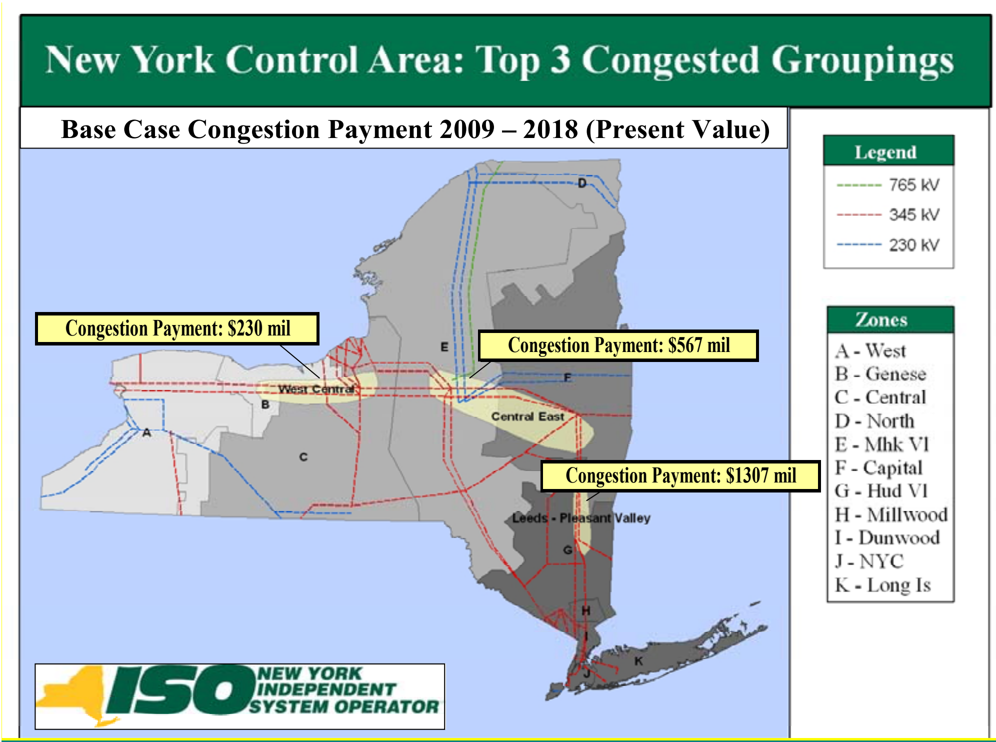

Figure 5-2: Base Case Congestion Payment of the Top 3 Congested Groupings

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5.4. Potential Generic Solutions

~~1.4.2Methodology~~

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The congestion of each ~~grouped elements~~of the three groupings being studied ~~will be relieved~~is mitigated by individually applying one of the generic resource types; transmission, generation and demand response. The resource type ~~will be~~ is applied based on the rating and size of the "blocks" determined in the Generic Solutions Cost Matrix included in Appendix C. ~~The following guidelines will be used in order to select how the resource type "block" will be integrated into the system~~In regard to the generic solutions, it is important to note the following:

~~Transmission:~~

- ~~The generic transmission solution will consist of a new transmission line interconnected to the system upstream and downstream of the grouped congested elements being studied.~~
- ~~The generic transmission line will terminate at the nearest existing substations of the grouped congested elements.~~

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- ~~If there is more than one substation located near the grouped congested elements which meets the required criteria, then the two substations that have the shortest distance between the two will be selected.~~

~~Generation:~~

- ~~The generic generation solution will consist of the construction of a new combined cycle generating plant connecting downstream from the grouped congested elements being studied.~~
- ~~The generic generation solution will terminate at the nearest existing substation of the grouped congested elements.~~
- ~~If there is more than one substation located near the grouped congested elements which meets the required criteria, then the substation that has the highest relative shift factor will be selected.~~

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~~Demand Response:~~

- ~~The generic demand response solution will be modeled as a reduction in load within the zone that the most downstream grouped congested element being studied is terminated.~~
- ~~The on peak demand is assumed to be concentrated in the top 60-100 highest load hours.~~
- ~~The demand response installed in a zone will be limited to less than 10% of the peak zonal load. If the "block" demand response exceeds 10% of the peak zonal load, then it will be prorated based on peak load between the selected zone and the next downstream zone.~~

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~~1.4.2.1Modeling Modifications~~

~~Upon selection of the potential solutions for each resource type for each grouped elements studied, the potential solutions will be individually modeled in the base case in order to determine its impact on the grouped element's congestion. It will be assumed that the generic potential solution will be installed in the first study year. This will allow for the calculation of the full 10 year production cost and additional metrics resulting from the potential solution.~~

~~The base case transfer limits for the appropriate interfaces will be recalculated for the mid-year and horizon year with all facilities in-service.~~

~~Initially one single "block" size for each resource type will be modeled. If a majority of the congestion of the grouped elements being studied is not relieved, then an additional block will be installed. However, if adding the additional block will result in reducing the benefit to cost ratio, then it will not be included.~~

~~The costs of the generic solution's potential system impact on reliability are included in the System Upgrade Facilities generic cost estimate ranges. Therefore, the potential solutions impact on reliability is not investigated.~~

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~~1.4.2.2Disclaimers~~

- Other solutions may exist which will alleviate the congestion on the studied elements.

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- No attempt has been made to determine the optimum solution for alleviating the congestion.

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- No engineering, physical feasibility study, routing study or siting study has been completed for the generic solutions. Therefore, it is unknown if the generic solutions can be physically constructed as proposed.

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1.3.3 Grouped Congested Elements Potential Solutions

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1.3.3.1 Central East Interface

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In order to determine the upstream and downstream locations needed to develop the potential solutions for relieving the congestion on the Central East Interface, the elements that make up this interface as shown in Table 5-10 below were examined.

Table 5-10 - Elements which Comprise the Central East Interface

Interface	From Bus Number	From Bus Name	From Bus Voltage (KV)	To Bus Number	To Bus Name	To Bus Voltage (kV)
CENTRAL EAST	100511	GRAND IS	115	147852	PLAT T#3	115
CENTRAL EAST	130797	E.SPR115	115	137886	INGHAM-E	115
CENTRAL EAST	137200	EDIC	345	137452	N.SCOT77	345
CENTRAL EAST	137210	PORTER 2	230	137730	ROTRDM.2	230
CENTRAL EAST	137210	PORTER 2	230	137730	ROTRDM.2	230
CENTRAL EAST	137228	INGMS-CD	115	137886	INGHAM-E	115
CENTRAL EAST	137228	INGMS-CD	115	137302	INGHAMS	46
CENTRAL EAST	137453	N.SCOT99	345	147833	MARCY T1	345

This interface includes two lines which meets the guideline of tying into an existing 345kV substation for Zones A-G. These lines are Edic to New Scotland and Marcy to New Scotland. It has been determined that the physical distance between Edic to New Scotland is less than Marcy to Scotland. Therefore, the initial potential generic solutions for relieving the Central East Interface for each resource types are as follows:

- Generic solutions are not assessed for impacts on system reliability.

In order to mitigate the congestion identified on the three groupings that comprise the three CARIS studies, all three types of potential generic solutions – transmission, generation, demand response - were applied to each congested groupings consistent with the methodology explained in Section 4 of this report. The results of the three potential generic solutions are to provide indicative information to interested parties. The following potential generic solutions were applied for each study:

Study #1 – Leeds - Pleasant Valley

The following generic solutions were applied for Leeds-Pleasant Valley Study:

- Transmission: A new 345 kV line from Leeds to Pleasant Valley- 39 Miles. The new line relieves the Pleasant Valley Leeds thermal limit and increases the UPNY-SENY voltage limit by approximately 1000 MW and Central East voltage limit by 50 MW.
- Generation: Install a new 500 MW Plant at Pleasant Valley
- Demand Response: Install 100 MW Demand Response and 100 MW Energy Efficiency in Zone G (200 MW is less than 10% of Zone G's peak load)

Table 5-9 shows the NYCA production cost savings from 2009 to 2018 for Leeds-Pleasant Valley study after potential generic solutions were applied.

Table 5-11: Leeds - Pleasant Valley: NYCA Production Cost Savings (Present Value $ in Millions)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Transmission	4.8	5.3	14.0	13.9	12.6	10.4	9.6	10.9	11.0	12.4
Generation-500	29.9	36.4	40.5	37.2	33.4	34.2	33.3	33.8	35.3	31.8
Demand Response	24.1	28.9	27.6	25.2	24.2	24.2	24.6	23.9	22.9	20.9

The new Leeds-Pleasant Valley 345 kV transmission solution relieves the congestion across existing Leeds-Pleasant Valley transmission lines and the UPNY SENY transmission interface. The total ten-year production cost savings of $162 million are dependent upon the spread between upstate and downstate fuel costs. Relieving the congestion on the Leeds-Pleasant Valley lines increases the congestion on the other two study groups: Central East and West Central.

Study #2 - Central East

The following generic solutions were applied for Central East study:

- Transmission: A new 345 kV line from Edic to New Scotland, 90 Miles. The new line relieves the Central East thermal limit and increases the Central East voltage limit by 500 MW.
- Generation: ~~Install a~~A new ~~250~~500 MW Plant at New Scotland
- Demand Response: Install 100 MW Demand Response and 100 MW Energy Efficiency in Zone F (200 MW is less than 10% of Zone F's peak load)

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~~In order to determine the number of blocks required for each resource type, the potential generic solutions were applied for a mid and horizon year. Table 5-5 shows the comparison of the resulting dollar demand congestion between the base case and generic potential solution for years 2013 and 2017.~~

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Table 5-10 shows the NYCA production cost savings from 2009 to 2018 for Central East study after potential generic solutions were applied.

Table 5-~~5 Dollar Demand Congestion Comparison for Central East for Block Size Determination~~

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	~~2013~~			~~2017~~			
	~~Base Case~~	~~Solution Case~~	~~% Change~~	~~Base Case~~	~~Solution Case~~	~~% Change~~	~~Comment~~
~~Transmission~~							~~>40% No Further Blocks Needed~~
~~Generation 1 Block~~							~~<40% Add 1 Additional Block~~
~~Generation 2 Blocks~~							~~>40% No Further Blocks Needed~~
~~Demand Response~~							~~See note below~~

~~Note: Since the number of Demand Response blocks required to impact the congestion by 40% or more is not realistically achievable, only one block size is included for informational purposes.~~

~~The recommended generic solution and block sizes for each resource type based on the amount of relieved congestion are as follows:~~

~~Transmission: A new 345 kV line from Edic to~~ 12: Central East: NYCA Production Cost Savings (Present Value $ in Millions)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Transmission	1.8	6.1	2.8	2.0	2.5	1.4	2.7	2.6	2.9	1.7
Generation	21.0	25.2	25.7	18.8	17.5	23.8	23.0	21.6	24.9	22.4

Demand Response	22.0	26.6	26.2	19.1	22.0	21.4	20.9	21.4	19.4	16.9

- The addition of the Edic-New Scotland~~, 90 Miles~~

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- ~~Generation: Install a new 500 MW Plant at New Scotland~~

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- ~~Demand Response: Install 100 MW Demand Response and 100 MW Energy Efficiency in Zone F (200 MW is less than 10% of Zone F's peak load)~~

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~~The transmission generic solution reduced the congestion on the Central East interface in 2013 from $35.1 M to $7.5 M or 79% and in 2017 from $86.5 M to $29.1M or 66%. Since the majority of the congestion is relieved, no additional block will be added for this solution.~~

~~The generation generic solution reduced the congestion of~~ relieves the Central East ~~Interface in 2013 from $35.1 M to $21.9 M or 38% and in 2017 from $86.5M to $xxxM. Since the majority of the congestion was not relieved, a second 250MW block of generation is installed. Adding a second block resulted in the congestion being reduced to $15.2 M or 57% in 2013 and to $50.7 M or 41% in 2017.~~

~~The demand response solution reduced the congestion of the Central East Interface in 2013 from $35.1 M to $ 33.3 M or 5.1% and from $86.5 to $82 M or 5.2%. Since a majority of the congestion is not relieved, additional blocks of demand response is required.~~

congestion but does not have significant impact on production cost because of the Leeds~~-~~-Pleasant Valley congestion which bottles generation in upstate New York.

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Since the Leeds - Pleasant Valley line terminates at substations that meet the guidelines, the initial potential generic solution for relieving the Leeds to Pleasant Valley congestion for each resource types are as follows:

- Transmission : A new 345kV line from Leeds to Pleasant Valley- 39 Miles
- Generation: Install a new 250 MW Plant at Pleasant Valley
- Demand Response: Install 100 MW Demand Response and 100 MW Energy Efficiency in Zone G (200 MW is less than 10% of Zone G's peak load)

In order to determine the number of blocks required for each resource type, the potential generic solutions were applied for a mid and horizon year. Table 5-5 shows the comparison of the resulting dollar demand congestion between the base case and generic potential solution for years 2013 and 2017.

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Table 5-6 – Dollar Demand Congestion Comparison for Leeds – Pleasant Valley for Block Size Determination

	2013			2017			
	Base Case	Solution Case	% Change	Base Case	Solution Case	% Change	Comment
Transmission							>40% No Further Blocks Needed
Generation- 1 Block							<40% Add 1 Additional Block
Generation – 2 Blocks							>40% No Further Blocks Needed
Demand Response							See note below

Note: Since the number of Demand Response blocks required to impact the congestion by 40% or more is not realistically achievable, only one block size is included for informational purposes.

The recommended generic solution and block sizes for each resource type based on the amount of relieved congestion are as follows:

- Transmission : A new 345kV line from Leeds to Pleasant Valley- 39 Miles
- Generation: Install a new 500 MW Plant at Pleasant Valley
- Demand Response: Install 100 MW Demand Response and 100 MW Energy Efficiency in Zone G (200 MW is less than 10% of Zone G's peak load)

Update the numbers
The transmission generic solution reduced the congestion on the Leeds to Pleasant Valley Lines in 2013 from $38.5 M to $0 M. Since all of the congested is relieved, no additional block will be added for this solution.

The generation generic solution reduced the congestion of the Leeds to Pleasant Valley lines in 2013 from $38.5 M to $26.2 M or 32% and in 2017 from $44.2 M to $xxM. Since the majority of the congestion was not relieved, a second 250MW block of generation is installed. Adding a second block resulted in the congestion being reduced to $18.5 M or 52% in 2013 and to $20.5 M or 54% in 2017.

The demand response solution reduced the congestion of the Leeds-Pleasant Valley lines in 2013 from $38.5 M to $36.6 M or 4.9% and in 2017 from $44.2M to $42.5 M or 3.9%. Since a majority of the congestion is not relieved, additional blocks of demand response are required.

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Study #3 - West Central ~~Interface~~

In order to determine the upstream and downstream locations needed to develop the potential solutions for relieving the congestion on the West Central Interface, the elements that make up this interface as shown in Table 5-105 below were examined.

Table 5-7 - Elements which Comprise the West Central Interface

Interface-Name	From Bus Number	From Bus Name	From Bus kV	To Bus Num	To Bus Name	To Bus kV	Branch Circuit
WEST CENTRAL-OP	130764	MEYER230	230	130767	STOLE230	230	1
WEST CENTRAL-OP	130926	WOLCOT34	34.5	149122	C708 LD	34.5	1
WEST CENTRAL-OP	131242	MACDN115	115	149026	QUAKER (Sta #121)	115	1
WEST CENTRAL-OP	131243	SLEIG115	115	149004	S121 B#2	115	1
WEST CENTRAL-OP	131243	SLEIG115	115	149005	CLYDE199 (Sta #199)	115	1
WEST CENTRAL-OP	131251	BROWNS C	34.5	131252	CLYDE 34	34.5	1
WEST CENTRAL-OP	131344	PALMT115	115	135260	ANDOVER1	115	1
WEST CENTRAL-OP	131345	S.PER115	115	149010	STA 162	115	1
WEST CENTRAL-OP	135860	LAWLER-1	115	135861	MORTIMER (sta #82)	115	1
WEST CENTRAL-OP	135861	MORTIMER (Sta #82)	115	136213	LAWLER-2	115	1
WEST CENTRAL-OP	136150	CLAY	345	149001	PANNELL3 (Sta #122)	345	1
WEST CENTRAL-OP	136150	CLAY	345	149001	PANNELL3 (Sta #122)	345	2
WEST CENTRAL-OP	136167	HOOKRD	115	149074	STA127	34.5	1
WEST CENTRAL-OP	136183	CLTNCORN	115	149005	CLYDE199	115	1
WEST CENTRAL-OP	136194	FARMGTN1	115	149075	FARMNGTN	34.5	1
WEST CENTRAL-OP	136197	FRMGTN-4	115	149146	S168	12	1
WEST CENTRAL-OP	136197	FRMGTN-4	115	149025	PANNELLI (Sta #122)	115	1
WEST CENTRAL-OP	149118	CLYDE 34	34.5	149005	CLYDE199 (Sta #199)	115	1
WEST CENTRAL-OP	149141	FRMNGT2	34.5	136197	FRMGTN-4	115	1

This interface includes only one line which meets the guideline of tying into an existing 345kV substation for Zones A-G. This is the Pannell to Clay 345kV line. Therefore, the initial potential generic solutions for relieving the West Central Interface for each resource types are as follows:

- Transmission: A new 345kV line from Pannell to Clay 62 Miles
- Generation: Install a new 250 MW Plant at Clay
- Demand Response: Install 100 MW Demand Response and 100 MW Energy Efficiency in Zone C (200 MW is less than 10% of Zone C's peak load

In order to determine the number of blocks required for each resource type, the potential generic solutions were applied for a mid and horizon year. Table 5-5 shows the comparison of the resulting dollar demand congestion between the base case and generic potential solution for years 2013 and 2017.

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Table 5-8 – Dollar Demand Congestion Comparison for West Central for Block Size Determination

	2013			2017			
	Base Case	Solution Case	% Change	Base Case	Solution Case	% Change	Comment
Transmission							>40% No Further Blocks Needed
Generation- 1 Block							<40% Add 1 Additional Block
Demand Response							See note below

Note: Since the number of Demand Response blocks required to impact the congestion by 40% or more is not realistically achievable, only one block size is included for informational purposes.

The recommended generic solution and block sizes for each resource type based on the amount of relieved congestion are as follows:

- Transmission : A new 345kV line from Pannell to Clay- 62 Miles
- Generation: Install a new 250 MW Plant at Clay

The following generic solutions were applied for the West Central study and the results are shown in Table 5-11:

- Transmission: A new 345 kV line from Niagara to Pannell to Clay- 149 Miles.

  The West Central transmission constraint is due to the West Central voltage limit for the loss of Ginna generator. Initial voltage analysis was performed with the addition of a Pannell Rd-Clay 345 kV transmission line but the transmission line did not result in any improvement in the voltage performance. Recognizing the voltage performance may be more a function of local system problems and that West Central is tightly coupled with the Dysinger East transmission interface, a new circuit from

Niagara to Clay was inserted and the voltage limit improved by over 500 MW. This was chosen to stay within the procedures for the development of generic solutions, although it is recognized that other non-bulk power system solutions may exist as well.

