Exhibit 30

CASE 99-T-1423
LIPA – RIVERHEAD TO SOUTHAMPTON LINE

LIPA'S RESPONSE TO INTERROGATORY/DOCUMENT REQUEST PII

Ques. PII1: Please provide LIPA's estimate of the cost of the proposed Riverhead to Southampton transmission line (hereinafter "the proposed transmission line") and please provide all studies, reports, or other documents from which LIPA estimated the cost of the line.

a) Please describe how the cost of the proposed transmission line will be recovered from LIPA's customers.

b) Please state whether LIPA will benefit financially from increased throughput of electricity over the proposed transmission line.

c) Please state whether LIPA will have a disincentive to support energy efficiency and cleaner distributed generation on the South Fork if the proposed transmission line is approved because energy efficiency and cleaner distributed generation will reduce throughput.

d) Please describe any methods of avoiding disincentives for energy efficiency and cleaner distributed generation if the proposed transmission line is built.

Response: The cost estimate is contained in Exhibit 9 of the Application. Descriptions of the equipment to be installed and the proposed route, which formed the basis of this cost estimate, are contained in the Application, and in LIPA's East End Long Range Transmission Study, December 1999, previously provided. The costs of the line will be part of LIPA's revenue requirement. LIPA will not experience financial benefits specifically attributable to the line. As evidenced by its Clean Energy Program, LIPA is committed to energy efficiency and conservation.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII2: Please provide LIPA's estimate of annual O&M and A&G costs for the proposed transmission line, and the basis for those estimates.

Response: The O&M costs of this line are estimated to be less than $5,000 per year. This estimate was based on a review of the components that require regular maintenance, which consist of SF6 circuit breakers and protective relaying equipment. Since the cable itself is of solid dielectric construction and installed in PVC conduit, there are no fluid dielectric circulation pumps and no cathodic

protection system to maintain, making this cable type less expensive to maintain than the pipe-type cables installed on the LIPA system.

The Management Services Agreement, under which KeySpan Energy manages the LIPA T&D system, does not include an A&G charge for capital projects.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques.PII3: Please provide any local protection rules in place for the Long Island generation system.

Response: The generating units on the South Fork are dispatched for voltage control in the East of Riverhead area. The generation dispatch order is included in LIPA's response to Staff Interrogatory ECS-2 (attached).

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII4: Please provide LIPA's estimate of energy and peak demand losses on the proposed transmission line and the basis for those estimates.

Response: The estimated peak demand loss for the new proposed Riverhead to Southampton cable circuit is 0.7 MW. The annual energy loss is estimated to be 1826 MWh. Loss estimates are based on load flow simulations and the use of load duration information for the load pocket.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII5: Please specify the geographic point at which the loads shown in Figures D-2 and D-3 of the Application are measured.
a) Please explain why this point represents the South Fork Load Pocket.

Response: The system load data was acquired by the Energy Management System, and represents the load flows on the Tiana-Southampton and Tiana-Bridgehampton overhead circuits and the Buell-Southold cable plus the generation on line in the East of Tiana load pocket. Geographically, this represents all South Fork loads east of the Shinnecock Canal, since there are no distribution feeders crossing the canal.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII6: Please provide all data available on the level of load reduction from distribution system outages (Application p. 4).

Response: The reference to distribution system outages was a strictly qualitative acknowledgement of the fact that the peak of July 5 was clearly reduced between the hours 1300 and 1600, and distribution feeder outages did indeed occur. In addition, one 28 MVA substation power transformer bank at the Buell Substation experienced an outage during this period. Following the transformer bank outage, the 13 kV bus-tie breaker was closed to pick-up the feeders supplied from that bank. For the various distribution feeders that experienced outages due to conductor overloads and failure, distribution circuit switching operations restored at least portions of these circuits. The extent to which the peak may have been attenuated is not specifically known, and consequently it has not been corrected. The effect on the daily peak of 167 MVA is not likely to be large, perhaps 1-2 MVA.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII7: Please explain why LIPA would have shed 32% of South Fork customers to avoid even a fraction of a MW of overload (Application p. 4).

Response: As indicated on page 4 of the Application, the load shed scheme was designed to deal with the first contingency outage of the present double circuit 69 kV overhead line extending from Riverhead to Tiana, and eastward to Southampton, Bridgehampton and Buell. For the most limiting contingency, an outage between Tiana and Southampton, the load limit is currently 120 MVA. For this reason, a significant load shed is required. The protective relaying scheme works on undervoltage, and would have performed in the same way whether the impending voltage collapse occurred under steady state or contingency conditions.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII8: Please provide the power factor at the 1999 peak hour at each point in the South Fork for which LIPA monitors power factor.

Response: The on-line monitoring system recorded the following peak hour power factors for the major distribution substations in the South Fork load pocket:

Southampton	Bank #1	7/6/99	17hr.	93% pf
	Bank #2	7/6/99	16hr.	96% pf
Bridgehampton	Bank#1	7/5/99	18hr.	94% pf
	Bank#2	7/5/99	17hr	97% pf
Buell	Bank#3	7/5/99	15hr.	98% pf
	Bank#4	7/5/99	13hr.	95% pf

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII9: Please provide all documents produced by LIPA's engineering department on the load and capacity situation affecting the South Fork.

Response: The Application and LIPA's East End Long Range Transmission Study, December 1999, previously provided, contain such documentation.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII10: Please provide any documents produced by LIPA's engineering department on the facilities that could alleviate the capacity constraint at South Fork, including the timing and cost of capacity conditions.

Response: The Application and LIPA's East End Long Range Transmission Study, December 1999, contain such documentation.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII11: Please provide the capacity of each of the following facilities for the South Fork:

a) each substation from Riverhead east,

b) each segment of the transmission lines east of Riverhead,

c) each distribution line feed from each substation, from Riverhead and each other substation to the east of Riverhead.

Response:

Bank	Name Plate Rating (MVA)	Fan Cooled/Pumped Oil Rating N/LTE/STE (MVA)	Feeders	Circuit Rating N/E (amps)
Bridgehampton 69-13 kV				
1	28.0	41.8/48.6/56.0	2	517/600
2	28.0	36.5/42.5/56.0	2	517/600
Buell 69-13 kV				
3	28.0	37.0/43.0/53.0	2	517/600
4	28.0	34.2/39.8/56.0	3	517/600
Southampton 69-13 kV				
1	28.0	33.9/40.6/50.2	3	517/600
2	28.0	33.1/39.4/50.5	4	495/510
Amagansett 23-13 kV				
1	3.65	5.1/6.2/7.3	1	255/275
2	7.0	9.6/11.3/14.0	1	400/470
Culloden Point 23-13 kV				
1	7.0	11.1/13.0/14.0	1	410/410
Culloden Point 23-4 kV				
2	3.65	5.9/7.0/7.3	1	458/510
Hero 23-13 kV				
1	7.0	10.3/12.3/14.0	1	410/410
Hither Hills 23-4 kV				
1	3.65	6.7/7.3/7.3	1	458/576
2	3.65	6.0/7.0/7.3	1	458/576
Montauk 23-4 kV				
1 & 2	6.0	8.4/10.2/12.0	2	458/510

Transmission line ratings may be obtained from the response to Staff Interrogatory ECS-1 (attached) and from the basecase load flows contained in LIPA's East End Long Range Transmission Study, December 1999.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII12: For each year 1993 to 1999, please provide the peak load on each of the following facilities:

a) each substation from Riverhead east,

b) each segment of the transmission lines east of Riverhead,

c) each distribution line feed from each substation, from Riverhead and each other substation to the east of Riverhead.

Response: See response to PII21.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII13: Please provide LIPA's projection of the peak load on each of the following facilities, for each year for which LIPA has prepared such a projection:

a) each substation from Riverhead east,

b) each segment of the transmission lines east of Riverhead,

c) each distribution line feed from each substation, from Riverhead and each other substation to the east of Riverhead.

Response: For the last four years, the Summer Operating Study has been performed in a load pocket format. Projections of peak load for the East of Tiana load pocket were taken from these studies as follows:

1996	120 MVA
1997	124 MVA
1998	135 MVA
1999	141 MVA

Projections for both transmission lines and substations can be taken from the basecase load flows in these operating studies. These load flows are supplied for the years 1996-1997 (attached). The summer operating studies are based on forecasts using the Area Load Forecast procedure, which relies on historical data, additions of known lump loads and projections of area load growth. Load flows using more recent load forecasts are contained in the Application, and in LIPA's East End Long Range Transmission Study, December 1999. Data at the distribution feeder level cannot be made available in the time allocated for these responses, however, data at the load pocket and substation levels, together with the transmission load flows, provide ample documentation of the requirements for the transmission system serving the South Fork.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII14: Please provide LIPA's projection of the first year at which each of the following facilities will require reinforcement:

a) each substation from Riverhead east,

b) each segment of the transmission lines east of Riverhead,

c) each distribution line feed from each substation, from Riverhead and each other substation to the east of Riverhead.

