water dependent uses in the coastal area. Some areas addressed by the program include: public access, harbor management, coastal habitat restoration, coastal permitting, municipal development, urban waterfront revitalization, and protecting the public trust. As a result of the Coastal Management Program, over 13.9 miles of public access have been added and 1,600 acres of tidal wetland have been restored.

Other Long Island Sound management programs include the LISS and the CCMP referenced earlier. Active participants include federal, New York and Connecticut government officials, researchers, user groups and other concerned organizations and individuals. The partners recently signed the Long Island Sound 2003 Agreement pledging their continued commitment to goals of the CCMP and the conservation and management of Long Island Sound.

2.3 Regional Energy Needs and Infrastructure

In general terms, PA No. 02-95 requires the Task Force to examine approaches for avoiding or minimizing construction of new energy and telecommunications infrastructure across Long Island Sound, and evaluating the reliability and operational impacts to the state and region attributable to such limitations on new cross-Sound infrastructure. To address these issues, it is imperative to first understand the energy needs and existing infrastructure within Connecticut and the region. In the context of protecting Long Island Sound, the "region" specifically includes both Connecticut and Long Island. As an island, nearly all of Long Island's fuel portfolio used for heating, transportation, industrial production, and electrical generation must be imported by tanker, barge, truck, or pipeline across the surrounding bodies of water. Long Island's indigenous energy supplies are at present, limited to solar power, solid waste and landfill gas, wind, and other potential renewable energy sources, which can meet only a small percentage of Long Island's energy requirements. Long Island also relies on electric cable interconnections with Connecticut and New York City across Long Island Sound and the East River, respectively. For these reasons, an evaluation of alternatives or limitations to new Long Island Sound energy infrastructure crossings must be based in part on an understanding of Long Island's energy demand, generation capacity, fuel sources, imports, and the electric and gas transmission infrastructure serving Long Island, and to a certain extent, the adjacent New York City boroughs of Queens and Brooklyn.

In the Assessment Report Part I, the energy infrastructure and reliability of SWCT was discussed in the context of the state's resources within the New England electric grid, operated by New England's Independent System Operator (ISO-NE). This section of the Assessment Report Part II, which summarizes the Connecticut information previously presented in Part I, presents equivalent information for Long Island, and focuses on the electric and gas interconnections between Connecticut and New York.

Council Forecast of Loads and Resources, total electricity requirements in Connecticut are projected to grow at an annual average growth rate of 1.1%, to 36,064 GWh in 2011.[86]

Generation Resources

Connecticut's installed electric generating capacity currently totals 7,037 MW based on summer ratings.

Table 5 – Connecticut's Electric Generation Capacity[87]

Station Name (location)	Owner or Primary Contract Holder[88]	Summer Capability (MW)	Primary Energy Source	Alt Energy Source	Commercial Operation
AES Thames (Montville)	NU	181	Coal	DFO	12/1/1989
Branford 10 (Branford)	NRG	16	Jet Fuel		1/1/1969
Bridgeport Energy 1 (Bridgeport)	Duke Energy	448	Gas		8/1/1998
Bridgeport Harbor 2 (Bridgeport)	PSEG	34	RFO		8/1/1961
Bridgeport Harbor 3 (Bridgeport)	PSEG	372	Coal	RFO	8/1/1968
Bridgeport Harbor 4 (Bridgeport)	PSEG	10	Jet Fuel		10/1/1967
Bridgeport RESCO (Bridgeport)	UI	59	MSW		4/1/1988
Bristol Refuse (Bristol)	NU	13	MSW	DFO	5/1/1988
Bulls Bridge (New Milford)	Select Energy Inc.	8	Hydro		1/1/1903
CDECCA (Hartford)	El Paso Merchant Energy	55	Gas	DFO	11/1/1988
Cos Cob 10 (Greenwich)	NRG	18	Jet Fuel		9/1/1969
Cos Cob 11 (Greenwich)	NRG	18	Jet Fuel		1/1/1969
Cos Cob 12 (Greenwich)	NRG	16	Jet Fuel		1/1/1969
Derby Dam (Shelton)	NU	7	Hydro		3/1/1989
Devon 11 (Milford)	NRG	30	Gas	DFO	10/1/1996
Devon 12(Milford)	NRG	30	Gas	DFO	10/1/1996
Devon 13(Milford)	NRG	33	Gas	DFO	10/1/1996
Devon 14(Milford)	NRG	30	Gas	DFO	10/1/1996
Devon 7(Milford)	NRG	107	RFO	NG	1/1/1956
Devon 8(Milford)	NRG	107	RFO	NG	1/1/1958
Dexter (Windsor Locks)	NU	38	Gas	DFO	5/1/1990
Exeter (Sterling)	NU	26	Tires	DFO	12/1/1991
Falls Village (Canaan)	Select Energy Inc.	10	Hydro		1/1/1914
Franklin Drive 10 (Torrington)	NRG	16	Jet Fuel		11/1/1968
Lake Road 1 (Killingly)	PG&E	223	Gas	DFO	7/1/2001
Lake Road 2 (Killingly)	PG&E	231	Gas	DFO	11/1/2001
Lake Road 3 (Killingly)	PG&E	237	Gas	DFO	5/1/2002

[86] Connecticut Siting Council, *Review of the Connecticut Electric Utilities' Ten-Year Forecasts of Loads and Resources, 2002.*
[87] ISO-NE, *2003 Capacity Energy Load and Transmission (CELT) Report*, April 2003 Does not include units less than 5 MW or units where all generation is used on-site by host.
[88] Primary Contract Holder is shown where the project owner is not a NEPOOL participant

Station Name (location)	Owner or Primary Contract Holder[88]	Summer Capability (MW)	Primary Energy Source	Alt Energy Source	Commerci. Operation
Lisbon Resource Recovery (Lisbon)	NU	13	MSW		1/1/1996
Middletown 10 (Middletown)	NRG	17	Jet Fuel		1/1/1966
Middletown 2 (Middletown)	NRG	117	RFO	NG	1/1/1958
Middletown 3 (Middletown)	NRG	236	RFO	NG	1/1/1964
Middletown 4 (Middletown)	NRG	400	RFO		6/1/1973
Millstone Point 2 (Waterford)	Dominion Nuclear CT, Inc.	872	Nuclear		12/1/1975
Millstone Point 3 (Waterford)	Dominion Nuclear CT, Inc.	54	Nuclear		4/1/1986
Millstone Point 3 (Waterford)	Dominion Nuclear CT, Inc.	20	Nuclear		4/1/1986
Millstone Point 3 (Waterford)	Dominion Nuclear CT, Inc.	1057	Nuclear		4/1/1986
Montville 10 & 11 (Montville)	NRG	5	DFO		1/1/1967
Montville 5 (Montville)	NRG	81	RFO	NG	1/1/1954
Montville 6 (Montville)	NRG	407	RFO		7/1/1971
New Haven Harbor (New Haven)	PSEG	461	RFO	NG	8/1/1975
Norwalk Harbor 1 (Norwalk)	NRG	162	RFO		1/1/1960
Norwalk Harbor 2 (Norwalk)	NRG	168	RFO		1/1/1963
Norwich Jet (Norwich)	CMEEC	15	DFO		9/1/1972
Wallingford Unit 1	PPL	45	Gas		7/31/2001
Wallingford Unit 2	PPL	41	Gas		7/31/2001
Wallingford Unit 3	PPL	46	Gas		7/31/2001
Wallingford Unit 4	PPL	42	Gas		7/31/2001
Wallingford Unit 5	PPL	41	Gas		7/31/2001
Rainbow Windsor	NU	8	Hydro		1/1/1980
Rocky River (New Milford)	Select Energy Inc.	29	Hydro		1/1/1929
SCRRA-Preston	NU	16	MSW	DFO	1/1/1992
Shepaug (Southbury)	Select Energy Inc.	42	Hydro		1/1/1955
So. Meadow 11 (Hartford)	Select Energy Inc.	36	Jet Fuel		8/1/1970
So. Meadow 12 (Hartford)	Select Energy Inc.	38	Jet Fuel		8/1/1970
So. Meadow 13 (Hartford)	Select Energy Inc.	38	Jet Fuel		8/1/1970
So. Meadow 14 (Hartford)	Select Energy Inc.	37	Jet Fuel		8/1/1970
So. Meadow 5 (Hartford)	NU	26	MSW		11/1/1987
So. Meadow 6 (Hartford)	NU	27	MSW		11/1/1987
Stevenson (Monroe)	Select Energy Inc.	28	Hydro		1/1/1936
Torrington Terminal 10 (Torrington)	NRG	16	Jet Fuel		8/1/1967
Tunnel 10 (Preston)	Select Energy Inc.	17	Jet Fuel		1/1/1969
Wallingford Refuse (Wallingford)	NU	6	MSW	DFO	3/1/1989
Total		7,037			

The total installed capacity includes 1,042 MW from the new gas turbines at Wallingford (250 MW)[89] and the Lake Road facility in Killingly (792 MW), which began commercial operation in 2002. Although the Lake Road generation facility is physically located in Connecticut, electrically it is considered to be interconnected in Rhode Island. Several other projects are in development, but have not yet begun commercial operation, including:

> Milford Power, which consists of two gas-fired 268 MW (536 total MW) combined cycle turbine units (summer rating). Construction is nearly complete, but due to contractual and legal issues, commercial operation could be delayed to late 2003 or even beyond.
>
> Quinnipiac Energy intends to refurbish the formerly deactivated English Station in New Haven, and operate it as an oil-fired peaking facility consisting of two 35 MW steam turbine generators (70 MW total). Commercial operation is expected in 2003.
>
> Meriden Power, which consists of two gas fired 235 MW combined cycle turbine units (470 total MW). Construction at the Meriden project is inactive. The project is reportedly near bankruptcy, but has received an extension from the Siting Council.
>
> Oxford Power (also referred to as Towantic Energy), which consists of two combined cycle gas-fired combustion turbines totaling 536 MW. The Oxford project received Siting Council approval, but has not yet commenced construction due to litigation. Moreover, ISO-NE approval was rescinded in March 2003.
>
> Kleen Energy Systems, which consists of two gas-fired combined cycle turbines totaling 520 MW. This project was certificated by the Siting Council in November 2002. However, this unit has not received ISO-NE approval to start commercial operation.

At present, 67% of the installed electric generation capacity geographically located in Connecticut is derived from fossil fuels, approximately 28% is derived from Millstone #2 and #3 nuclear units, and approximately 5% is derived from hydropower and solid waste (Figure 2).

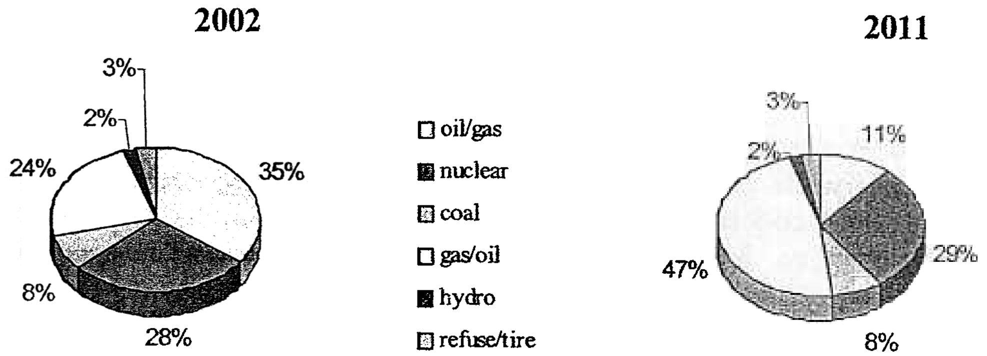
With the exception of Quinnipiac Energy's refurbishment of the old English Station, virtually all new generation capacity installed in Connecticut since 1999 or under construction is gas-fired. In addition, there is approximately 2,209 MW of oil- and gas-

[89] PPL Wallingford recently made filings with ISO-NE seeking to temporarily deactivate four (4) of the five (5) LM6000 simple cycle gas-fired generating units for a period of two (2) to four (4) years beginning on or before July 1, 2003.

fired quick-start generating units in New England[90] that are often forced to operate under uneconomic dispatch. For 2002, ISO-NE issued an RFP and developed 80 MW of temporary demand response capability for SWCT. In the spring of 2003, CL&P issued two RFPs seeking up to 80 MW of additional generation for SWCT for the summer 2003 peak load period.

In response to low cost natural gas in the second half of the 1990s, continued turbine technology improvements, new supply sources from Atlantic Canada, and increasingly stringent environmental emissions restrictions, natural gas has become the fuel of choice for new generation throughout New England. Upon commercialization of the remaining generation capacity that has received Siting Council approval, the new fleet of gas fired plants, with or without backup fuel oil capability, will become the predominant generation technology type in Connecticut (Figure 2).

Figure 2 – Connecticut's Electric Capacity Fuel Mix[91]



Transmission Infrastructure

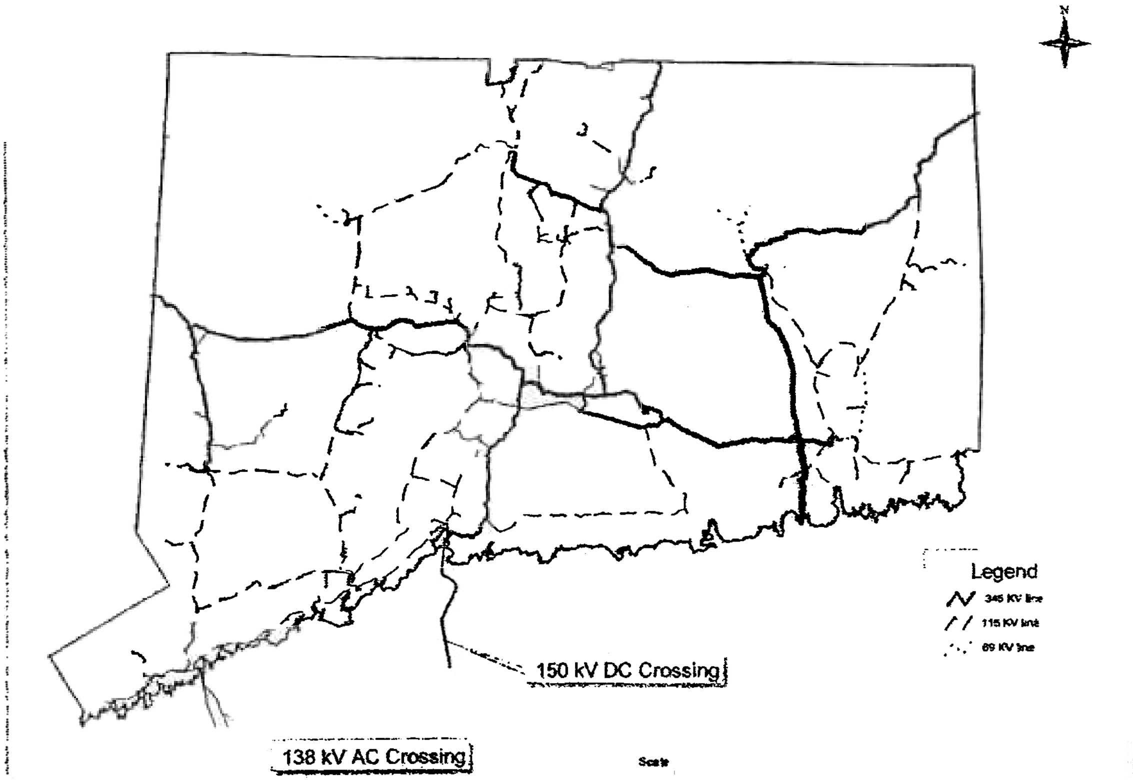
CL&P and United Illuminating (UI) own a total of 1,807 circuit miles of transmission lines within Connecticut. Connecticut's utility ownership of transmission lines is shown in Figure 3 and Table 6.

These lines are part of the NEPOOL high voltage transmission grid, consisting of over 8,225 miles of power lines rated 69 kilovolts (kV) and above. The 345 kV system is the backbone of the New England grid, extending from coastal Maine to south-central Connecticut. High-voltage east-west 345 kV segments also traverse central Connecticut, but do not extend into SWCT. As discussed in Part I, SWCT is served by 115 kV lines that interconnect with the 345 kV system in Bethel, Southington, and Watertown to the north and in New Haven to the east. In north-central Connecticut, the 345 kV system

[90] ISO-NE Seasonal Claimed Capability (SCC) Report as of 5/01/03 (summary information on p. 10) May 2003 Excel file at: http://www.iso-ne.com/seasonal_claim_capability_report/.
[91] Source: Connecticut Siting Council Forecast of Loads and Resources 2002.

interconnects the CL&P service territory to its affiliate utility, Western Massachusetts Electric Company, in Ludlow, Massachusetts. To the east, the 345 kV transmission system in Connecticut interconnects with the National Grid-owned portion of the NEPOOL grid in Rhode Island. Other 115 kV interconnections with Massachusetts and Rhode Island are also part of the NEPOOL grid.

Figure 3 – Connecticut Electric Transmission Map[92]



[92] Source: ISE, based on data submitted by CL&P to the Siting Council.

Table 6 – New England and Connecticut Electric Transmission Lines (miles)

Voltage Ratings	New England	CL&P	UI
HVDC line	192	0	0
345 kV	1,769	392.3	6.1
230 kV	481	0	0
69, 115 & 138 kV	5,909	1,296.4	113.0
Total	8,351	1,688.7	119.1

Most of New England's high voltage transmission lines are Pool Transmission Facilities (PTF), providing regional transmission and reliability services. The PTF are operated by ISO-NE, but are owned and maintained by the transmission owner members of NEPOOL. The costs of expanding and maintaining PTF assets are recovered by the transmission owners through regional network service transmission tariffs approved by FERC and administered by ISO-NE.

New England Interties

New England has historically maintained important transmission interconnections with surrounding control areas. The transmission circuits between neighboring control areas provide access to low cost energy while helping to maintain grid reliability and voltage stability. New England's interties consist of both AC interties with New York and New Brunswick, and DC high voltage connections with Hydro Quebec. The Phase II DC line with Hydro Quebec provides 1200 - 1500 MW of transfer capability into the 345 kV Sandy Pond Substation in Ayer, Massachusetts. Also to the north, there is a DC link to Vermont with Hydro Quebec rated at 225 MW and an AC link with New Brunswick Power rated at 700 MW.

A number of transmission connections allow for exports and imports between New England and New York. In west-central Connecticut, the New England grid is connected to the New York Power Pool grid by a 345 kV intertie at Long Mountain (NU Line 398). To the south, the two control areas are connected by a 138 kV AC cable across Long Island Sound between Norwalk Harbor and Northport, New York (1385 Line). The 1385 Line is jointly owned by NU and the Long Island Power Authority (LIPA).

Cross-Sound Cable is a 330 MW high voltage direct current (HVDC) merchant transmission line connecting the 345 kV system in New Haven with the 138 kV system on Long Island at Brookhaven, New York. As discussed in Section 2.6.1, this cable has not commenced commercial operation. In the short term, power on Cross-Sound Cable is expected to flow predominantly from ISO-NE to Long Island, subject to authorization. As a controllable DC cable, the power flow on the Cross-Sound Cable is bidirectional and controllable; therefore, during emergency and peak demand periods, Connecticut could import power from Long Island, if it were available.

Outside Connecticut, the New England grid is also connected to the New York control area by a 345 kV line from the Alps substation in New York to the Berkshire substation in western Massachusetts, a 230 kV line to Bear Swamp substation in Massachusetts, and three 115 kV lines from upstate New York to Vermont. The net transfer capability of all of the interconnections between New York and New England ranges from 1,400 MW to 1,700 MW in the summer and winter, respectively.[93] The transfer capability from New England to New York ranges from 1,000 MW to 1,675 MW in the summer and winter, respectively (Table 7).

Table 7 – Transfer Capability New England to New York (MW)

Summer	1,000	1,400
Winter	1,675	1,700

From 1999 to 2001, New York has been a net exporter of power to New England.[94] In 2001, the net energy flow was into New England from New York, about 87% of the year. Power flows into New England generally reflect the availability of lower priced hydropower and coal-fired generation from upstate and western New York to higher value areas in New England. This percentage has slightly decreased since 1999 and may decrease further as new gas-fired generation capacity continues to come on-line throughout New England.

According to data compiled by NYISO, the interface flows on the interties from west-central Connecticut to New York (Line 398) and from Northport, Long Island to Norwalk Harbor (1385 Line) both have historically experienced bi-directional power flows.[95] The magnitude and direction of flow has varied significantly on a monthly basis. Over the period of record, power flowed from New York to New England on Line 398 for the majority of hours during 1998, 1999, and 2001. The opposite was true in 2000. Flow on the 1385 Line has historically been predominantly from Connecticut to Long Island, but there have been hours in nearly each month of record when power flowed from Long Island into Connecticut (Figure 4).

