Appendix D-5

Energy Planning Process

D-5

Table of Contents

List of Exhibits

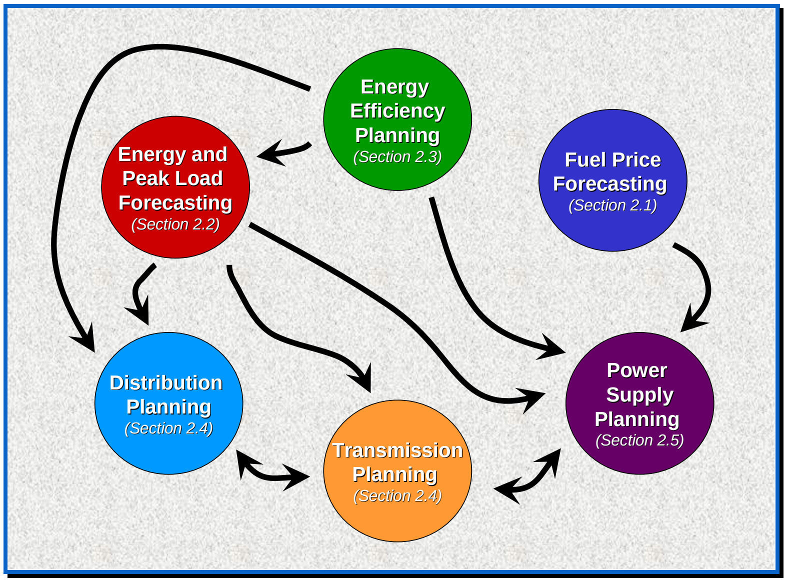
1 Introduction

LIPA's resource planning is a flexible process that seeks to meet both the short and long-term needs of the customer, while taking into account the changing conditions in the market, system, and industry. At the same time, the planning process seeks to balance the sometimes conflicting objectives of competitive cost, high reliability, and minimal environmental impact. The following steps are involved in this process:

- Determine projected energy balance (supply and demand) and assess the need for new resources,
- Identify diverse set of solutions to meet the need,
- Evaluate alternatives,
- Formulate a strategy to meet demand for electricity,
- Plan implementation, and
- Re-evaluate and update plan as conditions change.

These basic steps are applied in the planning process for each of the major system components: generation, transmission, and distribution. The resource planning process is driven by a number of elements or subprocesses, including; energy and peak load forecasting, fuel price forecasting, power supply planning, demand planning, transmission planning, and distribution planning. Exhibit 1-1 depicts the interaction among the major processes, and the data and information flow that occurs during the development of LIPA's comprehensive Electric Resource Plan.

Exhibit 1-1 Interaction of Planning Processes



2 Forecasting and Planning Processes

The remaining sections in this section describe the processes identified in Exhibit 1-1 that support the overall resource planning process, the tools used to support the process, and the criteria that frame the process.

2.1 Fuel Price Forecasting Process

Integrated fuel price forecasts are prepared, which include projections for natural gas, low sulfur residual oil (No. 6), and distillate oil. The forecasts are designed to capture near term market volatility as well as the uncertainty of the long range market. This is accomplished by forecasting a range of outcomes based on alternative scenarios. The forecasts are then monitored and updated as required to meet changing market conditions.

At minimum, two fuel forecasts are completed each year, one in the fall and one in the spring. The first three years of each price forecast are based on fuel prices in the commodities market for natural gas, residual oil, and fuel oil. Commodity prices are monitored, and trends are analyzed to select an appropriate forecast day. The commodity futures prices for natural gas and fuel oil, and swap prices for residual oil are used as the basis for the forecast. Delivery costs to the power plants are developed based on historic relationships. These two components are combined to get the monthly forecast price for the fuels.

Beyond three years, an econometric model forms the basis for the fuel price forecast for production area prices for natural gas and fuel oil. Residual oil long term forecasts are based on New York Harbor prices. An appropriate transportation cost is added to get to the forecasted delivered fuel price to the power plants. The long range forecast is combined with the short range forecast to get a scenario based fuel price forecast. The most likely long term scenario is combined with the short term base case to form a reference case forecast.

The fuel forecast inputs are monitored throughout the year. If market conditions change, long term assumptions are revised, or new input becomes available, the fuel forecasts are revised as required. LIPA’s goal is to provide a regularly reviewed and updated price forecast that presents a flexible and current outlook.

2.2 Energy and Peak Load Forecasting Process

The energy forecast is a fundamental component of energy planning. It is also used in conjunction with the fuel forecast to establish revenue projections and fuel and purchased power budgets. The peak load forecast is used for short and long term resource planning, the evaluation of specific projects and alternatives for the resource portfolio, transmission planning, and distribution planning. In addition, the energy and peak load forecasts are necessary for LIPA to comply with regulatory requirements, including New York State’s section 6-106 Energy Planning Process and EIA Form A-411. Forecasts are also provided to the NYISO for planning purposes.

The following describes the development of the energy (sales) forecast. Econometric regression models are developed to establish the relationships between the historic values of monthly or annual electricity consumption and the variables that are considered to drive consumption, including weather, number of customers, employment, income, and the price of electricity, among others. Specifically, the variables are developed as follows:

- *Numbers of Customers* - Historical customer numbers are obtained from LIPA's Customer Accounting System, categorized by residential and commercial/industrial rate classes. The commercial/industrial sector is also categorized by North American Industrial Classification System (NAICS). The gross annual new residential and commercial/industrial customer forecast is developed by LIPA's New Customer Advisory Task Force, which includes participants from Engineering Design & Construction (ED&C), Electric Marketing (including Major Accounts & Economic Development), Forecasting, Area Planning and Budget. The new customer forecast is based on factors such as population growth, work order backlogs for new building construction, building permit applications, housing starts, long-term expansion plans of major account customers, economic development incentives, interest and mortgage rates, etc. The gross new customer forecasts are adjusted for meter locks, meter unlocks, and transfers between rate classifications to develop the final forecast number of customers for each modeled rate class and NAICS.
- *Employment* - Historic employment levels by NAICS are obtained from the New York State Department of Labor. Future employment is developed using projections from the New York Independent System Operator's (NYISO) economic consultant, adjusted based on trend analysis, research of recently published regional economic articles, and discussions with local experts.
- *Price of Electricity* - The historic average price of electricity is developed from LIPA's historic revenue and energy sales. The nominal annual electric price changes used in the forecast are based on LIPA projections, which consider the level of revenue necessary to meet financial requirements and to provide customers with demand side management (DSM), economic development, and retail access programs. The electric prices used in the econometric models are real prices, adjusted for inflation, using projected values of the Gross Domestic Product (GDP) Implicit Price Deflator (IPD) for commercial prices, and the New York-Northern New Jersey Consumer Price Index (CPI) for residential prices.
- *Income* - Historic Long Island personal income data is obtained from the U.S. Bureau of Economic Analysis. Future income growth is developed using projections from the NYISO's economic consultant. Income variables used in the models include real personal income per household and real personal income per customer.
- *Degree-Days* - Normal cooling and heating degree-days are based on the most recent thirty-year average of Central Park temperature and humidity data. Cooling degree-days are based on a temperature humidity index (THI) base of 60, whereas heating degree-days are based on the dry bulb temperature base of 65 degrees F.

The resulting forecast of electric energy requirements consists of sales to customers minus reductions for demand side management (DSM) plus system use and losses. The complete forecast of residential and commercial / industrial sales resulting from the various forecast methodologies is also presented in Appendix D-4, Long Range Forecast of Energy Requirements.

Predicted values of econometric and demographic variables and normal weather variables are used in the models to produce the forecasted customer consumption of electricity. The system sales forecast is developed from four residential and ten commercial/industrial models predicting monthly sales and annual use per customer, along with simple trending for several of the smaller rate classes and categories.

The following describes the development of the peak load or demand forecast. First, the most recent experienced peak load is adjusted to eliminate the effect of unusual weather. Weather normalization of the experienced peak load is necessary to analyze recent year over year trends in growth. Second, peak load growth by component (residential, commercial, industrial, etc.), following from the sales forecast, is summed up to develop the growth in peak load for the system. The individual models used to develop the reference and alternative load forecasts are described in greater detail as follows:

- *Peak Normalization Model* - Normalization of system peak demand uses normal weather defined as the average of the actual peak producing weather conditions experienced over the past thirty years. Normalization is achieved from a peak demand use per customer regression model developed to establish the historical relationship between LIPA peak demand and the key weather variables driving peak temperature and humidity. The model is used to adjust the actual peak demand occurring at experienced weather conditions to normal demand at normal weather. The specifications and statistical results for the peak demand normalization model and the resulting normalized peak demand can be found in Appendix D-4 Long Range Forecast of Energy Requirements.
- *System Peak Demand Forecasts* - The summer System Peak Load forecast is developed using the Hourly Electric Load Model (HELM). HELM is used to “share down” forecast annual sales into monthly, daily, and hourly sales and therefore provides a realistic, bottom-up approach to peak demand forecasting by capturing the changing relationships among the residential, commercial, and industrial components used to model LIPA System Sales. The energy forecast is disaggregated into the 16 residential, commercial, industrial, and other end-uses represented in HELM, and the resulting HELM peak demand forecast is calibrated to the normalized system peak demand described above prior to predicting future peaks.

In order to better position LIPA to respond to the changing conditions that define the load forecasts, a probabilistic approach is taken to develop the reference and alternative forecast scenarios. Uncertainty is accounted for in the estimating process by first identifying key variables that drive forecasted peak demand growth. These load forecast drivers include:

- *Weather Uncertainty* - Historic weather experienced during the past thirty years is used to develop energy and peak-load probability tables. Using this information, peaks can be predicted for a cool summer season, normal summer season, hot summer season, and extreme heat summer season. The Weather Conditions at System Peak Day and Hour, Table G found in Appendix D-4 Long Range Forecast of Energy Requirements.
- *Forecast Uncertainty* - These include forecasting modeling errors and changes in consumption associated with varying assumptions in economic growth. Experienced peak loads, adjusted for weather, were compared against multi-year forecasts produced over the previous 17 years to analyze the forecast uncertainty due to such factors as changes in the economic environment and modeling error.
- *Economic Uncertainty* - Two sales scenarios, one high scenario representing an economic upswing and one low scenario representing a more pronounced economic downturn, are developed. A detailed description of the methodology used and the results are presented in Appendix D-4 Long Range Forecast of Energy Requirements.

A probabilistic distribution is assigned to each case. Then a probabilistic assessment is created by running simulations through a decision model that combine the key variables with the various outcomes to produce a confidence banded load forecast that displays a range of possible results with an expected value case that lies in the range of extreme outcomes. The confidence banded load forecast is then fed into the resource planning process, as further described below.

