LIPA Generation Planning Review

Caithness Long Island II, and
E.F. Barrett and Port Jefferson Repowerings

PREPARED FOR

Long Island Power Authority

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Redacted Version

This report was prepared for Long Island Power Authority under the contract management of the New York Power Authority. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group as a whole or its clients.

Commercially sensitive information has been redacted from this report.

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Contents

I. Executive Summary

This report provides an assessment of the resource planning criteria, methods and assumptions, and results of studies conducted by or on behalf of the Long Island Power Authority (LIPA) with primary focus on the current reliability and expected economic impacts of the Caithness Long Island II (CLI-II) combined cycle plant as well as the E. F. Barrett and Port Jefferson repowering projects. The Brattle Group did not perform any independent modeling for this study, but instead reviewed and evaluated the latest Integrated Resource Plan (IRP) and prior LIPA and PSEG Long Island (PSLI) studies to compare them to the authors' own beliefs and experience about best practices and reasonable assumptions.

Historically, Long Island has had to plan for more severe reliability risks than the rest of New York due to its geography and limited interconnection to adjacent power markets. In essence, it has had to worry about being more "self-insured" than other regions. This was especially true for the first decade or so after LIPA acquired LILCo, when the New York Independent System Operator (NYISO) was also new and its practices and market structures had not matured. Accordingly, beginning in the early 2000's, LIPA applied more conservative reliability tests than other New York regions. These more conservative criteria were applied in the needs analysis that, in part, formed the basis for its capacity solicitation (RFP) in 2010. CLI-II was a respondent to the 2010 RFP, and one of its proposals was selected for further consideration. On January 1, 2014 PSLI became responsible for managing LIPA's transmission and distribution assets, and in anticipation of PSLI assuming responsibility for power supply planning on January 1, 2015 LIPA requested PSLI to reassess the need for CLI-II. PSLI's study of reliability standards and resource adequacy indicated that there was no longer a need for more conservative island-specific reliability standards and no apparent capacity need for CLI-II. Accordingly, PSLI recommended that any contracting considerations with CLI-II or other plants be deferred until after a full assessment as part of the upcoming IRP. The analyses in that study find no need for additional capacity until at least 2030[1], and no economic savings from CLI-II or from the possible repowering projects of Barrett or Port Jefferson.

Our assessment is that these studies have reached the right conclusions. Specifically, as explained herein, PSLI's recommendation that LIPA defer consideration of CLI-II for further study was reasonable and appropriate. In fact, it now appears that none of the possible projects under consideration are needed for reliability reasons over the coming decade, nor would they be expected to provide net economic savings during that time. There is also now ample depth of supply on Long Island to meet near term needs, as well as a possibility of longer term economic and regulatory changes towards market conditions that may be even less auspicious for these plants.

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1 The first year when additional capacity is needed is identified as 2030 based on the 2016 load forecast used in the study and 2035 based on a more recent 2017 load forecast.

We focus our analysis on a detailed decomposition of what happens to system costs for LIPA customers with and without the proposed projects in 2025, an indicative year of the ten-year period of primary interest in the IRP. By 2025, CLI-II and the two repowering projects are installed in their respective scenarios (Construction Scenarios), but there are no additional changes to other long run generation resources by then in any of the scenarios. By 2030 and thereafter, generic capacity additions are added to the Reference and Construction Scenarios for resource adequacy, and these affect the system costs. (There may be such impacts because of CLI-II or the repowering projects deferring distant future capacity needs or achieving operating cost savings in those out-years. But for reasons explained below, we regard such savings as too speculative to merit consideration in the current review of the need for any of these plants). Our analysis of 2025 shows that CLI-II would increase that year's costs by about $238 million, while Barrett repowering would increase costs around $71 million, and Port Jefferson would increase costs by about $59 million. 20-year present value calculations in the IRP analysis confirm that all three would increase overall costs, by several hundred million dollars or more.

This lack of benefits is consistent with the dramatic and unexpected shift in power market conditions nearly everywhere in the US towards extremely low load growth and declining wholesale energy and capacity prices since around 2010. The shift is largely due to a renaissance in natural gas production from plentiful and inexpensive shale gas sources, many of which are quite close to New York, and to a lesser extent to mandated entry by renewable resources and the increase in energy efficiency standards. Since the early 2000's Long Island has increased its connection to adjacent power markets through new transmission lines, and market mechanisms in NYISO have stabilized, so now LIPA can conduct its reliability planning process with increased certainty. These changes make it appropriate for LIPA to use the NYISO IRM and LCR requirements for capacity adequacy as its planning criteria.

Furthermore, there are uncertain, but directionally likely, market changes forthcoming in NY due to its ambitious policies for encouraging renewable energy (the Clean Energy Standard, NY City's 80-by-50 aspirations, and a goal to install 2,400 MW of offshore wind, with a significant portion of it likely to be brought onshore in Long Island) and for modernizing distribution-level power delivery and energy management (under the NY REV). The initiatives will tend to reduce the need for additional baseload capacity and to reduce both energy and capacity wholesale power prices. They also have the potential to reduce load growth even further, and increase the need for small, very flexible peakers and power supply resources that can rapidly supply ancillary services to integrate such non-conventional (often intermittent and non-dispatchable) supply. Given the significant uncertainty in the pace and eventual success of pursuing these policies, as well as uncertainties regarding long run conditions and no pressing current need, it is prudent for LIPA to wait and see what type and timing of long-lived resources, if any, will be needed. It would be imprudent to commit to a large, irreversible investment in assets that may not suit the eventual market conditions.

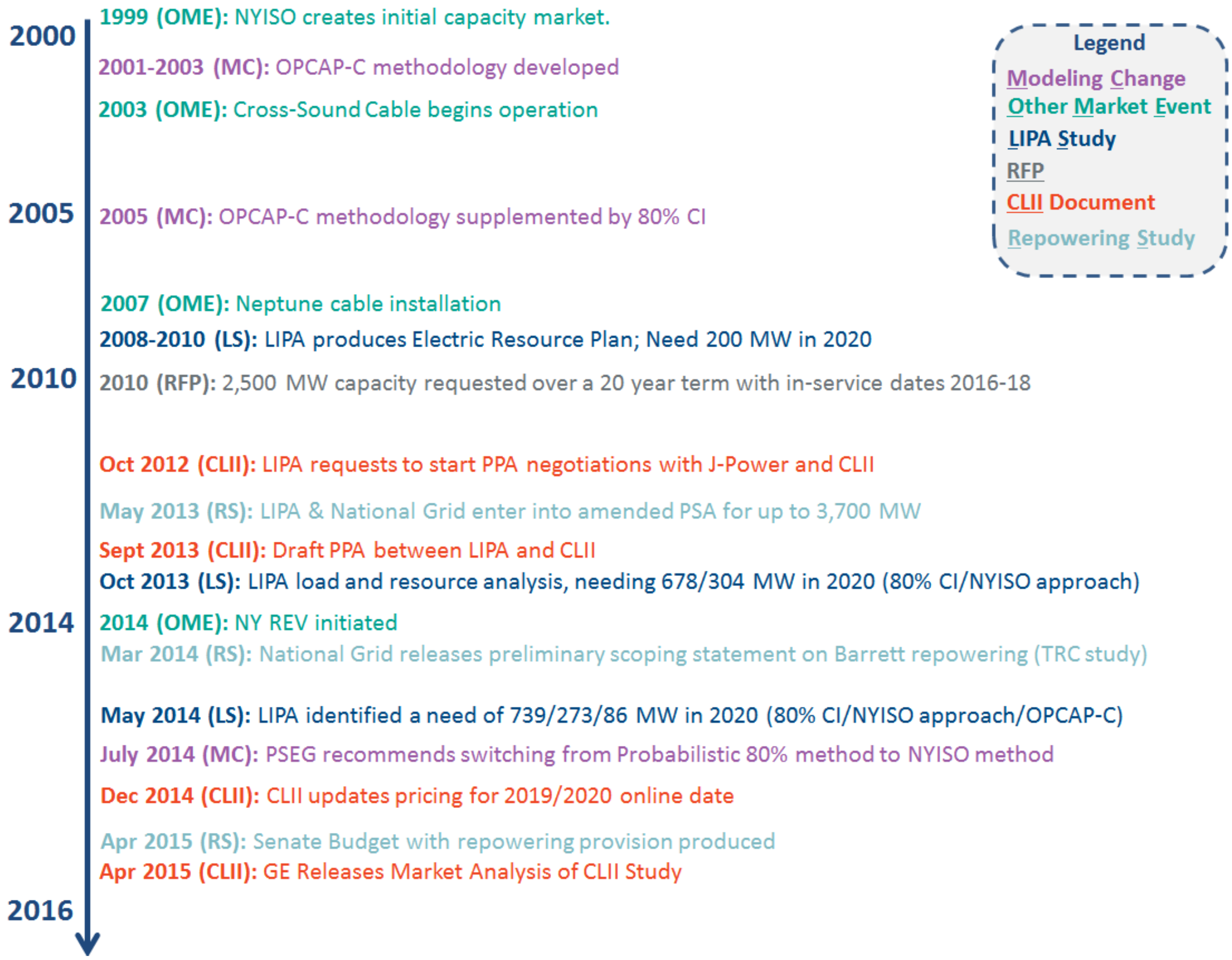
II. Introduction – Purpose, Approach and Scope of Analysis

The Brattle Group was engaged in the beginning of 2017 to review the methods and findings of studies conducted over the past decade by LIPA, PSLI and other New York (NY) power market participants that have evaluated the reliability and expected economic impacts of the proposed Caithness Long Island II combined cycle (CC) plant as well as the potential repowering projects of the E. F. Barrett and Port Jefferson power plants. This report summarizes our approach and findings.

In 2013 LIPA selected the Caithness Long Island – II (CLI-II) 750 MW power plant proposal in response to LIPA's 2010 RFP (RFP) soliciting up to 2,500 MWs of new capacity. Negotiations about contract terms and required infrastructure improvements were conducted, but the contract was not finalized. In 2014, a study by PSLI found that CLI-II was not needed for reliability purposes under the NYISO criteria. The main drivers of this new finding was the considerable drop in forecasted load growth since the RFP and the reduction in the "need for capacity" based upon use of a different planning standard *i.e.* the NYISO planning criteria. PSLI recommended that any contracting decisions on CLI-II or other possible generation resources be deferred until a future integrated resource plan (IRP) could evaluate the need and/or economic costs and benefits for Long Island (LI) ratepayers. In April 2015 CLI-II released a study conducted for it by GE Energy Consulting which found that there would be system energy benefits from the plant to LI and to NY as a whole. However, the GE 2015 Study did not compare those benefits to the costs of the plant and did not consider the plant's required upgrades to both the existing electric transmission system and local gas infrastructure.

LIPA's approach to reliability planning and resource selection has evolved over the past decade in response to: shifting system conditions (especially its improving connectivity with the rest of New York, PJM, and New England ISO), changes in NYISO methods and parameters for determining overall needs (the Installed Reserve Margin, or IRM targets, and Locational Minimum Installed Capacity Requirements, or LCRs, for zones within the NYISO like Zone K for LI that have limited or frequently constrained transmission to the rest of the system), changes in the economic value of energy and capacity in its region, and changes in its own long run demand outlook. The timeline shown in Figure 1 summarizes this history of how resource requirements have been measured and how those findings have affected resource procurement discussions and plans. This figure also tracks relevant RFPs, CLI-II correspondence, repowering studies, and other events that could influence Long Island's resource planning process.

Figure 1: Timeline of Important Resource Planning Events Relevant to Long Island



Rows in this figure shown in a purple font (labeled MC, for "Modeling Change") indicate when LIPA has used different tools and metrics for reliability planning over the last 15 years, beginning with its own Operating Capability – Test C (OPCAP-C) standards developed in 2001 - 2003, followed by adding in 2005 a new reliability modeling approach referred to as the 80% Confidence Interval (80% CI) method. In 2014, PSLI recommended use of the NYISO reliability criteria.

The analyses conducted by PSLI and LIPA subsequent to the 2010 RFP have found that there is neither a reliability need nor an economic need for Caithness. However, there is still a question of whether there are special risks, market circumstances, or expansion constraints facing LI that are not captured sufficiently by NYISO procedures, and if so, whether the CLI-II plant would meet those needs. The Brattle Group was retained at the beginning of 2017 to assess that question by reviewing and critiquing the following:

- The **reliability standards** used by the NYISO, LIPA and other similar agencies over time (i.e., the past studies mentioned above Figure 1 in dark blue and labeled LS for LIPA

Study (2008-2010, Oct 2013, May 2014) in regard to whether those criteria are sufficient for identifying capacity needs for Long Island)

- The **changing economic and regulatory circumstances** in NY and on LI from 2010 to present (and currently foreseen for the future from 2017 through the next decade and beyond) and how those affect the reliability or economic needs for CLI-II or any other new generation on Long Island, and
- The **merits of proposed repowering projects of the E. F. Barrett and Port Jefferson plants**, which would add new combined-cycle technology to the LIPA system that is more efficient than the current plants at those sites, without any material increase in their total capacity.