The 1385 Line is operated at lower power levels so that it can respond to a contingency on either side of the interconnection by allowing power to flow to where it is most needed. This line helps LIPA meet its peak load requirements and helps CL&P to maintain reliability in the SWCT[96] area. The transfer of electricity within New England

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93 ISO-NE RTEP02

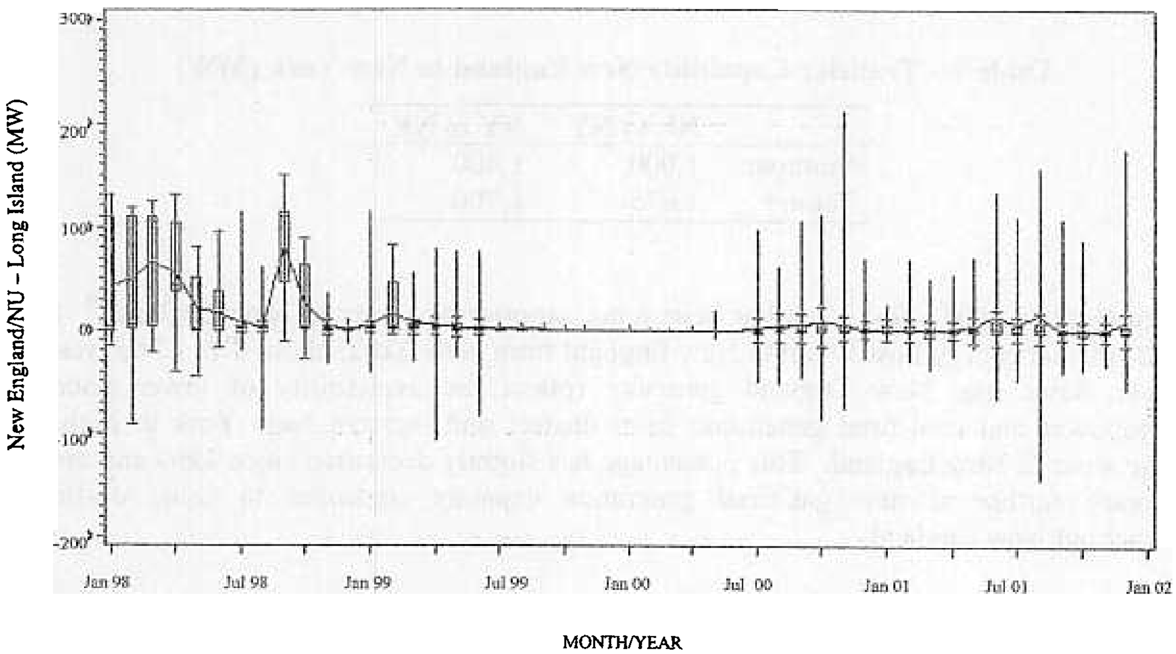
94 NYISO 2001 Transmission Performance Report, NYISO Operations and Engineering, April 2002. See http://www.nyiso.com/services/documents/studies/index.html#os

95 *Ibid.*

96 SWCT defined by ISO as: (1) **SWCT:** Southwestern Connecticut, an RTEP sub-area; (2) SWCT **(geographic):** SWCT consists of the following 52 towns and municipalities: Branford, Bridgeport, Darien, Easton, Fairfield, Greenwich, New Canaan, Norwalk, Redding, Ridgefield, Stamford, Weston, Westport, Wilton, Ansonia, Branford, Beacon Falls, Bethany, Bethel, Bridgewater, Brookfield, Cheshire. Danbury, Derby, East Haven, Hamden, Meriden, Middlebury, Milford, Monroe, Naugatuck, New

and to the other control areas has been based on market forces, and the need to meet reliability, voltage, and stability requirements.

Figure 4 – Historical Average Interface Flow Northport to Norwalk Harbor 1385 Line[97]



<u>Resource Adequacy</u>

The Siting Council provides a Forecast of Loads and Resources in Connecticut over a ten-year planning horizon. This inventory of resource availability includes installed capacity, anticipated capacity additions and retirements, transmission import capability, and load management actions. The Siting Council's forecast estimates reserve margins

Fairfield, New Milford, New Haven, Newtown, North Branford, North Haven, Orange, Oxford, Prospect, Roxbury, Seymour, Shelton, Southbury, Stratford, Trumbull, Wallingford, Waterbury, Watertown, West Haven, Woodbridge, and Woodbury; and (3) **SWCT** (electrical): The area served by the four 115 kV busses in Bethel, Watertown, Southington, and New Haven.

[97] NYISO Operations Engineering, 2001 Transmission Performance Report, April 2002. The y-axis of this "box and whiskers" plot represents MW transferred each month from New England to New York. A negative value signifies net transfer from New York to New England. The vertical lines (whiskers) represent the span between the maximum and minimum values for each month. The red bars represent the interquartile range, in which 50% of the data values lie. The bar in the middle of the box is the statistical median. The tick marks on the whiskers separate the extremes (1.5 times the interquartile range) from the remainder of the monthly data points.

of 45% and 31% for 2004 and 2011, respectively.[98] Based on the estimated reserve margins, the Siting Council report concludes that, "The State's supply resources are anticipated to be adequate to meet demand during the forecast period, provided all active generators committed to the ISO-NE remain available for continuing use. However, some subregions such as southwest Connecticut are threatened with supply deficiencies and voltage instability problems due to insufficient transmission and inadequate resources within the region."

The calculation of reserve margin for Connecticut alone obscures the fact that system reliability must be required by both generation resources as well as transmission capacity. Resource adequacy analysis and planning are conducted on a regional basis by ISO-NE. As discussed in the Assessment Report Part I and in Section 2.2.1 of this report, ISO-NE plans and operates the New England bulk power system to criteria that address both adequacy of generating resources to meet projected demand, and that comply with transmission planning/operating criteria set forth in NEPOOL's Planning Procedures. ISO-NE's transmission expansion plan is based on the reliability criterion that the bulk power system should not fail to meet load more than once every ten years.[99] This criterion is probabilistically calculated as a LOLE by simulating the operation of the bulk power system, reflecting scheduled maintenance and unscheduled (or forced) outages of both generation and transmission assets, as well as unusual customer demands.

In the 2002 Regional Transmission Expansion Plan Report (RTEP02 Report), ISO-NE transmission planners concluded that SWCT, and particularly the Norwalk-Stamford sub-area (NOR), will have severe reliability problems beginning in 2004 if the largest single generation source in the area, the Milford Power project, fails to achieve commercial operation. Even if the Milford Power project begins operating, SWCT and especially the NOR sub-area, will have reliability problems in later years if other generation or other transmission resources do not become available.

Under current operating conditions, ISO-NE has designated SWCT, including the NOR sub-area, as a deficient load pocket due to transmission constraints. Deficient load pockets require the operation of more expensive local generation to meet moderate and peak load requirements because less expensive electric generation outside of the load pocket can not be transported to serve local load. The additional costs to run more expensive generation "out of merit order" is paid by customers in the form of congestion charges. Under ISO-NE's Standard Market Design (SMD) rules, as of March 1, 2003, the congestion charges for SWCT including the Norwalk-Stamford sub-area will be paid for by Connecticut customers alone, and will no longer be socialized across all of New England. ISO-NE has estimated that the projected congestion costs in New England

[98] Connecticut Siting Council, Review of the Connecticut Electric Utilities' Ten-Year Forecasts of Loads and Resources, 2002. The reserve margin scenario calculation assumes that all units 40 years and older will be retired by 2011. Estimated state resources also include transmission import capability and demand response actions.

[99] This criterion refers to the bulk power system, comprised of generation and transmission assets, and does not include utility distribution systems.

under SMD could range from $50 to $300 million in 2003, with most of these costs attributable to SWCT.[100]

In addition to the RTEP02 Report, ISO-NE has prepared several recent studies focused on electric reliability in Connecticut. ISO-NE's recent assessment of the generating resources in Connecticut utilized the LOLE method in addition to other analytical tools to assess system reliability through 2006.[101] For planning purposes, this study does not include the Lake Road, Killingly, Connecticut generating facility among the generation resources available to directly serve Connecticut load, because it is electrically in the Rhode Island RTEP sub-area. In addition, ISO-NE also excluded one-third of the quick start peaking capacity in Connecticut, about 109 MW, based on ISO-NE's experience that this is the approximate amount of generation that has historically failed to start when called on in emergencies to operate. Based on this analysis, the available installed capacity in Connecticut is 6,138 MW (summer capacity).[102]

This report contained the following key conclusions:

> All existing generation in Connecticut is required to ensure reliability of service, unless new resources are added or transmission improvements are made.
>
> Additional new resources are needed in SWCT to ensure the reliability of service. These resources will provide the greatest value if placed in the NOR sub-area. Additional resources placed elsewhere in SWCT would also provide benefits, but to a lesser degree.
>
> To meet the 2003 high demand load periods and average forced outage scenario, about 300 MW of new resources are needed in SWCT to supplement the existing generation resources. Assuming both new Milford Power generating units achieve commercial operation and Devon units 7 and 8 are deactivated, 140 MW would still be needed under an average forced outage scenario.
>
> When the 2006 reference or high demand cases are considered, about 480 MW of new resources will be needed to supplement the existing system. With both Milford units operating by 2006, this shortfall is reduced to a range of 170 to 300 MW, depending on the demand and forced outage scenario considered.

[100] RTEP02 Report

[101] ISO-NE, System Planning. January 29, 2003. Technical Assessment of the Generating Resources Required to Reliably Operate Connecticut's Bulk Electric System 2003 and 2006. Final Report.

[102] The resource inventory assumes that all plants will be able to comply with the requirements of Public Act No. 02-64, which imposes sulfur dioxide emission limits on older oil-fired generators by the end of 2004. Potentially 2,700 MW of generation in Milford, New Haven, Norwalk, Bridgeport, Montville, and Middletown are subject to these new rules.

2.3.2 Electric Reliability on Long Island and the New York Region

Long Island's electrical service is primarily provided by LIPA. LIPA is responsible for providing electric service to 1.1 million customers.[103] In 2001, 52% of normalized sales were to the approximately 103,000 industrial and commercial customers, while 46% were to the approximately 960,000 residential customers.[104]

LIPA was created by New York legislation enacted in 1986 to resolve the controversy over the Shoreham Nuclear Power Plant (Shoreham) and to seek lower utility rates for customers on Long Island. In May 1998, LIPA acquired the stock of the Long Island Lighting Company (LILCO), and thereby assumed LILCO's transmission and distribution system, its interest in Nine Mile Point 2 nuclear plant, and its Shoreham regulatory asset, and became responsible for serving electric customers on Long Island. LIPA's acquisition of LILCO resulted in average rate reductions of 20%[105]

At the same time, Brooklyn Union Gas merged with LILCO to form KeySpan. The merged company retained LILCO's natural gas distribution business on Long Island and the electric generation facilities in Nassau and Suffolk counties. LILCO also transferred its on-Island electric generation and gas system to operating subsidiaries wholly owned by KeySpan. Under KeySpan's holding company structure, KeySpan has since expanded by acquiring other gas distribution and generation assets throughout the Northeast, most notably Eastern Enterprises. KeySpan's electric services segment (KES) has subsidiaries that operate LIPA's electric transmission and distribution system, and supply LIPA with energy conversion and ancillary services that allow LIPA to provide electricity to its customers.

KeySpan's on-Island electric generation capacity is about 4,000 MW of electricity from five base-load plants and 42 gas turbines and diesel peaking units located in Nassau and Suffolk Counties and the Rockaway Peninsula in Queens. KeySpan also includes subsidiaries that own, lease and operate the 2,200 MW Ravenswood generation plant in Queens, New York.

Electric Load on Long Island

LIPA estimates that the annual demand for electricity on Long Island will grow at a rate of approximately 90 MW per year, as energy intensity increases and population grows, particularly in Suffolk County.[106] This estimate, however, is based on "normal"

[103] LIPA Draft Energy Plan, October 17, 2002, p. 8.
[104] LIPA Draft Energy Plan, October 17, 2002, p. 3-2.
[105] LIPA Draft Energy Plan, October 17, 2002, p. 1-5.
[106] The 2002 Long Island Population Survey estimates that as of January 1, 2002, the total population of the Nassau-Suffolk region was 2.78 million people – an increase of 16,877 persons (0.6%) over the number reported in LIPA's 2001 survey. Importantly, the survey also calculated an increase in household electric use from 615 kilowatt hours (kWh) per month in 1990 to 728 kWh per month in 2002 – a jump of 18.5% despite the fact that the average household size decreased by 1.4%.

weather.[107] During the summer of 2002, extremely hot weather caused an increase in peak load of more than 130 MW to 5,059 MW (excludes municipal load not supplied by NYPA, approximately 36 MW), representing a 2.7% increase over the prior year, exceeding the forecasted peak load of 4,775 MW.[108] In fact, many usage records were set during the summer of 2002. For the entire month of July 2002, the LIPA requirements were 2.289 million MWh, 17% higher than July 2001. During August 2002, a new weekend record of peak demand of 4,447 MW was set.[109]

According to the NYISO 2002 Gold Book, LIPA's peak load was expected to grow 1.85% from 2002 to 2003, assuming normal weather in both years, and 1.61% per year, on average, over the next 20 years. In January 2003, LIPA projected a demand growth of 1.9% for 2003 and 1.7% thereafter.[110] If heat and humidity are unlike that in a "normal" year, actual peak load growth could be higher or lower.

Generation Resources

As an island with limited transmission capability to import power, Long Island has had to rely heavily upon on-island generation resources. Generation facilities located on Long Island for 2002 had a maximum capacity of approximately 4,885 MW (summer rating). The majority of these facilities are aging fossil steam units and combustion turbines owned by KeySpan (Table 8). LIPA has the contractual right to the total capacity and output of the KeySpan units. In addition to the KeySpan generation, LIPA also owns an 18% share in Nine Mile Point 2 nuclear plant and has several power purchase agreements with NYPA and independent power producers on and off the Island. These power purchase resources total 784 MW (Table 8).

Between 1977 and 2001, approximately 650 MW of new electric generation capacity was brought on line on Long Island. These facilities include the 251 MW Wading River plant, NYPA's 145 MW Richard M. Flynn plant, and a range of smaller combined cycle and resource recovery (waste-to-energy) units. Over the same period, peak load grew by 1,674 MW.

To address growing customer demand, LIPA entered into agreements with Calpine, FPL Energy, KeySpan Energy Development and PPL Global to install 408 MW of new combustion turbines (LM6000s) on a fast-track basis in preparation for the summer 2002 peak. The total capability listed in Table 8 does not include 200 MW of portable flatbed truck-mounted emergency generators that were also installed on a temporary basis last summer. The emergency units were operated as part of LIPA's demand response

[107] Normal weather is generally calculated as the average heating and cooling requirements, determined as "degree days" over the prior 30-year period.
[108] LIPA Government Officials / Major Account Customer Briefing, Huntington Hilton, June 11, 2002.
[109] Updated information provided by LIPA.
[110] *Ibid.*

program, discussed in Section 2.8.5. These units were removed from service following the summer of 2002, but LIPA retains the ability to redeploy them based on need.[111]

Table 8 – Long Island Generation Resources[112]

Facility	Summer DMNC Rating	Fuel	Year of Commercial Operation
Steam Turbines			
E.F. Barrett 1, 2	389	Gas, Oil	1956, 1963
Far Rockaway 4	110	Gas	1953
Glenwood 4, 5	229	Gas	1952, 1954
Northport 1 – 4	1,520	Gas, Oil	1967 - 1977
Port Jefferson 3,4	386	Gas, Oil	1958, 1960
Subtotal	2,634		
Combustion Turbines			
E.F. Barrett 1-12	330	Gas, Oil	1970-1971
Wading River	251	Oil	1989
East Hampton 1	22	Oil	1970
Glenwood 1-3	121	Oil	1967-1972
Holtsville 1-10	570	Oil	1974-1975
Northport G-1	15	Oil	1967
Port Jefferson G-1	15	Oil	1966
Shoreham	65	Oil	1966, 1971
Southhampton 1	10	Oil	1963
Southhold 1	14	Oil	1964
West Babylon	48	Oil	1971
Fast Track LM6000s[113]	408	Gas	2002
Subtotal	1,869		
Internal Combustion			
East Hampton	6	Oil	1962
Montauk 2-4	6	Oil	1961
Subtotal	12		
Purchase Power Agreements[114]			
NYPA Flynn	145	Gas, Oil	1994

[111] LIPA Draft Energy Plan, Executive Summary at 4, October 17, 2002.
[112] LIPA Draft Energy Plan.
[113] Various locations.
[114] Various contract expiration dates. For example, the contract with NYPA for 124 MW (summer) from the FitzPatrick nuclear power plant expires at the end of 2003.

Facility	Summer DMNC Rating	Fuel	Year of Commercial Operation
Other On-Island (11)	225	Various, including Gas, MSW, and landfill gas	
NYPA Off-Island (2)	414	Hydro and nuclear	
Sub Total	784		
Total Resources	5,299		

LIPA recently announced new agreements with power developers to build, own, and operate peaking plants on Long Island by the summer of 2003 totaling 189 MW. These facilities include:

A 79.9 MW facility developed by Calpine Corporation located on the Stony Brook campus of SUNY. LIPA will purchase any additional power not used by the campus under a separate agreement with Calpine.

A 55 MW Pratt & Whitney Swift-Pac, simple cycle, low emission turbine generator to be constructed by Global Common within the Village of Greenport. The new unit will provide power to be sold to LIPA under the terms of a Power Purchase Agreement that LIPA has negotiated with Global Common. It is expected to be in service by summer 2003.

A Pratt & Whitney simple-cycle, low-emission combustion turbine to be constructed by FPL Energy, which would generate 55 MW of electricity. Due to limitations in the natural gas supply line to the Rockaways, the turbine will operate on No. 2 fuel oil, but could use natural gas when supplies become available. The anticipated in-service date for this project is June 2003.

In addition, three new merchant power facilities have been proposed on Long Island for the 2005 time frame:

KeySpan Energy submitted an application to the New York Board on Electric Generation Siting and the Environment (New York Siting Board) in January 2002 for a natural gas-fired 250 MW combined cycle plant referred to as the Spagnoli Road Energy Center in Huntington, Suffolk County, New York On May 6, 2003, the New York State Board on Electric Generation Siting and the Environment granted KeySpan a Certificate of Environmental Compatibility and Public Need (Article X) to construct and operate a 250-MW combined-cycle electric generating facility. This is the final approval required for the project. KeySpan expects that the new plant could be operational by 2005.[115]

[115] KeySpan Press Release, February 5 ,2003

ANP received certification from the Siting Board on August 14, 2002 for construction of a gas-fired 580 MW combined cycle plant in Brookhaven, Suffolk County, New York. ANP expects construction to begin in 2003 and take approximately two years to complete.

In January 2002, PPL Global submitted an application to the Siting Board for a 300 MW simple cycle plant proposed for Kings Park, Smithtown, Suffolk County, New York. In January 2003, PPL Global announced that it would seek a buyer and not proceed with development of this project, citing low energy prices and the unavailability of a power contract. PPL Global subsequently transferred all development rights to Sterling Energy Associates. Pending the filing of amended application materials by a substitute applicant, the Siting Board has placed this application and the companion DEC permitting cases on hold.

Long Island's Transmission Infrastructure

LIPA owns 1,282 miles of transmission and sub-transmission lines that deliver power to 175 electric substations in its electric system. Table 9 breaks out these assets by voltage level.[116]

Table 9 – Long Island Transmission Assets

Voltage Level (kV)	Overhead Miles	Underground Miles	Total Miles	Circuit Capacity (MW)
345	0	8	8	660
138	237	110	347	383
69	570	76	646	104
33	92	3	95	26
23	138	48	186	22
Total	**1,037**	**245**	**1,282**	

Obtaining electricity from outside Nassau and Suffolk Counties is constrained by the limited electrical interconnections from New York City and from Connecticut. Long Island is connected to the remainder of the New York Power Pool grid via four transmission lines (Figure 5): a pair of 138 kV transmission lines from Con Edison's Jamaica Station in Queens to Long Island (Lines 901 and 903), and a pair of 345 kV lines from Westchester County, beneath the westernmost portion of Long Island Sound, to Long Island (Line Y-49 from Sprainbrook to East Garden City and Line Y-50 from Dunwoodie to Shore Road). The Y-49 and Y-50 transmission lines each have a normal rated capacity of approximately 600 MW. The Y-50 is a jointly owned cable between LIPA and Con Edison. Under contractual arrangement, Lines 901 and 903 are used to deliver Con Edison's portion of Y-50 to its Jamaica Station.

[116] LIPA Draft Energy Plan, at 3-5, updated by LIPA

Long Island is also interconnected with the ISO-NE grid via the 1385 Line from Norwalk Harbor, Connecticut to Northport, New York. This interconnection has a 286 MW normal capacity, but system conditions limit its import to 200 MW. The total transfer limit into Long Island from New York City and Connecticut is approximately 1,130 MW, excluding the Cross Sound Cable, which has yet to receive full approval to operate.[117] The transfer limit of transmission lines is less than the sum of the rated capacities of the lines, which does not adequately consider proper contingency-based operation. LIPA's import capacity is summarized in Table 10.

Table 10 – Long Island Transfer Limits

From	Transfer Limit (MW)
Con Edison / NYPA	930
Northeast Utilities (1385 Line)	200
Sub Total	1,130
Cross-Sound Cable (HVDC)	330[118]
Total	1,460

In the past 12 months, both the Y-49 and Y-50 cables were damaged in separate incidents. Not only were these cables limited in their carrying capacity, but the damage to these lines also reduced the ability of the 1385 Line to import electricity from Connecticut by an additional 100 MW. [119] In November 2002, the 1385 Line was also damaged by a survey vessel. Repair and replacement of the 1385 Line is discussed in Section 2.5.2.

[117] Update information provided by LIPA.
[118] Not in commercial operation.
[119] LIPA Press Release, June 18, 2002.