2.3 Energy Efficiency Planning Process

LIPA's energy efficiency plan was developed to provide lower cost resources to serve customer needs. The efficiency plan has been developed through a review of LIPA's load shape to identify appropriate preferred solutions, evaluating alternative energy efficiency and demand reduction strategies, and developing a portfolio of customer solutions that meet the identified needs. The steps of the analysis are summarized below. A screening tool was used to formulate alternative measure portfolios to compare and contrast their costs and benefits in order to select the preferred efficiency options for inclusion in the ultimate plan.

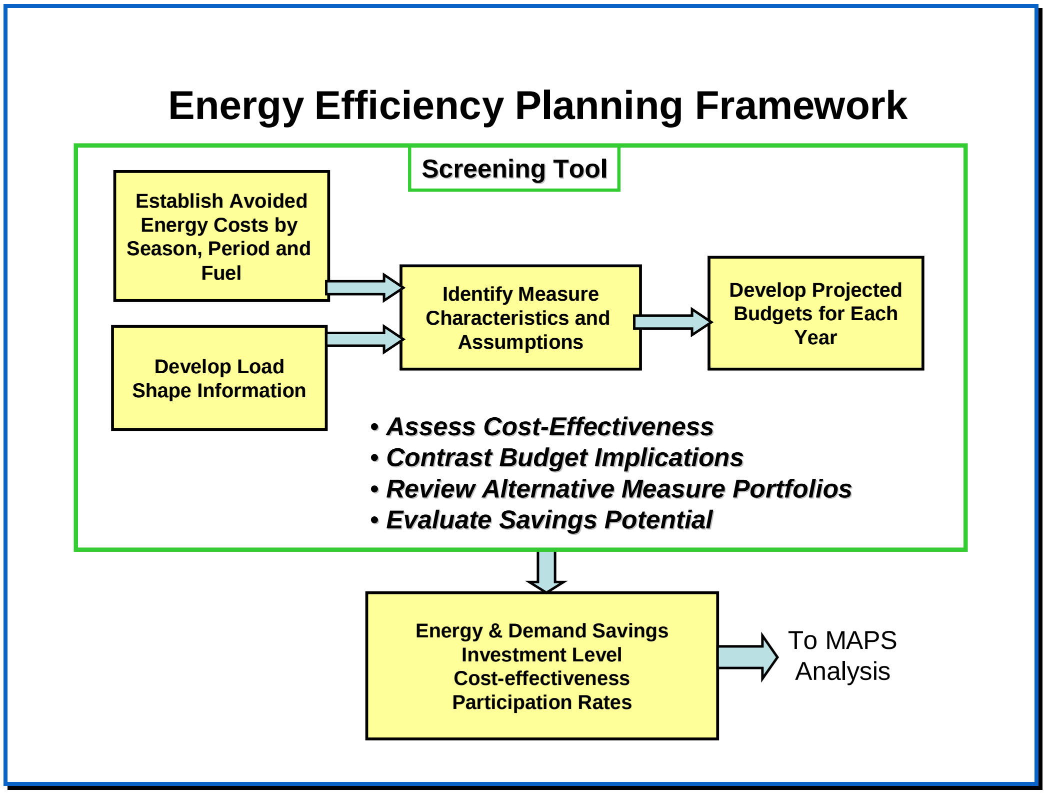
- Avoided costs were developed for five energy costing periods: summer peak, summer intermediate, summer off-peak, winter peak, and winter intermediate; for summer demand capacity costs; and for fuel costs. The value of energy and demand savings from any measure or portfolio of measures was determined using these avoided costs.
- More than 100 different energy efficiency technologies were analyzed for various markets and building types for a total of 2,032 targeted efficiency measures. Each measure was characterized by
    - anticipated measure life,
    - incremental installed cost,
    - customer incentive level necessary for measure adoption,
    - projected annual energy and demand savings,
    - associated fossil fuel savings,
    - operation and maintenance benefits, and
    - deferred replacement benefits for some retrofit measures.

  Customer penetration rates were developed for each measure and market.
- Load shapes were developed through which each measure's energy savings were allocated to the five energy periods, and the demand savings determined for the summer capacity period.
- Budgets were developed for each initiative suitable for the given levels of activity and incentives for the 10- or 20-year initiative period. Budget levels were largely based on experience with successful efficiency initiatives elsewhere.
- The avoided costs, measure characterizations, load shapes and initiative budgets served as inputs to the Screening Tool, which performs the cost-effectiveness and related calculations for each measure and initiative and for the overall portfolio.
- The screening outputs include: total monetized benefits and costs; cost-effectiveness using the Societal Test and Utility Test; electric energy savings by energy period; summer peak demand savings; and other useful metrics. Measures were only included in the analysis if found to be cost-effective to society.
- Electric energy savings for each of the five defined energy periods were parsed into hourly outputs for each year of the 20-year analysis horizon. These served as inputs to LIPA's MAPS model.

Using the screening tool, analysis of each measure or grouping of measures produced an assessment of their cost-effectiveness as measured by standard industry tests. The tests used in the screening tool are the Societal Test and the Utility Test. The Societal Test compares the total costs and total benefits to society which includes the utility and its customers. The Utility test compares the costs and benefits only to the utility. Typically the cost-effectiveness of a measure or initiative is expressed in a ratio of the benefits to the costs or in the net present value of a stream of program benefits and costs; for each a value greater than one or a value greater than zero reflect a good measure or initiative. All benefits and costs are expressed as present value 2006 dollars.

Exhibit 2-1 provides an overview of the methodology used for the efficiency screening and savings analysis.

Exhibit 2-1 Energy Efficiency Planning Framework



2.4 Transmission and Distribution Planning Process

The planning process for the T&D System begins with the load forecast. The load forecast at the system level is based on econometric models, and is developed on both a weather-normalized and weather-probabilistic basis as described in the Load Forecast section of this report. Load forecasts are also developed for specific load areas using system load data acquired by the Energy Management System (EMS) and other systems in National Grid's T&D Operations. Under a research and development project, specific techniques have been developed to weather normalize system load data on an area specific basis. Underlying, or supporting, the aforementioned system and load area forecasts, is the development of a three year normalized load forecast for each distribution substation and circuit on the LIPA System. This load forecast is based on the previous summer or winter experienced peak load for each facility and projected for the next 3 years utilizing a specific normal load growth rate. This load growth rate is based on historical trends for the individual substation/circuit service area. Specific major known or planned load additions are also factored into the load forecast, so that the total load growth for a particular substation or circuit is the sum of major new load additions and a projected load growth rate.

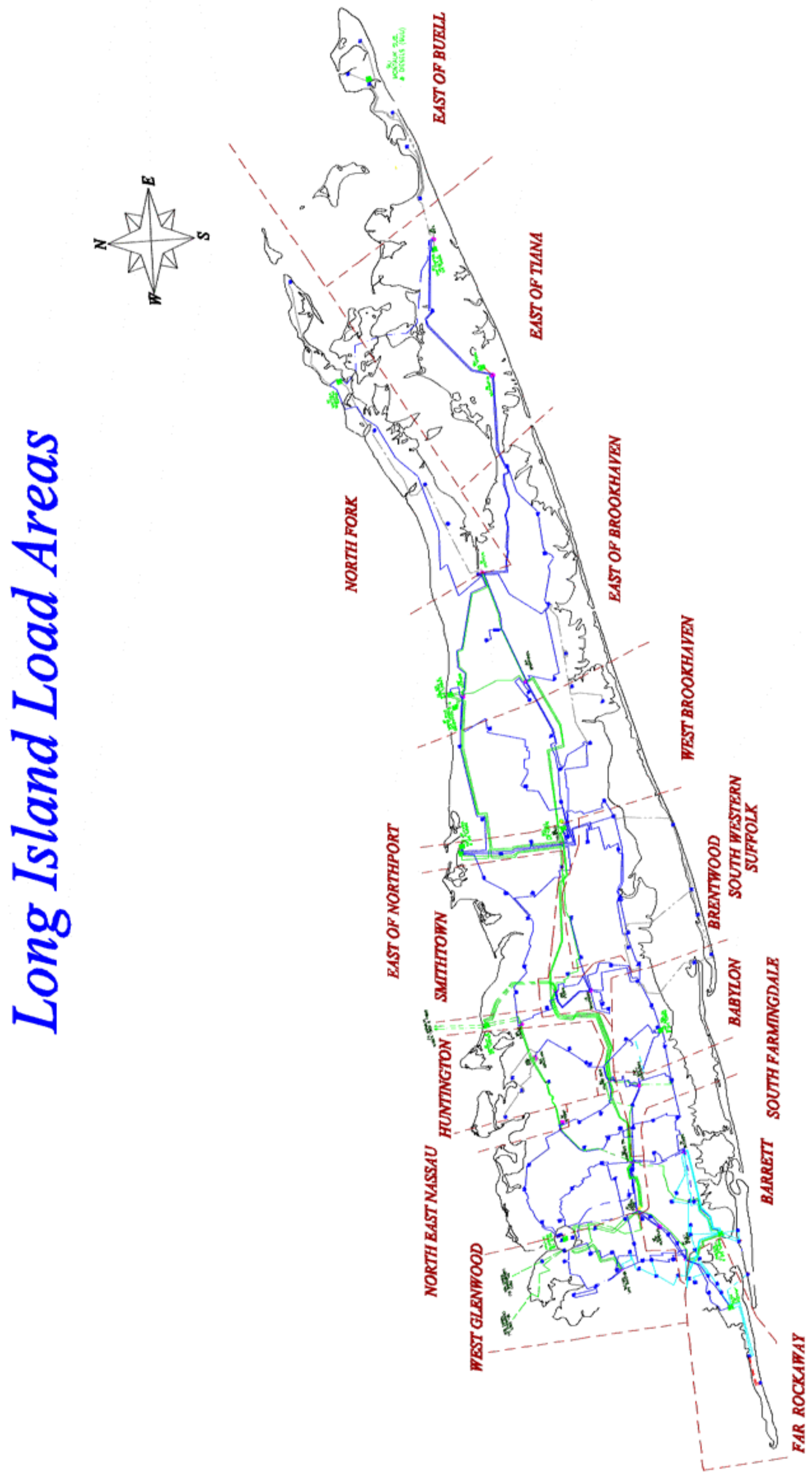
The resultant load forecasts are utilized in three types of planning studies which assess the ability of the T&D system to meet future customer load requirements. These are:

- Long-range transmission studies,
- Area studies, and
- Interconnection studies.