This report addresses those topics in that order. For our review, we have relied wherever possible on: public past planning studies by LIPA, PSLI, CLI-II, NYISO, and NYSRC, the current IRP analyses, as well as proprietary documentation and correspondences regarding the terms of potential power supply agreements with CLI-II, Island Park (E. F. Barrett repowering) and National Grid (Port Jefferson repowering). Our review of past planning studies included resource and reliability planning, as well as, load forecasts and other expectations. **Please note that proprietary information has been redacted (marked REDACTED in red font) from this report.** We also contacted the managers of CLI-II and received an oral history of their perceptions of the advantages of the plant. We have not conducted independent system modeling analyses of Long Island's needs nor of the NYISO power pool and surrounding markets. However, we have decomposed the IRP analyses in a manner that isolates how each of these projects affects total system costs, and we have evaluated the reasonableness of those findings in relation to our understandings of the LI and NYISO market environment.

III. LIPA and NYISO Planning Criteria and Risk Assumptions

A. Reliability Criteria

Reliability planning is a critical issue facing the utility industry, for several reasons. First, power supply and demand must be instantaneously balanced, moment by moment, across the entire power system in order for it to be stable and secure. If there is any material discrepancy for even fairly modest periods of time, parts of the system may have to be curtailed or the system can collapse, as has happened on a few rare but dramatic occasions. Second, the value of power supply to customers is generally considered to be far greater than its average cost to supply. That is, disruptions can be very costly and even dangerous, while carrying extra power plants in reserve to standby for conditions of stress is not as expensive, at least until the depth of reserves becomes extreme. Reliability criteria and planning tools are intended to identify the point of economic tradeoff between the costs of having more backup resources and the benefits of reduced risk of outages.[2]

The generally accepted reliability criterion in the continental U.S. is commonly referred to as "1/10 LOLE" (referring to a Loss of Load Expectation of one day in ten years). This criterion requires a power provider to maintain its system so that the probability of disconnecting any firm load due to generation resource deficiencies shall be, on average, not more than once in ten years. The 1/10 LOLE assessment typically looks ahead at least one year or more and accounts for peak load conditions, recognizing future load growth, potential and probable outages of the various bulk power system elements, including generators and transmission assets, and other foreseen changes to the system conditions, such as planned expansions and retirements. The LOLE assessment helps identify the quantity, timing, and also location of bulk power system assets needed to ensure the 1/10 LOLE criterion is satisfied for future years. It should be recognized that island systems with limited transfer capability to external regions will require more generating capacity to achieve the same LOLE because the limited transfer capability reduces the "portfolio" effect of outages provided by greater diversity from access to larger, interconnected systems.

In New York, the New York State Reliability Council, LLC (NYSRC)—a non-profit entity responsible for promoting and preserving the reliability of the New York State power system—calculates the necessary annual statewide Installed Reserve Margin (IRM) needed to achieve this conventional 1/10 LOLE standard. The IRM is the quantity of in-state or firm, committed, importable power supply of dependable generation resources needed under Base Case conditions for New York to maintain this LOLE criterion. It is expressed as a percentage of

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2 Oftentimes studies don't explicitly address the marginal economics of increased reliability, but instead rely on past industry norms for when that tradeoff is balanced, e.g. the widely used 1/10 LOLE.

installed capacity for the whole NYISO in excess of system coincident peak. The latest IRM requirement for New York (IRM requirement for the 2017 Capability Year, corresponding to May 2017 through April 2018) indicates that the state needs a reserve margin of 18.0%.[3] This is a fairly typical level of required planning reserves. Other states, power pools, and Regional Transmission Organizations around the country typically require between 12 and 20% reserve margins, depending on the character of demand and supply conditions in their area.

The IRM assessment is performed annually by the NYSRC for the upcoming Capability Year using the GE Multi Area Reliability Simulation (MARS) model[4]—a probabilistic model that runs Monte-Carlo type simulations (exhaustive risk scenarios spanning many combinations of randomly occurring, uncertain factors) with varying generator unit outages and alternative load and transmission representations—to identify the IRM level and confirm that the expected service disturbances will be less than 1 event per ten years if the IRM percentage is met. Power supplies qualifying for recognition as satisfying the IRM have to be deliverable throughout the New York Control Area (NYCA) under conditions of possible disruptions to parts of the transmission grid. If not, the IRM must be increased until any outage of a critical single element would not disturb the reliable operation of the bulk power system.[5]

In parallel to the IRM assessment, NYSRC provides a preliminary estimate of the Locational Minimum Installed Capacity Requirements (LCR)—the quantity of generation resources that must be supplied locally to cope with regions of limited transfer capabilities with the rest of the state—such as New York City and Long Island. In essence, these regions have more peak load than the transmission wires into them can deliver, resulting in regional obligations for how the IRM must be satisfied. Some portion of it can come from rights to the output of generation located anywhere in the NYISO. However, for regions that tend to have transmission constraints into them, it is not acceptable to have all of the reliability obligations met by remote generation.

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[3] NYISO, "Locational Minimum Installed Capacity Requirements Study, covering the New York Balancing Authority Area for the 2017-2018 Capability Year." January 13, 2017.

[4] NYISO, acting as a technical resource for NYSRC, performs the MARS simulations under guidance of NYSRC's Installed Capacity Subcommittee (ICS). MARS is widely used throughout the industry by various utilities, system operators, among various market participants.

[5] More specifically, in determining the reliability of the NYCA several types of randomly occurring events are taken into consideration. Among these are the forced outages of generating units and transmission capacity. Monte Carlo simulation models the effects of such random events in the MARS model. Deviations from the forecasted loads are captured by the use of a load forecast uncertainty model. To ensure adequate statistical sampling, the MARS model is run for 1,000 iterations. If at the 1000th iteration the desired standard error of 0.025 of the mean LOLE for calculating the 95% confidence level is not achieved, the number of iterations is increased in increments of 250 until the desired standard error is met or exceeded.

Instead, some of it must be from generation resources behind or inside of the flow constraints. There are three such regions in NY: New York City, Long Island, and the Lower Hudson Valley region. The 2017 Capability Period's LCRs are 81.5% for New York City and 103.5% for Long Island (and the Lower Hudson Valley region's LCR was calculated to be 91.5% using the finalized New York City and Long Island LCR values.) That is, at least 103.5% of the LI installed capacity (ICAP) resources out of the total satisfying its 18.0% IRM must be physically or functionally[6] located within Zone K. These obligations have been confirmed by NYISO and approved by FERC. Load Serving Entities in these three regions need to satisfy both the IRM and LCR.[7]

The IRM (and LCR) and ICAP of generator resources are adjusted downwards (derated) to reflect the available capacity that can be can be delivered during peak load hours. Unforced Capacity (UCAP) is the ICAP adjusted for performance through the Generating Availability Data System (GADS), accounting for availability based on the past 5 years of plant performance, such as derating and outages. Using UCAP rather than ICAP rewards suppliers who maintain the equipment in a manner that provides higher availabilities. For instance, wind resources are not assured of performing on peak because the wind itself may not be blowing steadily at that time, so they are not scored as having full nameplate value, i.e. their IRM capacity value is derated from their maximum capacity when the wind is blowing. Similarly, thermal units are either derated for their history of being available on peak, or their potential output may be simulated directly in a manner that reflects their unplanned outage rates.[8]

Similarly, NYISO calculates the minimum Unforced Capacity Requirement (UCR) for each Capability Period (the Summer Capability Period is May through October, and the Winter Capability Period is November through April) by adjusting the IRM to reflect the Equivalent Forced Outage Rate on Demand (EFORd).[9] The EFORd value used is the average EFORd value of

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6 A generation asset is deemed functionally equivalent to being on island if it is deliverable over a transmission path for which a load serving entity on LI has firm capacity rights. As an example LIPA has a contract for 685 MW of capacity from the Marcus Hook generating facility which is physically located in Pennsylvania but is considered as On-Island capacity by virtue of the fact that LIPA has firm transmission deliverability of that capacity to Long Island via the Neptune Cable contract.

7 NYISO, "Locational Minimum Installed Capacity Requirements Study, covering the New York Balancing Authority Area for the 2017-2018 Capability Year." January 13, 2017.

8 Conventional plants are derated based on historical unplanned, or "forced" outage rates, while Special Case Resources (SCRs) such as energy efficiency programs are based on registrations about expected performance and are derated based on tested and historic performance.

9 UCR = ICR * (1-EFORd)

the 6 most recent 12-month rolling average EFORds of all New York Resources. Similar to LCR, the local UCR for New York City and Long Island is calculated.[10]

All load serving entities (LSEs) in New York are required to provide or secure enough UCAP capacity to satisfy both the IRM and LCR (statewide and local) requirements for the coincident peak of their individual loads.[11] UCAP may be purchased either through bilateral transactions or through NYISO capacity market auctions. Securing enough UCAP indicated that the NYISO reliability criteria are met for the LSE.

B. Special Reliability Considerations for Long Island

Long Island's situation in the NY power system is different due to its limited transfer capability from the rest of the state and neighboring ISO's. For example, in the early 2000s LI was reliant on five interties from Con Edison and Connecticut Light and Power with a transfer capability of about 1,200 MW.[12] The 330 MW Cross Sound Cable was placed in service in 2004, and the 660 MW Neptune Cable was added in 2007. Even with these expansions, Zone K can only import approximately 40% of its peak load requirements.

As a result of these transmission import limitations, as well as other local development constraints, LIPA had taken a conservative approach to resource planning by looking at its resource requirements from a local contingency planning perspective under more extreme than normal conditions. Part of this conservatism was based on LI's operating experience with satisfying NY planning requirements that had turned out to not suffice for LI operations. In particular, in 2000, voltage reductions were initiated on LI due to load coming within 50 MW of available supply even while LI had maintained the NYISO planning reliability criteria. The aforementioned OPCAP-C methodology was developed by LIPA in the early 2000s in response to such concerns. It was designed to make sure that sufficient resources on Long Island were available under the following conditions:

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[10] The resource adequacy calculation described here is part of a broader NY Reliability Planning Process (RPP). The RPP includes two studies, the Reliability Needs Assessment (RNA) and the Comprehensive Reliability Plan (CRP). The RNA performs the resource adequacy assessment (using a probabilistic approach) and the transmission system adequacy assessment (using a deterministic approach). The RPP by itself is one of the four steps of the Comprehensive System Planning Process (CRPP); the Local Transmission Planning Process (LTPP), the RPP, the Congestion Assessment and Resource Integration Study (CARIS), and the Public Policy Transmission Planning Process (PPTPP).

[11] Load serving entities include Transmission Owners serving native loads (providers of last resort), load aggregators with retail access, large industrial loads, and Municipals.

[12] Long Island Power Authority, "Biennial Report of the Consulting Engineer and Rate Consultant for the Period January 1, 2000 through December 31, 2001." August 31, 2002.

- 10% of on-island generating capacity is unavailable,
- The Long Island peak load is at the 80th percentile of historic weather conditions in the past thirty years, and
- The largest generating unit and transmission intertie on Long Island are unavailable at the same time.

OPCAP-C assesses reliability differently from the NYISO approach and therefore the capacity requirements were different, and generally more stringent than the NYISO standards.

Another reason for LIPA's past conservatism in reliability planning in the 2000-2010 time period was that LIPA had observed that its NYISO-assigned LCR values and its own LI or Zone K load forecasts were both uncertain and often more variable from year to year than other regions in the state. This variability created a risky situation, because it was then LIPA's experience that soliciting, siting, contracting and construction of a new plant on LI might take up to 7-8 years. That lead time is long enough that load growth on the high side of typical levels, or an adverse finding that the LCR should increase, could cause a material supply shortage before new assets could be built.

To address these kinds of interacting uncertainties, a probabilistic reliability planning method was developed around 2005 to supplement the OPCAP-C method. This method, called the "80% Confidence Interval" (80% CI), assigns probability distributions around each major variable affecting the timing and size of need, such as the load forecast.[13] Monte Carlo simulations were run to generate statistical results across the ranges for key variables that affect power supply adequacy, including:

- Load Forecast & Growth
- Demand Side Management
- Long Island LCR
- Resource Level & Availability
- Installation & Retirement Dates for Supply and Demand Side Resources

The outputs of these analyses were then sorted into confidence levels (for probability of occurrence) that generally ranged between 5% and 95% in 5% increments. LIPA would then identify a resource plan (or specify its generic resource procurement needs) with enough capacity development to assure adequate performance at the 80th percentile of potential conditions.

For a while, LIPA used the NYISO, OPCAP-C and its 80% CI approaches in parallel, and the most binding approach was used to determine capacity needs. Observing that the probabilistic

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13 Note that the GE MARS model used for resource adequacy assessment is a probabilistic model. However, some of the input assumptions, including load forecast used are deterministic.

approach was almost always binding (requiring the most new capacity), the probabilistic approach was selected in 2005 as the published method for determining future resource needs on LI while other methods continued to be evaluated internally.