Response: Transmission and substation requirements for the East End are documented in LIPA's East End Long Range Transmission Study, December 1999. In addition, the following projects are required:

Buell 13 kV feeder addition	2000
Eastport 13 kV feeder addition	2000
Amagansett replace 3/7 MVA transformer bank	2001
Eastport replace 6/14 MVA transformer bank; add one 13 kV feeder	2003

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII15: Please explain whether the transmission line running east from Tiana is supplied by Tiana, or from the other end, at typical peak conditions.

Response: The Tiana-Southampton/Tiana-Bridgehampton lines are supplied from the Riverhead Substation via the Riverhead-Tiana and Eastport-Tiana lines. The Eastport Substation is also supplied by the Moriches-Eastport line, which is supplied from the Brookhaven Substation. See the basecase loadflows in LIPA's East End Long Range Transmission Study, December 1999.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII16: Please provide the current capacity and peak load for each year from 1993-99, for each of the following facilities for the South Fork:

a) each segment of the transmission line west of Tiana,

b) each substation served by that transmission line,

c) each distribution line feed from each substation on that transmission line.

Response: The following data are for the segment of the LIPA 69 kV transmission system between the Tiana Substation and the Eastport Substation. The Eastport substation has two 69 kV supplies: the Riverhead-Eastport line, and the Moriches-Eastport line, which is supplied from the Brookhaven Substation, by the Brookhaven-Moriches line. Transmission line ratings and load flows, and substation loadings, at peak load conditions are contained in the basecase load flow diagrams contained in LIPA's East End Long Range Transmission Study, December, 1999, and in additional load flow diagrams taken from the 1996-1997 Summer Operating Studies (see response to PII13). The load flows are

toward the Tiana substation and into the East of Tiana load pocket. Substation loads for the July 5, 1999 peak are also provided.

Bank	Name Plate Rating (MVA)	Fan Cooled/Pumped Oil Rating N/LTE/STE (MVA)	Feeders	Circuit Rating N/E (amps)
Eastport 69-13 kV				
3	14.0	19.2/22.5/28.0	2	517/600
2	6.25 (Standby)	6.8/9.1/9.1	0	
Suffolkaire 69-13 kV				
3	6.25	8.5/10.4/12.5	1	354/433
4	6.25	8.1/9.6/12.5	1	337/400
Quogue 69-13 kV				
1	6.25	8.7/10.2/12.5	1	360/425
2	6.67	8.8/10.3/12.6	1	365/429
Tiana 69-13 kV				
1	12.5	19.3/21.9/25.0	2	517/600
2	12.5	17.0/19.9/24.0	2	517/600

Substation Loads on July 5, 1999
From Tiana to Eastport

69-13 kV Substations	Load @ Distribution Buses
Tiana	27.9 MVA
Quogue	17.6 MVA
Suffolkaire	15.4 MVA
Eastport	18.4 MVA

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII17: For each year from 1990-1998, please provide the forecast prepared in that year for the South Fork's load, for any period LILCO or LIPA prepared such forecasts.

a) Please provide these forecasts for each transmission line segment, substation, and feeder in the South Fork.

Response: See response to PII13.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII18: Please describe in detail any interruptible loads on the South Fork.

a) Please provide the required number of hours of interruption for each year 1990-99 and for any future period for which LIPA has produced estimates.

Response: There are no interruptible loads on the South Fork.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII19: Please provide the hours of generation by each unit in the South Fork, for each year from 1993-99.

a) Please provide the number of hours in which the South Fork generation was dispatched out of merit order, due to the transmission constraint.

Response: Hours of generation by each unit East of Riverhead for the years 1993-99 are plotted on the attached charts. The Southold unit, located on the North Fork, is included because of the transmission interconnection between Southold and Buell. Since these are small peaking units, their run time is predominantly in fulfillment of requirements for system voltage support, rather than under economic dispatch.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII20: Please provide LIPA's estimate of the annual probability of a repeat of 1999 summer weather conditions.

Response: LIPA has no estimate of the probability of a repeat of the 1999 summer weather. For purposes of comparison however, LIPA produced 1999 peak load forecasts using the weather conditions which occurred at peak for each of the last 30 years. The 1999 peak conditions produced the highest such forecast. The magnitude of system load peaks is dependent on two factors: the actual weather conditions and the timing of these conditions. The highest system peaks occur during weekdays, and are driven by the intersection of the commercial and industrial loads and residential loads; the highest peaks on the South Fork tend to occur on weekends and holidays.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII22: Please provide the guidelines LIPA uses in planning transmission facilities.

a) Please describe the decision-making path that LIPA follows to determine whether an upgrade to the T&D system is required.

Response: LIPA's transmission and distribution planning criteria are described in the attached report, Electric Transmission and Distribution System Planning Criteria, June 1998.

KeySpan Energy, in its role as T&D System Manager, identifies needs for capital projects through application of the planning criteria in system studies to address load growth and reliability requirements. The system studies include system design for lump load additions; distribution feeder and substation transformer contingency analyses; substation area studies; and bulk transmission system studies. Loads on transmission and distribution lines and transformers are projected under normal and contingency conditions, and any required corrective actions are identified. These studies are provided to LIPA management, and the results are discussed in regular meetings with LIPA management and Navigant staff. Projects identified through these studies are sorted by date of need and ranked in priority order. Beginning with these project listings, project justification documents and budget cost estimates are completed to develop a proposed five-year capital budget, which is filed with LIPA on July 1 of each year. The budget is reviewed by Navigant staff, and is reviewed with LIPA management in a series of meetings. In these meetings, the proposed projects are prioritized, along with any additional system requirements that may be attributable to more recent load additions or equipment failures. After deletions, additions and deferrals are agreed upon by LIPA and KeySpan Energy, the budget is presented to the LIPA Board for approval. The LIPA budget is approved only for the current year, however, funding for engineering and procurement required for projects in future years is included as necessary.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII23: In the case of the proposed transmission line, please state when LIPA decided that the proposed line was necessary.

a) When were the studies of alternatives to the proposed line, especially demand-side management and distributed generation, performed by LIPA?

b) Who performed, participated or was involved in the preparation of these alternative studies?

c) Please provide copies of all studies of alternatives to the proposed transmission line that LIPA prepared or that were prepared for LIPA by others.

Response: Presentations on the July 1999 heat wave experience were made by KeySpan Energy to LIPA management on July 26 and July 30. These presentations, and the discussions that followed, included analyses of system conditions and recommendations for improvement of system performance, including, where appropriate, transmission, generation and DSM alternatives. A presentation was made to the Public Service Commission Staff on August 9. In the two weeks following this meeting, LIPA further evaluated the alternatives, including the schedules for placing these alternatives in service. LIPA then made a decision to proceed with the proposed transmission line and with a targeted DSM program for an amount of peak load reduction that was determined to be achievable. The proposed transmission line and its associated projects represent an acceleration of a previously identified plan.

These studies are documented in the Application.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII24: Please explain whether LIPA plans its transmission system for loads experienced under normal peak weather, worst-observed weather conditions, or something in between.

a) Please provide any documents that incorporate these standards.

Response: The determination of individual substation and feeder load projections are based on actual peak loads experienced on the system. They represent actual weather conditions for the last peak load period. The attached General Operation Procedure (GO-10126) Electric Distribution Substation Bank and Feeder Load Forecasting describes this method. Transmission system planning uses the results of individual distribution substation load projection reflected to the high side of the distribution substation and then "normalized" for the electric system load forecast that represent weather adjustment and coincident to the system peak. For specific area studies, the load forecast is based on the transmission bus loads without normalization to the system peak.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII25: Please provide the MW load reduction required in the South Fork to avoid overloads in the summer 2000, with

a) normal weather,
b) 1999 weather.

Response: The most limiting system conditions to deliver the expected South Fork load for the year 2000 are not thermal overloads, but the expected system voltage collapse during first contingencies on the transmission system. The first contingency voltage limit of the South Fork load pocket is about 120 MVA and expected normal weather forecast is 170 MVA. Using 95% power factor, this translates respectively to 114 and 160 MW. The load reduction required is about 46 MW for normal weather load forecast. The extreme weather South Fork load forecast for the year 2000 is 180 MVA. Using 95% power factor, this represents 171 MW load. The extreme weather load reduction is 57 MW (171 MW expected load less the 114 MW first contingency voltage limit).