Long-range transmission studies are completed for the 5 to 20 year forecast time frame and address the bulk transmission system and the underlying sub-transmission system, which supplies substations. Area studies are generally for a 3 to 10 year forecast time frame and address specific load areas, including the area transmission system, substations and distribution feeders. Both of these types of studies are designed primarily to assess the ability of the system to deliver power to load centers and to serve customer load. Interconnection studies are designed to determine the required interconnection facilities and system reinforcements required for specific generation and transmission projects to enable them to be effective over the life of the project.

As the industry changes as a result of a more competitive environment, the importance of local generation increases. To reflect this importance, and to conform to how the system operator actually operates the system, planning and operating studies are conducted according to defined load areas. Seventeen load areas have been identified in the LIPA region and are identified in Exhibit 2-2.

Exhibit 2-2 Long Island Load Areas



The 3 year load forecast for distribution substations and circuits is also used in analyzing the 13 kV and 4 kV LIPA distribution systems to address near-term (1 to 3 years) normal and /or first contingency overloads on these distribution systems.

The LIPA T&D system is planned for a "peak hour" load level that has a 50% probability of occurrence. The design criteria specifies that the forecasted load on any element of the T&D system will not exceed the normal rating of that element during normal system operating conditions, nor exceed either the short term emergency (STE) or long term emergency (LTE) ratings during emergency operating conditions (first contingency loss of an element).

The following are examples of routine planning studies conducted on a recurring basis:

- Distribution feeder evaluation for a particular substation, including projected normal loading and contingency capability, in conjunction with ties to adjacent substations and/or circuits;
- An evaluation of projected normal substation transformer bank loads and emergency loads following the loss of a single bank within a 2 bank substation, or the loss of a transformer at an adjacent substation with distribution feeder ties;
- An evaluation of the sub-transmission system in a particular load area, with projected substation loads; and,
- An evaluation of transfer limits for key bulk transmission interfaces with projected system loads and potential generator interconnections.

Planning studies evaluate alternatives for system reinforcements to address load growth and generator interconnection requirements, and they enable planners to recommend the most appropriate, cost effective projects to meet system needs. The proposed projects are placed on a five-year project priority list, which is updated periodically based on revised load forecasts and area studies. Load forecasts are revised annually in October to reflect the experience of the previous summer peak, and area studies are revised to reflect these forecasts and the natural evolution of project concepts. Project electrical one-line diagrams are developed for each project to serve as the basis for development of work scopes and conceptual cost estimates. Exhibits 2-3 and 2-4 provide an overview of the T&D planning subprocesses for major capital transmission and/or substation projects, and distribution line projects, respectively.

Examples of projects, progressing from the distribution to the bulk transmission level, include the following:

- Reinforcement of distribution feeders,
- Addition of distribution feeders,
- Expansion of existing substations,
- Construction of new substations and associated transmission,
- Replacement of conductors on existing transmission lines, and
- Construction of new transmission lines.

Exhibit 2-3 T&D Planning Process - Transmission and Substation Projects

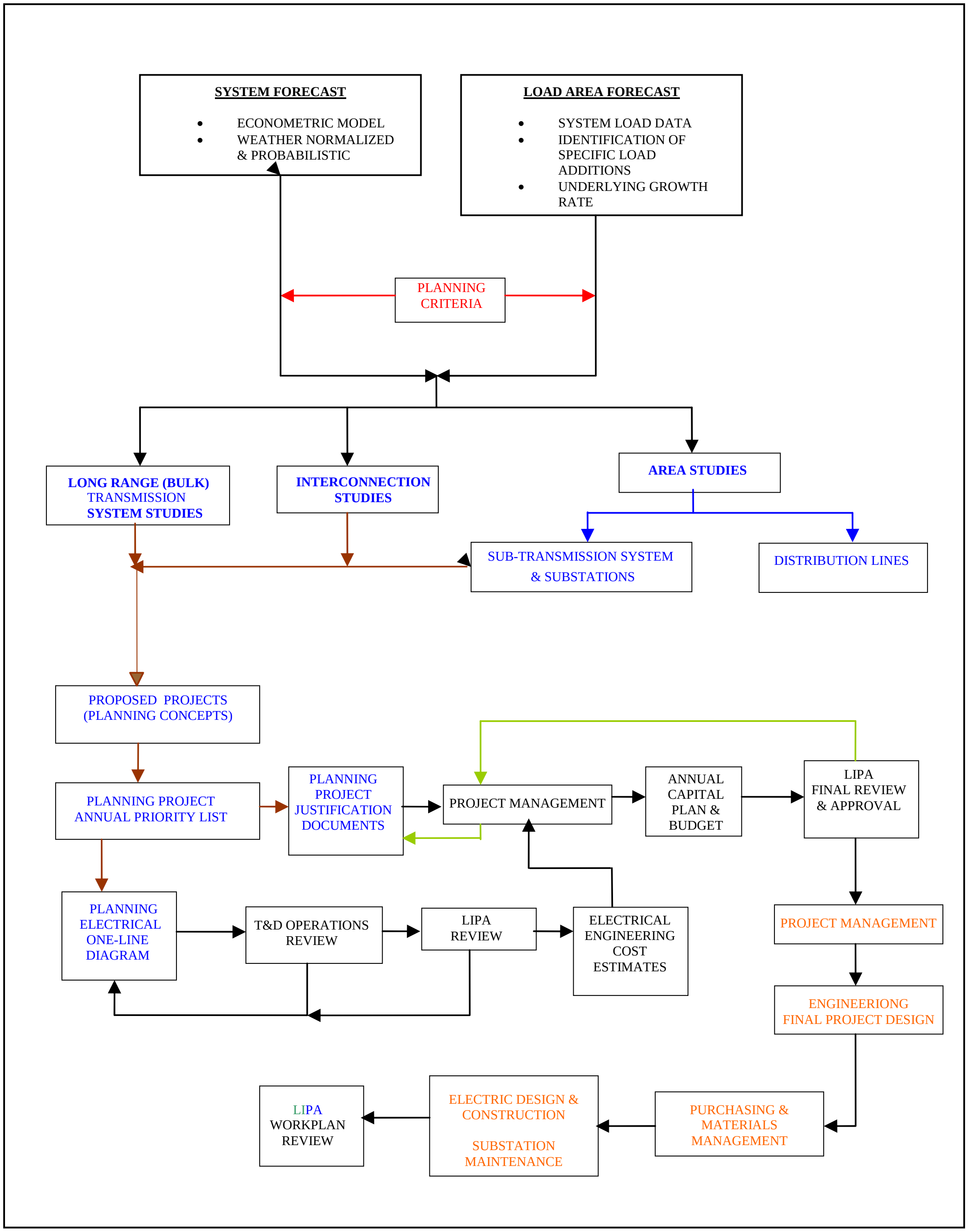
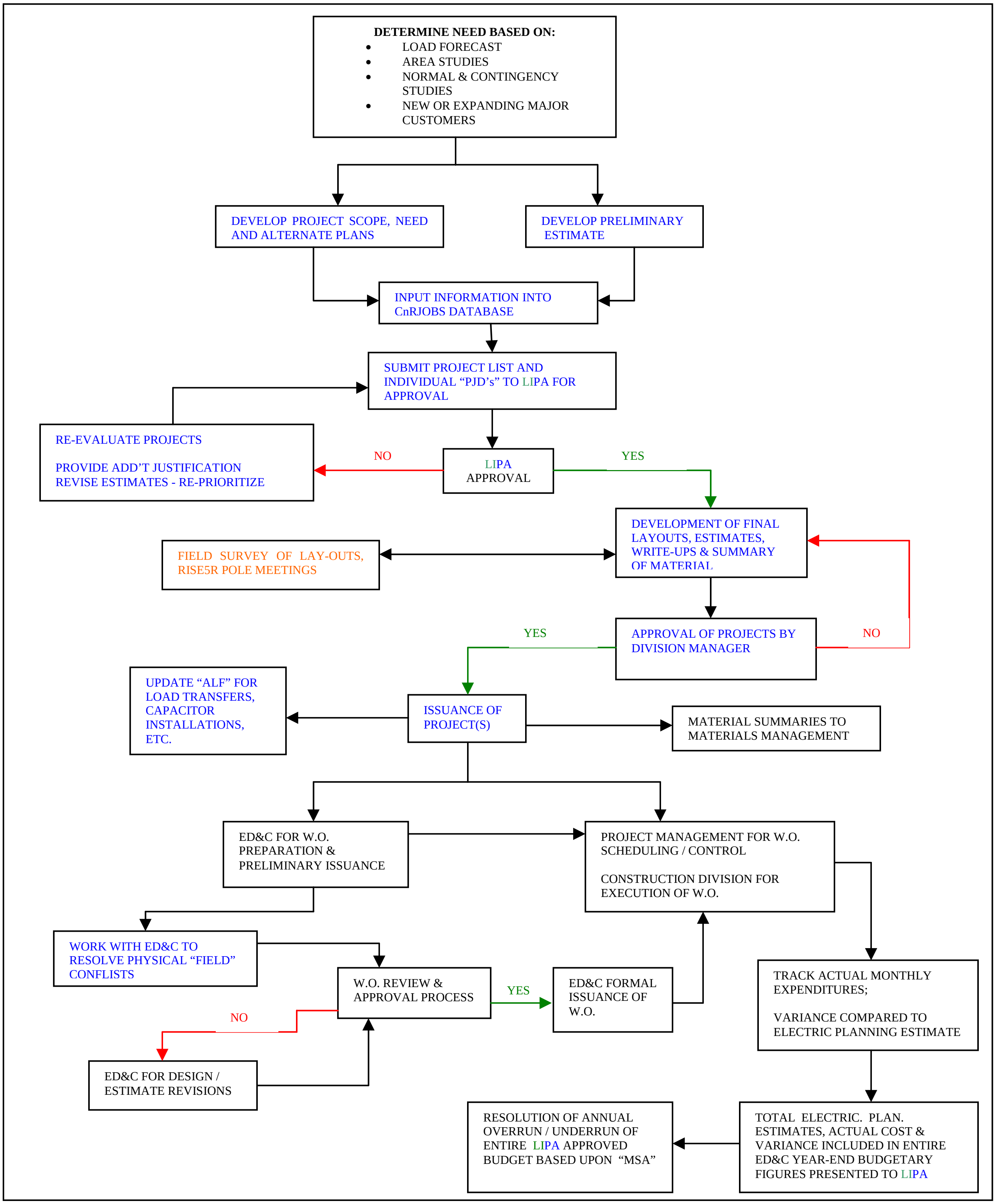


Exhibit 2-4 T&D Planning Process - Distribution Lines Projects



Project electrical one-lines are reviewed for LIPA by National Grid's planning, engineering, and T&D operations staff as part of an internal approval process, leading to development of project justification documents and cost estimates, which comprise the LIPA T&D Capital Plan. The LIPA T&D Capital Plan is submitted to LIPA for review on July 1. The Capital Plan, as modified and approved by LIPA, is developed into a T&D capital work plan. LIPA reviews the capital work plan after completion for assurance that each project has been completed.