- Generation: Install a new 500 MW Plant at Clay
- Demand Response: Install 100 MW Demand Response and 100 MW Energy Efficiency in Zone C (200 MW is less than 10% of Zone C's peak load)

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~~**1.4.2.5Dunwoodie - Long Island Interface**~~

~~Since the Dunwoodie-Shore Rd line terminates at substations that meet the guidelines, the initial potential generic solution for relieving the Dunwoodie to Shore Rd line congestion for each resource types are as follows:~~

- ~~Transmission: A new 345kV line from Dunwoodie to Shore Rd.- 19 Miles~~
- ~~Generation: Install a new 250 MW Plant at Shore Rd. 345kV~~
- ~~Demand Response: Install 100 MW Demand Response and 100 MW Energy Efficiency in Zone K (200 MW is less than 10% of Zone K's peak load)~~

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~~The transmission generic solution reduced the congestion on the Dunwoodie to Long Island interface in 2013 from $30.9 MW to $0 M Since all of the congested in relieved, no additional block will be added for this solution.~~

~~The generation generic solution reduced the congestion of the Dunwoodie- Long Island interface in 2013 from $30.9 M to $15.3 M or 50.5%. Since the majority of the congestion was relieved, a second 250MW block of generation is not installed.~~

~~The demand response solution reduced the congestion of the Dunwoodie-Long Island interface in 2013 from $30 M to $25.6 M or 15% and in 2017 $26.5 M to $22.7M or 14%. Since a majority of the congestion is not relieved, additional blocks of demand response are required. **Need to added results of installing additional blocks.~~

Table 5-11 shows the NYCA production cost savings from 2009 to 2018 for West Central study after potential generic solutions were applied.

Table 5-13: West Central: NYCA Production Cost Savings (Present Value $ in Millions)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Transmission	8.0	7.9	8.1	7.7	11.4	10.0	11.2	11.2	8.3	8.2
Generation-500	9.5	12.5	16.1	13.4	12.6	15.5	16.7	16.0	20.0	19.0
Demand Response	19.6	25.1	25.1	18.4	21.5	22.3	21.7	22.7	20.2	20.1

The addition of Niagara-Rochester–Pannell-Clay 345 kV transmission line relieves the West central congestion. The production cost savings increase with time as the fuel prices increase and there is sufficient generation in Ontario and West New York to transfer to the rest of New York.

The summation of production cost savings, from 2009 to 2018, of the three generic solutions for each congestion grouping, is shown in Figure 5-3. The greatest production cost savings for each congestion grouping has resulted from the generic generation solutions. It is worth noting that the energy efficiency generic solutions resulted in the second highest production cost savings for each grouping.

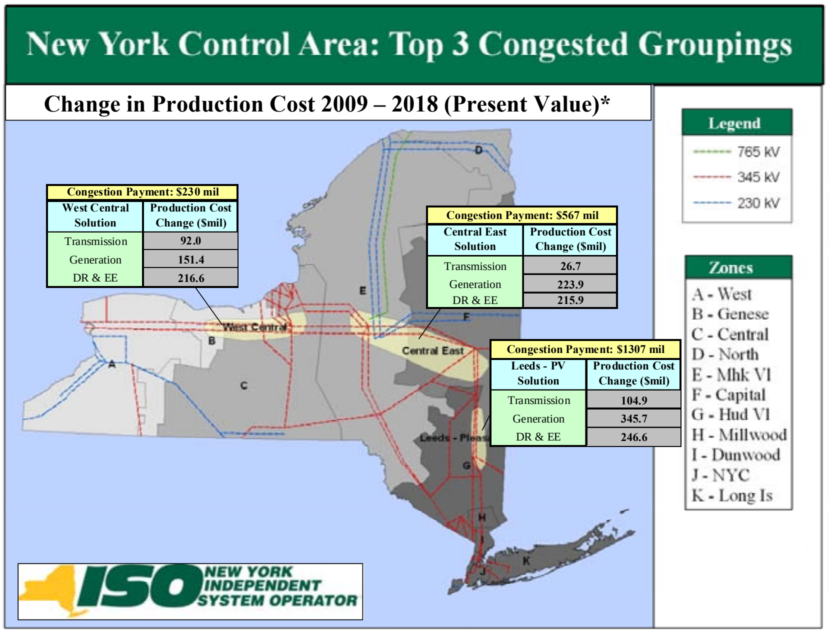

Figure 5-3: Production Cost Savings 2009-2018

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5.5. Benefit/Cost Analysis

The NYISO conducted benefit/cost analysis for each of the three studies comprising the CARIS: Central East, Leeds - Pleasant Valley, and West Central.

5.5.1. Cost Analysis

Table 5-12 includes the total order of magnitude cost estimate for each potential generic solution based on the unit pricing included in Appendix C. The detailed cost breakdown for each solution is included in Appendix E.

Table 5-14: Potential Generic Solution Costs for Each Study Table

Potential Generic Solution Cost Summary ($M)

Congested Groups	Central East	Leads - Pleasant Valley	West Central
Transmission			
Substation Terminals	Edic to New Scotalnd	Leeds to Pleasant Valley	Niagara to Pannell to Clay
Miles	90	39	149
High	$477	$222	$790
Mid	$333	$155	$552
Low	$189	$87	$313

Generation			
Substation Terminal	New Scotland	Pleasant Valley	Clay
# of 250MW Blocks	2	2	2
High	$831	$911	$831
Mid	$681	$751	$681
Low	$531	$591	$531

Demand Response			
Zone	F	G	C
# of Blocks	1	1	1
High	$580	$580	$580
Mid	$390	$390	$390
Low	$190	$190	$190

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5.5.2. Primary Metric Results

The primary metric used to conduct benefit/cost analysis for the three CARIS studies is the change in NYCA-wide production costs. Identified congestion on each of the three congested groupings was mitigated by applying three potential generic solutions, including transmission, generation, and demand response. As Table 5-13 below indicates that the highest savings in production costs would be achieved if Leeds - Pleasant Valley constraint is mitigated. By adding a new 500 MW generation, the production cost would be reduced by $345.7 million from 2009-2018. Further investigation revealed that the most efficient generation placed at the New Scotland 345 kV substation has increased the congestion over the Leeds-Pleasant Valley interface, thus most of the efficient energy produced by the generic generator flows into the ISO-NE area.

Table 5-15: NYCA Production Cost Generic Solutions Savings 2009-2018 (Present Value - $ in Millions)

	Central East	Leeds to Pleasant Valley	West Central
Transmission	26.7	104.9	92.0
Generation	223.9	345.7	151.4
Demand Response & EE	215.9	246.6	216.6

5.5.3. Benefit/Cost Ratios

Disclaimer associated with benefit to cost ratios

These benefit/cost ratios are used to give a relative indication of the project's economic merit. The costs used are overnight costs and were not translated in an annual revenue requirement. The annual revenue requirements are highly dependent on the assumed life of the project and many factors associated with the specific location and developer. For a specific project, the benefits would be dramatically different than those based on production cost savings: these could include generator payments as well as capacity payments.

Figure 5-4 shows the B/C ratios when a carrying charge of 16% is applied for illustrative purposes.

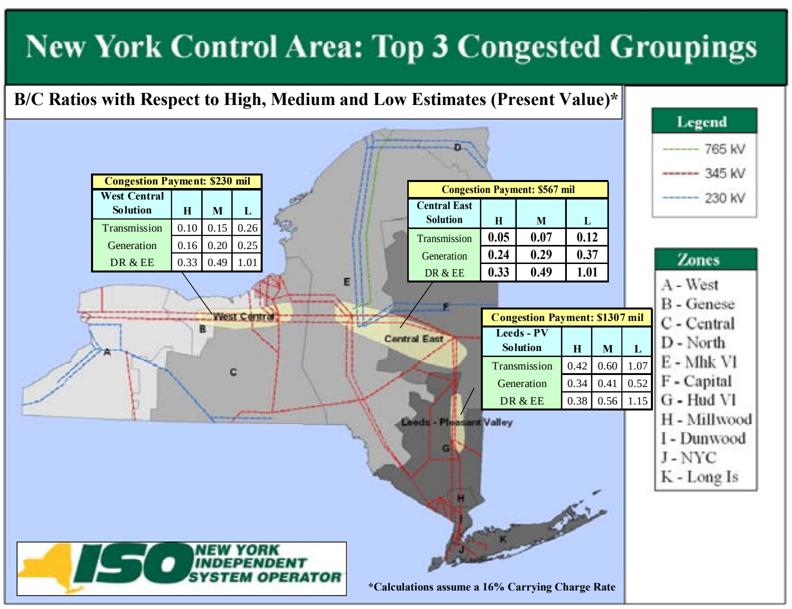

Figure 5-4: B/C Ratio (High, Medium, and Low Cost Estimate Ranges)

Plotted in Figures 5-5, 5-6 and 5-7 are the 10 year cumulative benefits from 2008 to 2018 for each of the three generic solutions. The Benefit-Cost ratios displayed are based on the cumulative present value of the benefits and an assumed 16% project carrying cost charge. The ratios of the cumulative benefits to an overnight cost, plus a 16% adder for a project carrying cost ("the total cost"), are also shown in the figures. For example, looking at the cumulative graph of the Central East generic generation solution in Figure 5-5, by 2018, 41% of the total cost would be recovered by production cost savings. There are additional benefits continuing beyond the ten-year planning horizon that are not included here.

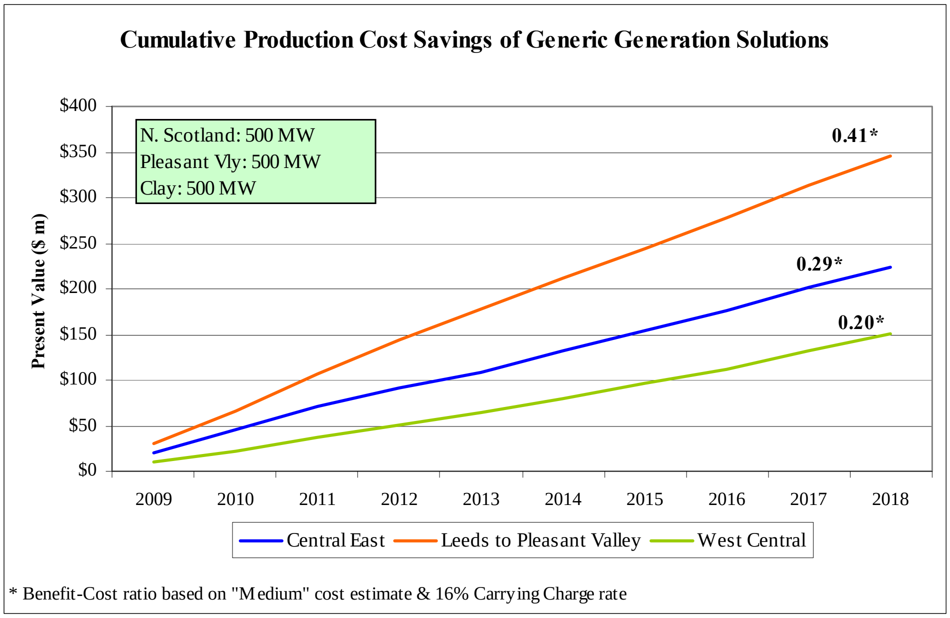

Figure 5-5: Cumulative Benefits of Generic Generation Solutions of Each Study (Present Value $ in Millions)

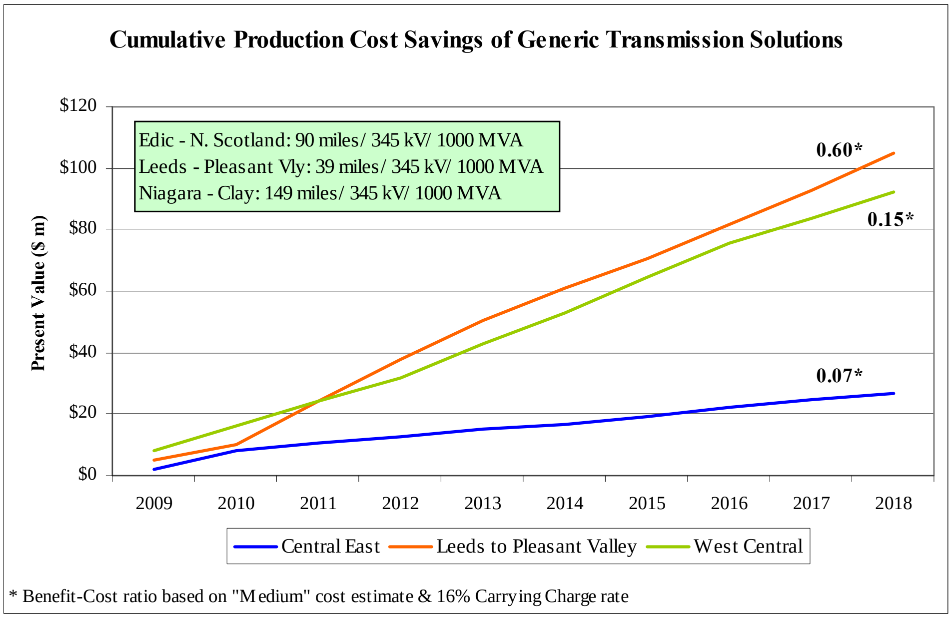

Figure 5-6: Cumulative Benefits of Generic Transmission Solutions of Each Study (Present Value $ in Millions)

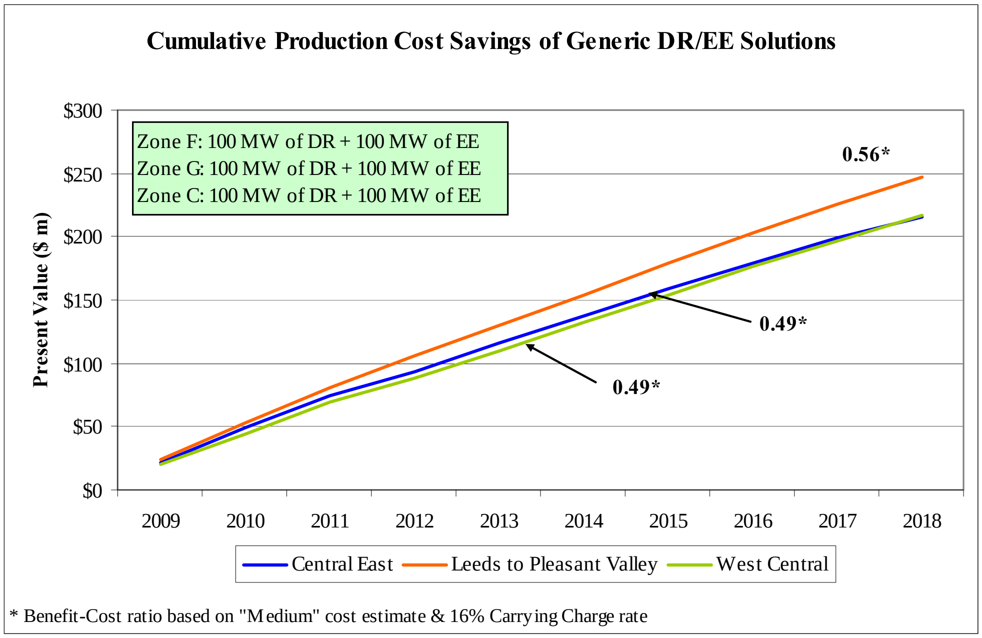

Figure 5-7: Cumulative Benefits of Generic Demand Response/Energy Efficiency Solutions of Each Study (Present Value $ in Millions)

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5.5.4. Additional Metrics Results

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Additional ~~Metrics~~metrics, which are provided for information purposes in Phase ~~I,~~ ~~include~~1, are presented in Table 5-14 and Table 5-15 to show the change in: generator payments; LBMP-based load payments~~, generator payments,~~; TCC payments (~~$),~~congestion rents); marginal load payment losses; emission costs~~ and marginal losses.~~/tons; and ICAP MW impact after the potential generic solutions are applied. The values represent the difference between the applied potential generic solutions' values and the base case values for all the metrics except for the ICAP metric. Negative values imply a reduction in costs/tons. The ICAP numbers represent the amount of capacity that can be removed across NYCA and still meet the base LOLE requirement after the potential generic solutions are applied.

Table 5-16: Change in Generator Payments, Load Payments, TCC Payments, Losses and ICAP

Study	Solution	Generator Payments ($ m)	Load Payments ($ m)	Congestion Rents* ($ m)	Losses ($ m)	ICAP (MW)
	Transmission					
Central East	Edic - New Scotland	67	86	94	-798	0
Leeds - Pleasant Valley	Leeds - Pleasant Valley	306	-76	-738	-279	250
West Central	Niagara - Clay	-519	-358	176	76	0
	Generation					
Central East	New Scotland	-257	-479	276	101	255
Leeds - Pleasant Valley	Pleasant Valley	-52	-784	-326	-14	595
West Central	Clay	-389	-457	310	250	220
	Dd Response & Energy Eff.					
Central East	Zone F	-343	-442	21	-31	70
Leeds - Pleasant Valley	Zone G	-347	-478	-36	-73	225
West Central	Zone C	-352	-480	44	8	70

* Congestion Rents are calculated as Shadow Price times Flow across all constraints in the system.

Table 5-17: Change in CO_2, SO_2 and NO_X Emissions

		Emissions					
Study	Solution	CO2		SO2		NOx	
		'000s Tons	Cost ($m)	Tons	Cost ($m)	Tons	Cost ($m)
	Transmission						
Central East	Edic - New Scotland	77	0.4	178	3.0	203	0.1
Leeds - Pleasant Valley	Leeds - Pleasant Valley	-1,558	-8.0	-1,908	-0.1	-1,960	-0.7
West Central	Niagara - Clay	-1,255	-6.7	31	0.0	-396	0.0
	Generation						
Central East	New Scotland	-2,229	-11.1	-9,375	-0.4	-5,266	-3.1
Leeds - Pleasant Valley	Pleasant Valley	361	2.2	-9,693	-0.4	-7,413	-3.9
West Central	Clay	999	5.4	-6,445	-0.3	-4,758	-2.7
	Dd Response & Energy Eff.						
Central East	Zone F	-1,565	-7.7	-1,370	0.0	-959	-0.5
Leeds - Pleasant Valley	Zone G	-1,942	-9.5	-1,715	-0.1	-1,333	-0.7
West Central	Zone C	-1,535	-7.5	-1,324	0.0	-992	-0.6

Figures 5-8 and 5-9 below depict the projected base case LBMP in 2009 and 2018 respectively. The average LBMP in 2009 is $45, ranging from $41 in West zone to $48 in NYC and Long Island zones. In 2018, an average projected LBMP is $76, ranging from $64 in West zone to $84 in NYC and Long Island zones.