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII26: Please provide the cumulative MW reductions from the current load forecast that would be required to defer the need for the proposed transmission line for two years, five years, and ten years.

a) Please provide the derivation of these estimates.

Response: The normal weather forecast for 2001 is 177 MVA or 168 MW. The cumulative load reduction for two years is 54 MW (168-114).

The normal weather forecast for 2004 is 213 MVA or 202 MW. The cumulative load reduction for 5 years is 88 MW (202-114).

The normal weather forecast for 2009 is 247 MVA or 234 MW. The cumulative load reduction for 10 years is 120 MW (234-114).

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII27: Please provide estimates of load growth for the whole LIPA system, the South Fork and any smaller subset of the South Fork for which such data exists.

a) Please provide copies of all studies, memoranda, or other bases for LIPA's estimates of load growth in these areas.

Response: The latest official load forecasts for the LIPA system are contained in the load and capacity projections contained in the New York Power Pool report, Load and Capacity Projections, July 1999. Data specific to the LIPA system are

contained in Table V-2, which is attached. More recent system forecasts are in the final stages of development by KeySpan Energy, and LIPA review of these forecasts has not yet been completed.

Load growth estimates for the South Fork, including the subsets, East of Tiana, and East of Buell, are provided in the application and in LIPA's East End Long-Range Transmission Study, December 1999.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII28: Please provide descriptions of the methodology used by LIPA/LILCO to project load and provide all estimates of load growth prepared over the last five years.

Response: Attached are descriptions of the current system sales requirements and peak forecasting methodology used by KeySpan Energy. This methodology has evolved over the years and continues to be modified and enhanced with each new forecast.

Also attached is a summary of Peak and Requirement Forecasts prepared in 1994 through 1998, along with the actual and normalized Peaks and Requirements experienced in the following year.

System Peak Forecast for 2000-2004
The peak forecast was developed using the Hourly Electric Load Model (HELM). Two independent checks were then performed on the forecasted values. The first was performed on a system basis using historical trends in load factors. Although the actual load factor has generally been declining, the normalized load factor has remained relatively stable over the decade, declining slightly from 50.8% to 48.7%. The forecasted peaks (and associated requirements) for the years 2000 through 2004, result in load factors which fall within the range of normalized values experienced over the past five years.

A second check was performed using a "bottom up" approach based on new construction growth and existing building expansion as forecasted by ED&C/Area Planning, adding the increased air conditioning saturation by existing residential customers, as developed by Forecasting. This independent approach appears to support the new forecasted peak for the year 2000, as developed using HELM. However, additional research and analysis needs to be performed on the "bottom up" approach to accurately account for the non-expansion peak growth component of existing commercial customers. This research and analysis will be one of several follow-up studies to be completed prior to the next forecast.

HELM

The Summer System peak load forecast was developed using Hourly Electric Load Model (HELM), developed for the Electric Power Research Institute. HELM is used to "share down" forecasted annual sales into monthly, daily and hourly sales, with the results used for economic dispatch modeling. The application of HELM to peak load forecasting provides a realistic, bottom-up approach by capturing the changing relationships among the residential, commercial and industrial components used to model LIPA System Sales.

The LIPA system, as represented in HELM, includes one industrial, two commercial, nine residential (air conditioning, refrigerator, range, etc.) and four "other" types (Street Lighting, LIRR, etc.). The electric sales forecast is developed primarily from a combination of monthly and annual econometric models. Sales forecasts are obtained from the model results using several methods. First, the results of the monthly and annual industrial models are used directly for the industrial sector. The commercial 2L and commercial MRP split is obtained from the commercial models using ratios developed from billed sales data. The residential end uses are obtained from the models using ratios developed from residential energy audits conducted during 1997 through 1999. Finally, the "other" sectors are non-modeled and are developed directly from trend analysis.

Forecasted annual sales are distributed into each hour of the year using one of two methods: either a Day-Type or a Weather Sensitive Load Shape Representation (LSR). The Day-Type LSR utilizes fixed ratios to allocate a portion of the annual energy to each month, and then to each day. The Weather Sensitive LSR uses a weather response function to determine the daily load for each day based upon a weather value (degrees F or THI) assigned to that day from the 30-year normal weather. Both Weather Sensitive and Day-Type LSRs use fixed ratios to distribute the daily energy to each hour. Each of the 16 end uses is handled in one of these two ways. For example, the Residential Central Air Conditioning end use is weather sensitive while the Industrial end use is Day-Type.

Since there is variation in the hourly loads for each end use, there is one hour with the greatest share of the annual end use load, called the non-coincident peak. HELM sums up the hourly loads for all of the end uses resulting in hourly system sales. Again, there is one hour with a greatest share of the annual system load, called the coincident peak or simply the peak.

Growth in before-reduction annual system sales for the years 2000-2003, forecasted to be 1.87%, 2.00%, 2.04% and 1.78% respectively, corresponds to forecasted growth in before-reduction system sales peaks of 2.36%, 1.70%, 1.60% and 1.62% respectively, from HELM. The same LSRs and normal weather are used for each of these years, ensuring that the same relative amount of forecasted sales is allocated to each month for each end use. Therefore,

LIPA can trace changes in the system peak growth that differ from changes in system sales growth to changes in the forecasted level of sales by end use from year to year. HELM captures the differences in the rates of growth for residential, commercial and industrial components of system sales and the impact that these changing relationships have on the system peaks.

Description of Energy and Demand Models

A variety of procedures were used to develop the electric forecast. The following sections give a general description of the methodologies used.

The forecast of electric system sales is derived by adding the projections for the following individual sectors:

(1) residential;
(2) commercial-industrial;
(3) other, "non-modeled" classes including, Long Island Rail Road usage, electric vehicles, etc.

The methodology used to forecast short and intermediate range electricity sales to each of these sectors is described below. The long range forecast is developed at the system level.

Residential Sales

The forecast for the residential sector is derived from two separate and distinct modeling methodologies (monthly and annual econometric models), depending upon the time frame involved. Specifically, sales for the "short range" (the year 2000) was obtained from monthly econometric models. Sales for the intermediate years 2001 through 2003 were derived from a combination of monthly and annual econometric modeling.

Short range residential sales were forecasted using monthly econometric models for the following four rate classes:

(1) general, non-electric space heat;
(2) electric water heating;
(3) electric space and water heating;
(4) mandatory Multiple Rate Periods (MRP).

Depending on the particular rate class, models were developed with databases consisting of approximately 9 to 17 years of monthly data. The models relate monthly sales to variables such as: average electricity price, customers, income, heating and cooling degree days, lagged sales and the number of days in the month. Projected sales for each model are determined based on the individual forecasts for each of the independent variables particular to the modeled class.

Sales to the remaining (0.5% of sales) smaller residential classes (i.e., Voluntary Multiple Rate Periods and Off-Peak Storage) were obtained using historical average use per customer multiplied by forecasted customers.

The annual econometric residential model was developed from 24 years of historical data and used cooling degree days, real price of electricity, real household income and the previous year's use per customer as explanatory variables. Use per customer predicted by the annual model was multiplied by projected numbers of customers to forecast residential sales.

Intermediate-range residential sales were forecasted by averaging the results from the monthly and annual residential econometric models.

Commercial-Industrial Sales

The forecast for the commercial-industrial class is derived from two distinct methodologies: monthly and annual econometric modeling. In particular, the commercial-industrial sales forecast is derived using:

(1) monthly econometric models for the first year (2000);
(2) a combination of monthly and annual econometric models for the years 2001-2003.
(3) a combination of the industrial econometric and commercial end-use models for the year 2004 and beyond.

The two methodologies are described below.

The monthly econometric model is intended to capture economic fluctuations/ trends present in the short run (i.e., through year 2000) horizon, as well as seasonal weather patterns inherent to Long Island. The model consists of four equations representing about 97% of all commercial and industrial sales. The four equations explain sales related to the following classes:

(1) "General Large"
(2) Mandatory Multiple Rate Periods
(3) Electric Space Heating
(4) Non-Demand Metered "General Small"

The driving variables include electricity price, employment, customers, weather indicators, days in the month and lagged sales. Forecasted values for the driving variables are obtained from both in-house and outside sources. These forecasted values are then inputted into the respective equations, yielding forecasted monthly sales by major rate class. Monthly sales are then summed to derive the annual forecast for the first year of the forecast horizon (2000).