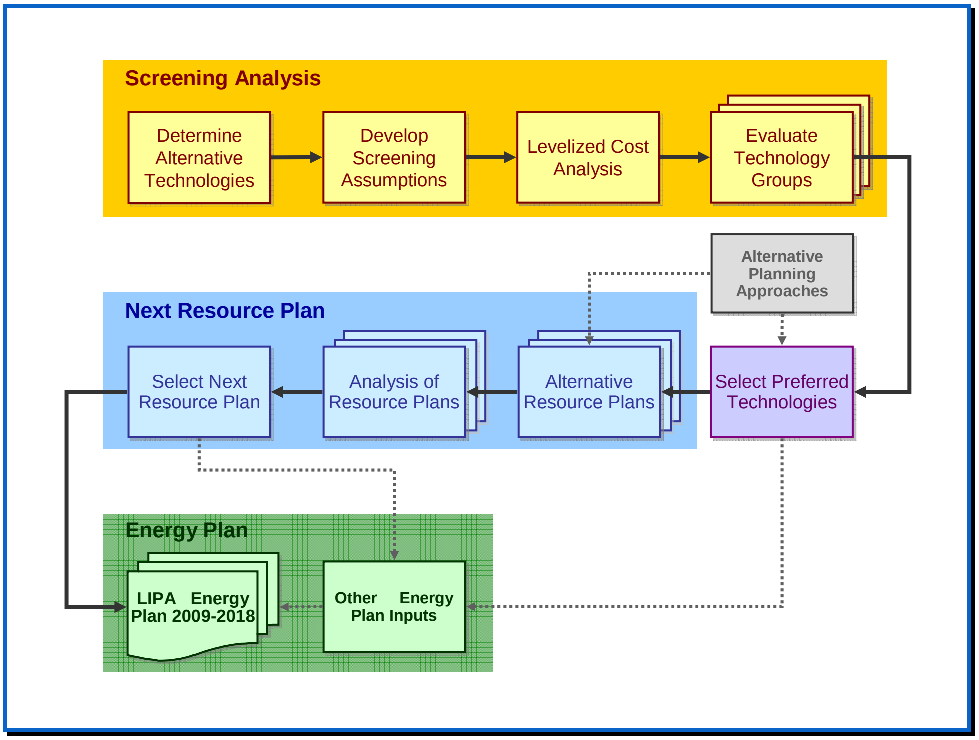
2.5 Power Supply Planning Process

LIPA uses a probabilistic planning process to meeting customer electricity needs. The process was developed in order to respond to rapidly changing conditions and to provide a better way of ensuring reliable future supplies at the competitive cost. The result is a resource plan designed to meet customer's electricity requirements with reliable, competitive options.

2.5.1 The Supply Planning Process

The key steps of the power supply planning process are shown in Exhibit 2-5.

Exhibit 2-5 Power Supply Planning Process



Technology Screening Analysis

The process begins with a screening analysis to determine which technologies either alone or in combination would best meet LIPA objectives for cost, reliability and the environment. Alternatives include traditional supply, transmission interconnections, energy efficiency and peak reduction related alternatives. Exhibit 2-6 summarizes typical alternative resources that might be considered into six categories: supply, efficiency, renewable, repowering, retirement and transmission options.

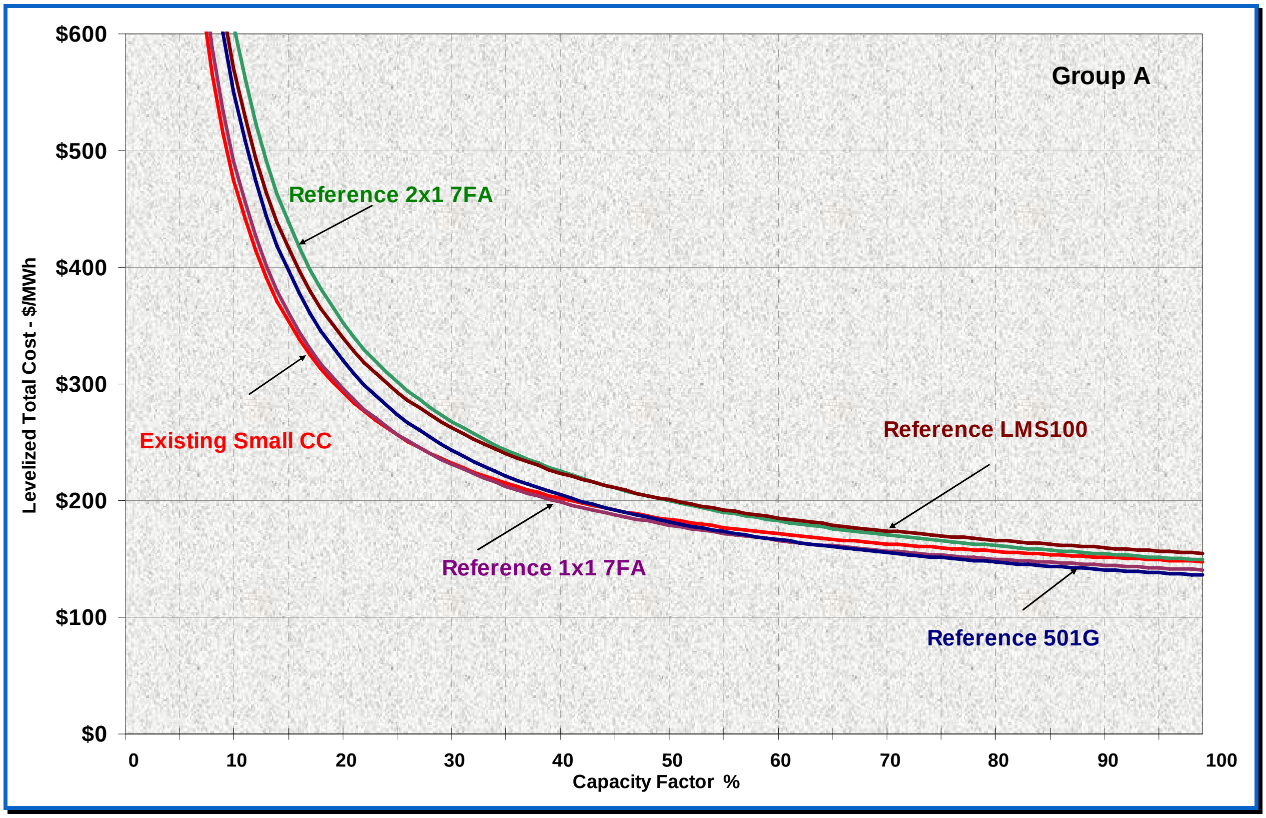
Exhibit 2-6 Examples of Alternative Technologies

Supply Options	**Transmission Options**
Generic On-Island Combined–Cycle	Loss Reduction
Generic On-Island CT LMS 100 CC	NUSCO Upgrade 1
Generic Off-Island Combined–Cycle	Neptune Cable (RB)
Combined-Cycle CT LM6000	Neptune Cable (UDR)
Simple-Cycle CT LM6000	PJM Cable II (RB)
Mobile Generating Units	Neptune Cable w/Marcus Hook
Pratt & Whitney (Twin Pac)	Hydro Quebec Inter-tie Reinforcements
Generic Off-Island Nuclear	
Efficiency Options	**Renewable Options**
Clean Energy Initiative	Landfill Waste-to-Energy[1]
ELI Base Program	Barrett 1,2, Convert to B20 Diesel
ELI Advanced & Accelerated Program	East Hampton, Convert to B20 Diesel
Intelligent Metering	Resource Recovery
	On-Island CT Bio-Diesel
	Photovoltaic Roof
	On-Shore Wind
	Off-Shore Wind
Repowering Options	**Retirement Options**
Barrett Repowering	Barrett Retirement
Northport Repowering	Northport Retirement
Port Jefferson Repowering	Port Jefferson Retirement

Alternatives are compared on a levelized cost basis across a range of expected capacity factors. The alternative technologies were compared on the basis of economic and environmental metrics. A major part of the process of reviewing alternative technologies is the collection of the quantitative and qualitative information needed to sift among alternatives. Once the data has been gathered, it is relatively straight forward to conduct the analysis.

Technologies within each group are evaluated and ranked on both a levelized energy ($/MWh) and capacity cost ($/kW-month) basis. Levelized cost is a unitized cost calculated by discounting both an annual stream of costs ("then year" dollars, that include the effect of inflation & escalation) and an annual stream of output ("then year" output in MWh) using a discount rate representative of LIPA's cost of debt, including inflation. Levelized total costs include fixed, production, and emission allowance costs. Exhibit 2-7 shows what a typical levelized cost curve comparison would look like.

Exhibit 2-7 Typical Supply Technologies – Levelized Cost Curves



In addition to levelized cost curves depicted in the previous exhibit, a table comparing costs at a predicted level of operation with the emission rates associated each technology is assembled to facilitate analysis. Refer to Exhibit 2-8 as an example of what such a table would look like.

Exhibit 2-8 Typical Supply Technologies – Predicted Cost & Emission Rates

		Levelized Cost				Environmental Emissions		
ICAP MW	Name	Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 lb/MWh
75	Existing Small CC	$26.55	$111.09	79%	$157.10	973	0.0887	0.0048
105	Reference LMS100	$33.75	$108.19	42%	$218.22	1125	0.8700	0.0068
240	Reference 1x1 7FA	$28.46	$101.20	75%	$153.30	875	0.0825	0.0053
367	Reference 501G	$33.63	$89.73	82%	$145.76	828	0.0575	0.0042
480	Reference 2x1 7FA	$37.32	$97.51	78%	$163.18	862	0.0834	0.0051

Analysis of the results in Exhibit 2-7 reveals a relatively small but significant economic advantage to the General Electric 7FA and the Westinghouse 501G technologies dependant on their range of operation. The 7FA machine is the more cost effective operating at capacity factors below 50%. Above 50% capacity factor the higher efficiencies of the 501G machine make it the lower cost choice. In terms of their likely dispatch within the Long Island market the above table, Exhibit 2-8, confirms the technology preferences stated previously with the 501G machine as the lowest cost followed by the 7FA machine. From an environmental emissions standpoint the picture is much the same with the 501G having a consistently lower emissions profile followed by the 7FA machine.

The lower total cost and environmental emission technologies within each group are summarized by type of resource. A preferred list of selected technologies is then developed from the resources with the lowest cost and other preferred characteristics. LIPA utilizes the screening tool to narrow down the technology choices into viable economic groupings and then proceeds to identify alternative portfolios or plans that could address the identified resource need.