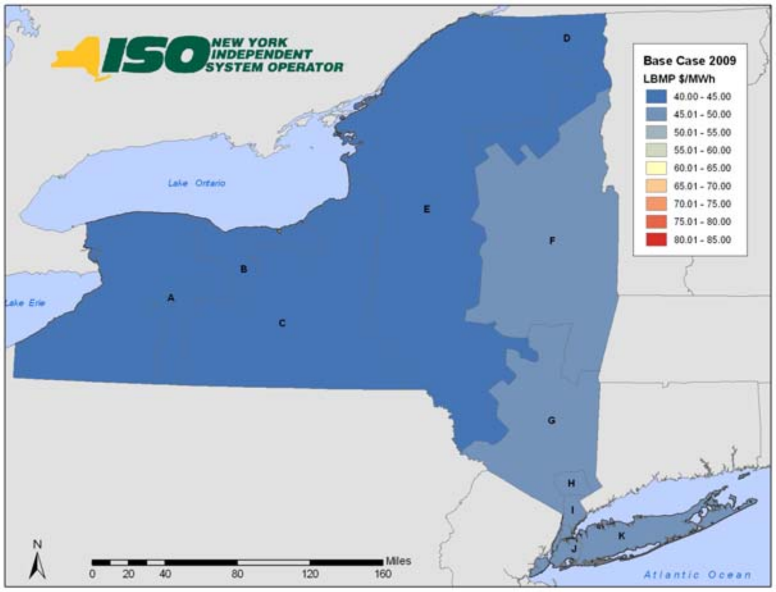

Figure 5-8: 2009 Base Case LBMP/MWh

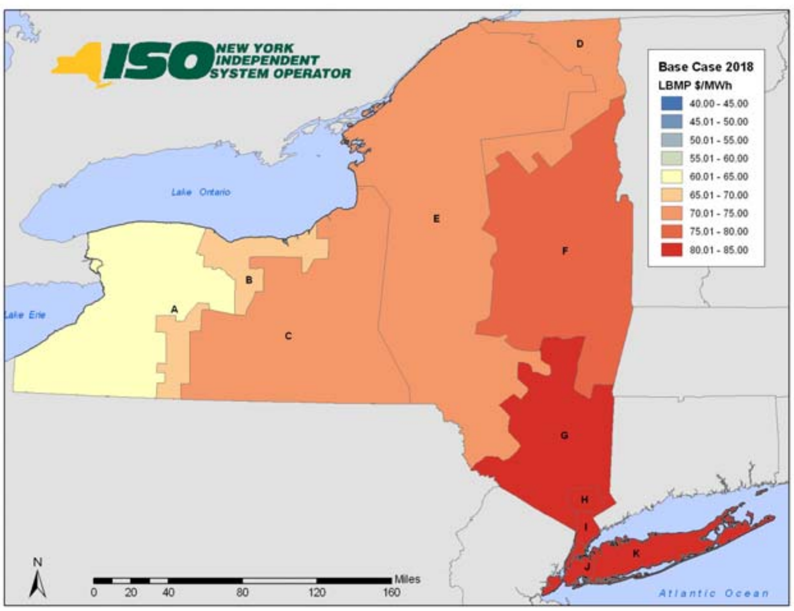

Figure 5-9: 2018 Base Case LBMP/MWh

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5.6. Scenario and Sensitivity Analysis ~~(consider a separate section)~~

~~22009 CARIS Findings – Study Phase~~

~~2.1Base case Findings~~

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Scenario ~~Findings~~/sensitivity analysis is performed to explore the impact of uncertainties associated with significant drivers or variables to the base case. Since this is an economic study and not a reliability analysis these scenarios should particularly explore factors that impact the magnitude of congestion across constrained elements. Therefore, the assumptions modeled within these scenarios may not necessarily apply the same criteria as a reliability planning approach.

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A forecast of congestion is impacted by many variables for which the future values are uncertain. Scenario and sensitivity analyses are methods of identifying the relative impact of pertinent variables on the cost of congestion. The CARIS Scenario studies were presented to ESPWG and modified based upon the input received and the availability of NYISO resources. The focus of these studies was to examine the impact of proposed State policies, fuel price and load forecast uncertainties, costs of emissions, and impacts of various new resources. The objective of the scenario study is to determine change in the costs of congestion on the top three congested paths within in NYCA, resulting from assumptions that differ from the base case. The simulations were conducted for the mid period year 2013, and 2018.

5.6.1. Variables for Consideration

Load Growth

The impact of a higher forecast of load growth was evaluated by using the high load forecast prepared for the 2009 RNA... The impact of a low load growth forecast utilized the full “15 X 15” forecast from the 2009 RNA. The updated load forecasts for the 2009 RNA was developed from the 2008 Load and Capacity Data “Gold Book”.

Fuel Price Uncertainty

The impact of a higher and lower fuel price forecast was also evaluated. The fuel forecasts utilized in CARIS employed historical price volatility to build a statistical profile around the expected prices that were used in the base case. The high fuel price forecast is one standard deviation above the expected price and the low fuel price forecast is on standard deviation below the expected price. The updated fuel price forecast used the same methodology as the base fuel price forecast applied to slightly more current market data.

New Resources

New resources usually impact the cost of congestion and can raise or lower it. New resources can come from the market, the planning process, government initiatives, as well as other sources. New York State is currently proposing an expanded Renewable Portfolio Standard. This proposal will require New York to obtain 30% of its electricity from certain types of new renewable resources by 2015. The study assumed that incremental renewable energy requirements of this proposed standard would be satisfied through the use of wind energy. The contemporaneous work of the NYISO on its wind study provided the location, project size, and production profiles examined in this study. In 2013, 5,100 GWH of additional renewable energy will be required. The requirement rises to 7,100 GWH in 2015 and is then capped.

The NYISO update scenario also includes the build out at the Astoria Energy facility to the limit of its existing Interconnection Agreement. Some additional wind generation facilities have been added since the work done for the 2009 RNA. These include Wethersfield, High Sheldon, and Canandaigua.

New resources can have a significant impact on the cost of congestion in New York. Scenarios were constructed to examine the impacts on the cost of congestion when additions are located at or near a border location or in congested areas. One scenario examined the impact of connecting a 500 MW natural gas combined cycle plant to the 345 kV system at the position currently occupied by the Poletti Station. Two other analyses were conducted for a similar facility located on Staten Island, the southern end of the NYCA system and for Massena at the NYCA's northern boarder, respectively. The dispatch cost for these facilities was set at 95% of its running cost to simulate the effects of the new, economically attractive source of energy.

Environmental Mandates and Retirements

The 2009 RNA examined the potential impact of several developing environmental regulations. The first was the implementation of the Regional Greenhouse Gas Initiative, (RGGI) which limits the total CO2 emissions from power plants across a ten state region. The 2009 RNA scenario analysis concluded that under some combinations of fuel prices and CO2 Allowance prices that some coal fired power plants would be more likely to retire. The CARIS analysis continues to treat coal fired power plants with capacity factors below 50% as likely candidates for retirement. In the State Policy Case this retirement criteria was applied.

New York State is in the process of revising NOx emission regulations for fossil fired power plants. The 2009 RNA examined the impact of these regulations on reliability. The State Policy Case uses the same capacity limitations on the High Emitting Combustion Turbines.

Emission Costs

Emissions of SO2, NOx, and CO2, all have costs that are determined by various cap and trade programs currently in effect in New York and in most of the surrounding regions. Forecasts used in the base case for these allowance costs were developed using various proprietary forecasts and market prices from the Chicago Climate Futures Exchange. To examine the sensitivity of congestion costs to variations in the prices of these allowances, the forecast prices of SO2 and NOx were doubled. The price of CO2 allowances was established at $25/ton in 2013 and forecasted to escalate at CPI plus 5% as prescribed HR 2454 and the Kerry-Boxer Senate proposal.

Energy Efficiency

Energy efficiency and demand response act to reduce the cost of congestion when they are installed downstream of a transmission constraint. EE and DR reduce congestion by reducing peak load and altering the load profile. EE and DR are examined as generic solutions in the studies of each of the three congested interfaces. EE and DR act to alter the load forecast and have been factored into the base case. The working assumption for the base case was that the identified funding will achieve approximately one third of the load reduction necessary to achieve the "15 x15" goal. A low load forecast has been developed to examine the impact of the "15 x 15" goal on the cost of congestion.

5.6.2. Scenarios

Table 5-16 summarizes the scenarios studied in the CARIS Phase 1 report. More specific description on each scenario is presented as follows.

Case #1 – State Policy

The purpose of this case is to examine the aggregated impact of new and likely to emerge State and Federal policies on the cost of congestion. In his January 7, 2009 State of the State Address, Governor Paterson announced a "45 x 15" initiative that sets targets for the State to meet 45 percent of its electricity needs through improved energy efficiency and renewable energy by 2015. The Draft State Energy Plan released on August 10, 2009 provides that the energy efficiency portion of that Governor's initiative is 15 of the total 45 percent. (This is also known as the "15 x 15" Energy Efficiency Portfolio Standard recently implemented by the Public Service Commission's June 23, 2008 "Order Establishing Energy Efficiency Portfolio Standard and Approving Programs" (Case 07-M-0548).) While the Public Service Commission has yet to directly address the renewable portion of the "45 x 15" initiative, this scenario assumes that the State's current Renewable Portfolio Standard (RPS) (Case 03-E-0188) will be expanded to meet 30 percent of the retail electricity use with renewable energy generation by 2015.

This case uses the low load growth forecast which is the equivalent of the full 15 x 15 from the 2009 RNA. Fuel prices will be the same as the base case. New wind resources beyond those in the 2009 RNA will be added with a simulated additional 5,100 GWh annually in 2013. These new wind resources selected based on their respective positions in the Interconnection Queue. Similarly, 7,100 GWh annually beyond the 2009 RNA will be simulated for 2017. To simulate the effects of unit retirements, the model will be run in an iterative manner to identify coal fired generators which experience a drop in production to levels below a 50% capacity factor. These units will be removed and the models rerun. SO2 and NOx allowance prices will be doubled from the base case to simulate continuing evolution of the reductions required through the CAIR program on Ozone SIP calls. CO2 prices will start at $25/ton in 2013 and increase consistent with the prescribed requirements of the proposed legislation. The impact of

OTC NOxRACT limitations will be simulated through the use of capacity limits on High Emitting Combustion Turbines as examined in the 2009 RNA.

Case #2 - NYISO Update

This case will examine the impact of updated load and fuel price forecasts as well as the addition of several units that now would meet the criteria for consideration in the RNA. All other variables are the same as in the base case.

Case #3 - High Growth

This scenario will examine the impact on the cost of congest that results from a higher load growth forecast. To the extent that additional generation is required to maintain an acceptable LOLE, then peaker units will be added at existing facilities to meet the requirement. All other inputs are as they are in the base case.

Case #4 - High Fuel Price

This case will examine the impact of higher fuel prices on the cost of congestion. All other inputs are as they are in the base case.

Case #5 - High Growth and High Fuel Price

This scenario will examine the impact of the combined changes from Cases #4 and #5. All other inputs are as they are in the base case.

Case #6 - Low Fuel Price

This case will examine the impact of lower fuel prices on the cost of congestion. All other inputs are as they are in the base case.

Case #7 - New Resources on the HQ Interface

This analysis will include two new generic 500 MW combined cycle plants that inject energy at Massena. The plants will dispatch at 95% of running cost to simulate the maximum impact on congestion. The transmission system, together with other inputs is as it is in the base case.

Case # 8 - Modified Policy

This case will be designed to similar to Case # 1, however, the low load growth, and low fuel prices will be utilized. All other inputs remain the same as in the base case.

Case #9 - New Astoria Generator on 345 kV

This scenario examined the impact on the cost of congestion of locating a new generic 500 MW natural gas combined cycle plant connected to the 345 kV system at the position currently occupied by the Poletti Station. The plant will dispatch at 95% of running cost to simulate the maximum impact on congestion. All other inputs are as they are in the base case.

Case # 10 - New Staten Island Generator

This scenario examined the impact on the cost of congestion of locating a new generic 500 MW natural gas combined cycle plant connected to the 345 kV system at Goethals. The plant will dispatch at 95% of running cost to simulate the maximum impact on congestion. All other inputs are as they are in the base case.

Table 1-1: Scenario Matrix

Variables → / Scenarios ↓	Load Forecast Uncertainty	Fuel Price Uncertainty	New Resources	Retirements	Emissions Data & Cost of Allowances	Environmental Mandates	Energy Efficiency Mandates
State Policy Case # 1	Low Load Growth	Base case	NYS RPS	Coal with less than 50% capacity factor	Double NOx&SO2 prices, CO2@ $25/ton	NOxRACT Capacity Limits on OTC HECTs	High DR/EE Full 15x15
NYISO Update Case #2	2009 Goldbook	New Fuel Price Forecast	Add 2009 RNA Update Plants	None	Base case	Base case	Base case
High Growth Case #3	High Load Growth	Base case	New Peakers to Maintain LOLE < 0.1	None	Base case	Base case	None
High Fuel Price Case #4	Base case	High Fuel Prices	None	None	Base case	Base case	Base case
High Growth and High Fuel Price Case #5	High Load Growth	High Fuel Prices	New Peakers to Maintain LOLE < 0.1	None	Base case	Base case	Base case
Low Fuel Price Case #6	Base case	Low Fuel Prices	None	None	Base case	Base case	Base case
New HQ Resource on the Border Case #7	Base case	Base case	500 MW CC @ Chateguay and 500 MW CC @ St. Lawrence Both Dispatch @ 95% of Cost	None	Base case	Base case	Base case
Modified State Policy Case # 8	Low Load Growth	Low Fuel Prices	NYS RPS	Coal with less than 50% capacity factor	Double NOx&SO2 prices, CO2@ $25/ton	NOxRACT Capacity Limits on OTC HECTs	High DR/EE Full 15x15
New Astoria Generator @ 345 kV Case #9	Base case	Base case	Generic 500 MW Generator @ Poletti Bus 345kv	None	Base case	Base case	Base case
New Staten Island Generator @ 345 kV Case #10	Base case	Base case	Generic 500 MW Generator @ Goethals	None	Base case	Base case	Base case

Table 5-17 represents the impact of each scenario on congestion and reports the change in congestion values between the scenario's congestion values and the base case congestion values. Negative numbers represent a reduction in congestion..

Table 1-2: Comparison of Base Case and Scenario Cases

	Change in Congestion - $ m					
	Central East		**Leeds - Plsnt. Valley**		**West Central**	
Scenario	2013	2018	2013	2018	2013	2018
1 – State Policy	21	149	(81)	(59)	(51)	(83)
2 - NYISO Update	151	177	94	29	(19)	(9)
3 - High Growth	(11)	(38)	18	49	3	9
4 - High Fuel Price	87	85	177	188	66	66
5 - High Growth and High Fuel Price	65	27	201	254	75	81
6 - Low Fuel Price	(5)	(26)	68	86	10	9
7 - New Resources on the HQ Interface	164	196	77	197	(28)	(36)
8 - Modified Policy	1	149	(38)	(59)	(50)	(83)
9 - New Astoria Generator on 345 kV	(2)	(4)	(46)	(50)	(2)	(2)
10 - New Staten Island Generator	(3)	(5)	(6)	(8)	(2)	(1)
Change is calculated as Solution minus Base						

6. 2009 CARIS Conclusions – Study Phase

To be added at a later date.

7. Next Steps

7.1. Phase 2 –– Specific Transmission Project Phase

Upon the approval of the Phase 1 study results by the NYISO Board, the NYISO staff will start conducting Phase 2 - the Project Phase - of the CARIS process. Phase 2 deals with the specific project proposals seeking cost recovery submitted by the developers to mitigate congestion identified in Phase 1. Regulated economic transmission project proposals and accelerated regulated backstop solutions[23] to the congestion identified in Phase 1 will be considered by the NYISO in Phase 2. Nevertheless, any interested party can request an additional study of congestion on the NYCA bulk power system at any time. Those studies can analyze the benefits of alleviating congestion with all types of resources, including transmission, generation and demand response, and compare benefits to costs if the NYISO is provided cost information by the study requestor.

Transmission projects seeking cost recovery will be further assessed by NYISO staff to determine whether they qualify for cost allocation and cost recovery under the NYISO Tariff[24]. To qualify, the total capital cost of the project must exceed $25 million, the benefits must exceed their cost measured over the first ten years from the proposed commercial operation date, and a super-majority (>.80%) of the weighted vote cast must be in favor of the project. Additional details on Phase 2 process can be found in Appendix F and Initial CARIS Manual.

7.2. Project Phase Schedule

[23] Regulated backstop solutions will qualify for the cost allocation and cost recovery only if the implementation of such regulated backstop solutions is accelerated solely to reduce congestion in earlier years of the study period.
[24] Market-based responses to congestion identified in Phase 1 of the CARIS are not eligible for regulated return and therefore are not obligated to follow the requirements of Phase 2. The cost of a market-based project shall be the responsibility of the developer.

Phase 2 of the CARIS process will start after the NYISO Board's approval of the Phase 1 study results, which is anticipated to occur in the beginning of 2010. Throughout the 2010, NYISO staff will be evaluating submitted regulated economic transmission proposals for benefit/cost analysis, and if a developer seeks cost recovery, determining beneficiaries. The results of these analyses will provide a basis for beneficiary voting on each proposed transmission project. Upon the completion of the 2011 CRP, the next CARIS cycle will start.

