LIFE CYCLE 2006 – Connecticut Siting Council Investigation into the Life Cycle Costs of Electric Transmission Lines

DRAFT REPORT

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Prepared for the Connecticut Siting Council
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1. Background and Introduction

Pursuant to Connecticut General Statutes § 16-50r (b), the Connecticut Siting Council is required to prepare and publish information on transmission line life cycle costs (LCCs) every five years. This information is intended to enable informed decisions regarding transmission alternatives being considered to meet the State's future electricity needs. This report was prepared in response to that requirement. Transmission line LCCs include:

- Costs that are incurred to permit, acquire, and build a line;
- Costs of operating and maintaining the line over its useful life; and
- Costs of energy losses resulting from the line's use. (Typically, all of these costs are expressed in the equivalent dollar value for a single year, such as the year the line is first energized.)

In preparing this report, two key objectives were: to provide information that is relevant to Connecticut's future transmission decisions; and to provide data useful in comparing one transmission line to another equivalent line. Achieving these objectives was a challenging assignment. The best information sources on transmission costs are the costs for recently-constructed lines, because the costs of lines built 10 to 20 years ago are no longer representative. However, relatively few lines have been built in the last decade. While recent lines are clearly the best sources of cost data, future transmission lines may have attributes that result in either higher or lower costs. Also, as this report discusses, two different transmission lines of the same voltage may have characteristics that make them quite difficult to compare as exact substitutes for one another. In response to these challenges, this report provides the best available cost information on recent transmission facilities and a detailed discussion of how these costs might vary (and by how much) for future lines with different attributes.

This report is organized in a way that should facilitate its use. In addition to providing quantitative data, it provides useful information about cost elements that vary significantly from one line to another, due to factors such as the terrain along of the right-of-way, the numbers of highway and river crossings, the need to traverse urban and suburban areas, and mitigation of environmental impacts. Chapter 2 introduces the concept of a transmission line's life cycle cost and discusses its major cost components. Chapter 3 provides first costs for those line types most applicable to Connecticut. Chapter 4 describes in detail some factors that may cause the cost for any specific line to differ from those in Chapter 3. Chapter 5 discusses the cost impacts of different and emerging line technologies. Chapter 6 addresses the major elements of annual operating and maintenance costs and their assumed values for Connecticut transmission lines. Chapter 7 describes transmission losses, which vary in proportion to future regional energy and capacity costs. Chapters 8 and 9 then discuss the electric and magnetic fields (EMF) and environmental impacts, respectively, that result from transmission lines and the costs of mitigating these impacts. Finally, Chapter 10 illustrates the calculation of actual transmission line LCCs for a number of typical line types. Appendices follow with some useful reference data.

2. Life Cycle Costs

Life cycle costs are the total costs of ownership of an asset or facility from its inception to the end of its useful life. These costs include the design, engineering, construction, operation, maintenance, repair and removal of the asset. Life cycle costs provide the information to compare project alternatives from the perspective of least cost of ownership over the life of the project or asset.

Life cycle costing is not an exact science and involves much judgment by engineers on what are reasonable expectations for costs of design, construction, operation and maintenance of facilities. The use of life cycle costs to compare alternative assets, systems, or projects allows the sometimes limited perspective of individual interests such as engineering, operations, finance, or purchasing to be incorporated into a holistic evaluation of benefits [1].

Life cycle cost calculations use the "time value of money" concept to evaluate alternatives on a common basis. Present value (PV) computations bring all anticipated expenses of a project or asset, over its entire useful life, to a present day value that is then used for comparison with other alternatives. Present Value analysis is an accepted standard method for financial evaluation of alternatives in the capital budgeting process and is commonly used by utility companies as a life cycle cost methodology.

Transmission line life cycle costs are a function of many factors and as such, can vary greatly from one project to another. Life cycle costs are influenced by the line design required to meet the specific need, the geographic area through which the line is to be built, the regulatory and permitting requirements of the jurisdiction(s) involved and many other factors. Because each transmission line project is unique, the life cycle costs for each project are specific to that application, and caution should be exercised in any attempt to compare life cycle costs across different projects in different time periods. This report will discuss in detail the major elements of costs included in life cycle costs, the factors influencing those costs, and the overall impact of the cost factors on a life cycle analysis.

In the case of life cycle cost analyses for transmission lines in Connecticut, the transmission operating utilities have a common view of what cost elements should be included and how they should be considered. There is general agreement that the life cycle cost comparisons should be used to compare two assets that have a roughly equivalent useful life. [2, p. 15]. Whether a transmission line life is estimated at thirty-five years or forty years is a subjective judgment based on the best information available. Present value analysis of transmission line costs shows that operating and maintenance costs incurred beyond year twenty-five have very little bearing on the present value of a project and therefore, become insignificant in terms of materially changing the overall life cycle cost evaluation. If there are no anticipated major investments for rebuild or upgrade, for example, beyond the twenty-five year horizon, whether the estimated life of a transmission line alternative is thirty-five years or forty years is less significant. The critical factor is that alternatives be compared over an equivalent lifetime.

The transmission operating utilities in Connecticut have identified the following items as the major components of the life cycle cost of an electric transmission line.

- **First costs**
  Typically include the following costs:
  - Structures (poles/foundations or ducts/vaults)
  - Conductors or cables associated hardware
  - Site work
  - Construction work
  - Engineering
  - Sales Tax
  - Administration and project management

- **Operating and Maintenance costs**
  Typically include labor and expenses for control and dispatching, switching, and other elements of routine operation of a transmission line. Maintenance include the costs of scheduled inspection and servicing of equipment and components as well as right of way vegetation management, painting, general repairs, emergency repairs and all other activities required to keep a line in proper operating condition.

- **Electrical losses**
  Include the cost of the resistive losses of electrical energy that occur on a transmission line as reflected by the costs of producing or purchasing that electricity.

Each of these components of transmission line life cycle costs are examined in detail in this report. Both the key elements of costs and the factors that affect those costs are discussed. Chapter 10 of this report will give examples of transmission line life cycle costs based on typical cost data from utilities that own and operate transmission lines in the State of Connecticut. Appendix A of this report presents that same cost data as thirty-five year present value calculations for the types of transmission lines discussed throughout the report.

As mentioned earlier in this chapter, transmission line projects are specific to a particular need and application. Therefore it is difficult to develop "typical" life cycle costs that are meaningful beyond the specific project for which they are calculated. This report will, however, use recent project cost information to represent how different cost components can influence the life cycle cost of a project. To be relevant to the State of Connecticut, this report examines the life cycle costs of four basic types of transmission lines. The four types of lines are currently in use in Connecticut and the types that are most likely to be used in the near future. These include:

- 115 kV overhead transmission lines

- 115 kV underground transmission lines
- 345 kV overhead transmission lines
- 345 kV underground transmission lines

Within each of these four basic types of lines there are variations of design and materials that will also be considered in the sample cost calculations. The following Figures 2.1 through 2.4 are provided as a high-level distribution of life cycle costs according to the basic cost elements defined earlier. These charts offer a basis for understanding the contribution of the basic life cycle cost elements that are detailed in this report.

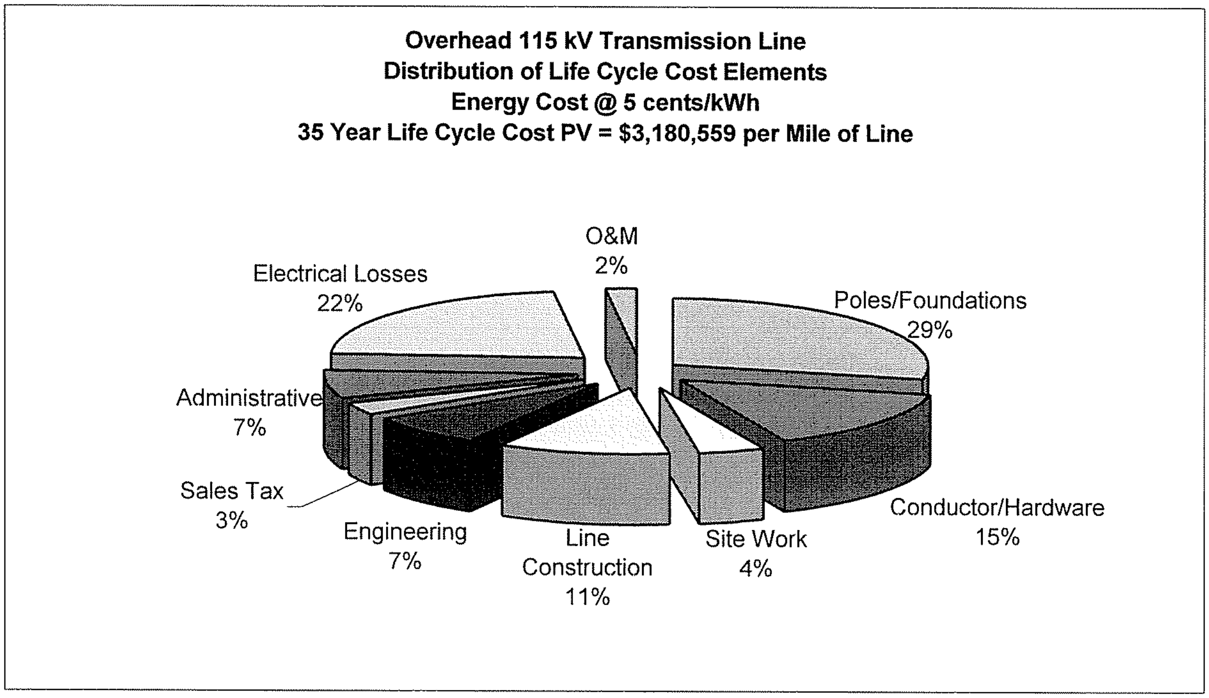


Figure 2-1 Typical Life Cycle Cost for 115 kV Overhead Line

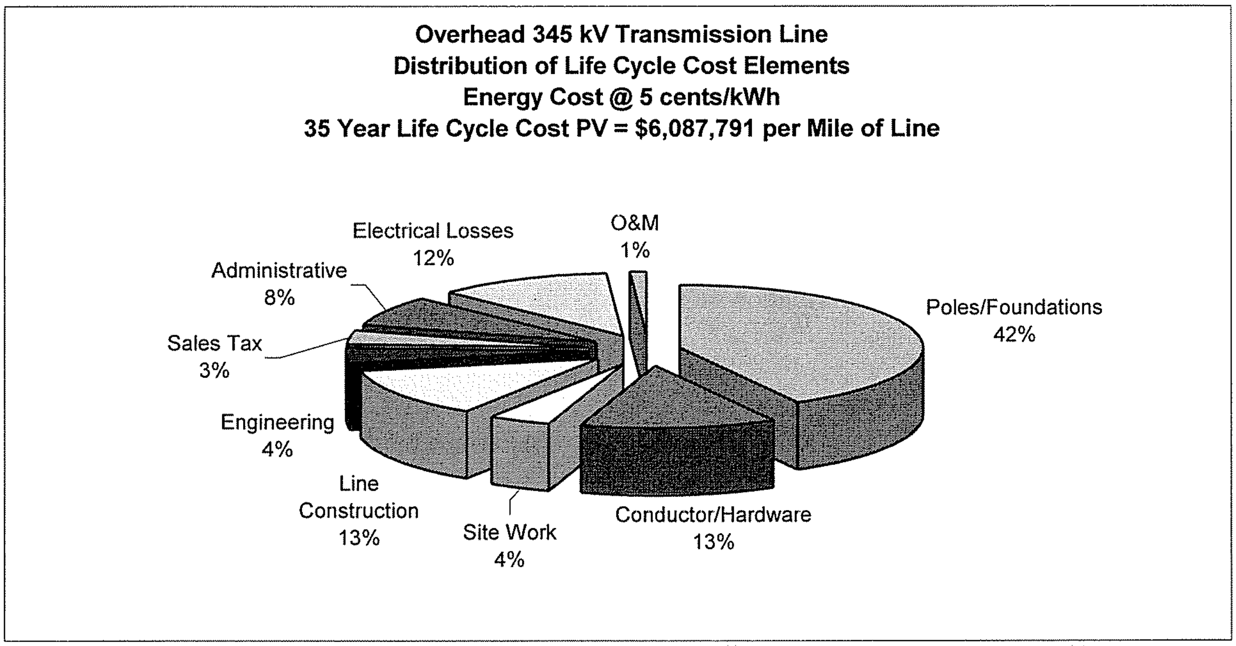


Figure 2-2 Typical Life Cycle Cost for 345 kV Overhead Line

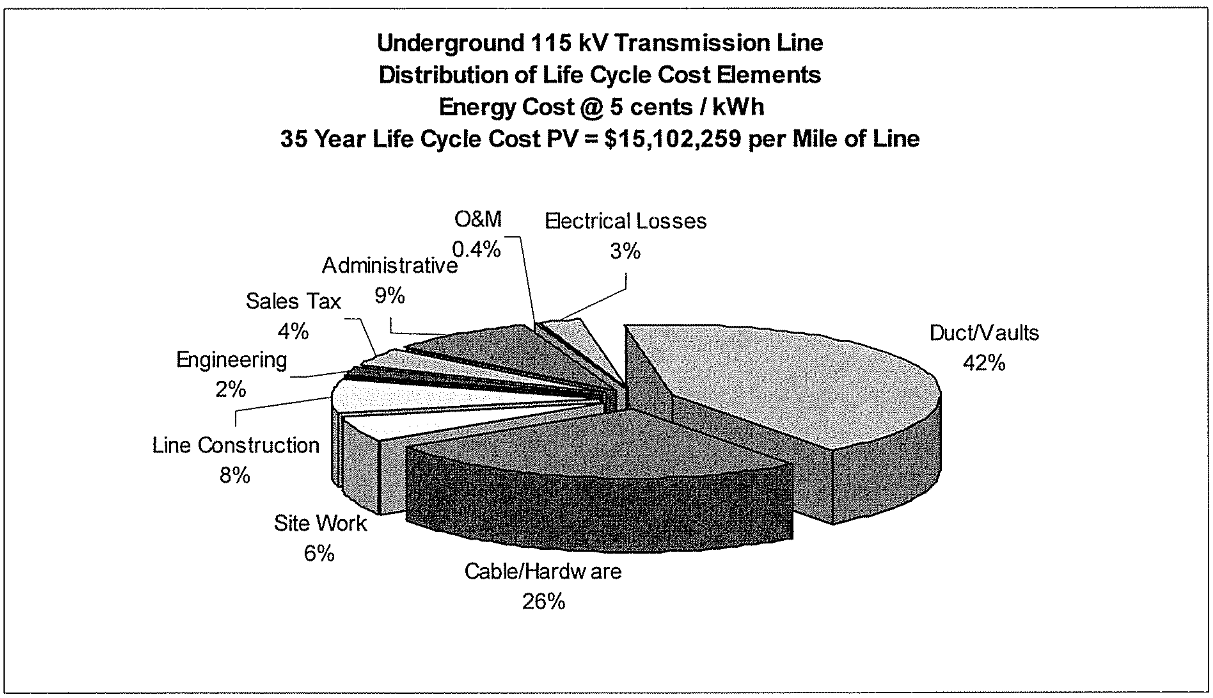


Figure 2-3 Typical Life Cycle Cost for 115 kV Underground Line

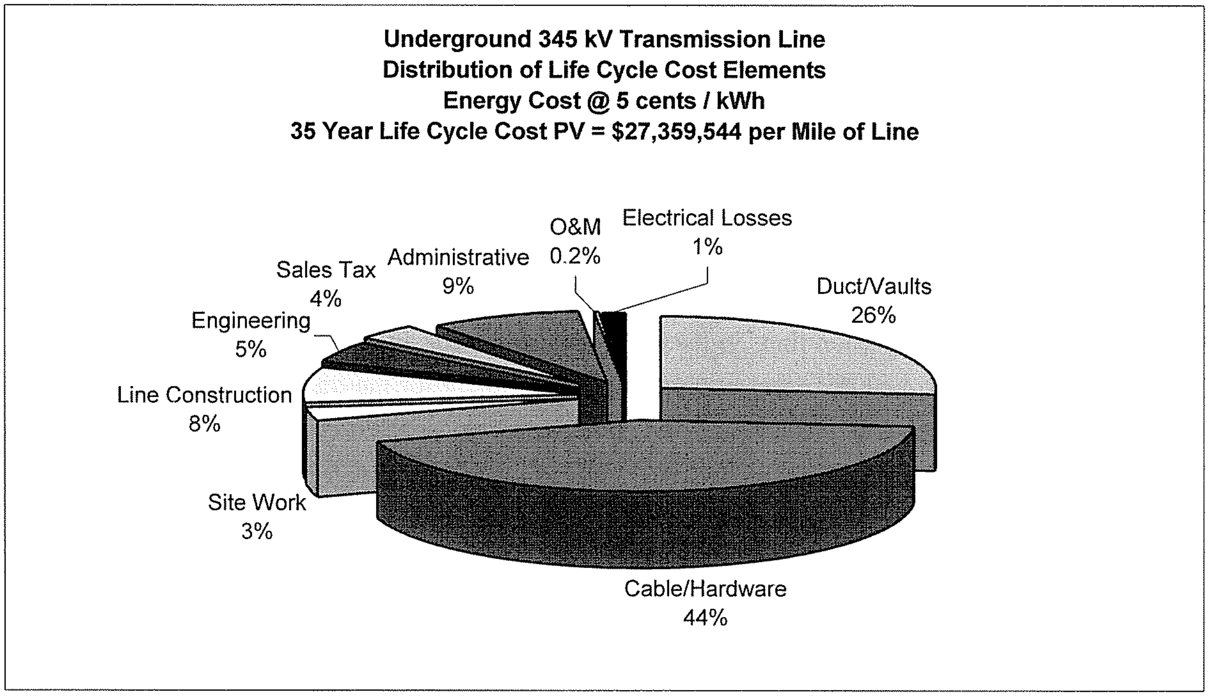


Figure 2-4. Typical Life Cycle Cost for 345 kV Underground Line

References

1. Barringer, H. Paul and David P. Weber 1996, *"Life Cycle Cost Tutorial* **", Fifth International Conference on Process Plant Reliability,** Gulf Publishing Company, Houston, TX.

2. Connecticut Siting Council, RE: Life-Cycle 2006, Investigation into the Life-Cycle Costs of Electric Transmission Lines, January 12, 2006, Hearing Transcript.

3. First Costs of Transmission Lines

3.1 Introduction

Transmission systems provide the physical means to transport bulk electric power and constitute an essential link between producers and consumers of electric energy. The transmission system consists of a network of transmission lines, in which normally there is more than one transmission line connected to each line termination, thus providing redundancy. This report, for the purpose of identifying the first costs of representative transmission lines in the state of Connecticut, includes all capital, installation and permitting costs associated with the transmission line itself, except for the transmission line terminations and associated equipment (switchyard equipment, protection and controls, etc.). Electric power can be transmitted between any two geographical locations by overhead transmission lines, underground transmission lines, or a combination of the two. The first costs of overhead and underground transmission lines are presented in the following two sections.

3.2 Overhead Transmission

Overhead transmission lines are located above the ground level and are easily seen by the general public. There are different designs of overhead transmission lines that are built to meet different purposes, consistent with the National Electrical Safety Code (NESC). Some of the factors that are included in the design of an overhead transmission line are voltage level, type of supporting structure, and number of circuits per supporting structure. In a single-circuit, alternating current (AC) transmission line, there are three current-carrying conductors. These current-carrying conductors are made of stranded aluminum or a mix of stranded aluminum and steel and are electrically isolated by the surrounding air. The transmission line voltage is the magnitude of the electric potential difference between any two of its current-carrying conductors, normally referred to as the "line-to-line" voltage. The voltage is usually expressed in kilovolts or kV. (One kilovolt is equal to one thousand volts.)

In the State of Connecticut, the most common overhead transmission lines voltages are: 69 kV, 115 kV, and 345 kV. Because of their limited electric power capacities, transmission lines at 69 kV are no longer options for new overhead transmission lines in Connecticut. Therefore, this report addresses the first costs of 115 kV and 345 kV overhead transmission lines.

In overhead transmission lines, the current-carrying conductors are supported by insulators, which in turn are attached to the transmission line structure. The conductors and insulators are mechanically supported by structures, which are made from different designs and materials, such as wood or steel. The conductors and insulators of overhead transmission lines can be attached to the supporting structures in different arrangements according to specific design requirements. Similarly, transmission lines can have more than one circuit on a single supporting structure.

A large number of different overhead transmission line designs are used in the U.S. In the State of Connecticut, however, the major utilities have indicated that six transmission line designs represent the overhead transmission line designs that are most likely to be built in the future. Therefore, this report addresses the first costs of these designs only. Table 3-1 shows the key characteristics of the six overhead transmission line designs that would be considered for use in Connecticut.

Table 3-1 Characteristics of Overhead Transmission Line Designs in Connecticut

Voltage (kV)	Supporting Structure / Material	Conductor Configuration	No. of Circuits	See Drawing
115	Poles/Laminate Wood	Delta	1	p. 11-14
115	Poles/Steel	Delta	1	p. 11-16
345	H-Frame/Laminate Wood	Horizontal	1	p. 11-18
345	Poles/Steel	Delta	1	p. 11-20
115	Poles/Laminate Wood	Vertical	2	p. 11-10
115	Poles/Steel	Vertical	2	p. 11-12

As shown in Table 3-1, the conductor configurations for overhead transmission lines in Connecticut are Vertical, Delta, and Horizontal. These "names" are common terminology within the major utilities in Connecticut and relate to the physical appearance of the transmission line.

The major electric power utilities in Connecticut identified the use of laminate wood poles and steel poles as the primary structural materials for the line designs listed in Table 3.1. The companies also confirmed that lattice steel structures have not been used for new projects for decades [1]. The designs listed in Table 3.1 include both single and double circuits for 115 kV overhead transmission lines. For 345 kV overhead transmission lines, the utilities in Connecticut use only single circuits. Perceived increased risk of reliability has led the utility companies away from building 345 kV double circuit lines for the foreseeable future [2]. Therefore, this report does not address the costs of 345 kV double circuit lines.

As illustrated in the drawings on pages 11-10 through 11-14, the physical appearance of one overhead transmission line design may be quite different when compared to another, even at the same voltage level of 345 kV. In order to present the full range of first cost information for the overhead transmission line designs listed in Table 3-1, a cost breakdown by costing accounts is necessary. As identified by the utilities in Connecticut, the first costs of overhead transmission lines include all capital, installation, and permitting costs and are classified in the following costing accounts as listed and described below. The accounts used for this purpose are established and defined by the Federal Energy Regulatory Commission (FERC) and are included in the FERC Uniform System of Accounts.

- Poles/Foundations—include all labor, materials, and expenses incurred in the acquisition and installation of structural components.

- Cable/Hardware—include all labor, materials, and expenses incurred in the conductors, insulators, and associated items (including cable splices).

- Site Work— include all labor, materials, and expenses incurred in cleaning and preparing the land and foundations, erecting the structures, stringing the conductors, etc.

- Construction— include all labor, materials, and expenses incurred during construction

- Engineering— include all labor, materials, and expenses incurred in engineering activities.

- Sales Tax (4.6 %)—includes overall taxes in Connecticut

- Project Management— include all labor, materials, and expenses incurred in project administration. All permitting costs are included in this costing account.

The costs of land and land rights are not included in the above accounts. These costs are highly variable, site and project specific, and constitute one of the key factors that affects the overall cost. This will be discussed in greater detail in Chapter 4.

The first costs for single circuit, 115 kV overhead transmission line designs are listed in Table 3-2. These costs are per unit of transmission line length, i.e., United States Dollars (USD)/mile, and are based on the information provided by the major utilities in Connecticut [1,2].

Table 3-2 First Costs for Single Circuit, 115 kV Overhead Transmission Lines

Cost Item USD/Mile	**Line Design Supporting Structure / Material/ Conductor Configuration**	
	Poles/Laminate Wood /Delta	Poles/Steel/Delta
Poles/Foundations	298,025	642,135
Cable/Hardware	337,256	337,256
Site Work	90,802	90,802
Construction	157,524	247,790
Engineering	61,536	168,755
Sales Tax (4.6 %)	43,477	68,390
Project Management	98,862	155,513
Total Cost/Mile	1,087,482	1,710,641

The first costs for double circuit, 115 kV overhead transmission line designs are listed in Table 3-3. These costs are per unit of transmission line length, i.e., USD/mile, and are based on the information provided by the major utilities in Connecticut [1,2].

As can be seen in Table 3-2, for 115 kV overhead transmission lines, single circuit, with Delta configuration, the use of steel poles has an impact on the cost for poles/foundations, construction, engineering, and project management and results in 57% higher total cost per mile, when compared with wood poles.

Also from Table 3-3, a similar observation applies for the 115 kV overhead, double circuit lines, with vertical configuration in which the use of steel poles results in 32% higher total cost per mile, when compared with wood poles.

Table 3-3. First Costs for Double Circuit, 115 kV Overhead Transmission Lines

Cost Item	Line Design Supporting Structure / Material/ Conductor Configuration	
	Poles/Laminate Wood /Vertical	Poles/Steel/Vertical
Poles/Foundations	324,025	718,255
Cable/Hardware	774,478	774,478
Site Work	121,805	121,805
Construction	263,045	347,130
Engineering	94,919	121,111
Sales Tax (4.6 %)	72,600	95,808
Project Management	165,087	217,859
Total Cost/Mile	1,815,959	2,396,446

The first costs for two 345 kV overhead transmission line designs are listed in Table 3-4. These costs are per unit of transmission line length, i.e., USD/mile, and are based on the information provided by the major utilities in Connecticut [1,2]. The H-Frame structure with laminated wood and horizontal conductor configuration results in 45% lower first cost, when compared with the Delta configuration with steel poles.

Table 3-4. First Costs for Single Circuit, 345 kV Overhead Transmission Lines

Cost Item	Line Design Supporting Structure / Material/ Conductor Configuration	
	H-Frame/Laminate Wood /Horizontal	Poles/Steel/Delta
Poles/Foundations	661,375	1,814,372
Cable/Hardware	560,032	560,230
Site Work	183,300	183,300
Construction	301,809	546,869
Engineering	104,339	176,445
Sales Tax (4.6 %)	83,299	150,936
Project Management	189,415	343,215
Total Cost/Mile	2,083,569	3,775,367

3.3 Underground Transmission

Underground transmission lines are located below the ground level and are not easily seen by the general public. As with overhead lines, there are several different designs for underground transmission lines that are built for various purposes. A number of factors are considered in the design of underground transmission lines including voltage, type and size of cable technology, type of installation, and number of circuits. As with overhead lines, in a single-circuit, AC underground transmission line, there are three current-carrying conductors and the magnitude of the electric potential difference between any two of them constitutes the transmission line voltage.

Due to the reasons mentioned before regarding the 69 kV transmission lines, this report addresses the first costs of 115 kV and 345 kV underground transmission lines.

The conductors for underground transmission lines are cables, which consist of a central core made of copper surrounded by electrical insulation. There are different technologies for transmission cables based on the type of insulation that surrounds the copper core. This insulation medium can be a fluid-filled system, a compressed gas, or a solid dielectric. Examples for different insulation media include: for fluid-filled, kraft paper, impregnated with mineral oil; for gas, sulfur hexafluoride; and for solid dielectric system, cross-linked polyethylene. There are different types of installations for underground transmission. Normally, the cables are located inside steel or PVC ducts which are immersed in thermal sand or lean mix concrete that is contained by a concrete trench. Inside this underground concrete trench, the ducts and conductors can be laid in different arrangements and can have single or double circuits according to specific design requirements for the type of installation.