This document involves pipeline location information and is not available at this Internet site due to homeland security-related considerations. This portion of the Islander East consistency appeal administrative record may be reviewed at NOAA's Office of General Counsel for Ocean Services, 1305 East-West Highway, Silver Spring, Maryland.

In 2002, LIPA made significant investments in its transmission system. Twelve internal transmission line upgrades were completed, improving over 100 miles of transmission circuits. In addition, LIPA upgraded 28 substations and completed 110 minor upgrade projects. In total, LIPA invested $82 million to improve its transmission facilities, plus $113 million to tie new generation facilities into the transmission system and $36 million on distribution system improvements, upgrades, and maintenance. In 2003, LIPA continues to make investments in improving its transmission and distribution infrastructure.

Resource Adequacy

LIPA is subject to specific planning requirements established by the NYISO and other industry reliability standards. Consistent with other utilities in the state, LIPA is currently required to maintain an installed capacity reserve of at least 18% above its forecast annual peak demand.[120]

LIPA is also required to maintain on-island generation of at least 95% of projected peak load due to the limited capacity of Long Island's transmission links with neighboring electric systems.[121] At present, NYISO is proposing a modification to these capacity requirements in order to attract more generation resources to be developed.[122] This modification, however, will not eliminate LIPA's basic premise of local and total reserve margin requirements.

In its 2002 Draft Energy Plan, LIPA concluded that an additional 200 MW of supply-side or demand-side resources is necessary to meet Long Island's energy needs for 2003 consistent with NYISO guidelines. Even with the current demand-side management programs, LIPA also expects to need additional resources of approximately 100 MW per year through 2011 (Figure 6).

LIPA's Draft Energy Plan proposes to meet this requirement through a combination of conservation and load management, as well as new generation and transmission capacity. Committed and planned new capacity anticipated by the LIPA Draft Energy Plan to meet this shortfall include but are not limited to:

> The Brookhaven and Spagnoli Road gas-fired combined-cycle projects, expected to be in commercial operation by 2005 (830 MW);
>
> New, fast-tracked gas-fired peaking plants being developed by third parties under contract to LIPA, anticipated to be available for summer 2003 (189 MW);
>
> The Cross-Sound Cable, included among the 2003 resources (330 MW);

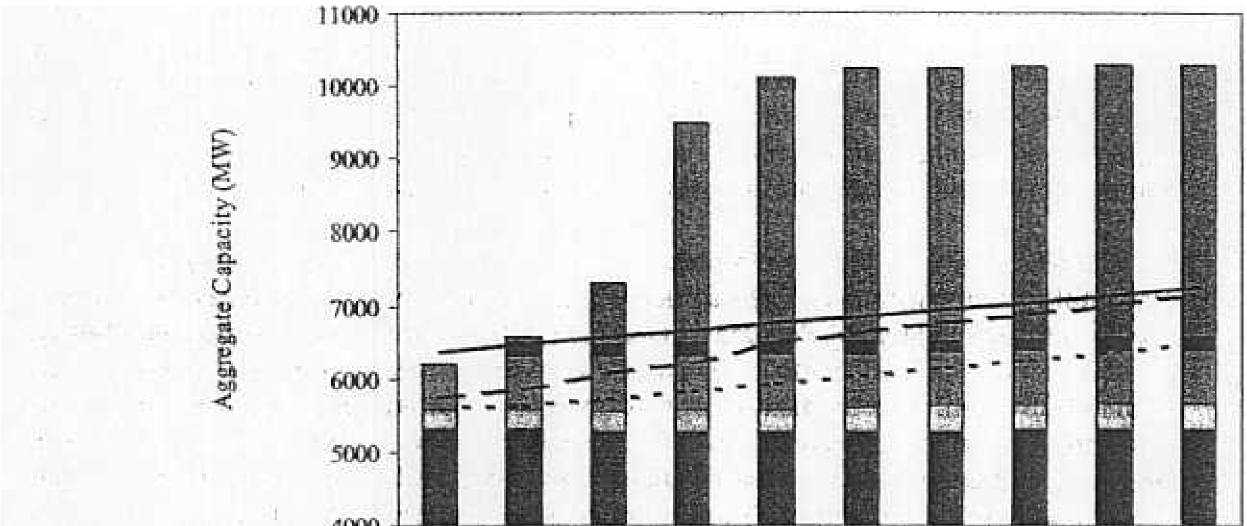
[120] LIPA Draft Energy Plan, p. 5-21.
[121] LIPA Draft Energy Plan, Executive Summary, pp. 13, 14.
[122] The NYISO Management Committee recently voted to institute a "demand curve" mechanism whereby more generators will be able to collect a capacity payment from load-serving entities such as LIPA.

Repowering of Wading River Units 1-3, adding 116 MW by 2006; and

Repowering of EF Barrett Unit 2, adding 279 MW by 2006.

Additional options, discussed in Sections 2.8.4 and 2.8.5, are under study. LIPA also hopes to attract new merchant generation projects to Long Island, but has stated that should those projects not materialize, LIPA would expect to enter into additional agreements with third party developers.

Figure 6 – Long Island Resource Requirements and Resource Plan[123]



	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Under Study	0	94	822	3008	3597	3717	3717	3717	3717	3717
Planned	0	171	171	171	171	171	171	171	171	171
Committed	636	738	738	738	738	738	738	738	738	738
Demand Side Management	266	271	287	298	306	317	331	342	352	349
Existing Load Serving Capability	5313	5313	5285	5289	5294	5298	5302	5306	5311	5315
——— Operational Requirements	6370	6475	6575	6670	6763	6859	6955	7052	7152	7253
— — Probabilistic View	5740	5845	6077	6208	6498	6628	6760	6893	7006	7150
- - - - NYISO Minimum	5590	5648	5726	5832	5936	6042	6147	6255	6366	6481

[123] LIPA 2002 Draft Energy Plan.

2.4 REGIONAL NATURAL GAS PIPELINE SYSTEM

New England has no indigenous supply of natural gas. New York's gas supplies are sourced from Western Canada (41%), the U.S. Gulf Coast and Mid-continent producing regions (57%), and from production indigenous to western New York (2%). Historically, most of the natural gas consumed in New England and New York is derived from traditional supply sources in the Gulf Coast. In 2001, natural gas consumption in New England and New York amounted to 734 billion cubic feet (Bcf), and 1,171 Bcf, respectively.

In 1992, the Iroquois Pipeline began importing significant gas quantities from western Canada into the Northeast. Gas supplies for New England originate from Western Canada (27%), the U.S. producing fields in the Gulf Coast and Mid-continent (43%), and, since 1999, Sable Island off the coast of Nova Scotia (11%). The remaining 11% of the region's gas supplies are imported liquefied natural gas (LNG) delivered to the LNG terminal at Everett, Massachusetts, primarily from Trinidad and Algeria.

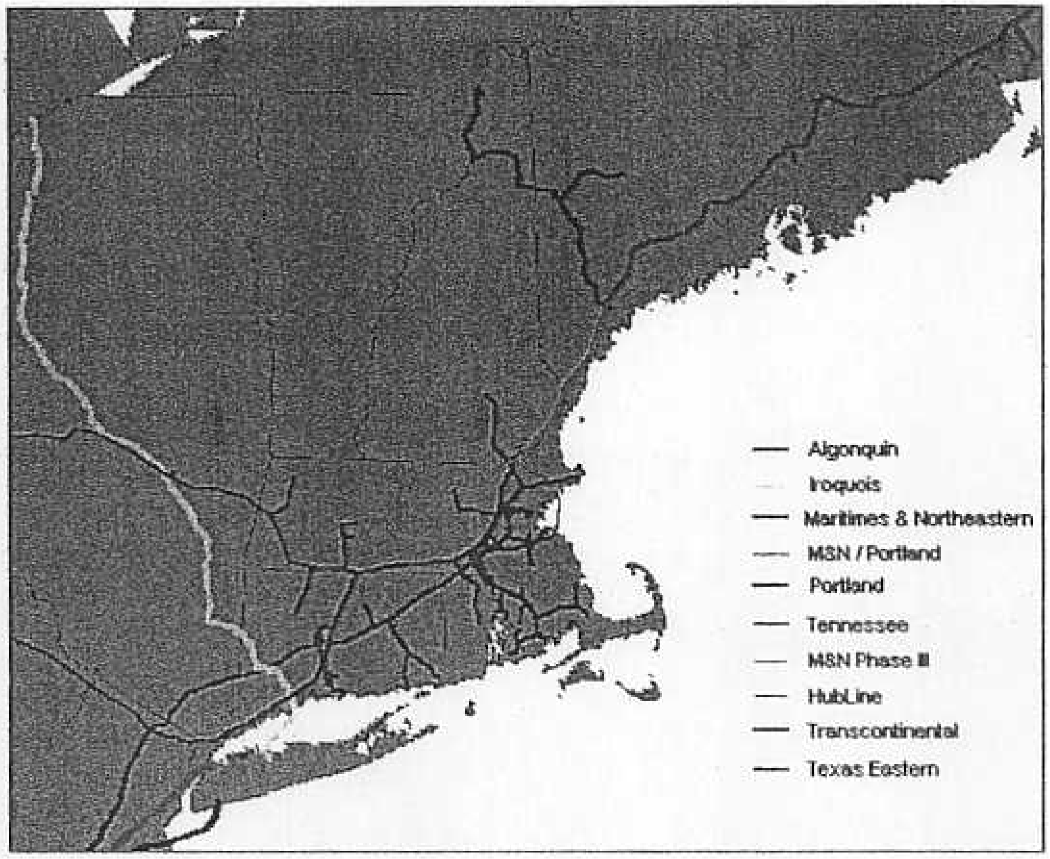
In addition to pipeline-transported natural gas from the Gulf Coast and Canada, natural gas utilities throughout the Northeast depend on conventional underground storage and LNG facilities to maintain adequate service during the winter. Vast storage facilities are located in western and central Pennsylvania, West Virginia, Southern Ontario, and upstate New York. Gas utilities arrange for gas to be injected during the summer so they can withdraw the gas and have the pipelines transport to their systems during the heating season. Utilities throughout New England, New York City, and Long Island also use LNG imported primarily from Trinidad or, in some instances, manufactured on site, to supplement pipeline supplies during the heating season. Most LNG is transported via supertankers to the large Distrigas terminal in Everett, outside of Boston, the only LNG receipt point in the Northeast. Distrigas has a storage capacity of 3.5 Bcf and a maximum daily sendout capability around 1.0 Bcf via pipeline, plus another 0.1 Bcf/d as liquid that is shipped via refrigerated trucks to satellite terminals in New England. Total LNG storage capacity in New York is about 3.4 Bcf. Total LNG storage capacity in New England is 15.1 Bcf on the gas utilities systems, in addition to the storage at Distrigas.[124] Most of the LNG facilities are satellite terminals that can store and vaporize the LNG; the others are full-service plants that can liquefy LNG as well. LNG facilities are generally located on the local gas utility system, and therefore do not require pipeline transportation._A 2.0 Bcf LNG storage/production facility is proposed in Waterbury, Connecticut by Yankee Gas Service Company. The project is before the Connecticut DPUC, with a decision expected in July 2003. Regulatory approvals are being obtained; local land use approvals have been issued. Ground breaking is projected in 2004 with a likely in-service date of 2007.

Gas supplies from the Gulf Coast are transported to New York and New England through several long-haul interstate pipelines: Transcontinental Gas Pipeline (Transco),

[124] Northeast Gas Association, 2003 Statistical Guide (May 2003 Preliminary Edition)

Tennessee Gas Pipeline Co. (Tennessee), Columbia Gas Transmission Company (Columbia), Texas Eastern Transmission Company (Texas Eastern), and Algonquin Gas Transmission Company (Algonquin) (Figure 7). The primary conduit from western Canada is TransCanada PipeLines, Ltd. (TransCanada), which serves the major market centers in Ontario and Quebec. TransCanada transports natural gas for redelivery through Tennessee and Iroquois from Niagara, New York and Waddington, New York, respectively. TransCanada, to a lesser extent, also transports natural gas for redelivery to New England.

Figure 7 – Interstate Gas Pipeline System Serving the Northeast



Algonquin and Tennessee have traditionally transported gas into New England, including Connecticut. Since commencing operation, Iroquois has fundamentally altered supply dynamics in the Northeast. By increasing its mainline delivery capability through a series of new compression stations, Iroquois has heightened competition among rival producers in competing supply basins. Iroquois provides New England with pressure and flow via Algonquin and Tennessee, and delivers about 0.2 Bcf/d to gas utilities and power producers in southern Connecticut. Iroquois extends across Long Island Sound and delivers additional volumes into the New York Facility System at the terminus of the pipeline at Commack, Long Island. Iroquois is nearing completion of its Eastchester pipeline from its mainline at Northport, Long Island, westward through Long Island Sound to serve power and other loads around New York City.

Until 1999, nearly all of the pipeline supplies serving gas utilities and power producers in Connecticut and the remainder of New England came from the Gulf Coast or from western Canada. About three years ago Duke Energy completed the Maritimes & Northeast Pipeline (M&N) to transport gas from the Atlantic Canada region off Nova Scotia southwest through Maine into eastern Massachusetts. With new supplies from Atlantic Canada, New England is no longer at the proverbial end of the pipeline. M&N has greatly shortened the "supply chain" from a major natural gas producing area to New England. Whereas conventional supplies from the Gulf Coast or western Canada are between 1,700 miles and 2,000 miles from New England's borders, the new supply from Atlantic Canada is only 750 miles away. At present, all natural gas transported through M&N is consumed by gas utilities and power producers in New England. Total delivery capacity on M&N into New England is 0.43 Bcf/d. If incremental production is realized from Atlantic Canada, M&N will deliver those increased volumes through expanded M&N facilities for redelivery into Algonquin's new HubLine project. The HubLine project is a marine lateral across Boston Harbor connecting M&N in Beverly to Algonquin in Weymouth, Massachusetts. The fourth phase of M&N's market growth is slated to double M&N's delivery capability within New England around 2005. Increased flow through HubLine into the easternmost end of Algonquin's mainline in southeast Massachusetts will provide Algonquin with greater flexibility across its entire route system, thereby potentially allowing natural gas from Atlantic Canada to flow physically or via displacement into both Connecticut and New York. Duke Energy's proposed Islander East project from Algonquin's C-1 mainline in North Haven, Connecticut to Brookhaven, New York, would extend the transportation pathway to allow gas from Atlantic Canada, and possibly from western Canada and the Gulf Coast, to flow to Long Island. Duke Energy also anticipates that this project will expand gas transportation capacity and flexibility in southern Connecticut.[125]

Production from Atlantic Canada is comparatively small in relation to traditional producing areas in the Gulf Coast and western Canada. Currently, daily production of raw gas off Sable Island averages about 0.5 Bcf/d, equivalent to about 0.45 Bcf/d of processed gas flowing to New England. The project operator is Exxon Mobil. In contrast, daily production from the Gulf Coast averages 28.6 Bcf/d and 16.7 Bcf/d from western Canada. However, Atlantic Canada is regarded as a promising area for future gas supplies in North America, particularly in light of the maturation of the conventional resource base in the Gulf Coast, including Texas, and western Canada.

[125] In an Islander East docket interrogatory, the FERC, which has approved the project, expressed the following: "...the available capacity on Algonquin Gas Transmission Company's (Algonquin) HubLine facilities is substantially less than the capacity of Islander East's facilities." (Docket CP01-384. FERC 09/07/2001data request.) In response, Islander East states: "Transportation paths are available beyond the Algonquin system as a result of its existing interconnections with Tennessee, Iroquois, and Texas Eastern and others, including its future interconnection with Maritimes and Northeast via the HubLine project." (Docket CP01-384. Islander East 09/24/2001 response).

In the last few years, major oil and gas producers in Canada have committed billions of dollars to expand production of natural gas from the Scotian Shelf as well as to expand the deliverability of pipelines in the Maritime Provinces and New England. EnCana Corporation, a major Canadian producer, estimated that by 2010, Sable Island will produce over 2.0 Bcf/d. While Shell, a key producer, has reduced its reserves estimate, other producers have maintained optimistic views about the recovery potential of 2,800 Bcf (proved and probable) in Atlantic Canada. Recently, the development of Nova Scotia's offshore gas fields has been slowed by a series of expensive dry holes. In February 2003, EnCana decided to ask for a regulatory "time out" on development of its $1.2 billion Deep Panuke project, considered by geologists to be the most promising of the offshore tracts.[126] While acknowledging the "promising new opportunities" for Atlantic Canada, EnCana has stated that "The project at this juncture of the regulatory process would provide an insufficient risk-adjusted return in the context of EnCana's other investment opportunities."[127]

As production from the initial wells in Atlantic Canada begins to decline, the second tier wells are scheduled to begin producing later this year to maintain overall gas flows of 0.45 Bcf/d into New England. Over the next three years, there is likely to be much additional exploration and drilling off the coast of Nova Scotia by major gas producers in order to define reserves before drilling licenses expire. As production from the first and second tier wells declines over time, other fields, such as Deep Panuke, will have to make up the shortfall. It is not known how the uncertainties surrounding the high cost and high risk of drilling in Atlantic Canada will impact pipeline developments in the New England and New York market areas. The quantity of Atlantic Canada gas that will, in the future, be destined for markets in Connecticut and Long Island is unknown.

2.4.1 Natural Gas Supply, Demand, and Infrastructure in Connecticut

In Connecticut, residential, commercial, and industrial natural gas customers are typically served by local distribution companies (LDCs). There are four LDCs in Connecticut. Three are investor-owned utilities regulated by the Connecticut Department of Public Utility Control: Yankee Gas is a subsidiary of Northeast Utilities; Southern Connecticut Gas and Connecticut Natural Gas are both subsidiaries of Energy East. The fourth LDC is the City of Norwich Department of Public Utilities, a municipally owned LDC whose rates are not regulated by the DPUC.

The four gas utilities receive gas at gate stations along the interstate pipelines traversing Connecticut: Algonquin, Tennessee, and Iroquois. There are 571 miles of gas transmission pipeline and 7,063 miles of distribution mains[128] in the state serving 514,455 customers.[129] Of Connecticut's 169 towns and cities, natural gas mains serve all or part of 113 of them. Portions of northwestern and eastern Connecticut remain without gas

[126] EnCana press release, February 14, 2003.
[127] *Ibid.*
[128] Northeast Gas Association.
[129] Information provided by the three investor owned utilities.

utility service. Connecticut's total annual gas consumption in 2001 was 144 Bcf. Connecticut residential customers consume about 28% of total demand, commercial customers 31%, industrial customers 18%, and power generation 23%.[130] Historic peak day demand experienced by the LDCs in 2000 was approximately 0.8 Bcf.[131] The Connecticut regulated LDCs forecast peak day demand to grow about 1.5% to 1.7% annually over the next five years. The forecasted peak day firm demand exclusive of interruptibles for the winter of 2003/2004 is approximately 0.76 Bcf (761,000 Mcf).[132]

Peak day deliverability of the LDCs is predominantly provided by interstate pipeline transportation. On-site storage facilities such as LNG or propane plants augment pipeline supplies as required. The LDCs in Connecticut have approximately 0.58 Bcf/d of pipeline capacity under contract, with approximately 0.13 Bcf/d of LNG vaporization capability and 0.06 Bcf/d of propane/air peak shaving capability.[133]

Natural gas is used extensively in Connecticut as a fuel in electric generating facilities. There is approximately 2,803 MW of existing gas fired electric generation (704 MW gas only, 2,099 MW combined gas and oil) in Connecticut.[134] These facilities have a maximum consumption of approximately 0.45 Bcf/d of natural gas. There are 2,642 MW of new gas-fired electric generating facilities that have been approved by the Siting Council since 2002. In a recent ISO-NE study, it was noted that electric generating facilities typically do not contract for interstate pipeline capacity on a firm basis for the plant's entire fuel requirements. Instead, these plants purchase gas on a less expensive, interruptible basis, and must rely on fuel oil to the extent allowed under air permit conditions, or not operate at all, on the coldest days when "core" gas customers utilize the pipelines' full capacity. ISO-NE's studies indicate that there is not sufficient pipeline capacity within New England's borders to meet the coincident gas requirements of New England's gas utilities and merchant generators during the coldest part of the heating season.[135]

2.4.2 Natural Gas Supply, Demand, and Infrastructure on Long Island

Long Island's growing demand for gas to serve its core heating load and to fuel new and repowered electric generation has created a market opportunity for interstate pipeline companies to expand service to Long Island. To understand the transportation and gas supply alternatives available to Long Island, this section presents an overview of the

[130] U.S. Energy Information Administration.
[131] Information provided by the three investor owned utilities. This number is not inclusive of Norwich's peak day volume.
[132] Information provided by the three investor owned utilities. This number is not inclusive of Norwich's forecasted peak day demand.
[133] Information provided by the three investor owned utilities.
[134] Connecticut Siting Council Review of the Connecticut Electric Utilities Ten Year Forecast of Loads and Resources 2002.
[135] ISO-NE *Steady-State and Transient Analysis of New England's Interstate Pipeline Delivery Capacity, 2001-2005* (2002).

Long Island gas market, the existing infrastructure, and related energy and environmental challenges.

The Brooklyn Union Gas Company (doing business as KeySpan Energy Delivery New York, or KEDNY) provides gas distribution services to customers in New York City in the boroughs of Brooklyn, Queens, and Staten Island. KeySpan Gas East Corporation (doing business as KeySpan Energy Delivery Long Island, or KEDLI) provides gas distribution services to customers in Nassau and Suffolk counties and the Rockaway Peninsula in Queens. The two separate, but contiguous, service territories served by KEDNY and KEDLI comprise approximately 1,417 square miles, and 1.66 million residential, commercial, and industrial customers.