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Appendix A – Glossary

~~Loop Flows~~

~~When the actual electricity path differs from the routes scheduled for it, the departure is known as "loop flow." Loop flows occur in all interconnected transmission systems as the flow of electricity follows physical laws across the continent.~~

~~Nomogram~~

~~Heat Rate~~

~~The term "heat rate" refers to a power plant's efficiency in converting fuel to electricity. Heat Rate is expressed as the number of British thermal units (Btu) required to generate a kilowatt hour.~~

~~Implied Heat Rate~~

~~The market implied Heat Rate refers to the projected LBMP price divided by the forecasted natural gas price.~~

~~1. Congestion Rent~~

~~The hourly congestion rent for a constrained facility is defined as the active power flow (MW) on the constrained facility multiplied by its shadow price. Shadow price is defined as the incremental production cost saving if the constrained element flow limit is increased by 1MW. Shadow prices on constrained elements are non-zero during hours of congestion (or constrained element MW flow is equal to constrained element limit).~~

~~Congested rent value by constraint = sum of all hours (constrained element MW x Shadow Price $/MW)~~

~~Total congestion rent = Sum of all constraints congestion rent~~

~~Constrained facilities are then listed in descending order based on their congestion rent values in order to show highly congested locations on the NYCA system. Other information such as number of congested hours will be provided.~~

~~2. Demand$_Congestion~~

~~Demand$_Congestion is the congestion cost component paid by NYCA load. It is defined as the shadow price of each constrained elements multiplied by the load affected and calculated as follows:~~

~~Demand$_Congestion by constraint = For all areas (For all hours (ShadowPrice x AreaGSF x AreaLoad))~~

~~Total Demand$_Congestion = Sum of all constraints' Demand$_Congestion~~

~~Constrained facilities are then listed in descending order based on their Demand$_Congestion values in order to show highly congested locations on the NYCA system. Demand$_Congestion values by zone can also be reported.~~

~~3. Generator Payment Metric~~

~~Generator Payment is also referred to as Generator Revenues. It is a zonal LBM based revenues or payment to generators located in a zone. The hourly revenue or payment to each generator is the determined as the hourly generator MW dispatch multiplied by the generator's LMP or spot price. The annual generator payment is then the sum of all 8760 hourly generator payments.~~

~~Annual generator LBMP payment = sum of all hours (generator LMP x generator MW dispatch)~~

~~Zonal generator payment = sum of generator payment located in a zone~~

~~Generator Payment benefits or saving of a proposed project is then the change in the NYCA Generator Payment for the "with" and "without" project cases. Total Generator payment benefits are also calculated on a zonal basis.~~

~~4. Load Payment Metric~~

~~Load Payment or LBMP payment is the total energy cost to consumers. It is a zonal LBMP based consumer payment. Hourly load-weighted average LBMP price for each zone is calculated and multiplied with the zonal load to determine the hourly zonal load payment. The annual load payment is then the sum of all 8760 hourly load payments.~~

~~Annual Zonal LBMP payment = sum of all hours (zonal LBMP x zonal load)~~

~~Zonal LBMP = zonal average load-weighted LMP~~

~~Load Payment benefit or saving of a proposed project is then the change in the NYCA Load Payment for the "with" and "without" project cases. Total Load Payment benefits are also calculated on a zonal basis.~~

~~5. NYCA Production Cost and Production Cost Benefit Metrics~~

~~NYCA production cost is the total generation cost of producing power to serve NYCA load. The total cost includes the following components:~~

~~1.Fuel cost (fuel consumption MBtu multiplied by fuel cost $ /MBtu)~~
~~2.Variable O&M cost (VOM adder $/MWh)~~
~~3.Emission cost (emission allowance price multiplied by total allowance)~~
~~4.Start-up Costs (number of starts multiplied by start-up cost)~~
~~5.NYCA Imports or Exports evaluated at the LMP values. (Needs further clarifications)~~

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~~Production cost benefit or saving of a proposed project is then the change in the NYCA production cost for the "with" and "without" project cases. Total Production Costs benefits are also calculated on a zonal basis.~~

~~Appendix B Congestion Assessment and Resource Integration Study (CARIS) Process~~

~~Overview~~

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~~B.1.Phase 1 – Study Phase~~

~~The purpose of Phase 1 or the Study Phase, Figure B - 1 is to gather, organize, and develop information related to congestion as it impacts the NYCA for stakeholders. More specifically:~~

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~~a.Post historic congestion and identify significant causes of historic congestion;~~

~~b.Project congestion on the New York State BPTFs over the ten-year planning period;~~

~~c.Identify the most congested elements or contingency pairs of elements;~~

~~d.Identify, through the development of appropriate scenarios, factors that might mitigate or increase congestion;~~

~~e.Provide information regarding generic projects to reduce congestion;~~

~~The study phase starts with the gathering of historic and the projection of future congestion information. That information is used to identify significant and reoccurring congestion. The historic congestion information is a compilation of the last six years of congestion data which is posted quarterly and the projected congestion is simulated from security-constrained unit commitment and economic dispatch software and posted once per CARIS cycle. A CARIS cycle is two years.~~

~~Based upon the combination of historic and projected congestion metrics each congested element or contingency pairs of elements are ranked by the following formula developed in conjunction with the ESPWG:~~

~~***Present Value in Year 1 = [(Sum of the Future Value of Congestion from the Prior 5 Historic 12-Month Periods) + (Sum of the Present Value of Congestion from the Future 10 years)]***~~

~~**The rankings are posted for stakeholder review. The rankings are finalized after the stakeholder review and from this final ranking the top three congested elements/contingency pairs of elements are selected and posted for study. Additional information can be found in CARIS Procedure X – Criteria for the Selection of CARIS Studies, Appendix F.**~~

~~**During this process a request for additional studies from stakeholders is posted by the NYISO. These studies are in addition to the three identified studies noted above. Any stakeholder is eligible to request an additional study. All requests will be posted on the NYISO website. Additional details can be found in CARIS Procedure X – Process for Additional Studies, Appendix F.**~~

~~**Once the three studies are selected, benefit/cost analysis is performed. To perform the benefit analysis assumptions for the baseline system are developed in conjunction with the ESPWG. Based on Attachment Y of the Tariff, the baseline system for the CARIS simulations assumes a reliable system throughout the Study Period, based upon the solutions identified in the most recently completed and approved CRP. The baseline system for the CARIS incorporates sufficient viable market-based solutions to meet the identified Reliability Needs as well as any regulated backstop solutions triggered in prior or current CRPs. If more market based solutions have been proposed than the minimum needed to meet the identified Reliability Needs, the NYISO, in conjunction with the ESPWG, has developed methodologies to scale back market-based solutions to the minimum needed to meet the identified Reliability Needs. Regulated backstop solutions that have been proposed but not triggered in the most recent CRP shall also be used if there are insufficient market-based solutions for the ten-year study period. Additional information can be found in CARIS Procedure X – Procedure for inclusion of Market Based Solutions & Regulated Backstop Solutions in CARIS Base Case, and Procedure to Scale Back Market Based Solutions, Appendix F.**~~

~~In conducting the CARIS, the NYISO conducts benefit/cost analysis of each potential generic solution to the congestion identified. One potential generic solution is determined by NYISO for each resource type (generation, transmission, and demand response) for each of the three congestion studies. During each cycle, NYISO will develop with ESPWG specific project criteria for each resource type (generation, transmission, and demand) including block size and construction assumptions. Following the identification of the three studies, each resource type shall be applied in year one of the planning horizon, in sufficient quantities of generic block sizes associated with each resource type and specific locations to alleviate a substantial and comparable portion of the identified congestion over the planning horizon. Additional details can be found in CARIS Procedure X – Potential generic Solutions, Appendix F.~~

~~The principal benefit metric for the CARIS analysis will be expressed as the present value of the NYCA-wide production cost reduction that would result from each potential solution. Additional benefit metrics calculated include estimates of reduction in losses, LBMP load costs, generator payments, ICAP costs, Ancillary Services costs, emission costs, and TCC payments. Additional details can be found in CARIS Procedure X – Additional Benefit Metrics for CARIS Studies Methodology and Models to Develop and Implement Additional Metrics, Appendix F.~~

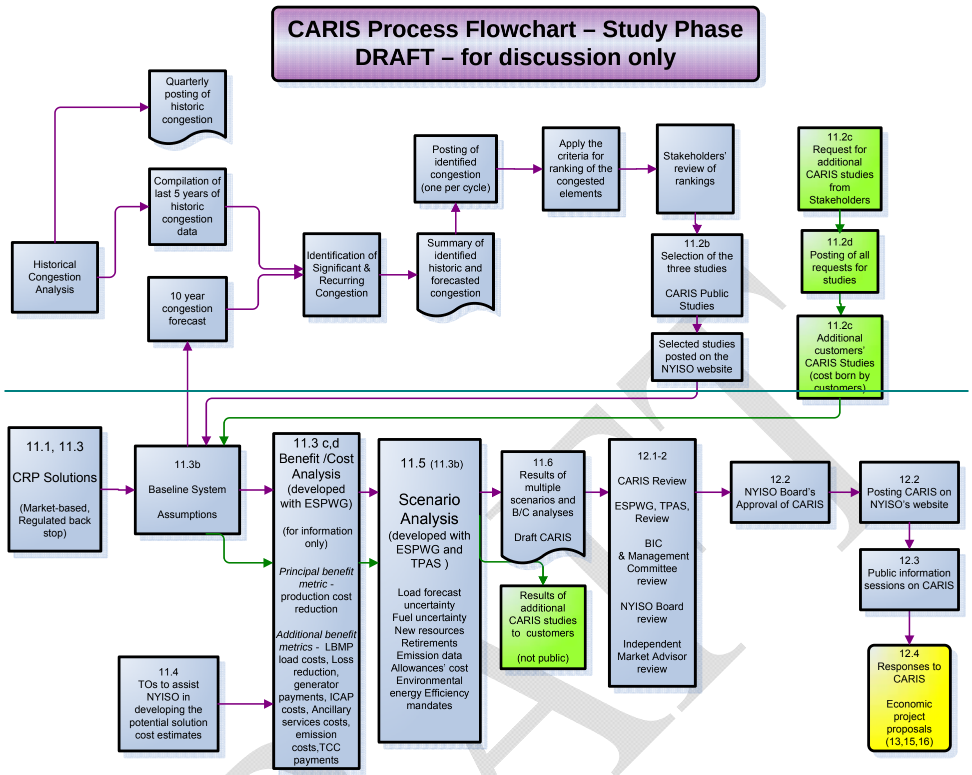
~~The costs of potential generic solutions utilized in the benefit/cost analysis are order of magnitude estimates developed for each resource type. The costs will be developed for relevant geographic locations during each CARIS cycle. The order of magnitude costs will be provided to the ESPWG for their review and acceptance during each CARIS cycle as part of the Assumption Matrix approval process. If upon a cursory review of the location for the potential solution identifies unusual complexities, a contingency factor will be applied to the costs.~~

~~To add additional information to the benefit/cost analysis, scenario analysis is performed. The scenarios are developed in conjunction with the ESPWG.~~

~~Variables for consideration in the development of these scenarios include but are not limited to: load forecast uncertainty, fuel price uncertainty, new resources, retirements, emission data, the cost of allowances and potential requirements imposed by proposed environmental and energy efficiency mandates, as well as overall NYISO resource requirements.~~

~~The NYISO will prepare a draft of the Study Phase of the CARIS which includes a discussion of assumptions, inputs, methodology, and results of the analyses. The draft of the Study Phase of the CARIS shall be submitted to both TPAS and the ESPWG for review and comment. Following completion of that review, the draft of the Study Phase of the CARIS shall be sent to the Business Issues Committee and the Management Committee for discussion and action. Following the Management Committee vote, the draft of the Study Phase of the CARIS, with Business Issues Committee and Management Committee input, will be forwarded to the NYISO Board for review and action. Concurrently, the draft of the Study Phase of the CARIS will be provided to the Independent Market Monitor for his review and consideration. Upon approval by the Board, the NYISO shall issue the Study Phase of the CARIS to the marketplace by posting it on its website.~~

~~In order to provide ample exposure for the market place to understand the content of the Study Phase of the CARIS, the NYISO will provide various opportunities for Market Participants and other potentially interested parties to discuss final CARIS. Such opportunities may include presentations at various NYISO Market Participant committees, focused discussions with various industry sectors, and /or presentations in public venues.~~



~~Figure B - 1 Phase 1 or Study Phase of the CARIS Process~~

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~~B.1.1.Phase 1 – Procedures~~

~~Summary of the procedures associated with Phase 1 – Study Phase include the following:~~

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~~a.Criteria for Selection of CARIS Studies (Attachment Y: Section 11.2.b)~~

~~The congestion metric that is used to select the three CARIS studies is the change in total bid/forecasted production costs in accordance with Appendix A to Attachment Y of the NYISO OATT. Congestion will be identified from the list of most congested monitored element/contingency pairs.~~

~~This procedure will utilize an unweighted present value cost of congestion for the most congested elements considering both historic (5 years) and 10-year forecasted data. The three congested elements with the highest present value ranking shall be utilized for further assessment under the CARIS process for that cycle. This assessment will be accomplished in multiple iterations to include additional elements that appear as limiting when each of the top three constrained elements are unconstrained. The assessed element groupings will then be ranked based upon change in bid production cost. The three ranked groupings with the largest change in bid production cost will then be selected as the three CARIS studies.~~

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~~b.Process for Additional Studies (Attachment Y: Section 11.2.c)~~

~~Any NYISO Market Participant or other stakeholder (requestor) is eligible to request such congestion and/or resource integration studies. Requests will be accepted throughout the CARIS cycle. The requestor is responsible for all reasonable actual costs incurred by the NYISO for the additional study(-ies). The NYISO will post the requests for additional studies on its Website. The postings shall include a general description of the study requests, the date of receipt, and the identity of the requestor. There is a provision to allow combination/cost sharing of identical/similar or overlapping study requests from different parties if the parties agree.~~

~~The results of these additional studies will NOT be posted on the NYISO website or otherwise released by the NYISO to parties other than the requestor – except with the express written permission of the requestor. If a requestor should seek regulated cost recovery under the NYISO Tariff based upon the results of such studies, the studies would be posted on the NYISO website at that time.~~

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~~c.Procedure for inclusion of market-based & regulated backstop solutions in CARIS base case and Procedure to scale back market-based solutions (ATTACHMENT Y: SECTION 11.3.b)~~

~~CARIS will assume a reliable system based upon the solutions identified in the most recently completed and approved CRP. The baseline system for the~~

~~**CARIS shall first incorporate sufficient viable market-based solutions to meet the identified Reliability Needs as well as any regulated backstop solutions triggered (and not subsequently halted) in prior or current CRPs. If a TO, or an other developer, is proceeding with an alternative regulated solution that has been approved by the PSC and not subsequently halted, then such project shall be included in the CARIS base case. Resources modeled in the CARIS base case will not be evaluated as potential economic solutions.**~~

~~**If more market-based solutions were proposed than needed to meet the Reliability Needs, the market-based solutions will be scaled back to the minimum needed to meet the identified Reliability Needs (statewide LOLE of 0.1) by using the following methodology:**~~

~~***All MBS will be sorted by size from largest to smallest regardless of resource type and scaled back sequentially until both the LCR and statewide LOLE requirement are met.***~~

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~~**d.Procedure for additional benefit metrics for CARIS studies, methodology and models to develop and implement additional metrics - 11.3.d.**~~

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~~**In addition to the principal benefit metric (NYCA-wide production costs) for CARIS studies, the NYISO will also use the additional benefit metrics in conducting the CARIS study. The additional metrics will estimate the benefits of the potential solutions to the congestion identified and will be used for information purposes only**~~

~~**Additional metrics include:**~~

~~***a.LBMP load costs***~~

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~~***b.Generator payments***~~

~~***c.Reduction in losses***~~

~~***d.TCC payments***~~

~~***e.Emission metric***~~

~~*f.ICAP costs*~~

~~**e.Draft procedure for determination of potential generic solutions - 11.4.**~~

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~~**One potential generic solution (Phase 1) will be determined by NYISO for each resource type (generation, transmission, and demand response) using a cost matrix methodology. The cost matrix methodology will be based upon a typical block size generic solution and a list of construction assumptions for each resource type.**~~

~~**The NYSIO will provide recommended order of magnitude costs for each resource type. The costs will be developed for relevant geographic locations during each CARIS cycle. The cost matrix will be provided to the ESPWG for their review and acceptance during each CARIS cycle as part of the Assumption Matrix approval process.**~~

~~**Each potential generic solution, for each of the three studies, will be applied to alleviate identified congestion starting in year one of the ten-year planning horizon.**~~

~~**B.2.Phase 2 – Projects Phase**~~

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~~**The results of the Phase 1- Study Phase will provide information to stakeholders who are interested in proposing an actual project to address specific congestion identified in the CARIS Study Phase report. Any interested developer can propose any type of project, such as a generator or demand response, to specific congestion identified in the Study Phase. However, Phase 2 – Specific Project Phase applies only to regulated economic transmission project responses to specific congestion issues and regulated backstop solutions when the implementation of the regulated backstop**~~

~~solution is accelerated solely to reduce congestion in earlier years of the study period.~~

~~Market-based responses to congestion identified in the Study Phase of the CARIS are not eligible for regulated return and therefore are not obligated to follow the requirements of Phase 2. The cost of a market-based project shall be the responsibility of the developer of the market based proposal.~~

~~To be eligible for cost recovery in Phase 2, the benefit of the proposed project must exceed its cost measured over the first ten years from the proposed commercial operation date for the project, the total capital cost of the project must exceed $25 million, and a super-majority of the beneficiaries must vote in favor of the project.~~

~~Phase 2, Figure B - 2 starts with the NYISO evaluating proposed project to determine if the proposed project is an economic transmission project. If the proposed project is an economic transmission project, the NYISO will perform a ten year B/C analysis from the proposed in-service date, which is paid for by the developer. The benefit metric will be expressed as the present value of the annual NYCA-wide production cost savings that would result from the implementation of the proposed project, measured for the first ten years from the proposed commercial operation date of the project. The estimated cost of each economic transmission project will be supplied by the developer and the cost metric will be the present value of the annual total revenue requirement for the project, reasonably allocated over the first ten years from the proposed commercial operation date of the project.~~

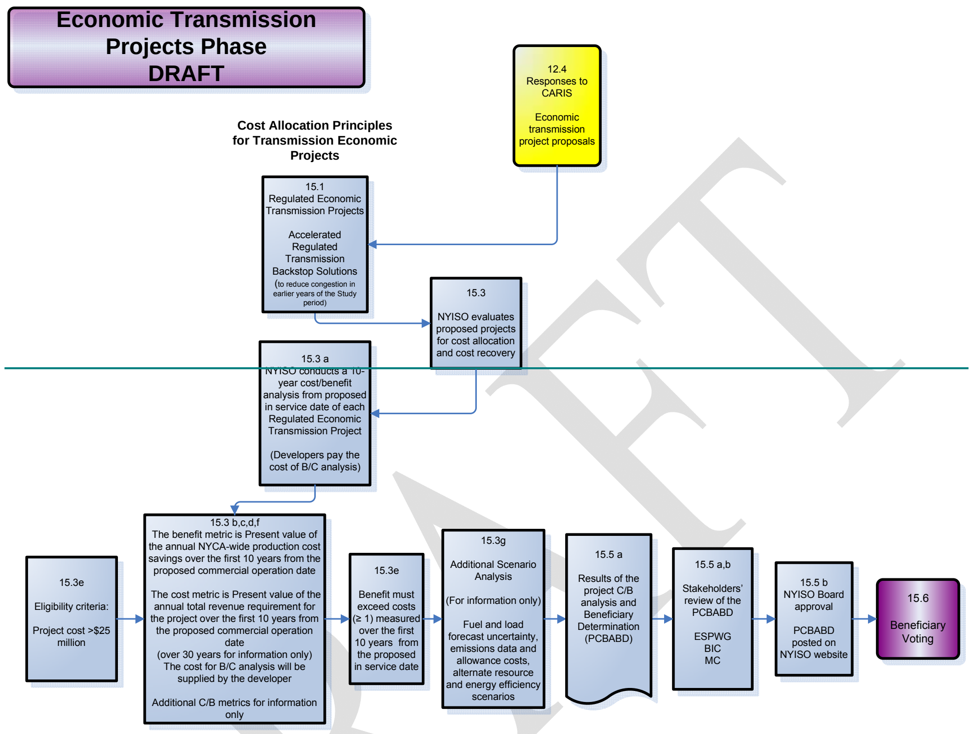
~~As stated above, if the proposed economic transmission project has a B/C >1 over the first ten years from the proposed commercial operation date of the project and the total capital cost of the proposed project is greater than $25 million, then the proposed project will be eligible to proceed to the next steps.~~