The resources within each group that best fit LIPA's strategic objectives are selected to develop alternative representative plans for more detailed analysis.

2.5.2 Incorporating Uncertainty

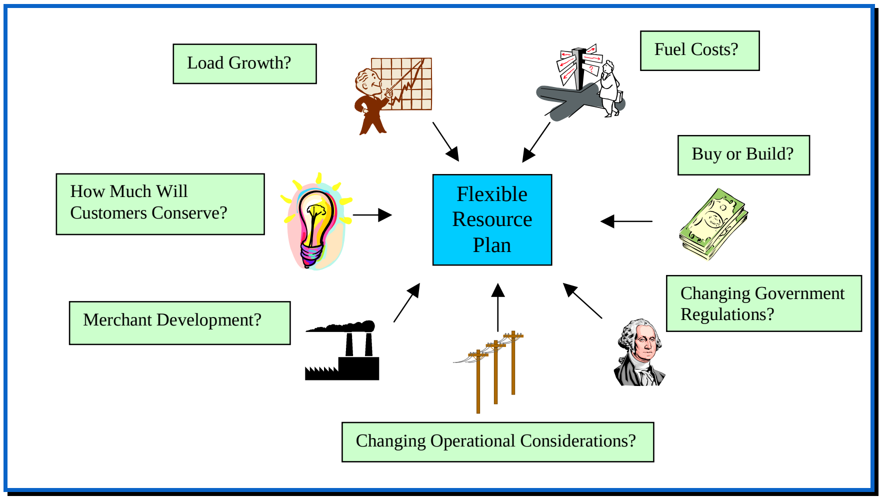
Both the process and the plan are constantly evolving, and new simulation models have been developed to support the determination of need and the evaluation and analysis of future alternatives. A stochastic model is used specifically to assess the impact of uncertainty associated with the major elements of the plan that define the need for future resources.

LIPA is planning for the future. It is increasing and improving the availability of energy sources to provide competitive energy to a growing region. The process, however, is not risk-free. LIPA must plan now to adjust for changes that may occur over the next decade and beyond. To better understand the complexities of resource planning, it is important to review a partial list of the unpredictable factors that have shaped the demand and supply for electricity on Long Island in the past few years. Some of these are depicted in Exhibit 2-9 and include:

- *Changing Customer Demand for Electricity* – change in economic conditions, weather variations (two out of the last four summers have exceeded predicted levels by significant amounts, while two years were well below normal);
- *Changing Fuel Supply and Cost* - pipeline availability, fuel exploration, and the balance of supply with demand all contribute to variability in fuel supply and cost;
- *Merchant Plant Development* - proposed projects are identified in the NYISO study queue for LI; some may come to fruition, others may be cancelled, and new ones may be proposed;
- *Transmission Tie-line Development* – Development of additional transmission ties is dependent on economic feasibly, market interests, and the permitting process.
- *Operational Considerations* – ongoing operational assessments of power supply resource adequacy reflecting the actual versus planned performance of generating units, transmission interconnections, demand reduction measures, and variations in peak-load forecasts based on both normal and extreme weather conditions.

To account for uncertainties, LIPA uses an approach that provides the flexibility to incorporate the impacts of new technologies, customer programs, generation alternatives, and supply options. New methods of analysis were developed to help plan for contingencies and assess the risks of various courses of action.

Exhibit 2-9 Questions Resource Planners Face



The resource planning process uses information from all customer segments, every section of the company, and the business environment. The process is iterative in that it provides numerous opportunities for information to be reintroduced and used throughout the process. This is extremely important in arriving at the best solution under changing and highly variable conditions. Specifically addressed are the issues of: timing – when additional resources are likely to be needed; magnitude – the amount of resources needed to avoid deficiencies; and technology – the combination of traditional and emerging demand and supply-side resources that best meet these goals.

2.5.3 Determination of Resource Need

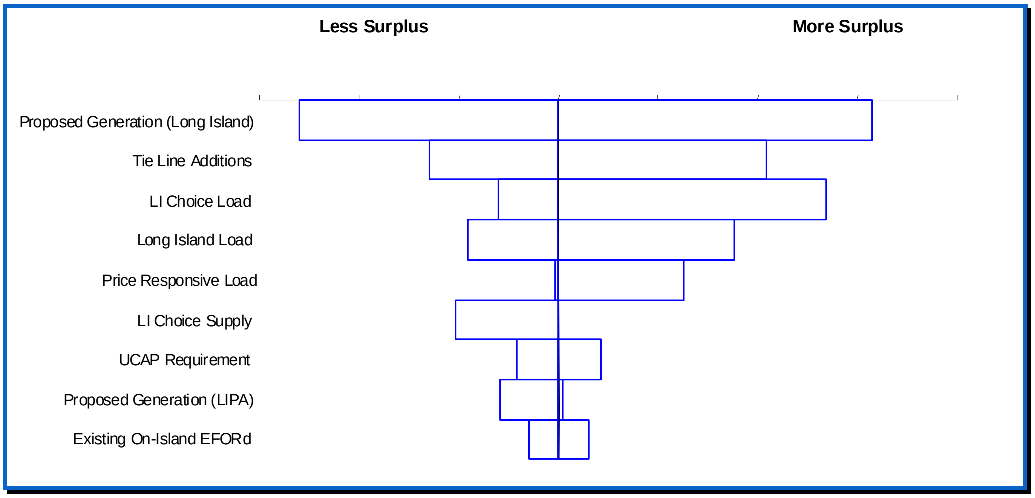
In parallel or sequentially another step in the process identifies the timing and magnitude of the need for additional resources. A detailed Load and Capacity Model is used for this determination. The following variables are examples of key inputs into the determination of need or required resources:

- Load Growth,
- Energy Efficiency Penetration,
- New York ISO Reserve Requirement,
- Existing Generating Unit Reliability,
- Proposed New Resource Additions,
- Proposed New Transmission Tie-Lines Additions,
- Long Island Choice Load Penetration, and
- Price Responsive Load Penetration.

To account for the uncertainties associated with these variables, probability distributions are assigned to each variable based on actual or forecasted experience. The potential impact on required resources is determined by varying each variable from its low to high value and measuring the swing in resources required, the broader the swing, the more critical the variable to the planning process. For example, the "tornado" diagram in Exhibit 2-10 graphically depicts the importance of each variable to the need for additional resources. This example indicates that the magnitude of new generation development on Long Island is the most significant variable, followed by the magnitude of transmission tie-line development. Conversely, the variables at the bottom of the diagram indicate those that are less critical to the determination of resource requirements and may not require additional study. This step of the process serves to focus the detailed analysis on those variables that have significant implications.

Exhibit 2-10 Key Variable Sensitivity

Example "Tornado Diagram" – Megawatt Swing



The probabilities developed are based on a number of quantitative and qualitative factors depending on the specific variable in question. For variables where the available information does not lend itself as readily to quantitative analysis, subject matter experts are used to determine the appropriate probability distributions. Accuracy but not necessarily, precision is the goal when assigning probabilities. The process readily lends itself to testing the sensitivity of any given probability. In the event that results prove to be highly sensitive to a given variable's probability, further analysis may be warranted to understand the nature of the sensitivity.

A stochastic model is used to combine the key variables with their respective uncertainty distributions into the many possible scenarios or energy futures. These thousands of possible energy futures are combined to create a probabilistic view of the amount of additional resources required to meet varying levels of confidence. For example, if the goal were to be absolutely certain (worst case for all key variables) that the required resources never exceed the resources available the goal would translate to planning to the 100 percent confidence level.

Exhibit 2-11 illustrates what a typical Confidence Level Table would look like. Referring to this exhibit, planning to the 100 percent confidence level in this example would require the addition of 186 MW in 2005, increasing to 959 MW in 2012. While planning to the 100% confidence may be prudent in the near term (1 to 2 years), it may not be a cost-effective strategy for the long-term. This is because our knowledge of the future, and more importantly our ability to predict the future decreases significantly as you move out in time. This is illustrated in Exhibit 2-11 by the increasing range of possible resources required as you move further out in time. For example, in the year 2003 the resources required range from a surplus of 123 MW to a surplus of 741 MW or a range of 618 MW. In the year 2012, the range is 1,467 MW. In general, it is desirable to plan to a higher confidence level in the short-term (1-5 years) and a lower confidence level in the long-term because there is still time to plan for that future. The planning confidence level selected depends upon a tradeoff of the cost of failing to meet requirements against the cost of planning for additional resources.

Exhibit 2-11 Example Resource Requirement Table[1]

Surplus/Deficiency by Confidence Level (megawatts)

Confidence Levels %	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
100%	121	(74)	(339)	(443)	(613)	(715)	(872)	(974)	(1069)	(1201)
95%	330	196	(16)	(110)	(273)	(353)	(506)	(604)	(697)	(824)
90%	387	237	32	(57)	(217)	(295)	(449)	(547)	(639)	(767)
85%	414	265	73	(13)	(160)	(244)	(396)	(493)	(585)	(712)
80%	436	291	118	41	(79)	(154)	(306)	(403)	(490)	(613)
75%	452	321	176	108	2	(72)	(222)	(316)	(403)	(526)
70%	466	349	215	149	56	(14)	(162)	(254)	(340)	(459)
65%	472	371	240	174	92	28	(120)	(213)	(298)	(418)
60%	485	390	260	198	122	51	(96)	(187)	(271)	(391)
55%	497	407	280	220	145	79	(69)	(160)	(245)	(364)
50%	507	424	301	241	173	104	(42)	(133)	(218)	(337)
45%	514	441	324	268	202	131	(15)	(106)	(190)	(309)
40%	526	454	352	301	244	172	27	(63)	(148)	(267)
35%	537	472	392	349	302	240	94	8	(74)	(190)
30%	543	491	437	396	358	294	152	65	(16)	(131)
25%	556	515	470	434	412	348	208	120	39	(76)
20%	572	542	499	464	463	399	262	178	102	(9)
15%	585	573	527	497	507	452	312	228	152	39
10%	602	604	566	541	563	503	364	281	205	93
5%	626	640	652	633	660	603	468	387	314	204
Reference	497	413	226	165	98	57	(89)	(180)	(264)	(384)

LIPA's supply planning process looks at resource requirements from multiple perspectives in order to ensure the needs of its customers and Long Island are met. Three views are focused on resource requirements and the fourth is focused on meeting energy requirements. Confidence tables such as in the example above are developed for each of these resource requirement views:

- Long Island on-Island resource requirements,
- LIPA on-Island resource requirements, and
- LIPA total resource requirements.