The commercial/industrial sector is disaggregated into three major types of business based on Standard Industrial Classification: industrial (manufacturing), commercial (non-manufacturing), and not elsewhere classified. Annual models are developed for the industrial and commercial sectors. Both the commercial and industrial customer classes were modeled with 22 years of annual data. The driving variables include electricity price, employment, customers, weather and lagged sales. Forecasted values for the driving variables are obtained from both

in-house and outside sources. These forecasted values are then inputted into the respective equations, resulting in individual forecasts for the commercial and industrial sector sales. Not elsewhere classified sales are projected to be 3.7% of commercial and industrial sales. Adding sales over the three customer groups produces a forecast for the entire commercial-industrial class.

In addition to its use in developing the short-range forecast, econometric modeling is also utilized for the commercial/industrial sector's intermediate range forecasts.

For the years 2001 through 2003, the results of the commercial and industrial monthly and annual econometric models were blended to yield the annual forecasted sales. Monthly sales were then derived based on the monthly model ratios.

Non-Modeled Classes

Sales forecasts for the remaining non-modeled classes are developed outside the econometric models since either they possess unique energy using characteristics which exclude them from being combined with the existing configuration of models or they are relatively new rate classes and , lacking sufficient history, do not lend themselves to formal econometric modeling. These non-modeled rate classes include voluntary time-of use, real time pricing, outdoor area lighting, etc. These sales forecasts are developed using a variety of techniques, including trend analysis, historical use per customer data, information from internal marketing organizations, etc.

In addition, Brookhaven National Laboratories (BNL), Long Island Rail Road (LIRR), Street and Highway Lighting (SHL) and Electric Vehicles (EV), are not modeled. BNL provides their own forecast of energy needs, while LIRR projections are based on previous usage, modified to reflect expected increases in ridership. SHL usage reflects anticipated increases based on household growth and EVs are based on the number of Long Island households likely to purchase an EV. To reflect the requirements of the Clean Air Act, the use of electric vehicles is included in the forecast beginning in 1999. As a result, the electric sales attributed to charging these vehicles, is included as a separate customer "class".

PFJ is a New York State program where lower cost NYPA power is made available to LIPA commercial and industrial customers who meet certain criteria. The forecast for PFJ is based upon NYPA's projections of available peak power. The program increases to 66 MW in the year 2000 and then declines. Energy is determined from the extrapolation of exiting PFJ customer usages to the future allocations.

Area Load Forecast Methodology

The attached General Operations Procedure (GO-10126), Electric Distribution Substation Bank and Feeder Load Forecasting, describes the area load forecast procedure. The methodology involves monitoring of load data at the

distribution feeder and substation transformer level and projecting future load through a combination of identified "lump load" additions and an underlying area load growth rate. Unlike the system forecast, the area forecast is tailored to specific substation or load pocket areas.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII29: In the future, will LIPA employ the same methodology for load projections that has been used in the past by LILCO?

a) If not, how will LIPA's load projection methodology differ?

Response: The system forecast methodology presented in the response to PII28 is the current methodology used by KeySpan Energy. KeySpan will continue to explore other approaches to improve the accuracy of the system sales forecast and to address the marketing and system design information needs of LIPA.

The software for the area load forecast is undergoing significant revision to make better utilization of the on-line data from the Energy Management System that has been available since March 1998 and to improve the data analysis necessary to produce the forecast.

In addition, under the Long Island R&D Initiative, the State University of New York at Stony Brook has embarked upon an R&D project specifically tailored to the development of load forecasts at the load pocket level. The project is evaluating use of load data, weather data and economic data as tools for improvement of forecasting methodology at the load pocket level. As such, this model could become a "hybrid" of the current system and area load forecast methodologies.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII30: Please provide information on the utilization of the T&D system by time of year and time of day for LIPA's entire system, the South Fork and any other smaller subset for which you have such information.

Response: This question is best addressed by the attached load duration curves. The curve for the system covers the period August 1998 through July 1999. The curve for the South Fork covers the period May through September, and for comparison 1998 and 1999 are shown on the same plot. Retrieval of this data is limited,

because the data warehouse associated with the Energy Management System first became operational in March 1998.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII31: Please state how much electricity demand would have to be reduced on the South Fork to delay the need for the proposed transmission line by one year?

Response: This is the same question as PII26 for the first two years. The project is deferred to 2001. The value of a one-year delay can be determined by multiplying the cost of the project by an annual charge rate of 15%.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII32: Please provide data on new home construction (number, size, value) on the South Fork over the last ten years.

Response: The following data are taken from a June 1999 report prepared by the Nassau-Suffolk Regional Planning Board. The 1999 data through June were obtained directly from Southampton and East Hampton towns. No data are available on size or value of construction.

New Residential Construction based on Permit Authorization
Towns of Southampton and East Hampton

Year	1991	1992	1993	1994	1995	1996	1997	1998	1999
Permits	495	537	531	697	701	813	756	1049	469*

*Through June 1999

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII33: Please estimate new home construction rates (number, size, value) on the South Fork over the next ten years.

Response: LIPA has no specific projections for the South Fork; gross new residential and commercial customer projections are made on a system basis, and are used in the system load forecast.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII34: Please provide LIPA's estimate of the value to Long Island ratepayers of the increased reliability due to the proposed transmission line.

a) Please provide the basis for this estimate.

Response: LIPA has no specific valuation of the increased reliability attributable to the proposed transmission line. See response to PII35.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII35: Please provide all studies in the possession of LIPA or its consultants on the value of electric reliability in:

a) Long Island,

b) other areas of New York.

Response: In 1991, the New York State Public Service Commission adopted standards for reliability and quality of electric service for all New York State Utilities. LIPA voluntarily follows these standards when providing electric service to its customers. Attached is a copy of the standards. LIPA does not have any other studies on the value of electric reliability.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII36: Please provide the following data for LIPA (or LILCO) for each year, 1990 to 1998, and for whatever portion of 1999 data is available:

a) System Average Interruption Frequency Index (SAIFI)

b) System Average Interruption Duration Index (SAIDI)

c) Momentary Average Interruption Frequency Index (MAIFI)

Response:

RELIABILITY INDICES FOR LIPA (or LILCO)

YEAR	SAIFI	SAIDI (Minutes)	MAIFI**
1990	1.316	80	-
1991	1.271	79	-
1992	1.324	84	-
1993	1.406	92	-
1994	1.353	90	-
1995	0.881	63	12.5
1996	0.875	66	11.2
1997	0.745	53	8.4
1998	0.773	59	8.3
1999*	0.794	54	7.3

* 1999 data represents the 12-month period ending 12/22/99.

** MAIFI index was not tracked prior to 1995.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII37: Please provide all studies or other information available to LIPA regarding the power-quality requirements of its industrial and commercial customers, and how well LIPA is currently meeting those needs.

Response: Attached is a summary of how LIPA responds to power quality concerns, as well as a summary of our Power Quality Research & Development (R&D) Efforts.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII38: Please provide all available data on expenditures for power quality improvements by:

a) LIPA,

b) its customers.

Response: The LIPA T&D reliability program includes the installation of Digital Feeder Protection (DFP) relays, which are microprocessor based relays that significantly reduce momentary interruptions. The DFP relays have been

installed on 75 distribution feeders per year, at an average cost of approximately $15,000 per feeder.

LIPA does not have any data available on power quality expenditures by its customers.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII39: Please provide the avoided costs currently being used by LIPA for screening demand side management ("DSM") programs.

Response: Analysis, reports and available documentation discussing avoided costs and LIPA's demand side management ("DSM") programs can be found in the attached document titled Draft LIPA Clean Energy Portfolio, submitted to the LIPA Board of Directors and dated November 2, 1998. Avoided cost information is also presented in the attached document titled Long Island Choice Phase I Implementation Plan, dated January 1999, and the attached document titled Clean Energy Initiative, dated May 3, 1999 and found at the LIPA web site at www.lipa.state.ny.us/vbdoc.html.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII40: Please provide the avoided costs currently being used by LIPA for screening distributed generation programs.

Response: See response to PII39.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII41: Please provide LIPA's estimate of the benefits of deferral of the proposed transmission line, including:

a) The value of deferring the project to 2001,

b) The value of deferring the project each additional year,

c) The present value of benefits resulting from deferrals through various years.

Response: See response to PII31. The present value of deferrals for various numbers of years can be calculated using an appropriate value for the LIPA cost of money. Seven percent would be a reasonable figure.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII42: Please provide all documents, including internal LIPA analyses, memoranda, reports, studies, or emails regarding updates, revisions or corrections to LIPA avoided cost calculations since 12/31/97.

Response: See response to PII39.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII43: Please provide all documents, including internal LIPA analyses, memoranda, reports, studies, or emails regarding updates, revisions or corrections to LIPA avoided costs provided to LIPA by consultants since 12/31/97.

Response: See response to PII39.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII44: Please provide all communications (including letters, memoranda, and emails) regarding updates, revisions, corrections to LIPA avoided costs from LIPA to any consultant or other outside party since 12/31/97.