~~In addition to the metrics used in the B/C analysis, for informational purposes only, the NYISO will also calculate the present value and annual total revenue requirement for the project over a 30 year period commencing with the proposed commercial operation date of the project. Also, the NYISO will work with the ESPWG to consider the development of additional metrics for informational purposes only. These additional metrics shall include those that measure reductions in LBMP load costs, changes to generator payments, ICAP costs, Ancillary Service costs, emissions costs, losses and TCC payments. Consideration of these additional metrics will take into account the overall resource commitments of the NYISO.~~

~~In addition to the B/C analysis, the NYISO will work with the ESPWG to consider the development and implementation of scenario analyses, for information only, which shed additional light on the cost and benefit of a proposed project.~~

~~Additional details can be found in CARIS Procedure X – NYISO cost allocation procedures for regulated economic transmission projects, Appendix F.~~

~~The results of the B/C analysis, additional metrics and the scenario analysis, along with the determination of the beneficiaries, will be documented and submitted to the ESPWG for review and comment. Following completion of that review, the NYISO's analysis shall be forwarded to the Business Issues Committee and Management Committee for discussion and action. Following the Management Committee vote, the NYISO's project B/C analysis and beneficiary determination will be forwarded, with the input of the Business Issues Committee and Management Committee, to the NYISO Board for review and action. Upon final approval of the Board, project B/C analysis and beneficiary designations shall be posted by the NYISO on its website.~~



~~Figure B - 2 Phase 2 – Project Phase of the CARIS process~~

~~B.2.1.Phase 2 – Procedures~~

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~~a.NYISO cost allocation procedures for regulated economic transmission projects (Attachment Y, Sections 15.3 & 15.4)~~

~~To be eligible for cost allocation and recovery, the benefit of the proposed project must exceed its cost measured over the first ten years from the proposed commercial operation date for the project. The benefit metric for eligibility under the NYISO's cost/benefit analysis will be expressed as the present value of the annual NYCA-wide production cost savings that would result from the implementation of the proposed project, measured for the first ten years from the proposed commercial operation date for the project.~~

~~**The cost for the NYISO's benefit/cost analysis will be supplied by the developer of the project, and the cost metric for eligibility will be expressed as the present value of the annual total revenue requirement for the project, reasonably allocated over the first ten years from the proposed commercial operation date for the project.**~~

~~**The beneficiaries will be those load zones who experience net benefits measured over the first ten years from the proposed commercial operation date for the project. Load zones not benefiting from a proposed project will not be allocated any of the costs of the project.**~~

~~**b.Draft Procedure for Project Cost Overruns – 15.4.c.**~~

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~~**This procedure will be used for the purposes of the Project Phase (Phase 2) of the CARIS process to allocate the risk of increases in project costs after benefit/cost analysis is completed. The developers will provide a risk profile with their project proposals. The risk profile will address the following items:**~~

- ~~***The stage of project development and the level of accuracy of the project cost estimate.***~~

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- ~~***Required cost overruns sharing if any between the Developer and the LSEs benefiting from the project.***~~
- ~~***Required project cost increase sharing if any due to a force majeure between the Developer and the LSEs benefiting from the project.***~~
- ~~***Identification of conditions if any for canceling the project by the Developer including terms and conditions for allocating sunk costs and lost benefits.***~~

~~**The developers will provide quarterly project status reports to the benefiting LSEs and the NYISO which will include any changes to the project schedule or costs.**~~

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~~B.3.Voting, Cost Allocation, and Cost Recovery~~

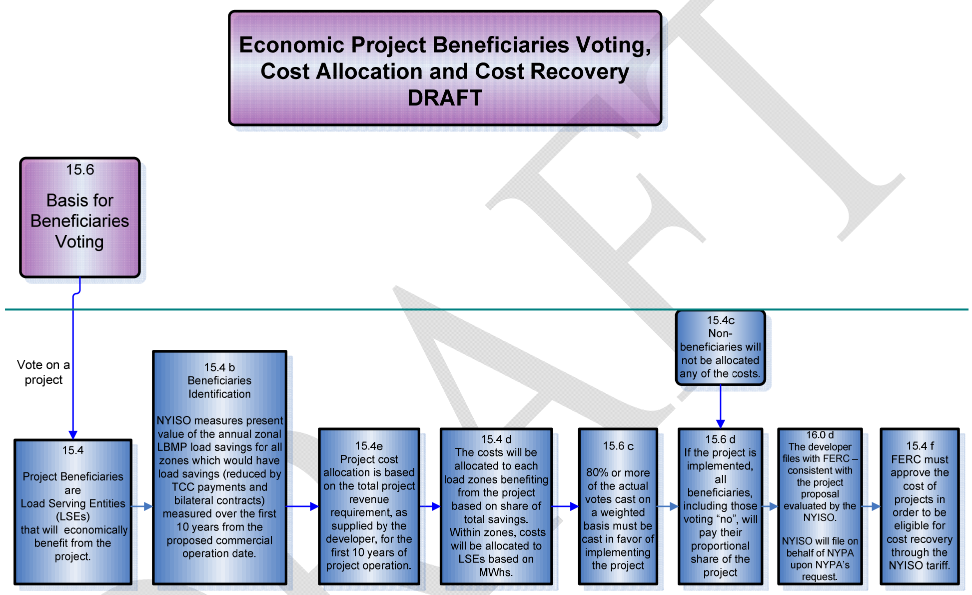
~~The CARIS process requires the determination of beneficiaries for voting and cost allocation, Figure B - 3. The cost of a regulated economic transmission project will be allocated to those entities that would economically benefit from implementation of the proposed project. The NYISO will identify the beneficiaries of the proposed project over a ten-year time period commencing with the proposed commercial operation date for the project.~~

~~The NYISO will measure the present value and annual zonal LBMP load savings for all load zones which would have a load savings, net of reductions in TCC payments, and bilateral contracts (based on available information) as a result of the implementation of the proposed project. Additional information can be found in Procedure X - Procedure to estimate the TCC revenues, Appendix F. The beneficiaries will be those load zones who experience net benefits measured over the first ten years from the proposed commercial operation date for the project. For each load zone that would benefit from a proposed project, the NYISO will allocate the cost of the project to load based on share of total savings. Within zones, costs will be allocated to Load Serving Entities based on MWhs. Load zones not benefiting from a proposed project will not be allocated any of the costs of the project. There will be no "make whole" payments to non-beneficiaries.~~

~~Only Load Serving Entities defined as beneficiaries of a proposed project shall be eligible to vote on a proposed project. The voting share of each Load Serving Entity shall be weighted in accordance with its share of the total project benefits. For the proposed project to proceed, eighty (80) percent or more of the actual votes cast on a weighted basis must be cast in favor of implementing the project. If the project meets the required vote in favor of implementing the project, and the project is implemented, all beneficiaries, including those voting "no," will pay their proportional share of the cost of the project. Additional information can be found in Procedure X - Voting Procedures, Appendix F.~~

~~If the proposed economic transmission project has a B/C >1 over the first ten years from the proposed commercial operation date of the project, Plus the~~

~~total capital cost of the proposed project is greater than $25 million, and receives a super-majority (>=80%) of the beneficiaries vote in favor of the project, then the Developer shall have the right to make a filing with FERC, under Section 205 of the Federal Power Act, for approval of its costs associated with implementation of the project. Also, upon request by NYPA, the NYISO will make a filing on behalf of NYPA. FERC must approve the cost of a proposed economic transmission project for that cost to be recovered through the NYISO tariff.~~



~~Figure B - 3 Voting, Cost Allocation, and Cost Recovery of the CARIS process~~

~~B.3.1.Voting, Cost Allocation, and Cost Recovery – Procedures~~

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~~a.Procedure to estimate the TCC revenues – 15.4.b.(iii)~~

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~~*(Pending FERC Approval from May 19, 2009 filing)*~~

~~The procedure will be used for the purposes of the Project Phase (Phase 2) of the CARIS process for regulated transmission project cost allocation, which~~

~~will estimate net reduction in TCC revenues when calculating LBMP load savings to identify beneficiaries of a proposed project. The estimate will reflect the estimated impact of the project on:~~

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- ~~*TSC (Transmission Service Charge) offset applicable to load in each zone*~~
- ~~*NTAC (NYPA Transmission Adjustment Charge) offset applicable to load in that zone*~~
- ~~*Congestion rents made to LSEs serving load in each zone that own grandfathered rights/TCC that are not included in the calculation of the TSC and NTAC offsets.*~~

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~~**e.Voting Procedures – 15.6**~~

~~**The voting procedure will be used for the purposes of the Project Phase (Phase 2) of the CARIS process related to the beneficiary voting on a proposed regulated economic transmission project. Only LSEs defined as beneficiaries of a proposed project will be eligible to vote on a proposed project.**~~

~~**A project is approved when 80 % or more of the actual votes cast on a weighted basis must be cast in favor of implementing the project. Abstentions will not be counted as votes. Voting share of each LSE will be weighted in accordance with its share of total project benefits. If the project is voted on in favor of implementing the project, all beneficiaries, including those voting "no" will pay their proportional share of the cost of the project. If no LSE votes on a proposed project, the project will be rejected. The**~~

~~**BIC will approve the list of voting LSEs developed by the NYISO and ESPWG. The Chair of the BIC will oversee voting and announce the results of the vote.**~~

~~**Add Procedure**~~

~~Appendix C – Baseline System Assumptions~~

~~C.1. CARIS Model - Base Case Modeling Assumptions for 2009-2018 CARIS Study Phase~~

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~~**Implementing CARIS requires the understanding of a significant amount of data. Taken from Section 11 of Schedule Y of the Tariff, *"The CARIS for economic planning will align with the reliability planning process. Each CARIS will use a ten-year planning horizon consistent with the reliability planning horizon. Each CARIS will be based on the most recently concluded and approved CRP. The base case for each CARIS will assume a reliable system for the ten-year planning horizon based upon the CRP."***~~

~~**The data utilized in the base case simulations for CARIS is based on 2009 CRP/RNA and CARIS Assumption Matrix, Table C - 1, shown below. Major components of data includes base load flow data, fuel prices, unit capacities, transmission constraint modeling, load growth and shape representation, both simulated and real actual and scheduled interchange values, O&M cost, and environmental cost components. The Power Flow Assessment Output is Confidential Energy Infrastructure Information (CEII)) and is subject to CEII rules.**~~

~~**Table C - 1: CARIS Assumption Matrix**~~

~~**Parameter**~~	~~**Modeling for CARIS Base Cases**~~	~~**Basis for Recommended Assumptions for CARIS**~~
~~**7.2.1.1Peak Load**~~	~~**Forecast as per 2009 RNA Base. Scenarios for other forecasts.**~~	~~**Based on CRP Peak Forecast**~~ ~~**Use 2009 Base Case Energy**~~

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~~Parameter~~	~~Modeling for CARIS Base Cases~~	~~Basis for Recommended Assumptions for CARIS~~
		~~Forecast~~
~~Load Shape Model~~ ~~Energy Forecast~~	~~2002 Load Shape, constant over ten year period.~~ ~~2009 RNA Base Case Forecast~~	~~2002 load shape is an appropriate representation for this analysis. For base year, use 2002 Load Shape, Adjusted for Energy Forecast if needed , Evaluate alternative in future~~
~~Load Uncertainty Model~~	~~Statewide and zonal model updated to reflect current data., constant over ten year period~~	~~Base Level Forecast will be used. Other load uncertainty levels not evaluated.~~
~~Generating Unit Capacities~~	~~Same as CRP - Per 2009 CRP, updated DMNC test values plus units~~	~~Any changes in CRP capacities through time to be represented in CARIS.~~
~~New Units~~	~~As per the CRP and scaled back according to procedure (Tariff Attachment Y: Section 11.3.b)~~	~~N/A~~
~~Wind Resource Modeling~~	~~Existing units derived from hourly wind data with average Summer Peak Hour capacity factor of approximately 11 %. New units from wind shapes from wind study.~~	~~Typical shape for location as per MARS and wind studies.~~
~~Non-NYPA Hydro Capacity Modeling~~	~~Pondage~~	~~N/A~~

~~Parameter~~	~~Modeling for CARIS Base Cases~~	~~Basis for Recommended Assumptions for CARIS~~
	~~Run of River(Hourly)~~	
~~Special Case Resources~~	~~Those sold for the program, discounted to historic availability and distributed according to zonal performance.~~ ~~Assume 15% growth rate for all zones. Modify load SCR/EOP to proportion available SCR by load amount by zone. See SCR determinations in Attachment G.~~	~~N/A~~
~~EDRP Resources~~	~~Those registered for the program, discounted to historic availability (45 % overall). July & August values calculated from 2008 July and August registrations.~~	~~Need to define costs associated, firm modifiers vs. price responsive.~~
~~External Capacity – Purchases~~	~~Based on NYISO forecast. Sensitivity performed to remove contracts and see the effect on LCR-IRM curve. Results should not impinge on IRM. Sensitivity with 20 MW MISO wheel through Ontario to Zone A).~~	~~N/A~~
~~Retirements~~	~~2008 Gold Book over ten year period~~	~~As per the CRP~~
~~Planned Outages~~	~~Per 2009 CRP, based on schedules received by NYISO & adjusted for history., constant over ten year period~~	~~As per the CRP~~
~~Outage Scheduling~~ ~~Planned~~	~~Continue with approximately 150 MW after reviewing last year's data.~~	~~As per the maintenance schedules in long term adequacy studies~~

~~Parameter~~	~~Modeling for CARIS Base Cases~~	~~Basis for Recommended Assumptions for CARIS~~
~~Gas Turbines Ambient Derate~~	~~Continue with approximately 150 MW after reviewing last year's data, constant over ten year period~~	~~Reflected only in summer/winter ratings~~
~~Environmental Modeling~~ ~~Adders~~ ~~Externalities~~ ~~Allowances~~	~~Studied as scenarios.~~ ~~Built into the development of cost curves of resources. Optimization is cost driven.~~	~~Any impacts assumed in CRP carried forward.~~ ~~Limits on emissions done through allowances, not hard limits~~ ~~Allowance cost from Chicago Climate Futures Exchange~~
~~Commitment and Dispatch Options~~ ~~Operating Reserves~~	~~Each Balancing Authority Commits separately~~ ~~Hurdle Rates are employed for commitment and dispatch~~ ~~Operating Reserves as per NYCA requirements~~	~~N/A~~
~~Fuel Price Forecast~~	~~EIA data obtained quarterly, adjusted for seasonality on monthly basis, monthly volatility based on historical patterns~~	~~NYISO to calibrate forecast based on public information and historical data~~
~~Cost Curve Development~~	~~Developed from Heat Rate Curve, Fuel Price forecast, environmental adders, penalty~~	~~Allowances from Chicago Climate~~

~~Parameter~~	~~Modeling for CARIS Base Cases~~	~~Basis for Recommended Assumptions for CARIS~~
	~~factors~~	~~Futures Exchange,~~ ~~Heat Rate development under discussion, confidential issues~~
~~Heat Rates~~ ~~NYCA~~ ~~External Systems~~	~~Developed from vendor supplied data and fuel input data matched with MWhr data for NYCA~~	
~~Local Reliability Rules~~	~~List and develop appropriate nomograms~~	~~Fuel burn restrictions, operating restrictions and exceptions, commitment/dispatch limits~~
~~Energy Storage~~ ~~Gilboa PSH~~ ~~Lewiston PSH~~	~~Gilboa and Lewiston scheduled against NYCA~~	~~N/A~~
~~Transmission System Model~~		
~~Power Flow Cases~~	~~As per CRP~~	~~N/A~~
~~Interface Limits~~ ~~Monitored/contingency pairs~~ ~~Nomograms~~	~~Transfer limit analysis done in RNA/CRP for critical interfaces. External system limits from input from neighboring systems.~~	~~Based on historical congestion, planning study results, NERC book of flowgates, PROBE/SCUC list of active/potential constraints, Special Protections Systems including Athens SPS~~

~~Parameter~~	~~Modeling for CARIS Base Cases~~	~~Basis for Recommended Assumptions for CARIS~~
~~Joint, Grouping~~ ~~Unit Sensitive Voltage~~		
~~New Transmission Capability~~	~~As per CRP~~	~~N/A~~
~~Internal Controllable Lines (PARs,DC,VFT)~~	~~Optimized in simulation~~	~~N/A~~
~~Neighboring Systems~~		
~~Outside World Area Models~~ ~~Fuel Forecast~~	~~Power flow data from CRP, "production" data developed by NYISO with vendor and neighbor input~~ ~~Linked with NYCA forecast~~	~~N/A~~
~~External Capacity~~ ~~Load Forecast~~	~~Firm and grandfathered are included.~~ ~~Neighboring systems data reviewed and held at required reserve margin~~	~~Neighboring systems modeled consistent with reserve margins in the RNA/CRP analysis~~
~~System representation in Simulation~~	~~HQ modeled as load/gen pair~~ ~~Full Representation/Participation~~ ~~-NYISO~~	~~N/A~~

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~~Parameter~~	~~Modeling for CARIS Base Cases~~	~~Basis for Recommended Assumptions for CARIS~~
	~~NE-ISO~~ ~~IESO~~ ~~PJM Classic &~~ ~~Full Representation: NYISO,NEISO,IESO,PJM (PJM Classic, AP,AEP,CE,DLCO,DAY,VP)~~ ~~Proxy Bus:~~ ~~HQ-NYISO, HQ-NEISO~~ ~~Transmission Only/Zeroed Out:~~ ~~MECS,FE,SPP, MAR, NIPS,OVEC,TVA, FRCC,SERC,ERCOT,WECC~~	
~~External Controllable Lines (PARs,DC,VFT, Radial lines)~~	~~A,B,C and J,K "wheel"~~ ~~Both sets set at 600 min, 1200 max, imbalance monitored~~ ~~Ramapo +/- 1000 MW~~ ~~Norwalk +/- 100 MW~~ ~~L33,34 - +/- 300 MW~~ ~~PV20 – 130, 0 MW~~ ~~Neptune and CSC as per CRP firm X 24 hrs, economy remainder~~	~~N/A~~

~~Below are descriptions of key data in more detail. The data was developed based on the OATT and in collaboration with stakeholders. Input assumptions based on the 2009 RNA/CRP~~

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~~C.1. Generic Solution Cost Matrix~~