Gas consumption on a peak winter day in KEDNY and KEDLI is approximately 2.2 Bcf/d (2.2 thousand dekatherms per day (MDth/d)). Current total annual gas consumption by KEDNY and KEDLI customers is 252 Bcf, including 70 Bcf for electric generation. Peak day gas supplies for the two systems come from a mix of gas shipped via long-haul pipeline, via pipeline from storage fields in Pennsylvania and western New York, and from LNG. As shown in Table 11, KEDNY and KEDLI each have currently sufficient resources to meet peak day requirements of up to approximately 2.0 BCF (2,036 MDth) and 0.73 Bcf (745 MDth), respectively.[136] The New York Energy Plan forecasted natural gas demand state-wide to grow at the rate of 1.5% per year over the next 20 years, with a low case forecast of 1.3% per year, and a high case forecast of 1.6% per year.[137] However, KeySpan forecasts a growth rate of 3.3% on Long Island, or twice the state-wide average, due to conversions from oil to gas for both core loads and new gas-fired generation. KeySpan has stated that, in addition to its current core heating load, "there is the need for incremental gas capacity and supply to serve future generation and the conversion of existing oil burning electric generation to gas."[138]

Table 11 – New York City and Long Island Natural Gas Delivery Capacity (Bcf (MDth)/d)

Source	KEDNY	KEDLI	Total
Pipeline	0.731 (752)	0.257 (263)	0.99 (1,013)
Underground Storage	0.758 (779)	0.287 (294)	1.05 (1,073)
Peaking Supplies	0.492 (505)	0.182 (188)	0.65 (692)
Total	1.981 (2,036)	0.726 (745)	2.71 (2,778)

Four interstate pipelines deliver gas to KEDNY and KEDLI: Transco, Texas Eastern (TETCO) , Iroquois, and Tennessee. Keyspan's distribution of pipeline capacity on Long Island is as follows: Transco – 58.8%, TETCO (via Transco) – 25.4%, Iroquois – 9.7%,

136 Brookhaven Energy Project, Article X Application to the Siting Board, June 2001, Docket 00-F-0566, at 9-5.

137 New York Energy Planning Board, *New York Energy Plan and Final Environmental Impact Statement*, June 2002.

138 KeySpan presentation to the Task Force, February 28, 2003.

and Tennessee (via Iroquois) - 6.1%.[139] Transco and Texas Eastern are the primary source of pipeline capacity into New York City. Iroquois' Eastchester lateral into the Bronx, when completed, will add 0.22 Bcf/d. Tennessee's lateral into Westchester County comprises a comparatively small portion of total pipeline capacity into New York City, however. Transco and Iroquois are the only two pipelines directly connected to the KEDLI system on Long Island: Transco delivers Gulf Coast supplies via a southern path from New Jersey, across lower New York Harbor to Long Beach on the south shore of Long Island, and Iroquois delivers western Canadian supplies via a northern path from Milford across Long Island Sound to Commack.

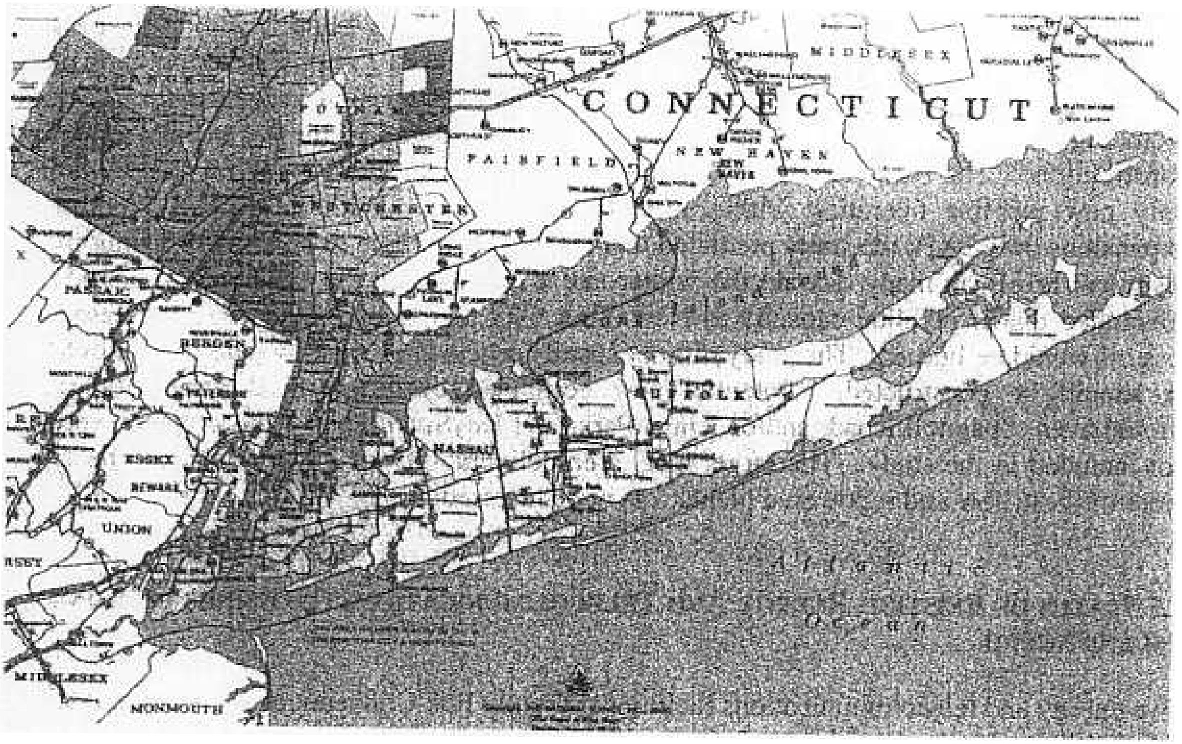
Prior to the construction of Iroquois, Long Island historically had insufficient pipeline service. Consequently, Long Island today still has the highest concentration of oil heat customers in the continental U.S. Power generation on Long Island also relies heavily on oil. Through the 1980s and 1990s, KEDLI's predecessor on Long Island, LILCO, was forced to limit the number of new gas customer hookups. Even today, several areas in eastern Long Island do not have access to natural gas. Since Iroquois' commercialization in 1992, Long Island's constraints on pipeline capacity and natural gas supply have been alleviated, but not eliminated. The enhanced supply of natural gas transported via Iroquois has allowed KEDLI to significantly add new residential and commercial customers over the last decade. KEDLI has also made significant investment in its on-island gas distribution network.

Gas supplied to KEDNY and KEDLI customers is delivered via the New York Facility System, a high-pressure natural gas pipeline network extending across the Hudson River counties of Westchester, Putnam, Orange, and Rockland into New York City and Long Island (Figure 8). The New York Facility System is operated by Con Edison and KeySpan for purposes of maintaining adequate delivery capability to distribution customers throughout New York City and Long Island. From an operational standpoint, natural gas flows predominantly eastward across the New York Facility System. By delivering gas into western Suffolk County, Iroquois has "freed up" capacity in the congested New York City and Nassau County area and made it easier to serve new customers. Because the New York Facility System runs near its capacity limits most of the winter, Con Edison, KEDLI, and KEDNY supplement supplies with LNG from satellite tanks located in Astoria, Greenpoint, and Holtsville, New York. Both Con Ed and KeySpan intend to expand the capacity of the New York Facility System to accommodate increased demand, including new power generation facilities. KeySpan has begun a three-year expansion of the Facility System on Long Island by replacing 12.8 miles of 8" pipe with 20" pipe,[140] expected to be completed in 2004.

[139] Brookhaven Energy Project, Article X Application to the Siting Board, June 2001, Docket 00-F-0566, at 9-5.

[140] Brookhaven Energy Project, Article X Application to the Siting Board, June 2001, Docket 00-F-0566, at 9-2.

Figure 8 – New York and Long Island Facility System



LIPA's Draft Energy Plan, issued in October 2002,[141] supports development of an additional pipeline connection to Long Island to meet the increasing on-Island demand, provide reliability benefits, and offer an additional source of natural gas supply. LIPA notes that the Islander East project would provide physical access to upstream reserves in Atlantic Canada, which can compete against the traditional Gulf Coast and western Canadian supplies. KeySpan has also noted that Islander East would also facilitate gas deliveries directly to an area of high population growth in Suffolk County, thereby freeing up some of the capacity on the constrained New York Facility System.

The question of pipeline adequacy is not a simple exercise of comparing pipeline capacity and gas demand within a region. Gas deliverability is a complex function of upstream supply, storage, and transportation capacity, the hydraulics and physical characteristics of the interconnected pipeline systems, hourly and daily withdrawals and injections of gas (including LNG), the location and capacity of compressor stations, and other parameters. The seasonal variability of LDC gas demand, the availability and relative price of alternative fuels, and the dispatch of gas-fired electric generation on an hourly, daily, and seasonal basis are all critical factors in assessing regional gas demand.

[141] LIPA Draft Energy Plan, October 17, 2002.

As part of New York's 2002 Energy Plan, NYSERDA and NYISO initiated a study of the interrelationship between the electricity and natural gas systems in New York.[142] The study included integrated modeling of the natural gas pipeline and electric generation systems, with a particular focus on the downstate area, including Long Island. The study concluded that "New York has sufficient gas delivery capacity to deliver the amounts of gas required for 2005 generation projects and pipeline expansion scenarios analyzed, including the scenarios where pipeline expansions are limited to those currently under construction." The base case model assumed that the Eastchester Pipeline would be the only new pipeline operating within Long Island Sound. With no further pipeline expansions post-2003, the study predicted that oil would continue to be burned at roughly historical levels on many days in the winter and a few days in the summer. The study concluded that if pipeline capacity to New York City and Long Island were increased, less oil would be burned. The study did not specify where such pipeline additions would or should be constructed. Potential new combined cycle gas-fired generation at Brookhaven, Spagnoli Road, and/or Kings Park, and KeySpan repowering projects were not included in the study. Therefore, local area deliverability on Long Island to one or more of these new and repowered plants was not addressed.

2.5 Status of Existing Energy and Telecommunications Crossings of Long Island Sound

Five energy and telecommunications facilities presently link Connecticut and Long Island via crossings of Long Island Sound. These include:

Two electric transmission cable systems

> The 1385 Line cable system (AC), which is jointly owned by CL&P and LIPA and consists of seven cables that link Norwalk and Northport, Long Island; and
>
> Cross-Sound Cable's system (DC), consisting of a bundle of two solid dielectric cables and a fiber optic telecommunications cable, which traverses between New Haven and Brookhaven, Long Island (1,800 feet of cable has not been installed to depths required by permits).

One natural gas pipeline (the Iroquois pipeline), which extends across Long Island Sound from Milford to Northport, Long Island.

Two telecommunications cables:

> AT&T's fiber optic cable, which traverses from East Haven to Shoreham, Long Island; and

[142] Charles River Associates. *Task 4: Initial Report The Ability to Meet Future Gas Demands from Electricity Generation in New York* 2002.

MCI's fiber optic cable, which extends from Madison to Rocky Point, Long Island.

In addition to these interstate energy and telecommunications facilities, a variety of other submarine facilities traverse portions of Long Island Sound, typically to provide mainland utility services to certain of the state's inhabited islands (e.g., the Thimble Islands), as well as to islands that have lighthouses and Fishers Island, New York. These facilities provide electricity, telecommunications service, and potable water to the islands, as well as power to lighthouses used in navigation.

Further, four other major submarine energy and/or telecommunication facilities traverse Long Island Sound, but are located entirely in New York. These facilities, which are in the central and western portions of Long Island Sound, consist of:

Two 345 kV electric transmission lines between Westchester County and Long Island; the Y-49 line, owned by the New York Power Authority, and the Y-50 line, owned by LIPA and Con Edison;

Iroquois' recently constructed Eastchester natural gas pipeline, which extends 35 miles from Northport, Long Island to the Bronx; and

The Flag's fiber optic cable, which was installed within the last five years and which extends from Northport, Long Island, eastward through Long Island Sound to Europe.

This inventory focuses on the five energy and telecommunications facilities that cross Long Island Sound between Connecticut and Long Island. These facilities are separated both spatially (none of the five facilities are located in close proximity) and temporally (none of the five facilities were constructed within the same time frame).

Information for this section was drawn in part from project status reports that the Task Force requested from the owners of the crossings.[143,144,145,146,147] Other data were compiled from presentations made by project proponents and regulators to the Task Force. In addition, reports, permits, and regulatory decision-making documents relevant to the five crossings were reviewed.

[143] Iroquois Gas Transmission System (Iroquois).

[144] Cross-Sound Cable Company, LLC, Letter to Joel Rinebold from Jeffrey A. Donahue dated February 5, 2003.

[145] Islander East Pipeline Company. Letter to Joel Rinebold from Gene H. Muhlherr dated July 24, 2002.

[146] Northeast Utilities System. Letter to Joel Rinebold from Paula M. Taupier dated February 5, 2003.

[147] The Task Force requested information from AT&T and MCI, but did not get a response and was unable to acquire information other than that contained in the DEP permits issued for their projects.

2.5.1 Background For Existing Crossings

The first of the five cross-Sound links was the 1385 Line, which was installed in 1969 and went into operation in 1970. The other four crossings were constructed within the past 12 years: Iroquois' pipeline in 1991; AT&T's fiber optic cable in 1993; MCI's fiber optic cable in 1996; and Cross-Sound Cable in 2002.

During the 33 years between the installation of the 1385 Line and the Cross-Sound Cable, significant changes have occurred in federal and state environmental protection requirements as a whole, as well as in the regulatory mechanisms that afford protection to Long Island Sound's natural resources during the construction of energy or infrastructure facilities (e.g., NEPA, MMPA, the Coastal Zone Management Act of 1972, Marine Protection Research and Sanctuaries Act (1972), ESA, the Clean Water Act of 1972 (CWA), PUESA, Connecticut's Tidal Wetlands Act, IWWA, and CMA, the FERC certificate conditions, Section 404 ACOE regulations, and the NHPA Sec. 106 Review). Likewise, electric cable, telecommunications, and pipeline technologies and designs have evolved and submarine construction techniques have become more sophisticated, both to facilitate work in marine environments and to minimize impacts to ecological resources.

Given the limited environmental regulatory requirements 35 years ago, pre-construction evaluations concerning the 1385 Line focused primarily around engineering and constructability parameters, rather than on establishing ecological baseline information or on analyzing the potential for impacts on natural resources. Similarly, 35 years ago, there were no certificate or permit conditions that required post-construction environmental monitoring.

With the promulgation of more protective state and federal environmental laws and regulations, and greater recognition of potential environmental impacts, detailed pre- and post-construction environmental information concerning proposed routes has become a requisite of permit/certificate applications and approvals. As a result, baseline environmental data for recent projects, such as Cross-Sound Cable, are extensive.

However, the lack of comprehensive long-term ecological data regarding energy and infrastructure facilities, as well as that of many other activities in Long Island Sound, limits the ability to evaluate the environmental status of cross-Sound infrastructure over time. Moreover, it is often difficult, if not impossible, to determine whether (or the extent to which) changes in environmental conditions along an energy or infrastructure route, such as species diversity and abundance, are attributable to the project or to other phenomena (e.g., other man-made disturbance, upland land management practices, non-point and/or point source pollution, natural processes, or a combination thereof).

Finally, over the past three decades, both state and federal regulators have invested substantial efforts to coordinate and refine initiatives and plans to protect the resources of Long Island Sound. This is evidenced by the Long Island Sound Study's *Comprehensive Conservation and Management Plan* for Long Island Sound, as well as by the stringent federal and state permit and certification processes that must be completed by applicants proposing energy or telecommunications infrastructure facilities in Long Island Sound. This Task Force is recommending enhancements to the current energy and telecommunications infrastructure siting process; providing for more transparent public participation and independent study of proposed projects; and endorsing closer interstate coordination with respect to projects proposed to cross Long Island Sound.

Considering the evolution of the environmental protection movement over the past 30 years and the increased public awareness about the importance of Long Island Sound's ecosystem, it is important to recognize that projects constructed using current technology, in accordance with existing regulatory requirements, can not be expected to experience the same impacts observed in connection with projects installed decades ago or even within the past 5-10 years.

2.5.2 Environmental Status of Electric Cable Crossings

The 1385 Line

The 1385 Line cable system traverses approximately 11 miles from the Norwalk Harbor Substation on Manresa Island in Norwalk, across both the seabed of Sheffield Harbor and Sheffield Island, to the Northport Substation in Northport, Long Island. The 138 kV cable system, which is owned by CL&P in Connecticut and LIPA in New York, was installed in 1969 and commenced operation in 1970. The system consists of seven separate three-inch-diameter fluid-filled cables, each containing a single hollow core copper conductor surrounded by paper insulation, a lead covering, and outside armoring. To serve as an effective insulator, the paper is impregnated with dielectric fluid maintained under pressure.

The cables are separated for safety and reliability reasons, as well as to allow for cable repairs. The spacing between the cables varies, depending on their location. In general, the cables are spaced farther apart in the offshore area (approximately 900 feet) and closer together approaching and on land (i.e., in the vicinity of Sheffield Island and the Norwalk Harbor Substation).

CL&P and LIPA have proposed removal of the seven existing cables and replacement with three solid core dielectric transmission cables. The proposed alignment for the replacement cables is along the route of the three easternmost existing cables. In conjunction with planning for the cable replacement project, CL&P commissioned detailed studies of the existing cable route, including bulk physical and chemical sampling and analysis, sediment transport analysis, and fisheries and benthic evaluations. CL&P submitted applications for the replacement project to the Siting Council and DEP in 2001 and 2002, with the Siting Council issuing a Certificate of Environmental Compatibility and Public Need in September 2002.

Construction History CL&P received a permit for the Connecticut portion of the 1385 Line project from the Connecticut Water Resources Commission, the predecessor of

DEP, in February 1969. CL&P and LIPA received an ACOE permit for the entire crossing in March 1969. On or about that time, CL&P purchased the state and local shellfish leases within the cable route.

Two primary construction methods were used to install the submarine portion of the 1385 Line. Although these methods were considered "state of the art" in 1969, they would not be used today, given the advances that have been made over the past 35 years in construction technology.

From the Connecticut shoreline to a point just past Sheffield Island, open trenching, using a combination of conventional and hydraulic dredges, was used to install the cables below the seabed. For the remainder of the route in Connecticut to the vicinity of the Long Island landfall at Northport, the cables were laid directly on the natural bottom of Long Island Sound. The state and federal permits issued for the project imposed certain depth of burial requirements, placed certain limitations on dumping of fill, and required restoration of the seabed as needed.

A review of documentation from the 1969 cable installation revealed that certain difficulties were encountered during the construction process. Some of these included:

> Rock and other hard bottom materials made cable burial difficult.
>
> Discharge currents from the Norwalk Harbor and Northport Power Stations affected the contractor's ability to control the laying of the cables, and divers had to be used.
>
> Initial trenching technology dispersed sediments on the water surface such that the ACOE restricted the use of the dredging method.
>
> Installation of the cables across the Federal Navigation Channel took longer than anticipated, necessitating longer closure of the Channel.
>
> Near the conclusion of construction, inspections revealed little or no cover over the portion of the cables between Sheffield Island and Norwalk Harbor Substation; resolution of the responsibility for backfilling to complete the work required almost a year and in some areas concrete material was added to the trenches to complete the backfilling process.

<u>Documented Impacts</u> Construction of the 1385 Line cable system pre-dated the promulgation of requirements for comprehensive baseline environmental studies and post-construction environmental monitoring. As a result, there is no pre- and post-installation environmental data that can be used to compare the present condition of the cable area to that immediately after the completion of the project over 35 years ago.

Since the mid-1990s, environmental monitoring has been conducted primarily to evaluate the effects of dielectric fluid releases caused by anchors or other objects hitting and damaging the cables. The most recent such damage occurred in November 2002 when the 1385 line was damaged by a survey vessel that dragged its anchor, severing four of the seven cables. CL&P and LIPA expect to restore the full transfer capability by summer 2003.

CL&P has reported these accidental releases to the DEP and other regulatory agencies in accordance with applicable requirements, including the Consent Orders issued to CL&P and LIPA in 1995/1996 and 1998 by DEP and the NYSDEC. Impact assessments also were conducted in accordance with these Consent Orders.

Except as displaced by anchor drag or other accidents and associated repairs, the existing 1385 Line cables have remained approximately where they were first installed. Certain portions of the cables that were not originally buried have settled into the silt on the seabed or have been covered by drifting sediments.

Although environmental baseline data were not compiled when the 1385 Line was installed in 1969, surveys of the cable routes were performed recently in support of CL&P's applications for certificates and permits for the cable replacement project. Such detailed environmental surveys include various analyses of existing conditions within and near the cable corridor.[148,149,150,151] Benthic survey transects were extended up to 1,000 feet outside of the mapped cable route in both eastern and western directions, specifically for the purpose of determining what differences in productivity there were between areas inside this cable route and those outside.[152] Chemical and physical characteristics of the sediments in which the cables would be buried were collected for both the proposed route and its principal alternatives, and a benthic environmental survey was performed of the more sensitive estuarine portions of the area near the existing/proposed cable route. These studies identified six different benthic habitats near the existing cable system; these ranged from silty fine sands with scattered shell debris in which were found both mud snails and macroalgae (near the Norwalk shoreline) to large rocks with small amounts of eastern oysters and blue mussels (on the south side of Sheffield Island). The number of oysters present in the project area varied, commensurate with the variations in habitat crossed, whereas hard clams were found throughout the survey area. In addition,

[148] CL&P (The Connecticut Light and Power Company). Final Report, Hydrographic, Geophysical, and Geotechnical Survey Program. Prepared for the KeySpan Energy (Northeast Utilities interconnect, Northport, NY to Norwalk, CT, OSI Project # 00ES088. Submitted to the Siting Council, as bulk Filing #1 to Docket 224, March. 2002.