There are a number of different underground transmission line designs in the US. In the State of Connecticut, the major utilities have identified four underground transmission line designs that represent the majority of the underground transmission lines that are likely to be built in the future. Therefore, this report addresses the first costs of these designs only. These designs are based on two cable technologies: High Pressure Fluid Filled pipe type cable (HPFF), and cross-linked polyethylene cable (XLPE).

Table 3-5 lists the key characteristics of the underground transmission line designs in the state of Connecticut.

Table 3-5. Typical Underground Transmission Line Designs used in Connecticut

Voltage (kV)	Cable Technology / Size	Conductor Configuration / Cables per Phase	No of Circuits	See Drawing
115	HPFF / 1750 kcmil	Delta / One Cable per phase	1	p. 11-2
115	XLPE / 1750 kcmil	Horizontal / One cable per phase	1	p. 11-4
345	HPFF / 2500 kcmil	Delta / One cable per phase / circuit	2	p. 11-6
345	XLPE / 3000 kcmil	Horizontal / One cable per phase	2	p. 11-8

The costing accounts identified for overhead transmission lines apply for underground transmission lines with one exception: the "pole foundations" costing account is replaced by "Duct/Vaults", which is more appropriate for underground transmission lines. This "Duct/Vaults" costing accounts includes all labor, materials, and expenses incurred in the acquisition and installation of the structural components for underground transmission lines.

As mentioned previously, the cost of land is not included in the costing accounts and will be addressed in Chapter 4.

The first costs for 115 kV underground transmission lines are listed in Table 3-6. These costs are per unit of transmission line length, i.e., USD/mile, and are based on the information provided by the major utilities in Connecticut [3-4].

Table 3-6. First Costs for 115 kV Underground Transmission Lines, Single Circuit

Cost Item	Line Design Cable Technology - Size / Conductor Configuration - Cables per Phase	
	HPFF -1750 kcmil / Delta - One cable per phase USD/Mile	XLPE -1750 kcmil / Horizontal - One cable per phase USD/Mile
Duct/Vaults	3,290,651	4,208,485
Cable/Hardware	3,153,217	1,588, 244
Site Work	611,780	611,780
Construction	823,186	823,186
Engineering	242,613	241,667
Sales Tax (4.6 %)	373,587	343,775
Project Management	987,821	935,641
Total Cost/Mile	9,482,855	8,752,778

As can be seen in Table 3-6, for single circuit, 115 kV underground transmission lines, the cost of cable/hardware for HPFF is higher than for XLPE, while the cost of Duct/Vaults for HPFF is lower than for XLPE. The remaining categories have similar costs. Overall, for single circuit, 115 kV underground transmission, the HPFF cable system results in 8.34% higher cost per mile, when compared with the XLPE cable system.

The first costs for 345 kV underground transmission lines are listed in Table 3-7. These costs are per unit of transmission line length, i.e., USD/mile, and are based on the information provided by the major utilities in Connecticut [3].

Table 3-7. First Costs for 345 kV Underground Transmission Lines, Double Circuit

Cost Item	Line Design Cable Technology - Size / Conductor Configuration - Cables per Phase	
	HPFF -2500 kcmil / Delta - One cable per phase USD/Mile	XLPE - 3000 kcmil Horizontal - One cable per phase USD/Mile
Duct/Vaults	3,786,400	5,133,353
Cable/Hardware	3,686,500	8,469,288
Site Work	171,500	617,838

Construction	764,440	1,517,070
Engineering	252,265	950,224
Sales Tax (4.6 %)	398,411	697,852
Project Management	905,952	1,738,562
Total Cost/Mile	9,965,468	19,124,187

While one-to-one comparisons are not particularly precise, the key observation to be made from Table 3-7 is that as opposed to 115 kV cable systems, the total cost per mile of XLPE cable is higher than HPFF for 345 kV. The total cost per mile of underground transmission line using XLPE cable is 91% higher than HPFF. Additional investigation shows that for the XLPE cables, "splice vaults" and other costs related to the cable installation have a big impact on this. When two cable segments need to be joined, large and costly concrete enclosures called "splice vaults" are installed below the ground level to protect the cable joints. The dimensions of these splice vaults are approximately 27 feet long x 8 feet wide x 8 feet high (See Figure 3-1). The implications in material and labor costs of burying these splice vaults are significant. As noted by Robert Carberry, Manager, Transmission Siting and Permitting, for Connecticut Light and Power (CL&P): "It's like burying the back end of a tractor-trailer truck" [5]. The splice vaults used for XLPE cable systems are physically larger than the ones used for HPFF. Furthermore, for 345 kV underground transmission with two circuits and one cable per phase, six of these splice vaults would be required for an XLPE cable system every mile. For HPFF cable systems, however, only two splice vaults would be required per mile. Other factors are related to the vault's location, i.e., on the road, or off the road on private property, and the amount of soil resulting from the excavation activities that has to be disposed of in a environmentally friendly manner. These issues can add many millions of dollars to the cost of XLPE duct vault installations. These will be further discussed in Chapter 4.

In addition to these first costs, there are a number of other accessories required for the proper operation of cable systems, such as pressurization plants and shunt reactors. These accessories and their associated costs are discussed in Chapter 5.

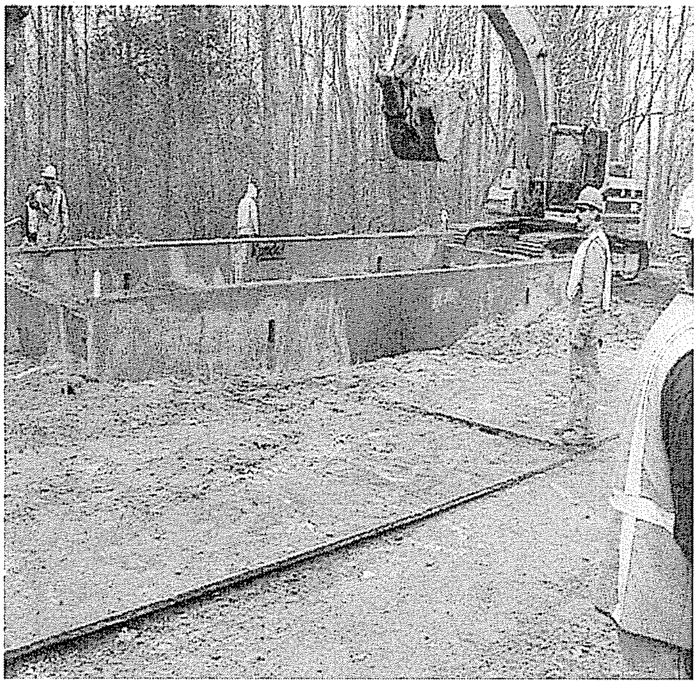


Figure 3-1. Typical 345 kV, XLPE Splice Vault (Under Construction)

(Source: Docket 217 -- Weekly Environmental Inspector Report dated February 23, 2006)

While overhead transmission is significantly different from underground transmission in many aspects and one-to-one comparisons are not always possible, a key observation is that the total cost per mile of an underground 345 kV transmission line can be six to eight times higher than the total cost of an overhead 345 kV transmission line. There are a number of factors in addition to first costs that need to be examined, as they provide basis for this significant cost difference. These factors are discussed further in Chapter 4.

References

1. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2006, Connecticut Siting Council Investigation into the Life Cycle Costs of Electric Transmission Lines, Question-CSC-002, December 12, 2005.
2. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2006, Connecticut Siting Council Investigation into the Life Cycle Costs of Electric Transmission Lines, Question-CSC-003, December 12, 2005.
3. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2006, Connecticut Siting Council Investigation into the Life Cycle Costs of Electric Transmission Lines, Question-CSC-004, December 12, 2005.

4. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2006, Connecticut Siting Council Investigation into the Life Cycle Costs of Electric Transmission Lines, Question-QLF-2, May 2, 2005.
5. Connecticut Siting Council Technical Meeting, RE: Life-Cycle 2006, Investigation into the Life-Cycle Costs of Electric Transmission Lines, March 14, 2006, Hearing Transcript.

4. Key Factors Affecting First Costs

4.1 Introduction

The previous section presented the basic component for any transmission line life cycle cost calculations—the first costs. This section presents the key factors that affect these first costs, which include:

- Transmission line right of way
- Permitting and legal requirements
- Land and land rights
- Materials, labor, and associated cost escalation
- EMF mitigation.

These factors are all are interrelated. Each of them has a role in any project, but the weight of each one is very project specific. While these factors are not all inclusive, they represent a selected list of factors that need to be considered as variables that can influence the first costs. Furthermore, these factors can provide some basis for the significant cost difference between overhead and underground transmission lines.

EMF mitigation is included in the list of key factors above, but will be discussed in another Chapter in this report.

4.2 Transmission Line Right of Way

The term "right of way" (ROW) generally has two meanings. The first one relates to the sliver of land over which facilities such as highways, railroads, or other utility infrastructures are built. The second one relates to the right to pass over property owned by another party. Combinations of the two in a given application are also possible. For transmission lines, the ROW usually includes the area of land in which the transmission lines structures are located and the additional areas around the transmission line required for its proper operation and maintenance. Occasionally, and particularly in urban areas, the right to pass over specific property owned by a third party is part of the transmission line ROW.

There are many variables that relate to a transmission line ROW and affect transmission line costs. The most relevant variables are the types of terrain, obstacles along the ROW, and the level of development near the ROW. The impact of these variables on transmission line design and its possible effect on costs are discussed.

4.2.1 Types of Terrain

The types of terrain are related to the possible areas that may be encountered between the two points to be electrically connected through a transmission line and can have a significant impact on the cost of a project. In this discussion, we consider five basic types of terrain: flat, rolling, mountainous, rocky, and wetlands. The impact that the different types of terrain may have on the overhead and/or underground transmission line designs and associated costs include:

- Incremental length of the transmission line to avoid difficult types of terrains
- Incremental number of stronger structures and foundations for terrain with different elevations, i.e., rolling terrain
- Incremental labor for foundations for rocky terrain
- Special foundations for water crossing.

Flat and dry terrain provides the ideal scenario and serves as the baseline for analyzing the impact of types of terrain on the transmission line designs. Rolling terrain may result in higher costs associated with stronger structures and foundations which are required between two contiguous towers at significantly different elevations. For mountainous terrain, in addition to the higher costs due to stronger structures and foundations, the transmission line length may increase to avoid passing through the mountain. The different kinds of structures are discussed in the next section of this chapter.

Wetlands are typically environmentally sensitive areas and the transmission line length may increase to avoid passing through this type of terrain. If the transmission line needs to cross wetlands, special foundations are typically required, resulting in higher costs.

Rocky terrains may present particular challenges. Given this type of terrain in Connecticut, blasting may be required to install structure foundations for overhead transmission lines or to excavate the cable trench and manholes/splice vaults required for underground transmission lines. For blasting and rock removal, special procedures must be followed to assure compliance with Connecticut regulations. Excavated material that cannot otherwise be used at the site has to be removed and properly disposed of elsewhere. Underground cable installation typically involves the excavation of a trench about 4 feet wide and 5 feet deep, as well as areas (every 1,500 – 2,000 feet) for manhole or splice vaults that are about 27 feet long by 8 feet wide and 8 feet high. Substantially more blasting is required to create the required trench and excavations for splice vaults for the underground route than would be required for the structure foundations on the overhead route [1]. Based on the recent Bethel-Norwalk 345 kV transmission project, more than twenty five percent (25%) of the trench excavation has been in rock. Rock excavation can be almost four times more expensive than soil excavation [2].

Evidence of this cost impact is emphasized by the following response from United Illuminated regarding cost of underground construction: "Based on CL&P's experience with the underground portion of the Bethel to Norwalk project and UI's environmental and test pit surveys along its portion of the route of the Middletown-Norwalk project, estimates for trench excavation due to rock and soil disposal have both been increased" [3].

The degree to which design changes defined by terrain affect costs is very project specific, but experience with difficult terrain does allow cost impacts to be estimated. According to the study titled "Transmission Line Capital Costs", prepared for the US Department of Energy [4], the incremental cost per mile for rolling terrain is 10% of the total capital costs (without land and land rights, environmental costs, etc.). As noted by, Robert Carberry, Manager, Transmission Siting and Permitting, for Connecticut Light and Power (CL&P): "We have seen 100-200 % increases in foundation costs in areas that have large rock formations, as compared to the costs of foundations in more agricultural types of land" [5]. Additional incremental costs will be proportional to the amount of difficult types of terrains and wetlands encountered, which will determine the incremental length of the transmission line and the number of special foundations required for water crossing, respectively.

4.2.2 Obstacles along the ROW

A second factor is related to obstacles that may be encountered in specific locations along the transmission line ROW. In this discussion we consider four types of obstacles: private houses, schools, public buildings and parks; rivers and streams; roads and railways; and other infrastructure or utilities. Since these obstacles typically do not spread over a wide geographical area, the impact on costs tend to be smaller when compared to factors related to type of terrain. The impact that the obstacles may have on the overhead and/or underground transmission line design and the associated costs include:

- Incremental length of the transmission line due to avoiding obstacles
- Incremental number of stronger structures and foundations for road crossings
- Special foundations for water crossings
- Incremental labor for installation of underground lines due to presence of other utilities

For private houses, schools, public buildings and parks, the transmission line length may increase to avoid passing through these obstacles and that may affect the costs. Rivers and streams are typically environmentally sensitive areas and the transmission line length may increase to avoid passing through these obstacles. If the transmission line needs to cross the rivers or streams, a number of special foundations are typically required, resulting in higher costs.

In the case that an overhead transmission line needs to cross a road, stronger structures and foundations are required. There are different types of structures that are built for different purposes. On most lines, the majority of structures are *suspension structures* that carry the conductor on either a straight line or a very shallow angle (5°-10°) and the insulators and associated hardware are not designed to resist the full tension of the wires. Sharper bends (up to 45°) require stronger *angle structures* in which the insulators and associated hardware are most robust, but are not capable of resisting the loss of all the wires in one end. At each end of the line, and periodically along its length *dead-end structures* are used. Unlike *suspension* and most *angle* structures, dead-end structures are designed to withstand the unbalance load carried in the event that all the conductors on one side go slack [6]. For an overhead transmission line that requires crossing a state road, normally one dead-end structure is added to each side of the road.

Underground utilities may also impact the design of underground transmission lines. To the extent other underground utilities exist within an underground transmission line right of way, additional labor and materials will be required to avoid conflicts with the other utilities.

The impact that the different kinds of obstacles may have on costs will be proportional to the size or length of the obstacle which will determine the incremental length of the transmission line. Similarly, additional incremental costs will be proportional to the incremental number of special foundations or stronger structures and foundations required for water crossing and road crossing respectively. The absolute impact of cost on these issues is very project specific.

4.2.3 Level of existing development near the ROW

In this discussion we consider three basic levels of existing development near the transmission line ROW: urban, suburban, and rural. The impact existing development may have on the overhead and/or underground transmission line designs and its associated costs include:

- Incremental length of the transmission line due to additional number of turns in the transmission line route
- Incremental number of stronger structures and foundations (dead-end and angle structures) due to additional number of turns in the transmission line route
- Taller structures with concrete foundations due to narrow ROW in urban/suburban areas

A number of the implications of building a transmission line in a urban/suburban area are summarized by CL&P, "With the degree of urban and suburban land development that we encounter, especially in Southwest Connecticut, existing transmission line routes take many turns to avoid densely developed areas. Each turn requires more deadend and angle structures, which in turn causes the line length to increase. Tall steel structures, and specially dead-end and angle structures, require much larger poles and foundations, resulting in significantly higher material and construction costs [5]. As stated by, Robert Carberry, Manager, Transmission Siting and Permitting, for CL&P: "In areas where wider right-of-ways are available (rural areas), shorter wood pole H-frame structures can be constructed, but in Connecticut, we are frequently confined to a narrow ROW that can only accommodate vertically-configured lines on taller steel poles" [5].

The impact that existing development near the ROW may have on costs will be related to the specific details of the suburban/urban area and the characteristics of the right of way within these areas, which will determine the number of turns that need to be made. Therefore, the absolute impact in cost due to increased transmission line length and due to the incremental number of taller and stronger structures and foundations is very project specific.

4.3 Permitting and Legal Requirements

Utilities' permitting costs are broad in nature and include but are not limited to the following activities: development of permit applications, environmental reports and maps; permit/certificate application filing fees; support of the permit applications at agency hearings; and preparation of plans and/or studies that may be required for permit approval [6]. While the utilities in Connecticut do not specifically track permitting costs, they agree that the costs related to permitting have increased during recent years and they believe that trend is expected to continue.

There are many variables in the permitting and legal requirements for transmission lines that affect transmission line costs. We have identified the most relevant government entities that impose specific requirements that affect the transmission line design and associated costs. Those government entities include: the Connecticut Siting Council (CSC), the Connecticut Department of Transportation (CDOT), the Connecticut Department of Environmental Protection (CTDEP), and the US Army Corps of Engineers (USACE).

4.3.1 Connecticut Siting Council (CSC)

The Connecticut Siting Council has jurisdiction over the siting of power facilities and transmission lines in the State of Connecticut and evaluates utility applications for those facilities and lines. When conceptualizing the addition of a new transmission line to the power system, utilities perform a great deal of planning and preliminary engineering activities. This work ultimately leads to the development of an application to the Connecticut Siting Council for a new transmission line. In addition to the details of the proposed line, the application includes a set of alternative solutions that have been evaluated by the utility in an effort to confirm that the proposed line represents the optimum solution based on the relevant evaluation criteria. Those criteria typically include system benefit (reliability and operability), technical feasibility (ability of a project to be engineered and built), property impact (social perception), environmental impact, and cost. The submittal of the application by the utilities is the first step in a statutorily defined permitting process [7, Page 43].

On June 2004, the Connecticut Legislature enacted Public Act 04-246, "An Act Concerning Electric Transmission Line Siting Criteria" was established. In basic terms, PA 04-246 requires: 1) to maximize the technologically feasible lengths of new underground 345 kV transmission lines in areas of certain land uses, and 2) to apply the best management practices for electric and magnetic fields for electric transmission lines. The impact of this Public Act on the overhead and/or underground transmission line designs and associated costs include:

- Incremental length of the underground segments for 345 kV transmission lines in certain land uses
- Incremental length of the transmission line (overhead and underground)
- Use of more expensive XLPE cables, instead of HPFF
- Increased complexity and costly time for planning and siting 345 kV transmission lines.
- Increased number of underground-overhead transition stations
- Increased project cost due to requiring significant magnetic field management measures

Although PA 04-246 requires the use of underground designs in the defined areas, the utility companies seeking to build new facilities will also, in fulfilling their obligation to manage costs, invest substantial effort to develop alternative designs to evaluate the technical and financial viability of those alternatives.

4.3.2 Connecticut Department of Transportation (CDOT)

The mission of the CDOT is to provide a safe and efficient transportation system for the people traveling in Connecticut. In order to accomplish this mission, the CDOT works with the public, transportation partners, state and federal legislators, and other state and local agencies [9]. The CDOT has direct responsibility for the efficient operation of ground transportation such as railways, state roads, and even local streets in urban areas. When a transmission line right of way is located near roadways, railways or rights of way that fall under the CDOT jurisdiction, special procedures must be followed. CDOT requirements and regulations can affect underground transmission line designs for installations in rural, urban, and suburban areas. CDOT requirements may result in:

- Incremental costs due to easements over private property for transmission line ROW
- Costs of construction due to special requirements for cable splice vaults, attachment of cables on bridges and work schedule restrictions.

Specific examples of the type of impact CDOT requirements can have on project costs, as experienced by the utilities in Connecticut, are summarized below.

Vault location

As stated in a previous Chapter, the physical dimensions of the splice-vaults for 345 kV XLPE cables are considerable. Because the installation of these splice vaults can require road closures with an estimated time required to bury these vaults of up to three weeks, the CDOT has prudently decided as many vaults as possible be built off the roadway. The impact on cost of this requirement include: the cost of obtaining easements over private property adjacent to the road, and the increased costs of turning the cable ducts off of and then back onto the road at each vault, which results in the crossing of more buried utilities, adds trench and cable length, therefore requiring additional vaults.

Working schedule

A measure taken by the CDOT in order to preserve the efficient ground transportation is related to the working schedule at the construction site. The contractors working on underground transmission lines in state roads are allowed to work only during the night shift. This may have impacts in costs since the working hour window for labor at the site may be reduced to 6-8 hours due to the considerable set up and clean up time is required for each shift [2].

Cable installations along bridges and special construction methods

Historically, the attachment of the cables to any highway bridges or other state structures crossing water bodies and/or railroads has not been allowed. Special construction methods such as horizontal directional drilling or "jack and bore" are the alternatives. In the horizontal directional drilling, a pilot hole is drilled and then reamed out to an appropriate size, and the duct or pipe pulled into the hole. Boring and jacking involves construction of pits on either side of the obstacle and a small tunnel is built while simultaneously a pipe in installed as the tunnel is formed [10]. These methods normally place the cables at greater depths, minimum 15 feet below the surface and may require significant environmental impact controls and associated costs.

The degree in which these design changes imposed by CDOT affect costs is very project specific, but generally these issues may cause an increment of 10 to 20% on the *construction costs* for underground transmission lines [2].

4.3.3 Connecticut Department of Environmental Protection (CTDEP)

The mission of the CTDEP is to conserve, improve and protect the natural resources and environment of the State of Connecticut while still encouraging the social and economic development of Connecticut [11]. When a transmission line right of way is located near an environmentally sensitive area under the CTDEP jurisdiction, special procedures must be followed. CTDEP requirements and regulations can affect underground transmission line designs for installations in rural, urban, and suburban areas. The impact of CTDEP requirements include incremental costs of construction due to management of excavated soil materials.

A specific example that provides insight into the effect of CTDEP requirements on project costs as experienced from the utilities in Connecticut is summarized below.

Contaminated Soil

Due to the fact that a large percentage of the soil under the local and state roads in Southwest Connecticut is contaminated, prudent environmental measures have been implemented by CTDEP in which the excavated soil cannot be reused in the closure of underground cable trenches and is subject to special storage rules. As was the case with CSC Docket 272 for the Middletown-Norwalk project, this results in increased disposal and transportation costs.

The degree in which these design changes imposed by CDOT affect costs is very project specific, but generally these issues may cause an increment of 5-10% on the *construction costs* for underground transmission lines [2].

4.3.4 U.S. Army Corps of Engineers

The U.S. Army Corps of Engineers (USACE) is responsible for investigating, developing and maintaining the nation's waterways and related environmental resources. When a transmission line right of way is located near waterways under the USACE jurisdiction, special procedures must be followed. The impact of USACE requirements includes increased project lead-time and costs of the project due to permitting. Normally for the permits required from the Corps of Engineers a final design is needed. This permit, which may take up to a year, has to be done in parallel with other permits by the Council or the CTDEP. Therefore it may add to the total project time and have a direct impact on the project costs.

4.4 Land and Land Rights

As mentioned before, the first costs information included in Chapter 3 does not include the costs of land and land rights. In some US states, and particularly within rural areas, these costs are relatively small and may not be significant when compared with other material and labor costs. According to the study titled "Transmission Line Capital Costs", prepared for the US Department of Energy [4], 5.5% of the materials (cable, structures, etc) costs would be enough to cover for land and land rights in a non urban area.

According to the utilities in Connecticut, however, the magnitude of the costs of land and land rights are quite significant and therefore deserve extensive review.

The impact of the cost of land and land rights on overhead and/or underground transmission line project cannot be overemphasized. *These costs can be the decisive factor to build a transmission line either underground or overhead.* Referring to land costs, Richard J. Reed, Vice President, United Illuminated (UI), states: "this issue becomes so specific that it can actually change what you're going to build just because of the land costs". As an example for a recent project in Connecticut, Mr. Carberry stated: "In the comparison of the life-cycle costs of overhead and underground 345 kV transmission line alternatives between East Devon (Milford) and Norwalk Substation sites in the recently approved Middletown-Norwalk 345 kV transmission project, the right of way costs were a critical driver of the CL&P initial preference for underground construction over 24 miles of the project route. In this part of the project, there was no available and acceptable overhead right of way, so that overhead construction would have required the expansion of existing rights of way through densely settled suburban areas, at very significant cost, both for the acquisition price and for project delays. On the other hand, there were available highway rights-of-way that could accommodate underground construction, and the underground route was shorter than an overhead route would have been" [8]. Clearly, a shorter underground transmission line would tend to lower total project cost, but still a cost comparison of the overhead vs underground alternatives reveals that the land costs have significant impact and in this case, make the underground segment slightly higher than the overhead, as shown below:

- All underground construction for Segment 3 and 4, HPFF cable $539 Million
- Nearly all overhead (Alternative B) $520 Million

The Council's Finding of Fact, estimated a range of life-cycle costs as follows:

- 24 miles of underground construction $713-871 Million
- Nearly all overhead (Alternative B) $549-631 Million

The costs associated with land and land rights are both highly variable and very project specific. As stated by, Robert Carberry, Manager, Transmission Siting and Permitting CL&P: "… if a new right of way or expansion of an existing right of way is required for overhead construction through a densely populated area the cost thereof can be the single largest component of overall capital costs. New rights of way costs through rural areas are less significant" [4].

Richard J. Reed, Vice President, United Illuminated (UI), states: "I just would never feel comfortable assuming an average land cost because it just differs so much and it differs on where you're going to build it." Regarding the specific land cost differences in Connecticut, recent estimates indicate that for the Bethel-Norwalk 345 kV transmission project an acre of land near Bethel, a suburb of Danbury, costs approximately 100,000 USD, where as for Norwalk the cost is 350,000 USD. In this project, one of the alternatives required a wider right-of-way and—50 million dollars—was the estimation for acquiring for the most part what was 40 or 50 feet of additional right-of-way [12, page 94]. Twenty (20) miles for fifty (50) million dollars is two and a half million a mile. Comparing this 2.5 million USD per mile with the other capital costs for 345 kV overhead transmission lines identified in Chapter 3, we can see that the land costs become by far the single largest component of the overall capital costs. For underground transmission lines, however, 2.5 million USD per mile of land costs become the third largest component, just after Duct/Vaults and Cable/Hardware.

4.5 Materials, Labor, and Cost Escalation

Once a transmission line design has been completed an estimated scope of materials to be used is defined. Similarly, construction estimates have detailed lists for the expected labor hours required to build the transmission line. Materials, labor and its associated cost escalation may have an impact on the initial first costs that were estimated when the project was approved. Since transmission projects may take one to seven years to complete, there may be a significant increase in first costs simply due to the cost escalation of materials and labor over time.

The cost escalation for materials and labor depends on many social and economic variables. Some of the factors that drive these cost escalations are: high demand for raw materials, limitations on manufacturing capacity for large cables, labor and material shortages due to national disasters, fuel costs, etc. [8]. In the state of Connecticut, since the inception of the Middletown-Norwalk 345 kV transmission project, estimates for materials have increased approximately 45%, mainly due to the increased cost of copper and steel [3].

There are significant differences in the amount of materials and labor required to build an overhead vs. underground transmission line. The amount of materials and labor associated with underground transmission lines design and construction is significantly higher when compared with overhead transmission lines.

Information on transmission line first costs provided by utilities in Connecticut was analyzed and Table 4.1 lists the material and labor percentage shares of total cost for overhead and underground transmission line designs.