~~A potential generic solution was determined by NYISO utilizing each resource type (generation, transmission, and demand response) as required in Tariff attachment Y Section 11.3c. The development of the generic solutions and their costs were accomplished by using a cost matrix methodology. This methodology was based on utilizing typical MW block size generic solutions, a standard set of assumptions and an order of magnitude costs for each resource type. The block sizes, assumptions and cost estimates were vetted through the stakeholder process at the ESPWG.~~

~~Order of magnitude unit pricing cost estimates were developed based on the block sizes and assumptions for each resource type. The NYISO utilized engineering consultants to develop order of magnitude cost estimates based on their experience in the industry and similar existing projects or programs currently being considered within NY. The order of magnitude cost estimates took into account the cost differences between geographical areas within NY. Three sets of costs were developed that are reflective of the differences in labor, land and permitting costs between Upstate, Downstate and Long Island.~~

~~All costs were reviewed by the Transmission Owners and Market Participants through the stakeholder process. As part of this process, ranges for the cost for each element were developed in order to address the wide variability that can occur in a project due to such items as permitting, right of way constraints and existing system conditions.~~

~~During the stakeholder review process, it was noted that the cost for new generation in Zone G may be more closely matched to the costs seen Downstate in (Zones H-I) versus costs seen in Upstate (Zones A-F). In reviewing the generation costs for various Zones that were prepared for the ICAP Deamnd Curve study reported in the~~ ~~*Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator*~~ ~~report, the costs for new generation in Zone G falls half way between~~

~~the costs for Zone F and Zone J. Therefore, in order to be consistent with the other resource types, it was decided that the generation costs for Zone G will be the same as the other Upstate Zones. If during the potential generic solution process, it is determine that a generator is to be installed in the southern portion of Zone G, then applying a complexity factor to the generator cost will be considered.~~

~~The Demand Response resource type costs were based on New York utility EEPS filings for their Demand Side Management programs which consider the potential market value and not actual costs to build or implement DSM. The NYISO will consider developing a customer installed cost approach in future CARIS analysis so that cost estimates for all resource types will be predicting actual cost to implement such a project.~~

~~Estimates included in the Potential Generic Solution Cost Matrix should not be utilized for purposes outside of the CARIS process. Also, these estimates should not be assumed as reflective or predictive of actual projects or imply that facilities can necessarily be built for these generic solution order of magnitude estimates.~~

~~**Generic Solutions Cost Matrix**~~

~~**Table C - 2: Transmission Cost Matrix**~~

~~**Base Case Modeling Assumptions for 2009-2018 CARIS Study Phase**~~

~~**Potential Generic Solution**~~

~~Transmission Cost Matrix~~

~~Order of Magnitude Unit Prices~~

~~(Estimates should not be assumed reflective or predictive of actual project costs)~~

_	_			~~Transmission~~			~~Substation~~	-
~~Item #~~	~~Location~~	~~Line System Voltage (kV)~~	~~Block Ampacity (Amp)~~	~~Block Capacity (MVA)~~	~~Construction Type~~	~~Transmission Cost ($M/Mile)~~	~~Line Terminal Addition per Substation ($M)~~	~~System Upgrade Facilities ($M)~~
~~T-1 High~~	~~Zone A-G~~	~~345~~	~~1673~~	~~1000~~	~~Overhead~~	~~$5.0~~	~~$9.0~~	~~$9.0~~
~~T-1 Mid~~	~~Zone A-G~~	~~345~~	~~1673~~	~~1000~~	~~Overhead~~	~~$3.5~~	~~$6.0~~	~~$6.0~~
~~T-1 Low~~	~~Zone A-G~~	~~345~~	~~1673~~	~~1000~~	~~Overhead~~	~~$2.0~~	~~$3.0~~	~~$3.0~~
~~T-2 High~~	~~Zone H-J~~	~~345~~	~~1673~~	~~1000~~	~~Undergrd~~	~~$25.0~~	~~$40.0~~	~~$50.0~~
~~T-2 Mid~~	~~Zone H-J~~	~~345~~	~~1673~~	~~1000~~	~~Undergrd~~	~~$20.0~~	~~$25.0~~	~~$30.0~~
~~T-2 Low~~	~~Zone H-J~~	~~345~~	~~1673~~	~~1000~~	~~Undergrd~~	~~$15.0~~	~~$10.0~~	~~$10.0~~
~~T-3 High~~	~~Zone K~~	~~138~~	~~2092~~	~~500~~	~~Undergrd~~	~~$20.0~~	~~$20.0~~	~~$25.0~~
~~T-3 Mid~~	~~Zone K~~	~~138~~	~~2092~~	~~500~~	~~Undergrd~~	~~$15.0~~	~~$12.0~~	~~$15.0~~

~~T-3 Low~~	~~Zone K~~	~~138~~	~~2092~~	~~500~~	~~Undergrd~~	~~$10.0~~	~~$4.0~~	~~$5.0~~

~~**Assumptions:**~~

~~**1. *Estimates herein should not be utilized for purposes outside of the CARIS process. Also, these estimates should not be assumed as reflective or predictive of actual projects or imply that facilities can necessarily be built for these generic solution order of magnitude estimates. Estimate ranges were identified after Transmission Owner input, a review of recent proposed transmission projects in NY, and reaching consensus at the ESPWG.***~~

~~**2. Lines constructed within Zones A through G will be comprised of single circuit AC overhead construction.**~~

~~**3. Lines constructed within Zones H through K will be comprised of AC underground cable construction.**~~

~~**4. The transmission line will be interconnected into an existing 345kV substation for Zones A-J and 138kV for Zone K.**~~

~~**5. The cost for lines that cross between Zones G and Zones H or I will be pro-rated as overhead or underground based on the mileage of the line included within each Zone.**~~

~~**6. The line can be permitted and constructed utilizing the shortest distance between the two selected substations.**~~

~~**7. The existing substation selected as the interconnection point consists of open air construction and has sufficient space within the fenced yard for adding a new breaker and a half bay for the new line terminal. If the selected substation is Gas-Insulated, a**~~

~~factor of 4 times will be applied to the base substation terminal costs.~~

~~8. The control house at the existing substations selected as the interconnection point has sufficient space for installing the new protection and communication equipment for the new line terminal.~~

~~9. Estimates include costs for material, construction labor, engineering labor, permits, testing and commissioning. The estimates do not include Allowance of Funds During Construction (AFDC)~~

~~10. The cost per mile includes a range to account for the variable land and permitting costs associated with a project such as utilizing an existing ROW, expanding an existing ROW or obtaining new ROW.~~

~~11. The substation line terminal costs include a range to account for necessary protection and communication equipment.~~

~~12. System Upgrade Facilities costs include a range to account for line terminal relay upgrades and replacement of overdutied breakers.~~

~~13. If upon a cursory review of the location for the potential solution identifies unusual complexities, a contingency factor will be applied to the costs included in the matrix. These complexities may include but are not limited to right of way restrictions, terrain and/or permitting difficulties, etc. Field inspections will not be completed as part of the cursory review.~~

~~**Table C - 3: Generation Cost Matrix**~~

~~Base Case Modeling Assumptions for 2009-2018 CARIS Study Phase~~

~~Potential Generic Solution~~

~~Generation Cost Matrix~~

~~Order of Magnitude Unit Costs~~

~~(Estimates should not be assumed reflective or predictive of actual project costs)~~

~~Item #~~	~~Plant Location~~	~~Plant Block Size Capacity (MW)~~	~~Plant Cost per Block Size ($M)~~	~~Electric Unit Transmission Cost ($M/Mile)~~	~~Substation Terminal Cost ($M)~~	~~System Upgrade Facilities ($M)~~	~~Gas Unit Transmission Cost ($M/Mile)~~	~~Gas Regulator Station Cost ($M)~~
~~G-1 High~~	~~Zone A-G~~	~~250~~	~~$400.0~~	~~$5.0~~	~~$9.0~~	~~$9.0~~	~~$5.0~~	~~$3.0~~
~~G-1 Mid~~	~~Zone A-G~~	~~250~~	~~$330.0~~	~~$3.5~~	~~$6.0~~	~~$6.0~~	~~$3.5~~	~~$2.0~~
~~G-1 Low~~	~~Zone A-G~~	~~250~~	~~$260.0~~	~~$2.0~~	~~$3.0~~	~~$3.0~~	~~$2.0~~	~~$1.0~~
~~G-2 High~~	~~Zone H-J~~	~~250~~	~~$480.0~~	~~$25.0~~	~~$40.0~~	~~$50.0~~	~~$20.0~~	~~$3.0~~
~~G-2 Mid~~	~~Zone H-J~~	~~250~~	~~$400.0~~	~~$20.0~~	~~$25.0~~	~~$30.0~~	~~$15.0~~	~~$2.0~~

~~G-2 Low~~	~~Zone H-J~~	~~250~~	~~$320.0~~	~~$15.0~~	~~$10.0~~	~~$10.0~~	~~$10.0~~	~~$1.0~~
~~G-3 High~~	~~Zone K~~	~~250~~	~~$470.0~~	~~$20.0~~	~~$20.0~~	~~$25.0~~	~~$5.0~~	~~$3.0~~
~~G-3 Mid~~	~~Zone K~~	~~250~~	~~$390.0~~	~~$15.0~~	~~$12.0~~	~~$15.0~~	~~$3.5~~	~~$2.0~~
~~G-3 Low~~	~~Zone K~~	~~250~~	~~$310.0~~	~~$10.0~~	~~$4.0~~	~~$5.0~~	~~$2.0~~	~~$1.0~~

~~Assumptions~~

~~**1.** ***Estimates herein should not be utilized for purposes outside of the CARIS process. Also, these estimates should not be assumed as reflective or predictive of actual projects or imply that facilities can necessarily be built for these generic solution order of magnitude estimates. Estimate ranges were identified after Transmission Owner input, a review of recent proposed generation projects in NY, and reaching consensus at the ESPWG.***~~

~~**2. It is assumed that the plant will be gas combined cycle type. Configured as a 2 x 1 7EA block with selective catalytic reduction (SCRs), total generation 250MW.**~~

~~**3. The plant cost includes real estate and permitting.**~~

~~**4. The plant cost includes generator step-up transformer and generator substation yard including associated protection and communication equipment.**~~

~~**5. The plant will be interconnected into an existing 345kV substation for Zones A-J and 138kV for Zone K.**~~

~~**6. The generator lead will be rated 345kV, 1673A, 1000MVA for Zones A-J and**~~

~~138kV, 2092A, 500MVA for Long Island. The generator lead will be built with overhead construction for Zones A-G and underground construction for Zones H-K.~~

~~7. It is assumed that the existing substation selected as the interconnection point consists of open-air construction and has sufficient space within the fenced yard for adding a new breaker and a half bay for the new line terminal. If the selected substation is gas-insulated, a factor of 4 times will be applied to the base substation terminal costs.~~

~~8. It is assumed that the plant will require a 10in dia. gas line extension to bring a 450 psig gas supply to the plant and a single gas regulator station per block along with gas conditioning, startup gas heaters and metering. It is assumed that an adequate gas supply is available.~~

~~9. It is assumed that the existing substation selected as the interconnection point and outgoing transmission lines has adequate rating to interconnect new generation.~~

~~10. It is assumed that the control house at the existing substation selected as the interconnection point has sufficient space for installing the new protection and communication equipment for the new line terminal.~~

~~11. It is assumed that the generator lead and gas line can be permitted and constructed utilizing the shortest distance.~~

~~12. It is assumed that the ROW is generally unobstructed and significant relocation of underground interferences is not required and that rock excavation is not required.~~

~~13. It is assumed that the ROW does not require mitigation of environmentally sensitive areas.~~

~~14. Estimates include costs for material, construction labor, engineering labor, permits, testing and commissioning. The estimates do not include Allowance of Funds During Construction (AFDC)~~

~~15. The plant cost includes a range to account for the variable land and permitting costs associate a project.~~

~~16. The cost per mile includes a range to account for the variable land and permitting costs associated with a project such as utilizing an existing ROW, expanding an existing ROW or obtaining new ROW.~~

~~17. The substation line terminal costs include a range to account for necessary protection and communication equipment.~~

~~18. System Upgrade Facilities costs include a range to account for line terminal relay upgrades and replacement of overdutied breakers.~~

~~19. The transmission and gas transmission unit cost will be applied during the study as necessary dependent on the location of the congestion location to be studied.~~

~~20. If upon a cursory review of the location for the potential solution identifies unusual complexities, a contingency factor will be applied to the costs included in the matrix. These complexities may include but are not limited to right of way restrictions, terrain and/or permitting difficulties, etc. Field inspections will not be completed as part of the cursory review.~~

~~**Table C - 4: GENERATOR COST PER UNIT - 2009 PRICE LEVEL**~~

~~GENERATOR COST PER UNIT - 2009 PRICE LEVEL~~										
~~-~~	~~DESCRIPTION~~	~~REFERENCE USED~~	~~MATL~~	~~LABOR~~		~~SUBTOTAL DIRECT COST~~	~~PROJECT INDIRECTS~~	~~LAND AND PERMITTING~~	~~TOTAL WITH PROJECT INDIRECTS~~	
~~-~~		~~-~~	~~M$~~	~~GENERIC M$~~	~~ADJUSTED FOR ZONE M$~~	~~M$~~	~~20%~~	~~M$~~	~~-~~	
~~UPSTATE~~	~~250 MW~~	~~GENERIC 2 X 2 X 1 7EA + SCR ($ 938/KW DIR)~~	~~$173.0~~	~~$61.5~~	~~$99.6~~	~~$272.6~~	~~$54.5~~	~~$0.2~~	~~$327.3~~	
~~DOWN STATE~~	~~250 MW~~	~~GENERIC 2 X 2 X 1 7EA + SCR ($ 938/KW DIR)~~	~~$173.0~~	~~$61.5~~	~~$150.0~~	~~$323.0~~	~~$64.6~~	~~$12.0~~	~~$399.6~~	
~~LONG ISLAND~~	~~250 MW~~	~~GENERIC 2 X 2 X 1 7EA + SCR ($ 938/KW DIR)~~	~~$173.0~~	~~$61.5~~	~~$149.2~~	~~$322.2~~	~~$64.4~~	~~$1.4~~	~~$388.0~~	

~~**Table C - 5: Demand Response Cost Matrix**~~

~~**Base Case Modeling Assumptions for 2009-2018 CARIS Study Phase**~~

~~Potential Generic Solution~~

~~Demand Response~~

~~Order of Magnitude Unit Costs~~

~~(Estimates should not be assumed reflective or predictive of actual project costs)~~

~~Item #~~	~~Demand Response Block Size (MW)~~	~~Portfolio Type~~	~~Location~~	~~Unit Cost ($M/MW)~~	~~Total Portfolio Cost ($M)~~
~~D-1 High~~	~~100~~	~~Energy Efficiency~~	~~Zone A-G~~	~~$4.2~~	~~$420~~
~~D-1 Mid~~	~~100~~	~~Energy Efficiency~~	~~Zone A-G~~	~~$2.8~~	~~$280~~
~~D-1 Low~~	~~100~~	~~Energy Efficiency~~	~~Zone A-G~~	~~$1.4~~	~~$140~~
~~D-2 High~~	~~100~~	~~Demand Response~~	~~Zone A-G~~	~~$1.6~~	~~$158~~
~~D-2 Mid~~	~~100~~	~~Demand Response~~	~~Zone A-G~~	~~$1.1~~	~~$105~~
~~D-2 Low~~	~~100~~	~~Demand Response~~	~~Zone A-G~~	~~$0.5~~	~~$53~~
~~D-3 High~~	~~100~~	~~Energy Efficiency~~	~~Zone H-J~~	~~$5.7~~	~~$570~~
~~D-3 Mid~~	~~100~~	~~Energy~~	~~Zone H-J~~	~~$3.8~~	~~$380~~

		~~Efficiency~~			
~~D-3 Low~~	~~100~~	~~Energy Efficiency~~	~~Zone H-J~~	~~$1.9~~	~~$190~~
~~D-4 High~~	~~100~~	~~Demand Response~~	~~Zone H-J~~	~~$2.1~~	~~$210~~
~~D-4 Mid~~	~~100~~	~~Demand Response~~	~~Zone H-J~~	~~$1.4~~	~~$140~~
~~D-4 Low~~	~~100~~	~~Demand Response~~	~~Zone H-J~~	~~$0.7~~	~~$70~~
~~D-5 High~~	~~100~~	~~Energy Efficiency~~	~~Zone K~~	~~$3.9~~	~~$390~~
~~D-5 Mid~~	~~100~~	~~Energy Efficiency~~	~~Zone K~~	~~$2.6~~	~~$260~~
~~D-5 Low~~	~~100~~	~~Energy Efficiency~~	~~Zone K~~	~~$1.3~~	~~$130~~
~~D-6 High~~	~~100~~	~~Demand Response~~	~~Zone K~~	~~$2.7~~	~~$270~~
~~D-6 Mid~~	~~100~~	~~Demand Response~~	~~Zone K~~	~~$1.8~~	~~$180~~
~~D-6 Low~~	~~100~~	~~Demand Response~~	~~Zone K~~	~~$0.9~~	~~$90~~

~~Assumptions~~

~~1. *Estimates herein should not be utilized for purposes outside of the CARIS process. Also, these estimates should not be assumed as reflective or predictive of actual projects or imply that facilities can necessarily be built for these generic solution order of magnitude estimates. Estimate ranges were identified after Transmission Owner input and reaching consensus at the ESPWG.*~~

~~**2. Costs are based on representative NY utilities' Demand Side Management filings.**~~

~~**3. Expected peak demand impact was used to scale the present value of the total portfolio budget to produce 100MW peak reduction.**~~

~~**4. Costs from each portfolio are based on 10 years of peak demand reduction.**~~

~~**5. Cost estimation is developed by dividing each year's cost by the peak demand reduction for that year and then calculating the present value of the $/MW over a 10 year period.**~~

~~**6. The range is derived from the utility filings as the "Low" and the "Mid" and "High" represents 2 and 3 times the "Low", respectively.**~~

~~**7. Due to a lack of Demand Response filing data for Upstate, it is assumed that the Upstate costs will be 75% of the Downstate costs. This is representative of the cost difference between to the Energy Efficiency programs for the two areas.**~~

~~Appendix D – CARIS Benchmarking~~

~~Benchmarking Process~~

~~Appendix E – 2009 Detail Analyses of CARIS Phase 1~~

~~E.1. Congestion Assessment – Historic and Projected~~

~~One of the features of a Locational Marginal Price (LMP) based market is the ability to identify grid locations that are difficult to serve with economic generation due to transmission bottlenecks (constraints) and quantify the cost of this congestion. The NYISO calculates and publishes LMP's with three components:~~

~~1.Energy component – Marginal electricity cost without the adjusted cost of congestion and losses.~~

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~~2.Congestion component – Cost of out-of merit generation dispatch relative to an assumed unconstrained reference point at Marcy substation.~~