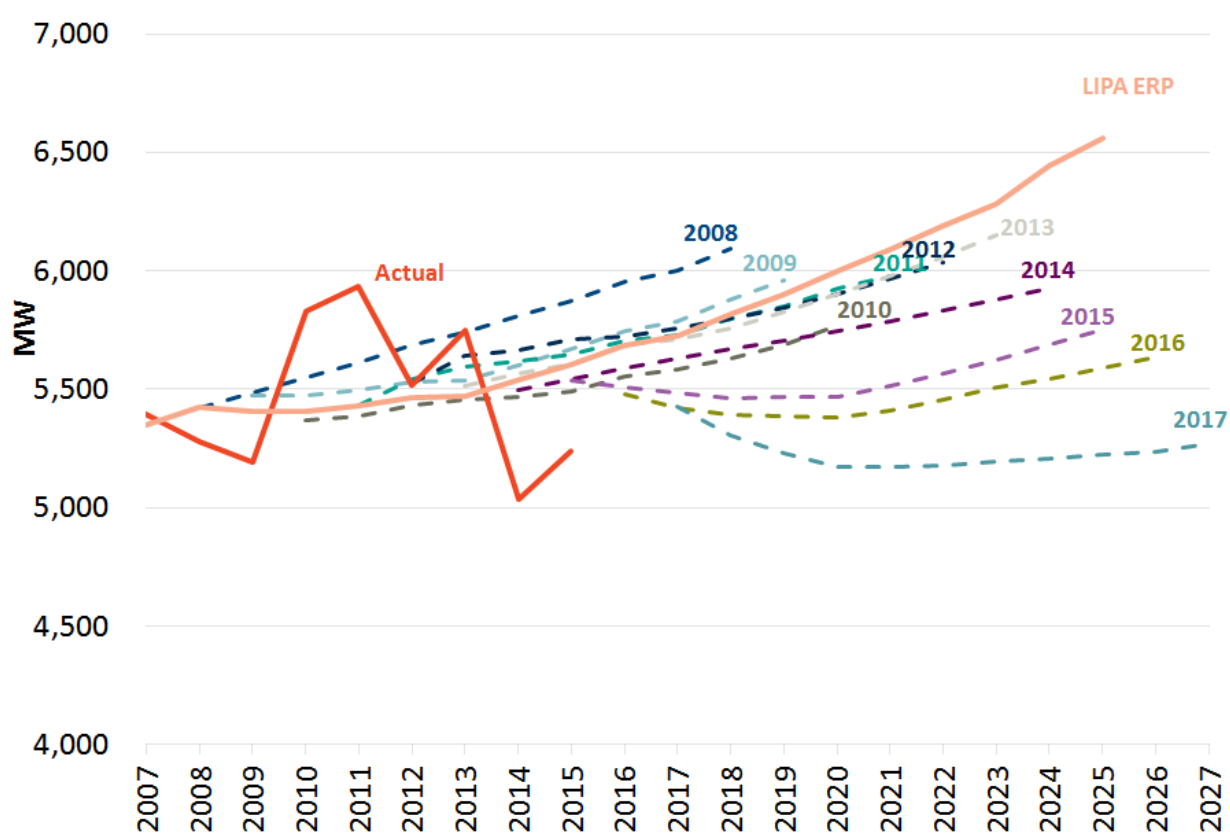
In the meantime, NYISO's own reliability planning process and its market structure have evolved and matured. For instance, NYISO's capacity market has matured from using ICAP to UCAP that gives suppliers a strong incentive to maintain their units for reliable performance, and introducing the sloped demand curve (replacing what was effectively a vertical demand curve with a sloped demand curve). These changes have resulted in NY generators providing better performance and alleviating LSEs concerns for purchasing necessary UCAP every season (up to 6 months ahead) from the capacity market to satisfy their IRM and LCR. While this is not a panacea for long run supply adequacy, it is a method of obtaining (and compensating) commitments from plants that they will be available and dedicated to NYISO, thereby providing more certainty about the coming season and also taking some pressure off of generation self-reliance. Also, as mentioned above, a number of transmission projects strengthened the ties between Long Island and the rest of New York and PJM, the largest of these being the Neptune 660 MW project from Sayerville, NJ to the Newbridge Rd substation on LI, which was completed in 2007. The process for siting and developing new generation in NY has also been streamlined considerably, such that the necessary lead time has generally become shorter; by 2014 LIPA was finding it possible to develop a plant in approximately 6 years, eliminating about two years of need uncertainty.

Perhaps most significantly, for reasons both planned (e.g., energy efficiency programs) and unplanned (the Great Recession), as Figure 2 below shows, the Zone K load forecast has come down dramatically over the past decade, causing the risk of LI becoming capacity-short to be reduced significantly for years to come, regardless of the reliability metric applied. The curves in this figure are the ten-year peak load forecasts for the LI zone that have been used annually by NYISO and LIPA for resource planning purposes since 2008. The line labeled "ERP" is the peak load forecast underlying the need assessment that resulted in the 2010 RFP in which CLI-II participated. Not shown on this graph is the projected capacity LIPA was expecting to then have on hand in those future years; this amount was about 200 MW in 2020 <u>below</u> the amount needed to satisfy LIPA's 80% CI reserve requirements. From 2020-2030, load was expected to grow by another 750 MW or so, hence necessitating new capacity.

Figure 2 also shows that by 2014, the ten year outlook was well below the 2008 ERP forecast. All these changes in NYISO, LCR variability, plant siting, and load expectations by 2014 led PSLI to recommend using the NYISO reliability criteria.

Furthermore, the 2026 peak load, based on the initial 2017 forecasts, is projected to be essentially the same as the actual 2008 peak. Given this significant drop in projected peak load, even if LIPA were to continue to use the 80% CI approach, it is likely that there would not be any pressing need for new capacity that justifies pursuing development soon. With the 80% CI approach and the 2010 ERP forecast, they had an expected need date of 2020 when the peak load was approximately 6,000 MW. However, as seen in Figure 2 below the most recent 10-year peak load forecast never reaches 6,000 MW - in fact the peak load forecast remains well below that level by several hundred MWs.

Figure 2: New York ISO Zone K Non-Coincident Peak (after DSM reductions) vs. LIPA 2010 ERP



Sources: 2008-2016 NYISO Goldbook; 2017 Preliminary NYISO Goldbook; 2010 LIPA Electric Resource Plan.

IV. Assumptions and Findings at the time of the 2010 ERP and 2010 RFP

Based on the projected load growth shown above as of the 2010 ERP, LIPA reasonably found a long-term need for capacity.[14] It also wanted to pursue a policy of fleet modernization, so it issued an RFP in 2010 for up to 2,500 MW, to which there were 16 respondents offering 45 alternatives. These were filtered in an iterative process that first excluded proposals not comporting with the terms of the RFP, not having sufficient specificity to evaluate, or not having evidence of organizational, technical or financial readiness to execute their proposals reliably. This left about half of the offers, which were then screened using the GE MAPS production costing model to determine how the offered plants would interact with the rest of LIPA's fleet and the NYISO generally. Also, the proposals were evaluated for any additional costs or benefits they might have on the LIPA system because of their need for intra-island transmission or fuel (gas) supply infrastructure upgrades. It was found that none of the offered plants in the RFP would have saved money for LIPA ratepayers, i.e., none were displacing other, more expensive generation alternatives already in place or under consideration, or meeting future load growth at a marginal cost below the average cost of existing service. They were all going to meet future needs but result in increased rates to varying degrees and with varying impacts on the system.

CLI-II offered several alternative sizes and configurations of possible plants in its RFP response, from which LIPA selected the largest, a 750 MW 2x1 Combined Cycle plant with duct-firing. A smaller J-Power plant (377 MW) was also a co-finalist in the RFP screening. The largest of the CLI-II offers had the lowest unit cost and it was also of interest because its size and timing offered an opportunity, if appropriate, to shut down and subsequently repower the existing Port Jefferson plant.

LIPA studies at that time also indicated the CLI-II plant would require considerable transmission system and natural gas infrastructure upgrades, estimated at the time as costing around REDACTED in capital expenditures for the former and approximately REDACTED per year in natural gas infrastructure access and upgrade fees for the latter.[15] The transmission system

14 The ERP found 200 MW of capacity needs by 2020.

15 The amounts estimated to be needed for this transmission interconnection have varied considerably over time. By the time of final selection of CLI-II for contract negotiations, LIPA's estimate had increased to nearly REDACTED, while the current estimate, used later in this report's analysis of rate impacts, is approximately REDACTED. Caithness has filed with the NYISO for transmission requirements to achieve recognition as a capacity resource, and that cost was put at around $28 million (Source: NYISO. "Notice of Class Year 2015 Initial Project Cost Allocations for System Upgrade Facilities and System Deliverability Upgrades." December 2, 2016. Available at: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Interconnection_Studies/Notices_to_Market_Participants/CY2015_Notice%20Regarding%20Cost%20Allocations-InitialRound_12-2-2016.pdf). However, as noted, NYISO ignores intra-zonal

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upgrades were necessary because the plant's output was exposed to a double-circuit contingency problem on its East-West electric transmission corridor, such that if two of those lines were lost, the resulting rerouting of CLI-II power would damage much of LIPA's lower voltage circuits. Reinforcements to prevent this were a system cost that LIPA customers would ultimately bear.

Such needs for intra-zone or intra-utility transmission system reinforcements are allowed by the NYISO in capacity resource and transmission planning, but the NYISO itself does not evaluate or consider them in qualifying a proposed plant as a capacity resource. That is because the NYISO treats each zone as a homogeneous region with no internal constraints, as if its internal transmission and distribution resources were a copper sheet. The NYISO assesses feasibility of delivery into and out of the zones. In fact, in order to be compatible with this approach, it is necessary for zones to add any improvements required for the new plant(s) to be fully utilizable within their systems without overloading any circuits.

CLI-II was also found to require new gas pipeline upgrades for fuel supply. LIPA included the respective infrastructure build-out costs in their analysis for all plants under consideration.

Given the planning and operational history of LIPA with regard to its local electric system conditions and risks, it was reasonable for LIPA to apply in 2008 - 2010 its more conservative criteria and reach a finding of need for 200 MW of capacity by 2020.[16] It was also reasonable to solicit much more capacity than this, both to determine the potential (and cost) for fleet modernization, and because there are economies of scale in power plants and long lead times in their siting and construction that can make it more efficient to build more capacity than is immediately needed. This also recognizes that power plants have very long lives, so building a larger facility can defray future needs for additional capacity. Also, an efficient new plant may have economic benefits from displacing more expensive existing power supplies or market purchases (i.e. reducing operating costs) and from deferring the need to build future capacity.

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transmission constraints in its capacity requirements, except insofar as they affect transfer capability to and from the zone.

Caithness opposed at FERC the applicability of the LIPA reinforcements to its project under the NYISO minimum interconnection standard, and FERC agreed with Caithness that local deliverability could not be considered in that process. Notwithstanding the lack of local deliverability considerations in the NYISO process, we understand that LIPA and PSLI would not consider a PPA with CLI-II that did not provide the needed internal transmission reinforcements. Also, were CLI-II to be constructed as a merchant plant, its dispatch could be constrained if the reinforcements were not constructed.

16 In LIPA's October 25, 2012 RFP memo to trustees, the capacity need is stated as 600 – 900 MW by 2022.

These economic benefits can justify a larger and different type of plant than would be needed just for reliability.

Since CLI-II and the other leading contender in response to the RFP were both large baseload plants, their value to the system depended on both their capacity and their potential economic savings. Both of those can and did change fairly rapidly after the initial discussions in 2012 with CLI-II, mostly changing in the direction of having less need and less economic benefit from a large gas combined cycle plant, especially one requiring a fair amount of system expansion to interconnect. These changes are explained below.

V. Declining Market Needs for New Capacity in 2010 - 2015

As Figure 2 illustrated, by 2014 it was becoming more apparent that new capacity in Zone K was unlikely to be needed as early as had been foreseen at the time of the ERP and the issuance of the RFP. In addition to the decline in recent past realized load and expected future load growth, a precipitous decline in natural gas prices resulted in lower electric power prices throughout all of NY and adversely affected the economics of new efficient baseload generation technology.

These load and gas price reductions occurred roughly concurrently starting around the time of the Great Recession of mid-2007 - 2009. That recession was induced by undisciplined lending, securitizing and multiple reinsuring of the mortgage industry to home owners, leading to a speculative bubble in housing and many types of financial securities which unraveled rapidly when escalating mortgage defaults caused a few major lenders to fail to meet borrowing covenants. A cascading failure of interconnected banks and insurance companies drove the economy into its deepest recession since the Great Depression of the 1930s. For the electric industry this resulted in significant reductions in peak demand and changes in consumer behavior towards more efficient energy usage that have persisted well beyond the end of that recession in June 2009.