Table 4-1. Percentage Shares From Total Cost for Labor and Materials for Overhead and Underground Transmission Lines

Cost Category	Overhead Transmission Line	Underground Transmission Line
Labor	35 %	24 %
Materials	65 %	76 %
Total	100 %	100 %

As it can be seen in Table 4.1, a cost escalation in materials would have a higher impact for underground transmission lines. Due to the fact that the values included in Table 4.1 are relative numbers and the magnitude of the costs for materials for underground transmission are up to six times the costs of overhead transmission, it is likely that in absolute terms, costs escalation in materials will have a higher impact on underground transmission lines.

4.6 References

1. Connecticut Siting Council, Findings of Facts, Docket No. 217, "345 kV electric transmission line between Bethel and Norwalk", July 14, 2003.
2. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2006, Connecticut Siting Council Investigation into the Life Cycle Costs of Electric Transmission Lines, Question-CSC-005, January 10, 2006.
3. United Illuminated, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2006, Connecticut Siting Council Investigation into the Life Cycle Costs of Electric Transmission Lines, Question-CSC-005, January 10, 2006.
4. K.R. Hughes and D.R. Brown, "Transmission Line Capital Costs", Pacific Northwest Laboratory, prepared for the US Department of Energy under contract DE-AC06-76RLO 1830.
5. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2006, Connecticut Siting Council Investigation into the Life Cycle Costs of Electric Transmission Lines, Question-CSC-004, January 10, 2006.
6. "Life Cycle Costs Study for Overhead and underground Electric Transmission Lines", ACRES International Corporation, July 1996.
7. Connecticut Siting Council, RE: Life-Cycle 2006, Investigation into the Life-Cycle Costs of Electric Transmission Lines, January 12, 2006, Hearing Transcript.
8. Pre-file Testimony of Robert E. Carberry, on behalf of The Connecticut Light and Power Company, Re: Docket Life Cycle 2006, Connecticut Siting Council Investigation into the Life-Cycle Costs of Electric Transmission Lines, January 6, 2006.
9. http://www.ct.gov/dot/cwp/view.asp?a=1380&Q=302028.
10. Connecticut Siting Council, Findings of Facts, Docket No. 272, "345 kV electric transmission line between Middletown and Norwalk", April 7, 2005.
11. http://dep.state.ct.us/.
12. Connecticut Siting Council Technical Meeting, RE: Life-Cycle 2006, Investigation into the Life-Cycle Costs of Electric Transmission Lines, March 14, 2006, Hearing Transcript.

5. Cost Differences Among Transmission Technologies

The cost to design, build, operate and maintain an overhead transmission line is lower than an underground equivalent due to basic cost differences in materials and construction methods. Also, the technology of overhead transmission is less complex than underground transmission and therefore requires less in the way of special equipment or facilities to operate the transmission system. The various types of overhead structures and line configurations, as well as different types of underground cable can impact total project costs significantly.

5.1 Electrical and Operating Characteristics of OH and UG Lines

A basic issue in the design of a transmission line is the difference in electrical characteristics between overhead and underground lines and the need to compensate for those differences. A prevalent issue in the difference in electrical characteristics of the lines is the difference in inductance and capacitance between the two types of lines. Inductance and capacitance are properties of an electric circuit related to the voltage induced into a circuit by a charging current (inductance) and the charge on the conductors per unit of potential difference between them (capacitance).

Underground lines have a higher capacitance than overhead lines due to the closer spacing of the conductors. When a line is energized, the capacitance can cause the line voltage to rise above acceptable limits and therefore must be controlled or cancelled. If the load on the circuit is not capable of absorbing the reactive power resulting from the high capacitance of the underground cables, shunt reactors must be installed to compensate for the excess reactive power. While this is a normal operating characteristic of an underground line, it does result in additional costs to a project.

Shunt reactors, when needed in underground circuits, are installed at the terminal facilities where overhead/underground transitions are made. Because this equipment is physically located in a transition station, it is not technically considered to be part of the transmission "line." However, because it is the line design that creates the need for the shunt reactors, or other equipment, the cost of that equipment is appropriately considered as part of the first cost of the transmission line and included when evaluating an underground alternative. (More detail on transition stations is provided in the following section on Hybrid Lines.)

A specific recent example in Connecticut of increased line cost is the twenty-four mile extension of underground transmission as part of the 345 kV Middletown to Norwalk line. The additional underground cable resulted in higher transient voltages throughout the CL&P and UI systems. The higher transient voltage resulted in the need to replace 1,500 surge arresters at various substations and also required use of 500 kV class equipment at various substations instead of equipment rated for 345 kV operations.

In the case of hybrid lines, all of the above issues may be involved as both the overhead and underground sections of the line may require additional equipment to compensate for the unique operating issues created by the hybrid line. Other considerations of hybrid lines include the effect of fault currents on the circuit. The cables in underground lines have lower impedance than the bare conductors in overhead lines, and therefore are susceptible to higher fault currents. This could endanger the cables and requires compensation in the form of installation of a series reactor to reduce the fault level or in the form of higher rated circuit breakers.

5.2 Hybrid Lines

A hybrid line is one that consists of both overhead and underground sections over the course of the line route. This is sometimes called a "porpoising" line as a reference to the above and below surface nature of the line, similar to a porpoise swimming at sea.

There can be many viable reasons for a line to be designed and constructed in this manner. The most obvious reasons are associated with the line routing and the difficulty that may be involved in building certain segments of a line overhead. Rough terrain, dense urban development, unsuitable subsurface conditions, bodies of water and any other number of obstacles may cause these difficulties. It should be stated that engineering technology exists to build a line in most any configuration desirable at any location. The consequence however is the excessive cost that would be incurred to build a line underground, for example, across a granite mountain range. Therefore, a hybrid line is sometimes the most feasible option for line construction at a reasonable cost.

Hybrid lines do require additional equipment and facilities as compared to fully overhead or fully underground lines. An overhead line requires switching stations or substations at each end of the line. An underground line requires similar terminal stations at each end of the line. A hybrid line, however, may require terminal facilities at each point where the line changes from overhead to underground and again to overhead. At a minimum, a hybrid line would require underground termination facilities within existing stations along the route of a line. So the first costs of a hybrid line, in addition to the fundamentally higher cost of underground construction, would also increase by the additional cost of terminal facilities required for overhead/underground transitions. These facilities are generally referred to as "transition stations."

Transition stations significantly influence first costs of a transmission line project. As discussed earlier, additional equipment to compensate for operating characteristics of underground circuits are required and represent additional project costs. Also, the land area required for the project increases to accommodate the transition stations. Additional land requirements carries additional environmental impact costs as well. The issues of land and land rights for transmission line projects are discussed in a later chapter but it should be noted here that land rights are, in most cases, the determining factor in the design and location of a transmission line. Figure 5.1 shows an example of a typical transition station.

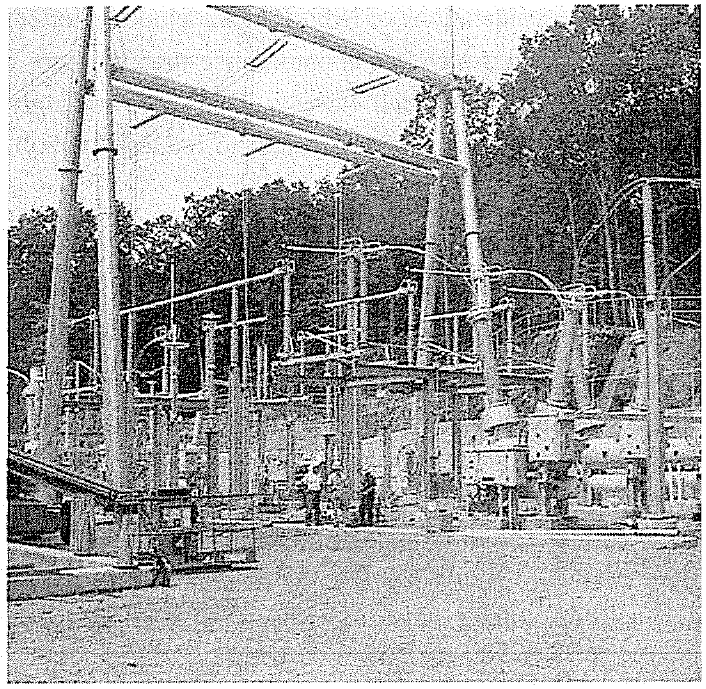


Figure 5-1 Archer's Lane 345-kV Transition Station (Under Construction)
(Source: Docket 217 -- Weekly Environmental Inspector Report dated July 26, 2006)

To illustrate the variability of project costs for overhead, underground and hybrid lines, Table 5.1 provides information on project estimates originally created for the Bethel to Norwalk line, proposed by CL&P in 2003. This example shows that costs for this typical transmission line vary by as much as $60 million depending upon line configuration and technology employed. Note that the most expensive alternative is a hybrid line, as opposed to fully overhead or fully underground. In that option, $20 - $25 million of the additional cost was for the transition stations and shunt reactors required due to the hybrid design.[1]

Table 5-1 Bethel to Norwalk Transmission Line Alternatives
(all costs in 2003 dollars)

Option 1 - Overhead

345/115-kV All Overhead	
345/115-kV overhead transmission line	$ 54,500,000
Right-of-Way acquisition	$ 33,700,000
Substations (Plumtree and Norwalk)	$ 41,700,000
Total	**$129,900,000**

Option 2 - Hybrid (Overhead & Underground)

345-kV Overhead /115-kV Underground	
345-kV/ overhead transmission line and 115-kV from Norwalk Jct. to Norwalk	$ 43,200,000
Right-of-Way acquisition	$ 39,800,000
115-kV underground transmission line	$ 66,000,000
Substations (Plumtree and Norwalk)	$ 41,500,000
Total	**$190,500,000**

Option 3 - Underground

345-kV Underground	
345-kV underground transmission line	$136,800,000
Substations (Plumtree and Norwalk)	$ 48,500,000
Total	**$185,300,000**

Source: CSC Docket 217 Findings of Fact

5.3 New and Emerging Transmission Technologies

As the need for more transmission capacity increases throughout the state of Connecticut, as well as the entire country, new technologies are being introduced to facilitate higher throughput of energy. These technologies are being used in both retrofit applications to existing lines as well as initial design elements of new lines. These technologies are in the areas of materials and systems devices and include Flexible Alternating Current Transmission Systems (FACTS), High Voltage Direct Current transmission (HVDC), and HTLS (High Temperature, Low Sag) composite conductors. Each has benefits in certain line applications and represents additional tools and methods for future use to increase transmission capacity.

5.3.1 FACTS and Typical Costs

Flexible AC Transmission Systems are systems that incorporate electronic-based controllers with other static controllers to enhance controllability of a transmission system and increase power transfer capability. Problems created in transmission networks today by uncontrolled power flows and transient and voltage stability have created a need for more dynamic regulation of networks to reduce the likelihood of power transfer bottlenecks and blackouts. FACTS devices can be used for dynamic voltage control and for steady state power flow regulation.

FACTS devices include:

SVCs (static VAr compensators): a shunt-connected static VAr generator or absorber whose output is adjusted to exchange capacitive or inductive current to maintain or control specific parameters of the power system (e.g., bus voltage). Used for voltage regulation through reactive power injection, dynamic reactive power compensation of AC-DC converters and HVDC links, power factor regulation, transient stability improvement, damping of voltage flicker from arc furnace operations, improvement of network stability during contingencies, and other applications.

STATCOM (static synchronous compensator): a static synchronous generator operated as a shunt connected static VAr compensator whose capacitive or inductive output current can be controlled independent of the ac system parameters. Used for dynamic voltage regulation, power factor regulation, transient stability improvement, steady-state power flow improvement, active filtering of harmonic currents and other applications.

Other FACTS devices and the primary applications for them are included in **Table 5.2.**

Table 5-2 Primary applications of FACTS devices

FACTS APPLICATIONS				
FACTS Equipment	Dynamic voltage stability	Power flow control	Voltage unbalance compensation	Reduction of short-circuit level
Static VAr Compensator (SVC)	X	X	X	
Static Synchronous Compensator (STATCOM)	X	X	X	
Phase Shifting Transformer (PST)		X		
Thyristor Controlled Series Compensator (TCSC)	X	X		
Unified Power Flow Controller (UPFC)	X	X		X
Interphase Power Controller (IPC)		X		X

The operational benefits of FACTS are to improve and control the system power flow and grid stability. This means that transmission networks can operate with more efficiency and thereby improve power throughput. Installation of FACTS devices is becoming more widespread as system capacity limitations create dynamic operational problems whenever a contingency occurs.

The cost of FACTS devices varies widely across the range of technology and also by the application of the technology, as exhibited in Table 5-3.

Table 5-3 Typical Costs for FACTS Devices

FACTS Typical Costs	
Transmission System Capacity	Installed Cost (millions of dollars)
200 MW	\$5 - \$10
500 MW	\$10 - \$20
1000 MW	\$20 - \$30
2000 MW	\$30 - \$50

5.3.2 HVDC Typical Costs

High voltage direct current transmission systems involve the conversion of alternating current power to direct current for the purpose of transmitting the power over long distances, typically hundreds of miles. Shorter applications are also feasible depending upon the specific requirements. A recent example in the state of Connecticut is the Cross Sound cable, a 40 km, 330 MW, ±150 kV HVDC cable connecting Connecticut with Long Island, New York. The cable connects the 345 kV transmission system at New Haven to the 138 kV system at Shoreham Generating Station on Long Island.

HVDC is used, as in the case of the Cross Sound cable, for submarine applications and is also applied to long distance transmission, connecting AC systems of different system strengths, connecting AC systems of different or incompatible system frequencies, and for connecting remote hydro or wind interconnections to the grid.

HVDC has the following characteristic benefits:

- Controllable – power injected where needed
- Higher power over the same right of way, thus fewer lines
- Bypassing congested circuits – no inadvertent flow
- Two circuits on less expensive line
- No distance stability limitation
- Reactive power demand limited to terminals
- Less losses over long distances

Each potential application of HVDC must be evaluated in comparison to an AC circuit to meet the same need. HVAC and HVDC are not equal technical alternatives. Long distance, point-to-point power transfers are an application where HVDC is the only reasonable alternative. The Cross Sound cable is an example. The high cost of terminal converter stations required for HVDC often offset any potential savings compared to an AC line. Only long distance applications tend to overcome this cost addition.

HVDC must also be considered in the context of being a component of a larger AC system. The compatibility of the systems, the locations and land requirements for converter stations, future load growth, long term maintenance costs and many other considerations must be taken into account when considering an HVDC application. These are all critical elements of a life-cycle cost analysis that compares HVDC and HVAC for each specific situation. Some examples of installed cost of two terminal HVDC systems are shown in Table 5-4.

Table 5-4 HVDC Typical Costs

2 Terminal HVDC Typical Costs	
Transmission System Capacity	Installed Cost (millions of dollars)
200 MW	\$40 - \$50
500 MW	\$75 - \$100
1000 MW	\$120 - \$170
2000 MW	\$200 - \$300

The potential use of HVDC transmission as an alternative to the proposed Bethel to Norwalk HVAC transmission line was studied and debated in detail during the Docket 272 proceedings in 2004. The end result was that HVDC lines were rejected as a viable alternative for the proposed ac line. The reasons for rejecting HVDC were:

1. The risk of introducing harmonics into the system associated with classical HVDC solutions.
2. Increased complexity in the control and operation of HVDC systems…due to the scheduling of power.
3. The likelihood that an HVDC "…solution may preclude any additional generation from ever being installed between Beseck and Norwalk due to the additional costs of 100 to 150 million dollars for each generator connection and the difficulty in recovering these high costs. (TR. 7/29/04, p. 139).

In this case, the additional costs for each generator connection are those associated with building an additional HVDC terminal.

Many other aspects of embedding an HVDC line were also discussed during the Docket 272 hearings. These and the above-mentioned factors make it unlikely that either an overhead or underground HVDC line will be installed within the State of Connecticut as a direct alternative to an HVAC line. Therefore, the life cycle costs of such lines are not addressed in this report.

5.3.3 Composite Conductors

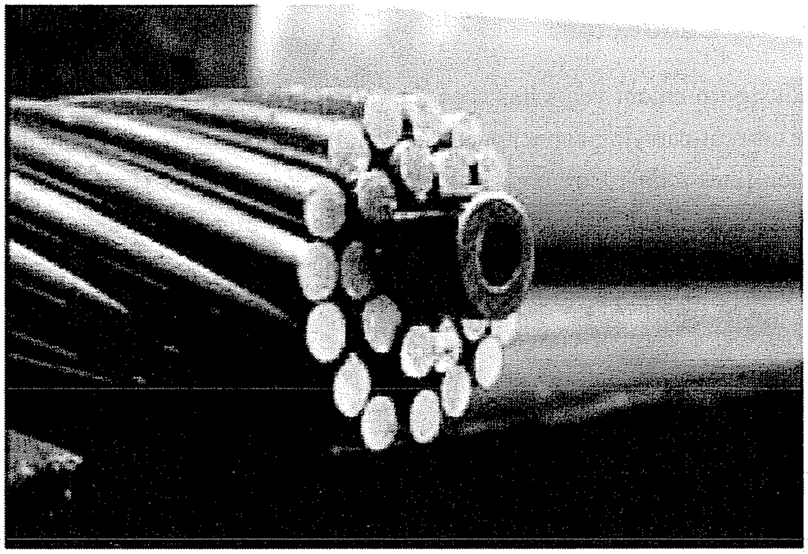
The transmission industry in recent years has seen the introduction of new conductor materials that bring the benefit of higher current-carrying capacity, lower weight and greater strength than materials generally in use for transmission lines today. Composite conductors, also known as HTLS (high-temperature, low-sag) conductors, are regarded as a solution to line congestion and loading issues at a reasonable cost of installation.

Composite conductors use a core of composite materials as the mechanical support component of the conductor while continuing to use stranded aluminum as the exterior, current carrying component. The composites replace the steel core found in most conductors today. Benefits to be gained from use of composite conductors include:

- Higher current capacity and up to 10% lower resistance, thereby reducing line losses.
- Higher strength to weight ratio (up to 50% lighter than conventional) resulting in less conductor sag and increased reliability during heavy loading conditions (ice).
- Because of lighter weight, composite conductors allow the capacity of a line to be increased using existing rights-of-way and transmission structures.

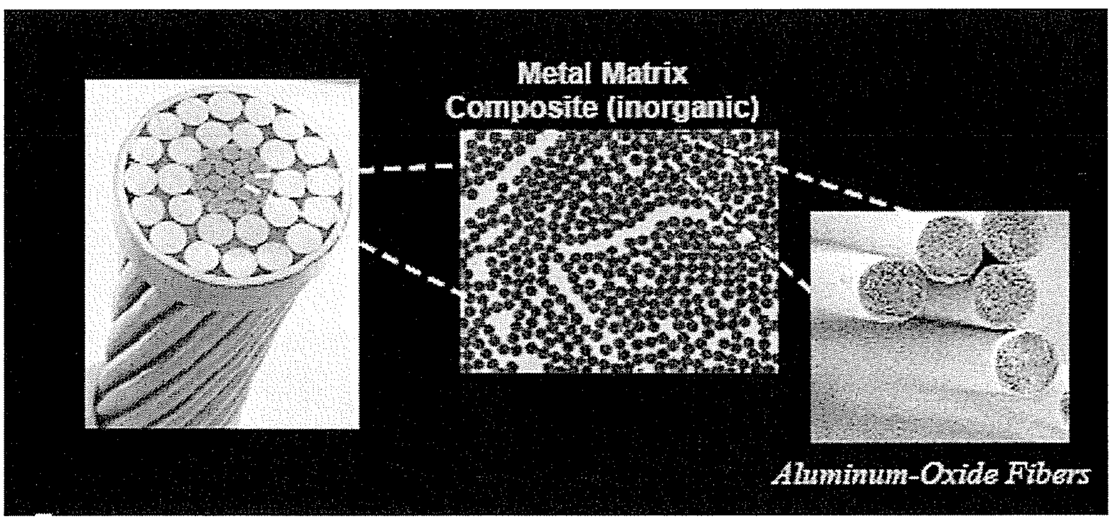
Figure 5-2 shows examples of the construction of composite conductors

COMPOSITE-REINFORCED ALUMINUM CONDUCTOR



The new composite-reinforced aluminum conductor is stronger, lighter, and has a higher current capacity than conventional utility transmission lines.

Source: US Department of Energy



Source: 3M Corporation

Figure 5-2. Examples of composite conductors

Composite conductors are not in widespread use in the U.S. as of yet as the technology is still considered by some utilities to be in a field-testing stage. However, several utilities around the country have installed composite conductors in areas where line capacity is an immediate issue. Areas of current use include California, Arizona, and Minnesota.

The first cost implications of composite conductors are significant. The material costs of composite conductors can be 9 to 12 times greater than conventional steel reinforced conductor (CSC Docket Life-Cycle 2006, Interrogatories CL&P). However, as a consideration for line life extension and upgrade, composite conductors can facilitate increased line capacity within an existing right-of-way using existing structures. This has the direct benefit of reducing cost incurred in permitting and constructing new lines to provide additional capacity. The cost of line losses can also be reduced through use of this technology.

Composite conductors have been proven to have two to three times the current carrying capability of conventional conductors (ACSR). Quantifiable benefit from the use of composite conductors will vary by project and by utility. It is reasonable, however, to expect significant cost savings from the use of existing rights of way and structures, along with a shorter construction period, to gain two times the existing line capacity. For use in new construction, composite conductors are less economically feasible than conventional conductors.

Table 5.5 shows cost comparisons between aluminum conductor-steel reinforced (ACSR) and aluminum conductor-composite reinforced (ACCR). The comparison is based on use of existing structures and conductor sizes of comparable current carrying capability.

Table 5-5 Conductor cost comparisons

Comparison of Conductor Costs				
Line Type	Conductor Type	Conductor Size	Material Cost ($ per Pound)	Installed Cost ($ per Mile)
115 kV	ACSR	1590 kcmil	$2	$100,000
115 kV	ACCR	1272 kcmil	$18 - $25	$450,000 - $600,000

Source: CSC Docket No. Life-Cycle 2006, Interrogatories

5.3.4 Life-cycle Cost Impact of Transmission Technology

The preceding discussion explores some of the technologies that are currently available for consideration in design and construction of transmission lines. In addition to the items highlighted, varying combinations of traditional materials and methods also add to the options available to utility company planners when considering new line designs. Transmission lines are designed and engineered to meet the requirements of specific circumstances of load and location and as such, are customized for the situation. It follows that life-cycle costs associated with a particular line are specific to that line design and location. While typical costs can be used for estimating purposes, the final costs will be dependent upon the technology used to meet the need identified and will be unique to that project.

References:

1. Connecticut Siting Council, RE: Life-Cycle 2006, Investigation into the Life-Cycle Costs of Electric Transmission Lines, January 12, 2006, Hearing Transcript, page 51.

6. Operating and Maintenance Costs

6.1 General

After a transmission line is constructed and energized, there are many tasks that must be performed on either an on-going periodic basis, or on an as-needed conditional basis, in order to ensure economical, safe, and reliable performance. Two major categories for these tasks are: 1) operating, and 2) maintenance.

6.2 Operating Costs

The fundamental principles of electric power system operation emanate from the fact that electricity cannot be easily stored. Electrical energy must be consumed as it is being produced, requiring the generation output to match the customer demand on a continuous basis. This is a complex process involving many decisions and actions each day by experienced personnel. It also is an important part of each electric utility's program to ensure the economic, reliable, and safe delivery of power throughout the system.

Operation of an electric power transmission system has two principal goals:

- Reliable supply of power to customers, and
- Production of power in the most economical way possible.

These two goals must be achieved while adhering to requirements for safe and reliable operation. This includes such things as ensuring that all system components operate within their thermal ratings; that system voltages remain within acceptable limits and that all generators connected to the system operate in synchronism. These operating requirements must be met in a dynamic environment. The electric system is continuously exposed to disturbances of varying severity, including short-circuits, failure of transmission line components, or failure of generating units. Transmission operating limits must be properly adjusted to provide for these contingencies. For example, short circuits that cause breaker lockouts change load flow patterns, frequently resulting in increased loading or abnormal voltages on critical circuits. Operators must decide on rerouting power to alleviate these conditions if established limits are exceeded. Similarly, failure of transmission or generation components can result in load or voltage changes that must be corrected to avoid further system problems.

In addition to abnormal conditions as described, normal operating environment changes such as load fluctuations due to weather, time of day, or off system demand for power purchases create a continuously changing environment that must be monitored and managed by operations personnel. Weather condition changes for example, can bring about sudden changes in the load or outages. Fast moving cold or warm fronts can result in lightning or storms with high winds that may cause sharply increased loads and/or widespread outages. The system is designed and built to handle certain contingencies, but the system operator must be able to recognize and react to developing conditions in a timely fashion.

The major costs associated with the operation of the transmission system can be grouped into four classes:

- Those associated with the operation of equipment;
- Those associated with the technical control of the transmission system and with administrative transactions costs;
- Those that are incurred as a result of constraints on the operation of the power transmission system; and
- Those associated with losses (see Chapter 7 for more information).

Specific operating costs include the labor costs and expense items required to execute the activities required to meet the operational requirements associated with transmission lines. These activities may include such tasks as allocating loads to plants and interconnections with other companies; directing switching operations to take certain equipment out of service for construction and maintenance or for load management; controlling system voltages; load tests of circuits; and various inspection and analysis activities associated with line operations. In addition to these tasks, there are many administrative requirements on system operations personnel to create and maintain the system records required for operations, maintenance and regulatory purposes.

These are routine activities that occur frequently as a result of predictable, common activities, including the administrative, record keeping, and switching activities due to cyclical or seasonal changes in system conditions. There are also significant non-routine activities that are unplanned, such as line overloads, generating unit or major transmission forced outages, or storm conditions. These activities can be very costly, and can account for large overruns of budgeted expenditures. In addition to large amounts of time and costs associated with switching and coordination of system recovery, special studies must then be performed for the new system conditions.

6.3 Maintenance Costs

In addition to operating activities, proper line maintenance is required to achieve optimum levels of service reliability. A highly reliable transmission line is based on many factors that begin with sound design, including mechanical, dielectric, and thermal aspects; good construction practices to minimize installation problems; and high quality materials, including conductors, structures, hardware, and splices. Once constructed and put into service, transmission line reliability and performance is then dependent upon good maintenance practices, with appropriate time intervals and techniques.

Good maintenance practices include many elements, beginning with field inspection, repair and replacement of components. However, effective maintenance must also included rigorous failure analysis, including obtaining root causes and identifying systematic contributing causal factors. Such failure analysis is dependent upon keeping good outage records that are produced through strict adherence to reporting requirements and effective database design.

6.3.1 Overhead transmission line maintenance

Transmission line maintenance tasks are specifically designed to reduce the probability of occurrence of the most common types of outages. Common maintenance tasks are focused on periodic inspection of the structural and electrical components of a line and the routine care of vegetation along the right-of-way on which the line is constructed.

Routine structural maintenance activities include such things as:

- Wood pole testing and treating, typically performed on a frequency interval based on reliability indicators, such as failure rates, level of deterioration experience encountered, line criticality, and cost considerations.
- Wood pole replacement, typically performed after inspection / treatment activities; program typically starts with replacing those on critical lines with higher outages and older poles
- Steel pole repainting

Routine electrical maintenance may include:

- Infrared inspection to identify hot spots on splices and connectors
- Climbing inspections, performed at intervals based on age, deterioration, reliability history, and criticality
- Foot patrols to allow visual inspection of both structural and electrical components.
- Helicopter patrols to identify components that may be deteriorated or damaged.