Response: See response to PII39.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII45: Please provide all workpapers and other documentation supporting the loss factors used in LIPA's current avoided costs.

Response: Electric system losses on the LIPA transmission and distribution system are based on periodic system loss studies using load flow simulation of actual system conditions and statistical sampling techniques for services and meter losses.

Loss calculations are based on the determination of average power and energy system losses through the various components of the electric system. Energy losses are calculated using load duration curves associated with power delivery. Actual generation, tie-line flows, line configuration and loads are used to calculate losses for various load levels, including the peak load. The resulting losses are then prorated over 8760 hours to calculate an annual loss factor. Fixed (energization) and variable (load) components of the losses are determined separately.

Loss calculations are categorized into line, transformer, services and meter losses. Line losses include the various transmission, distribution and secondary voltage levels of the LIPA system. The transformer loss calculations include the various transformation levels from a higher voltage level to a lower level such as from the 69 kV system to 13 kV level.

The comparison of actual system losses and the calculated values support the validity of the LIPA model.

LIPA System Loss Summary

Summer Losses

	Average Energy	Peak
Secondary	2.73	3.03
Primary	1.60	2.70
Tran 23-69	0.98	1.21
Trans 138-345	1.13	1.00
Total %	6.44	7.94

Winter Losses

	Average Energy	Peak
Secondary	2.71	2.70
Primary	1.52	2.10
Tran 23-69	1.00	1.02
Trans 138-345	1.11	1.02
Total %	6.34	6.84

Note: Values include both Fixed (Energization) and Variable Losses.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII46: Please provide all studies, reports, or other documents from which LIPA estimated market energy and capacity prices on Long Island.

Response: See response to PII39.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII47: Please provide the following information for each merchant power plant currently proposed or under construction in New York City or Long Island:

a) name

b) location

c) developer

d) planned summer capacity

e) planned winter capacity

f) estimated cost (and the source of that estimate)

g) number and type of turbines to be used in the plant, by manufacturer and model number

h) number of steam generators to be used in the plant

i) status of licensing, transmission studies, and other pre-construction activities.

Response: Attached is a list of proposed generation projects for the New York Control Area taken from the NYISO website. This list includes all projects for which System Reliability Impact Studies are in progress or under review by the NYISO Operating Committee and its Transmission Planning Subcommittee.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII48: Please provide any information available to LIPA on the costs of recent or potential gas pipelines to Long Island.

Response: LIPA does not have this information.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII49: Please provide any data available on the market price of capacity in downstate New York in:

a) 1998

b) 1999

c) current contracts for 2000 or beyond.

Response: The following is a summary of installed capacity costs for the summer capability period for the years 1998-1999. For the year 2000 capability period, there will be an installed capacity auction. The rules for this process are still under development by the NYISO.

Year	Cost Range ($/kW-month)	Average Cost ($/kW-month)	Average Capacity (MW)
1998	1.15-1.70	1.61	125
1999	1.00-2.50	1.88	470

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII50: Please provide any information available to LIPA on the prices of each contract for downstate New York power-supply signed in 1998 or 1999, including standard-offer service.

Response: See response to PII49.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII51: Please state whether LIPA believes that a system of CO_2 taxes, tradable allowances, or similar restraints is likely to be imposed in the United States within the useful life of the proposed transmission line, and if so:

a) when

b) the likely value of the tax or allowances

c) the likely effect of the tax or allowances on market energy prices in New England and Long Island.

Response: It is likely that some type of Carbon Dioxide (CO_2) restraint will be imposed during the life of the proposed transmission line.

a) In 1997, the Kyoto Protocol established emission targets for developed nations; the target for the United States was 7% below 1990 levels of CO_2 emissions. Should the Protocol enter into force as written, the emission targets would have to be achieved on average over the commitment period 2008 through 2012. However, these targets, and the manner in which each country should meet them, are the subject of much ongoing debate and negotiation. This debate is likely to continue due to the tremendous complexity of setting a worldwide emission control structure and the associated significant economic impacts. Therefore, predicting actual regulatory time frames for CO_2 compliance is difficult.

b) The exact form and manner of regulatory control in the United States and in other countries is currently in preliminary conceptual discussions at both the national and global levels. Therefore, it is premature to attempt to forecast the value of any CO_2 allowances or the cost of any CO_2 tax.

c) Again, due to the great uncertainty associated with future CO_2 regulations, LIPA has not attempted to predict their potential effect on the energy market in New England or Long Island.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII52: Please provide the regional transmission charges that LIPA or its customers could avoid by reducing load levels.

Response: The existing interties to the New York and New England transmission grids are loaded to the extent of available transfer capacity by firm and economy power purchases. Any reductions in peak loads are therefore not likely to result in reduced transmission utilization and associated charges.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII53: Please provide LIPA's current estimate of avoided generation capacity costs, and the basis for that estimate.

Response: See response to PII39.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII54: Please provide all transmission projects planned by LIPA over the next ten years that would facilitate supply to Long Island from off-island sources. For each please provide:

a) Projected in-service date
b) Projected cost
c) Need and justification for the line

Response: LIPA is currently evaluating bids to engineer, construct and operate a proposed HVDC intertie from New England, connecting with the LIPA system at the Shoreham site. This followed a detailed feasibility study. Should LIPA decide to proceed with this project, the earliest projected in-service date is summer 2002. The cost of the proposed line will be determined by the bids received by LIPA. These bids constitute confidential information until LIPA's evaluation is completed, and a recommendation is made to the LIPA Board.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII55: Please provide all transmission projects planned by LIPA over the next ten years that would facilitate supply to Riverhead. For each please provide:

a) Projected in-service date

b) Projected cost

c) Need and justification for the line

Response: The most significant planned changes to the transmission system supporting power deliver to the Riverhead substation are as follows:

The installation of the second 220 MVA 138/69 kV stepdown bank at the Brookhaven 138 kV substation is planned for 2002 at an estimated cost of $2,917,000. This project is required to prevent voltage collapse on the Brookhaven area transmission system for the contingency loss of the single 224 MVA, 138-69 kV stepdown transformer at the Brookhaven Substation.

Reconductoring of the William Floyd to Brookhaven 69 kV transmission line is planned for 2003 at an estimated cost of $830,000. This is required to prevent normal overloads on this transmission line.

Reconductoring of the existing Brookhaven to Moriches 69 kV transmission line is planned for 2003 at an estimated cost of $1,040,000. This project is required to prevent first contingency overloads on this transmission line.

Beyond these projects, it is anticipated that the existing 69 kV circuits from Wildwood to Riverhead and Brookhaven to Riverhead will be converted to 138 kV operation within ten years, however, a specific need date has not yet been established.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII56: Please explain whether the avoided energy costs used by LIPA in screening DSM reflect around-the-clock baseload market prices or market prices for energy with the LIPA retail load shape.

Response: See response to PII39.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII57: Please provide LIPA's current projection of avoided capacity costs by month, and the derivation and basis for that projection.

Response: See response to PII39.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII58: Please explain whether LIPA's analysis of the benefits of DSM, photovoltaics, and other lower-pollution energy sources include any allowance for the environmental benefits of reducing energy generation.

a) If so, please provide the most complete available description and documentation of the environmental credit.

b) If not, please explain why.

Response: See response to PII39.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII59: Please provide the projection of market electric energy prices LIPA uses in screening DSM and distributed generation.

a) Please provide the basis for that projection.

b) Please explain whether these are values for baseload energy, commercial lighting, air conditioning, or some other end use or load shape.

c) Please provide the split of energy between on-peak and off-peak hours reflected for these prices.

Response: See response to PII39.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII60: Please provide all fuel prices used in LIPA's screening of DSM and distributed generation.

Response: See response to PII39.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII61: Please specify the inflation rate LIPA assumes.

Response: The Management Services Agreement, under which KeySpan Energy manages the LIPA T&D system, specifies the use of the Regional Employment Cost Index—Service Producing Industries. For the year 2000, the rate is 3.2 percent.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII62: Please provide the most recent data available to LIPA on the distribution of ages of T&D equipment at retirement.