Zone K's energy, which is nearly all LIPA, fell comparably to the NYISO total reduction. In fact, as shown below, the reduction in 2025 total energy forecasted in LIPA's 2010 ERP versus the amount for that year projected in NYISO's 2016 Goldbook is over 5.5 TWh[17], which is larger than CLI-II's estimated annual output.[18]

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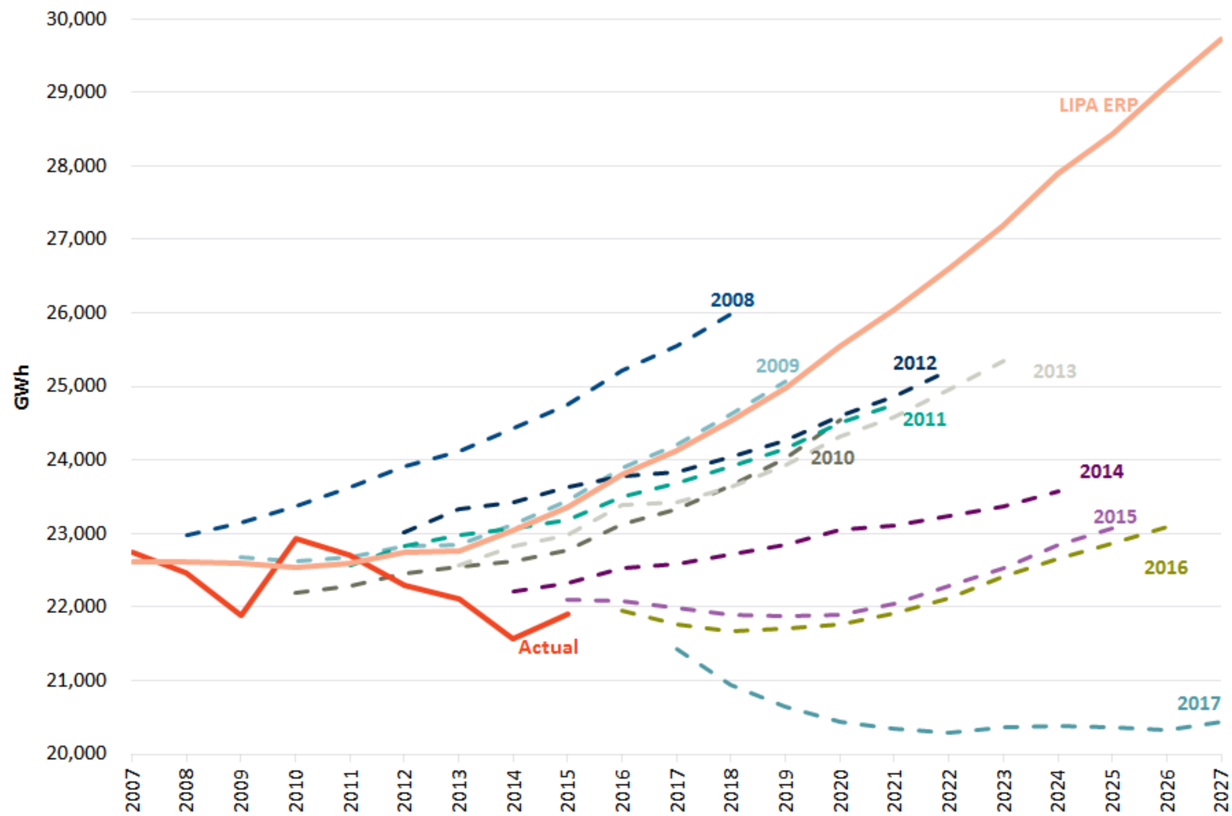
17 NYISO. "2016 Load and Capacity Data: Goldbook". April 2016.

Long Island Power Authority. "Electric Resource Plan 2010 – 2020." February 2010.

18 A 750 MW plant operating at a 75% capacity factor can achieve ~4.9 TWh of annual production.

Figure 3: New York ISO Zone K Total Energy Forecast (including reductions from DSM) vs. Outlook in LIPA 2010 ERP

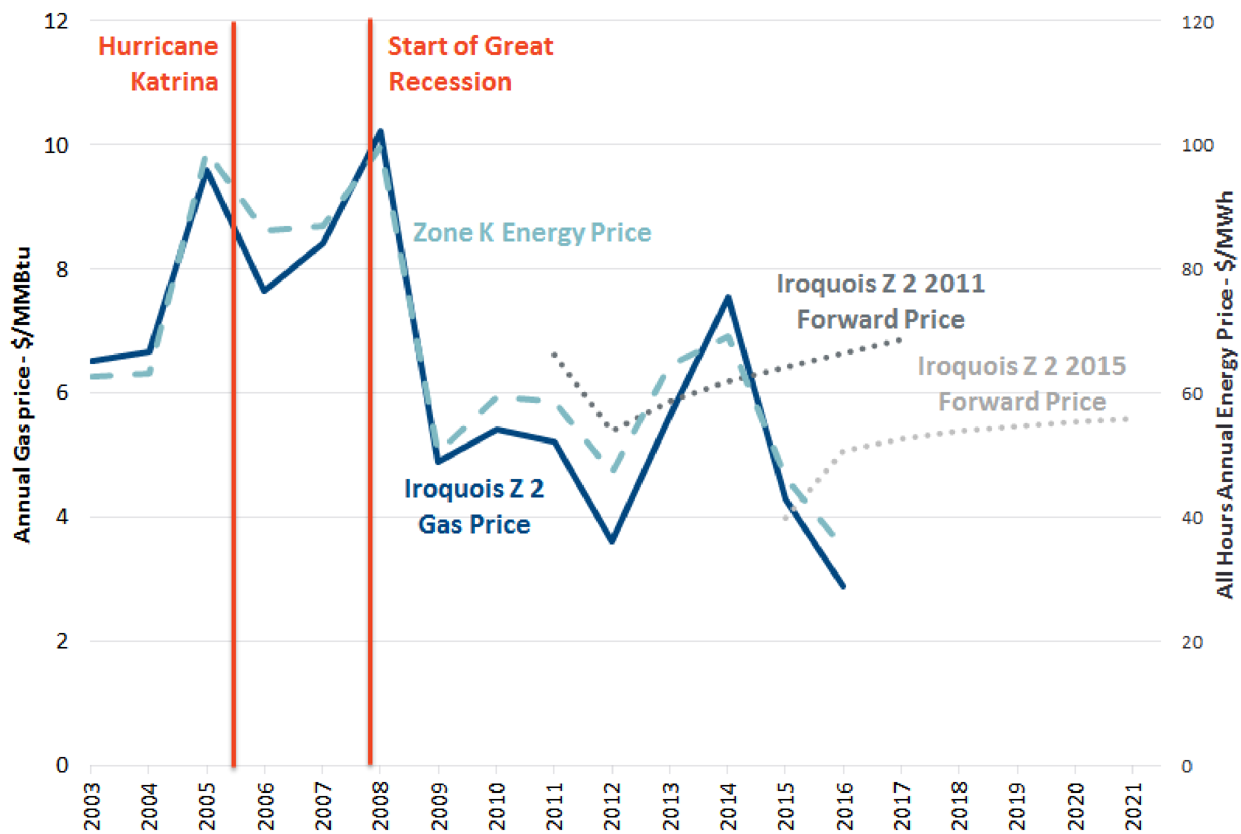


Sources: 2008-2016 NYISO Goldbook; Preliminary 2017 NYISO Goldbook; 2010 LIPA Electric Resource Plan

Natural gas prices also fell dramatically, for a different reason. In the period from about 2004-2008 there was increasing worry that the US was running out of economical sources of natural gas, and so gas spot and forward prices rose dramatically (along with nearly every other major industrial commodity, driven largely by Chinese economic growth). Prices rose especially dramatically after Hurricane Katrina took out a large portion of domestic offshore drilling capacity in late summer of 2005. However, by 2008 and continuing thereafter, there had been a largely unexpected improvement in technology for finding and extracting new sources of non-conventional gas supplies, especially so-called shale gas. This is a very broadly distributed source of gas in the US, which became accessible due to improvements in horizontal drilling and natural gas "fracking" to release it from its attachment to shale rock (which is under most of Pennsylvania, New York, Texas, the Dakotas, and many more locations with abundant trapped gas and oil).

This renaissance caused a massive decline in gas prices, especially gas delivered to and consumed in the Northeast. These lower prices have persisted, such that shale gas is now the dominant source of gas in the US and is expected to be available for perhaps five years or more at roughly current real costs per MMBtu.

Figure 4: New York's Natural Gas Prices vs. Energy Prices



Sources:

SNL Day-Ahead natural Gas Prices – Annual.

OTC Global Holding Natural Gas Forwards from SNL as of 11/1/2011 & 1/2/2015.

ISO Day-Ahead – Annual All Hours NYISO Zone K Energy Prices, pulled from SNL.

Natural gas prices are important to power resource planning because the market price of power in many regions, including the NYISO, are often set by the dispatch of gas-fired power plants (which tend to be at the top of the merit order for least cost scheduling). In NYISO as a whole, natural gas combined cycle plants tend to be on the margin about 67% of the time.[19] This is

[19] Potomac Economics. "2015 State of the Market Report for the New York ISO Markets." May 2016.

evident on the above chart by virtue of how closely the Zone K energy (spot electricity) price follows the time pattern of gas prices delivered to LI on the Iroquois Z2 location. As gas prices fall, market prices for wholesale electric energy also tend to fall, reducing the value of savings that can be obtained from new plants even if they are more efficient than existing plants.

VI.2014 and 2015 Assessments by PSLI and GE of CLI-II

In 2014 PSLI conducted a reliability study reevaluating the need for capacity. In that study, reported on July 29, 2014, PSLI concluded that the 80% CI criteria had been using was no longer necessary for LIPA, because NYISO structure and requirements had stabilized, load forecasts were flatter and lower (as shown above), and lead times for development of new plants had become shorter. Accordingly, PSLI recommended deferring any contractual activity on CLI-II or any other plants for further evaluation in the upcoming IRP. Shortly thereafter, Caithness released a study conducted for them by GE Energy Consulting that reached a different conclusion about the apparent energy benefits of the plant.

C. PSLI 2014 Reliability Needs Study

The July 29, 2014 study by PSLI, entitled "Resource Planning Criteria Review" and summarized in a PowerPoint presentation, found that using the 80% CI criteria led to LIPA securing resources at a level much higher than the NYISO-set LCRs levels. For example, LIPA's on-island resource level using the 80% CI criteria, on average for 2001 - 2013, was over 500 MW higher than what it would have been if LIPA followed the NYISO criteria. It was further observed that the 80% CI criteria indicated much greater projected resource needs than either the NYISO criteria or LIPA's own OPCAP-C criteria. For example, the needs assessment performed in 2014 using both the OPCAP-C or NYISO approach indicated 2019 to be the first year for resource needs while the 80% CI approach indicated 2016 to be the first year for resource needs and 2019 as being nearly 440 MW short.

It was observed in that report that any excess capacity secured by LI would have ripple effects to the market and the LIPA ratepayers. It would lower the LI capacity prices and therefore dis-incentivized new generation development. This in turn would require LIPA to support new capacity suppliers through long-term PPAs, which would effectively make the LIPA ratepayers assume the value-in-use risks otherwise borne by merchant suppliers.

These observations, along with the additional buffers (including approximately 80 MW of Special Case Resources, 90 MW of additional Unforced Capacity Deliverability Rights through the Cross-Sound Cable, and 55 MW of additional potentially available output from existing resources, among others) that LIPA had not included in its planning, along with a lower load growth rate all indicated that LIPA could safely defer any contractual activity on CLI-II or any other plants at least until a more complete analysis was made in the upcoming IRP.

In our judgment, this was a reasonable finding and recommendation by PSLI as to both the method of analysis and the prudence of waiting to see how economic conditions would unfold (since there was no pressing need for capacity for reliability or economics).[20]

D. GE 2015 Study for Caithness

Shortly after the PSLI study was released, Caithness LLC retained GE Energy Consulting (GE) to independently evaluate the potential economic benefits of the CLI-II plant to LIPA and New York. In response, GE conducted a "Market Analysis of the Caithness Long Island II Project" (GE 2015 Study) the results of which were published April 10, 2015. The GE MAPS model (the same tool used by LIPA to evaluate RFP bids) was used to simulate the economic dispatch of CLI-II within the existing New York electric system (NYISO) and the rest of the Eastern Interconnection (most of the eastern half of the US). The model was run for the years 2019 – 2025, where 2019 is a partial year starting with the CLI-II installation date.

The key modeling assumptions in that analysis were made by GE based on public information. It was not a study designed to reflect a Caithness viewpoint about potential market conditions, but GE's perspective. The existing transmission and generation configurations and performance capabilities of those assets were based on GE's regularly maintained power systems database. Furthermore, GE added additional transmission detail about the Long Island system for its study. The system load was based on the 2014 NYISO Goldbook load, which assumed Long Island (Zone K) annual energy around 23 TWh and peak load around 5.8 GW over the projected time frame.[21] Gas and oil price forecasts were based on the 2014 Annual Energy Outlook (AEO), a widely used standard source of energy commodity forecasts, in which the Henry Hub gas prices were projected to be around $5.7/MMBtu over the study period.[22] Gas delivery charges to the various market areas were added to the Henry Hub prices. The gas-burning Long Island generating units were dispatched at Iroquois and TRANSCO Zone 6 natural gas prices which averaged $6.60 and $6.88 respectively.[23]

All of these are reasonable sources of data and resulting assumptions, widely used by other planners in the power industry. However, since those forecasts were developed, market conditions have softened considerably. For instance, if this study were repeated using the 2016 NYISO Goldbook and 2016 AEO, the Long Island energy forecast over the study period would on average be 8% lower, the peak load forecast would be 6% lower, and Henry Hub natural gas

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20 PSEG Long Island. "Resource Planning Criteria Review." July 29, 2014

21 NYISO. "2014 Load and Capacity Data: Goldbook". April 2014.

22 Energy Information Administration. "Annual Energy Outlook 2014." May 7, 2014. Average of nominal Henry Hub price from 2019-2025.