A higher priority is placed on both the Long Island and LIPA on-Island requirements given the limited nature of on-Island resource options. While the NYISO does not hold LIPA responsible for meeting the needs of Long Island as a whole, LIPA nonetheless feels it is necessary to review the Long Island requirements as a prudent and responsible step in the development of its Electric Resource Plan. If LIPA were to meet its on-Island requirement, but the total Long Island requirements were not met, the reliability of everyone, including LIPA's customers, would be adversely affected.

Alternative Scenario Analysis

Once the forecasted need is established, LIPA then identifies how that need can be met through both individual preferred technologies as well as portfolios of preferred technologies previously identified through the screening process. Assembling these potential alternative energy futures or representative plans requires a significant amount of technical analysis. These representative plans are compared using key planning metrics that address economics, efficiency, reliability and the environment to arrive at the recommended electric resource plan. The specific evaluation metrics are outlined in Exhibit 2-12.

---

[1] Note: This table represents example data only and should not be used for analysis purposes.

Exhibit 2-12 Evaluation Metrics

Economic
Net Present Value (NPV) total revenue requirements Annual revenue requirements Annual average electric rates
Production Efficiency
Average heat rate of LIPA contracted/owned resources
Reliability Metrics
Surplus or deficit compared to probability weighted NYSRC Total Statewide Requirements for LIPA Surplus or deficit compared to probability weighted NYISO Locational Requirement for LI
Environmental Metrics
Projected SO_2 allowances compared to SO_2 emissions from LIPA contracted units Projected NO_X allowances compared to NO_X emissions from LIPA contracted units Energy weighted share of statewide CO_2 RGGI emissions allowance compared to CO_2 emissions from LIPA contracted units Total LIPA footprint of CO_2 emissions from LIPA contracted units plus market purchases of energy at ISO/RTO incremental emissions per MWh Assess alternative plans on $/ton Carbon reduced or increased from the Reference Case

These alternative plans are developed to evaluate differing approaches to meeting the projected resource need. In order to compare the various alternative plans, LIPA develops a reference case against which all others are benchmarked. The reference plan does not represent LIPA's preferred plan, but is simply a means to measure the relative attractiveness of the alternative plans. Alternative plans are developed to test various strategies such as:

- Relying upon specific types of resources such as energy efficiency, repowering, or renewables;
- Achieving certain objectives such as reducing CO_2 emissions, minimizing rate impacts or reducing the impacts of fuel price volatility; or
- Combining strategies based on the information gained from evaluating other strategies.

The reference plan provides a benchmark that all alternative plans are compared to on a differential basis to determine the relative attractiveness of a given approach. The reference and alternative plans are analyzed using the General Electric Market Analysis and Portfolio Strategies (MAPS) model, which incorporates transmission constraints in the analysis.

Exhibit 2-13 is an example of how results are summarized and compared. In this case alternative plans focused on efficiency investment are compared. Metrics include reliability, cost, efficiency, and emissions.

Exhibit 2-13 Example Efficiency Group Results

	Reliability		Cost			Case (2018 / 2028)				Emissions Target Years Met			CO_2 Emissions		
Cases	New Generation (MW)	Capacity Criteria	Cum. Annual Rev. Req. ($Bil)	Cum. Annual Rev. Req., NPV	Avg. of Ann. Rev Rate (Cents/kW)	2018 Sales of Electricity (TWh)	2028 Sales of Electricity (TWh)	Avg. LI Sys Heat Rate, 2018 (BTU/kWh)	Avg. LI Sys Heat Rate, 2028 (BTU/kWh)	SO_2	NO_x	CO_2	Cum. Compliance (mTons)	Cum Footprint (mTons)	Net Cost (Savings) per Footprint Reduction ($/ton)*
26) Alternate Reference Case	3,191	20	115.7	66.9	22.7	24.7	30.5	9,013	8,099	20	20	6	191.5	295	-
2) Continue CEI	-367	20	-0.4	-0.2	0.4	-0.7	-0.7	75	-30	20	20	6	-5.4	-6	-75
11) ELI Base - Block 8	-1,101	20	-4.2	-1.9	0.4	-1.5	-1.9	294	171	20	20	7	-19.5	-11	-796
3) 15x15 and RPS	-2,202	20	-11.5	-5.3	1.2	-4.0	-5.0	703	800	20	20	13	-47.5	-30	-584

In Exhibit 2-13 the reference plan is identified as Case 26 and highlighted in orange. Compared to the reference plan, the efficiency programs presented here result in reductions in both sales and annual revenue requirements. Customers consume fewer kWh and therefore average bills decrease, despite increasing average electric rates.

Both the ELI Base and the 15 x 15 cases reduce peak load, resulting in deferral of new capacity. This results in the system on Long Island generating fewer megawatts, less efficiently. However, the overall fuel consumption required to meet customer demand decreases. The ELI Base case defers 1,101 MW of capacity, reduces sales by 1.5 TWh in 2018, and decreases Long Island generation efficiency by almost 3.3% in 2018. The 15 x 15 case defers 2,202 MW of capacity, reduces sales by 4.0 TWh in 2018, and decreases Long Island generation efficiency by almost 8% in 2018.

In each of the cases presented in Exhibit 2-13, there are some years where CO2 emissions exceed LIPA's projected energy weighted share of statewide CO2 RGGI emissions allowances. The RGGI program is auction based, and has no planned "allocation" to meet its compliance target. LIPA would purchase additional credits in the RGGI auctions. Both the ELI Base and the 15 x 15 cases reduce CO2 emissions from contractual plants significantly.

This type of analysis is performed over a wide range of alternative resource combinations. Ultimately the plan selected as LIPA's recommended Electric Resource Plan is the combination that best meets LIPA's strategic objectives for reliability, cost, and the environment.

3 Planning Models

In addition to the load forecasting models mention earlier in this section, Exhibit 3-1 outlines the major analytical tools used to support and enhance the T&D system planning effort.

Exhibit 3-1 Electric System Planning Models

MODEL	DESCRIPTION	PURPOSE
MAPS	General Electric Market Analysis and Portfolio Strategies (MAPS); transmission constrained generation dispatch model	Energy costs/pricing
MARS	General Electric Multi-Area Reliability Simulation (MARS); probabilistic assessment of area power system reliability	Loss of Load Expectation (LOLE)
PSS/E	Power Technologies Inc. Power System Simulation/ Electric System; transmission system load flow model	Transmission system load flow; thermal, voltage, and fault analyses under normal, contingency conditions
PSLF	General Electric Power System Load Flow (PSLF); transmission system load flow model	Transmission system load flow; thermal, voltage, and fault analyses under normal, contingency conditions
ASPEN	Advanced Systems for Power Engineering, Inc; short circuit analysis program	Breaker fault duty analyses
Cymdist	Cognicase-Cyme Inc., Cymdist Distribution Primary Analysis; analysis of radial and network distribution systems	Thermal, voltage, and contingency analyses of distribution feeders and networks.
SUBREL	General Reliability: Substation Reliability Evaluation Program	Computes the reliability indices for a substation and compares alternative substation configuration(s) through reliability evaluation(s).

4 Planning and Operating Criteria

The set of rules and standards that govern the manner in which an electrical system is planned and operating are collectively referred to as planning criteria. These criteria ensure that alternative solutions are compared on an equal basis and that the system is planned and built to maintain a consistent level of reliability. The sections that follow discuss the criteria that are applied by LIPA in its energy planning process.

4.1 Resource Planning Criteria

Electric resource planning refers to the planning of both demand-side management programs that reduce load requirements and supply-side facilities that generate power. Considered in the resource planning effort are the interconnection capabilities of the transmission lines that interconnect one system to other systems and allow the import and export of power for economic reasons, for high demand periods, and for emergency situations. This is particularly important to an island system, such as LIPA's, with limited transmission ties to other systems.

LIPA's resource planning criteria is based on both the NYISO criteria, which establish the minimum requirements for LIPA to meet its customers' requirements, and a broader operating criterion designed to ensure that all of Long Island's needs are met in the event of a series of adverse events.

4.1.1 NYISO Criteria

As a load serving entity and transmission owner within the State of New York, LIPA's resource planning is governed by the standards and criteria of the North American Electric Reliability Council (NERC), the Northeast Power Coordinating Council (NPCC), the New York Control Area (NYCA), New York Independent System Operator (NYISO), and New York State Reliability Council (NYSRC). LIPA is committed to meeting the reliability standards set by these organizations. These standards establish the minimum level of generation reserves required to meet customer load requirements in a reliable manner. The following are the major elements of the NYISO criteria.

New York State Installed Reserve Margin Requirement

The New York State criteria require adequate resource capacity be available to meet project system demands. Adequate resource capacity must exist in the New York State Control Area to ensure that, after allowance for scheduled outages and deratings, forced outages and deratings, assistance from neighboring systems, NYCA transmission capacity, uncertainty of load forecasts, and capacity and/or load relief from available operating procedures, the probability of disconnecting firm load (i.e. the Loss of Load Expectation or LOLE) due to a resource deficiency will be, on the average, no more than once in ten years.

Section 3.03 of the NYSRC Agreement states that the NYSRC shall establish the state-wide annual Installed Reserve Margin (IRM) for the NYCA consistent with NERC and NPCC standards. An engineering study is conducted each year by the NYSRC for the purpose of determining the appropriate NYCA required IRM for the May through April period of the following year in compliance with the Agreement. The NYISO implements the state-wide IRM as determined by the NYSRC in accordance with the NYSRC Reliability Rules and the "NYISO Installed Capacity Requirements" (ICAP) manual.

The NYISO also adjusts the required IRM to an individual unit "unforced capacity" basis in accordance with its ICAP market design.

Locational Capacity Requirements

Load Serving Entities (LSEs) are required to procure sufficient resource capacity for the entire ISO defined obligation procurement period so as to meet the state-wide IRM. Further, this LSE capacity obligation must be distributed so as to meet locational capacity requirements, considering the availability and capacity of the NYCA transmission system to maintain reliability requirements. A locational ICAP requirement specifies the minimum amount of installed capacity that must be procured from resources physically located within a locality, considering local generation within the locality and transmission import capability to the locality, to meet the resource adequacy reliability criteria of the NYSRC and the NPCC which requires a loss of load expectation not to exceed one day in ten years.

An engineering study is conducted each year by the NYISO to determine locational ICAP requirements for the NYCA for the Capability Year beginning May 1. The study has two specific steps. First, it reviews the locational Installed Capacity requirements (i.e. ICAP requirements for the New York City and Long Island localities). Then, it determines whether additional localities of the NYCA should be subject to locational ICAP requirements.