~~3.Losses component – Cost for supplying the losses from the accessible marginal generators to the grid point in question.~~

~~The cost of congestion commonly reported is the simple sum of the day ahead market LMP congestion component times the amount of load being affected (positively or negatively) by congestion (later referred to as "congestion payments"). While this congestion cost is relatively simple to calculate, this value is generally felt to be an over-simplified and deceiving congestion impact metric because:~~

~~1.This calculation does not incorporate the effect of supply and demand response when congestion is removed.~~

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~~2.The congestion cost is relative to an assumed uncongested reference point. If this reference point is moved, the congestion cost is shifted to the LMP energy component. The congestion versus energy cost calculation becomes arbitrary depending on the reference point chosen.~~

~~To better measure the true cost of transmission congestion, analysis tools and protocols were developed by the NYISO. The fundamental idea is to calculate what the day-ahead hourly clearing prices would be if there were no~~

~~transmission constraints, using the same data and calculation approach as the NYISO Security Constrained Unit Commitment software (SCUC). The congestion cost then is the difference between the actual SCUC transmission constrained LMP's, loads, and bids, and the same calculation with all transmission constraints ignored. Annual cost is the sum of daily costs.~~

~~The reported numbers are the result of a simulation of the NYCA market using the hourly bids and network status actually used by NYISO to clear the day-ahead market. The simulation performs a security constrained unit commitment for the market "as it was", then removes all transmission constraints (other constraints such as desired net interchange (DNI), generator ramp rates and minimum run times are still enforced). Unit commitment and dispatch are then recalculated for this unconstrained scenario with no changes in bids from those actually submitted. The constrained and unconstrained results are compared to derive the cost of congestion. All calculations represent all market segments (e.g., fixed load, virtual load and generation, imports and exports), and actual hour-by-hour network status. The unconstrained scenario fixes the amount of virtual load and generation at their original MW levels.~~

~~The major differences between the historical and projected congestion values are:~~

~~a.Historical congestion values include virtual bidding and projected congestion values do not; and~~

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~~b.Historical congestion values include the impact of transmission outages and projected congestion values do not.~~

~~**Congestion Metrics**~~

~~To suit various needs for viewing the impact of congestion, four congestion metrics were developed. All metrics report the difference between a constrained and an unconstrained value.~~

~~1. Change in Production Cost – This is the primary congestion impact metric chosen for use by the NYISO Operating Committee. The calculation compares the total production cost, based on mitigated bids, with and without transmission constraints limiting the unit commitment and dispatch. This measures the economic inefficiency introduced by the existence of transmission bottlenecks. In a sense, this is the *societal cost* of transmission congestion. A positive number means that transmission congestion increased electricity production cost.~~

~~An advantage of this metric is that production cost will always decrease when constraints are removed. The direct objective of SCUC is to minimize bid production cost; LMP's are the result of the commitment and dispatch that result from achieving this objective under generating unit and transmission constrained conditions. Since SCUC does not directly attempt to minimize LMP's, relieving all or some of the constraints may or may not decrease the market based electricity cost to load. In LMP markets, the load in a location pays the marginal price of the supply at that location, not the bid price. The result of constraint relief in an LMP market depends on how much load is affected, where the load is, and the response of supply and demand as constraints are relieved.~~

~~2. Change in Congestion Payments – This calculation, the sum of the LMP congestion component times the load affected, ignores the energy cost change as constraints are removed. With no simulation truly required to arrive at this congestion impact metric (the congestion cost in an unconstrained market is 0), this is the *accounting cost* of congestion.~~

~~Congestion payments can be hedged with transmission congestion contracts (TCC's) resulting in the unhedged congestion numbers reported. For this analysis, it was assumed that all TCC's are owned by load and are available for hedging congestion payments. A positive number means congestion increases load cost.~~

~~3. Change in Generation Payments – In addition to the LMP payments to generation (or other supply sources such as virtual generation, or imports), generators are also paid a Bid Production Cost Guarantee (BPCG) and for Ancillary Services (AS). BPCG compensates generators that are committed for reliability despite the fact their bids are greater than the LMP at the generator location. This can happen if ramp rates, minimum run times or other limits force unit operation, which minimizes overall production cost, even including BPCG payments. A positive number means generation payments went up due to congestion.~~

~~4. Change in Load Payments – This metric is the opposite side of the generation payments calculation. The calculation uses simulation to include the local energy cost response when transmission constraints are removed. Where the first congestion metric measures efficiency, this metric determines how much more New York load actually pays due to congestion and the market design; that is, the *bills impact*. The load payments congestion impact includes the effect of all market segments that can change when transmission constraints are relieved. These segments are:~~

- ~~LMP Components: While the LMP congestion component will be pushed to zero when no transmission constraints exist, the unbottled generation will sell more energy at a slightly higher price (in accordance with the bid curves), albeit at a lower bid than the units put on out-of-merit in the transmission limited case. This results in a likely increase in the LMP energy component as the LMP congestion component decreases. The LMP loss component will also change depending on the location and prices of the generation unbottled when constraints are relieved. Ancillary service costs (e.g., reserves) also affect LMP's, as generators trade-off between selling ancillary services or energy.~~

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- ~~Load payments due to congestion are hedged with TCC's, leading to the reported unhedged load payment. In this analysis, it was assumed that all TCC's were credited to load. The TCC auction cost is ignored, as it is part of the Transmission Service Charge (TSC).~~

- ~~TCC shortfall – In the event of a TCC shortfall (or surplus), the load pays for the imbalance. As transmission constraints are relieved or removed the imbalance changes. While the shortfall may be compensated for elsewhere in the TSC, from a congestion impact perspective this is considered a load cost.~~

~~Although the NYISO OATT describes details of the allocation of shortfall by transmission owner, for this analysis shortfall is stated for the NYCA only.~~

~~Schedule 1 imbalances – In accordance with the NYISO OATT, imbalances of energy and loss payments are a component of the OATT defined Schedule 1 payments. Relieving or eliminating transmission constraints affects these payments, and is thus considered a congestion impact in this analysis. Like shortfall, this analysis states the Schedule 1 effect for the NYCA only. A positive number means congestion increases load payments.~~

~~The historic and projected congestion metrics are shown in Table E - 1 through Table E - 7.~~

~~Table E - 1: Historic and Projected Congestion Metrics (2004-2018)~~

~~YEAR~~	~~CARIS Metrics - DAM bid based[1] million$~~				~~NYCA Actual GWh~~		
	~~Load Payment~~	~~Generator Payment~~	~~Production Cost[2]~~	~~Congestion~~	~~Demand~~	~~Generation~~	~~Interchange~~
~~2004~~	~~10,059~~	~~8,615~~	~~N/A~~	~~831~~	~~160,211~~	~~147,171~~	~~13,040~~
~~2005~~	~~15,314~~	~~13,153~~	~~N/A~~	~~1,382~~	~~167,208~~	~~153,265~~	~~13,943~~
~~2006~~	~~11,969~~	~~10,241~~	~~N/A~~	~~1,541~~	~~162,237~~	~~148,359~~	~~13,878~~
~~2007~~	~~12,831~~	~~10,840~~	~~N/A~~	~~1,451~~	~~167,341~~	~~150,407~~	~~16,934~~
~~2008~~	~~15,485~~	~~12,178~~	~~N/A~~	~~2,540~~	~~165,613~~	~~144,619~~	~~20,994~~
-	~~PROJECTED~~				~~PROJECTED~~		

~~2009~~	~~7,409~~	~~6,772~~	~~4,206~~	~~118~~	~~168,128~~	~~158,034~~	~~10,094~~
~~2010~~	~~9,817~~	~~8,714~~	~~5,159~~	~~119~~	~~169,747~~	~~155,017~~	~~14,730~~
~~2011~~	~~10,046~~	~~8,894~~	~~5,309~~	~~128~~	~~170,954~~	~~155,679~~	~~15,274~~
~~2012~~	~~10,520~~	~~9,269~~	~~5,578~~	~~140~~	~~171,927~~	~~155,939~~	~~15,988~~
~~2013~~	~~10,760~~	~~9,471~~	~~5,739~~	~~94~~	~~173,156~~	~~156,723~~	~~16,433~~
~~2014~~	~~11,343~~	~~10,000~~	~~6,074~~	~~99~~	~~174,800~~	~~158,246~~	~~16,553~~
~~2015~~	~~11,786~~	~~10,333~~	~~6,361~~	~~113~~	~~176,177~~	~~158,513~~	~~17,664~~
~~2016~~	~~12,369~~	~~10,779~~	~~6,678~~	~~134~~	~~178,250~~	~~159,559~~	~~18,691~~
~~2017~~	~~12,910~~	~~11,222~~	~~7,041~~	~~154~~	~~179,283~~	~~160,061~~	~~19,222~~
~~2018~~	~~13,618~~	~~11,638~~	~~7,190~~	~~186~~	~~180,427~~	~~158,571~~	~~21,856~~

~~(1)~~ ~~Source: Annual Congestion Report~~

~~(2)~~ ~~Market Reports reports Bid Production Cost values, which are negative numbers caused by a high number of negative market bids (Nuclear Units and other Bilaterals)~~

~~Table E - 2: Historic Congestion Demand Payment (2004-2008) by Zone~~

~~Congestion Demand Payment m$~~		-	-	-	
-	~~Historical~~				
~~Area~~	~~2004~~	~~2005~~	~~2006~~	~~2007~~	~~2008~~

~~West~~	~~(0.66)~~	~~(4.93)~~	~~0.90~~	~~(14.10)~~	~~(25.15)~~
~~Genessee~~	~~0.52~~	~~(1.33)~~	~~1.62~~	~~(14.01)~~	~~(9.42)~~
~~Central~~	~~0.49~~	~~(1.18)~~	~~3.46~~	~~9.41~~	~~18.42~~
~~North~~	~~(0.03)~~	~~(1.12)~~	~~(0.15)~~	~~(0.25)~~	~~(1.75)~~
~~Mohawk Valley~~	~~0.10~~	~~(0.34)~~	~~2.14~~	~~4.57~~	~~9.84~~
~~Capital~~	~~7.48~~	~~19.31~~	~~27.20~~	~~73.75~~	~~143.40~~
~~Hudson Valley~~	~~4.87~~	~~19.94~~	~~54.40~~	~~86.86~~	~~175.45~~
~~Millwood~~	~~2.74~~	~~11.81~~	~~26.73~~	~~30.78~~	~~78.02~~
~~Dunwoodie~~	~~4.39~~	~~23.56~~	~~44.11~~	~~56.12~~	~~124.41~~
~~NYCity~~	~~581.84~~	~~808.65~~	~~672.90~~	~~700.03~~	~~1402.66~~
~~Long Island~~	~~229.47~~	~~507.96~~	~~708.16~~	~~517.93~~	~~624.44~~
~~Total~~	~~831.2~~	~~1,382.3~~	~~1,541.5~~	~~1,451.1~~	~~2,540.3~~

~~Historical Congestion Source: PROBE DAM quarterly reports~~

~~DAM data include Virtual bidding & Transmission planned outages~~

~~Projected Congestion Source: NYISO CARIS Base Cases~~

Table E - 3: Projected Congestion Demand Payment (2009-2018) by Zone

	Congestion Demand Payment m$								-	-
-	Projected									
Area	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
West	(12.64)	(15.37)	(15.71)	(17.29)	(24.33)	(22.25)	(23.64)	(26.59)	(29.25)	(34.21)
Genessee	(5.21)	(4.34)	(4.29)	(4.33)	(13.41)	(12.01)	(12.91)	(14.90)	(17.03)	(21.14)
Central	0.29	1.13	1.29	1.33	0.18	0.47	0.12	0.01	0.19	(0.55)
North	0.49	0.21	0.24	0.32	0.18	0.14	0.20	0.32	0.38	0.81
Mohawk Valley	0.93	0.69	0.80	0.89	0.57	0.64	0.69	0.81	0.98	1.04
Capital	6.92	5.74	6.91	8.47	6.07	6.82	8.39	10.87	13.97	16.86
Hudson Valley	9.90	8.06	9.77	11.03	8.73	9.09	10.45	12.66	15.23	18.92
Millwood	3.05	2.51	3.03	3.38	2.71	2.77	3.18	3.82	4.54	5.64
Dunwoodie	7.14	5.66	6.81	7.60	6.07	6.20	7.03	8.36	9.84	12.27
NYCity	66.41	45.39	49.93	56.43	43.18	46.63	57.42	69.52	82.54	103.38
Long Island	40.44	69.09	69.00	72.58	63.89	60.78	61.85	69.00	72.25	82.73
Total	117.7	118.8	127.8	140.4	93.8	99.3	112.8	133.9	153.6	185.7

~~Table E - 4: Historical Load Payment (2004-2008) by Zone~~

~~Load Payment m$~~	-	-	-	-	-
-			~~Historical~~		
~~Area~~	~~2004~~	~~2005~~	~~2006~~	~~2007~~	~~2008~~
~~West~~	~~855~~	~~1,196~~	~~868~~	~~983~~	~~1,061~~
~~Genessee~~	~~741~~	~~874~~	~~649~~	~~668~~	~~754~~
~~Central~~	~~717~~	~~1,097~~	~~779~~	~~928~~	~~1,060~~
~~North~~	~~288~~	~~473~~	~~351~~	~~413~~	~~474~~
~~Mohawk Valley~~	~~359~~	~~551~~	~~400~~	~~443~~	~~469~~
~~Capital~~	~~735~~	~~1,022~~	~~720~~	~~818~~	~~1,008~~
~~Hudson Valley~~	~~498~~	~~883~~	~~761~~	~~864~~	~~1,114~~
~~Millwood~~	~~207~~	~~344~~	~~252~~	~~263~~	~~385~~
~~Dunwoodie~~	~~452~~	~~544~~	~~442~~	~~494~~	~~706~~
~~NYCity~~	~~3,665~~	~~5,739~~	~~4,394~~	~~4,696~~	~~5,919~~
~~Long Island~~	~~1,540~~	~~2,591~~	~~2,353~~	~~2,261~~	~~2,535~~
~~Total~~	~~10,059~~	~~15,314~~	~~11,969~~	~~12,831~~	~~15,485~~

~~Historical Load Payment Source: PROBE DAM quarterly reports~~

~~DAM data include Virtual bidding & Transmission planned outages~~

~~Projected Congestion Source: NYISO CARIS Base Cases~~

~~**Table E - 5: Projected Load Payment (2009-2018) by Zone**~~

	Load Payment m$							-	-	-
-				Projected				-	-	-
Area	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
West	624	807	820	852	873	922	954	990	1,029	1,086
Genessee	404	534	541	563	570	606	630	657	686	719
Central	679	897	915	951	975	1,027	1,063	1,107	1,151	1,212
North	285	376	384	400	410	430	442	458	473	501
Mohawk Valley	309	415	424	442	451	474	490	509	528	544
Capital	506	670	685	720	737	776	807	846	889	942
Hudson Valley	492	655	674	705	720	759	787	824	863	911
Millwood	123	164	169	177	182	191	198	207	217	230
Dunwoodie	298	394	404	420	428	446	460	479	500	528

~~NYCity~~	~~2,593~~	~~3,441~~	~~3,545~~	~~3,746~~	~~3,858~~	~~4,098~~	~~4,291~~	~~4,550~~	~~4,762~~	~~5,043~~
~~Long Island~~	~~1,096~~	~~1,464~~	~~1,486~~	~~1,546~~	~~1,556~~	~~1,616~~	~~1,663~~	~~1,743~~	~~1,811~~	~~1,902~~
~~Total~~	~~7,409~~	~~9,817~~	~~10,046~~	~~10,520~~	~~10,760~~	~~11,343~~	~~11,786~~	~~12,369~~	~~12,910~~	~~13,618~~

~~Table E - 6: Historical Generator Payment (2004-2008)~~

~~Generator Payment m$~~	-	-	-	-
-	~~Historical~~			
~~Area~~	~~2004~~	~~2005~~	~~2006~~	~~2007~~	~~2008~~
~~West~~	~~1,356~~	~~1,971~~	~~1,530~~	~~1,630~~	~~1,701~~
~~Genessee~~	~~314~~	~~435~~	~~418~~	~~491~~	~~476~~
~~Central~~	~~1,493~~	~~2,282~~	~~1,612~~	~~1,753~~	~~1,825~~
~~North~~	~~543~~	~~760~~	~~633~~	~~659~~	~~779~~
~~Mohawk Valley~~	~~150~~	~~336~~	~~230~~	~~206~~	~~234~~
~~Capital~~	~~415~~	~~747~~	~~704~~	~~883~~	~~1,175~~
~~Hudson Valley~~	~~1,093~~	~~1,174~~	~~533~~	~~571~~	~~532~~
~~Millwood~~	~~900~~	~~1,371~~	~~1,145~~	~~1,252~~	~~1,725~~
~~Dunwoodie~~	~~22~~	~~88~~	~~56~~	~~39~~	~~39~~
~~NYCity~~	~~1,291~~	~~2,308~~	~~1,895~~	~~2,072~~	~~2,405~~

~~Long Island~~	~~1,036~~	~~1,682~~	~~1,485~~	~~1,282~~	~~1,286~~
~~Total~~	~~8,615~~	~~13,153~~	~~10,241~~	~~10,840~~	~~12,178~~

~~Historical Generator Payment Source: PROBE DAM quarterly reports~~

~~DAM data include Virtual bidding & Transmission planned outages~~

~~Projected Congestion Source: NYISO CARIS Base Cases~~

~~Table E - 7: Projected Generator Payment (2009-2018) by Zone~~

	~~Generator Payment m$~~							~~-~~	~~-~~	~~-~~
~~-~~	~~Projected~~									
~~Area~~	~~2009~~	~~2010~~	~~2011~~	~~2012~~	~~2013~~	~~2014~~	~~2015~~	~~2016~~	~~2017~~	~~2018~~
~~West~~	~~1,000~~	~~1,324~~	~~1,343~~	~~1,396~~	~~1,419~~	~~1,495~~	~~1,543~~	~~1,596~~	~~1,653~~	~~1,736~~
~~Genessee~~	~~191~~	~~250~~	~~255~~	~~265~~	~~266~~	~~280~~	~~289~~	~~300~~	~~308~~	~~310~~
~~Central~~	~~1,346~~	~~1,722~~	~~1,750~~	~~1,823~~	~~1,868~~	~~1,965~~	~~2,025~~	~~2,100~~	~~2,181~~	~~2,280~~
~~North~~	~~363~~	~~476~~	~~485~~	~~505~~	~~520~~	~~550~~	~~570~~	~~591~~	~~622~~	~~635~~
~~Mohawk Valley~~	~~146~~	~~191~~	~~194~~	~~203~~	~~207~~	~~217~~	~~226~~	~~235~~	~~243~~	~~257~~