Response: The following data is for substation equipment and is presented using this convention:

Equipment Age at Retirement (Number of Units)

Substation Transformers 1995-1999:
7(1); 29(1); 32(1); 33(1); 38(1); 44(1); 45(2); 47(1); 46(7); 50(3); 51(6); 52(1); 53(1); 54(1); 55(1); 57(4); 58(2); 60(1); 65(3); 66(3); 67(4); 68(1); 69(3); 70(3)

Oil Circuit Breakers 1997-1999:
138 kV: 31(1); 30(1); 26(2); 24(1)

69kV: 68(1); 57(1); 51(1); 46(3); 44(1); 43(1); 42(2); 41(1); 40(2); 34(1); 31(1); 29(2); 25(1); 24(1); 18(1)

33 kV: 47(1); 45(1); 44(2); 43(1); 41(2)

23 kV: 54(2); 42(1); 40(1); 39(1)

13kV: 67(1); 66(1); 58(2); 57(2); 50(1); 49(1); 48(4); 47(1); 46(2); 41(4); 36(1); 35(2); 34(1)

Voltage Regulators 1995-1999:
57(1); 48(7); 47(1); 44(1); 34(3)

Air Circuit Breakers 1995-1999:
28(3); 25(2); 31(3); 33(1); 37(3); 38 (3); 39(6); 42(1); 47(3); 48(2)

Vacuum Circuit Breakers 1994-1999:
1(1); 2(7); 1(16), 23(9)

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII63: Please provide LIPA's total distribution capital budget for each year from 2000-2010. Please:

a) provide the justification for each project,

b) provide the location of each project,

c) provide the cost of each project,

d) indicate whether the project is load-related.

Response: As described in the response to PII22, KeySpan Energy develops proposed capital budgets for five years. LIPA approves a capital budget only for the upcoming year, however, this budget includes funding required for engineering

and procurement associated with projects for the following years as necessary. The budget for the year 2000, as approved by LIPA and made publicly available, is attached. Budgets for future years have not been approved, and have been altered by decisions made during the most recent budget review cycle. The attached Project Justification documents provide the additional information requested.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII64: Please provide LIPA's distribution capital budget for the South Fork for each year, 2000-2010, including for each project:

a) a project description,
b) the justification,
c) location,
d) cost,
e) whether the project is load-related.

Response: See responses to PII14 and PII63.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII65: Please explain whether LIPA considers the costs of improvements and upgrades to substation, feeders, line transformers, secondary lines, and service drops to be avoidable?

a) If not, please explain why for each cost category.

Response: LIPA does not consider these costs to be avoidable, since the projects are required to serve additional load and maintain reliability. Through planning studies, LIPA makes every effort to find a least-cost solution for meeting system requirements. LIPA also makes every effort to time the installation of these projects with the date of need as dictated by the latest projections of area load growth or new lump load additions. In many cases, this process will result in system requirements being addressed on an incremental basis, e.g. reinforcements of distribution circuits or addition of transformer banks at existing substations prior to construction of new substations.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII66: Please provide LIPA (or LILCO) expenditures over the last five years on upgrading service drops to increase capacity.

Response: Expenditures for overhead service replacements for the last three years are as follows. It should be noted that underground services are replaced only for failures, since the construction standard is such that upgrades for load additions are not normally required. In addition, within the last five years, the standard for new overhead services has been changed to avoid the need for future upgrades for load additions.

1996	$550,026
1997	$556,238
1998	$618,500

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII67: What level and type of DSM programs could LIPA have engaged in over the last five years that would have delayed the need for the proposed transmission line?

a) Please provide an estimate of the cost of such DSM programs.

Response: LIPA took control of LILCO's transmission and distribution system in May 1998. Within a year of this transaction, LIPA's Board of Trustees approved an aggressive five-year, $160 million Clean Energy Program, which promotes energy efficiency and the adoption of clean renewable technologies. Subsequent efforts are underway to bring these programs to full implementation in the marketplace. No studies have been performed as to what programs could have been undertaken over the last five years by LIPA.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII68: Please identify the next ten areas on Long Island where LIPA believes that transmission and distribution system upgrades costing over $1 million will be required over the next five years.

a) For each such area, please provide the estimated cost of the required upgrade.

Response: Based on current plans, the list below describes ten areas where LIPA expects to reinforce the transmission and distribution substation systems.

	Project Description	Estimated Cost ($ Millions)
1	Miller Place, new distribution substation	2.91
2	Bayport, distribution substation bank addition	1.77
3	Syosset, distribution substation transformer bank replacement	2.89
4	Pilgrim-Brentwood, transmission line reconductoring	3.20
5	Bar Beach, distribution substation transformer bank addition	1.29
6	Tech Drive, new distribution substation	1.81
7	Central Islip-Tech Drive-Watson, transmission lines	6.05
8	Mattituck-Southold 23-69 kV, transmission line	7.27
9	Northport, transmission, breaker additions	1.43
10	Tuthill-Mattituck 23-69 kV, transmission line	2.25

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII69: Please explain why LIPA considered addition of 72 MW of generation to solve the small overloads expected on the South Fork (Application at p. 6).

Response: First, the projected deficiency in electric supply capability is significant in terms of providing adequate margin for operation under normal and contingency conditions. Second, the 72 MW addition was considered a feasible alternative that would be an "equivalent" alternative to a Riverhead-Southampton transmission line.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII70: Please explain why additional generation would not eliminate the need for the new transmission line (Application at p. 7).

Response: See response to Staff Interrogatory JFM-1, Question 3, previously supplied.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII71: Please explain how long 72 MW of generation would defer the need for the new transmission line (Application at p. 7).

Response: See response to Staff Interrogatory JFM-1, Question 3.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII72: Please provide the current plan for "expansion of the gas transmission system" (Application at p. 7).

Response: Except as explicitly identified for the generation alternative described in the Application, LIPA does not have access to KeySpan Energy's plans for expansion of the gas transmission system. See response to PII73.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII73: Please quantify the extent of acceleration of the current plan for "expansion of the gas transmission system" that would be required by the generation option (Application at p. 7).

Response: See response to Staff Interrogatory JFM-1, Question 3.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII74: Please provide the estimated total cost of the generation option (Application at p. 7) and all supporting documentation.

a) Please provide the credits applied against the generation costs for the market value of energy and capacity, including avoided line losses.

Response: The cost of the generation option is set forth in the Application, including electric and gas transmission costs. Information on the generation option was provided to LIPA by KeySpan Energy on an expedited basis to address the system conditions identified in the 1999 summer experience on the South Fork.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII75: Please provide the Request For Proposal ("RFP") or other such solicitation for the competitive procurement process and all responses received (Application at p. 7).

Response: A copy of the LIPA Capacity RFP is attached. This document was previously made available on the LIPA website. The responses are confidential pending evaluation by LIPA and a recommendation to the LIPA Board.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII76: Please explain whether the RFP included any incentives to locate generation in the South Fork or other constrained load pockets, and if so, explain those incentives and demonstrate that the incentives reflect the full avoided cost of the South Fork transmission project.

Response: The capacity RFP explicitly made provision for distributed generation by defining "load pockets" down to the substation area level. The South Fork was also explicitly identified as a transmission load pocket. See response to Staff Interrogatory JFM-1, Question 10. The RFP did not define any predetermined incentives. Instead, the evaluation methodology employed is to evaluate any proposals for capacity in those load pockets against previously identified T&D projects to reinforce the electric supply to that area. This methodology enables LIPA to identify any specific T&D benefits of the proposed project, rather than rely on values that at best could reflect "average" system benefits that may either overstate or understate the value.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII77: If the RFP did not include any incentives to locate generation in the South Fork or other constrained load pockets, please explain how the RFP is relevant to targeting generation to avoid the South Fork or any other transmission project.

Response: See response to PII76.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII78: Please explain how LIPA's concerns about licensing time, expansion of the gas transmission system, and the total cost of the generation project (Application at p. 7), would be affected by reduction of the generation options to the amount of capacity necessary to keep the South Fork line within its capacity limit.

Response: Concerns relating to generation cost, gas supply and environmental requirements would extend to smaller increments of generation as well. One of the key environmental requirements is Article 7 of the Suffolk County Sanitary

Code, which prohibits new or increased storage of petroleum in excess of 250 gallons, except for onsite heating requirements. See response to Staff Interrogatory JFM-1, Question 3. Indeed, gas supply, petroleum storage and electric interconnection requirements could actually be compounded by location of smaller increments of generation capacity at multiple sites.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII79: Please provide the studies, memoranda, or other bases for LIPA's estimates of cost and potential for distributed generation in the South Fork.

Response: LIPA has not performed any studies of distributed generation on the South Fork beyond the evaluation of alternatives associated with the proposed transmission line. On the other hand, the recent LIPA RFP explicitly included the South Fork as part of a detailed description of load areas comprising the LIPA system. The RFP produced no responses involving small, distributed resources on the South Fork. See response to Staff Interrogatory JFM-1, Question 10.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII80: Please provide all studies, memoranda, or analyses of the cost and potential for distributed generation on Long Island, including those that:

a) Identify technologies,

b) Estimate potential for photovoltaics,

c) Identify peaking-capacity options,

d) Estimate the value of on-site back-up generation to customers,

e) Estimate potential for cogeneration.