Vegetation management, or maintenance of the line right of way, is a continuous process that provides for routine clearing of trees, brush and other vegetation that could interfere with proper operation of the transmission line. Vegetation management is scheduled periodically for any given line or line segment, with the frequency determined by operating history and budgetary requirements. Vegetation management may include:

- Mowing the right-of-way
- side-trimming trees along the edge of the right-of-way
- removal of trees within the right-of-way
- removal of trees that are outside the limits of the right-of-way but due to their size and condition represent a risk of falling into the transmission line.

Many companies also use herbicide treatments on rights of way to inhibit the growth of fast growing species of grasses, weeds and trees.

6.3.2 Underground transmission line maintenance

Even though some transmission lines are located underground, there is still a considerable amount of routine maintenance that must be performed to ensure that the underground system performs reliably. Depending upon the type of underground system involved, maintenance can include the inspection and required actions within underground vaults or transition stations as well as along the route of an underground line. Typical activities may include work associated with conduits; work associated with conductors and devices; retraining and reconnecting cables in manhole, including transfer of cables from one duct to another; repairing conductors and splices; repairing grounds; and repairing electrolysis preventive devices for cables.

Maintenance of underground manholes and vaults could include cleaning ducts, manholes, and sewer connections; minor alterations of handholes, manholes, or vaults; refastening, repairing, or moving racks, ladders, or hangers in manholes or vaults; repairs to sewers and drains, walls and floors, rings and covers; re-fireproofing of cables and repairing supports; and repairing or moving boxes and potheads.

In the case of underground systems that are fluid filled and pressurized, there is a considerable amount of maintenance involved with the equipment in the fluid system. This includes pumps, reservoirs, piping, valves, etc. The fluid itself requires maintenance also in the form of testing, purifying, replenishing, or even replacement.

Because of the nature of underground systems and their design, safety restrictions can be an issue with maintenance activities. Space within vaults and manholes is limited and depending upon the type of equipment being inspected or maintained, special protective measures for personnel may be required. These all add to the time and expense for the maintenance activity, whatever it may be.

6.4 Variability of Costs

O&M costs vary between utilities and from year-to-year for the following reasons:

- Age of the line – as indicated above, replacement programs for poles in later years will drive up the costs; also replacements of hardware, splices, etc., have similar influences.

Other maintenance activities will also likely increase in frequency with age, including insulator washing, pole treatment, pole and guy adjustments, and ground maintenance.

- Weather impacts – a huge impact on costs incurs during years having severe weather spells (ice, wind, thunderstorms) that result in major outages and associated costs.

- Reporting differences – accounting practices vary between utilities; FERC accounts (see Section 6.5 for FERC discussion), the primary guidelines for cost information, are vague in some instances, contributing to differences that could mislead those comparing these results among utilities. Among these vagaries are treatment of line terminal equipment, joint use land, conduits and poles between transmission and distribution, unit of property designations, capital vs. O&M classification of replacement components/parts.

- Line length – when considering costs on a per mile basis, utilities with relatively short lines will look high, due to the fixed costs associated with many cost components, including engineering, overheads, and underground equipment. Both first cost and variable cost numbers may be distorted due to these factors.

Also contributing to O&M cost variations are proactive repairs and replacements, especially in older systems. Large projects involving repairs, upgrades, or replacements may be classified as O&M and could trigger large increases in spending. The return on such investments may be low in economical terms, but justifiable when considering reliability benefits. In such cases, utilities with higher investments in reliability improvement may look costly in comparative terms; however, a longer view of comparative terms may prove otherwise as reliability deficiencies manifest themselves in higher outage costs.

6.5 O&M Cost Assumptions for LCC Analysis

Ideally, it would be useful to assign a specific O&M cost figure to each type of transmission line and to distinguish between 115 kV and 345 kV line costs for a specific line type. However, electric utilities do not account for their O&M costs on a line-by-line basis or on a voltage class basis. Instead, transmission O&M costs are assigned to certain standard cost accounts, as specified by the Federal Energy Regulatory Commission (FERC). Four of these are operations accounts, including:

- Account 560 – Operation Supervision and Engineering

- Account 561 – Load Dispatch

- Account 563 – OH Lines Expenses

- Account 564 – UG Lines Expenses

There also are three maintenance accounts, including:

- Account 568 – Maintenance Supervision and Engineering
- Account 571 – Maintenance of OH Lines
- Account 572 – Maintenance of UG Lines

Connecticut transmission line O&M costs were taken from the information provided by UI and CL&P to FERC. The average of the $/circuit-mile values for years 2004 and 2005 will be used as the base year values for life cycle cost analyses of overhead lines. Both utilities felt that the recent years' data would be more relevant for projection purposes. Cost escalation was assumed to be 4% per year in determining future year costs. For analyses involving underground lines, it was agreed that FERC records include significant components that do not apply, e.g., costs associated with submarine cables. Subsequent analysis concluded that a value of $3488 / mile was appropriate for O&M for underground costs for life cycle analysis purposes. The actual O&M costs reported by the two utilities for the years 2004 and 2005 are shown in Table 6.1.

Table 6-1 FERC Records for Transmission O&M Costs

TRANSMISSION LINE OPERATING & MAINTENANCE COSTS

	2004		**2005**	
	UI	**CL&P**	**UI**	**CL&P**
Trans. Expenses				
Operation				
560 Oper Supv & Eng	$ 1,513,033.00	$ 4,399,082.00	$ 1,595,059.00	$ 4,711,764.00
561 Load Dispatch	$ 2,799,825.00	$ 4,695,676.00	$ 3,207,540.00	$ 5,631,543.00
563 OH Lines Expenses	$ 4,053.00	$ 764,232.00	$ 6,710.00	$ 504,649.00
564 Underground Lines Expenses	$ 33,330.00	$ 300,588.00	$ 27,271.00	$ 144,278.00
TOTAL OPERATION (UG + OH)	$ 2,837,208.00	$ 5,760,496.00	$ 33,981.00	$ 648,927.00
Maintenance				
568 Main Supv & Eng	$ 84,214.00	$ 1,196,168.00	$ 108,205.00	$ 1,935,618.00
571 Main of OH Lines	$ 367,814.00	$ 3,414,493.00	$ 514,945.00	$ 4,135,434.00
572 Main of UG Lines	$ 34,001.00	$ 115,761.00	$ 27,058.00	$ 150,000.00
TOTAL MAINTENANCE (UG + OH)	$ 443,922.00	$ 4,128,338.00	$ 596,105.50	$ 5,253,243.00
Ckt Miles - OH	99.63	1680.40	99.63	1680.40
Ckt Miles - UG	16.89	43.00	16.89	43.00
OPERATION & MAINTENANCE IN $ / CKT MILE				
Overhead	$ 28,183.82	$ 5,567.32	$ 33,306.76	$ 6,604.93
Underground	$ 28,015.15	$ 12,407.19	$ 30,744.44	$ 10,111.37
STATE AVERAGES ($ / CKT MILE)				
Overhead Construction	$6,833.19		$8,099.46	
Underground Construction	$16,808.90		$15,930.25	

Two of the FERC accounts relate to O&M Supervision and Engineering, including Accounts 560 and 568, respectively. After discussions with the Connecticut transmission-owning utilities, it was decided that 50% of the costs reported to Account 568 would be included as "line-related" operating costs.

The resulting average, base-year O&M cost figures for Connecticut transmission lines (in 2005 dollars) were:

- Overhead line O&M: 7466 $/circuit-mile
- Underground line O&M 3488 $/circuit-mile*

These figures are used in the sample life-cycle cost calculations made in Chapter 10, and they are recommended for use in future analyses until updated by the Connecticut Siting Council.

*This value is based on analysis of only the records pertaining to applicable underground facilities likely to be considered for installation in future years. Costs associated with submarine cables, e.g., are included in FERC accounts but are not considered applicable for future life cycle cost analyses.

7. Transmission Loss Costs

7.1 General

Since no device is 100% efficient, there will be a certain amount of loss associated with any movement of power through an electrical component, thus lowering the output of power flow.

A significant amount of the variable component of the transmission line life cycle costs may be attributable to the losses incurred during operation of the line. In addition to the magnitude of the load current, there are many factors that affect the impedance value that have a direct bearing on the loss costs.

7.2 Types of Losses

There are two fundamental types of resistive losses:

- No-load losses are primarily generated in the steel cores of transformers and other devices with windings. These losses vary with the voltage, not the load, and therefore are typically considered to be of constant value while the component is energized. (Note: These only occur in substations, and are not considered part of the transmission line life cycle costs)

- Load losses are present in the windings of transformers and other devices, as well as in transmission lines and cables. As they vary with the square of the current, the magnitude of load losses can range greatly between valley and peak load conditions.

In addition to resistive losses, significant losses occur on transmission systems resulting from the inductance in the windings and conductors created by the alternating current. These losses are the result of higher line loads required to carry the necessary reactive power component. The magnitudes of these losses are generally controlled through the insertion of capacitor banks which can be switched in fixed or variable increments automatically or remotely.

7.3 Costs

There are two basic components of the costs of losses.

- Energy costs are associated with the consumption of fuel and related expenses required to generate the energy that is lost. Costs associated with the resulting increase in system losses are also typically included here.

- Capacity, or demand costs are the costs associated with the additional generation and transmission equipment required due to the presence of these losses. This is usually based on the magnitude of losses occurring at the system peak.

Energy costs can be determined on an incremental or average system cost basis, depending on the cost assignment approach taken. The incremental approach utilizes the "marginal cost" representing the cost of supplying the next unit of energy required during the course of time considered. The average cost approach is based on the average energy costs occurred during the course of the year.

The incremental approach is often seen to be more accurate than the average approach for the following reasons:

It is typically considered to be more theoretically correct since the losses to be evaluated represent an incremental addition to the existing load.

Incremental costs are typically much higher than average costs, and a significant amount of load losses occur during high load conditions when the energy costs are the highest.

Some users will utilize energy costs associated with nearby generating units, especially if the lines are connected to switchyards at plant sites. Others will consider all losses to be incremental in nature and use the same costs system wide.

Capacity (demand) costs can be treated as incremental or average also. They can also incorporate the timing of new generation and/or transmission by calculating the NPV associated with an advancement of an installation date of a planned addition caused by the additional losses.

7.4 Contributing Factors to the Cost Of Losses

There are several factors that influence the magnitude of the cost of losses in a given transmission line, including:

- Line length – the impedance of the line increases proportionally with the length of the line.

- Conductor type & size – different types of conductors have different resistive and reactive characteristics. The larger the conductor, the lower the resistance.

- Load magnitude – as mentioned above, the load losses vary with the square of the load current.

- Loss factor – defined as the average loss / peak loss. This factor represents the level of uniformity of the loss over the given period of time, usually one year. Since the loss varies with the square of the load, as load increases, the loss factor increases by the square of the load increase, and the loss costs increase accordingly.
- Load growth – the higher the load growth, the greater the NPV of the cost of losses.
- Generating unit type – energy and demand costs vary widely for various types of generation.
- Voltage level – no-load losses will vary depending on the level of the operating voltage.

7.5 Loss Cost Formula

The following formulas are used by KEMA to approximate cost of transmission losses. The loss calculations are based on typical peak load currents approximate typical loss costs in this study.

EC (Energy Cost) = 3 x R x I^2 x 8760 x LF x AIC x LIF, and

DC (Demand Cost) = 3 x R x I^2 x IDC x LIF

Where

EC = energy cost, $ / yr

DC = demand cost, $ / yr

R = conductor resistance (ohms/phase/mile) X line length (miles)

I = peak load current on the line (amperes)

8760 = hours / year

LF = loss factor (average loss / peak loss)

AIC = average incremental energy cost for the year ($ / kWh)

LIF = loss increase factor (1 + PU system losses reflecting increase)

IDC = incremental demand cost ($ / kW-yr)

8. Cost Effects of EMF and Mitigation

Electric and magnetic Fields (EMF) are invisible lines of electrical and magnetic force that surround any electrical conductor with a current flowing along its length. For EMF at 60 Hz the electric field and the magnetic field may be treated separately. Both types of fields are present in the immediate vicinity of most power transmission lines, and in general:

- The electric field level (measured in kilovolts/meter, kV/m) increases in direct proportion to line voltage.

- The magnetic field level (measured in milligauss, mG) increases in direct proportion to the current flow in the line.

The levels of the both the electric field and the magnetic field are much higher in close proximity to a transmission line than they are at some distance from the line.

Transmission line EMF has been discussed at some length over the last 20 years, because there is concern that these fields may present health risks to those who are exposed to them on a regular basis. However, as stated previously by Acres (1):

> The biological effects from extremely low frequency fields are difficult to detect and define. At the present time, many studies on the subject of health risk and EMF have been conducted worldwide. To date, the scientific evidence is inconclusive, and a direct link between adverse health and EMF associated with electric power frequency (60 Hz in North America) cannot be confirmed or denied.

Despite this lack of proof, standards have been adopted by some governmental agencies as a safeguard for public health. Because there often are additional costs associated with mitigating EMF, this chapter addresses the field levels associated with the types of lines anticipated for Connecticut and discusses the costs needed to reduce them. These field levels were not explicitly modeled for the exact line designs illustrated in Section 3. Instead, field profiles from other studies for similar line types and voltages are presented in this section to show the relative magnitudes of such fields, some alternatives for reducing the field levels, and the approximate cost of doing so.

8.1 Overhead Construction

Both electric and magnetic fields are present in the area surrounding any overhead a.c. transmission line. The levels of these fields vary with line voltage and current, line design, and distance from the three phase conductors. These effects are illustrated in this section for typical 345 kV and 115 kV lines. Background on the assumed line configurations is provided in Appendix B.

8.1.1 Effects of line configuration and voltage

The arrangements and spacing of conductors on an overhead line significantly influence the EMF levels under the line. For example, Table 8-1 shows the magnetic and electric fields for both horizontal and delta conductor configurations at 345 kV. Magnetic fields for the delta configuration are 64% of those for the horizontal configuration directly under the line. However, delta configuration magnetic fields are approximately half of those for the horizontal configuration at distances of 20-100 ft from the centerline. Maximum electric fields for the delta configuration are only 15% lower than those for the horizontal configuration, but they are 50% lower at distances from 40 to 100 feet from the centerline. These reduced magnetic and electric fields for lines with a delta configuration must be balanced against first costs that are approximately 80% higher.

Line voltage also is an important factor in determining EMF levels near an overhead transmission line. Table 8-2 shows various magnetic and electric field levels for both horizontal and delta conductor configurations at 115 kV. When compared with similar EMF levels in Table 8-1 for 345 kV lines, the Table 8-2 data confirm that electric fields are impacted most by changes in line voltages. The line voltages in Table 8-2 are approximately one-third of those for Table 8-1, but the maximum electric fields are reduced by almost a factor of four. In this case, the reductions are due not only to changes in voltage but also to changes in conductor height and spacing. Because the assumed current flows for the 115 kV lines are 1000 Amperes per phase, as was the case for the comparable 345 kV lines, magnetic field levels changed for less between Tables 8-1 and 8-2. Once again, the changes are primarily due to minor differences in conductor configuration and spacing.

8.1.2 Effects of split-phasing

Split-phasing is a line design concept that reduces EMF by canceling the fields using additional phase conductors on the transmission towers. The most typical arrangements use two conductors per phase, for a total of six conductors. However, the towers must be comparable to those required for a double-circuit line, with the associated additional cost. Table 8-1 (part C) shows the very significant reduction in the magnetic field that result from split-phasing, especially at distances of 20 to 100 ft. from the right-of-way (ROW) centerline. Electric fields with split phasing are only incrementally lower than those for a delta configuration. First costs associated with split-phasing at 345 kV are, typically 40% higher than those for a single-circuit, wood H-Frame design (R.I. Study). Table 8-2 (part C) shows similar reductions for a split-phasing arrangement at 115 kV.

Table 8-1. 345-kV EMF Strengths from the Rhode Island Study

	Configuration and Field	Maximum Field	Distance from Centerline of Structure (ft)						
			0	20	40	60	80	100	200
A.	Horizontal								
	Magnetic field (mG)	210 at 0 ft	210	208	141	77.1	45.4	29.4	7.39
	Electric field (kV/m)	4.32 at 30 ft	2.73	3.67	3.75	1.89	0.92	0.5	0.07
B.	Davit (Delta)								
	Magnetic field (mG)	135 at -10 ft	132	95.7	58.7	35.6	22.8	15.6	4.23
	Electric field (kV/m)	3.64 at -20 ft	2.54	1.90	1.61	0.99	0.58	0.36	0.07
C.	Split-phase (Vertical)								
	Magnetic field (mG)	67.4 at 0 ft	67.4	52.8	29.2	15.5	8.69	5.2	0.83
	Electric field (kV/m)	3.00 at 10 ft	2.45	2.99	1.36	0.7	0.46	0.3	0.05

Table 8-2. Calculated 115-kV EMF Levels for Various Conductor Configurations

Configuration and Field	Maximum Field	Distance from Centerline of Structure (ft)						
		0	20	40	60	80	100	200
A. Horizontal								
Magnetic field (mG)	181 at 0 ft.	181	141	77.3	37.0	22.9	16.9	3.20
Electric field (kV/m)	1.16 at 0 ft.	0.40	1.14	0.76	0.34	0.16	0.095	0.015
B. Davit (Delta)								
Magnetic field (mG)	109 at 1 ft.	108	82.3	43.4	22.9	13.3	10.1	1.83
Electric field (kV/m)	0.945 at 12 ft.	0.72	0.90	0.46	0.20	0.11	0.069	0.015
C. Split-phase (Vertical)								
Magnetic field (mG)	43.4 at 0 ft.	43.4	29.7	13.7	6.40	2.97	1.83	0
Electric field (kV/m)	0.72 at 12 ft.	0.58	0.65	0.23	0.057	0.019	0.011	0

Table 8-3. Calculated EMF Levels for Single- and Double-Circuit 115 kV Overhead Lines

Configuration and Field	Maximum Field	Distance from Centerline of Structure (ft)						
		0	20	40	60	80	100	200
A. Single-circuit (vertical)								
Magnetic field (mG)	102 at 8ft	93.9	90.1	53.5	31.3	19.9	13.7	5.3
Electric field (kV/m)	1.18 at 8ft	1.02	0.87	0.26	0.03	0.04	0.05	0.02
B. Double-circuit (vertical)								

Magnetic field (mG)	171 at 0ft	171	139	87.8	51.9	34.4	24.4	6.1
Electric field (kV/m)	1.99 at 0ft	1.99	1.21	0.32	0.04	0.05	0.06	0.02

8.1.3 Single vs. Double-Circuit Lines

Table 8-3 lists EMF levels at various distances from the center-line of a single-circuit and a double-circuit 115 kV overhead line. The conductors for each circuit are arranged vertically, and a nominal loading level of 1000 Amperes per phase was assumed for both lines. Even though the power flow is doubled under these loading assumptions, EMF levels for the double-circuit line increase by less than a factor of two. This is due to some cancellation in the fields from the two circuits. A comparison of EMF levels for the single-circuit line in Table 8-3 that has a vertical conductor configuration with those for the single-circuit line in Table 8-2 that has a delta configuration shows quite similar field levels. Greater EMF level reductions are possible with more compact delta configurations that have less space between the conductors for each phase.

8.2 Underground construction

EMF from underground lines differs from EMF from overhead lines in two major respects:

1) Electric fields are zero above an underground line because the ground is at zero potential, and it is an excellent conductor of electricity.

Magnetic fields above an underground line can be higher than those beneath an overhead line because the conductors are much closer to the ground level, where most human contact would take place.

Because of the first consideration, only the magnetic field associated with underground lines need to be examined. This section discusses how these magnetic fields vary with cable configuration and examines the effectiveness of metallic shielding in mitigating these fields.

8.2.1 Effects of cable configuration

As is true with overhead transmission lines, the magnetic fields associated with underground lines vary considerably with the configuration of the cables for each of the three phases. Horizontal and delta configurations are both very common, and the magnetic fields for both are highest in the center of the ROW. As Figure 8-1 shows, the maximum magnetic field for the assumed 115 kV XLPE line with cables in a horizontal configuration and a loading level of 1000 Amperes per phase is approximately 200 mG, but it is less than 60 mG only 20 ft from the center of the ROW. For a 115 kV XLPE line with similar cables in a delta configuration and

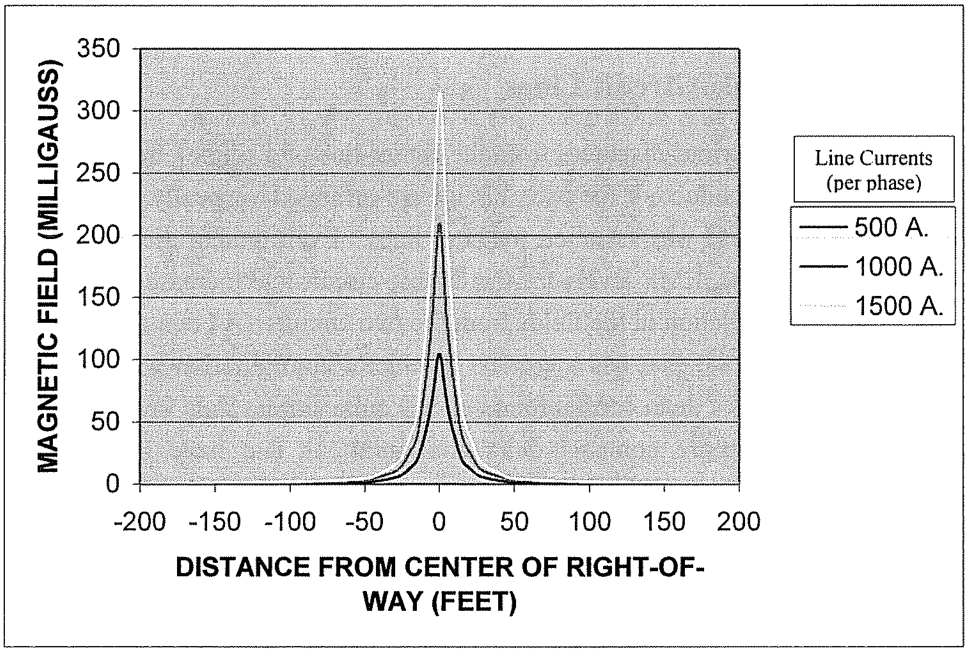


Figure 8-1 Magnetic Field Profiles for 115 kV XLPE Line with Horizontal Cable Arrangement

similar loading, the maximum field is approximately 95 mG and the field is less than 25 mG only 20 ft from the ROW centerline (See Figure 8-2). Magnetic field levels for three different line loadings are presented in Figures 8-1 and 8-2. Conductor sizes and physical arrangements are shown in Appendix B.

8.2.2 Effects of cable type

Magnetic fields are much lower for pipe-type underground lines, because the cables are compactly configured within a metal pipe. Also, a steel pipe provides the maximum shielding effect on magnetic fields, compared to a flat steel plate. As Figure 8-3 shows, the maximum field for a 115 kV HPFF cable, at an assumed loading level of 1000 Amperes per phase, is only 30 mG, and field levels at 20 ft or more from the ROW centerline are negligible.

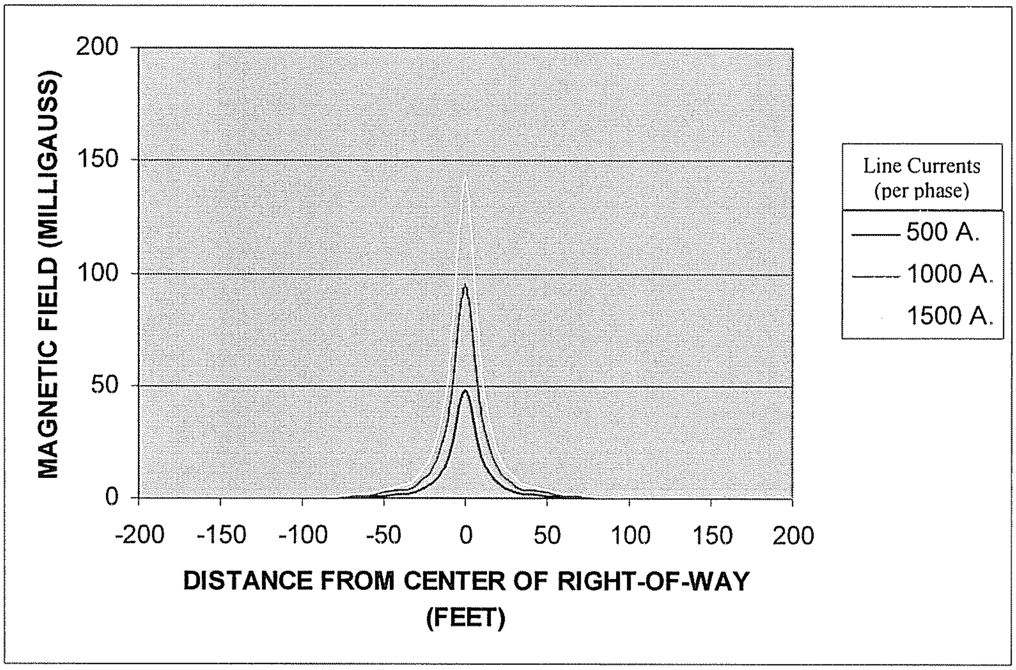


Figure 8-2 Magnetic Field Profiles for 115 kV XLPE Line with Delta Cable Arrangement

8.2.3 Mitigation alternatives

The two most common methods for mitigating the magnetic fields of solid dielectric cables include cable reconfiguration and shielding. Cable reconfigurations are used to reduce magnetic fields by cancellation among the three phases in a manner similar to the split-phasing of overhead transmission lines. In this case, it is common to use two cables per phase and to arrange one set of three cables with phase ordering A-B-C, while arranging the other set of three cables in a B-C-A phase order. The two sets of cables are configured in parallel, either horizontally or vertically. When configured as a double circuit line such alternate phasing schemes can reduce magnetic fields by up to 50% with little additional cost above that for a standard double circuit line. When used as an alternative to a three-cable, single circuit line, however the cost penalty is large because the total required length of cable is doubled.