[149] CL&P. Benthic Habitat Mapping & Shellfish Enumeration, Sediment Dispersion Modeling, and Simulations of Sediment Transport and Deposition Long Island Sound Connecticut. Submitted to the Siting Council, May 2002, in response to interrogatory CSC-02-052, Docket 224.

[150] CL&P. Dielectric Fluid in Long Island Sound: An Environmental Perspective Attachment 6-13, in Application to the Siting Council for a Certificate of Environmental Compatibility and Public Need for the Norwalk, Connecticut to Northport, New York Submarine Cable Replacement Project. Submitted to the Siting Council, February 2002, Docket 224.

[151] CL&P. Responses to interrogatories (CSC-01-021 and CSC-01-022) from the Siting Council, Docket 224.

[152] Norwalk, Connecticut to Northport, New York Submarine Cable Replacement Project; Benthic Habitat Mapping & Shellfish Enumeration, Sediment Dispersion Modeling, and Simulations of Sediment Transport and Deposition Long Island Sound-Connecticut: CL&P May 2002.

researchers found annelid worms, mollusks, small amphipods and crabs in all samples collected in the survey.

The Whitlatch OSI studies concluded that there were no discernible differences in sediment type or biological communities between habitats over the existing cables and those not over the cables[153]. Based on these studies, CL&P concluded that despite the relatively crude construction techniques (compared to those available today) used to install the 1385 Line, benthic productivity in the impact area recovered over time.

However, in one area -- the shallow portions of the sheltered cove north of Sheffield Island – researchers did find fewer numbers of species and individuals in depressions located over the buried cables. Researchers could not determine whether this reduction was related to differences in bottom topography or the dense accumulations of macroalgae found in these depressions.

Since the cables commenced operation in 1970, there have been approximately 55 instances resulting in the release of alkylbenzene-containing dielectric fluid into the marine environment. In response to Consent Orders issued in the mid-1990s, areas that were subject to dielectric fluid leaks were studied for impacts to shellfish and sediments.[154, 155, 156, 157, 158, 159, 160, 161, 162, 163, 164, 165, 166, 167] Remediation of fluid releases

[153] Norwalk, Connecticut to Northport, New York Submarine Cable Replacement Project; Benthic Habitat Mapping & Shellfish Enumeration, Sediment Dispersion Modeling, and Simulations of Sediment Transport and Deposition Long Island Sound-Connecticut; CL&P May 2002.

[154] NUSCO (Northeast Utilities Service Company). 1997a. Literature search and review, effects of alkylbenzenes in the marine environment. Prepared for The Connecticut Light and Power Company arid Long Island Lighting Company by Northeast Utilities Environmental Laboratory, Waterford, CT Submitted to DEP and NYSDEC on February 28, 1997. 18 pp.

[155] NUSCO. 1997b. Baseline distribution study of alkylbenzenes in western Long Island Sound sediments. Prepared for The Connecticut Light and Power Company and Long Island Lighting Company by Northeast Utilities Environmental Laboratory, Waterford, CT. Submitted to DEP and NYSDEC on June 27, 1991. 14 pp.

[156] NUSCO. 1998a. Characterization of oyster (Crassostrea virginica) growing conditions in the vicinity of Norwalk Harbor underwater electric cables. Prepared for The Connecticut Light and Power Company and Long Island Lighting Company by Northeast Utilities Environmental Laboratory, Waterford, Connecticut. Submitted to DEP and NYSDEC on June 24, 1998. 14 pp.

[157] NUSCO. 1998b. Laboratory studies of the behavior of dielectric fluid in marine sediments and oysters using chemical fingerprinting techniques. Prepared for The Connecticut Light and Power Company and Long Island Lighting Company by Northeast Utilities Environmental Laboratory, Waterford, CT. Submitted to DEP and NYSDEC on October 27, 1998. 50 pp.

[158] NUSCO. 1999a. Dielectric fluid concentrations in sediments and shellfish following the December 1996 cable leak off Northport Station, Long Island, NY. Prepared for The Connecticut Light and Power Company and Long Island Lighting Company by Northeast Utilities Environmental Laboratory, Waterford, CT. Submitted to DEP and NYSDEC on February 10, 1999. 15 pp.

[159] NUSCO. 1999b. Dielectric fluid concentrations in sediments and shellfish following cable leaks beginning in April 1998 at the Norwalk Harbor Station Shoreline. Prepared for The Connecticut Light and Power Company and Long Island Lighting Company by Northeast Utilities Environmental Laboratory, Waterford, CT. Submitted to DEP and NYSDEC on February 25, 1999. 10 pp.

[160] NUSCO. 1999c. Long-term monitoring of alkylbenzenes in Norwalk Harbor sediments and shellfish (1996-1998). Prepared for The Connecticut Light and Power Company and Long Island Lighting

was not required, based on results from studies.[168,169] According to the reports, alkylbenzene levels in sediment and shellfish near the cables were found to be consistent with background levels for Long Island Sound.

John Volk, then Director of the Department of Agriculture, Bureau of Aquaculture, noted in a presentation to the Task Force that some trenches are still evident after 30 years.[170] He also noted that while alkylbenzene is relatively inert, the state required closure of a shellfish bed following one of the incidents.

Cross-Sound Cable

Company by Northeast Utilities Environmental Laboratory, Waterford, CT. Submitted to DEP and NYSDEC on July 8, 1999. 12 pp.

[161] NUSCO. 1999d. Alkylbenzene concentrations in sediments and shellfish following cable leaks first detected in September 1998 on the Norwalk Shoreline and in Mid-Long Island Sound. Prepared for The Connecticut Light and Power Company and Long Island Lighting Company by Northeast Utilities Environment Laboratory, Waterford, CT. Submitted to DEP and NYSDEC on October 8, 1999, 10 pp.

[162] NUSCO. 2000a. Alkylbenzene concentrations in sediment and shellfish following cable fluid leaks located on June 2, 1999 in Long Island Sound south of Sheffield Island, Norwalk Connecticut. Prepared for The Connecticut Light and Power Company and Long Island Lighting Company by Northeast Utilities Environmental Laboratory, Waterford, CT. Submitted to DEP and NYSDEC on April 5, *2000. 6* pp.

[163] NUSCO. 2000b. Alkylbenzene concentrations in sediment and shellfish following cable fluid leaks, June 25 and August 13, 1999 environmental leak monitoring. Prepared for The Connecticut light and Power Company and Long Island Lighting Company by Northeast Utilities Environmental Laboratory, Waterford, CT. Submitted to DEP and NYDEC on July 3, 2000. 6 pp.

[164] NUSCO. 2000c. Alkylbenzene concentrations in sediment and shellfish following cable fluid leak, February 8, 2000, environmental leak monitoring. Prepared for The Connecticut Light and Power Company and Long Island Lighting Company' by Northeast Utilities Environmental Laboratory, Waterford, CT. Submitted to DEP and NYDEC on September 29, 2000.6 pp.

[165] NUSCO. 2001. Alkylbenzene concentrations in sediment and shellfish following cable fluid leakage, February 4 and June 8, 2000 environmental leak monitoring. Prepared for The Connecticut Light and Power Company and Long Island Lighting Company by Northeast Utilities Environmental Laboratory, Waterford, CT. Submitted to DEP and NYDEC on March 31, 2001. 7 pp.

[166] NUSCO. 2001. Alkylbenzene concentrations in sediment and shellfish following cable fluid leakage, October 31, 2000 environmental leak monitoring. Prepared for The Connecticut Light and Power Company and Long Island Lighting Company by Northeast Utilities Environmental Laboratory, Waterford, CT. Submitted to DEP and NYDEC on July 27, 2001, 7 pp.

[167] NUSCO. 2001. Alkylbenzene concentrations in sediment and shellfish following cable fluid leakage, March 17, 2001 environmental leak monitoring. Prepared for The Connecticut Light and Power Company and Long Island Lighting Company by Northeast Utilities Environmental Laboratory, Waterford, CT. Submitted to DEP and NYSDEC on December 2, 2001. 7 pp.

[168] CL&P. Dielectric Fluid in Long Island Sound: An Environmental Perspective Attachment 6-13, in Application to the Siting Council for a Certificate of Environmental Compatibility and Public Need for the Norwalk, Connecticut to Northport, New York Submarine Cable Replacement Project. Submitted to the Siting Council, February, 2002, Docket 224.

[169] CL&P. Responses to interrogatories (CSC-01-021 and CSC-01-022) from the Siting Council, Docket 224.

[170] Presentation by Mr. John Volk, then Director of the Department of Agriculture, Bureau of Aquaculture, to Task Force meeting of September 19, 2002. John Volk retired from the Department of Agriculture in May 2003.

Recently constructed but not operational, the Cross-Sound Cable interconnects the electric transmission grids of New York and New England between Brookhaven, Long Island and New Haven. The Siting Council granted Cross-Sound Cable a Certificate of Environmental Compatibility and Public Need in January 2002. The project received permits from DEP and ACOE in March 2002.

Construction History In May 2002, the cable system, consisting of two solid dielectric power cables and one fiber optic telecommunication cable, was buried in a common trench within the seabed of Long Island Sound for the entire 24-mile route. Approximately 21,400 linear feet of the cable system was routed within the Federal Navigation Channel (Channel) in New Haven Harbor to substantially avoid cultivated shellfish beds.[171] In anticipation of possible future dredging of the Channel, the ACOE and DEP prescribed a minimum burial depth of -48 feet mean lower low water. The installation method used HDD and remotely operated water jetting burial tools from a self-positioning vessel. Construction was also subject to time-of-year installation restrictions.

Cross-Sound Cable's contractors subsequently determined that several short sections of the cable within the Channel collectively totaling 1,800 feet were not installed to the required burial depth of -48 feet mean lower low water. According to Cross-Sound Cable, the results of the characterization studies indicated that all but one of the sections of the cable system requiring further burial are located in areas of sediments. In the remaining section, the cable system is resting on bedrock for approximately 500 feet. Cross-Sound Cable has proposed alternative construction methods to achieve the required depth in these sediment areas, but DEP has stated that further review is pending until the moratorium established pursuant to PA No. 02-95 expires.

Documented Impacts In accordance with the state-approved benthic monitoring plan, Cross-Sound Cable completed the first post construction (six-month) monitoring in November 2002.[172] A similar pre-installation survey was completed in May 2002. Cross-Sound Cable reports that the results of the post-installation survey indicate the following:

> The only observable change in the seabed geomorphology from the pre--installation report is a shallow, localized, linear depression representing the path of cable installation. The depressions range from 0.5 to 3 feet deep, and 2 to 8 feet wide.
>
> The six benthic habitat types identified in the pre-installation survey are still detected in the post installation surveys. Based on video imagery and sediment

[171] Presentation by Mr. Michael Ludwig, a Fisheries Biologist for NOAA, before the Task Force on September 19, 2002.

[172] Six-Month Post Installation Benthic Monitoring Survey for the Cross-Sound Cable Project, New Haven CT, to Shoreham, NY. October 14 to November 20, 2002. Prepared by Ocean Surveys Inc. The survey protocol was approved by DEP with consultation with Department of Agriculture, Bureau of Aquaculture, NMFS, and the ACOE.

profile images, the only visible changes in substrate characteristics is in the Federal Navigation Channel. In this area is a patchy, thin, 1 to 2 cm sediment layer comprised of fine sandy silt. This feature was not observed in any of the other survey areas.

The types and diversity of bottom dwelling organisms and macroalgae observed in the video imagery remained consistent between the pre- and post-installation surveys. Prominent organisms observed in remote video images obtained over the cable centerline were comparable to those observed in video obtained along survey lines offset from the cable area. More disturbance of sediment layers by biological activity was evident in the post-installation survey conducted in October/November compared to the pre-construction April/May survey, presumably due to seasonal conditions. The biological activity confirms recruitment of organisms into the installation area.

Sediment oxidation depths, a marker for the quality of the benthic habitat in estuaries like Long Island Sound, were consistent between pre- and post-installation surveys. This measurement combined with the other parameters measured through sediment profile imagery suggests that the installation of the cable did not adversely impact habitat quality for benthic communities.

Magnetic field readings did not detect the presence of the cable, which was not in service during the post-installation survey. Magnetic field readings did not detect any isolated magnetic anomalies representative of ferrous objects in any of the areas and observed magnetic field readings were normal for this geographic region on the earth. A comparison of the measured variation and expected variation at each area indicates there is minimal local disturbance to the magnetic field in the survey areas. Additional tests would be conducted to confirm magnetic field variations during line operations.

2.5.3 Environmental Status of Gas Pipelines

Iroquois Gas Transmission System

The Iroquois Gas Transmission System pipeline enters Long Island Sound in Milford and emerges at Northport, Long Island, New York. This 24-inch steel pipeline traverses 26.3 miles across Long Island Sound; of this, approximately 16.1 miles are in Connecticut. Installation of the Long Island Sound portion of the pipeline was completed in 1991, pursuant to certificate approvals from the FERC, the Siting Council, DEP, and the NYPSC, and a permit from ACOE. The entire 375-mile Iroquois pipeline system achieved commercial operation in 1992.

Construction History The location of the Iroquois crossing of Long Island Sound, including the alignment across shellfish lease areas off Milford, was determined based on consideration of engineering and environmental factors and on consultations with various federal and state regulatory agencies, including the Siting Council, Department of Agriculture (Bureau of Aquaculture), NMFS, the FERC, ACOE, and DEP.

To install the submarine pipeline, Iroquois used various construction methods available at the time, including dredging, plowing, and jetting, depending on water depth and sediment type.[173] Like the 1385 Line, these methods represented available existing technology at the time of Iroquois' construction.

Clamshell dredging was utilized to pre-excavate the pipeline trench for approximately 2.5 miles, from the Milford landfall through shallow-waters, including through shellfish lease areas. The excavated material was temporarily sidecast adjacent to the pipe trench to be later utilized to backfill the installed pipe. Plowing and jetting were generally used to install the pipeline in offshore areas.

The time window for construction was restricted to late winter and early spring to minimize potential impacts to commercial shellfish and other fisheries. Accordingly, the pipeline was installed in the winter and spring of 1991. A storm event, which occurred during installation, caused the sidecast spoils to partially refill the trench and re-deposit outside of the route, which required an additional pass of the dredge and clean fill to be brought in to supplement the backfill operation, in some discrete areas.

In nearshore areas of shellfish production in Milford, after dredging a trench and installing the pipe, Iroquois backfilled and then smoothed the pipeline trench with a drag beam. During this operation, the contractor experienced difficulty confining the movements of the drag beam to the prescribed 300-foot wide construction corridor in the nearshore area. Consequently, the contractor disturbed the surface sediments outside the route. The drag beaming operation resulted in 85% of the seabed within the 300-foot wide nearshore area to be restored to within one foot of the original bathymetry, and a mass balance calculation generally showed that the highs were equal to the lows in the area. Iroquois reached agreement with permitting agencies that there were diminishing returns in continuing the beam dragging beyond this point, and remaining restoration could be accomplished with natural sedimentation.

Iroquois permits and certificates did not require burial of the pipeline in offshore areas beyond the shellfish lease beds. However, the offshore portion of the pipeline (beyond the shellfish lease beds) was jetted and plowed during installation to reduce the impact that the pipeline could potentially have on lobster migration.

<u>Documented Impacts</u> The principal issues raised with regard to the Iroquois pipeline pertain to impacts to the benthic environment, including shellfish lease areas. No documented issues were identified with respect to depth of cover over the pipeline.

In addition to the use of the drag beam to smooth the nearshore areas affected by dredging activities, Iroquois implemented various measures to mitigate shellfish-related

[173] Observations of Pipeline Corridor from 1999 High Resolution Multibeam Survey Construction Details from 1991 Long Island Sound Pipeline.

concerns. These ranged from pre-construction route modifications to compensation to the shellfish leaseholders. Among these mitigation measures were:

Alignment of the pipeline through shellfish lease areas as directed by the Bureau of Aquaculture and other involved agencies. The pipeline was routed to traverse areas primarily leased by a large shellfish leaseholder (Tallmadge Brothers); it was anticipated that routing through the Tallmadge leases would have less of an impact on the overall Tallmadge operations than would alignment through a single leaseholding of an individual. All but one of the leases along the Iroquois route was owned by Tallmadge. Route modifications to accommodate these initial shellfish-related concerns added approximately $2.1 million to the project capital cost.

Financial compensation of $5.2 million was paid to leaseholders affected by the construction.

Financial compensation of $525,000 was paid to Tallmadge to unload, store, and spread cultch on the disturbed lease beds after construction. At Tallmadge's request, this sum was instead paid to the Department of Agriculture for the purposes of funding a laboratory for the Bureau of Aquaculture.

Iroquois provided 1,250,000 bushels of cultch, valued at $1.5 million, for the restoration of public and private shellfish beds impacted by the construction of the pipeline, and to aid in the restoration and revived productivity of the seabed. However, in a settlement agreement with state agencies, Iroquois released all rights to the placement of the cultch as part of restoration. The cultch was instead placed on other state leases (public fields off Bridgeport and Stratford) to compensate for impacts along the Iroquois pipeline. It was reported that a productive oyster set was established at this alternative location.

Iroquois surveyed the pipeline route in 1993 and again in 1999.[174] Based on the results of these surveys, Iroquois concluded that natural sediment transport and infilling covered the offshore portion of the pipeline within a year or two of installation in those areas where the pipeline was installed by plowing in clay sediments. During that period, the sediment slopes across the trench in general were naturally reduced on the order of 5 to 20 degrees. In the nearshore area, the seabed was observed to be smooth, with little or no bottom relief.

Iroquois also conducted surveys along the pipeline route in the shellfish lease areas off Milford. These surveys were conducted in February/March 1991 (pre-construction) and July 1991 (post-construction), and involved comparisons of oysters per square yard at monitoring points ranging from 100 feet to 4,250 feet from the pipeline centerline. In general, the results of the surveys showed that compared to pre-construction conditions,

[174] Observations of Pipeline Corridor from 1999 High Resolution Multibeam Survey, Construction Details from 1991 Long Island Sound Pipeline.

the number of oysters decreased after construction at distances of 100 to 400 feet from the pipeline centerline, but increased after construction at distances greater than 1,270 feet from the centerline of the pipeline.

In addition, Iroquois performed a water quality monitoring program using live oysters. Six monitoring stations were established near the pipeline in March 1991. The oysters were recovered in July 1991. At each of the six locations, the oysters appeared normal in color and no offensive odor was detected.[175]

The Bureau of Aquaculture was extensively involved in monitoring the impacts of the Iroquois project on shellfish resources.[176] Bureau of Aquaculture staff reported that anchors associated with the construction equipment disturbed bottom substrate as far as 2,000 feet on either side of the pipeline centerline, creating long-term impacts to oyster habitats. Bureau of Aquaculture staff also have noted that despite attempts to level the bottom, depressions left by the anchors have filled in with fine-grained sediments and presently have low or no productivity. In the short-term, oysters are particularly vulnerable to suffocation from sediments that are suspended and redeposited during construction. During construction, the width of the sediment plume appeared to extend out as much as 4,000 feet from the construction area. As it takes two to four years for oysters to grow to harvestable size, such effects can result in long-term disruption of the harvest.

Commercial shellfishermen provided the Task Force with personal, anecdotal evidence of disruption of oyster aquaculture operations from construction of the Iroquois pipeline.[177] They attested that construction resulted in an impact area as much as 400 feet on either side of the pipeline. They suggested that the use of the drag beam to level the trench has proved only partially effective, and portions of the trench may be as much as 6 feet deep. The steep slopes along the trench have interfered with the use of oyster dredges. Oysters do not appear to have returned to areas within the trench, although the area was recolonized with hard-shell clams. The shellfishermen also noted that anchor scar drag marks, some 800 to 900 feet long, persist several hundred feet outside of the primary impact area. These anchor scars likewise affect harvesting.

The identification of definitive data concerning the impacts of the Iroquois construction on shellfish resources is further complicated by the lack of pre- and post-construction shellfish productivity data for the affected leases.[178] Shellfishermen have indicated to the Task Force that such productivity data is not recorded. In the 12 years subsequent to the installation of the Iroquois pipeline, three new shellfish leases have been created directly

[175] Summary of Data concerning Shellfish Resources in Milford Harbor Before and After Construction of the Iroquois Natural Gas Pipeline. Prepared by Andrew W. Rehm, Ph.D., September 1992.

[176] Presentation by Mr. John Volk, then Director, Bureau of Aquaculture, Connecticut Department of Agriculture to Long Island Task Force Meeting of September 19, 2002. John Volk retired from the Department of Agriculture in May 2003.

[177] Presentation by Mr. Larry Williams and Mr. David Hopp (independent shellfish farmers). Task Force meeting of March 12, 2003.