23 GE Energy Consulting. "Market Analysis of the Caithness Long Island II Project." April 10, 2015.

prices would be approximately 7% lower. More significantly, New York area gas prices have fallen over 60% from 2014 levels, due to moderate winter weather and the extensive shale development close to this market region.

The GE 2015 Study found that CLI-II would provide Zone K energy benefits of $164 million in 2020 growing to $217 million in 2025. This reported savings was calculated by adding the reductions in Cost to Serve Load ($55 - $85 million annually) to the CLI-II Net Energy Margins ($110 - $132 million). The former figure is the savings in power purchases that GE projected for all load that Zone K customers purchase from the NYISO, on the presumption (erroneous, as explained below) that LIPA's energy costs for load are incurred at local (on-island) spot market prices. Spot market prices on Long Island would likely fall due to new plants like CLI-II. However, as explained below, the PPAs that LIPA has with all of its on-island generation and the Transmission Congestion Contracts (TCCs) it has for virtually all of its off-island imported power over the transmission paths into LI eliminate nearly all of its sensitivity to local (on-island) spot power prices. Instead, it only experiences this kind of load cost-savings for a few percent of its needs that are sometimes purchased from merchant generation on Long Island.

GE's study also pointed out that there would be meaningful emissions reductions from the efficiency of the plant, displacing other units that burned more fuel for the same amount of energy output. Those emission savings were not valued directly, though they were reflected in part in the power price savings calculations because the emission allowance prices avoided by the cleaner CLI-II plant would contribute to load savings. The study did not consider capacity benefits from the plant. That is, it did not reassess whether LIPA needed the plant for reliability purposes, nor whether the plant would generate beneficial revenue from selling its capacity in the NYISO market. (It would, but these are likely to be fairly small in comparison to its energy market effects and its own fixed costs.)

The GE 2015 Study results are not surprising, i.e., that the CLI-II plant would have some level of profitable operations (net energy margins) and it would also reduce spot energy price for the region (and for the rest of NY). Virtually any new plant would accomplish some of this, because the efficiency of a new unit like CLI-II shifts the supply curve for power out and down, resulting in lower market prices in the NYISO market. This supply shift is captured in GE MAPS, and the units available in it are only dispatched (in the market and in the simulations) when they will produce savings. However, as noted above, these amounts are not savings or profits that accrue to LIPA's ratepayers. Instead, the primary (and almost entire) market benefit that LIPA customers can incur from a new power plant is how it changes the total fuel costs of LIPA's generation (including CLI-II, if it were built) and whether the new generator helps avoid some purchases entirely. This means that GE's $55 – 85 million of cost-of-load reduction benefits are not a benefit at all to LIPA, and its $110 – 132 million of plant energy margins are not the proper measure of the overall fuel and purchased power savings to LIPA. Further, GE did not close the loop by evaluating whether the savings it estimated are commensurate with the fixed costs of the plant and the associated costs of the electric and gas infrastructure upgrades. (They are not; those costs are larger than even the overstated savings GE estimated.) Thus, the study even on its own terms does not demonstrate that the plant is worthwhile economically. It simply shows that it would have some benefits, if/once built, ignoring its costs.

To understand why the spot market price reductions GE foresaw are not benefits to LIPA it is necessary to consider how LIPA's plants affect the net benefit and how its transmission rights affect the delivered price of power to load.

Even if LIPA's power supplies and demands were not hedged by PPAs and TCCs, there would be a significant overstatement in the GE 2015 Study of the energy savings benefits. The error arises by focusing on the savings to load purchases by LIPA's customers. If all of LIPA's supply sources were unhedged, these savings would be valuable to LIPA but not for 100% of the load. Instead, the net benefit is diluted, because the lower market prices of power also reduce the value of the output of the plants LIPA has under contract. These plants are typically economically dispatched to serve about 50% of LIPA's total load, and in those hours, the spot market price of that generation is almost the same as the local price of load, because there is very little transmission congestion within LI. Thus, about half of the load purchase savings would be offset by identical reductions in power sales (which are credited back to customers).

For the other portion of load, LIPA purchases nearly all of its off-island power supply over transmission paths that are covered by TCCs. These TCC rights mean that those imports can be purchased at the spot price of power in the connecting area with no additional import charge. Often those purchases are from PJM and ISO New England, hence having spot prices that are very insensitive to the effects of a new plant on LI. As a result, LIPA's cost to serve load is only reduced by purchases that are avoided entirely (i.e., reductions of off-island purchases and on-island merchant generation) and by any modest reductions in Locational Based Marginal Pricing (LBMP) in areas where the power is purchased. A new, efficient power plant will do a bit of both of these, but given the limited amount of documentation surrounding the GE 2015 Study, it is not possible to determine this offset precisely and make a corrective calculation. However, there is enough information to know the presented benefits are a material over-statement. [24]

On the other side of the ledger, it was noted above that GE understated benefits of the plant by ignoring the capacity value of the CLI-II plant. Since PSLI's study found no reliability need for the plant just a few months earlier this capacity value is likely to be very low. However, even under conditions of excess supply, the NYISO capacity market has been clearing at around \$4 -

24 While there is not sufficient detail in the reporting of the GE 2015 Study to breakdown what is purchased from where, with and without CLI-II being built, it is possible to discern in the 2016 IRP analyses how much load is or is not covered by TCCs. The uncovered portion is a few percent of load, depending on what plants are assumed to be built (CLI-II vs. the repowering projects). This would suggest that only a few percent of the 2015 GE load savings are realistic benefits.

$6/kW-month on LI, and Caithness would have been able to sell its capacity rights for this amount or thereabouts.[25] For a 750 MW plant, this would have been worth about $38 million per year.

Furthermore, as mentioned, the GE 2015 Study only considers benefits, not costs. For the plant to be economical to LIPA's customers, those (corrected) net benefits would have to cover the PPA payments for the capacity and fixed costs of the plant, as well as any transmission and fuel upgrade expenditures the plant would require. LIPA's proposed PPA fixed payments for CLI-II would be about REDACTED per year under the terms CLI-II offered in December 2014. These costs likely exceed the adjusted energy and capacity benefits estimated in the GE 2015 Study, even before recognizing the significant electric and gas system infrastructure costs which must be considered in evaluating the net attractiveness of any resource to LIPA (as it did in its own evaluation of the RFP and its subsequent IRP). As described above, LIPA has estimated these annual carrying costs to be about REDACTED for the electric transmission system upgrades and REDACTED per year for gas infrastructure.

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[25] Alternatively, LIPA as off-taker of CLI-II could have reduced its capacity purchase cost by the same amount.

VII. Current Economics of the Caithness Long Island II Project

The recently completed IRP included analysis of the current economics of the CLI-II plant. The study was done to evaluate potential changes in Long Island's long-term reliability and its costs of service, identifying the size and timing of any resource needs, the impacts of any changes in resource mix on system economics, NYSRC/NYISO planning criteria, and satisfaction of NY state policy objectives. The IRP focuses on the 2016 - 2035 time period, with emphasis on actions to be taken in the coming decade between now and 2025. The IRP used an array of tools to analyze the scenarios including: GE-MARS, GE-MAPS, Market Manager, and a LIPA-specific financial model.

For the Reference Scenario the IRP used the 2016 Goldbook peak load and energy forecasts for NYISO.[26] This load forecast follows the trend of the last several years, showing lower peak load and energy requirements through 2036 than were expected at the time of the predecessor 2015 forecast. For the existing generation fleet, the IRP assumed the contracts will expire at the current contract end dates, and that those plants will then operate as merchant assets, with the exception of the units under the Power Supply Agreement (PSA). For these units, the IRP assumes that the contract will be renewed in 2028. The IRP also assumes that 400 MW of renewables will be installed within its footprint by 2022, in line with current RFP processes, LIPA Board of Trustee expectations, and state energy policy mandates. The IRP used fuel and emissions allowance price forecasts from Energy Ventures Analysis, a widely respected vendor of fuel price forecasts within the energy industry. The CLI-II Scenario uses all the Reference Scenario assumptions and adds the CLI-II unit based on the specifications of the updated pricing proposal that LIPA received from the developers in December 2014.

The IRP defined a 10-year (2016 - 2025) actionable window relating to reliability needs analysis. That is, if the IRP cases showed a reliability need occurring in this time period in the Reference Scenario, LIPA would do further analysis on specific types of potentially attractive capacity and would look into starting a procurement process for that capacity now, in order to ensure that it could be built on time. Any analysis showing a reliability need date after 2025 would be addressed in future IRPs when the market conditions for those outer years are less speculative.

In fact, the IRP Reference Scenario found a reliability need for new capacity in 2030 (using the 2016 load forecast). This need was determined using the NYISO reliability method. The case in which CLI-II is assumed built and online by 2020 delayed this reliability need until 2035. However, both of these need dates are beyond the ten year "action" window, meaning CLI-II would not provide needed reliability value to LIPA. Indeed, no additional plants are needed for

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26 The IRP splits the Zone K load into two sub-areas, LIPA and non-LIPA Zone K. An additional Reference Scenario was performed using the 2017 Zone K peak load forecast, which decreases the peak and energy values in Zone K even further.

that purpose within the actionable window. Accordingly, all the focus on selecting new assets, if any, should be on finding the least cost way of satisfying state policy objectives or choosing new plants that have enough near term and present value economic benefits (system savings) to offset their own fixed and infrastructure costs, rather than on meeting distant future capacity needs prematurely.

For generation resource planning purposes, LIPA's relevant costs are the incremental generation and transmission costs to serve load, which (due to its PPAs and TCCs) consist almost entirely of fuel expenses, off-island purchases, and fixed costs needed to pay for capacity contract rights and infrastructure upgrades to support that capacity. Scenarios and strategies can be compared in terms of how these costs change by virtue of alternative plants or contracts being added to the supply mix. We conduct this analysis using 2025 herein as our comparison year, because it is after the assumed installation date of CLI-II, and the assumed repowering dates for Port Jefferson and E. F. Barrett in their respective hypothetical scenarios, but before any generic capacity is added in any scenario (beginning around 2030).

Figure 5 below (and Figures 6 and 7 later in the report) provides a breakdown of the costs (and offset to costs) in 2025 from the system values in the 2016 IRP Reference Scenario to their values when CLI-II is built (or, later, for the E. F. Barrett or Port Jefferson repowering projects, all referred to as the Construction Scenarios). Positive values indicate costs and negative values indicate offsets to the costs. The difference column subtracts the Reference Scenario values from the Construction Scenario values to see where there are net cost reductions (or increases). The figure decomposes those changes into three categories (indicated in the grey box at the left hand-side of the Figure):

1) <u>New fixed costs associated with the Construction Scenario:</u> New costs arise from the new plant's own PPA, any build-out of the electric transmission or fuel supply infrastructure to interconnect it reliably, and its impacts on PILOTs.
2) <u>Changes in existing fixed costs between the Reference Scenario and Construction Scenario:</u> Some fixed costs incurred in the Reference Scenario are avoided in the Construction Scenario, including those from the existing plant's PPA, revised PILOTs and potential cost offsets from the reduced capacity purchase costs. Please note that the anticipated capacity price and plant capacity will change between the Reference Scenario and Construction Scenarios.
3) <u>Change in variable costs between the Reference Scenario and Construction Scenario</u>: The new plant will alter several categories of operating costs born in LIPA rates, including fuel costs of all existing and new LIPA generation assets and how the cost and quantity of purchased power for load is affected by the new plant. Purchase power costs change for two reasons: First, because a new plant alters NYISO supply costs and hence on-island LBMPs, which affect LIPA's costs to the extent it has unhedged exposure to such impacts. Because of LIPA's generation contracts and transmission congestion contracts (TCCs),

only a few percent of its load is exposed to this change. Second, a new plant displaces some off-island purchases that would otherwise be made (so those costs are avoided entirely). This is also typically a few percent of load. Regarding LIPA's variable costs, the fact that the new plants are generally more efficient than the existing fleet causes them to reduce fuel costs from older units, but of course bearing their own, new fuel expenses. The combined effect of these is passed through to LIPA customers.

These net costs are summed up in the last section of the table, with the first total (LIPA Annual Costs) capturing everything that affects LIPA customers, while the subsequent totals exclude the build-outs for fuel access, transmission upgrades, other upgrades (if any), and changes to the PILOTs that are associated with the new plants. These values are shown just to indicate the effect of these outside-of-plant costs on the total.