~~Capital~~	~~716~~	~~1,000~~	~~1,017~~	~~1,063~~	~~1,086~~	~~1,143~~	~~1,178~~	~~1,232~~	~~1,277~~	~~1,330~~
~~Hudson Valley~~	~~198~~	~~283~~	~~291~~	~~309~~	~~312~~	~~333~~	~~342~~	~~362~~	~~386~~	~~388~~
~~Millwood~~	~~777~~	~~1,017~~	~~1,035~~	~~1,082~~	~~1,094~~	~~1,142~~	~~1,176~~	~~1,224~~	~~1,268~~	~~1,335~~
~~Dunwoodie~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~NYCity~~	~~1,482~~	~~1,709~~	~~1,761~~	~~1,834~~	~~1,900~~	~~2,029~~	~~2,121~~	~~2,239~~	~~2,342~~	~~2,457~~
~~Long Island~~	~~552~~	~~743~~	~~764~~	~~790~~	~~798~~	~~845~~	~~864~~	~~900~~	~~942~~	~~911~~
~~Total~~	~~6,772~~	~~8,714~~	~~8,894~~	~~9,269~~	~~9,471~~	~~10,000~~	~~10,333~~	~~10,779~~	~~11,222~~	~~11,638~~

~~E.2. Selection of three studies~~

~~E.3. Potential Generic Solutions~~

~~E.4. Benefit/Cost Analysis (including additional metrics)~~

~~Disclaimers~~

- ~~No verification has been completed to determine if the generic solution can be built within the generic cost estimate ranges.~~

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- ~~The generic solutions analysis is performed to provide a rough estimate of the benefit to cost opportunity.~~

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- ~~The NYISO does not guarantee that the benefit to cost ratio determined for the generic solutions can be achieved.~~

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~~E.4.1. Primary Metric Results~~

~~E.4.2. Additional Metrics Results~~

~~E5. Scenario Analysis~~

~~**Appendix F – CARIS Manual (link)**~~

~~**http://www.nyiso.com/public/webdocs/services/planning/initial_caris_manual_bic_approved/CARISmanual.pdf**~~

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~~Appendix G - 2009 RNA and CRP Reports (link)~~

~~The 2009 RNA and CRP reports can be found through the following links:~~

~~http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/RNA_2009_Final_1_13_09.pdf~~

~~http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/CRP__FINAL_5-19-09.pdf~~

TERM	DEFINITION
Ancillary Services	Services necessary to support the transmission of Energy from Generators to Loads, while maintaining reliable operation of the NYS Power System in accordance with Good Utility Practice and Reliability Rules. Ancillary Services include Scheduling, System Control and Dispatch Service; Reactive Supply and Voltage Support Service (or "Voltage Support Service"); Regulation Service; Energy Imbalance Service; Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves); and Black Start Capability. [FROM SERVICES TARIFF]
Bid Production Cost	Total cost of the Generators required to meet Load and reliability Constraints based upon Bids corresponding to the usual measures of Generator production cost (e.g., running cost, Minimum Generation Bid, and Start Up Bid). [FROM SERVICES TARIFF]
Bulk Power Transmission Facility (BPTF)	Transmission facilities that are system elements of the bulk power system which is the interconnected electrical system within northeastern North America comprised of system elements on which faults or disturbances can have a significant adverse impact outside of the local area.
Business Issues Committee (BIC)	A NYISO committee that is charged with, among other things, the responsibility to establish procedures related to the efficient and non-discriminatory operation of the electricity markets centrally coordinated by the NYISO, including procedures related to bidding, Settlements and the calculation of market prices.
Capacity	The capability to generate or transmit electrical power, or the ability to reduce demand at the direction of the NYISO.

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TERM	DEFINITION
Chicago Climate Futures Exchange (CCFE)	A landmark derivatives exchange that offers standardized and cleared futures and options contracts on emission allowances and other environmental products.
Clean Air Markets Division (CAMD)	A division of the US Environmental Protection Agency responsible for various market-based regulatory programs that are designed to improve air quality by reducing outdoor concentrations of fine particles, sulfur dioxide, nitrogen oxides, and mercury.
Comprehensive Reliability Plan (CRP)	An annual study undertaken by the NYISO that evaluates projects offered to meet New York's future electric power needs, as identified in the Reliability Needs Assessment (RNA). The CRP may trigger electric utilities to pursue regulated solutions to meet Reliability Needs if market-based solutions will not be available by that point. It is the second step in the Comprehensive Reliability Planning Process (CRPP)
Comprehensive Reliability Planning Process (CRPP)	The annual process that evaluates resource adequacy and transmission system security of the state's bulk electricity grid over a 10-year period and evaluates solutions to meet those needs. The CRPP consists of two studies: the RNA, which identifies potential problems, and the CRP, which evaluates specific solutions to those problems.
Comprehensive System Planning Process (CSPP)	A transmission system planning process that is comprised of three components: 1) Local transmission planning; 2) Compilation of local plans into the Comprehensive Reliability Planning Process (CRPP), which includes developing a Comprehensive Reliability Plan (CRP); 3) Channeling the CRP data into the Congestion Assessment and Resource Integration Study (CARIS)
Congestion	Transmission paths that are constrained, which may limit power transactions because of insufficient capability.
Congestion Rent	The opportunity costs of transmission Constraints on the NYS Transmission System. Congestion Rents are collected by the NYISO from Loads through its facilitation of LBMP Market Transactions and the collection of Transmission Usage Charges from Bilateral Transactions.
Contingencies	Electrical system events (including disturbances and equipment failures) that are likely to happen.
Day Ahead Market (DAM)	A NYISO-administered wholesale electricity market in which capacity, electricity, and/or Ancillary Services are auctioned and scheduled one day prior to use. The DAM sets prices as of 11 a.m. the day before the day these products are bought and sold, based on generation and energy transaction bids offered in advance to the NYISO. More than 90% of energy transactions occur in the DAM.
DC tie-lines	A high voltage transmission line that uses direct current for the bulk transmission of electrical power between two control areas. [?]
Demand Response	A mechanism used to encourage consumers to reduce their electricity use during a specified period, thereby reducing the peak demand for electricity.
Eastern Interconnection Planning Collaborative	A group of planning authorities convened to establish processes for aggregating the modeling and regional transmission plans of the entire

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TERM	DEFINITION
(EIPC)	Eastern Interconnection and for performing inter-regional analyses to identify potential opportunities for efficiencies between regions in serving the needs of electrical customers.
Economic Dispatch of Generation	The operation of generation facilities to produce energy at the lowest cost to reliably serve consumers.
Electric System Planning Working Group (ESPWG)	A NYISO governance working group for Market Participants designated to fulfill the planning functions assigned to it. The ESPWG is a working group that provides a forum for stakeholders and Market Participants to provide input into the NYISO's Comprehensive Reliability Planning Process (CRPP), the NYISO's response to FERC reliability-related Orders and other directives, other system planning activities, policies regarding cost allocation and recovery for reliability projects, and related matters.
Energy Efficiency Portfolio Standard (EEPS)	A statewide program ordered by the NYSPSC in response to the Governor's call to reduce New Yorkers' electricity usage by15% of forecast levels by the year 2015, with comparable results in natural gas conservation. Also known as 15x15.
Exports	A Bilateral Transaction or purchases from the LBMP Market where the Energy is delivered to a NYCA Interconnection with another Control Area. [FROM SERVICES TARIFF]
External Areas	Neighboring Control Areas including HQ, ISO-NE, PJM, IESO
Federal Energy Regulatory Commission (FERC)	The federal energy regulatory agency within the US Department of Energy that approves the NYISO's tariffs and regulates its operation of the bulk electricity grid, wholesale power markets, and planning and interconnection processes.
FERC Form 715	An annual transmission planning and evaluation report required by the FERC – filed by the NYISO on behalf of the transmitting utilities in New York State.
FERC Order No. 890	Adopted by FERC in February 2007, Order 890 is a change to FERC's 1996 open access regulations (established in Orders 888 and 889). Order 890 is intended to provide for more effective competition, transparency and planning in wholesale electricity markets and transmission grid operations, as well as to strengthen the Open Access Transmission Tariff (OATT) with regard to non-discriminatory transmission service. Order 890 requires Transmission Providers – including the NYISO – have a formal planning process that provides for a coordinated transmission planning process, including reliability and economic planning studies.
Grandfathered Rights	The transmission rights associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party Transmission Wheeling Agreements ("TWA") where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided in the Tariff, to retain those rights rather than to convert those rights to TCCs. [FROM SERVICES TARIFF]
Grandfathered TCCs	The TCCs associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling

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TERM	DEFINITION
	provisions; and (3) Third Party TWAs where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided by the Tariff, to convert those rights to TCCs. [FROM SERVICES TARIFF]
Grid View Software	An analytic tool for market simulation and asset performance evaluations.
Heat Rate	A measurement used to calculate how efficiently a generator uses heat energy. It is expressed as the number of BTUs of heat required to produce a kilowatt-hour of energy. Operators of generating facilities can make reasonably accurate estimates of the amount of heat energy a given quantity of any type of fuel, so when this is compared to the actual energy produced by the generator, the resulting figure tells how efficiently the generator converts that fuel into electrical energy.
High Voltage Direct Current (HVDC)	A transmission line that uses direct current for the bulk transmission of electrical power, in contrast with the more common alternating current systems. For long-distance distribution, HVDC systems are less expensive and suffer lower electrical losses.
Hurdle Rate	The minimum acceptable rate of return.
Imports	A Bilateral Transaction or sale to the LBMP Market where Energy is delivered to a NYCA Interconnection from another Control Area.
Independent Market Advisor	Person, persons or consulting firm retained by the NYISO Board pursuant to Article 4 of the NYISO's Market Monitoring Plan.
Independent System Operator (ISO)	An organization, formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), which coordinates, controls and monitors the operation of the electrical power system, usually within a single US State, but sometimes encompassing multiple states.
Installed Capacity (ICAP)	A generator or load facility that complies with the requirements in the Reliability Rules and is capable of supplying and/or reducing the demand for energy in the NYCA for the purpose of ensuring that sufficient energy and capacity are available to meet the Reliability Rules.
Installed Reserve Margin (IRM)	The amount of installed electric generation capacity above 100% of the forecasted peak electric consumption that is required to meet New York State Reliability Council (NYSRC) resource adequacy criteria. Most planners consider a 15-20% reserve margin essential for good reliability.
Load	A term that refers to either a consumer of Energy or the amount of demand (MW) or Energy (MWh) consumed by certain consumers. [FROM SERVICES TARIFF]
Locational Capacity Requirement (LCR)	Zone K and Zone J
Load Serving Entity (LSE)	Any entity, including a municipal electric system and an electric cooperative, authorized or required by law, regulatory authorization or requirement, agreement, or contractual obligation to supply Energy, Capacity and/or Ancillary Services to retail customers located within

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TERM	DEFINITION
	the NYCA, including an entity that takes service directly from the NYISO to supply its own Load in the NYCA. [FROM SERVICES TARIFF]
Load Zones	The eleven regions in the NYCA connected to each other by identified transmission interfaces. Designated as Load Zones A-K.
Local Transmission Planning Process (LTPP)	The first step in the Comprehensive System Planning Process (CSPP), under which stakeholders in New York's electricity markets participate in local transmission planning.
Locational Based Marginal Pricing (LBMP)	The price of Energy at each location in the NYS Transmission System.
MAPS Software	An analytic tool for market simulation and asset performance evaluations.
Market Based Solution	Investor-proposed projects that are driven by market needs to meet future reliability requirements of the bulk electricity grid as outlined in the RNA. Those solutions can include generation, transmission and Demand Response Programs.
Market Participant	An entity, excluding the NYISO, that produces, transmits sells, and/or purchases for resale capacity, energy and ancillary services in the wholesale market. Market Participants include: customers under the NYISO's tariffs, power exchanges, TOs, primary holders, load serving entities, generating companies and other suppliers, and entities buying or selling transmission congestion contracts.
New York Control Area (NYCA)	The area under the electrical control of the NYISO. It includes the entire state of New York, and is divided into 11 zones.
New York Independent System Operator (NYISO)	Formed in 1997 and commencing operations in 1999, the NYISO is a not-for-profit organization that manages New York's bulk electricity grid – a 10,775-mile network of high voltage lines that carry electricity throughout the state. The NYISO also oversees the state's wholesale electricity markets. The organization is governed by an independent Board of Directors and a governance structure made up of committees with Market Participants and stakeholders as members.
New York State Energy Planning Board (SEPB)	Established by New York's governor in April 2008 to create a state energy plan (SEP) that examines and lays out goals addressing all aspects of New York's energy use and conservation.
New York State Reliability Council (NYSRC)	A not-for-profit entity whose mission is to promote and preserve the reliability of electric service on the New York State Power System by developing, maintaining, and, from time-to-time, updating the Reliability Rules which shall be complied with by the New York Independent System Operator ("NYISO") and all entities engaging in electric transmission, ancillary services, energy and power transactions on the New York State Power System.
Nomogram	A graphical calculating device - a two-dimensional diagram designed to allow the approximate graphical computation of a function: it uses a coordinate system other than Cartesian coordinates. Like a slide rule, it is a graphical analog computation device; and, like the slide rule, its accuracy is limited by the precision with which physical markings can be drawn, reproduced, viewed, and aligned. Most nomograms are used in applications where an approximate answer is appropriate and

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TERM	DEFINITION
	useful. Otherwise, the nomogram may be used to check an answer obtained from an exact calculation method. [FROM WIKIPEDIA]
Northeast Coordinated System Planning Protocol (NCSPP)	ISO New England, PJM and the NYISO work together under the Northeast Coordinated System Planning Protocol (NCSPP), to analyze cross-border issues and produce a regional electric reliability plan for the northeastern United States.
NYISO Governance Process	A shared governance process by which representatives from stakeholder groups discuss debate and vote on issues directly affecting the NYISO's operations, reliability and markets. The three committees – Management, Operating and Business Issues – are supported by several subcommittees, which are made up of individuals from five major sectors of the marketplace: Transmission Owners, Generation Owners, Other Suppliers, End-Use Consumers, and Public Power and Environmental Parties.
Operating Reserves	Capacity that is available to supply Energy or reduce demand and that meets the requirements of the NYISO. [SERVICES TARIFF TERM]
Phase Angle Regulator (PAR)	Device that controls the flow of electric power in order to increase the efficiency of the transmission system.
Plan NYC	New York City goal, announced by Mayor Michael R. Bloomberg in 2007, of reducing its citywide carbon emissions by 30% below 2005 levels by 2030.
Proxy Generator Bus	A proxy bus located outside the NYCA that is selected by the NYISO to represent a typical bus in an adjacent Control Area and for which LBMP prices are calculated. The NYISO may establish more than one Proxy Generator Bus at a particular Interface with a neighboring Control Area to enable the NYISO to distinguish the bidding, treatment and pricing of products and services at the Interface.
Regional Greenhouse Gas Initiative (RGGI)	A cooperative effort by ten Northeast and Mid-Atlantic states to limit greenhouse gas emissions using a market-based cap-and-trade approach.
Regional Transmission Operator (RTO)	An organization that is responsible for moving electricity over large interstate areas. They schedule the use of transmission lines; manage the interconnection of new generation and monitor the markets
Regulated Backstop Solution	Proposals required of certain TOs to meet Reliability Needs as outlined in the RNA. Those solutions can include generation, transmission or Demand Response. Non-Transmission Owner developers may also submit regulated solutions. The NYISO may call for a Gap solution if neither market-based nor regulated backstop solutions meet Reliability Needs in a timely manner. To the extent possible, the Gap solution should be temporary and strive to ensure that market-based solutions will not be economically harmed. The NYISO is responsible for evaluating all solutions to determine if they will meet identified Reliability Needs in a timely manner.
Regulation Service	An Ancillary Service. See glossary definition for Ancillary Services.
Reliability Need	A condition identified by the NYISO in the RNA as a violation or potential violation of Reliability Criteria. (OATT TERM)

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TERM	DEFINITION
Reliability Needs Assessment (RNA)	An annual report that evaluates resource adequacy and transmission system security over a 10-year planning horizon, and identifies future needs of the New York electric grid. It is the first step in the NYISO's CRPP.
Responsible Transmission Owner (Responsible TO)	The Transmission Owner or TOs designated by the NYISO, pursuant to the NYISO Planning Process, to prepare a proposal for a regulated solution to a Reliability Need or to proceed with a regulated solution to a Reliability Need. The Responsible TO will normally be the Transmission Owner in whose Transmission District the NYISO identifies a Reliability Need.
Security Constrained Unit Commitment (SCUC)	A process developed by the NYISO, which uses a computer algorithm to dispatch sufficient resources, at the lowest possible Bid Production Cost, to maintain safe and reliable operation of the NYS Power System.
Smart Grid	A combination of transmission/distribution and communications technologies that enables the routing of power in optimal ways to respond to a wide range of conditions
Special Case Resource (SCR)	A NYISO Demand Response program designed to reduce power usage by businesses and large power users qualified to participate in the NYISO's ICAP market. Companies that sign up as SCRs are paid in advance for agreeing to cut power upon NYISO request.
Stakeholders	A person or group that has an investment or interest in the functionality of New York's transmission grid and markets.
Thermal transfer limit	The maximum amount of heat a transmission line can withstand. The maximum reliable capacity of each line, due to system stability considerations, may be less than the physical or thermal limit of the line.
Transfer Capability	The amount of electricity that can flow on a transmission line at any given instant, respecting facility rating and reliability rules.
Transmission Congestion Contract (TCC)	The right to collect, or obligation to pay, Congestion Rents in the Day Ahead Market for Energy associated with a single MW of transmission between a specified Point Of Injection and Point Of Withdrawal. TCCs are financial instruments that enable Energy buyers and sellers to hedge fluctuations in the price of transmission. (SERVICES TARIFF TERM)
Transmission Constraint	Limitations on the ability of a transmission facility to transfer electricity during normal or emergency system conditions.
Transmission District	The geographic area served by the Investor Owned Transmission Owners and LIPA, as well as the customers directly interconnected with the transmission facilities of the Power Authority of the State of New York. (SERVICES TARIFF TERM)
Transmission Interface	A defined set of transmission facilities that separate Load Zones and that separate the NYCA from adjacent Control Areas. (SERVICES TARIFF TERM)
Transmission Line Losses	Power consumed by the delivery system from electric current overcoming the resistance of the wires, transformers and other components of the power system that result in power being converted

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TERM	DEFINITION
	into heat.
Transmission Owner (TO)	A public utility or authority that provides Transmission Service under the Tariff
Transmission Planning Advisory Subcommittee (TPAS)	A group of Market Participants that advises the NYISO Operating Committee and provides support to the NYISO Staff in regard to transmission planning matters including transmission system reliability, expansion, and interconnection.
Wheels Through	Transmission Service, originating in another Control Area that is wheeled through the NYCA to another Control Area. [SERVICES TARIFF TERM]
Working Groups	Groups comprised of NYISO stakeholders, convened to address transmission system and market issues under the NYISO governance system.

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