[178] Presentation by Mr. David Warman, Vice President of Engineering – Iroquois, Long Island Sound Task Force meeting of September 12, 2002.

along the pipeline route (i.e., these leases were established over the pipeline route, in areas where no such leases existed previously). This indicates that at least some areas in the vicinity of the pipeline route remain economically viable for shellfish production.

The Bureau of Aquaculture records indicate that the three post-construction leases total 1,114 acres through which the pipeline runs approximately two miles, including a 0.5-mile break (non-leased area). The shellfishermen harvest hard shell clams from these lease areas.

2.5.4 Environmental Status of Telecommunications Cables[179]

AT&T

AT&T Communications installed a submarine fiber optic cable from Momauguin Beach, East Haven to Shoreham, Long Island, in accordance with a DEP permit issued in February 1993,[180] and an ACOE permit.

The DEP permit required that the cable be installed using HDD for 3,500 feet waterward of the high tide line, approximately 8 to 50 feet beneath the sediment surface, in order to avoid impacts to oyster beds. From the drilling exit point, the permit required that the cable be installed using the jet plow trenching process, to a depth approximately 10 feet below the sediment surface, except for an anchorage area where the burial depth was required to be 20 feet.[181]

Construction monitoring chiefly focused on potential releases of HDD drilling fluid, and appropriate containment measures for drilling fluids were required. The monitoring plan did not require AT&T to collect post-construction environmental data.

No further information on the environmental status of the AT&T cable was provided to the Task Force.

MCI

MCI Telecommunications Corporation installed a fiber optic telecommunications cable conduit from Madison to Rocky Point, Long Island, pursuant to permits issued by the DEP in December 1995[182] and ACOE. The DEP permit required MCI to install approximately 1,600 linear feet of the cable using HDD to a depth of 50 to 75 feet NGVD. Beyond the HDD exit hole, the permit required the cable to be installed to a depth of three to six feet beneath the sediment surface using a jet cable plow method.

[179] Siting Council does not have jurisdiction over telecommunication cables. See CGS Section 16-50i.
[180] Permit No. SD-LG-92-069 issued to AT&T Communications, February 18, 1993.
[181] Despite a request from the Task Force, AT&T and MCI did not provide additional information.
[182] Permit No. 199502243-DS issued to MCI Telecommunications Corporation, December 12, 1995.

The permit also imposed time-of-year restrictions, barring in-water construction between June 1 and September 30, to protect spawning shellfish in the area. However, the cable did not directly cross any shellfish concentration areas or leases, according to Department of Agriculture, Bureau of Aquaculture maps that were included in the permit.

MCI was also required to notify Connecticut licensed lobster fishermen who fish in the area of the jet plowing of the need to temporarily remove gear during construction.

Monitoring for accidental releases of HDD drilling fluid was required, and MCI was required to post a performance bond to secure the performance of the work in accordance with permit conditions.

No baseline or post-construction environmental monitoring was required under the permit, and no such information was available to the Task Force.

2.6 Status Update of Proposed Infrastructure Projects Within Long Island Sound

When PA No. 02-95 was enacted, at least eight new or replacement energy projects crossing Long Island Sound were announced and being actively pursued. In the last twelve months, however, project proponents have withdrawn, deferred, or not advanced all but four of these projects: Islander East, Cross-Sound Cable, the 1385 Line Cable Replacement Project, and the Eastchester Pipeline. Cross-Sound Cable was approved prior to PA No. 02-95 and was constructed, but is not yet operational.

The Assessment Report Part I summarized the projects crossing Long Island Sound that had been proposed or recently constructed as of January 1, 2003. This section provides a status update of the three remaining active projects, as well as a review of the projects which have either been cancelled, are inactive, or for which applications have not been filed.

2.6.1 Active Projects

CL&P/LIPA 1385 Line 138 kV Cable Replacement Project

The 1385 Line , which links the CL&P system with the LIPA system, has been in service for almost 35 years and is jointly owned by CL&P and LIPA. The Project calls for the replacement of the seven (six energized and one spare) existing fluid-filled paper insulated single-phase cables which lay on the bottom of Long Island Sound with three, three-phase solid dielectric cables. The new cables will be solid and will be buried within the existing cable corridor. In Connecticut, the permitting process is underway. The Siting Council issued a Certificate of Environmental Compatibility and Public Need to CL&P on September 9, 2002 and a permit application for a Structures, Dredging and Fill permit is pending before DEP. This cable replacement project is exempt from the moratorium provisions of PA No. 02-95.

LIPA is responsible for obtaining permits and approvals for the New York portion of the 1385 Line cable replacement project. LIPA remains committed to achieving a long-term solution for continued operation of the transmission interconnection between Connecticut and New York. LIPA has not yet completed its review of its potential options. At this time, LIPA and their Board of Trustees are still evaluating the long-term alternatives for this cable and have not agreed to move forward with the replacement project. CL&P remains firmly committed to the goal of completing the replacement project as expeditiously as possible.

In the interim, LIPA's Board has authorized and directed LIPA to work with CL&P to quickly address the most recent damage incident. CL&P and LIPA are in the process of repairing the existing 138 kV cables, four of which were damaged by survey vessel's anchor in November 2002, so that it will be back in-service and available to support reliability in Southwest CT this summer.

Cross-Sound Cable

The Cross-Sound cable, connecting New Haven and Shoreham, Long Island, was certificated by the Siting Council in January 2002, received required permits from DEP and ACOE, and installed the 330 MW HVDC cable in the spring of 2002. Seven areas of the cable did not achieve the required burial depth in New Haven harbor, and the project has not received authorization to operate. Cross Sound Cable has proposed to contract with a specialty construction firm, and if authorized, will remediate these areas.

Islander East

The Islander East pipeline project, sponsored jointly by Duke Energy and KeySpan Energy, would extend from the C-1 mainline of the Algonquin pipeline system in North Haven to Brookhaven, Long Island. The route would extend 10.2 miles through southern Connecticut and then 22.6 miles under Long Island Sound. Islander East's proposed initial capacity is 0.28 Bcf/d (285 MDth/d), but could be expandable to 0.43 Bcf/d (445 MDth/d). The Siting Council issued recommendations to the FERC on August 1, 2002.[183] The project received FERC approval on September 19, 2002. The DEP subsequently issued a determination of non-consistency with respect to the state's Coastal Zone Management Plan. Islander East appealed to the U.S. Secretary of Commerce. The appeal was stayed, upon agreement by both parties to pursue negotiations. These discussions, as well as Islander East's application to the DEP for a Section 401 Water Quality Certification and other state permits, are pending.

Eastchester Expansion

[183] Correspondence from Pamela B. Katz P.E., Chairman, to Anthony M. Fitzgerald, Esq. and the Service List for Siting Council Docket 221 dated May 29, 2003.

Iroquois' Eastchester Expansion is located in Long Island Sound, but fully within New York jurisdictional waters. It is designed to deliver up to 0.2 Bcf/d to New York City through the installation of two new compressor stations, upgrades to its three existing compressor stations, and the construction of a 30-mile lateral running from a point on the mainline at Northport, Long Island, westward across Long Island Sound, and into the Bronx where it ties into the New York Facility System. The project is under construction and is scheduled for commercial startup in 2003.

2.6.2 Inactive/Cancelled/Not Filed Projects

Connecticut Long Island Cable (CLIC)

Northeast Utilities (NU) filed an application to sell transmission rights on a proposed 300 MW HVDC merchant transmission cable to be built between Norwalk and Hempstead Harbor or Oyster Bay on Long Island. NU received the FERC approval for the CLIC project in March 2002. However, based on a weak market response during NU's open season solicitation, NU decided not to pursue this project, and withdrew its FERC application on November 25, 2002.

Eastern Long Island Extension (ELIE)

Iroquois proposed a 29-mile, 20-inch marine pipeline that would tap into its existing Milford to Northport, Long Island pipeline offshore near Milford, and deliver gas to the KEDLI Facility System in Brookhaven, Long Island. The FERC issued a favorable Preliminary Determination for the ELIE project in September 2002. This project was deemed by the FERC, in the Islander East final EIS, to have the fewest environmental impacts of the two projects.[184] Iroquois requested that the FERC defer further action on its application until January 2003, and made a similar request to the Siting Council. Subsequently, Iroquois withdrew its certificate application at the FERC on February 7, 2003 due to "the lack of continued customer support for this project."[185]

Connecticut-Long Island Lateral

In January 2001, Tennessee Gas Pipeline Company announced its intent to construct a 1.6 Bcf/d gas pipeline from Connecticut to Long Island. The lateral was intended to enable Tennessee to provide new transportation service from the company's mainline facilities in Massachusetts to markets in Connecticut and on Long Island, N.Y. Receipt and delivery points were not specified. Interested shippers responded to Tennessee's open season in February 2001. No project updates or press releases have been issued by the project proponent since spring 2001, and no applications have been filed at the FERC or state agencies.

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[184] Docket CP01-387, FERC Final Environmental Impact Statement (FE19), pp. 5-11.
[185] Status Report of the Iroquois Gas Transmission System, L.P., submitted to the FERC, February 7, 2003, Docket No. CP02-52-000.

NeptuneRTS Phase IV

The Neptune Regional Transmission System Project, sponsored by Atlantic Energy Partners, LLC, envisions a multi-phase project consisting of several thousand miles of HVDC cables that would connect generation in Maine, New Brunswick, and Nova Scotia with markets in Boston, New York City, Long Island, and Connecticut. The FERC approved NeptuneRTS's Phase I application for two 600 MW merchant transmission cables from Sayreville, New Jersey, to New York City and to Newbridge on the south shore of Long Island. The Phase I project received its completeness determination from the New York PSC in February 2002, and has an expected in-service date of 2004 to 2005. Phase II, from Nova Scotia to New York City, has not been filed with the New York PSC. No applications have been filed for Phase IV, a marine cable connecting Connecticut with Maine and Maritimes Canada; the status of this future project is uncertain.

2.7 Environmental and Ecological Impacts of Marine Infrastructure

PA No. 02-95 Section 3(D) requires the Task Force to evaluate the individual and cumulative environmental impacts of electric power line, gas pipeline, and telecommunication crossings of Long Island Sound, and the methods to minimize such impacts. This section provides a review of available background information regarding the short-term and long-term environmental impacts associated with each of the available marine construction methods, as well as the impacts associated with long-term operation of infrastructure crossings. The discussion also incorporates the measures available to avoid, minimize, or mitigate such impacts.

An overview of the construction methods and their general environmental impacts was presented in Part I. For convenience and completeness, relevant sections of that material are reproduced here. That discussion is augmented here with available information on current research in the scientific and regulatory communities on the ecological impacts of construction and operation of energy transmission and telecommunication cables in marine environments. Projects undertaken in the last two years, such as Cross-Sound Cable, the Hubline pipeline project in Boston Harbor and the Eastchester pipeline project in southwestern Long Island Sound have provided marine construction contractors with recent local field experience. The design of these projects represent the current "state of the art" with respect to marine energy infrastructure construction techniques and reflect a variety of methods for avoiding, minimizing, and/or mitigating adverse impacts to the marine environment. To the extent such information is available; it is incorporated in this section

2.7.1 Marine Construction Methods

Submarine pipeline, electric cable, and telecommunication cable projects utilize a variety of construction methods. It is not uncommon for pipeline and cable projects in marine environments to utilize different construction methods for different line segments. The selection of a particular method for use along specific segments is dependent on a number of factors, including biological communities and habitat resources, sediment characteristics, depth to bedrock, distance from shore, and water depth.

In general, there is similarity between the construction methods used for a submarine pipeline, and those used for an electric or telecommunications cable installation. However there are very significant differences as well. Even techniques that go by the same name, such as "jetting," operate on different principles for a pipeline installation than for an electric or telecommunications cable installation. There is also the difference in scale. The size of the equipment required to bury a 24-inch pipeline, such as the Eastchester Project, is necessarily larger than that required to bury an eight-inch cable.

Each construction method has an associated impact footprint on the substrate surface and can cause changes in water quality during construction. The impact zone for each construction method is summarized in Table 12, and includes the trench and the spoil areas. Seafloor impacts include the direct footprint of a trench and adjacent areas when sediments removed from the trench are sidecast, as well as far field areas where sediments released into the water column are redeposited. If excavated sediments are not removed, they may be subject to dispersion into far field areas by strong currents resulting from storm events. Seafloor impacts may also include the footprint of any anchors or spuds which are used to position and stabilize the installation barge.

All trenching methods, including dredging, plowing, and jetting, cause a direct impact to bottom sediments and fauna, and the extent to which this effect is magnified is a function of the physical dimensions of the trench being excavated, the placement or degree of sidecasting of spoils, and backfilling. To the extent that anchors and spuds are used in positioning the trenching and lay barges and the HDD support vessels, they also directly disturb bottom sediments and habitats. In addition, the sea floor may be disturbed by the cable sweep of the anchors in the span between the barge and the anchor points. The impact associated with the anchor cable sweep may be minimized through the use of mid-line buoys.

The recovery of the seafloor to pre-construction conditions depends on the construction method employed, the geophysical characteristics of the sediments disturbed, and the physical environment, as well as on whether the trench is backfilled. Restoration of ecological function depends on factors such as type of preexisting biological community, complexity of the habitat, source of biota for recruitment, and time of year of the impact.

Table 12 – Typical Widths for Pipeline and Cable Construction Activities (Marine)

Activity	Typical Construction Width (ft)[186]	
	Pipeline[187]	Cable
Plow Burial	75	50-75
Jet Burial	100 – 300	50-150
Dredging	150 – 200	N/A
Blasting (only occasionally required)	Varies	Varies
Offshore Lay Barge Anchoring*	2,000 – 4,000	
Shallow Lay Barge Anchoring*	200 (Spud) - 2,000	
HDD Support Mooring*: Jackup (Jackup Pads)	200 - 300	200-300
Spud Mooring	75-200	

*refers to anchor spread from vessel

Deep Water Pipeline Installation

Deep-water construction typically uses barges to first lay the pipeline on the bottom and then to bury and backfill the pipeline. A pipeline lay barge has on-board facilities to weld the pipe sections together and lower them to the sea floor. Once the pipeline is laid on the seafloor, the lay barge converts operations to burial. Using a jet or sub-sea plow, a trench is then excavated under the pipeline to bury the pipeline.

The deepwater barges are typically several hundred feet long, and positioned with eight to twelve anchors. The maximum extent of the mooring anchor array could be approximately 2,500 to 5,000 feet to the front and back of the installation barge, and up to 2,000 feet to either side. As the lay and bury barges advance, tugboats lift the anchors from the sea floor and reposition them at approximately 0.5 to 1-mile intervals in the direction of movement. The barges may be supported by a number of other craft such as pipe barges, dive support boat, and transport vessels.

186 The distances also reflect the impacts associated with the various construction methods, including most of the sediment load. The full extent of a sediment plume in the direction of the currents may exceed the indicated construction widths.

187 Reported by Duke Energy Gas Transmission and Iroquois in a joint presentation to the Task Force on November 13, 2002.

The anchor movements (i.e., anchor touchdown point, drag point, set point) required to position the construction vessels will create scars that will affect bottom habitat at varying distances from the immediate construction area. For example, for a pipeline lay vessel, anchors may be 8 feet wide by 10 feet long, with a 20-foot drag. A typical pipeline installation may result in three anchor sets per mile per pass.[188]

Plowing. Under this method, the bury barge pulls the sub-sea plow, which physically cuts a trench beneath the pipeline. Typically, the pipeline trench may be six to eight feet deep by 20 to 25 feet wide at the surface of the seabed. The spoil material is displaced on both sides of the trench. After the proposed pipeline is located to the desired depth, the sub-sea plow may undertake another pass to place the trench spoil back on top of the pipeline. The sub-sea plow is preferred to other in-water installation techniques, such as dredging or hydraulic jetting, in areas where immediate backfilling of the trench is required, or where low water turbidity is desirable.[189] Plowing is most feasible in soft sediments, and works less effectively in rock or sand.

Jetting. The jetting method of trenching uses high-pressure water or air jets to excavate the trench and lower the pipeline. Excavated materials are discharged away from the pipeline and the pipeline gradually settles into the trench created behind the jet sled. In suitable substrates, the depth of burial of three to six feet or more typically can be attained with one pass of the jet sled, depending on the characteristics of the underlying sediments. Greater trench depths typically require multiple jetting passes. Backfilling of the trench is generally accomplished by natural slumping of the trench walls due to tidal and ocean current forces, or by subsequent infilling by suspended sediments, particularly during storm events. If natural sedimentation processes do not fully backfill the trench, it may remain partially open. Some jetting equipment can be operated remotely from ships. This equipment may be self-positioning, eliminating the need for anchors or spuds.

The short-term impacts for pipeline installation include increased turbidity during construction. The potential long-term impacts include alteration of bottom habitat within the trench and adjacent area. Anchor cable sweep can also alter bottom conditions especially where multiple passes are required. Midline anchor buoys that suspend the anchor cable(s) above the seabed may serve to minimize these impacts.

Deepwater Trenching for Cable Installation

Deepwater trenching for a cable installation typically requires only one vessel, and does not require the eight to twelve anchors required by pipeline installation barges, nor their accompanying anchor tugs. Unlike pipelines, which are assembled and welded together on board the lay vessel, a cable may come as a continuous length mounted on large spools, which are loaded at the factory and delivered to the site by the cable laying ship. In the case of deepwater operations, the cable laying and the burial operation are done

[188] FERC Islander East Pipeline Project, DEIS, March 2002, pp 3-38 and 3-39.
[189] Siting Council Docket 221, Finding of Fact No. 82.

simultaneously (i.e. the majority of the cable is placed on the bottom, and buried with the jet or plow in the same pass), or sequentially (i.e. the majority of the cable is first placed on the bottom, and then buried with the jet or plow in a second pass).

Plowing. The sub-sea plow that is used for a cable installation is smaller, and operates on a different principle than the pipeline sub-sea plow. It does not cast material to the side as much as spread the sediment some ten inches apart so as to permit the cable to slip down in between its blades. As the sub-sea plow moves forward, the ground behind it resettles over the cable. The sub-sea plow is pulled forward either by an anchored bury barge, or more often the ship's propellers are sufficient for the purpose. The sub-sea plow can twist and damage the cable during installation. The sub-sea plows' potential for causing damage to the cable is one of the reasons jetting is often considered preferable.

Jetting. The jetting method of trenching uses high-pressure water or air jets to excavate the trench and bury the cable. Typically, the jet is not used for casting material aside, but rather it uses two side-by-side blades, which are inserted into the sediment on either side of the cable. These blades liquefy the sediment, and allow the cable, which is heavy, to settle down by gravity. A depth burial of three to six feet or more typically can be attained with one pass of the jet sled, depending on the characteristics of the sediment. Greater trench depths typically require multiple passes. Unlike the sub-sea plow, the jetting equipment is self-propelled and thus it does not depend on a tow line from its tender ship for its forward motion. Jetting equipment for cables, unlike other equipment mentioned above, is buoyed so as to be neutral in weight underwater, thus further reducing the footprint and effects to the seafloor.

Jet-plowing. A jet-plow is a hybrid between the sub-sea plow and the jet sled. The jet-plow is pulled by a surface ship, like the sub-sea plow, but it is equipped with hydraulic nozzles on its blades. The use of pressurized water significantly reduces the tension on the towline and also, by liquefying the soil, facilitates the burial of the cable.

The short-term effects of the deepwater trenching include turbidity during construction, and alterations of the sediments within the installation trench. In the case of the jet, the effective width of the trench depends on the characteristics of the sediment and the resultant angle of repose. The jet-plow could create a trench approximately nine feet deep, and six feet wide in fine-grained sediments or twelve and one-half feet wide in sand-grained sediments.[190] The majority of the hydrated sediment produced by the jetting equipment would remain in the trench, and settle immediately adjacent to the trench. A small percentage of the total volume of hydrated sediment becomes suspended in the water column, (sediment plume) and settles as a film of sediment generally in the direction(s) of the currents. The long-term signature of the trench, and the depth and extent of the sediment deposition from the plume, are among some of the issues being examined in connection with recent cable laying projects.

[190] Siting Council Docket 208, Finding of Fact No. 67

Shallow Water Installation

In both pipeline and cable installations, alternate construction techniques are required in shallow waters that are beyond the reach of the deepwater installation equipment.

Horizontal Directional Drilling. Horizontal directional drilling (HDD) is typically employed in near-shore environments to achieve minimal disturbance of the bottom materials that would normally occur with conventional open-cut technology and to allow installation under obstacles or sensitive areas. It can be used for both pipeline and cable installation. As it is a trenchless process, there is minimal direct disturbance of benthic communities as well as minimal indirect disturbance from resettling sediment. However, in determining the advisability of this technique, one must also consider whether there are suitable places for both the entry hole and the transition basin at the exit hole. As previously mentioned, that transition basin often requires supplementary underwater excavation. Hand-jetting might be sufficient, but if dredging is required, then the resulting potential for adversely affecting a nearby sensitive area (e.g., shellfish beds) is a consideration that is balanced against the benefits achieved via this trenchless process. The drilling process is completed in a series of steps, including pilot drilling, reaming, swabbing, and conduit installation. Electronic positioning systems guide each step. The drill rig is typically staged and operated from the landfall area, where the entry pit is established.