Response: See responses to PII79 and Staff Interrogatory JFM-1, Question 11.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII81: Please identify the areas served by Riverhead and points west in the South Fork Load Pocket that have natural gas service.

Response: Except as explicitly identified for the generation alternative described in the Application, LIPA does not have access to information regarding KeySpan Energy's gas transmission system. See response to PII73.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII82: Please provide LIPA's projection of gas costs on Long Island for:

a) central generation,

b) small utility-owned generation,

c) customer-owned distributed generation.

Response: Except as explicitly identified for the generation alternative described in the Application, LIPA does not have access to information regarding KeySpan Energy's gas transmission system. See response to PII73.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII83: Please provide all analyses of the potential for development of distributed generation on Long Island, including:

a) photovoltaics,
b) fuel cells,
c) micro-turbines,
d) cogeneration.
e) Please provide all cost curves that were developed for these alternatives.
f) Please provide all demographic data and analyses performed by or for LIPA concerning the financial ability of South Fork residents and commercial entities to purchase distributed generation systems.

Response: LIPA is currently in the process of completing an end-use assessment of the technical, economic and achievable potential of energy efficiency and clean energy renewable technologies on Long Island. See also responses to PII79 and PII 80.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII84: Please explain how LIPA identified and modeled cogeneration opportunities in existing and proposed facilities in the South Fork.

a) Provide all documents describing this process.

b) If LIPA has not studied cogeneration opportunities in the load pocket, please explain why.

Response: See response to PII79. The LIPA Capacity RFP made provision for distributed resources and did not exclude cogeneration.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII85: For each distributed generation technology, pleas provide LIPA's estimate of the number of hours of generation that would be economic, considering market energy prices and line losses to the South Fork.

a) Please provide the basis for those estimates.

Response: See response to PII79.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII86: Please provide any studies available to LIPA regarding the cost-effectiveness of distributed generation, including photovoltaics, fuel cells, and micro-turbines on Long Island.

a) Please describe how each such study addressed the effect of targeted distributed generation on avoiding transmission and distribution investment.

b) Please describe how each such study addressed the effect of distributed generation on market power in generation services on Long Island.

c) Please describe how each such study addressed the effect of distributed generation on power quality and reliability for customers near the distributed generation.

Response: See responses to PII76, PII79 and PII80.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII87: Please explain whether and how LIPA identifies areas to be targeted for distributed generation and DSM.

Response: See responses to PII76 and PII79.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII88: Please provide all LIPA studies of targeted DSM and distributed generation, as alternatives to construction of T&D projects.

Response: See responses to PII76 and PII79.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII89: Please explain how and where LIPA monitors loads on its T&D system.

Response: The primary monitoring of the system is through the Energy Management System, which collects data through the Supervisory Control and Data Acquisition (SCADA) system. The SCADA system collects data at the feeder and transmission line level; this data includes power injection from generators connected to transmission busses. Current, voltage and power factor are monitored. Power levels on a number of substation transformer banks are monitored through a separate system of power monitors, which are interrogated through a modem-based system. In addition, the DFP relays, which are being installed primarily to reduce momentary interruptions have monitoring capability, and are also interrogated through a modem-based system.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII90: For each level of the system (transmission, distribution substation, feeder, primary laterals from feeders, line transformers), please explain how LIPA determines whether the existing equipment is stressed, or would be overloaded by additional loads.

Response: KeySpan Energy, as LIPA's T&D System Manager, uses transmission and distribution system planning criteria to evaluate the performance at projected load levels. The analyses include transmission load flows for thermal and voltage assessments, and separate assessments of fault duty and system stability. The analyses also include assessment of substation transformer and feeder

loadings under normal and contingency conditions. Required corrective actions are identified in these evaluations. See response to PII22.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII91: Please provide a map of LIPA's transmission facilities, and the facilities of other utilities serving LIPA.

Response: A map of the LIPA transmission system is attached.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII92: Please provide all memos, studies, or reports describing LIPA's efforts to quantify, evaluate and mobilize distributed resources in the South Fork, including:

a) estimates of DSM potential and cost,

b) estimates of distributed generation potential and cost,

c) plans for implementation,

d) economic modeling.

Response: See responses to PII93, PII80 and PII83.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII93: Please provide a copy of the "evaluation of the expected impact of LIPA's extensive Clean Energy Program" referenced at p. 7 of the Application, together with all back-up documents to this evaluation and documents discussing this evaluation, including drafts, memos, emails and correspondence.

Response: In May of 1999, LIPA's Board of Trustees approved an aggressive five-year Clean Energy Program totaling $160 million or on average, $32 million per year. This program plan is comprised of energy efficiency and load management programs, in addition to programs promoting the advancement of renewable energy technologies on Long Island. Although highly aggressive, this program plan is not capable of making a significant contribution to the anticipated supply deficiency in the South Fork load pocket area. In total, the

Island-wide targeted 2000 peak reduction for LIPA's Clean Energy Programs is expected to be 66.1 MW. Proportionally, this would equate to approximately 1.1 MW on the South Fork when population and demographics are considered. (See Table 1 below).

Table 1

Program	Cumulative Peak Load Reduction Goal (kW)	Proportional Load Reduction by Population (kW)
Residential Ltg & Appliances	908	37
Residential HVAC	5,772	237
Resi Energy Affordability	523	21
Photovoltaic	362	15
Info & Education	1,062	44
Comm New Const/Renov	3,302	343
Premium Motors	18	2
Peak Reduction	50,000	0
Comm HVAC	403	42
Resource Cons Mgmt	2,726	284
Customer Driven Efficiency	1,071	111
Total	**66,147**	**1,135**

Note: Assumes 4.1% residential and 10.4% commercial customer population on South Fork in relation to total LI population. Peak Reduction Program not applicable due to demographics. (Program targeted to large Commercial/Industrial customers).

As illustrated by this projection, it is evident that while aggressive, the expected demand reduction is not capable of making a significant contribution to the anticipated deficiency in the required time frame.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII94: Please describe all "additional strategies" beyond LIPA's Clean Energy Program that LIPA considered in examining demand side management measures, as referenced in the Application at p. 7.

a) Please list all demand-side measures that LIPA considered as alternatives to the proposed transmission line.

b) Were these demand-side measures considered singly or in combination?

Response: LIPA considered several "additional strategies" beyond its Clean Energy Program. These included heightened, targeted marketing efforts of the existing Clean Energy Programs to the South Fork, in addition to the development of new targeted peak load reduction programs. In the former, efforts were focused on the promotion of those programs deemed to be most applicable to the demographics of the South Fork. In the latter, a direct load control program targeted to air conditioner (residential and commercial/ industrial) and pool

pump (residential) use was examined. All measures in these analyses were considered both singly and in combination. The following synopsis illustrates the rationale and expected contribution of such efforts. Calculations are summarized in Table 2.

DETAILED ANALYSIS SYNOPIS

CONSERVATION:

An evaluation of the census data indicates that the South Fork has a representation of approximately 41,000 residential customers and approximately 10,400 commercial customers.

Residential: The residential Clean Energy Programs that are likely to be effective in the South Fork are the Residential Lighting and Appliance Program, HVAC Efficiency Program, Residential Energy Affordability Program (REAP) and the Rooftop Photovoltaic Program.

Residential HVAC Efficiency Program

With the expectation that projected participation can be doubled, the following impacts can be expected from the Residential Central Air Conditioning Program:

328 participants 473 kW 515 MWh

Lighting and Appliance Program

Similarly, a doubled penetration rate for this program would yield:
2,640 participants 74 kW 877 MWh

Rooftop Photovoltaic Program

No data is available to predict performance, however, this program is recommended since participation would likely be higher in this region that in other areas of Long Island. A demonstration project is recommended in order to encourage participation.

Residential Energy Affordability Partnership (REAP) Program

Assuming a fairly equal distribution of low-income customers across Long Island, the REAP is expected to yield:
148 participants 15 kW 232 MWh

Commercial: The programs that can be expected to best succeed in this region are the Commercial New Construction and Renovation Program and the Regional High Efficiency HVAC Program.

New Construction/Renovation/Efficient HVAC Program

Again, assuming a doubling of expected participation in each program would yield the following results:

New Const/Renovation:	687 kW	2,769 MWh
Efficient HVAC	84 kW	134 MWh

PEAK LOAD REDUCTION:

A Direct Load Control (DLC) program using new technology can be developed within a short time period, and at relatively low cost. This program can use a pager-based method to shut off/cycle residential Central A/C equipment. This would be accomplished by activating/deactivating the circuit breaker tied to this equipment. It can be further expected that the average commercial account could participate in the program as well. This would require 2 circuit-breaker type units.