Figure 5: Caithness Long Island – II System Cost in 2025

	Measure	Units	Notes	Reference [A]	Caithness II [B]	Plant Value [C]: [B] - [A]
New Fixed Costs	New Fixed Costs					
	PPA-Related Costs	$mm	[1]	REDACTED	REDACTED	REDACTED
	Fuel Upgrades	$mm	[2]	REDACTED	REDACTED	REDACTED
	T&D Upgrades	$mm	[3]	REDACTED	REDACTED	REDACTED
	Other (ramp-down, demolition)	$mm	[4]	REDACTED	REDACTED	REDACTED
	PILOTs	$mm	[5]	REDACTED	REDACTED	REDACTED
	Total New Fixed Costs	**$mm**	**[6] sum([1] through [5])**	**-**	**294.61**	**294.61**
Old Fixed Costs and NYISO Capacity Costs	Old Fixed Costs					
	PPA-Related Costs	$mm	[7]	REDACTED	REDACTED	REDACTED
	PILOTs	$mm	[8]	REDACTED	REDACTED	REDACTED
	Total Old Fixed Costs	*$mm*	*[9]: [7] + [8]*	*REDACTED*	*REDACTED*	*REDACTED*
	NYISO Capacity Costs					
	LI Capacity Price	$/kW-mo	[10]	4.89	3.49	(1.40)
	Capacity	MW	[11]	-	748	748
	Reduced Capacity Purchases	*$mm*	*[12]: -([10] X [11] X 12)/1,000*	*-*	*(31.33)*	*(31.33)*
	Total Old Fixed Costs, net of NYISO Capacity Costs	**$mm**	**[13]: [9] + [12]**	**REDACTED**	**REDACTED**	**REDACTED**
	Total Fixed Costs	**$mm**	**[14]: [6] + [13]**	**-**	**263.28**	**263.28**
Net Market Purchases and Fuel Costs	Net Market Purchase Costs					
	LIPA Load	MWh	[15]	21,802,000	21,802,000	-
	LI Merchant Purchases, % of Load	%	[16]	6.0%	4.6%	-1.4%
	LI Merchant Purchases	MWh	[17]: [15] X [16]	1,300,000	996,000	(304,000)
	LI Avg LBMP	$/MWh	[18]	61.30	54.99	(6.31)
	Cost of Load from Merchant Gen	$mm	[19]: ([17] X [18])/1,000,000	79.69	54.77	(24.92)
	Percent of Off-Island Purchases	%	[20]	51.4%	43.3%	-8.1%
	Off-Island Purchases	MWh	[21]: [15] X [20]	11,206,228	9,440,266	(1,765,962)
	Cost of Off-Island Purchases and Sales	$mm	[22]	402.27	323.45	(78.82)
	Total Net Market Purchase Costs	*$mm*	*[23]: [19] + [22]*	*481.96*	*378.21*	*(103.75)*
	Variable Cost (fuel)					
	LIPA Existing Generation	$mm	[24]	485.14	344.38	(140.76)
	Caithness II	$mm	[25]	-	218.98	218.98
	Total Variable Cost (fuel)	*$mm*	*[26]: [24] + [25]*	*485.14*	*563.36*	*78.23*
	Total Net Market Purchases and Fuel Costs	**$mm**	**[27]: [23] + [26]**	**967.10**	**941.58**	**(25.52)**
	Total Variable Costs	**$mm**	**[28]: [27]**	**967.10**	**941.58**	**(25.52)**
Net Costs	System Cost					
	LIPA Annual Total Cost	**$mm**	**[29]: [14] + [28]**	**967**	**1,205**	**237.76**
	Without Fuel Upgrades	**$mm**	**[30]: [29] - [2]**	**REDACTED**	**REDACTED**	**REDACTED**
	Without T&D Upgrades	**$mm**	**[31]: [30] - [3]**	**REDACTED**	**REDACTED**	**REDACTED**
	Without Other (ramp-down, demolition)	**$mm**	**[32]: [31] - [4]**	**REDACTED**	**REDACTED**	**REDACTED**
	Without PILOTs	**$mm**	**[33]: [32] - [5] - [8]**	**REDACTED**	**REDACTED**	**REDACTED**

Sources and Notes:

[1] – [5], [7], [8], [11]: Draft Caithness II PPA.

[10], [16], [18], [20, [22], [24], [25]: 2016 IRP data.

[15]: LIPA portion of 2016 NYISO Goldbook Zone K Load Forecast, adjusted for demand side resources.

[24] Includes 18% LIPA PPA of Nine Mile and 10 MW LIPA PPA of Freeport.

[1] – [5]: PPA-related costs are REDACTED, fuel upgrades are REDACTED, levelized T&D upgrades are REDACTED, and PILOTs are REDACTED.

[3]: REDACTED.

[18]: Building CLI-II will have a durable impact on the LI LBMP while the effect on outside regions is much smaller.

As this Figure indicates, LIPA would incur several types of fixed costs if CLI-II were to be built. These costs include the proposed capacity and fixed cost payments under the PPA to CLI-II, annualized carrying charges (or tariffs) for the upgrade costs of the fuel pipeline to serve CLI-II, carrying costs on transmission and distribution (T&D) upgrades needed to ensure the full, reliable deliverability of energy from CLI-II to the rest of Long Island, and the PILOTs (payments in lieu of taxes) that have been negotiated by the CLI-II developers. These amounts are known from the updated PPA pricing proposal submitted by Caithness management from December 2014, along with evaluations completed by LIPA in regard to the necessary fuel and transmission upgrades. In aggregate, they total $295 million (row [6]) in 2025.

The new CLI-II would also be a capacity resource in NYISO under the control of LIPA, so that would reduce LIPA's costs for purchasing its IRM obligations, by an estimated at $31 million (row [12]). The net fixed cost, adjusted by capacity purchase savings, is $263 million (row [14]).

Results in the 2016 IRP GE MAPS simulations show that the CLI-II plant reduces the Zone K average LBMP in 2025 by $6.31/MWh compared to the Reference Scenario (row [18]), a result similar to (but larger per MWh than)[27] what was found in the GE 2015 study. However, the only actual savings to customers due to this LI LBMP reduction arises from a small percentage of purchases from on-island merchant generators for which LIPA lacks hedges (through PPAs and TCCs). The IRP analysis results show that on-island merchant purchases accounted for 6.0% of load in the Reference Scenario (row [16]), purchased at an average LBMP of $61.30/MWh (row [18]), while in the CLI-II Scenario this amount was reduced to 4.6% of load (row [16]) at $54.99/MWh (row [18]) when CLI-II is built. The resulting change in annual costs would be $25 million of customer savings (row [19]).[28]

The installation of CLI-II would also displace some off-island merchant purchases and increase LIPA exports to other zones. Comparing supply costs in the Reference and CLI-II Scenarios in the IRP studies show that in 2025 this is a net reduction of about 8.1% of load from the Reference Scenario to the CLI-II Scenario (row [20]) and that the overall change in cost is $79 million (row [22]).

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27 Despite higher gas prices in the GE 2015 Study, it found only a $2.98/MWh average LBMP reduction between their Reference and CLI-II Scenarios in 2025, leading to only an $85 Million reduction in the cost to serve load.

28 The TCCs held by LIPA do not fully hedge them against all energy market price changes, just against price changes in LI LBMPs. It is possible that there will be a slight reduction in NYISO and adjacent RTO market prices due to Caithness or the repowering projects. Such reductions would create savings for LIPA when it is buying from those areas. However, those effects are both smaller and more transient than on-island LBMP reductions – because LI is a much smaller region with limited transmission with neighboring areas, within which the effects new capacity have much longer lived impacts than in a larger interconnected area.

The presence of the newer, more efficient CLI-II would also reduce the use of existing generation, resulting in some fuel savings (off-set to cost) at those plants, projected for 2025 at $141 million (row [24]). However, there will be a fuel cost from CLI-II itself of about $219 million (row [25]). The resulting net change in fuel cost will be an increase of $78 million (row [26]). Altogether the combined net market purchase and fuel cost is estimated to be reduced by $26 million (row [28]).

The total cost to LIPA is estimated to increase by $238 million with CLI-II (row [29]) - the sum of the net fixed cost of $263 million (row [14]) and the combined net market purchase and fuel cost reduction of $26 million (row [28]). This cost increase will be reduced if the annualized carrying charges (or tariffs) for the upgrade costs of the fuel pipeline to serve CLI-II, carrying costs on transmission and distribution (T&D) upgrades needed to ensure the full, reliable deliverability of energy from CLI-II to the rest of Long Island, and the PILOTs (payments in lieu of taxes) that have been negotiated by the CLI-II developers, are netted out (rows [30] through [33]).

The IRP analysis does not break out these components of plant value separately in this fashion, instead focusing on annual total costs or rates to LIPA with and without various resources. However, it reports a result expressed in terms of impact of CLI-II on total rates that supports the finding shown above. Specifically, the IRP analysis shows that CLI-II would increase 2025 average customer rates by about 1.4 cents per kWh, from 20.74 to 22.17 cents/kWh relative to the Reference Scenario.[29] Similar analyses of this plant under high and low gas price conditions show that its net value (corresponding to the lower right corner of the above table) grows in a high gas price scenario (because its efficiency is more beneficial) and falls in a low gas price case, but in neither of these does it produce positive net values. The IRP results also include a present value calculation of how much overall costs to customers would change from 2016 - 2035 under each resource alternative evaluated, and that shows that CLI-II would cause more than a $1.6 billion NPV increase.

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[29] This 2025 change in rates is equivalent to a revenue requirement increase in that year of about $300 million. This is larger than the $238 million we calculate as the incremental generation and infrastructure costs because PPA fixed costs are treated like debt in LIPA ratemaking and so require a coverage allowance. This mark-up is required for LIPA to maintain its credit ratings.

VIII. Emerging NY Policy Outlook

The above breakdown of plant and system net value of CLI-II shows that it does not produce net economic benefits for LIPA in 2025, or on an NPV basis, under the range of conditions evaluated in the IRP. There are also some indications of other changes in the NY power system, that are not reflected in the above economic analysis, that could further adversely affect the type or timing of need or value for plants on LI. Below we describe these possibilities and the direction of impact they are likely to have, if they occur, on the attractiveness of CLI-II.

E. Off-Shore Wind

Governor Cuomo outlined in his 2016 State of the State address that the New York State Energy Research and Development Authority (NYSERDA) is crafting an Offshore Wind Master Plan. A Blueprint was issued by NYSERDA in the summer of 2016 with the Master Plan scheduled to be released by year end 2017. The Blueprint indicates that 2,400 MW of off-shore wind would be developed and installed in the Atlantic Ocean, south of Long Island, by 2030. The Blueprint also suggest the off-shore wind potential for New York off its Atlantic coast is estimated to be 39 GW (higher than the current summer peak load of 33 GW for the entire state)[30] and that off-shore wind can be a critical component to reach New York's Clean Energy Standard (CES) mandate that 50% of the state's electricity be from renewables by 2030.[31] Given that the off-shore wind development schedule and interconnection locations are still unclear, the impact for LI is hard to estimate, however, it will likely result in excess capacity being available to LI putting further downward pressure on the need for CLI-II or any new resource.

F. Indian Point Retirement

In January 2017, Governor Cuomo announced an agreement to close the Indian Point nuclear plant (IPEC) in 2020 and 2021. The closing of over 2,000 MW of capacity less than 40 miles north of New York City could have implications for NYISO's reliability planning in Zones G through K. In 2012, the NY Department of Public Service (DPS) commenced the proceeding to conduct an Indian Point Contingency Plan study, assuming the plant would shut down in December 2015 when its original license expired. The study identified that the IPEC shutdown would result in approximately 1,450 MW of new resource needs to maintain reliability. Through the course of the process, DPS approved three transmission projects that were proposed by NY

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30 NYSERDA, "Blueprint for the New York State Offshore Wind Master Plan,"

NYISO. "2016 Load and Capacity Data: Goldbook." April 2016.

31 New York State, "Governor Cuomo Announces Establishments of Clean Energy Standard that Mandates 50 Percent Renewables by 2030." August 1, 2016. Accessed at: https://www.governor.ny.gov/news/governor-cuomo-announces-establishment-clean-energy-standard-mandates-50-percent-renewables

Transmission Owners (TOTS projects) that relieved up to 600 MW of the anticipated need along with 180 MW of energy efficiency and demand response programs. DPS took no further action, assuming that the market would take care of itself for the balance.

Just as DPS anticipated, attracted by the potential of IPEC retirement and associated revenue increase, a number of merchant generator (and transmission) projects have been developed nearby the IPEC site. The 720 MW CPV Valley, currently under construction with an expected in service date of 2018 and the 1,020 MW Cricket Valley, currently applying for various permits and closed on financing with the expected in service date of 2019, are two of such projects. A 320kV HVDC line to bring power generated by renewables from upstate and/or Hydro Quebec is also being planned with an in service date of 2021. These new combined cycle plants that are being planned, in addition to the TOTS, EE and DR solutions, are anticipated to minimize the impact of IPEC's retirement.

G. NY REV

Reforming the Energy Vision (NY REV) is New York's plan to create a cleaner, more resilient, and ideally more affordable energy system through a regulatory overhaul of its distribution services model. NY REV aims to transform the state's energy distribution system, modernizing it towards being a platform for supplying some distributed (and perhaps cleaner) power among customers and back to the wholesale grid. The impact of NY REV to LI's resource adequacy is uncertain but its direction is clearly in support of that occurring at an increasing pace over the next few years. This would likely put downward pressure on the need for new resources, including CLI-II because it favors distributed energy resources and other renewable resources. If NY REV significantly reduces peak demand, generation in oversupplied areas, including LI, could become stranded.