Bentonite, a non-toxic, non-native clay, used to make the drilling fluid, is delivered to the cutting head to provide hydraulic cutting action, lubricate the drill bit, stabilize the hole, and remove cutting spoils as the drilling fluid returns to the entry point of the pilot hole. Typically, drilling fluid returns are processed to remove the cuttings, and the bentonite is recycled for use as the drilling operation continues. Some bentonite will leak from the HDD exit point. Because the drilling fluid is denser than water, it tends to remain near the seafloor, and can be recaptured at the exit hole. However, if the drilling fluid, which is under pressure, encounters a weakness in the soil or bedrock, it may "frac-out" and cause an uncontrolled discharge to the seafloor at a location other than the exit hole.

The feasibility of the HDD technique for a specific location is a dependent upon the subsurface geologic conditions, pipe diameter or cable strength, and entry and exit conditions. Installations through profiles with diverse geologic strata are difficult and may require re-tooling the drilling and reaming heads to accommodate the varying formations. Gravel lenses, cobble, or boulders within the profile strata represent the most adverse geologic condition for HDD installations, and consequently, the HDD technique is typically not a feasible alternative in this type of strata. Current technology can achieve directionally drilled installations of approximately 4,000 to 6,000 feet, under favorable conditions; however, the length of the installation may be limited by the physical characteristics of the cable or pipeline. Electric cables will not normally withstand such long cable pulls without some risk of damage.

Dredging (as sometimes used for pipeline installations). Dredging is used primarily for trenching along the shallow water portions of a pipeline route. Barges equipped with a crane and a bucket are used to excavate a trench to the appropriate depth. Barges may also support a hydraulic excavator. Depending on quality of the sediments and nature of the bottom environment, excavated material may be lifted to the surface and placed on a barge for transport to a disposal site, or side-cast adjacent to the trench. Barges are typically positioned by three spuds, large columns that are sunk into the bottom to anchor the barge. Once the pipeline has been installed and tested, the trench is backfilled. Dredging may also be used when directional drilling from an onshore location to offshore requires the construction of a transition basin, which must be made between the directionally drill exit hole and the pipeline or cable trench.

Short-term impacts may include an increase in water turbidity resulting from the loss of sediments from the bucket and release of contaminants. Longer-term impacts may include erosion of spoil mounds by wave action from storm events, if sediment is sidecast. Minimizing and mitigating these impacts calls for completing dredging, pipe lay and backfill of contaminated sediments in as short a time period as possible. The use of silt curtains, which are designed to restrict suspended sediments to a controlled area of the construction site, may be limited in certain areas (i.e., locations with less than 1-2 knot currents). Environmental dredge buckets, which minimize the loss of sediments from the dredge bucket, may also be employed for contaminated sediments. Monitoring of water quality is generally required during operations. Long-term impacts include alteration of bottom habitat within the trench footprint and sidecast footprint.

Dredging (as sometimes used for cable installations). For cable installations, this method need only be used in specialized instances where other techniques are impractical. For example, if there is a lens of material along the cable path that prevents installation to the required depth by jetting or plowing, the preferred solution is to circumvent the obstacle through a deviation in the route, or to simply leave the cable closer to the surface and protect it in other ways. However, if neither of these choices is allowed, then dredging is likely the only remaining option.

Jetting (the preferred technique for cable installations). For cable installations in shallow waters, jetting is the preferred technique, even for areas beyond the reach of a cable-laying ship. In this instance the jetting equipment is smaller, and may be diver assisted. The effects of operating a jetting burial tool in shallow water are no different from those in deep water, except that the column of water in which any escaping sediment disperses is much shallower.

Plowing (an alternate technique for cable installations). Plowing can also be used for cable installations, since both the dimensions of the sub-sea plow and the force required to pull it are moderate. The disadvantage of the sub-sea plow is that it is not self-propelled, and requires the barge from which is it operated to be solidly fixed at each pulling location with spuds or anchors.

Shoreline Trenching. Shoreline trenching refers to the use of conventional excavating equipment to install the cable or pipeline. Also called "conventional open-cut technology," it is an extension of the technique used in undergounding the inland portion of the cable or pipeline. In general, for both pipelines and cables, if this technique is utilized at all, it is only for the purpose of reaching the point where one of the previous techniques can be used. For electric cables, jetting equipment is available that reaches up to the high tide line, provided that the tender with the pumps can get close to shore. In such a case, shoreline trenching can be minimized. However, shorelines that are exposed to substantial wave action can be very resistant or coarse-grained, making jetting or plowing not feasible. In such cases a conventional trench is extended from the upland past the shoreline until the point where the sediment is sufficiently fine-grained to enable the jet or sub-sea plow to operate.

Hand Jetting. A diver-operated hand jet may be used to bury the cable or pipeline. Hand jetting is typically used for distances of less than several hundred feet, including where HDD-installed pipeline is connected to conventionally installed line, at tie-in pipeline welds, and at lateral side taps. For hand jetting, a support vessel provides pressurized water through a hose and nozzle maneuvered by a diver. The diver works the sediment from under the cable or pipe to create a trench into which the cable or pipe settles. Hand jetting is also commonly used by divers to locate damaged sections of cables or the ends of severed cables.

Surface Lay

For certain applications, the pipeline or cable is laid on the sea floor and covered with an armoring of stone rip-rap or concrete mats. This method may be employed where a line must cross bedrock, other cables or pipelines, or contaminated sediment where disturbance is undesirable. Typically this method is only utilized for short distances.

Armoring

Armoring is also required for short distances where the cable or pipeline, while not at the surface, cannot be buried sufficiently to protect it against external forces, such as wave action or damage from ships. Placement of armoring materials alters the benthic habitat along the construction footprint unless conditions happen to be roughly similar, such as they would be at a rocky seashore. In the right environment, these can be configured to serve as shelter, and a point of attachment for species requiring hard surfaces. In the wrong environment, however these structures may form a physical barrier to demersal or epibenthic organisms, or simply cause an unwarranted change to the litoral quality of the seashore.

Blasting

Underwater blasting may be required where the trench encounters resistant bedrock, where maintaining a predetermined depth is required, and/or where alternate techniques, such as armoring the cable or pipeline, are not practical or are not authorized by permits. Noise and pressure waves can cause short-term impacts on marine species including marine mammals, turtles, and fish.

2.7.2 Construction Impacts on Marine Resources

Construction impacts can be grouped into five basic categories:

Direct habitat disturbance related to excavation (plowing and jetting), dredging (soft and hard substrate), and blasting (some hard substrate);

Direct impact to marine species;

Sediment resuspension (water quality impacts) and deposition (benthic impacts) resulting from trench excavation, blasting, and to a lesser extent HDD exit points or "frac-outs"(release of bentonite drilling fluid);

Substrate disruption related to anchor cable sweep; and

Permanent habitat alteration related to placement of armoring materials.

The timing of construction affects the type and level of impacts that will occur. Avoiding construction during the sensitive life stages of marine species will minimize potential impacts. These impacts can vary depending on the species.

Water Quality Impacts

Water quality is directly affected by the displacement and disturbance of bottom sediments and the resultant release of sediments into the water column. This causes increased turbidity, which can affect habitat and marine species. Increased turbidity associated with construction activities is a function of the construction method employed, the amount of material that is displaced, and the sediment characteristics . The suspension of sediments into the water column can temporarily affect water quality through the reduction of dissolved oxygen and depth of light penetration. Contaminants, if present in the sediments, also may potentially be released. The suspended sediment drifts with the water currents and eventually settles on the bottom. The sediment plume's duration and extent of migration depend on many site-specific variables, including the amount of sediment in suspension, the size of sediment particles, water depth and temperature, current velocity and tidal stage, and wind direction and speed. Coarse sediments generally settle quickly, whereas finer sediments remain suspended in a plume for longer periods of time.

Water quality impacts associated with construction are generally short term in duration. Dredging, plowing, and jetting all have varying capabilities of releasing sediments into the water column so that the primary impact is increased turbidity. The duration of the impact depends on local hydrodynamics, grain-size composition of the sediment, and duration of the construction activity. Generally, a turbidity plume generated by bottom disturbance will dissipate within hours of cessation of the activity that caused it. Release of anoxic organic sediments into the water column can also remove dissolved oxygen from the water column in the immediate vicinity of the disturbance. Organic sediments are more commonly found in deep areas in the western portions of Long Island Sound and in some of the dredged material disposal areas (Appendix C, Figure C-19). The biological significance of this effect depends on the time of year. It is more likely to pose a potential problem in the summer, when dissolved oxygen levels are naturally suppressed.

There is also concern that contaminants can be released from sediments in the water column. Several monitoring programs[191,192] have shown that metals and organic pollutants such as PCBs are rarely dissociated from sediment particles and released into the dissolved form when sediments are disturbed. However, any contaminants that are bound to sediment particles will be transported with the particles.

The federal and state agencies that regulate construction activities in Long Island Sound generally require pre-construction sediment testing and analyses to assure that contaminated sediment areas are avoided. If avoidance is not possible, special mitigation techniques are typically mandated. Another short-term impact includes water quality impairment from the release of HDD drilling fluids, "frac-outs", and the disposal of spent drilling fluids and cuttings. The release of HDD drilling fluids has the potential to impact water quality and marine life through localized increases in turbidity and sedimentation. This very fine-grained material can suffocate benthic organisms and alter the seafloor habitat. The DEP currently requires all permit-holders in Long Island Sound who utilize HDD to post an environmental performance bond to guarantee cleanup, in the event of an uncontrolled release of bentonite fluid. In addition, applicants are required to prepare and implement a detailed monitoring plan to minimize the possibility of a release.

2.7.3 Impacts on Benthic Communities and Fish

Benthic communities and fisheries resources may potentially be impacted by direct disturbance of bottom sediments from trenching, barge anchoring and cable sweep, and by acoustic shock from bedrock blasting, if such construction methods are used. Indirectly, these organisms may be impacted by the associated turbidity and sediment deposition, and by subsequent erosion of the trench spoil mounds. Potential direct

[191] ACOE (New England Division) and Massachusetts Port Authority. 1995. Final EIR/EIS Boston Harbor Navigation Improvement Dredging and Berth Dredging Project.

[192] Pembroke, A.E. and J. Bajek. 2000. Disposal of Boston Harbor Sediments using In-Harbor CADS: Minimal Water Quality Effects. Presented at Sea Grant Conference on Dredge Material Management: Options and Environmental Considerations. Dec. 2000, Boston, MA.

significant adverse impacts in the construction area include mortality by dislodgement or burial, and disturbance and/or destruction of commercial shellfish resources. Potential indirect, significant, adverse impacts include mortality by suffocation beneath silt, interruption of spawning and migration, habitat loss or alteration, and introduction of water pollutants. Once again, the degree to which these effects may occur has to be investigated and evaluated based on site specific and project-specific conditions.

A primary concern relates to shellfish beds and fisheries resources and habitats in the nearshore and shallow marine environment (less than 30 feet). The effects of construction on such areas depends on the project and the specific installation techniques used. Recovery of the bottom habitat and shellfish resources depends on a number of factors, including depth of the scar or disturbance, the local sediment transport regime, the original nature of the benthic environment, and methods used to restore the substrate, such as placement of cultch or sandy top dressing. These factors are likely to be variable along a project route. For example, if anchor scars do not refill by natural sedimentation or are not actively backfilled, they might persist as depressions, accumulate fine-grained materials and organics, and develop different benthic communities. This would represent a long-term conversion of shellfish habitat.

Long Island Sound has been the subject of extensive research on successional stages in benthic communities. The number and type of organisms change based on the degree of environmental disturbance or stress.[193] One viewpoint relies on principles of landscape ecology to explain small, medium, and large-scale spatial and temporal variations in benthic community structure.[194] Another viewpoint focuses on the role of disturbance in creating successional stages in benthic communities. The number and type of organisms change based on the degree of environmental disturbance or stress. Communities typically progress from a Stage I, or early successional stage, typified by an abundance surface dwelling, resilient or opportunistic species, which have high reproductive rates and minimal or weak predation and competition defenses, are rapidly established following a disturbance. The Stage I community transitions to a Stage II community, which includes species such as the clams *Tellina agilis* and *Nucula annulata*. The final stage, Stage III, is a mature community typified by large, deep dwelling, subsurface deposit feeding species that include polychaete worms *Nephtys incisa* and razor clam *Ensis directus*. Stage III species burrow more deeply into the sediment. These species are longer-lived and their position deeper in the sediment provides greater protection against predation. These more mature communities are characteristic of fairly stable physical conditions. The successional stage of the community becomes important when estimating the level and time frame for recovery from potential impacts.[195] While useful to explain invertebrate communities in the Central Sound, this explanation may oversimplify Sound-wide invertebrate communities.[196]

[193] Rhoads, D.C., P.L. McCall, and J.Y. Yingst. 1978. Disturbance and production on the estuarine seafloor. *Am. Sci. 66*: 577-586.
[194] Zajac *et al.* 2000.
[195] Rhoads, D.C., P.L. McCall, and J.Y. Yingst. 1978. Disturbance and production on the estuarine seafloor. *Am. Sci. 66*: 577-586.
[196] Zajac *et al.*, 2000.

Disturbance and Recovery of Fine-grained Substrates

Potential benthic impacts in fine-grained sediments (clays, silts, and fine sands) include habitat burial, sediment resuspension and deposition, and substrate disruption. Construction using HDD may disturb habitat around the exit or entrance holes through dredging for the tie-in to other construction methods and through potential release of drilling fluids to the substrate.

Dredging, plowing, and jetting may disturb communities in the immediate trench footprint as well as the adjacent areas where sediments are sidecast. Benthic invertebrates in the areas of this direct impact footprint will likely be killed. Larger, more mobile invertebrates and fish may be able to avoid the disturbance. Loss of the benthic community also results in the loss value for predators.

Pioneering species of benthic invertebrates may start recolonizing disturbed sediments within a period of days to weeks, depending on when the disturbance occurs. Rhoads *et al.* found that organisms colonized azoic sediment trays in Long Island Sound within 10-29 days.[197] Murray and Saffert found that dredged material disposed at the Western Long Island Sound disposal site was initially recolonized in one to two weeks.[198] In areas where the pre-construction benthic community is typified by pioneering species, full recovery could occur within a month or less. Northeast Utilities Service Company (NUSCo) found that the sedimentary character and benthic infaunal communities recovered in five to six years after the Millstone Unit 3 intake structure was constructed and began withdrawing cooling water from Long Island Sound.[199] Other fine-grained habitats may support intermediate (Stage II) to climax (Stage III) communities and recovery would take longer, on the order of several months to several years (Table 13).

[197] Rhoads, D.C., P.L. McCall, and J.Y. Yingst. 1978. Disturbance and Production on the Estuarine Sea Floor.

[198] Murray, P.M. and H.L. Saffert. 1999. Monitoring Cruises at the Western Long Island Sound Disposal Site. DAMOS contribution No. 125. U.S. Army Corps of Engineers New England Branch. Waltham MA. 80 pp.

[199] NUSCo. 1992. Monitoring and Marine Environment of Long Island Sound at the Millstone Nuclear Power Station, Annual Report, (1991), Benthic Infauna, pp. 185 –222.

Table 13 – Results of Soft Substrate Recolonization Studies Including Location, Stressor, and Time to a Stage III Recovery

Study	Location	Stressor	Time to Recovery
Germano *et al.* 1994[200]	Coastal New England	Dredged material Disposal	6 months–1 year
Rosenberg 1971[201]	Sweden	Paper mill (sulfite)	3 years
Rosenberg 1976[202]	Sweden	Enrichment	5 years
Murray and Saffert 1999[203]	Western Long Island Sound	Dredged material disposal	1–4 months
MWRA[204]	Massachusetts Bay	Storms	1–2 years
Rhoads *et al.* 1978	Long Island Sound	Dredged material	1–2 years
Rhoads *et al.* 1978	Long Island Sound	Azoic sediment	6–8 months
NUSCo, 1992[205]	Eastern Long Island Sound	Dredging for power plant intake	5-6 years

Recovery of the fish and shellfish functions is in part dependent on the recovery of the benthic infauna, which help create the appropriate food resources and habitat for larger organisms. Mobile fish and larger invertebrates (e.g., lobster) may be able to avoid construction activities and return as part of the habitat recolonization. Other species that rely on substrate-specific characteristics (e.g., demersally spawning fish such as winter flounder) can begin using the habitat as it returns to its previous condition.

Dredging and jetting resuspend sediment and cause substrate disruption. As a result, these activities cause temporary, localized reductions in water clarity and sedimentation as suspended particles are released from the water column. Results from dredging studies indicate that recolonization to a Stage III community occurred in as little as one to four months to as much as one to two years. Disposal of dredged material has been found to

[200] Germano, J.D., D.C. Rhoads, and J.D. Lunz. 1994 An integrated, tiered approach to monitoring and management of dredged material sites in the New England region. DAMOS contribution no. 87. SAIC Report No. 90/75/234. U.S. Army Corps of Engineers, New England Division. Waltham, MA.

[201] Rosenberg, R. 1971. Recovery of the littoral fauna in Saltkallefjorden subsequent to discontinued operation of a sulphite pulp mill. Thalassia jugol. 7: 341-351.

[202] Rosenberg, R. 1976. Benthic faunal dynamics during succession following pollution abatement in a Swedish estuary. Oikos 27: 414-427.

[203] Murray, P.M. and H.L. Saffert. 1999. *op cit.*

[204] Kropp, R.K., Diaz, R., Hecker, B, Dahlen,D., Boyle, J.D. Hunt.C.D. 2000. 1999 Outfall Benthic Monitoring Report. Boston: Massachusetts Water Resources Authority. Report ENQUAD 2000-15. p. 230.

[205] NUSCo. 1992. Monitoring and Marine Environment of Long Island Sound at the Millstone Nuclear Power Station, Annual Report, (1991), Benthic Infauna, pp. 185 –222.

stimulate productivity, resulting in development of an advanced benthic community in as little as six to twelve months.[206] Studies along the New England coast suggest that dredged material disposal actually improves juvenile lobster habitat by increasing burrowing activity.[207]

Cable sweep is likely to disturb the surface of fine-grained substrates with some loss of organisms and disturbance of spawning habitat (depending on the time of year), but recovery is typically less than for trenching activities because of the shallower depth of the disturbance.

Disturbance and Recovery of Sandy Substrates

Potential impacts to sandy substrates are the same as for fine-grained substrates: habitat burial, sediment resuspension and deposition, and substrate disruption. Sandy sediments may support a more advanced benthic community than silty sediments, however, and would require a longer period for recovery from impacts. Suspended sandy sediments would be deposited more quickly than in fine-grained areas which are beneficial to water quality, although it increases the thickness of the depositional layer near the construction. Recovery could take from six months to several years (Table 13).

Disturbance and Recovery of Gravel and Cobble Habitat

Potential impacts in gravel and cobble sediments include habitat conversion from nearby sediment suspension activities (jetting), direct habitat disruption from plowing and armoring, and substrate disruption from cable sweep and anchoring. Recovery after habitat disruption would entail recolonization following substrate stabilization, with the assumption that there would be little survival of original fauna.

Disturbance and Recovery of Bedrock Habitat

Potential impacts in bedrock habitat include habitat conversion (siltation from nearby construction activities), direct habitat disruption from blasting, and substrate disruption from cable sweep and anchoring. Habitat conversions caused by sedimentation onto bedrock may result in a change to different functions and values. However, recovery to the original habitat is dependent on the depth of sediments and water depth, which will determine the likelihood that winter storms will disperse newly deposited materials. Recovery of kelp beds following overgrazing and subsequent population decimation of sea urchins provide an approximation of recovery of unpopulated hard substrate habitat. In Nova Scotia, recovery of kelp beds took as little as four to five months to as long as 18 months.[208] Surface fouling panels also provide an indication of recovery time. Fouling panel studies off coastal New Hampshire using Plexiglas panels set out in January reached peak biomass and percent frequency by July (six months), with a community that included most typical fouling

[206] Germano, J.D., D.C. Rhoads, and J.D. Lunz. 1994 An integrated, tiered approach to monitoring and management of dredged material sites in the New England region. DAMOS contribution no. 87. SAIC Report No. 90/75/234. U.S. Army Corps of Engineers, New England Division. Waltham, Massachusetts.

[207] *Ibid.*

[208] Johnson, C.R. and K.H. Mann. 1988. Diversity, patterns of adaptation, and stability of Nova Scotian kelp beds. *Ecol. Monogr.* 58:129-154.

species.[209] Surveys in shallow sublittoral rocky substrates after ice scour in eastern Newfoundland indicate that biomass returns to original levels in two months, with kelp recovery taking less than a year.[210] Artificial reef studies also provide an indication of recovery time. Concrete modules deployed in Delaware Bay had a well-developed epifaunal and fish community in one to two years.[211] An artificial reef in the New York Bight constructed from both concrete and coal ash contained fully developed communities by the end of the first year following deployment, although biological interactions led to continued successional changes during the following year.[212] In Puget Sound, invertebrate settlement on concrete blocks increased rapidly for a period of six months, and had stabilized after a 10-month period. Fish recruitment was complete after seven to nine months.[213]

Lobster

Potential impacts on lobster include barriers to movements and alteration of habitat especially for early benthic phase lobsters.