The model used in this study provides an assessment of the adequacy of the NYCA transmission system to deliver energy from one zone to another for meeting load requirements. Previous studies found that, under the conditions assumed, there are transmission constraints into the New York City and Long Island zones that could impact the LOLE of these zones, as well as the state-wide LOLE. To minimize these potential LOLE impacts, NYISO studies have shown that a minimum resource ICAP (i.e., locational ICAP) must be maintained in each of the New York City and Long Island zones. These locational ICAP requirements, recognized by NYSRC Reliability Rules and monitored by the NYISO, supplement the state-wide IRM requirement.

External Capacity

Installed capacity obtained from resources external to the NYCA for satisfying a portion of LSE capacity requirements both New York State and locational must be demonstrated to be available and deliverable to the NYCA borders. Installed capacity from resources external to the NYCA are permitted to the extent reliability requirements are satisfied.

Unforced Capacity

The NYISO uses unforced capacity (UCAP) to determine the amount of capacity that a resource is qualified to supply to the NYCA and to determine the capacity requirements of LSEs. UCAP is a measure of a resource's capacity recognizing forced outages. The NYISO continues to establish ICAP requirements based on installed capacity and then translates the ICAP requirement to a UCAP requirement based on an average availability of resources. The locational ICAP requirements are translated to locational UCAP requirements based on the average availability of resources located within the locality. The conversion to UCAP is, essentially, a transition from one index to another and not a reduction of actual on-line resources, so no degradation in reliability is foreseen. Theoretically, the transition to unforced capacity should provide financial incentives to decrease the forced outage rates, thus improving reliability.

4.1.2 Operational Planning Criteria

The planning criteria put in place by the NYSRC, the NYISO, and other parties described above, ensure that those conditions that impact the reliability of the New York electrical grid have been properly analyzed to establish the minimum amount of required reserves.

In addition to the NYISO criteria, good planning practice requires that a check be done to evaluate if there are any specific local conditions that impact LIPA and that criteria for planning the system including these specific requirements be developed. On Long Island, the condition that makes it unique is the fact it is an island with limited electrical transmission ties to other electrical systems. The loss of one of its ties can significantly reduce that capability. Similarly, the loss of a large generating unit can have a significant impact on the system. To guard against the potentially severe consequences of a major contingency occurring over a long period of time, LIPA has developed an alternative criteria that takes into consideration the specific operational conditions and contingencies that impact resource planning on Long Island.

In the 2004-2013 Energy Plan, this LIPA criterion, referred to as OPCAP-C, was the most binding planning criteria. In this Plan, for 2009-2018, the NYISO criterion is the most binding planning criteria. For simplicity in this report, LIPA is presenting only the NYSRC and NYISO criteria. LIPA will continue to monitor the OCAP-C criteria and, if it becomes more binding in the future, may use it to determine need for resources.

All of these above mentioned criteria require LIPA to have sufficient resources available to ensure uninterrupted service to the residents of Long Island under a combination of adverse system operational events or contingencies. The plan provides sufficient resources to address the simultaneous occurrence of the following four contingencies:

- Unavailability of 10% of Long Island generation at the time of peak demand due to forced or scheduled outages or derates;
- Long Island peak-load forecast based on the eightieth percentile experienced weather conditions[2];
- Loss of the largest source of energy to Long Island. Currently, this is represented by the loss of the 637 MW, 345 kV transmission interconnection to NYPA-ConEd; and
- Loss of the largest remaining generation source on Long Island. Currently, this is represented by the loss of the largest unit Northport Station, #4, at 348 MW[3].

4.2 Transmission Planning Criteria

The bulk power system is planned with sufficient transmission capability to withstand specific contingencies at projected customer demand levels and anticipated power transfer levels. These representative contingencies are listed in Exhibit 4-1. Analysis of these contingencies includes thermal, voltage, and stability assessments as defined by system design “Rules”. These Rules apply after any critical generator, transmission circuit, transformer, series or shunt compensating device, or HVDC pole

---

[2] Based on a review of historic weather patterns for the last 30 years, a peak load forecast is identified that accounts for 80% of the worst weather conditions (hottest summers) experienced during that period. Therefore, if historical patterns are a guide to future weather conditions, there is only a 1 in 5 (20%) chance that extreme weather conditions will produce a peak summer load greater than the weather assumptions used by the forecast.

[3] Unit 4 has a summer capacity rating of 387 MW, which when derated by 10%, yields 348 MW.

has already been lost, and generation and power flows are adjusted between outages by the use of Ten Minute Reserve and, where available, phase angle regulator control and HVDC control.

Exhibit 4-1 Design Criteria Contingencies

A. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with normal fault clearing.

B. Simultaneous permanent phase-to-ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with normal fault clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is not applicable.

C. A permanent phase-to-ground fault on any generator, transmission circuit, transformer or bus section, with delayed fault clearing.

D. Loss of Element without a fault.

E. A permanent phase-to-ground fault on a circuit breaker, with normal fault clearing. (Normal fault clearing time for this condition may not always be high speed.)

F. Simultaneous permanent loss of both poles of a direct current bipolar High Voltage Direct Current (HVDC) facility without an ac fault.

G. The failure of a circuit breaker associated with a Special Protection System (SPS) to operate when required following: loss of any element without a fault; or a permanent phase-to-ground fault, with normal fault clearing, on any transmission circuit, transformer or bus section.

In general, the design of the transmission system adheres to the following principles:

- The bulk power transmission system shall be planned with sufficient emergency capacity to meet the NYISO generation reliability criteria of one disconnect incident in ten years;
- The transmission system is planned with the normal capacity that is economically justified by production cost savings achieved on the basis of economic dispatch;
- The electric system shall be designed to comply with all applicable NERC, NPCC, NYSRC, NYISO and all other local utility planning and design standards;
- During normal and extreme weather conditions, the electric transmission system will meet NPCC and NYPP design standards after the loss of the two largest generators; and
- Fault duty studies will be conducted periodically under planned system reinforcement scenarios to determine if there are any three phase, line-to-line-to-ground, or line-to-ground fault circuit breaker overstress conditions.

Major transmission projects involving interconnections and the reinforcement of the bulk power systems are based on NYISO design standards. This maintains a consistency of design among all member utilities in New York State, thereby permitting uniform operating procedures in the interchange of power. The NYISO design standards specify steady state thermal and voltage conditions together with generator stability limits that are also consistent with the NPCC standards.

Assessment of extreme contingencies is also needed to recognize that the bulk power system may be subjected to events that exceed in severity the representative contingencies in Exhibit 4-1. These assessments measure the robustness of the transmission system and should be evaluated for risks and consequences. One of the objectives of extreme contingency assessment is to determine, through planning studies, the effects of extreme contingencies on system performance. Extreme contingency assessments provide an indication of system strength, or determine the extent of a widespread system disturbance; even through extreme contingencies do have low probabilities of occurrence. Extreme contingency assessments examine several specific contingencies listed in the Rules. They are intended to serve as a means of identifying those particular situations that may result in a widespread bulk power system shutdown.

4.2.1 Thermal Assessment Criteria

Pre-Contingency Thermal Criteria

For normal transfers, no transmission facility shall be loaded above its Normal Rating. For emergency transfers, no transmission facility shall be loaded above its Normal Rating. However, a facility may be loaded to the Long-Term Emergency (LTE) Rating pre-contingency, if the Short-Term Emergency (STE) Rating is reduced accordingly.

Post-Contingency Thermal Criteria

For normal transfers, no facility shall be loaded beyond its LTE Rating following the most severe of design criteria contingencies “A” through “G” specified in Exhibit 4-1 above. For emergency transfers, no facility shall be loaded beyond its STE Rating following the more severe of design criteria contingencies “A” or “D” listed in Exhibit 4-1. The STE Rating is based on an assumed pre-loading equal to the Normal Rating. Therefore, if the limiting facility is loaded above its Normal Rating pre-contingency, the STE Rating must be reduced accordingly.

4.2.2 Voltage Assessment

Reactive power shall be maintained within the bulk power system (BPS) in order to maintain voltages within applicable pre-disturbance and post-disturbance limits for both normal and emergency transfers, consistent with the NYSRC Reliability Rules and all applicable guidelines and procedures.

Pre-Contingency Voltage Criteria
For both normal and emergency transfers, no bus voltage shall be below its pre-contingency low voltage limit nor be above its pre-contingency high voltage limit.

Post-Contingency Voltage Criteria
No bus voltage shall fall below its post-contingency low voltage limit nor rise above its post-contingency high voltage limit. For normal transfers, design criteria contingencies “A” through “G” specified in Exhibit 4-1 are applicable. For emergency transfers, design criteria contingencies “A” and “D” specified in Exhibit 4-1 are applicable.

4.2.3 Stability Assessment

For normal transfers, stability of the BPS shall be maintained during and after the most severe of design criteria contingencies “A” through “G” specified in Exhibit 4-1. The BPS must also be stable if the faulted Element is re-energized by delayed reclosing before any manual system adjustment, unless specified alternate procedures are documented.

For emergency transfers, stability of the BPS shall be maintained during and after the more severe of design criteria contingencies “A” or “D” specified in Exhibit 4-1. The BPS must also be stable if the faulted Element is re-energized by delayed reclosing before any manual system adjustment. Emergency transfer levels may require generation adjustment before manually reclosing faulted Elements not equipped with automatic reclosing or whose automatic reclosing capability has been rendered inoperative.

With all transmission facilities in-service, generator unit stability shall be maintained on those facilities not directly involved in clearing the fault for:

- A permanent phase-to-ground fault on any generator, transmission circuit, transformer or bus section with Normal Fault clearing and with due regard to reclosing.
- A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with Normal Fault Clearing and with due regard to reclosing.

4.2.4 Extreme Contingency Assessment

Analytical studies shall be performed to determine the effect of the extreme contingencies outlined in Exhibit 4-2 below. Assessment of the extreme contingencies outlined in Exhibit 4-2 shall examine post-contingency steady state conditions as well as stability, overload cascading and voltage collapse. Pre-contingency load flows chosen for analysis should reflect reasonable power transfer conditions. The testing shall be conducted at megawatt transfers at the expected average transfer level. This may be at or near the Normal transfer limit for some interfaces.

After due assessment of extreme contingencies, measures will be use where appropriate, to reduce the frequency of occurrence of such contingencies or to mitigate the consequences that are indicated as a result of testing for such contingencies.

Exhibit 4-2 Extreme Contingencies

A. Loss of the entire capability of a generating station.

B. Loss of all lines emanating from a generating station, switching station or substation.

C. Loss of all transmission circuits on a common right-of-way.

D. Permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, with delayed fault clearing and with due regard to reclosing.