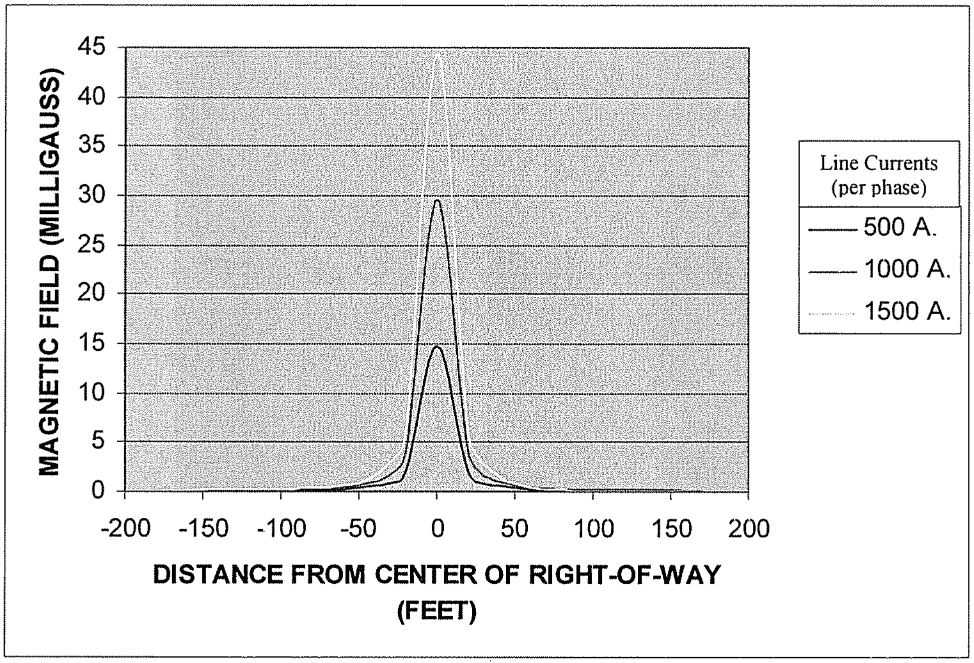


Figure 8-3 Magnetic Field Profiles for Typical 115 kV HPFF Line

Another mitigation method for single circuit XLPE lines is the use of metallic shielding. As Figure 8-4 illustrates for an underground line with a delta configuration, shield configurations can achieve a wide range of field reductions. To summarize, these results show:

- A flat plate shield will reduce magnetic fields by 33%.
- A half-round (180°) shield will reduce fields by 50%.
- A tubular shield with an opening of 10mm or less can reduce fields by 94-98%.

The costs of these shields vary with cable size and trench (or duct) size. However, they would most likely only be used in certain sensitive areas where human exposure to the field was a concern.

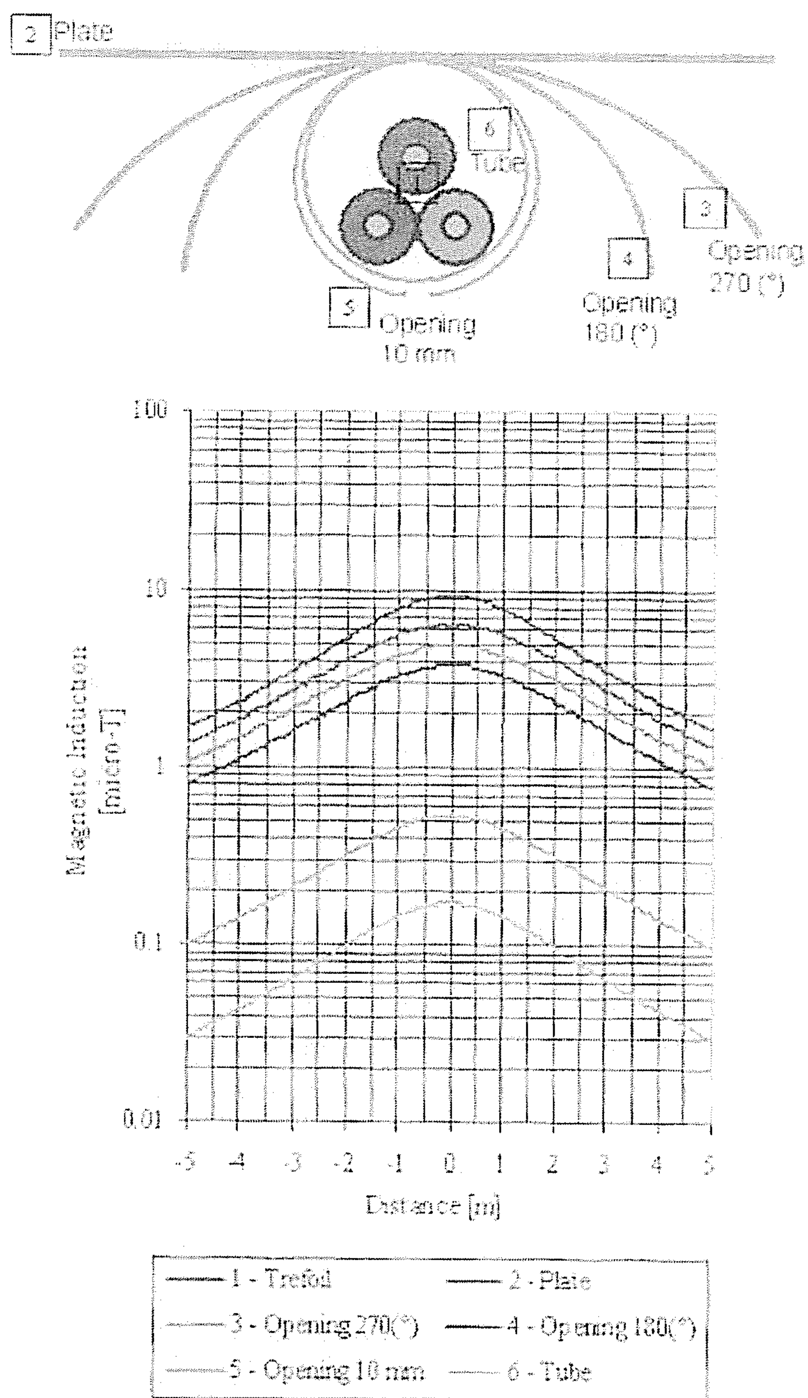


Figure 8-4 Magnetic Field Profile at 1 meter above Ground Level for Various Shielding Configurations (assumes 1500 Amps. Current flow)

9. Environmental Considerations and Costs

The State of Connecticut has a diverse and unique environment that is greatly valued by it's citizens. Accordingly, it is appropriate that the benefits of protecting and enhancing that environment are weighed against the associated costs. While electric power delivery enhances the lives of citizens in many ways, it also has impacts that can affect almost every aspect of their environment. This chapter identifies and discusses those impacts for all major environmental resources. Then it discusses, and where possible quantifies, the costs of mitigating key environmental impacts.

9.1 Environmental issues by resource type

Table 9-1 Summarizes the wide variety of environmental impacts that transmission lines can have for each of eight environmental resource categories. These include:

1) Resources related to life and habitat, such as air, water and biological resources;

2) Earth and land-related resources, including topography, geology, land-use and agricultural; and

3) Aesthetic considerations, such as visual, cultural, and historic resources.

The potential impacts listed for these resource categories are meant to be illustrative and are by no means exhaustive. Such impacts frequently conflict with one another and lead to tradeoffs. For example, in the State of Virginia it was found that running a line along the side of a long north-south ridge about halfway from the bottom to the top would be visually less noticeable from a distance. However, such siting was less desirable from a biological perspective because the hot, dry right of way would prevent certain forest amphibians from reaching higher elevations to reproduce. Other resources overlap with each other. Most notably, geology and soils almost always affect water resources, which also affect biological resources. An exhaustive discussion of each category is beyond the scope of this report, which is focused on the effects environmental impacts have on transmission line costs.

Both State and Federal agencies oversee certain aspects of Connecticut's environment, as listed in Table 9-2. Of these, the Connecticut Siting Council has the broadest responsibilities and must grant approval by issuing a Certificate of Environmental Compatibility and Public Need. The Connecticut Department of Environmental Protection (CDEP) also plays a key role in the siting of transmission facilities. Effects of construction on water quality and storm water are key concerns, and any projects in either coastal zones or "tidally influenced areas" receive greater scrutiny. Impacts in cultural and historic resources are overseen by the Connecticut Historical Commission, which requires a finding of "no adverse effect."

Finally the Department of Public Utility Control (DPUC) must approve the line construction methods and give final approval to energize.

Two Federal agencies also oversee some aspects of transmission line siting in the State of Connecticut. Of these, the U.S. Army Corps of Engineers has the greatest influence. Specifically, The Corps of Engineers requires a Section 404 permit for all dredge and fill activities (including wetlands and watercourses) and requires a Section 10 permit for any work that impact navigable waterways. It is our understanding that the Corps interprets the term "navigable" in very broad terms.

The U.S. Army Corps of Engineers (Corps) review permit applications and determines compliance pursuant to the Clean Water Act, and the Rivers and Harbors Act. The U.S. Fish and Wildlife Service, National Marine Fisheries Service, and the U.S. Environmental Protection Agency provide input to the Corps permitting process.

Table 9-1. Environmental Factors for Transmission Line Siting and Operation

Environmental Resources	Potential Impact Issues for Transmission Lines*
Water Resources	▪ Erosion and sedimentation into waterbodies ▪ Loss of stream and wetland habitat and function ▪ Alterations in localized groundwater flow due to blasting (e.g., individual wells) ▪ Adverse effects on water quality as a result of herbicide use ▪ Adverse effects of access roads and/or facilities placed in or across water resources
Biological Resources	▪ Disturbance to or loss of habitat ▪ Modifications to vegetative diversity ▪ Effects on birds (collisions, electrocution, disruption of nesting by vegetation clearing) ▪ Effects of herbicides ▪ Effects on RTE habitat or individuals ▪ Effects of stream bank and water quality modifications, as well as loss of riparian vegetation on fisheries
Land Use and Recreation	▪ Restrictions on use options for land ▪ Multiple use of right-of-way ▪ Impacts of unauthorized use (e.g., ATV use leading to erosion/-sedimentation)
Topography, Geology, and Soils	▪ Conditions affect engineering design of transmission facilities (e.g., structure footing, spans, practicality of undergrounding) ▪ Modifications to topography (and effect of topography on feasibility of transmission line installation) ▪ Amount of blasting required ▪ Soil erosion and/or instability ▪ Soil compaction
Visual Resources	▪ Intrusive effects of towers and/or maintained right-of-way and other aboveground facilities ▪ Degree of visual contrast to viewers
Cultural Resources	▪ Direct effects on buried cultural resource sites ▪ Indirect effects on standing historic structures as a result of views of transmission facilities
Air Quality and Noise	▪ Fugitive dust during construction ▪ Noise during construction and from transmission wires during operation (audible corona discharge (crackling), under certain weather conditions is unlikely to occur with 115-kV or lower voltage facilities)
Agricultural Resources	▪ Decrease in agricultural land production from placement of structures in agricultural areas ▪ Impacts to productivity caused by soil mixing, compaction (as a result of equipment access through agricultural areas, trenching) ▪ Impacts to livestock

Table 9-2. Environmental Permit/Certificate Approvals for Typical Transmission Line (Overhead or Underground)

Agency	Type of Approval Required
State	
Connecticut Siting Council	Certificate of Environmental Compatibility and Public Need
Connecticut Department of Environmental Protection	401 Water Quality Certification Storm Water Pollution Prevention Approval for temporary disturbance of more than 5 acres of land Coastal Zone Consistency Certification of Structures and Dredging Permit for coastal zone or tidally influenced areas (from DEP, Office of Long Island Sound Programs)
Connecticut Historical Commission	Review of archaeological and historic resources, consistent with the National Historic Preservation Act; approval by finding of no adverse effect
Department of Public Utility Control	Method and Manner of Construction approval Approval to Energize
Federal	
U.S Army Corps of Engineers, New England Division	404 permit for dredge and fill activities (wetlands and watercourses) or *nationwide permit approval (*for most utilities) Section 10 permit for work in navigable waterway
Federal Aviation Administration	Notification of presence of overhead lines only

9.2 Effects on line cost

While there are a wide range of environmental impacts associated with transmission line construction and operation, the cost effects of these impacts usually are attributable to one or more of the following cause categories:

- Higher cost tower structures and construction in affected areas
- Avoidance (or circumvention) of affected areas
- Toxic substance handling and disposal
- Site restoration activities
- Delays in project start-up or completion

Each of these categories is discussed briefly, with some examples, in the remainder of this section.

9.2.1 Higher cost towers and construction

Power lines that traverse environmentally-sensitive areas, such as wetlands, river crossings, tidal areas, and forested areas with endangered or threatened species, often must use higher cost structures or incur significantly higher construction costs. It is common in such areas to use higher, stronger poles/towers that permit longer spans and fewer foundations. Higher towers also permit the maintenance of vegetation, shrubs, and small trees under overhead lines. Such vegetation preserves moisture and moderates temperatures on the ground level along the line ROW. The higher towers are more expensive and usually require larger and more elaborate foundations.

Construction cost increases may result from the use of specialized methods and/or from complex work scheduling. For example, options considered during siting proceedings for the Middletown-Norwalk 345 kV line called for the use of wooden mats during construction in wetland areas. Such mats permit as much as a five-fold reduction in the surface area that is disturbed during construction.

Work scheduling also can be greatly complicated by efforts to protect fish and wildlife. The Department of Environmental Protection's (DEP's) suggested restrictions for the Middletown-Norwalk (M-N) line provide an illustrative example. Even though no significant watercourse impacts are anticipated from the M-N line, DEP offered the following guidelines for instream work and special habitat areas in its May 4, 2004, letter:

- "...the DEP Inland Fisheries Division suggests in stream work be restricted to the period from June 1 to September 30, inclusive."

- "The recommended window for construction activities in areas which support wood turtles and box turtles is November 1 to April 1...If any of these wetlands are riverine wetlands, it will be necessary to avoid any in stream work or access in these areas."
- "Unconfined in-water work is often prohibited in selected areas from February 1 to May 15 to protect winter flounder spawning areas. Anadromous migration should be protected from July 1 to September 30."
- "If a jack and bore crossing technique creates a substantial amount of noise, DEP may request a time-of-day restriction for work within the standard anadromous period from April 1 to June 30..."

9.2.2 Avoidance of affected areas

One of the most common approaches to dealing with environmentally sensitive areas, such as parks, wetlands, and cultural sites is to avoid them by routing the line around them or over some alternative route. At a minimum, such avoidance results in higher costs due to greater line length and higher cost structures, due to a less direct route and more angles in the ROW. For one important 765 kV transmission line from West Virginia to Virginia, the designation of a major river as "wild and scenic" by the Environmental Protection Agency caused the entire line application to be withdrawn and a new route identified. Several years were required to develop a new, much longer route."

The application phase for the Middletown-Norwalk (M-N) line provides numerous examples of the need to avoid environmentally sensitive areas. In some instances, complete avoidance was impossible, and it was necessary to select a route that would minimize exposure. For example, the Applicants for the line observed, "There are some wetlands that run longitudinally along the right-of-way for a distance, making it difficult to avoid wetland impacts. The Applicants would determine the area of the wetland where the depth of the water is the shallowest, and would minimize the impact of construction on that wetland."

In the most heavily developed sections of Southwest Connecticut, marine routes seemed to be an attractive option. However, shellfish beds presented a nearly insurmountable obstacle. For example, it was found that, "A route from the East Shore into New Haven harbor would have impacts to shellfish beds...The route would have to traverse the Housatonic River, a major source of seed oysters, and pass the Steward B. McKinney National Wildlife Refuge." Similarly, "the feasibility of a marine route from Singer Substation to Norwalk Substation was considered. Such a route would cross shellfish beds."

Also, the Coastal Zone Management Act scrutinizes shoreline development in the context of a "water-dependent" use. That is to say that a project that does not require water-front access is encouraged to be developed inland. Typically, electric transmission infrastructure is land-based.

Historical and cultural sites also are numerous in southern Connecticut. Two examples that affected the M-N line routing include:

- The Applicants support a change of the proposed transmission line infrastructure within the Town of Westport...(that) would reduce the length of the proposed route by approximately 2,750 feet and avoid the Westport historic district."
- In place of the proposed Norwalk River crossing, the Applicants support a change with an alternate crossing that would...avoid disruption of the cemetery location."

Both of these examples reflect cases where site avoidance actually could reduce costs by shortening the total line length. Thus, the scrutiny of line applications by various parties can in some instances lead to cost *benefits*.

9.2.3 Toxic substance handling and disposal

One might not expect that the construction of a new transmission line would incur high costs from the handling of toxic substances. However, this has been a major cost concern for the proposed M-N line in Southwest Connecticut. There are several reasons:

- Much of the line is to be constructed under existing state highways, and a significant amount of the soil under these highways is already contaminated. Once removed, however, the soil cannot be returned but must be replaced with uncontaminated soil.
- The proposed routed will cross both the Middletown-Durham and Wallingford landfills, and DEP requires that, "If any new pole structures fall within the footprint of any previously placed waste, an authorization for disruption of a solid waste disposal area must be obtained from the DEP Bureau of Waste Management."
- Testing for trichloroethylene (TCE) is required at the East Devon Substation site. "If contamination is found, removal and disposal of contaminated soils will be required."

Once contaminated soil is removed, it must be treated as a toxic substance and be properly disposed of, often involving transportation out of the state. Temporary storage prior to this removal also may incur high costs and subsequent clean-up.

9.2.4 Site restoration

Site restoration costs may be incurred in some locations. Typical examples include agricultural sites and areas with erodable soils and steep grades. The associated costs could include regrading and/or the planting of vegetation to prevent erosion. Because much of Connecticut is rocky with granite ledge that requires blasting, the need to engage in at least some site restoration is virtually assured.

9.2.5 Delays in project completion

Environmental reviews, discovery, and investigations may lead to necessary, but substantial delays in line construction and commissioning. During these periods of delay, escalations in both material costs and labor costs can cause substantial increases in a line's first costs, which are the largest component of its life cycle cost. A check of the increase in transmission line life cycle costs since the last Connecticut Siting Council LCC study in 1996 shows that this escalation is significantly higher than the general inflation rate over that same time period.

10. Life-Cycle Cost Calculations for Reference Lines

As outlined in Chapter 2 of this report, Life Cycle Costs are the total costs of ownership of an asset over its useful life. In the case of electric transmission lines, the useful life of the asset can be a subject of much study and debate. As was exhibited in Chapter 2 however, the useful life period used in a Present Value Life Cycle Cost calculation is less important as an absolute term than as a comparison of assets over an equivalent period of service. Also, as illustrated in that chapter, the first costs of a transmission line project are the primary drivers of life cycle costs with the cost of electrical losses being the most significant ongoing cost.

For the purpose of life cycle costs calculations for this study, a period of thirty-five years has been used. This is a term that is believed by the Connecticut utilities to be a fair representation of a life cycle analysis period for transmission lines and is consistent with models they employ.

This chapter offers information on the results of life cycle cost calculations for the ten transmission line designs that were identified in Chapter 3. These ten line designs are the ones that are in use, or will be used, in Connecticut for the foreseeable future. Also in this chapter is analysis of the life cycle cost results, the contribution of the major components to the life cycle costs, and some discussion of the primary drivers of the costs.

10.1 Life Cycle Cost Assumptions

The input data used in performing the calculations for life cycle costs for overhead and underground transmission line designs include first costs, operating and maintenance costs, and the cost of electrical losses.

The economic indicators and calculation variables used along with the values assumed include:

Capital recovery factor:	14.6%
Operation and maintenance cost escalation:	4.0%
Load growth:	1.2%
Energy cost escalation	5.0%
Discount rate:	10.0%

These factors are consistent with previous LCC studies done for the Connecticut Siting Council and are representative of variables used by utilities in their cost calculations. More detail on each variable follows.

Capital recovery factor: this factor is used to spread the first cost of a transmission line over the lifetime of the line. The factor includes allowances for taxes and cost of capital. The LCC calculation assumes a zero salvage value at the end of the 35-year lifetime of a transmission line.

O&M cost escalation: The cost escalation factor is used to account for the ongoing increases in the cost of materials and labor over the life of the asset. A factor of 4%, inclusive of economic inflation, has been used in this study and is consistent with the cost escalation factors used by the Connecticut utilities.

Load growth: The cost of electrical losses are the second most significant cost in a transmission line life cycle cost study. The losses experienced on a line are a factor of the line loading so increases in load have a direct impact on losses and therefore costs. In Connecticut, an average load growth estimate of 1.2% has been adopted as part of the 2005 Connecticut Siting Council Ten Year Load Forecast and was confirmed by the utilities as a reasonable estimate for the purpose of this study.

Energy cost escalation: The primary variable in the calculation of the cost of electrical losses is the cost of energy produced by the electricity generator. The cost of energy is directly tied to the cost of fuel and as such, can be highly variable, depending upon energy markets worldwide. For this study an energy escalation factor of 5% per year has been assumed.

Discount rate: The interest rate used to discount the cash flows over the 35 year life cycle cost period to their present value. Assumed at 10% for this study.

Using the factors outlined here, thirty-five year Present Value analysis of the costs of transmission lines has been done. The costs and cash flows used in this study are based on the current costs incurred by the Connecticut utilities for transmission line projects, operations and maintenance expenses, and electrical line losses. As stated in many instances in this report, however, the life cycle cost of a transmission line is specific to the particular project being evaluated. The high variability of costs for permitting, materials, land and other components can significantly alter the life cycle cost from one project to another.

This study has used recent cost information, as reported by the utilities to FERC, as the basis for the life cycle cost analyses. After extensive discussion with utility representatives, assumptions have been made that are believed to be fair and representative of current conditions in the State.

The thirty-five year life cycle cost calculations for ten transmission line designs are found in Appendix A. The remainder of this chapter will be used to highlight comparisons and present some analysis of these calculations.

10.2 Life Cycle Cost Comparison

The cumulative present value of a life cycle cost is the value used to compare design alternatives for the purpose of capital investment decisions. As highlighted earlier in this report, the first cost component of overhead versus underground design is the primary contributor to the life cycle cost and can represent differences in costs by factors as high as 4 to 6 times. Within a specific overhead or underground design, however, there are also differences that can vary the cost of a line significantly.

Table 10.1 shows the total life cycle costs for each of the overhead lines considered. For 115 kV, single circuit lines the LCC of a line with steel poles is 37% higher than a line with wood poles. This is entirely due to the differences in first costs, because the two lines' O&M and loss costs are identical. The life cycle economics of double circuit lines are clear in Table 10.1 for steel poles, because the line has two times the power capacity for only a 52% increase in LCC. The costs of the two 345kV transmission lines are less than twice the costs of comparable 115 kV lines, and yet they can carry three to four times as much power.

Figure 10.1 presents a summary of the variation of cumulative life cycle costs among the six overhead line designs discussed in this report. The results for all six lines show that 75% to 80% of total LCC are expended during the first 17 years. This means only 20-25% of the total LCC must be expended for the next 18 years. Such results are typical except when certain cost components escalate more rapidly than the assumed discount rate.

Table 10-1. Overhead Transmission Line Life Cycle Cost Components

:C Component	115 kV Wood Laminate Poles, Delta Single Circuit	115 kV Steel Poles, Delta Single Circuit	345 kV Wood Laminate H-Frame Single Circuit	345 kV Steel Poles, Delta Single Circuit	115 kV Wood Laminate Poles, Vertical Double Circuit	115 kV Steel Poles, Vertical Double Circuit
es & Foundations	419,633	904,156	931,247	2,445,721	456,242	1,011,337
Conductors & Hardware	474,872	474,872	788,551	788,830	1,090,502	1,090,502
Site Work	127,854	127,854	258,095	258,095	171,507	171,507
Construction	221,801	348,900	424,961	770,017	370,380	488,775
Engineering	86,646	237,615	146,914	248,443	133,650	170,530
Sales Tax	61,218	96,296	117,289	212,525	102,224	134,902
Administrative	139,202	218,970	266,705	483,263	232,450	306,756
Loses	710,162	710,162	710,162	710,162	1,420,324	1,420,324
O&M	115,689	115,689	115,689	115,689	115,689	115,689
Total LCC	2,357,077	3,234,514	3,759,614	6,141,746	4,092,969	4,910,322

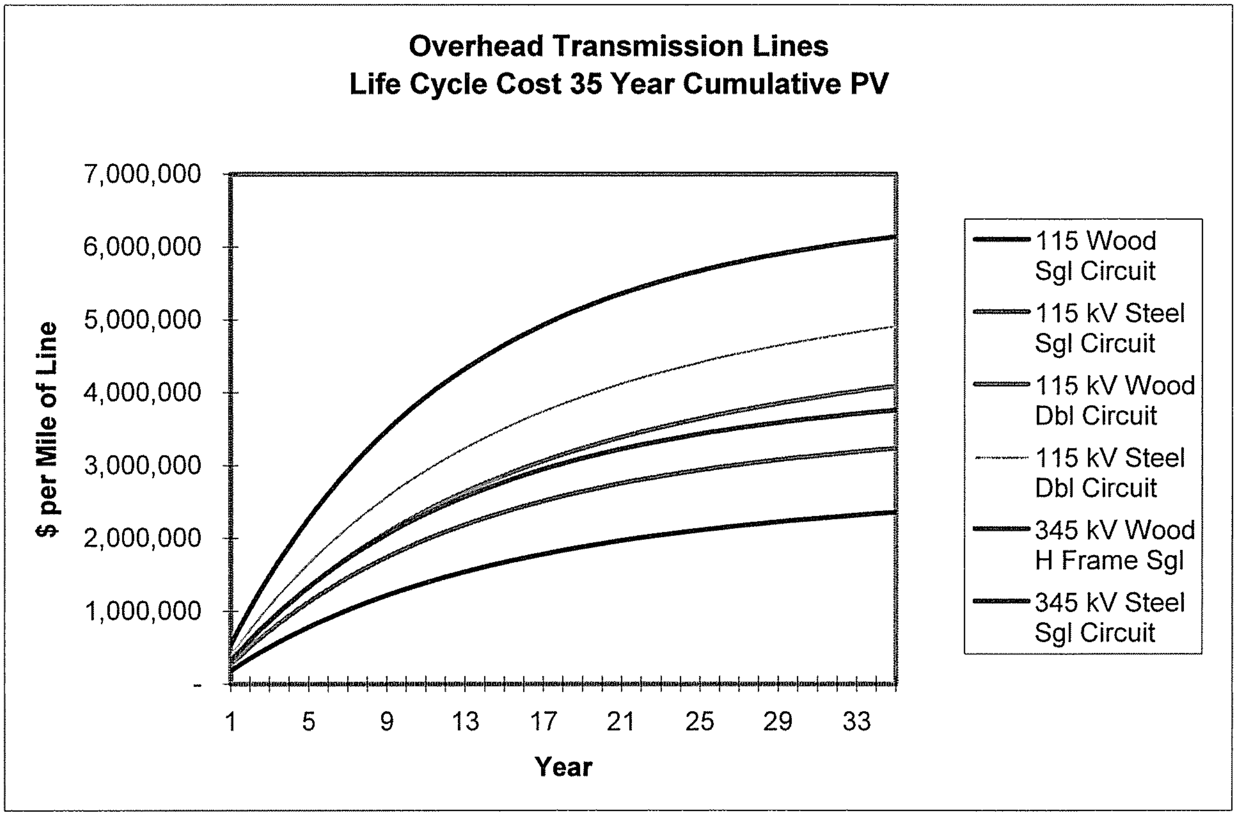


Figure 10-1. Overhead Transmission Line Life Cycle Costs

Table 10-2 shows the LCC by component for the four underground lines considered. These results clearly show the degree to which first costs dominate the LCCs of underground lines in Connecticut. Whereas the combined losses and O&M components were 25-30% for the overhead lines, they are 5% or less for the four underground lines.