Lobster movements can be classified into small-term movements, generally on a daily basis, and larger-scale movements occurring on a seasonal basis. Small-scale movements of lobsters greater than 45 mm in carapace length (CL) are generally less than 300 m.[214] The extent of these movements is inversely related to water temperature where activity decreases with lower water temperatures.[215] Lobsters in Long Island Sound are not thought to undergo large-scale migrations.[216]

Sources of mortality may include direct contact with construction equipment, the open trench as a barrier to migration increasing exposure to predators, burying of lobsters in the trench during backfilling, and loss of early benthic phase (EBP) habitat. Lobsters that directly encounter ongoing trenching and side casting construction activity are likely to be killed. Impacts can be minimized by restricting activity to cold water temperature periods when movement of lobsters is at the annual low, and the probability of encounter between

[209] Normandeau Associates. 1996. Seabrook Station 1995 Environmental Studies in the Hampton Seabrook Area. A characterization of environmental conditions during the operation of Seabrook Station. Prepared for the North Atlantic Energy Service Corp.

[210] Keats et al. 1985. (Cited in Mathieson, A.C., C.A. Penniman, and L.G. Harris. 1991. Northwest Atlantic rocky shore ecology. *in* A.C. Mathieson and P.H. Nienhuis, eds., Intertidal and Littoral Ecosystems, Ecosystems of the World, Vol. 24. Elsevier, Amsterdam, pp. 109-191.)

[211] Foster, K.L., F.W. Steimle, W. Muir, R.K. Kropp, and B.B. Conlin. 1994. Mitigation potential of habitat replacement: concrete artificial reef in Delaware Bay – preliminary results. *Bull. Mar. Sci.* 55:783-795.

[212] Woodhead, P.M.J. and M.E. Jacobson. 1985. Epifaunal settlement, the processes of community development and succession over two years on an artificial reef in the New York Bight. *Bull. Mar. Sci.* 37.

[213] Buckley, R.M. and G.J. Hueckel. 1985. Biological processes and ecological development on an artificial reef in Puget Sound, Washington. Bull. Mar. Sci. 37: 50-69.

[214] Cooper, R.A. and J.R. Uzmann. 1980. Ecology of Juvenile and Adult *Homarus*. Pages 97-142 *in* J.S. Cobb and B.F. Phillips, eds., *The Biology and Management of Lobsters, Vol. II.* New York: Academic Press.

[215] Ennis, G.P. 1984. Territorial behavior of the American lobster *Homarus americanus*. Trans. Amer. Fish. Soc. 113(3): 330-335.

[216] Briggs, P.T. and F.M. Mushacke. 1979. The American lobster in western Long Island Sound. *New York Fish and Game Journal* 26:56-86.

lobsters and construction is reduced. Regardless of the time of year, any lobsters residing in the path of the utility crossing will suffer mortality due to trenching activities, but the probability of "new" lobsters entering the area of construction activity is minimized when temperatures are lower.

Both the temporarily open trench for the pipeline and the pre-lowered pipe laid on the seafloor have the potential to form a barrier to lobster movements. The extent to which the trench forms a barrier is dependent on the slope of the sides of the trench and the probability of a lobster encountering the trench. To determine the impact of the side slopes of the proposed trenches, the slopes need to be compared to known natural lobster habitat to assess the potential to interfere with movements. The probability of a lobster encountering the trench will be dependent on the period of time the trench is exposed, the time of year of construction, and any behavioral attraction an open trench may exert on lobsters.

Depending on the underlying geology, sideslopes of a dredged trench are likely to be about 1:3 (vertical to horizontal). Lobsters are able to negotiate a 1:3 slope (about 20°).[217] However, the placement of a pipe in the bottom of the trench may form a partial barrier for lobsters attempting to cross over the trench, especially when water temperatures are low and lobsters are less active.

A plowed trench will initially have side slopes of approximately 4:5, or about 40°, but slumping will occur shortly after the plow passes, which will also assist in covering the pipe. As with the dredged area, this slope should not form a major barrier to lobster movements. Lobster habitat includes areas that have been extensively excavated with slopes from 5° to 70°. As with conventional dredging, the pipe at the bottom of the trench may form a barrier, particularly in sediments where there is minimal slumping.

Where jetting or a combination of plowing and jetting is proposed, generally the slopes of the trench would be approximately 2:1, or about 65°, but slumping occurs shortly after the equipment passes. Although lobsters can use areas with slopes as great as 70° as habitat for burrows,[214] it is likely that the slopes of the open jetted or plowed trench will be a partial barrier to movement. The length of time that the trench would be expected to remain open would be project-specific, depending on the water depth, substrate, frequency of disturbance, etc.

Any lobsters that construct burrows in the sides of the installation trench will likely be killed when the trench is backfilled as part of the installation. However, this impact can be reduced if construction is restricted to periods when low water temperature limits lobster activity.

The existing 1385 Line, which consists of seven cables, was placed on the sea floor and has remained for almost 35 years. No divers, that have descended to repair or inspect the cables, have reported observing lobsters in distress. These field observations suggest that electric cables on the seafloor do not pose a significant obstacle to lobster movement.

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[217] Cooper, R.A. and J.R. Uzmann. 1980. Ecology of Juvenile and adult *Homarus*. In: Cobb, J.S. , Phillips, B.F. (ed.) The Biology and Management of Lobsters, Volume II. Academic Press, Inc. New York, p. 97-142..

Construction Impacts on Early Benthic Phase Lobsters. EBP lobsters appear to prefer complex habitat that provides shelter. Incze and Wahle defined EBP lobsters as having a carapace length (CL) of 5-40 mm.[218] These lobsters are highly shelter dependent, gradually ranging out from their refuge as they reach 35-40 mm CL.[219] The preferred habitat for newly settled lobsters is cobble beds.[220] This shelter dependent phase lasts for about two years until they reach about 45 mm CL when they may begin nocturnal foraging away from their shelters.[214] Juvenile and adult lobsters also prefer shelter. Habitat consisting of a sand, gravel, or bedrock base with a rock overlay is a common inshore lobster habitat.[214]

Hard bottom substrate consisting of coarse glacial till (CGT: gravel, cobbles and boulders with sand) is important habitat for EBP and young lobsters. Habitat alteration or loss can be minimized by backfilling a plowed trench with the native gravel and cobble. In locations where plowing and jetting are to be used, it is possible that the gravel and cobble will be too widely dispersed for the backfill plow to replace all the material.

Attraction of Lobsters to Disturbed Sediments. Benthic organisms and lobsters may potentially be attracted to the disturbed sediments resulting from construction activities. Presumably, the disturbed sediments provide increased feeding opportunities for epibenthic organisms. The effects of a large-scale trenching operation on lobster movements and catch rates was assessed in Boston Harbor as part of the construction of the Third Harbor Tunnel, where a 40-foot trench was excavated through Boston Harbor. The east end of the trench area consisted primarily of soft sediments and was excavated by conventional dredging. Constructing the south end of the trench area required blasting through bedrock. A lobster monitoring program was implemented to determine the relative abundance and condition of lobsters adjacent to and ongoing blasting and dredging activities.[221] Data from the program indicated that there was a noticeable decline in the catch of lobsters in Boston Harbor during the two-month study at all stations. However, the decline was attributed to the occurrence of the annual molting period during construction activities.[222] The study did not indicate any attraction of lobsters to the trench, as there was no increase in catch per unit effort at stations near the trench during the construction activities.

Any significant trenching activity will disturb surface sediments where infaunal organisms live and expose azoic sediments that were previously below the water sediment interface. The

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[218] Incze, L.S., and R.A. Wahle. 1991. Recruitment from pelagic to early benthic phase in lobsters *Homarus americanus*. Marine Ecology Progress Series 79:76-89.

[219] Mackenzie, C. and J.R. Moring. 1985. Species profiles: Life histories and environmental requirements of coastal fishes and invertebrates (North Atlantic) – American Lobster. U.S. Fish and Wildlife Service Biological Report 82(11.56). U.S. Army Corps of Engineers, TR WL-82-4. p. 21.

[220] Palma, A.T., R.A. Wahle, and R.S. Steneck. 1998. Different early post-settlement strategies between American lobsters *Homarus americanus* and rock crabs *Cancer irroratus* in the Gulf of Maine. *Mar. Ecol. Progr. Ser.* 162:215-225.

[221] Noyes, C.L., S. Truchon, C. Meininger, and M. Best. 1993. Central Artery/Tunnel Project: A survey of lobsters in Boston Harbor during harbor dredging and blasting operations. Abstract of paper presented at the Eighth Annual Boston Harbor/Massachusetts Bay Symposium. Presented by the Massachusetts Bay Marine Studies Consortium. J.F. Kennedy Library, March 31 and April 1, 1993.

[222] Cortell (Jason M. Cortell and Associates). 1992. Boston Harbor Lobster Monitoring Program. Prepared for the Massachusetts Highway Department by Jason M. Cortell and Associates Inc. in association with ENST Consulting and Engineering under subcontract to Bechtel/Parsons Brinckerhoff.

volume of azoic sediments will be much larger than the surface sediments that contain infaunal organisms. Plowing and jetting would result either in overturning of surface sediments and covering them with the deeper azoic sediments (plowing), or in a wider dispersal of both surface and deeper azoic sediments (plowing and jetting). In either case, infaunal prey organisms will likely be smothered, resulting in a reduction in the food source for scavenging epibenthic megafauna such as lobsters and crabs. There is a possibility that scavenging epibenthic megafauna may be attracted to feeding on dead and injured infauna if present at the surface of the spoil mounds on either side of the trench, but the low water temperatures during trenching activities can minimize this activity.

2.7.4 Finfish Impact Assessment

Finfish have the potential to be affected by construction through direct contact with construction equipment, obstruction of migrations, blasting, and degradation of habitat. Fish are obviously mobile organisms that will to a great extent avoid construction activities. In addition, permit and/or certificate conditions typically prohibit or limit in-water construction activities during sensitive periods in the lifecycle of finfish.

Fish that move between fresh and salt water habitats to spawn and complete their life cycle (i.e.., anadromous and catadromous species) are most susceptible to disruption of migratory routes. Degradation of habitat can occur due to siltation from trenching activities, increased suspended solids affecting water quality, and from modification of the habitat following backfilling. Demersal fish that live on the bottom are most susceptible to habitat degradation. Release of pollutants from contaminated sediment is another possible source of habitat degradation.

Species Characterization and Impact Assessment

Marine fishes found in Long Island Sound include pelagic and demersal fishes. Pelagic fishes are found primarily in the water column. They are highly mobile and are able to use behavioral mechanisms to avoid areas of high turbidity. Environmental impacts due to turbidity exposure are likely to be limited to physiological effects such as increased respiration and coughing.[223]

Migratory Species

Adult anadromous fish migrate into freshwater to spawn, and the eggs and larvae develop in freshwater. Typically, YOY fish will migrate downstream and enter marine waters. When anadromous fish are sexually mature, they return to freshwater to spawn.

Alewife and blueback herring have similar life histories; the adults begin to ascend rivers in March for spawning. Eggs and larvae develop in freshwater throughout the spring and

[223] Newcombe, C.P. and J.O.T. Jensen. 1996. Channel suspended sediment and fisheries: A synthesis for quantitative assessment of risk and impact. *North American Jour. of Fish. Manage.* 16(4):693-727.

summer. By late summer through fall, YOY alewife and blueback herring descend the rivers and enter the ocean.

Rainbow smelt enter rivers and streams to spawn in March through May, with peak spawning occurring on the spring tides.[224] Adults return to nearshore coastal waters soon after spawning. The eggs develop throughout the spring and summer, and by fall YOY move into higher salinity waters.

The American eel is a catadromous fish (spawns in salt water and develops in freshwater) that occurs Long Island Sound. American eels spawn in the Sargasso Sea in February through April, and larvae develop as they are transported up the East Coast.[225] American eels reach the glass eel and elver stages by the time they reach Long Island Sound in the late winter and early spring, about one year after hatching. Upstream migration occurs in the spring, primarily between April and June. After spending several years in freshwater, eels may begin a spawning migration to the ocean in late summer and fall. Due to the complex life cycle of American eels, and long residence time in freshwater, they may be found in Long Island Sound year-round.

Nearshore construction has the greatest potential to disrupt anadromous fish migration when these activities take place in relatively narrow waters. Upstream migration tends to be concentrated temporally and, therefore, has the greatest potential for being affected. Downstream migration of YOY alewife, blueback herring, and rainbow smelt, and mature eels involve more of a diffuse movement that occurs throughout the summer and fall, than the upstream migration in the spring. Most of the downstream migration may be complete by October, and the remaining fish would be able to move around trenching activities. YOY Rainbow smelt may remain in the more saline portions of the estuary and may not leave the river at all.[224]

Pelagic Species

Fish eggs and larvae are susceptible to increased turbidity and siltation resulting from dredging, especially if the eggs are demersal. Most larvae are poor swimmers and it is not expected that they could avoid any areas of high turbidity. It is likely that elevated turbidity would occur temporarily and only in a small area around active construction.

The primary impact is likely to be a temporary increase in suspended sediments in the water column. Newcombe and Jensen rated the impacts of suspended sediments on fishes on a scale that included no effects, behavioral effects, sublethal effects, and lethal and paralethal effects depending on the concentration of suspended sediments and the duration of exposure.[223] Usually, the severity of the impacts increased with increasing concentrations of suspended sediments and duration of exposure. At low concentrations

[224] Buckley, J.L. 1989. Species profiles: life histories and environmental requirements of coastal fishes and invertebrates (North Atlantic) – Rainbow smelt. U.S. Fish and Wildlife Service Biological Report 82(11.106). U.S. Army Corps of Engineers, TR EL-82-4. 11pp.

[225] Facey, D.E. and M.J. Van Den Avyle. 1987. Species profiles: Life histories and environmental requirements of coastal fishes and invertebrates (North Atlantic) – American eel. U.S. Fish and Wildlife Service Biological Report 82(11.74). U.S. Army Corps of Engineers, TR WL-82-4. 28 pp.

and exposure times, only behavioral effects such as avoidance and alarm reactions occurred. At extremely high concentrations, reduced growth rates and mortality could occur. In practical terms for evaluating the impacts of dredging activities on fishes, these findings imply that fish will use behavioral mechanisms to avoid areas of high suspended sediments that may cause lethal or paralethal effects, assuming that the turbidity plume is not so large as to completely prevent escape.

Newcombe and Jensen used data from several studies to evaluate the effects of suspended sediments on adult estuarine nonsalmonids.[223] Some of the fishes used to represent estuarine nonsalmonids were considered by the authors to be relatively sensitive such as bay anchovy, Atlantic herring, Atlantic silverside, Atlantic menhaden, spot and fourspine stickleback. Few strictly demersal fish were included, and no data on winter flounder were available. Therefore, the impacts on fishes from the models of Newcombe and Jensen can be considered conservative, meaning that they will likely overestimate impacts.[223]

In an active construction area, exposure times are assumed to be short, one hour or less, because if given the opportunity, fish will move out of areas with high concentrations of suspended sediments. An increase suspended sediment concentrations of 30 to 55 mg/l, as might occur near an active bucket dredge, could result in temporary impacts including minor physiological stress such as increased respiration and coughing rates.[223] Jetting would be likely to cause greater increases in suspended sediment concentrations, but these concentrations would decrease rapidly. Suspended sediment concentrations of about 1,500 mg/l may result in minor to moderate physiological stress to indications of major physiological stress such as long-term reduction in feeding rate and success. Physiological stresses would decrease with distance from the source.

Demersal Species

Demersal fishes are found in close association with the bottom, and therefore are sensitive to siltation and changes in bottom composition resulting from trenching activities. In the short term, it is expected that most adult demersal fishes will be able to avoid construction activities. However, eggs and larvae, particularly demersal eggs, will be susceptible to siltation and turbidity effects. Demersal fishes with specific habitat requirements are most susceptible to the long-term impacts due to dredging, such as habitat modification. These fishes would include those that have specific preferences for spawning, YOY, or feeding habitat. Substrate restoration and other engineering measures to minimize siltation and turbidity can minimize the potential for population-level impacts to demersal fish species.

Short-Term Finfish Impacts

Short-term impacts include disruption of spawning habitat during construction, and impacts of the turbidity plume resulting from trenching on eggs and larvae. Most commercially important fishes have pelagic eggs and larvae that would not be directly affected by trenching. However the turbidity plume resulting from dredging, plowing, and plowing and jetting, could affect pelagic eggs and larvae. Eggs are expected to be more resistant to turbidity as their food source is contained within the egg. However, demersal eggs, especially the commercially important winter flounder and ocean pout, may become silted over and experience mortality. Larvae may be more susceptible to turbidity impacts because they have limited ability to avoid high turbidity and are actively seeking food sources after the yolk-sac stage.

Winter flounder are commercially and recreationally important fish found throughout Long Island Sound that deposit demersal, adhesive eggs in estuaries of nearshore areas from February through May.[226] The preferred habitat for deposition of eggs is not well described, but Bigelow and Schroeder state that they spawn over sandy bottom in water as shallow as 6 to 18 feet.[227] Crawford and Carey found winter flounder eggs deposited on a tidally submerged gravel bar and attached to fronds of macroalgae.[228] Pereira *et al.* stated that winter flounder eggs are generally collected from waters less than 15 feet deep and mortality will likely be complete for any winter flounder eggs in the area that are buried to a depth greater than 3 mm.[229] Scheduling construction activities in shallow waters outside of the winter flounder spawning season will minimize impacts to this species.

Winter flounder larvae are also susceptible to short-term impacts due to increased turbidity from trenching activities. Winter flounder larvae are non-dispersive, meaning that they remain close to spawning areas.[230] Therefore, the majority of winter flounder larvae will occur in waters less than 15 feet deep from February through August.

Long-Term Finfish Impacts

Long-term impacts are related to changes in physical habitat, such as substrate type, that are not naturally reversible. Fish with specific requirements for substrate are susceptible to these changes. Almost all demersal fishes probably have some preference for substrate type for various activities such as feeding, spawning, and juvenile habitat. However, for most fishes these preferences are not well described in the scientific literature.

2.7.5 Submerged Vegetation

Seagrass and algae beds may be impacted by underwater construction through direct disturbance, sedimentation, or water quality impairment. Seagrass beds are nearshore features and direct impacts can generally be avoided by route selection or construction method (HDD rather than open cut trench). They are susceptible to heavy sediment

[226] Klein-McPhee, G. 1978. Synopsis of biological data for the winter flounder, *Pseudopleuronectes americanus* (Walbaum). NOAA Technical Report, NMFS Circular 414. U.S. Dept. of Commerce, National Oceanographic and Atmospheric Administration, National Marine Fisheries Service.

[227] Bigelow, H.B. and W.C. Schroeder. 1953. Fishes of the Gulf of Maine. Fishery Bulletin of the Fish and Wildlife Service 74:53.

[228] Crawford, R.E. and C.G. Carey. 1985. Retention of winter flounder larvae within a Rhode Island salt pond. *Estuaries* 8:217-227.

[229] Pereira, J.L., R. Goldberg, J.J. Ziskowski, P.L. Berrien, W.W. Morse, and D.L. Johnson. 1999. Essential Fish Habitat Source Document: Winter flounder, Pseudopleuronectes americanus, life history and habitat characteristics. NOAA Tech. Mem. NMFS-NE-138.

[230] *Ibid.*

loads, although they naturally function as sediment traps. Exposure to total suspended solids in excess of 18 mg/l for extended periods (more than two months) may kill eelgrass plants.[231] Unlike channel or harbor dredging projects, construction of linear projects is likely to be centered in a particular area for a relatively short period of time. It is more likely, therefore, that turbidity will reach only sublethal levels, resulting in a short-term reduction in productivity. This effect can be further reduced by restricting the nearshore work to the winter when eelgrass production is low.

Algae beds are most likely to occur in areas where there is hard substrate for attachment. Impacts to Long Island Sound algal beds can be avoided by avoiding areas of hard substrate. Sedimentation or water quality impairment from nearby construction activities can reduce productivity, but this effect is likely to be very temporary in nature.

2.7.6 Birds

Marine waterbirds can be divided into three groups based on the period of their residency: summer, winter and year-round. Summer and year-round residents typically breed during their stay. The winter visitors are usually migrants from farther north or inland, seeking open water and food along the coast during the winter months. Marine waterbirds generally nest in colonies on small nearshore islands, which offer protection from mainland predators and most human disturbances. Many nesting locations are used annually by a number of species, however it is well documented that colonial waterbirds frequently relocate their nest sites.[232] Many species cycle through several locations, possibly due to changes in ecological conditions, competition among species, and human disturbance. Such shifting of nesting colonies is particularly characteristic of terns and waders. Foraging habitat for marine waterbirds is often widespread and diffuse.

Because birds are highly mobile during feeding and migration, impacts of the infrastructure crossing construction to most marine birds will be negligible. Various species may be displaced temporarily from feeding and resting areas as the construction passes through particular habitats. For example, shorebirds and waders may avoid the shorelines and mudflats at the landfalls during HDD activities, and diving ducks will avoid the immediate work area and most likely the sedimentation plume during jetting and plowing. However, because of their mobility and large ranges, the birds typically will utilize other available habitat during construction and move back into the work areas quickly after construction is complete. This brief loss, if any, of feeding and resting habitat generally represents little to no threat to any marine birds.

However, birds are much less mobile during nesting and many marine species nest in colonies on offshore islands, where they are vulnerable to disturbance. Timing restrictions imposed in permit and certificate conditions typically require that construction avoid such critical nesting periods.

[231] Short, F.T. 1994. Cited in Normandeau Associates, Inc., Sears Island Cargo Terminal Marine Resources Impact Assessment and Mitigation. 1995. Prepared for Maine Department of Transportation.
[232] Veit, R.R. and W.R. Petersen. 1994. *Birds of Massachusetts*. Massachusetts Audubon Society, Concord, MA. 514 pp.