H. Clean Energy Standard

The NY Clean Energy Standard (CES) was approved in 2016, and it now mandates that renewable sources should provide 50% of the State's electricity by 2030. Associated goals include a 40% reduction of Greenhouse Gas (GHG) from 1990 levels, and reducing energy consumption of buildings by 23% from 2012 levels. Various state programs supporting clean energy are being redesigned to accelerate market growth and unlock private investment. Some cities have taken their own initiatives that are complementary, such as New York City's "80 by 50" aspiration to have its energy footprint 80% decarbonized relative to 2005 levels by 2050. Especially given the low load growth projected for New York, achieving these CES and decarbonization goals will require that renewable resources increasingly displace fossil-fired generation plants.

It is impossible to be precise about the effects of these potential changes, because their efficacy and pace of accomplishment is uncertain, but our views are as follows:

- Offshore wind – When this happens, it is likely to reduce the need for capacity, because there is some overlap of typical offshore wind conditions with peak load. More significantly, it will reduce energy prices, thereby reducing the operating margins of CLI-II and its load cost savings, and reducing capacity prices (and similarly for all of LIPA's fleet). It will also depress the price of CO_2 unless RGGI standards are tightened considerably. It may also affect the transmission needs of LI (to make it possible to import and export that amount of new offshore capacity), and it may induce a need for smaller, faster, perhaps more dispersed peakers (rather than baseload units like CLI-II).
- Indian Point shutdown – This is likely to be fully offset by already planned and underway replacement generation projects, at least in regard to whether it affects the need for LI capacity.
- NY REV and CES – Both of these push against the need for more central station plants like CLI-II, except perhaps for fast integration and backup resources (likely many small peakers). CLI-II may be able to provide some of those ancillary services, but they will not be as valuable to LIPA as providing steady baseload energy and capacity would have been absent the REV and CES. Wholesale capacity and energy both will lose value as distributed energy resources (DERs) and mandated renewables become more prevalent. Overall, these are a negative influence on potential CLI-II value.

With the exception of shutting down Indian Point, all of these policies will tend to push towards preferring (or requiring) better sources of non-carbon emitting power than CLI-II. Thus, even though the thermal efficiency of CLI-II would displace emissions from some older, more emitting plants, those environmental benefits are likely to be eroded by, or better achieved by, the types of resources that would be developed under the above policy initiatives.

Another effect of all of these policies is that they increase uncertainty about what the scope and nature of future needs will be. As a general rule of resource planning, when the future becomes more uncertain, it becomes more economical to "wait and see" rather than commit to a large, irreversible expenditure. As long as not committing today does not foreclose obtaining a similar asset in the future, and as long as there are not very high interim costs of waiting to see how conditions change (such as very high shortage costs, or rapid escalation in development costs), it is beneficial to allow uncertain conditions to unfold. If they become more favorable to the asset in question, it can then be built or bought with more confidence that it will be economical. If conditions become less auspicious, LIPA will have avoided committing large amounts of money to an uneconomical fixed asset that it is now stuck with. One avoids some bad outcomes and not much is lost while waiting to see if a good outcome is likely, thereby gaining net value over committing today. This applies to CLI-II, so the future uncertainties further argue against pursuing that project now.

IX.Proposed Repowering Projects

LIPA was directed by the NY Legislature to evaluate the feasibility and benefits of repowering certain existing assets, the E. F. Barrett and Port Jefferson plants, and it has done so in its latest IRP. Technically, these are more replacing than repowering, in that in each scenario a new facility would be built on the same site, rather than carving out and upgrading portions of the existing plants.

I. E. F. BARRETT REPOWERING

The 2016 IRP Barrett Repowering Scenario assumes the new Barrett units will be placed in-service January 2021, with all but two combustion turbines of the existing facilities on the same date and no other changes to the assets from the IRP Reference Scenario. The "repowered" Barrett is a new 637 MW combined cycle project comprised of two 1x1 gas fired units.

It would be built adjacent to the existing Barrett facilities, so those facilities can continue to operate during the construction period of the new plant. The new plant is sized to essentially be a direct replacement of existing facilities. As a result, there is only a 50.8 MW net capacity difference (increase) between this scenario and the Reference Scenario. Relatedly, the resulting need date for additional, future LIPA capacity in the Barrett Repowering Scenario is the same as it was in the Reference Scenario, 2030 using the 2016 load forecasts, and 2035 using 2017 load forecasts.

The repowered project has better operating efficiencies than the units it would be replacing. These new CCs would have about a 6.8 MMBtu/MWh heat rate compared to a heat rate of about 10 for the old steam units and 14.8 – 16.5 MMBtu/MWh for the old combustion turbines. The heat rate of the new units is comparable to CLI-II in efficiency and market impact. Other advantages include lower emission rates, faster ramping capabilities, and a potential reduction in scheduled outages.

Even though it is only marginally larger than the old facilities, the new Barrett plant still has incremental direct costs and system economic impacts to LIPA. These impacts are summarized below in Figure 6. This figure is the same format as was used in Figure 5, to present information for CLI-II. That is, this figure compares annual, 2025 costs in the Reference Scenario to those in the Barrett Repowering Scenario to determine the net customer savings or costs.

Figure 6: Barrett Repowering System Costs in 2025

	Measure	Units	Notes	Reference [A]	Barrett [B]	Plant Value [C]: [B] - [A]
New Fixed Costs	New Fixed Costs					
	PPA-Related Costs	$mm	[1]	REDACTED	REDACTED	REDACTED
	Fuel Upgrades	$mm	[2]	REDACTED	REDACTED	REDACTED
	T&D Upgrades	$mm	[3]	REDACTED	REDACTED	REDACTED
	Other (ramp-down, demolition)	$mm	[4]	REDACTED	REDACTED	REDACTED
	PILOTs	$mm	[5]	REDACTED	REDACTED	REDACTED
	Total New Fixed Costs	**$mm**	**[6] sum([1] through [5])**	**-**	**188.67**	**188.67**
Old Fixed Costs and NYISO Capacity Costs	Old Fixed Costs					
	PPA-Related Costs	$mm	[7]	REDACTED	REDACTED	REDACTED
	PILOTs	$mm	[8]	REDACTED	REDACTED	REDACTED
	Total Old Fixed Costs	*$mm*	*[9]: [7] + [8]*	*REDACTED*	*REDACTED*	*REDACTED*
	NYISO Capacity Costs					
	LI Capacity Price	$/kW-mo	[10]	4.89	4.57	(0.32)
	Capacity	MW	[11]	586.60	637.40	50.80
	Reduced Capacity Purchases	*$mm*	*[12]: -([10] X [11] X 12)/1,000*	*(34.44)*	*(34.99)*	*(0.55)*
	Total Old Fixed Costs, net of NYISO Capacity Costs	**$mm**	**[13]: [9] + [12]**	**REDACTED**	**REDACTED**	**REDACTED**
	Total Fixed Costs	**$mm**	**[14]: [6] + [13]**	**50.18**	**153.68**	**103.49**
Net Market Purchases and Fuel Costs	Net Market Purchase Costs					
	LIPA Load	MWh	[15]	21,802,000	21,802,000	-
	LI Merchant Purchases, % of Load	%	[16]	6.0%	4.8%	-1.2%
	LI Merchant Purchases	MWh	[17]: [15] X [16]	1,300,000	1,044,000	(256,000)
	LI Avg LBMP	$/MWh	[18]	61.30	56.48	(4.82)
	Cost of Load from Merchant Gen	$mm	[19]: ([17] X [18])/1,000,000	79.69	58.96	(20.73)
	Percent of Off-Island Purchases	%	[20]	51.4%	44.8%	-6.6%
	Off-Island Purchases	MWh	[21]: [15] X [20]	11,206,228	9,767,296	(1,438,932)
	Cost of Off-Island Purchases and Sales	$mm	[22]	402.27	339.08	(63.19)
	Total Net Market Purchase Costs	*$mm*	*[23]: [19] + [22]*	*481.96*	*398.05*	*(83.92)*
	Variable Cost (fuel)					
	LIPA Existing Generation	$mm	[24]	485.14	339.12	(146.02)
	Repowered Barrett Units	$mm	[25]	-	197.49	197.49
	Total Variable Cost (fuel)	*$mm*	*[26]: [24] + [25]*	*485.14*	*536.61*	*51.47*
	Total Net Market Purchases and Fuel Costs	**$mm**	**[27]: [23] + [26]**	**967.10**	**934.66**	**(32.44)**
	Total Variable Costs	**$mm**	**[28]: [27]**	**967.10**	**934.66**	**(32.44)**
Net Costs	System Cost					
	LIPA Annual Total Cost	**$mm**	**[29]: [14] + [28]**	**1,017**	**1,088**	**71.05**
	Without Fuel Upgrades	**$mm**	**[30]: [29] - [2]**	**REDACTED**	**REDACTED**	**REDACTED**
	Without T&D Upgrades	**$mm**	**[31]: [30] - [3]**	**REDACTED**	**REDACTED**	**REDACTED**
	Without Other (ramp-down, demolition)	**$mm**	**[32]: [31] - [4]**	**REDACTED**	**REDACTED**	**REDACTED**
	Without PILOTs	**$mm**	**[33]: [32] - [5] - [8]**	**REDACTED**	**REDACTED**	**REDACTED**

Sources and Notes:

[1] – [5], [7], [8], [11]: Draft Barrett PPA.

[10], [16], [18], [20, [22], [24], [25]: 2016 IRP data.

[15]: LIPA portion of 2016 NYISO Goldbook Zone K Load Forecast, adjusted for demand side resources.

[24] Includes 18% LIPA PPA of Nine Mile and 10 MW LIPA PPA of Freeport.

[11]: ICAP Values are used.

[4]: REDACTED

[18]: Repowering Barrett will have a durable impact on the LI LBMP while the effect on outside regions is much smaller.

The repowered Barrett units will have a new PPA, but the PPA's gross cost (row [1]) is not the proper measure of the new Barrett's ratepayer impact because retirement of the existing Barrett reduces LIPA's ongoing expense for those units under the old PSA (row [7]). Specifically, in the Reference Scenario these units continue operating until 2028 under the existing PSA and LIPA assumes the PSA will be renewed under similar terms to the existing PSA through the IRP study period. The PSA costs of the retired Barrett units are avoided/replaced by the repowering. Therefore, only the net amount is an incremental cost to ratepayers from the repowering.

Unlike CLI-II, the Repowered Barrett plant will have no T&D or fuel upgrade costs because it is able to continue to use the infrastructure built for the original Barrett plant. Indeed, the repowering was sized to make this possible without incremental costs (rows [2] and [3]). LIPA will incur costs related to the ramp-down and demolition of retiring the existing Barrett units. These costs will be incurred when the actual ramp-down and demolition take place, which would not be captured in our 2025 analysis. To account for this we amortized these expenses over the 30 year life of the Barrett PPA (row [4]).

The plant also does not expose LIPA to any new PILOTs. Instead, the PILOTs associated with the new plant are projected to be modestly less than the payments associated with the existing plants (rows [5] and [8]).[32] Thus, there is a modest net PILOTs savings from the repowering. However, we understand that LIPA has ongoing tax assessment challenges on the existing plant, claiming a significant over-assessment of the valuation basis for the existing plant, and so such savings relative to the existing plant are somewhat speculative. It should be noted that as an economic benefit matter, PILOTs are not a true cost to the aggregate group of customers on Long Island. Rather, they are a transfer payment to taxpayers in towns with power plants from all ratepayers, most of whom are not in those towns. Thus it is a wealth transfer with no net cost or benefit to LI as a whole. Nonetheless, it is a cause of charges in LIPA rates, which would change due to some of these possible plants, so we include it in the impact comparisons.

The new Barrett plant would also produce a very modest increase in capacity available to LIPA from the 50.8 MW increase in size of the replacement vs. retired units. This would avoid that quantity of purchases from the NYISO capacity market for a savings estimated at $0.6 million (row [12]). The change in net fixed cost, adjusted by the capacity revenue offset, is estimated to be an increase of $103 million (row [14]).

The repowered Barrett plant reduces the load-weighted 2025 Zone K LBMP by $4.82/MWh (row [18]), but as with CLI-II, only a small portion (4.8%) of load costs are affected by this on-island LBMP reduction, for a $21 million savings (row [19]). In addition to this are: a $63 million savings from off-island net purchases (row [22]), $146 million of fuel savings at other units (row

32 LIPA analysis indicates that the existing PILOTs are significantly higher than those paid on new plants in other LI locations.

[24]), and its own fuel costs of $197 million (row [25]), adding up to a combined net market purchase and fuel cost reduction of $32 million (row [28]). These cover only a fraction of Barrett's net PPA costs.

Overall, we find that Barrett's 2025 incremental cost to the system in 2025 is $71 million *i.e.*, the repowering results in an increase in cost to LI customers. Consistent with this analysis, the IRP analysis found that Barrett would increase 2025 average rates by .57 cents/kWh compared to the Reference Scenario. On an NPV basis over 2016-2035, the IRP analysis finds an increase in costs due to Barrett repowering of $827 million.