Table 10-2. Underground Transmission Line Life Cycle Cost Components

LCC Component	115 kV XLPE	115 kV HPFF	345 kV XLPE Double Circuit	345 kV HPFF Double Circuit
Ducts & Vaults	5,925,746	4,633,392	7,228,003	5,331,430
Cable & Hardware	2,236,323	4,439,878	11,925,157	5,190,766
Site Work	861,415	861,415	869,945	241,480
Construction	1,159,085	1,159,085	2,136,106	1,076,368
Engineering	340,279	341,611	1,337,960	355,201
Sales Tax	484,051	526,028	982,609	560,981
Administrative	1,317,427	1,390,899	2,447,977	1,275,623
Losses	378,138	378,138	756,276	756,276
O&M	54,048	54,048	54,048	54,048
Total LCC	12,756,511	13,784,493	27,738,082	14,842,173

Figure 10-2 shows the yearly growth in LCC over the assumed 35 years of line life. The relative cost difference for a 345kV XLPE line versus a 345kV HPFF line is quite dramatic. Also of interest is the relatively small LCC difference between a 345kV HPFF line and either of the 115kV alternatives.

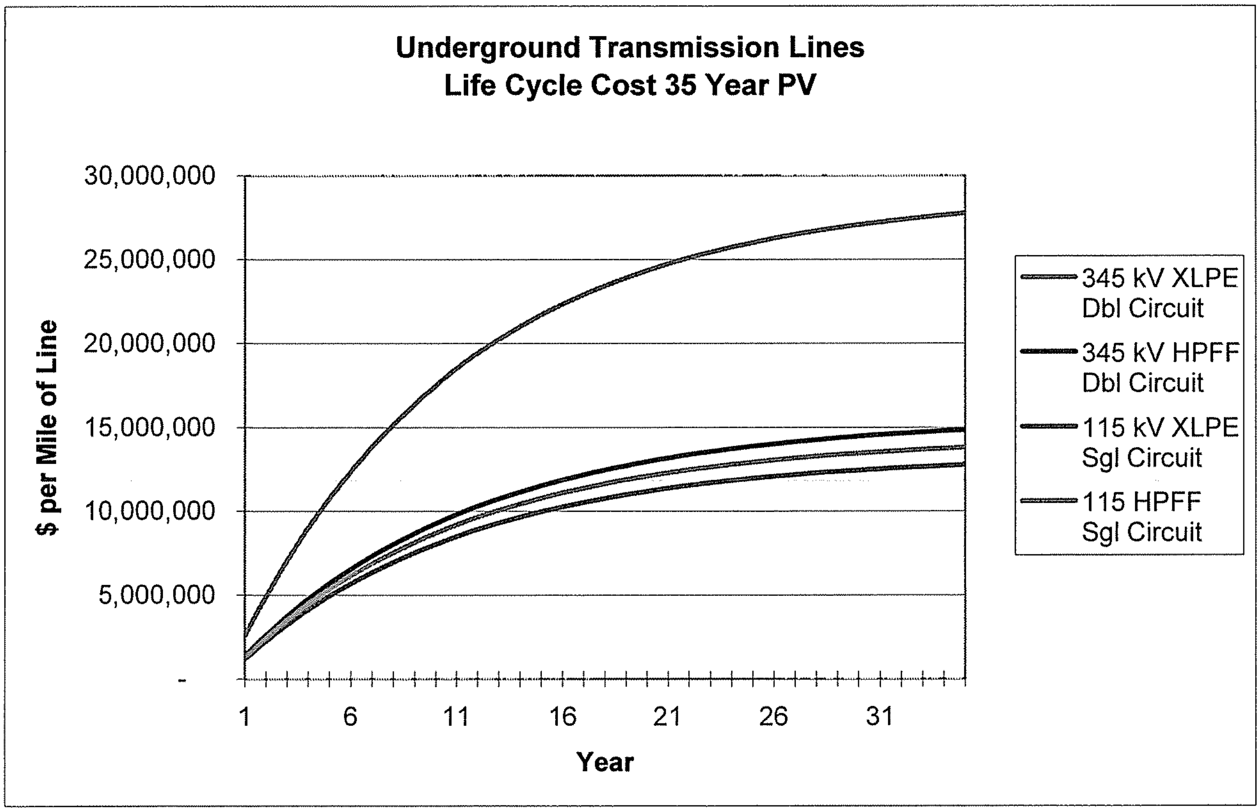


Figure 10-2. Underground Transmission Line Life Cycle Costs

Figures 10-3 through 10-6 show how the cumulative PV of LCC components vary over the overhead and underground lines, first at 115kV and then at 345kV. At both voltages, the cumulative variable components of O&M and losses are significant enough to "cross-over" the cumulative PV of first costs during the latter half of the lines' lives. The same is not true of either of the underground lines, due both to their higher first costs and their reduced loss costs.

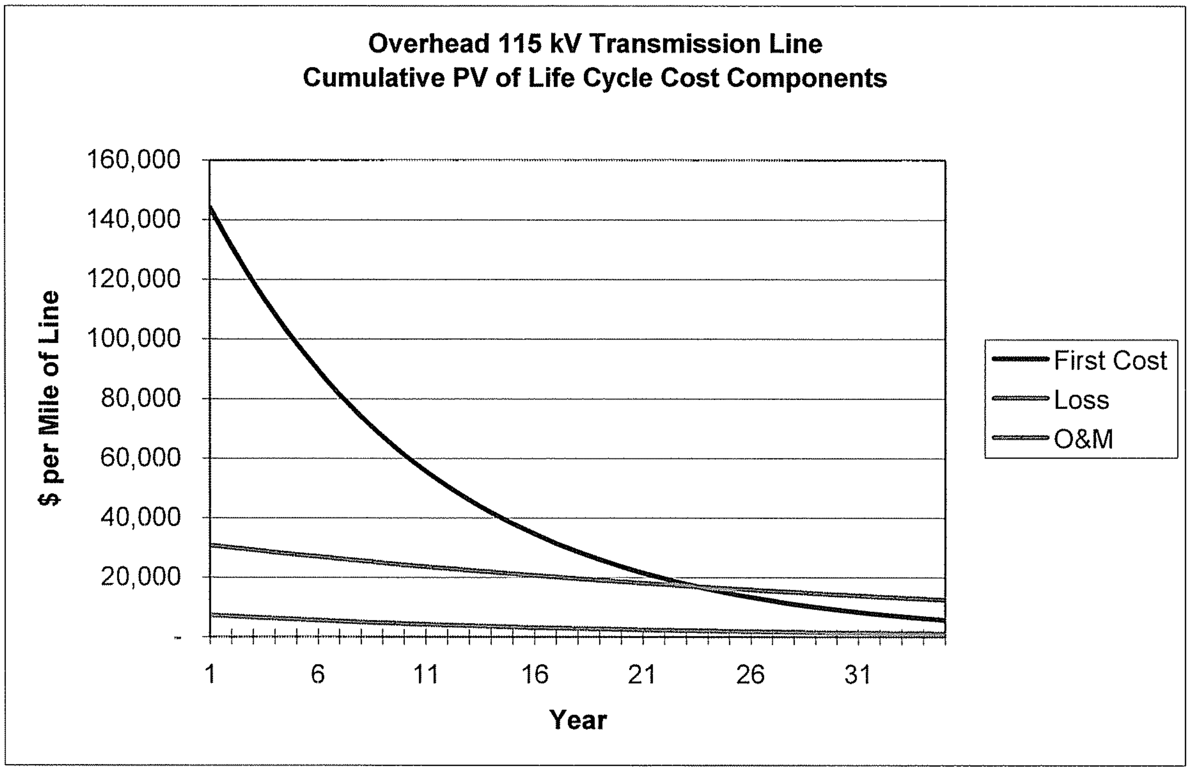


Figure 10-3. 115 kV Overhead Transmission Line Component Costs

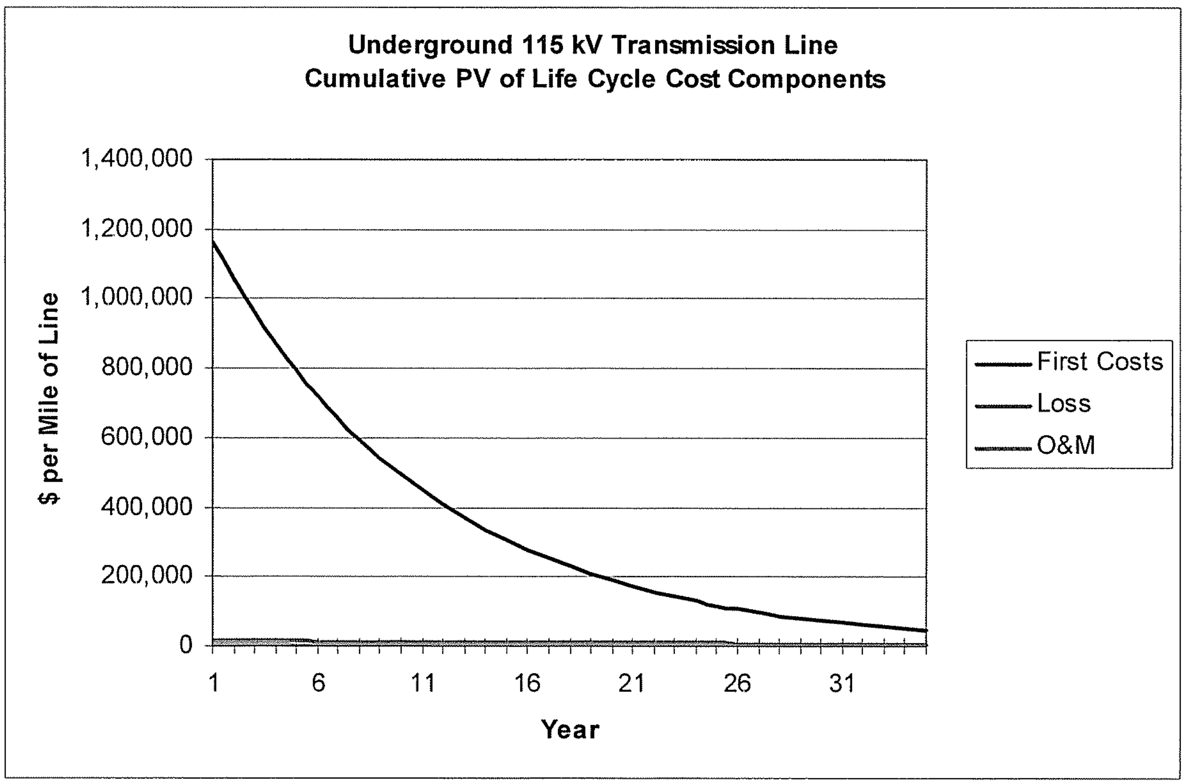


Figure 10-4. 115 kV Underground Transmission Line Component Costs

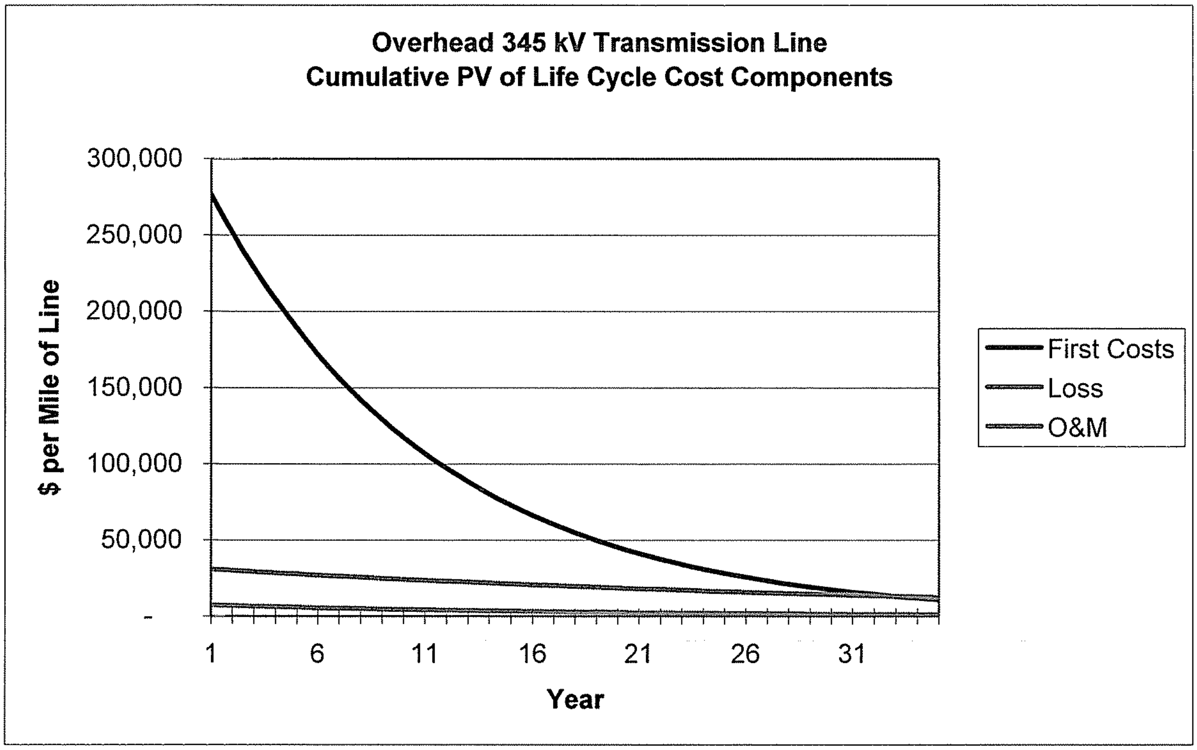


Figure 10-5. 345 kV Overhead Transmission Line Cost Components

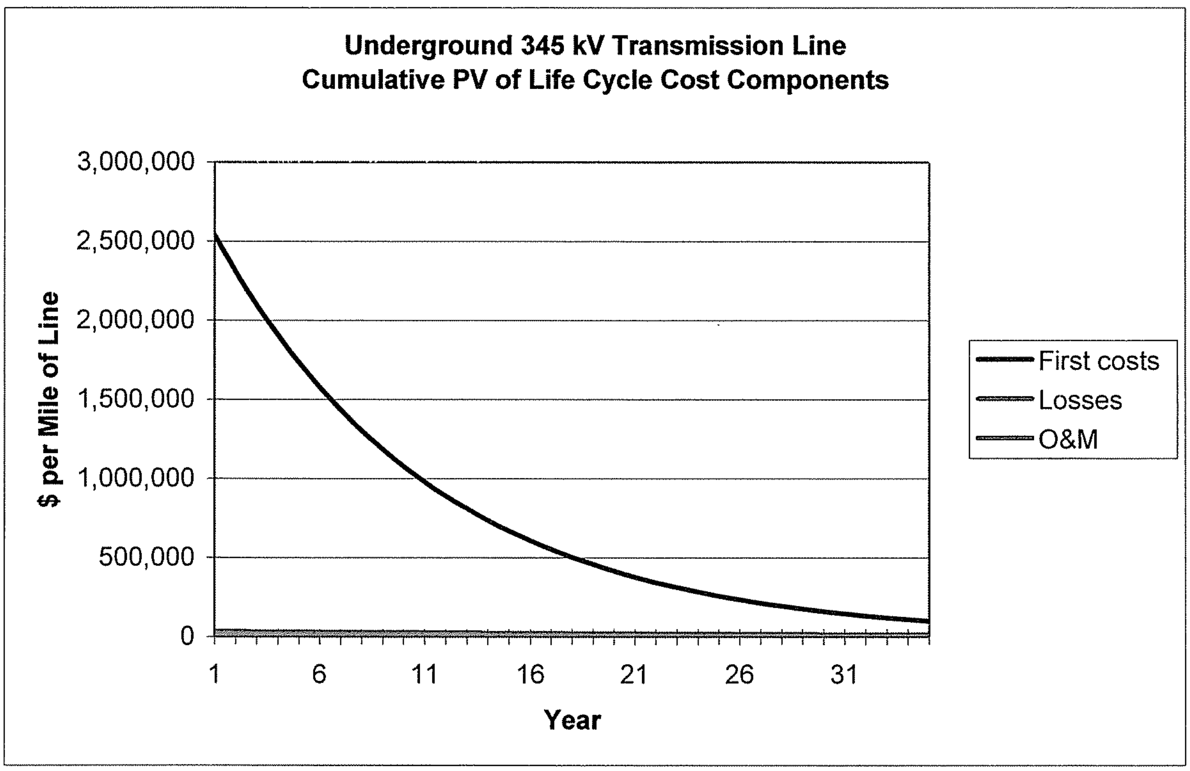
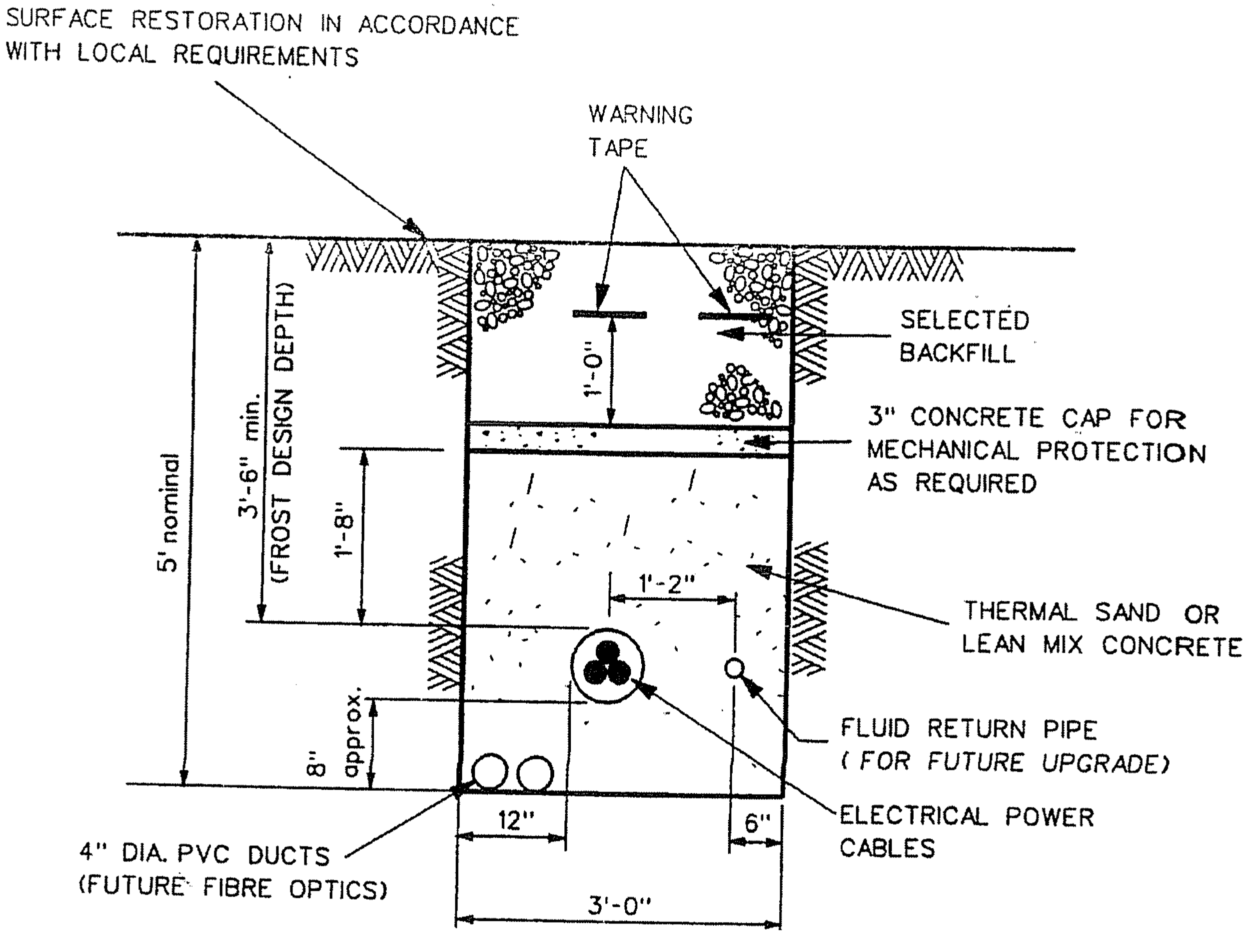


Figure 10-6. 345 kV Underground Transmission Line Component Cost

11. Appendix A – Life Cycle Cost Tables

115 kV Underground, HPFF



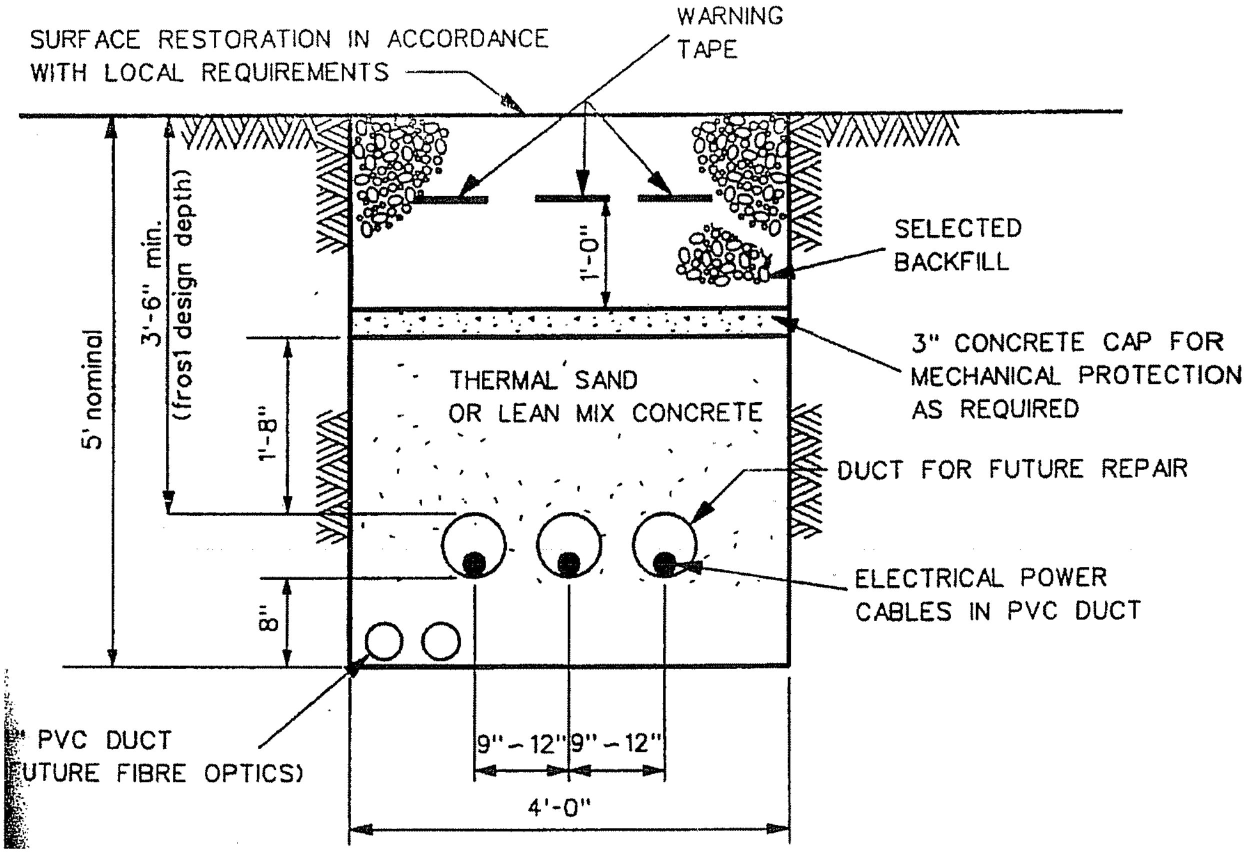
(Source: CL&P)

115 kV Underground, HPFF

First Costs		Losses	
Ducts & Vaults	3,290,651	Conductor	1750 kcmil
Conductor & Hardware	3,153,217	Resistance	0.03147 ohms/mi
Site Work	611,780	Load	1000 amps
Construction	823,186	Load growth	1.2%
Engineering	242,613	Loss factor	0.38
Sales Taxes	373,587	Energy cost	55.13 mils/kWh
Administration	987,821	Energy cost escal.	5.0%

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Cum. PV
1	0.91	1,258,633	16,388	3,430	1,278,451	1,278,451
2	0.83	1,144,212	15,958	3,243	1,163,413	2,441,864
3	0.75	1,040,193	15,539	3,066	1,058,797	3,500,661
4	0.68	945,630	15,130	2,898	963,659	4,464,320
5	0.62	859,664	14,733	2,740	877,137	5,341,457
6	0.56	781,512	14,346	2,591	798,449	6,139,906
7	0.51	710,466	13,969	2,450	726,884	6,866,790
8	0.47	645,878	13,602	2,316	661,796	7,528,586
9	0.42	587,162	13,245	2,190	602,596	8,131,183
10	0.39	533,783	12,897	2,070	548,751	8,679,933
11	0.35	485,258	12,558	1,957	499,773	9,179,706
12	0.32	441,143	12,228	1,851	455,222	9,634,928
13	0.29	401,039	11,907	1,750	414,696	10,049,624
14	0.26	364,581	11,594	1,654	377,830	10,427,454
15	0.24	331,438	11,290	1,564	344,291	10,771,745
16	0.22	301,307	10,993	1,479	313,779	11,085,524
17	0.20	273,915	10,704	1,398	286,018	11,371,542
18	0.18	249,014	10,423	1,322	260,759	11,632,300
19	0.16	226,376	10,149	1,250	237,775	11,870,076
20	0.15	205,797	9,883	1,181	216,861	12,086,937
21	0.14	187,088	9,623	1,117	197,828	12,284,765
22	0.12	170,080	9,370	1,056	180,506	12,465,271
23	0.11	154,618	9,124	998	164,741	12,630,012
24	0.10	140,562	8,885	944	150,390	12,780,402
25	0.09	127,784	8,651	893	137,327	12,917,729
26	0.08	116,167	8,424	844	125,435	13,043,164
27	0.08	105,606	8,203	798	114,607	13,157,771
28	0.07	96,006	7,987	754	104,747	13,262,518
29	0.06	87,278	7,777	713	95,768	13,358,286
30	0.06	79,344	7,573	674	87,591	13,445,877
31	0.05	72,130	7,374	637	80,142	13,526,019
32	0.05	65,573	7,180	603	73,356	13,599,375
33	0.04	59,612	6,992	570	67,174	13,666,549
34	0.04	54,193	6,808	539	61,540	13,728,089
35	0.04	49,266	6,629	509	56,405	13,784,493
		13,352,308	**378,138**	**54,048**	**13,784,493**	

115 kV Underground, XLPE



(Source: CL&P)