- With 23% of 41,000 residences using CAC equipment, and assuming a 3% penetration rate, the expected demand reduction is 1.1 MW. (Based upon 3.9 kW per 3 ton CAC unit).
- With a 1.5% penetration rate, with an average of two rooftop units for a total of 5 tons of A/C, the 10,400 commercial accounts in this region can be expected to provide approximately 0.94 MW demand reduction. (Based upon 6 kW per customer). Resultant load control totals to: 2.04 MW.

Table 2

Program	2000 kW Goal	2000 MWh Goal	Total Customers	South Fork Customers	Total kW	Total MWh
Resi HVAC	5,772	6,284	1,000,000	41,000	473	515
Resi Ltg & Appl	908	10,697	1,000,000	41,000	74	877
Resi Energy Aff	356	5,654	1,000,000	41,000	15	232
C/I New Const/Renov	3,302	13,314	100,000	10,400	687	2,769
C/I HVAC	403	644	100,000	10,400	84	134
				Subtotal	**1.33**	**4,528**
Resi DLC					1,100	
Comm DLC					946	
				Subtotal	**2.04**	
				Total	**3.37**	**4,528**

Note: All values represent cumulative year 2000 goals as approved by LIPA's Board of Trustees in May 1999 with the exception of the Residential Energy Affordability Program. Goal values for this program are incremental due to the programs expected launch in 2000.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII95: Did LIPA examine or consider an air conditioner maintenance program in considering demand-side measures as alternatives to the proposed transmission line?

a) If LIPA did consider air conditioner maintenance programs, please provide all documents that LIPA considered.

b) Please provide an estimate of the peak reduction of a $5 million air conditioner maintenance initiative targeted to the South Fork area.

Response: While LIPA did not consider a specific air conditioner maintenance program as an alternative to the proposed transmission line, its approved Clean Energy Program contains several programs/program components that are targeted to improving the efficiency, sizing and operation of air conditioning equipment. Specifically, the Residential HVAC Efficiency Program promotes the adoption of high efficiency central air conditioning equipment by offering consumer incentives for the purchase of qualifying high efficiency equipment. In addition, the program works closely with HVAC trade ally representatives to promote the proper sizing and installation of CAC equipment. Each of these initiatives are part of a regional effort in conjunction with the Northeast Energy Efficiency Partnership (NEEP) to further these values on a regional basis and send consistent messages to CAC manufacturers, distributors and installers. LIPA's Home Performance Program also targets residential air conditioner use. Here, LIPA is working with licensed professionals to promote in-depth home surveys that examine many home performance parameters, including the proper sizing, installation and maintenance of CAC equipment. As follow-up to these surveys, consumers are afforded the opportunity to work with the appropriate professionals to correct any deficiencies that are uncovered. In the commercial/industrial sector, LIPA's C/I HVAC Efficiency Program targets the installation of high efficiency HVAC equipment by offering consumer incentives for the purchase of high efficiency qualifying equipment. The program also works to promote the manufacturing of high efficiency equipment through substantial outreach to HVAC manufacturers and distributors. Each of the aforementioned programs will be targeted to the South Fork as part of LIPA's Clean Energy Program marketing efforts.

An estimate of the peak reduction of a $5 million air conditioner maintenance initiative targeted to the South Fork area is not available at this time.

Ques. PII96: Did LIPA consider a targeted peak load program that would pay customers to reduce peak load?

a) If LIPA did consider a targeted peak load program, please provide all documents that LIPA considered.

b) Please provide an estimate of the peak reduction of a $5 million peak load reduction program targeted to the South Fork area.

Response: LIPA considered several targeted peak load programs. LIPA first considered expansion of its current C/I Peak Load Reduction Program in the South Fork area. This program, however, cannot be expected to make a substantial impact since the demographics of the area do not match the customers targeted in this program, specifically large C/I customers with the ability to shed significant load (500 KW+) on demand. LIPA will, however, continue to solicit

participation for this program in 2000. Secondly, LIPA considered and adopted a series of direct load control programs targeted to residential central air conditioner and pool pump use and Commercial/Industrial HVAC use. These programs, which are further detailed in PII94, target the cycling of equipment that is coincident with LIPA's peak summer load as a means of mitigating its effect on the system.

An estimate of the peak reduction of a $5 million peak load reduction program targeted to the South Fork area is not available at this time.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII97: Please quantify and define "substantial contribution" as that term is used in the last full paragraph of p. 7 of the Application and provide all documentation that supports this quantification and definition.

Response: The term "substantial contribution," or as utilized in page 7 of the Application, "not be able to make a substantial contribution," refers to the fact that the resultant peak load reduction would not be able to yield a contribution significant enough to offset the need for the South Fork reinforcement project. A quantification of these results is presented in the response to PII93.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII98: Please provide all available documentation concerning the proposed targeted DSM programs described at pp. 7-8 of the Application.

Response: See responses to PII93-97. See also response to Staff Interrogatory JFM-1, Questions 4, 6-9.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII99: Please explain why LIPA's targeted DSM programs stop at the penetration, participation, and savings levels that they do, rather than at higher values.

a) Please provide cost-benefit analyses of any additional enhancements considered for the programs, but rejected.

Response: The penetration, participation and savings levels depicted in LIPA's $160 million Clean Energy Program were derived based on a comprehensive

planning process that considered the demographics of the Long Island marketplace, the current state of energy efficient technologies, and the overall goals outlined in LIPA's Clean Energy Policy Statement. In addition, current industry initiatives, including those of other utilities and other regional initiatives, were utilized as a benchmark in these planning processes. The overall process was thorough and comprehensive, and reflected the coordinated and collaborated effort of LIPA, its consultants, industry experts and LIPA's Clean Energy Advisory Panel.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII100: Please provide the studies, memoranda, or other bases for LIPA's estimates of cost and potential for DSM in the South Fork.

Response: See response to PII98.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII101: For each year from 2000-2005, please provide LIPA's estimate of the amount of load reduction in the South Fork that would occur due to LIPA and NYSERDA DSM programs, without any special effort to target DSM to the South Fork.

Response: The estimated peak load reductions from LIPA's DSM programs in the South Fork from 2000-2005 are as follows:

2000 - 1.1 MW
2001 - 2.4 MW
2002 - 4.1 MW
2003 - 5.9 MW
2004 - 7.0 MW
2005 - 7.0 MW

These figures are based on proportionate participation (i.e., South Fork population relative to Long Island population) for the programs/program goals approved in LIPA's $160 million Clean Energy Program Plan. All values reflect estimated cumulative peak load reduction in each of the referenced years.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII102: Please explain how LIPA determined the potential for enhancement of DSM programs in the South Fork, including:

a) For each existing or planned program:

i) Additional measures,

ii) Higher efficiency for each measure,

iii) Increased incentives,

iv) Enhanced marketing.

b) Additional programs, including residential and commercial retrofit programs.

Response: The potential for enhancement of DSM programs in the in the South Fork was based on two strategies. The first targeted identification of those existing programs with the highest propensity for success in the South Fork given the demographics of the area. Enhanced marketing of these programs was then considered as a means of increasing, and in some cases doubling expected participation. The second strategy focused on the development of programs that could yield results commensurate with peak load reduction. This included the development of both residential and commercial/industrial direct load control programs. See response to PII98.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII103: Please provide all information available to LIPA regarding the mix of load in the South Fork.

a) Load by class,

b) Type of buildings and businesses.

Response: See response to Interrogatory JFM-1, Question 1.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII104: Please provide any information available to LIPA regarding the drivers for load growth in the South Fork:

a) the types of customers,

b) whether from new construction or existing buildings,

c) whether from new customers or expansion of existing customers.

Response: See response to Staff Interrogatory JFM-1, Question 1.

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ques. PII105: Please provide a list of any additional development or load increases that have occurred or are now expected, and for each:

a) the types of customers,

b) the types of buildings,

c) whether they have thermal loads suitable for cogeneration,

d) whether they require high reliability, back-up generation, or high power quality.

Response: The following Commercial & Industrial Lump Load Additions (1,000 ckVA and over) are planned for the South Fork in 2000. Neither customer has indicated any particular power quality or reliability concerns, nor expressed interest in cogeneration.

Industrial Park Customer (December 1999)
Buell Substation

1500 ckVA 1100 dkVA (Summer)
715 dkVA (Winter)

Nursing Home (September 2000)
Southampton Substation

3000 ckVA 2250 dkVA (Summer)
1462 dkVA (Winter)

Name of Person
Preparing Response: M. N. Milhous Date: 12/30/99

Ex
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