J. PORT JEFFERSON REPOWERING

The 2016 IRP Port Jefferson Repowering Scenario is also modeled as an adjustment to the IRP Reference Scenario, with only the repowering being different from other assumptions. This repowering is completed in 2023. The "repowered" Port Jefferson is again actually a replacement project, with a new 397 MW combined cycle plant displacing the two existing Port Jefferson steam units on the same site. Unlike Barrett, the original Port Jefferson steam units must be retired (March 2019) to allow for the construction of the new plant. Once construction is completed there will be a small net capacity increase, 17 MW, relative to the Reference Scenario. Importantly, no generating capacity reliability need arises during construction from the temporary capacity reduction (due to the Long Island capacity surplus), and the eventual need date for long run additional capacity in the Port Jefferson Repowering Scenario is the same as it was in the Reference Scenario, 2030 using 2016 load forecasts, and 2035 using 2017 forecasts.

To review system impacts we again use 2025 as our analysis year. The Port Jefferson impacts are qualitatively similar to the Barrett repowering and are displayed below in Figure 7. Because Port Jefferson is smaller than Barrett, it has lower costs for nearly all the items, with two exceptions. First, it requires a modest increase in gas supply infrastructure. Second, there has been no agreement reached with the town of Port Jefferson about PILOTS for the new facility, therefore it is assumed, for the purposes of this study that there will be no net change in PILOT costs.[33] In total, Port Jefferson's net cost to the system in 2025 is at $59 million - an increase in costs to LI customers. The IRP analysis found that Port Jefferson repowering would increase 2025 average rates by .50 cents/kWh compared to the Reference Scenario. Its 20-year NPV impact is an increase of $655 million.

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33 LIPA analysis indicates that the existing PILOTs are significantly higher than those paid on new plants in other LI locations

Figure 7: Port Jefferson Repowering System Costs in 2025

	Measure	Units	Notes	Reference [A]	Port Jefferson [B]	Plant Value [C]: [B] - [A]
New Fixed Costs	New Fixed Costs					
	PPA-Related Costs	$mm	[1]	REDACTED	REDACTED	REDACTED
	Fuel Upgrades	$mm	[2]	REDACTED	REDACTED	REDACTED
	T&D Upgrades	$mm	[3]	REDACTED	REDACTED	REDACTED
	Other (ramp-down, demolition)	$mm	[4]	REDACTED	REDACTED	REDACTED
	PILOTs	$mm	[5]	REDACTED	REDACTED	REDACTED
	Total New Fixed Costs	**$mm**	**[6] sum([1] through [5])**	**-**	**151.14**	**151.14**
Old Fixed Costs and NYISO Capacity Costs	Old Fixed Costs					
	PPA-Related Costs	$mm	[7]	REDACTED	REDACTED	REDACTED
	PILOTs	$mm	[8]	REDACTED	REDACTED	REDACTED
	Total Old Fixed Costs	*$mm*	*[9]: [7] + [8]*	*REDACTED*	*REDACTED*	*REDACTED*
	NYISO Capacity Costs					
	LI Capacity Price	$/kW-mo	[10]	4.89	4.63	(0.26)
	Capacity	MW	[11]	379.80	396.80	17.00
	Reduced Capacity Purchases	*$mm*	*[12]: -([10] X [11] X 12)/1,000*	*(22.30)*	*(22.05)*	*0.25*
	Total Old Fixed Costs, net of NYISO Capacity Costs	**$mm**	**[13]: [9] + [12]**	**REDACTED**	**REDACTED**	**REDACTED**
	Total Fixed Costs	**$mm**	**[14]: [6] + [13]**	**49.24**	**129.09**	**79.85**
Net Market Purchases and Fuel Costs	Net Market Purchase Costs					
	LIPA Load	MWh	[15]	21,802,000	21,802,000	-
	LI Merchant Purchases, % of Load	%	[16]	6.0%	5.6%	-0.3%
	LI Merchant Purchases	MWh	[17]: [15] X [16]	1,300,000	1,224,000	(76,000)
	LI Avg LBMP	$/MWh	[18]	61.30	58.25	(3.05)
	Cost of Load from Merchant Gen	$mm	[19]: ([17] X [18])/1,000,000	79.69	71.30	(8.39)
	Percent of Off-Island Purchases	%	[20]	51.4%	47.3%	-4.1%
	Off-Island Purchases	MWh	[21]: [15] X [20]	11,206,228	10,312,346	(893,882)
	Cost of Off-Island Purchases and Sales	$mm	[22]	402.27	361.35	(40.92)
	Total Net Market Purchase Costs	*$mm*	*[23]: [19] + [22]*	*481.96*	*432.65*	*(49.32)*
	Variable Cost (fuel)					
	LIPA Existing Generation	$mm	[24]	485.14	379.59	(105.54)
	Repowered Port Jefferson Units	$mm	[25]	-	134.46	134.46
	Total Variable Cost (fuel)	*$mm*	*[26]: [24] + [25]*	*485.14*	*514.05*	*28.92*
	Total Net Market Purchases and Fuel Costs	**$mm**	**[27]: [23] + [26]**	**967.10**	**946.70**	**(20.40)**
	Total Variable Costs	**$mm**	**[28]: [27]**	**967.10**	**946.70**	**(20.40)**
Net Costs	System Cost					
	LIPA Annual Total Cost	**$mm**	**[29]: [14] + [28]**	**1,016**	**1,076**	**59.45**
	Without Fuel Upgrades	**$mm**	**[30]: [29] - [2]**	**REDACTED**	**REDACTED**	**REDACTED**
	Without T&D Upgrades	**$mm**	**[31]: [30] - [3]**	**REDACTED**	**REDACTED**	**REDACTED**
	Without Other (ramp-down, demolition)	**$mm**	**[32]: [31] - [4]**	**REDACTED**	**REDACTED**	**REDACTED**
	Without PILOTs	**$mm**	**[33]: [32] - [5] - [8]**	**REDACTED**	**REDACTED**	**REDACTED**

Sources and Notes:

[1] – [5], [7], [8], [11]: Draft Port Jefferson PPA.

[10], [16], [18], [20, [22], [24], [25]: 2016 IRP data.

[15]: LIPA portion of 2016 NYISO Goldbook Zone K Load Forecast, adjusted for demand side resources.

[24] Includes 18% LIPA PPA of Nine Mile and 10 MW LIPA PPA of Freeport.

[11]: ICAP Values are used.

[2]: Included in [1].

[4]: REDACTED

[18]: Repowering Port Jefferson will have a durable impact on the LI LBMP while the effect on outside regions is much smaller.

X. Conclusions

We were asked to independently analyze and provide a recommendation as to whether it was reasonable and appropriate for LIPA to adopt the NYISO planning criteria in 2014 and whether it is in the best interests of LIPA's ratepayers for LIPA to proceed with either CLI-II or the repowering projects at this time. To address that, we considered the following questions:

- Is there a basis for preferring a more conservative approach to reliability planning than the NYISO criteria would require? Was the 2014 decision to adopt NYISO criteria and hold off on pursuing the CLI-II plant until a full IRP was completed a prudent one?
- Does the economic outlook in the most recent IRP analysis justify CLI-II?
- Do any future uncertainties or pending regulatory policies make CLI-II potentially more attractive economically or environmentally than it currently appears?
- Are the repowering projects of E. F. Barrett and Port Jefferson needed for reliability and/or economic purposes?

Based on all of our analyses for this report, our short answer is that we do not find a compelling reason for LIPA to proceed with CLI-II or the repowering projects. None of the plants are needed for reliability or economic purposes. For all the options the plant costs exceed their benefits for at least the next decade. There is little likelihood of the plants, or other similar capacity, becoming rapidly or strongly needed or economical given the most likely market changes in the coming years.

More specifically with regard to the questions above, our answers are that it was appropriate to adopt the NYISO reliability planning standards in 2014, because conditions had changed to eliminate many of Long Island's isolation risks. In the period from about 2000 to about 2010 when NYISO rules and market processes in NY were being developed, there was a reasonable need for a more conservative approach to reliability planning for LI, but the gaps and risks that prevailed in the early 2000s were largely mitigated by 2014 by new market structures (capacity markets), physical expansion into and on LI that reduced risk and improved supply diversity (T&D upgrades), declining load growth, and more stable and less costly market conditions (lower natural gas and resulting wholesale power prices). Applying the 80% CI criteria today (as well as in 2014) would call for a significant over-supply of capacity, especially in an environment where the economic value of conventional, baseload fossil-fired power plants has been and may continue to decline.

None of the plants under consideration are economical in 2025. All three projects would raise costs and electric rates over time. Figure 8 below summarizes the major subtotals of LIPA customer costs in 2025 from the three figures previously presented on the impacts of each project.

Figure 8: Summary of 2025 System Costs

	Measure	CLI-II Plant Value	Barrett Plant Value	Port Jefferson Plant Value
New Fixed Costs	New Fixed Costs			
	Total New Fixed Costs	**294.6**	**188.7**	**151.1**
Old Fixed Costs and NYISO Capacity Costs	Old Fixed Costs			
	Total Old Fixed Costs	*REDACTED*	*REDACTED*	*REDACTED*
	NYISO Capacity Costs			
	Reduced Capacity Purchases	*(31.3)*	*(0.6)*	*0.25*
	Total Old Fixed Costs, net of NYISO Capacity Costs	***REDACTED***	***REDACTED***	***REDACTED***
	Total Fixed Costs	**263.3**	**103.5**	**79.8**
Net Market Purchases and Fuel Costs	Net Market Purchase Costs			
	Total Net Market Purchase Costs	*(103.7)*	*(83.9)*	*(49.3)*
	Variable Cost (fuel)			
	Total Variable Cost (fuel)	*78.2*	*51.5*	*28.9*
	Total Net Market Purchases and Fuel Costs	**(25.5)**	**(32.4)**	**(20.4)**
	Total Variable Costs	**(25.52)**	**(32.44)**	**(20.40)**
Net Costs	System Cost			
	LIPA Annual Total Cost	**237.8**	**71.1**	**59.4**
	Without Fuel Upgrades	***REDACTED***	***REDACTED***	***REDACTED***
	Without T&D Upgrades	***REDACTED***	***REDACTED***	***REDACTED***
	Without Other (ramp-down, demolition)	***REDACTED***	***REDACTED***	***REDACTED***
	Without PILOTs	***REDACTED***	***REDACTED***	***REDACTED***

The net costs of Barrett and Port Jefferson repowering projects are smaller than CLI-II. However, that comparison is not quite "apples to apples" because the CLI-II PPA is for 20 years, while the developer of the Barrett and Port Jefferson repowering projects has proposed 30-year PPAs. This means the annual carrying cost is slightly higher on CLI-II than it would be with the same amortization horizon. If the CLI-II PPA had a 30-year horizon, its annual costs would fall by about $30-50 million depending on the financing terms, still leaving this scenario with an increased cost of about $190 - 210 million to LIPA ratepayers in 2025.

While these analyses are only for one specific year, 2025, it is a representative one because it is after all three projects have been developed and before any generic capacity is built for much longer term needs that may not even materialize. The IRP analysis NPV calculations confirm the likely persistence of these patterns of higher costs over time.

One possibility we did not explore is whether CLI-II would be attractive if it were built and some similar amount of older PSA capacity was shut-down and demolished. This would be a scenario somewhat like the repowering projects, in which the new plants displace some of their on-site, older, less efficient selves. Hence, those scenarios inform, at least qualitatively, what would likely result. Of course, many line items would change in the before- and after- net cost tables. Notably, the "old fixed costs" potentially avoided by retiring a like amount of PSA capacity would not be great enough to overcome the economic burden of the Caithness II plant, especially in light of the loss of the capacity benefits of the old plants. There would be additional ramp-down and demolition costs from the retired asset, currently not arising as part of the CLI-II calculations when it is built as a stand-alone asset. Overall, the Port Jefferson scenario is an informative, probably optimistic representation of what a scenario with CLI-II less about 300MWs or more of other units could look like. As noted above, the Port Jefferson repowering is not economical.

These 2025 annual costs, rate impacts, and 20-year NPV calculations all indicate that while either of these repowering projects would be somewhat more economical than CLI-II, we find that *there is no compelling reliability or economic need for any of the three projects*. In the Reference Scenario, with neither CLI-II nor the repowering projects, the first date of reliability need for new capacity is 2030 based on 2016 load forecasts and 2035 based on 2017 load forecasts. This is pushed out a few years by CLI-II, but not with a net economic benefit sufficient to give it a positive NPV (net 20-year savings). And there is a great deal of time between now and that date of possible need to see if it even occurs, or if so, if any of these types of plants are the most economical for the system conditions at that time.

That is, looking forward, the exposure to future risks seems skewed strongly towards preferring other types of plants than those proposed. The probable developments are pushing away from situations that CLI-II or the repowering projects would help mitigate (like significant load growth and/or rising marginal energy prices) and towards possibilities that would make the proposals even less attractive. The more likely scenarios include very little net load growth, plus energy and capacity price reductions due to development of significant renewables and distributed energy resources. These scenarios will require a shift towards needing mainly very flexible, small, dispersed peakers on a reconfigured T&D grid. Given the considerable uncertainty about the pace, locations, and types of changes that may occur in the next 10 - 15 years in and around LI due to technology developments and new, NY energy policies, it would be prudent to take the most cautious approaches to securing capacity and energy over this horizon. In this case, such risk considerations coupled with the projects' unattractive initial economic and reliability considerations argue for not pursuing any of them.

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