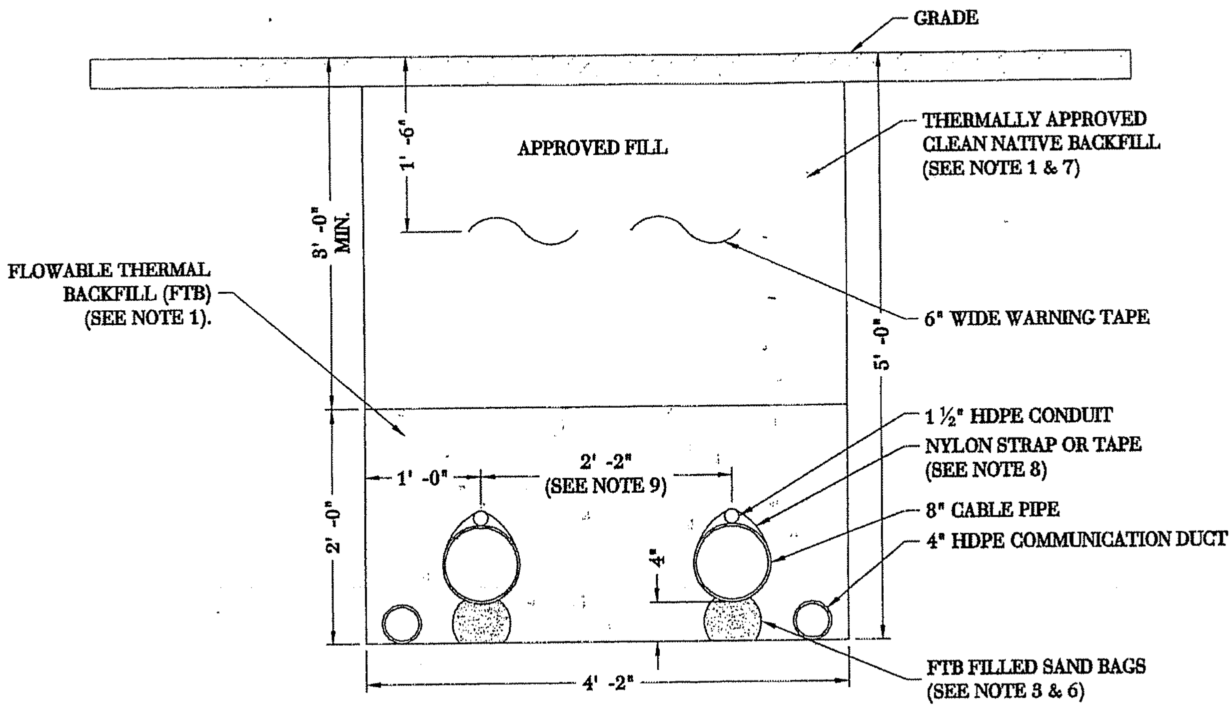
115 kV Underground, XLPE

First Costs	
Ducts & Vaults	4,208,485
Conductor & Hardware	1,588,244
Site Work	611,780
Construction	823,186
Engineering	241,667
Sales Taxes	343,775
Administration	935,641

Losses	
Conductor	1750 kcmil
Resistance	0.03147 ohms/mi
Load	1000 amps
Load growth	1.2%
Loss factor	0.38
Energy cost	55.13 mils/kWh
Energy cost escal.	5.0%

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Cum PV
1	0.91	1,161,732	16,388	3,430	1,181,550	1,181,550
2	0.83	1,056,120	15,958	3,243	1,075,321	2,256,871
3	0.75	960,109	15,539	3,066	978,714	3,235,584
4	0.68	872,827	15,130	2,898	890,856	4,126,440
5	0.62	793,479	14,733	2,740	810,952	4,937,392
6	0.56	721,344	14,346	2,591	738,281	5,675,673
7	0.51	655,768	13,969	2,450	672,186	6,347,859
8	0.47	596,152	13,602	2,316	612,070	6,959,930
9	0.42	541,957	13,245	2,190	557,391	7,517,321
10	0.39	492,688	12,897	2,070	507,655	8,024,976
11	0.35	447,898	12,558	1,957	462,414	8,487,390
12	0.32	407,180	12,228	1,851	421,259	8,908,649
13	0.29	370,164	11,907	1,750	383,820	9,292,469
14	0.26	336,512	11,594	1,654	349,761	9,642,230
15	0.24	305,920	11,290	1,564	318,774	9,961,004
16	0.22	278,109	10,993	1,479	290,581	10,251,585
17	0.20	252,827	10,704	1,398	264,929	10,516,514
18	0.18	229,843	10,423	1,322	241,587	10,758,102
19	0.16	208,948	10,149	1,250	220,347	10,978,448
20	0.15	189,953	9,883	1,181	201,017	11,179,465
21	0.14	172,684	9,623	1,117	183,424	11,362,889
22	0.12	156,986	9,370	1,056	167,412	11,530,302
23	0.11	142,714	9,124	998	152,837	11,683,138
24	0.10	129,740	8,885	944	139,569	11,822,707
25	0.09	117,946	8,651	893	127,489	11,950,196
26	0.08	107,223	8,424	844	116,491	12,066,687
27	0.08	97,476	8,203	798	106,476	12,173,164
28	0.07	88,614	7,987	754	97,356	12,270,519
29	0.06	80,558	7,777	713	89,049	12,359,568
30	0.06	73,235	7,573	674	81,482	12,441,051
31	0.05	66,577	7,374	637	74,589	12,515,639
32	0.05	60,525	7,180	603	68,308	12,583,947
33	0.04	55,022	6,992	570	62,584	12,646,531
34	0.04	50,020	6,808	539	57,367	12,703,899
35	0.04	45,473	6,629	509	52,612	12,756,511
		12,324,325	**378,138**	**54,048**	**12,756,511**	

345 kV Underground HPFF Double Circuit



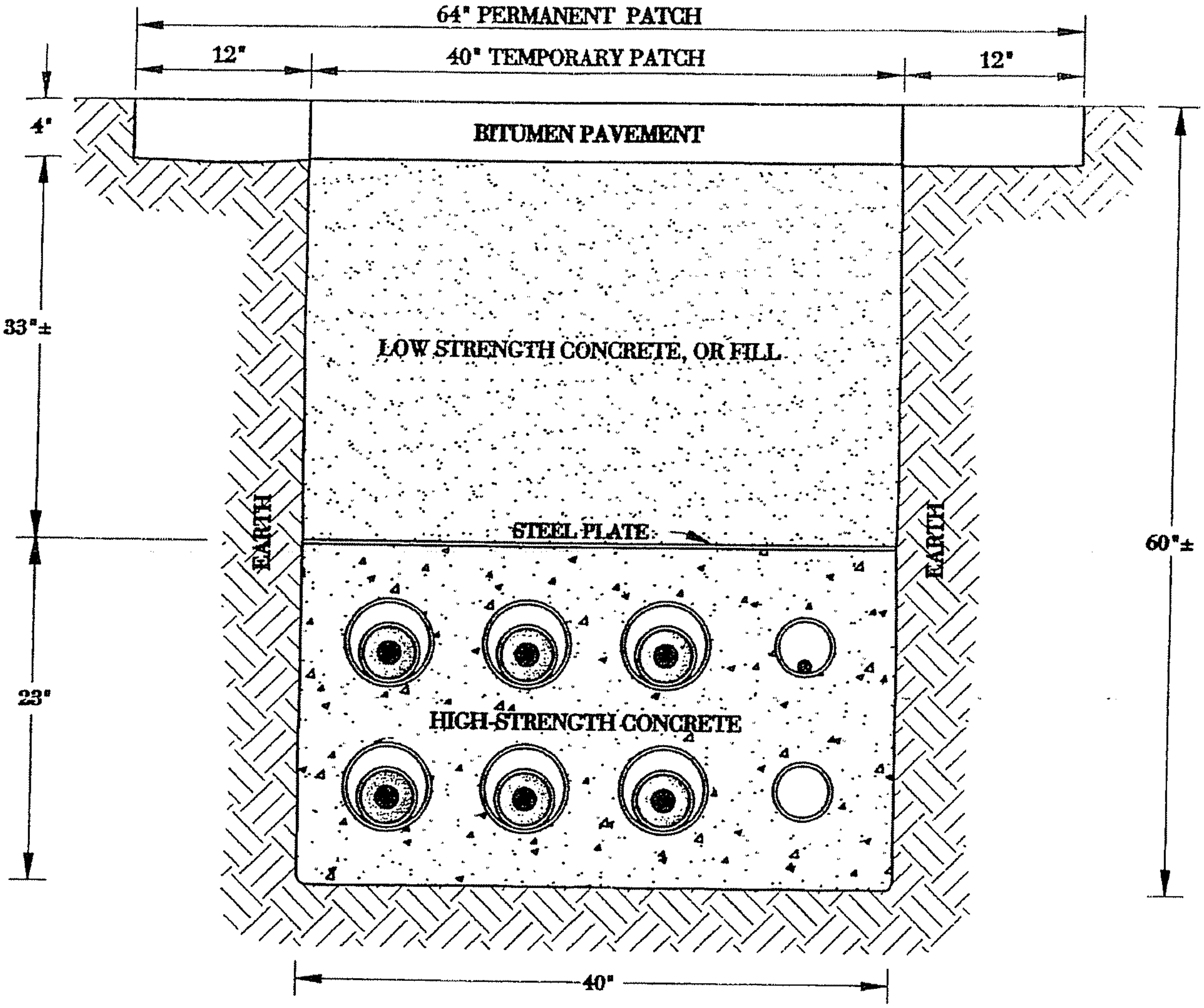
(Source: CL&P)

345 kV Underground, HPFF, Double Circuit

First Costs		Losses	
Ducts & Vaults	3,786,400	Conductor	3000 kcmil
Conductor & Hardware	3,686,500	Resistance	0.03147 ohms/mi
Site Work	171,500	Load	1000 amps
Construction	764,440	Load growth	1.2%
Engineering	252,265	Loss factor	0.38
Sales Taxes	398,411	Energy cost	55.13 mils/kWh
Administration	905,952	Energy cost escal.	5.0%

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Cum PV
1	0.91	1,322,689	32,776	3,430	1,358,895	1,358,895
2	0.83	1,202,445	31,915	3,243	1,237,603	2,596,498
3	0.75	1,093,132	31,077	3,066	1,127,274	3,723,773
4	0.68	993,756	30,261	2,898	1,026,915	4,750,688
5	0.62	903,415	29,466	2,740	935,621	5,686,309
6	0.56	821,286	28,692	2,591	852,569	6,538,878
7	0.51	746,624	27,938	2,450	777,011	7,315,889
8	0.47	678,749	27,204	2,316	708,269	8,024,158
9	0.42	617,044	26,490	2,190	645,724	8,669,882
10	0.39	560,949	25,794	2,070	588,813	9,258,695
11	0.35	509,954	25,116	1,957	537,028	9,795,722
12	0.32	463,595	24,456	1,851	489,902	10,285,624
13	0.29	421,450	23,814	1,750	447,013	10,732,637
14	0.26	383,136	23,188	1,654	407,979	11,140,616
15	0.24	348,305	22,579	1,564	372,449	11,513,065
16	0.22	316,641	21,986	1,479	340,106	11,853,171
17	0.20	287,856	21,409	1,398	310,662	12,163,833
18	0.18	261,687	20,846	1,322	283,855	12,447,688
19	0.16	237,897	20,299	1,250	259,446	12,707,134
20	0.15	216,270	19,766	1,181	237,217	12,944,351
21	0.14	196,609	19,246	1,117	216,973	13,161,324
22	0.12	178,736	18,741	1,056	198,533	13,359,857
23	0.11	162,487	18,248	998	181,734	13,541,591
24	0.10	147,716	17,769	944	166,429	13,708,019
25	0.09	134,287	17,302	893	152,482	13,860,501
26	0.08	122,079	16,848	844	139,771	14,000,272
27	0.08	110,981	16,405	798	128,184	14,128,456
28	0.07	100,892	15,974	754	117,620	14,246,076
29	0.06	91,720	15,555	713	107,988	14,354,064
30	0.06	83,382	15,146	674	99,202	14,453,266
31	0.05	75,801	14,748	637	91,187	14,544,453
32	0.05	68,910	14,361	603	83,874	14,628,327
33	0.04	62,646	13,984	570	77,199	14,705,526
34	0.04	56,951	13,616	539	71,106	14,776,632
35	0.04	51,773	13,259	509	65,541	14,842,173
		14,031,849	**756,276**	**54,048**	**14,842,173**	

345 kV Underground, XLPE, Double Circuit



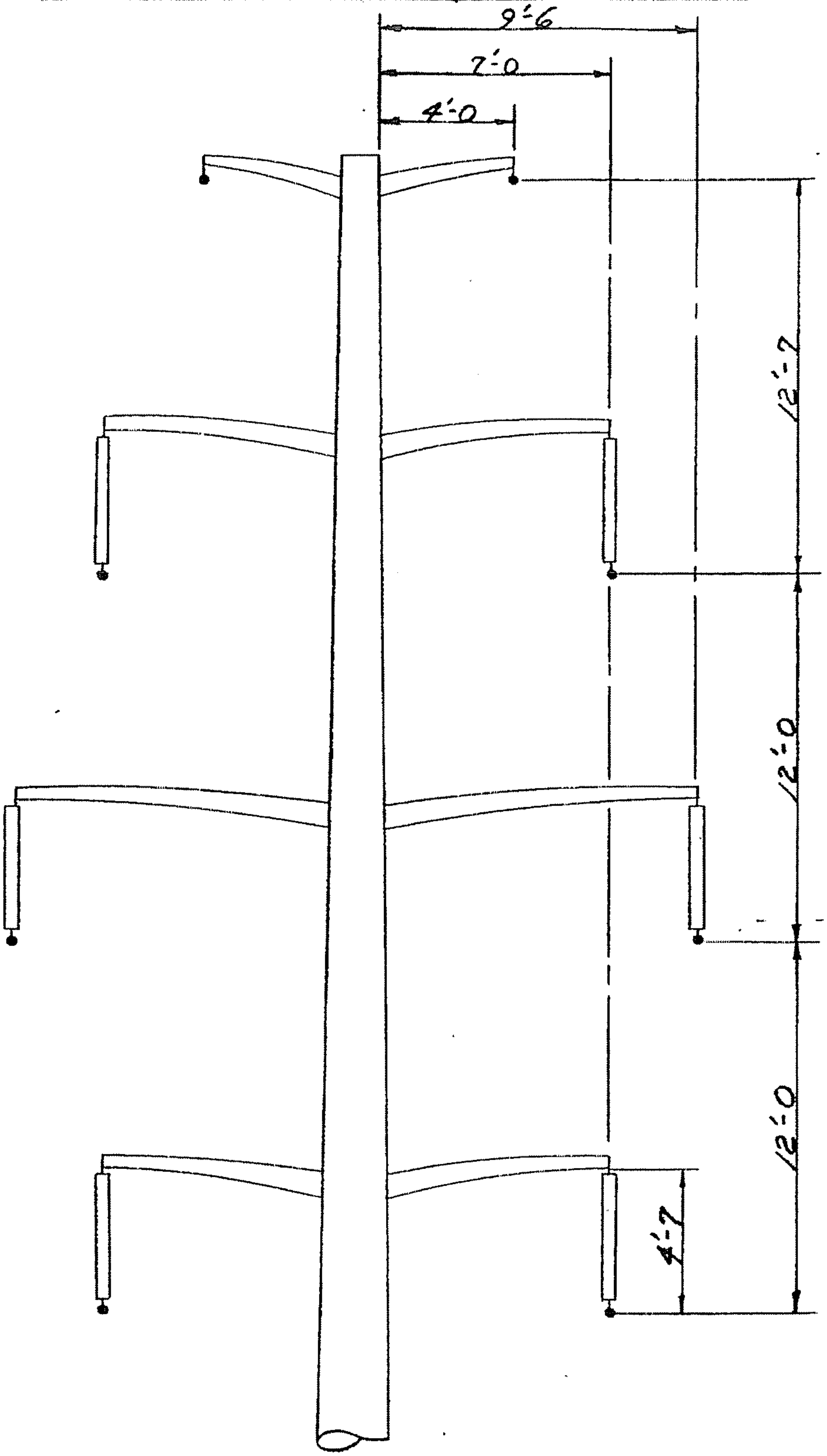
(Source: CL&P)

345 kV Underground, XLPE, Double Circuit

First Costs		Losses	
Ducts & Vaults	5,133,353	Conductor	3000 kcmil
Conductor & Hardware	8,469,288	Resistance	0.03147 ohms/mi
Site Work	617,838	Load	1000 amps
Construction	1,517,070	Load growth	1.2%
Engineering	950,224	Loss factor	0.38
Sales Taxes	697,852	Energy cost	55.13 mils/kWh
Administration	1,738,562	Energy cost escal.	5.0%

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Cum PV
1	0.91	2,538,301	32,776	3,430	2,574,507	2,574,507
2	0.83	2,307,547	31,915	3,243	2,342,704	4,917,212
3	0.75	2,097,770	31,077	3,066	2,131,912	7,049,124
4	0.68	1,907,063	30,261	2,898	1,940,222	8,989,346
5	0.62	1,733,694	29,466	2,740	1,765,900	10,755,246
6	0.56	1,576,085	28,692	2,591	1,607,368	12,362,614
7	0.51	1,432,805	27,938	2,450	1,463,193	13,825,807
8	0.47	1,302,550	27,204	2,316	1,332,070	15,157,877
9	0.42	1,184,136	26,490	2,190	1,212,815	16,370,693
10	0.39	1,076,487	25,794	2,070	1,104,351	17,475,044
11	0.35	978,625	25,116	1,957	1,005,698	18,480,742
12	0.32	889,659	24,456	1,851	915,966	19,396,709
13	0.29	808,781	23,814	1,750	834,345	20,231,053
14	0.26	735,255	23,188	1,654	760,098	20,991,151
15	0.24	668,414	22,579	1,564	692,557	21,683,709
16	0.22	607,649	21,986	1,479	631,114	22,314,823
17	0.20	552,408	21,409	1,398	575,215	22,890,038
18	0.18	502,189	20,846	1,322	524,357	23,414,395
19	0.16	456,536	20,299	1,250	478,084	23,892,479
20	0.15	415,033	19,766	1,181	435,980	24,328,459
21	0.14	377,302	19,246	1,117	397,666	24,726,124
22	0.12	343,002	18,741	1,056	362,799	25,088,923
23	0.11	311,820	18,248	998	331,067	25,419,990
24	0.10	283,473	17,769	944	302,186	25,722,176
25	0.09	257,703	17,302	893	275,897	25,998,074
26	0.08	234,275	16,848	844	251,967	26,250,040
27	0.08	212,977	16,405	798	230,180	26,480,221
28	0.07	193,616	15,974	754	210,344	26,690,565
29	0.06	176,014	15,555	713	192,282	26,882,847
30	0.06	160,013	15,146	674	175,833	27,058,681
31	0.05	145,466	14,748	637	160,852	27,219,533
32	0.05	132,242	14,361	603	147,206	27,366,739
33	0.04	120,220	13,984	570	134,774	27,501,512
34	0.04	109,291	13,616	539	123,446	27,624,958
35	0.04	99,355	13,259	509	113,123	27,738,082
		26,927,758	**756,276**	**54,048**	**27,738,082**	

115 kV Overhead, Wood, Double Circuit



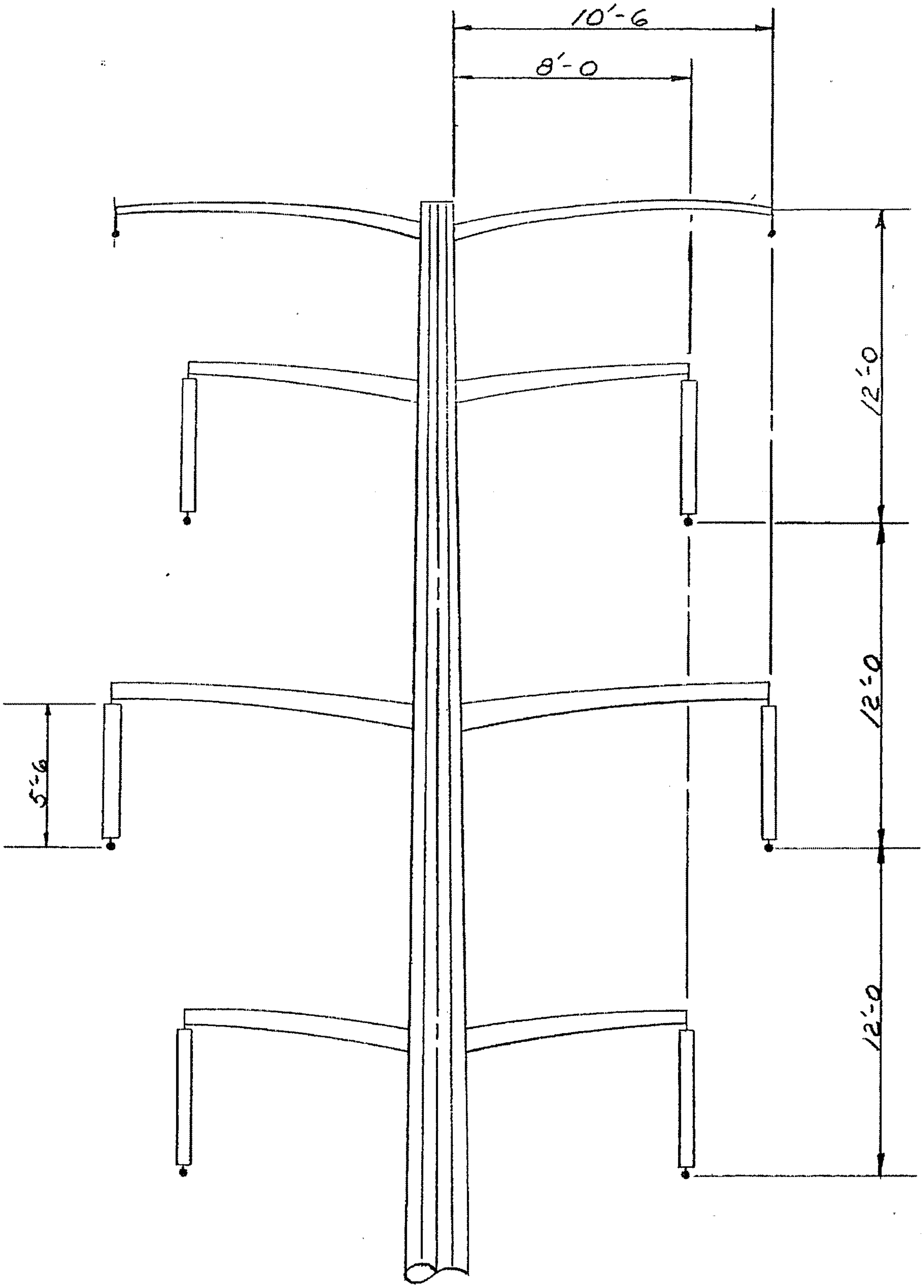
(Source: CL&P)

115 kV Overhead, Wood, Double Circuit

First Costs		Losses	
Ducts & Vaults	324,025	Conductor	1590 kcmil
Conductor & Hardware	774,478	Resistance	0.0591 ohms/mi
Site Work	121,805	Load	1000 amps
Construction	263,045	Load growth	1.2%
Engineering	94,919	Loss factor	0.38
Sales Taxes	72,600	Energy cost	55.13 mils/kWh
Administration	165,087	Energy cost escal.	5.0%

Year	PV Factor	First Costs	Losses	O&M	PV	Cum PV
1	0.91	241,027	61,556	7,341	309,924	309,924
2	0.83	219,116	59,939	6,941	285,995	595,919
3	0.75	199,196	58,364	6,562	264,122	860,042
4	0.68	181,087	56,831	6,204	244,123	1,104,164
5	0.62	164,625	55,338	5,866	225,829	1,329,993
6	0.56	149,659	53,885	5,546	209,089	1,539,082
7	0.51	136,054	52,469	5,243	193,766	1,732,849
8	0.47	123,685	51,091	4,957	179,733	1,912,582
9	0.42	112,441	49,749	4,687	166,877	2,079,459
10	0.39	102,219	48,442	4,431	155,092	2,234,551
11	0.35	92,926	47,170	4,190	144,286	2,378,836
12	0.32	84,479	45,930	3,961	134,370	2,513,207
13	0.29	76,799	44,724	3,745	125,268	2,638,474
14	0.26	69,817	43,549	3,541	116,907	2,755,381
15	0.24	63,470	42,405	3,348	109,223	2,864,604
16	0.22	57,700	41,291	3,165	102,156	2,966,760
17	0.20	52,455	40,207	2,992	95,654	3,062,414
18	0.18	47,686	39,150	2,829	89,666	3,152,079
19	0.16	43,351	38,122	2,675	84,148	3,236,227
20	0.15	39,410	37,121	2,529	79,059	3,315,286
21	0.14	35,827	36,146	2,391	74,364	3,389,650
22	0.12	32,570	35,196	2,261	70,027	3,459,677
23	0.11	29,609	34,272	2,137	66,018	3,525,695
24	0.10	26,917	33,371	2,021	62,309	3,588,004
25	0.09	24,470	32,495	1,910	58,876	3,646,880
26	0.08	22,246	31,641	1,806	55,693	3,702,573
27	0.08	20,224	30,810	1,708	52,741	3,755,315
28	0.07	18,385	30,001	1,615	50,000	3,805,315
29	0.06	16,714	29,213	1,527	47,453	3,852,767
30	0.06	15,194	28,445	1,443	45,083	3,897,850
31	0.05	13,813	27,698	1,365	42,875	3,940,726
32	0.05	12,557	26,970	1,290	40,818	3,981,543
33	0.04	11,416	26,262	1,220	38,897	4,020,441
34	0.04	10,378	25,572	1,153	37,103	4,057,544
35	0.04	9,434	24,900	1,090	35,425	4,092,969
		2,556,956	**1,420,324**	**115,689**	**4,092,969**	

115 kV Overhead, Steel, Double Circuit



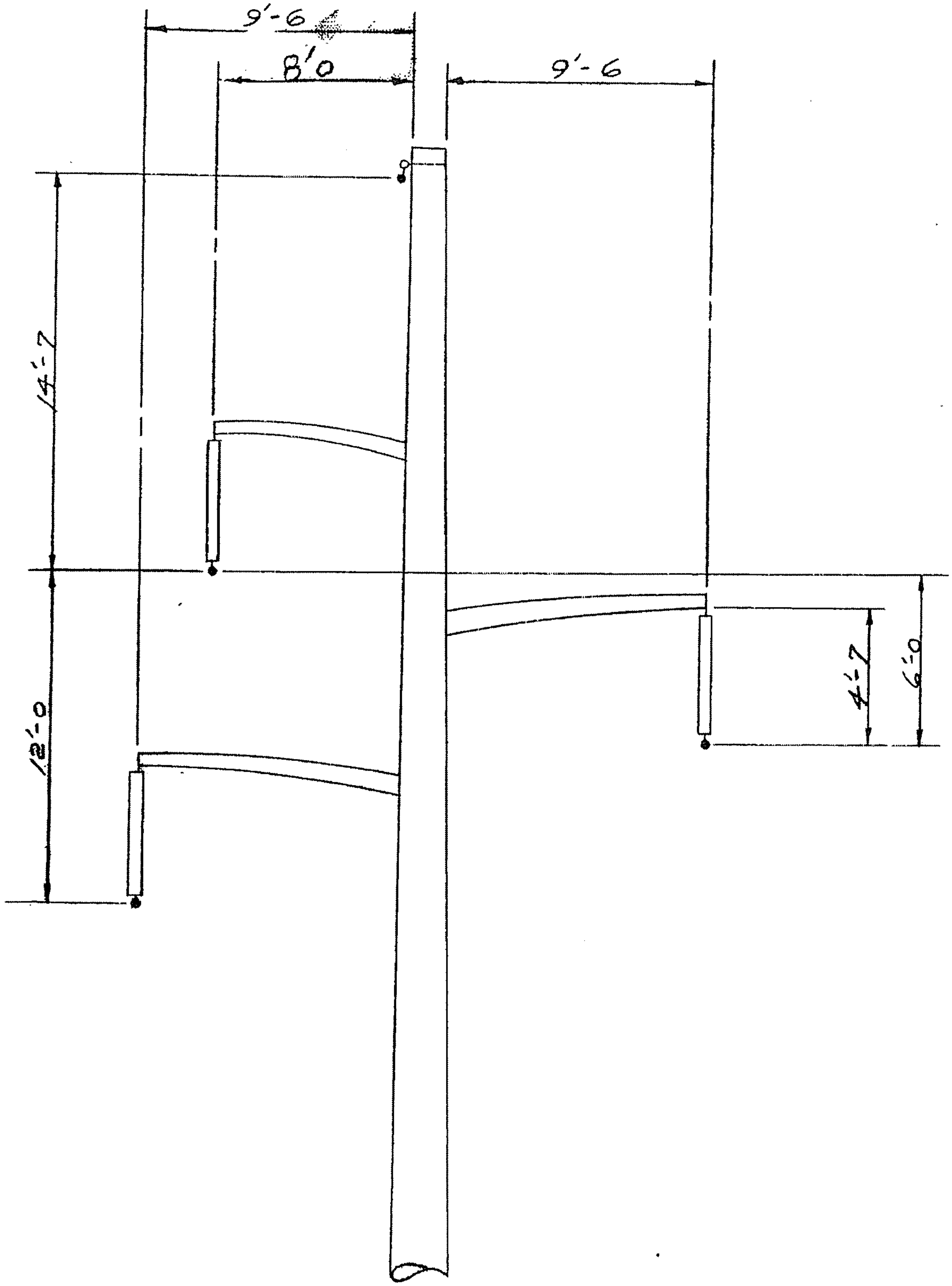
(Source: CL&P)