E. The sudden loss of a large load or major load center.

F. The effect of severe power swings arising from disturbances outside the BPS.

G. Failure of a Special Protection Scheme (SPS) to operate when required following the normal contingencies listed in Exhibit 4-1.

H. The operation or partial operation of a SPS for an event or condition for which it was not intended to operate.

The ability of the bulk power system to withstand representative and extreme contingencies is determined by simulation testing of the system as prescribed by the Rules. The transmission owner, or operator pursuant to contractual arrangement, consistent with applicable NYISO guidelines, determines thermal and voltage ratings for facilities to be included in transmission planning assessments. These ratings and limits are used for all studies conducted by the NYISO and Transmission Owners and in the operation of the Bulk Power System (BPS).

4.2.5 Power Transfer Capability

Fundamental to the transmission design is an ability to deliver energy from LIPA's firm capacity contracts in and out of its service territory and through its system to the Long Island load center. The concept of deliverability of generation capacity is fundamental to prudent utility transmission planning and is supported by the New York State Reliability Council Local Reliability Rule 3.1.2, which states:

"…LSE installed capacity located in New York State and sources external to New York State shall be distributed so as to meet the reserve requirement stated in Section 3.1.1 with recognition of internal transmission capability. Locational capacity requirements shall consider the availability of the New York State transmission system to the extent necessary to maintain reliability…"

Deliverability of generation is fundamental in determining locational capacity requirements. Only generation that can be delivered counts toward the locational capacity requirements and generation that cannot be delivered must be energy only. Also, under NYISO rules it is necessary to have deliverability to bid operating reserves and ancillary services into the market. LIPA has under contract the majority of existing "quick-start" gas turbines in the State, and, as discussed below, currently all the existing generation capacity under contract can be transferred across the major LIPA transmission interfaces at peak-load levels.

4.3 Transmission Operating Criteria

The electric system is operated to comply with all applicable NYSRC rules for the operation of the New York State Power System. These Rules are summarized in a document titled "NYSRC Reliability Rules for Planning and Operating the New York State Power System" adopted on September 10, 1999. In accordance with the NYSRC and NYISO/NYSRC Agreements, the Reliability Rules incorporate the NERC Planning Standards and Operating Policies, NPCC Criteria, Guidelines and Procedures and any Local Reliability Rules.

The Reliability Rules focus on that portion of the New York State Power System that constitutes the New York State Bulk Power System (BPS). Maintaining the reliability of the New York State BPS ensures that the entire NYCA system is protected from widespread and cascading outages. Therefore, the reliability of the New York State Power System is governed by maintaining New York State BPS reliability through the Reliability Rules.

NPCC defines the BPS as "the interconnected electrical systems within northeastern North America comprising generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area". The New York State BPS is "…the portion of the bulk power system within the NYCA, generally comprising generating units 300 MW and larger, and generally comprising transmission facilities 230 kV and above. However, smaller generating units and lower voltage transmission facilities on which faults and disturbances can have a significant adverse impact outside of the local area are also part of the New York State Bulk Power System…" The BPS for LIPA is comprised of its 345 kV and 138 kV power systems.

An objective of the Reliability Rules is to provide for the operation of the New York State BPS within the normal state. It is recognized, however, that certain system conditions may cause the system to depart from the normal state to four other operating states: Warning, Alert, Major Emergency, and Restoration. Examples of system conditions that could cause departure from the normal state are capacity deficiencies, energy deficiencies, loss of generation or transmission facilities, transmission facility overloads and high or low voltages, abnormal power system frequency, and environmental episodes. When the system enters an operating state other than the normal, the primary objective of the system operator is to return the system to the normal state as soon as possible by achieving the criteria shown in Exhibit 4-3.

Exhibit 4-3 System Conditions for NY State Bulk Power System Operating States

MONITORED CRITERIA	NORMAL	WARNING	ALERT	MAJOR EMERGENCY
Transmission Facility Pre-Contingency Flow	Flow is less than or equal to Normal rating	Flow is greater than Normal rating but less than or equal to LTE rating for not more than 30 minutes "OR" Emergency Transfer Criteria have been invoked but flow is less than or equal to Normal rating.	Emergency Transfer Criteria have invoked "AND" flow is greater than Normal rating but less than or equal to LTE for not more than 4 hours	Flow is greater than LTE rating "OR" flow is greater than Normal rating but less than or equal to LTE rating for 4 hours.
Transmission Facility Post-contingency Flow for loss of generation or single facility	Predicted flow is less than or equal to LTE rating	Predicted flow is greater than LTE rating but less than or equal to STE rating.	Predicted flow is greater than STE rating and there is sufficient time to take corrective action following contingency "AND" Emergency Transfer Criteria have not been exceeded for more than 30 minutes.	Predictive flow is greater than STE rating and there is not sufficient time to take corrective action following contingency "OR" Emergency Transfer Criteria have been invoked and criteria have been exceeded for more than 30 minutes.
Transmission Facility Post-contingency Flow for loss of two adjacent circuits on the same structure	Predicted flow is less than or equal to LTE rating	Emergency Transfer Criteria have been invoked. Post-contingency flow may exceed STE rating.	Emergency Transfer Criteria have been invoked. Post-contingency flow may exceed STE rating.	Emergency Transfer Criteria have been invoked. Post-contingency flow may exceed STE rating.
Actual Voltage	Voltage is within pre-contingency limits	Not Applicable	Voltage is less than its pre-contingency low limit or greater than its pre-contingency high limit for less than 15 minutes "OR" voltage is greater than its post-contingency high limit for less than 10 minutes and is indicative of a system problem.	Voltage is less than its pre-contingency low limit or greater than its pre-contingency high limit for 15 minutes and is indicative of a system problem "OR" voltage is less than its pre-contingency low limit, is indicative of a system problem, and appropriate voltage control measures have already been taken "OR" voltage is less than its post-contingency low limit and is indicative of a system problem "OR" voltage is greater than its post-contingency high limit for 10 minutes.

4.4 Distribution Planning Criteria

Distribution system design planning criteria have been established for substation transformers, circuit loading, primary voltage drop and main line sectionalizing capabilities. Each of these items is discussed below.

4.4.1 Distribution Substation Transformers

Distribution Substation Transformers are rated for loading according to the American Standards National Institute (ANSI) standards for maximum internal hot spot and top oil temperatures as detailed in the IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers up to and including 100 MVA with 55 0C or 65 0C winding rise (ANSI/IEEE C57.91-1995). The manufacturer's factory test data and the experienced 24-hour loading curve data are use in an iterative computer program that calculates allowable loading levels. The transformer's “ratings” for the Normal (N), Long Term Emergency (LTE), and Short Term Emergency (STE) load levels are identified based upon maximum internal temperatures and selected values for the loss of the transformer’s life caused by its operation at the criteria temperatures for a specified duration, and on a defined load curve.

The ratings of transformers are calculated from their thermal heat transfer characteristics and the expected electric loading experience over a 24-hour cycle. All distribution substation transformer bank ratings are evaluated seasonally for their summer and winter values.

A substation transformer will not be loaded above its Normal rating during non-contingency operating periods. The maximum load for Normal operation of the transformer is determined and set when the operation of the transformer at that level for the peak hour in the 24-hour load cycle causes a cumulative (24 hour) 0.2% loss of Transformer life, or the Top Oil Temperature exceeds 110 0C, or the Hot Spot Copper temperature exceeds 180 0C. Conditions above any of these limitations will result in a shortening of the transformer service life beyond prescribed design levels and/or physical damage to the equipment.

For First Contingency Emergency conditions involving the loss of one distribution substation transformer in an existing two-bank configuration, when the distribution bus-tie breaker is closed, the following system design criteria apply:

- In cases where a first contingency situation causes the LTE rating of a companion transformer to be exceeded, all load above the LTE rating of the companion transformer must be transferred to peripheral facilities within two hours (for recovery planning, a maximum of six load transfers are used), without exceeding the LTE rating of the substation transformers or distribution circuits, receiving the load. The LTE rating of a substation transformer is determined and set when the 24 hour operation of the transformer, with that additional load in each of the hours in the 24 hour load cycle curve, causes a cumulative (24 hour) 3.0% loss of transformer life or the Top Oil temperature to exceed 130 ^{0}C, or the hot spot copper temperature to exceed 180 ^{0}C. The load on all energized facilities must be brought down below their Normal ratings before the 25th hour.
- In cases where a first contingency situation will cause the STE rating of a companion transformer to be exceeded, load must be immediately reduced (dropped/shed) to a level less than STE. Within two hours (for recovery planning, a maximum of six load transfers are used), all load between the LTE and STE ratings, and any load that was initially shed to get the companion transformer below its STE rating, must be transferred to peripheral facilities without exceeding the LTE rating of the substation transformers or the distribution circuits receiving the load. The STE rating of a transformer is determined and set when the one hour operation of the transformer at that level for the peak hour in the 24 hour load cycle causes a cumulative (24 hour) 3.0% Loss

of Transformer Life or a hot spot copper temperature exceeding 180 ^{0}C. However, the maximum STE rating is limited to a value equal to twice the transformer's “nameplate” rating. The load on all energized facilities must be brought down below their Normal ratings before the 25th hour.

To reduce momentary interruptions to customers, and to reduce available fault currents on distribution circuits at two bank substations, the low voltage side of 4 kV or 13 kV distribution bus tie-breakers are operated in the normally open position. This mode of operation will minimize overhead covered wire burn downs when short circuit currents are sufficiently high enough to damage the covered wire before the instantaneous relay can clear the fault.

The exception to this design criterion is for distribution substations that supply a secondary network system or for substations where a load unbalance will occur on the individual transformers by opening the bus tie breaker resulting in a normal overload on one of the two transformers.

4.4.2 Distribution Circuit Loading

During normal and emergency conditions, circuit loading must not exceed the capabilities of the distribution line conductors specified in LIPA’s DA-10001, or exceed any other limiting equipment which will be subjected to those load conditions.

For first contingency emergency conditions on a distribution circuit, the worst of which is the loss of the circuit's exit cable or circuit breaker all interrupted load must be restored within one hour (for recovery planning a maximum of three load transfers are used). After transfers, all resultant components must be below the LTE ratings as defined by the appropriate loading guides.

4.4.3 Primary Circuit Voltage Drop

Under normal and contingency loading conditions, primary voltage drop shall be in accordance with LIPA’s DA-55001.

4.4.4 Main Line Sectionalizing Capabilities

Main line switching capabilities shall be incorporated in the design of all circuits in accordance with LIPA’s DA-51015.

The design criteria above apply generally to all work authorized under distribution line reinforcement programs.

4.4.5 Distribution Circuit Balancing

Adding new customer loads to the distribution circuit must not create imbalance on the distribution system and shall be in accordance with LIPA’s GO-62.