115 kV Overhead, Steel, Double Circuit

First Costs		Losses	
Ducts & Vaults	718,255	Conductor	1590 kcmil
Conductor & Hardware	774,478	Resistance	0.0591 ohms/mi
Site Work	121,805	Load	1000 amps
Construction	347,130	Load growth	1.2%
Engineering	121,111	Loss factor	0.38
Sales Taxes	95,808	Energy cost	55.13 mils/kWh
Administration	217,859	Energy cost escal.	5.0%

Year	PV Factor	First cost	Losses	O&M	PV	Cum PV
1	0.91	318,074	61,556	7,341	386,970	386,970
2	0.83	289,158	59,939	6,941	356,037	743,008
3	0.75	262,871	58,364	6,562	327,797	1,070,805
4	0.68	238,974	56,831	6,204	302,009	1,372,814
5	0.62	217,249	55,338	5,866	278,453	1,651,266
6	0.56	197,499	53,885	5,546	256,929	1,908,196
7	0.51	179,544	52,469	5,243	237,257	2,145,452
8	0.47	163,222	51,091	4,957	219,270	2,364,723
9	0.42	148,384	49,749	4,687	202,819	2,567,542
10	0.39	134,894	48,442	4,431	187,768	2,755,310
11	0.35	122,631	47,170	4,190	173,990	2,929,300
12	0.32	111,483	45,930	3,961	161,374	3,090,674
13	0.29	101,348	44,724	3,745	149,817	3,240,491
14	0.26	92,135	43,549	3,541	139,224	3,379,716
15	0.24	83,759	42,405	3,348	129,512	3,509,227
16	0.22	76,144	41,291	3,165	120,601	3,629,828
17	0.20	69,222	40,207	2,992	112,421	3,742,249
18	0.18	62,929	39,150	2,829	104,909	3,847,158
19	0.16	57,208	38,122	2,675	98,005	3,945,163
20	0.15	52,008	37,121	2,529	91,657	4,036,820
21	0.14	47,280	36,146	2,391	85,816	4,122,637
22	0.12	42,981	35,196	2,261	80,438	4,203,075
23	0.11	39,074	34,272	2,137	75,483	4,278,558
24	0.10	35,522	33,371	2,021	70,914	4,349,471
25	0.09	32,293	32,495	1,910	66,698	4,416,169
26	0.08	29,357	31,641	1,806	62,804	4,478,974
27	0.08	26,688	30,810	1,708	59,206	4,538,179
28	0.07	24,262	30,001	1,615	55,877	4,594,056
29	0.06	22,056	29,213	1,527	52,795	4,646,852
30	0.06	20,051	28,445	1,443	49,940	4,696,792
31	0.05	18,228	27,698	1,365	47,291	4,744,082
32	0.05	16,571	26,970	1,290	44,832	4,788,914
33	0.04	15,065	26,262	1,220	42,546	4,831,461
34	0.04	13,695	25,572	1,153	40,421	4,871,881
35	0.04	12,450	24,900	1,090	38,441	4,910,322
		3,374,309	**1,420,324**	**115,689**	**4,910,322**	

115 kV Overhead, Wood, Delta Framing



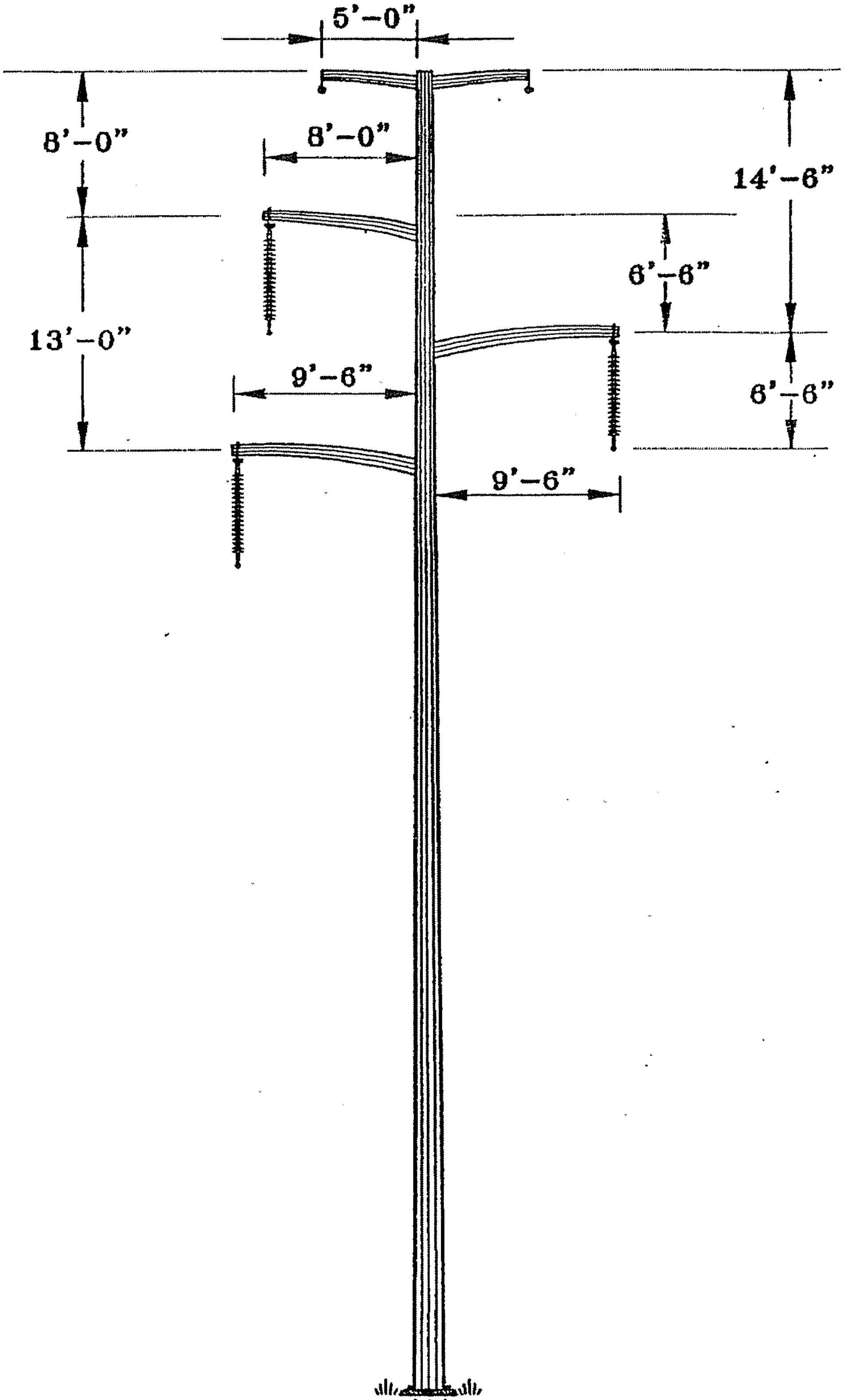
(Source: CL&P)

115 kV Overhead, Wood, Delta Framing

First Costs		Losses	
Ducts & Vaults	298,025	Conductor	1590 kcmil
Conductor & Hardware	337,256	Resistance	0.0591 ohms/mi
Site Work	90,802	Load	1000 amps
Construction	157,524	Load growth	1.2%
Engineering	62,536	Loss factor	0.38
Sales Taxes	43,477	Energy cost	55.13 mils/kWh
Administration	98,862	Energy cost escal.	5.0%

Year	PV Factor	First Cost	Loss	O&M	PV Cost	Cum PV
1	0.9091	144,339	30,778	7,341	182,457	182,457
2	0.8264	131,217	29,969	6,941	168,127	350,584
3	0.7513	119,288	29,182	6,562	155,032	505,617
4	0.6830	108,444	28,416	6,204	143,063	648,680
5	0.6209	98,585	27,669	5,866	132,120	780,800
6	0.5645	89,623	26,942	5,546	122,111	902,911
7	0.5132	81,475	26,235	5,243	112,953	1,015,864
8	0.4665	74,068	25,545	4,957	104,571	1,120,435
9	0.4241	67,335	24,874	4,687	96,896	1,217,332
10	0.3855	61,214	24,221	4,431	89,866	1,307,198
11	0.3505	55,649	23,585	4,190	83,423	1,390,621
12	0.3186	50,590	22,965	3,961	77,516	1,468,137
13	0.2897	45,991	22,362	3,745	72,098	1,540,234
14	0.2633	41,810	21,775	3,541	67,125	1,607,359
15	0.2394	38,009	21,203	3,348	62,559	1,669,918
16	0.2176	34,553	20,646	3,165	58,364	1,728,283
17	0.1978	31,412	20,103	2,992	54,508	1,782,790
18	0.1799	28,557	19,575	2,829	50,961	1,833,751
19	0.1635	25,961	19,061	2,675	47,696	1,881,448
20	0.1486	23,601	18,560	2,529	44,690	1,926,138
21	0.1351	21,455	18,073	2,391	41,919	1,968,056
22	0.1228	19,505	17,598	2,261	39,363	2,007,419
23	0.1117	17,731	17,136	2,137	37,004	2,044,424
24	0.1015	16,119	16,686	2,021	34,826	2,079,250
25	0.0923	14,654	16,247	1,910	32,812	2,112,062
26	0.0839	13,322	15,821	1,806	30,949	2,143,010
27	0.0763	12,111	15,405	1,708	29,224	2,172,234
28	0.0693	11,010	15,000	1,615	27,625	2,199,858
29	0.0630	10,009	14,606	1,527	26,142	2,226,000
30	0.0573	9,099	14,223	1,443	24,765	2,250,765
31	0.0521	8,272	13,849	1,365	23,485	2,274,250
32	0.0474	7,520	13,485	1,290	22,295	2,296,546
33	0.0431	6,836	13,131	1,220	21,187	2,317,733
34	0.0391	6,215	12,786	1,153	20,154	2,337,887
35	0.0356	5,650	12,450	1,090	19,190	2,357,077
		1,531,226	710,162	115,689	2,357,077	

115 kV Overhead, Steel, Delta



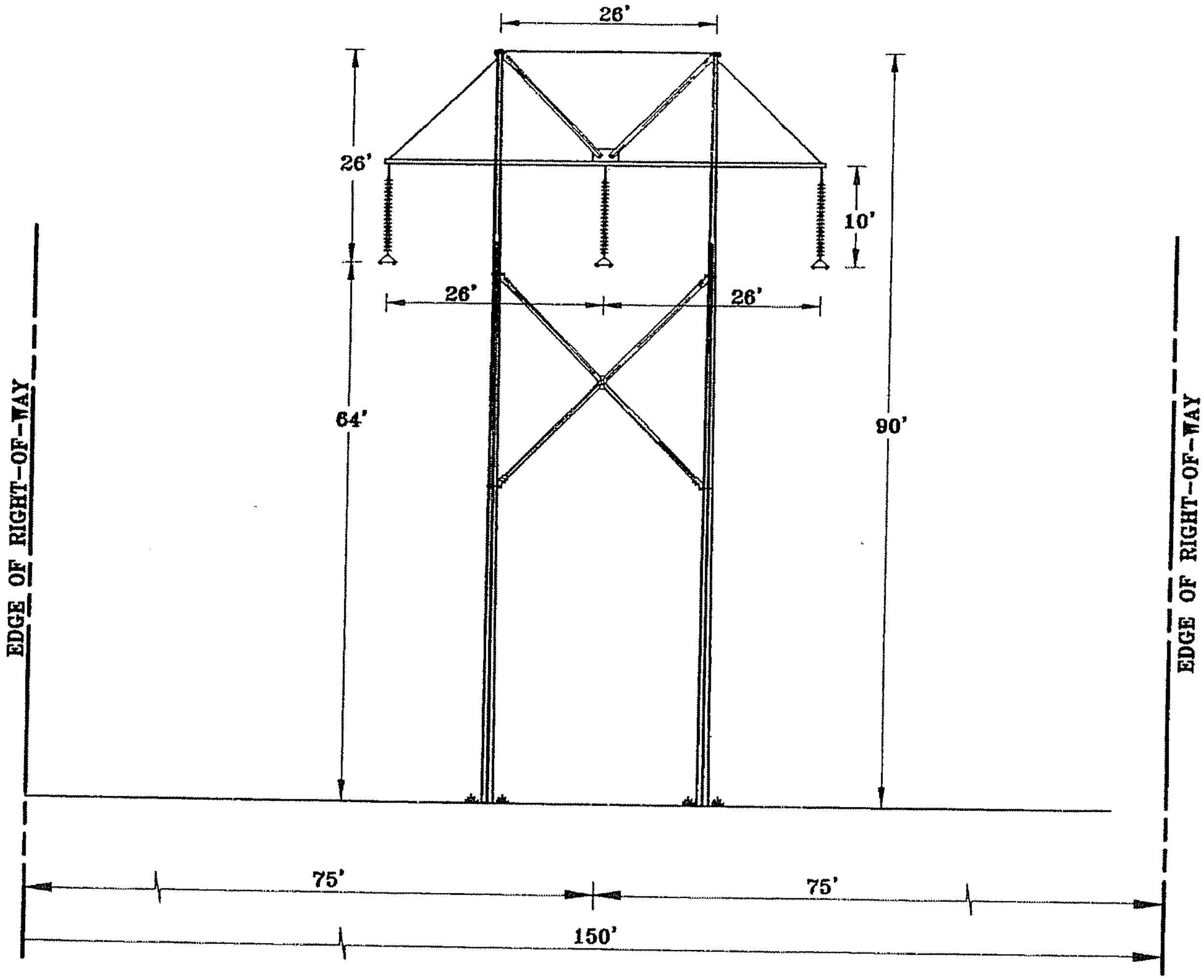
(Source: CL&P)

115 kV Overhead, Steel, Delta Framing

First Costs		Losses	
Ducts & Vaults	642,135	Conductor	1590 kcmil
Conductor & Hardware	337,256	Resistance	0.0591 ohms/mi
Site Work	90,802	Load	1000 amps
Construction	247,790	Load growth	1.2%
Engineering	168,755	Loss factor	0.38
Sales Taxes	68,390	Energy cost	55.13 mils/kWh
Administration	155,513	Energy cost escal.	5.0%

Year	PV Factor	First Costs	Losses	O&M	PV Cost	Cum PV
1	0.91	227,049	30778	7341	265,168	265,168
2	0.83	206,408	29969	6941	243,318	508,486
3	0.75	187,644	29182	6562	223,388	731,873
4	0.68	170,585	28416	6204	205,205	937,078
5	0.62	155,077	27669	5866	188,612	1,125,690
6	0.56	140,979	26942	5546	173,468	1,299,158
7	0.51	128,163	26235	5243	159,641	1,458,799
8	0.47	116,512	25545	4957	147,015	1,605,813
9	0.42	105,920	24874	4687	135,481	1,741,295
10	0.39	96,291	24221	4431	124,943	1,866,238
11	0.35	87,537	23585	4190	115,311	1,981,549
12	0.32	79,579	22965	3961	106,505	2,088,055
13	0.29	72,345	22362	3745	98,452	2,186,506
14	0.26	65,768	21775	3541	91,083	2,277,590
15	0.24	59,789	21203	3348	84,339	2,361,929
16	0.22	54,354	20646	3165	78,164	2,440,093
17	0.20	49,412	20103	2992	72,508	2,512,601
18	0.18	44,920	19575	2829	67,325	2,579,926
19	0.16	40,837	19061	2675	62,573	2,642,498
20	0.15	37,124	18560	2529	58,214	2,700,712
21	0.14	33,749	18073	2391	54,213	2,754,925
22	0.12	30,681	17598	2261	50,540	2,805,465
23	0.11	27,892	17136	2137	47,165	2,852,630
24	0.10	25,356	16686	2021	44,063	2,896,693
25	0.09	23,051	16247	1910	41,209	2,937,902
26	0.08	20,956	15821	1806	38,583	2,976,484
27	0.08	19,051	15405	1708	36,163	3,012,648
28	0.07	17,319	15000	1615	33,934	3,046,581
29	0.06	15,744	14606	1527	31,877	3,078,458
30	0.06	14,313	14223	1443	29,979	3,108,437
31	0.05	13,012	13849	1365	28,225	3,136,663
32	0.05	11,829	13485	1290	26,604	3,163,267
33	0.04	10,754	13131	1220	25,104	3,188,371
34	0.04	9,776	12786	1153	23,715	3,212,086
35	0.04	8,887	12450	1090	22,428	3,234,514
		2,408,663	**710,162**	**115,689**	**3,234,514**	

345 kV Overhead, Wood, H-Frame



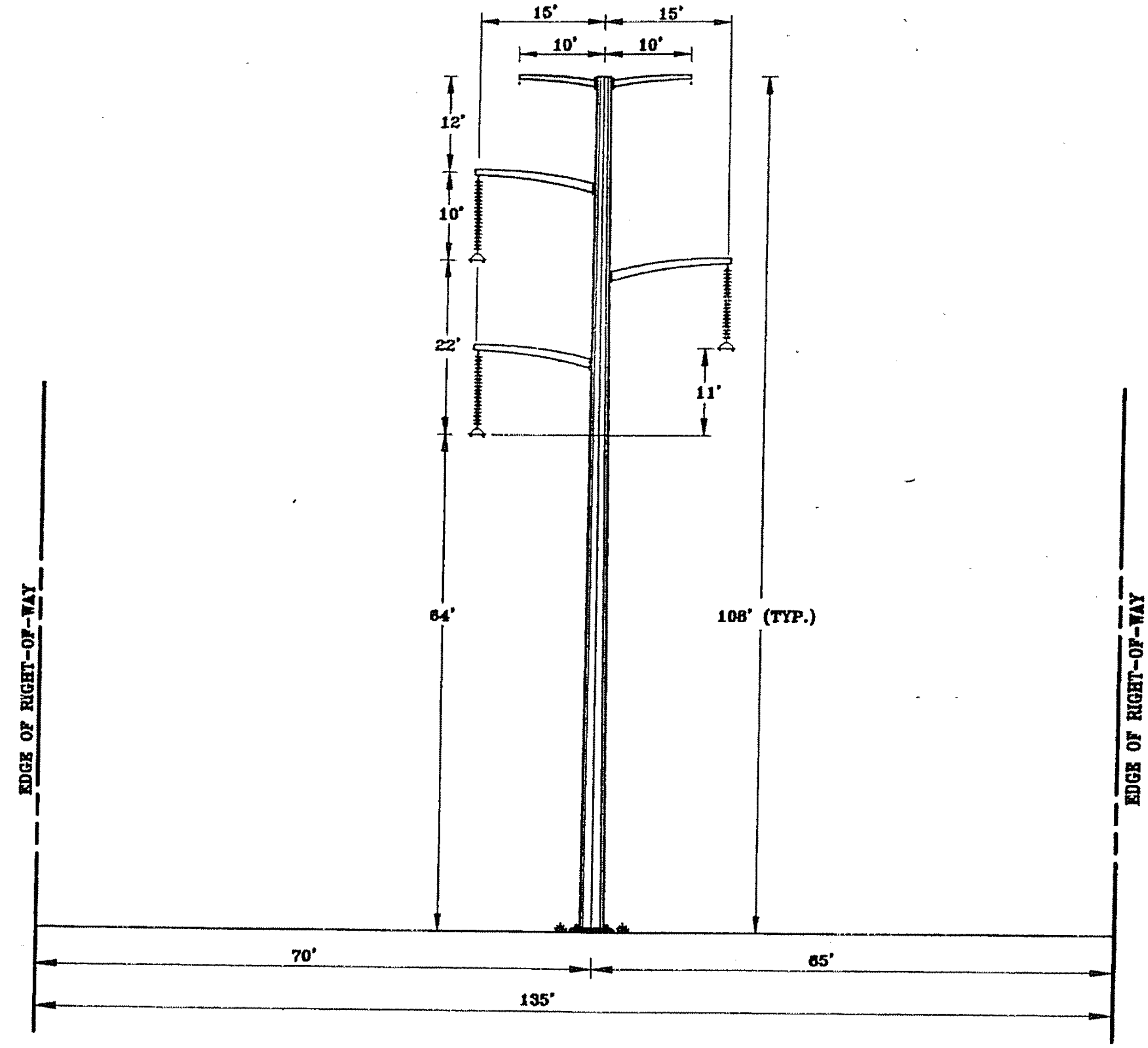
(Source: CL&P)

345 kV Overhead, Wood, H-Frame

First Costs		Losses	
Ducts & Vaults	661,375	Conductor	1590 kcmil
Conductor & Hardware	560,032	Resistance	0.0591 ohms/mi
Site Work	183,300	Load	1000 amps
Construction	301,809	Load growth	1.2%
Engineering	104,339	Loss factor	0.38
Sales Taxes	83,299	Energy cost	55.13 mils/kWh
Administration	189,415	Energy cost escal.	5.0%

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Cum PV
1	0.91	276,546	30,778	7,341	314,665	314,665
2	0.83	251,406	29,969	6,941	288,316	602,981
3	0.75	228,551	29,182	6,562	264,295	867,276
4	0.68	207,773	28,416	6,204	242,393	1,109,669
5	0.62	188,885	27,669	5,866	222,420	1,332,089
6	0.56	171,714	26,942	5,546	204,202	1,536,291
7	0.51	156,103	26,235	5,243	187,581	1,723,872
8	0.47	141,912	25,545	4,957	172,415	1,896,287
9	0.42	129,011	24,874	4,687	158,572	2,054,859
10	0.39	117,283	24,221	4,431	145,935	2,200,794
11	0.35	106,621	23,585	4,190	134,395	2,335,189
12	0.32	96,928	22,965	3,961	123,854	2,459,043
13	0.29	88,116	22,362	3,745	114,223	2,573,266
14	0.26	80,106	21,775	3,541	105,421	2,678,687
15	0.24	72,823	21,203	3,348	97,373	2,776,061
16	0.22	66,203	20,646	3,165	90,014	2,866,074
17	0.20	60,185	20,103	2,992	83,280	2,949,355
18	0.18	54,713	19,575	2,829	77,118	3,026,472
19	0.16	49,739	19,061	2,675	71,475	3,097,947
20	0.15	45,218	18,560	2,529	66,307	3,164,254
21	0.14	41,107	18,073	2,391	61,571	3,225,825
22	0.12	37,370	17,598	2,261	57,228	3,283,053
23	0.11	33,973	17,136	2,137	53,246	3,336,299
24	0.10	30,884	16,686	2,021	49,591	3,385,889
25	0.09	28,077	16,247	1,910	46,234	3,432,124
26	0.08	25,524	15,821	1,806	43,151	3,475,275
27	0.08	23,204	15,405	1,708	40,316	3,515,591
28	0.07	21,094	15,000	1,615	37,709	3,553,300
29	0.06	19,177	14,606	1,527	35,309	3,588,610
30	0.06	17,433	14,223	1,443	33,099	3,621,709
31	0.05	15,848	13,849	1,365	31,062	3,652,771
32	0.05	14,408	13,485	1,290	29,183	3,681,954
33	0.04	13,098	13,131	1,220	27,449	3,709,403
34	0.04	11,907	12,786	1,153	25,846	3,735,249
35	0.04	10,825	12,450	1,090	24,365	3,759,614
		2,933,764	**710,162**	**115,689**	**3,759,614**	

345 kV Overhead, Steel, Delta Framing



(Source: CL&P)

345 kV Overhead, Steel, Delta Framing

First Costs		Losses	
Ducts & Vaults	1,814,372	Conductor	1590 kcmil
Conductor & Hardware	560,230	Resistance	0.0591 ohms/mi
Site Work	183,300	Load	1000 amps
Construction	546,869	Load growth	1.2%
Engineering	176,445	Loss factor	0.38
Sales Taxes	150,936	Energy cost	55.13 mils/kWh
Administration	343,215	Energy cost escal.	5.0%

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Cum PV
1	0.91	501,094	30,778	7,341	539,213	539,213
2	0.83	455,540	29,969	6,941	492,450	1,031,663
3	0.75	414,127	29,182	6,562	449,872	1,481,535
4	0.68	376,479	28,416	6,204	411,099	1,892,634
5	0.62	342,254	27,669	5,866	375,789	2,268,423
6	0.56	311,140	26,942	5,546	343,628	2,612,051
7	0.51	282,855	26,235	5,243	314,332	2,926,384
8	0.47	257,141	25,545	4,957	287,643	3,214,027
9	0.42	233,764	24,874	4,687	263,325	3,477,352
10	0.39	212,513	24,221	4,431	241,165	3,718,518
11	0.35	193,193	23,585	4,190	220,968	3,939,485
12	0.32	175,630	22,965	3,961	202,557	4,142,042
13	0.29	159,664	22,362	3,745	185,771	4,327,813
14	0.26	145,149	21,775	3,541	170,464	4,498,277
15	0.24	131,954	21,203	3,348	156,504	4,654,781
16	0.22	119,958	20,646	3,165	143,769	4,798,550
17	0.20	109,053	20,103	2,992	132,148	4,930,698
18	0.18	99,139	19,575	2,829	121,543	5,052,242
19	0.16	90,126	19,061	2,675	111,862	5,164,104
20	0.15	81,933	18,560	2,529	103,022	5,267,126
21	0.14	74,484	18,073	2,391	94,948	5,362,074
22	0.12	67,713	17,598	2,261	87,572	5,449,646
23	0.11	61,557	17,136	2,137	80,830	5,530,476
24	0.10	55,961	16,686	2,021	74,668	5,605,144
25	0.09	50,874	16,247	1,910	69,032	5,674,175
26	0.08	46,249	15,821	1,806	63,876	5,738,051
27	0.08	42,045	15,405	1,708	59,157	5,797,208
28	0.07	38,222	15,000	1,615	54,837	5,852,046
29	0.06	34,748	14,606	1,527	50,880	5,902,926
30	0.06	31,589	14,223	1,443	47,255	5,950,181
31	0.05	28,717	13,849	1,365	43,931	5,994,111
32	0.05	26,106	13,485	1,290	40,882	6,034,993
33	0.04	23,733	13,131	1,220	38,084	6,073,076
34	0.04	21,575	12,786	1,153	35,515	6,108,591
35	0.04	19,614	12,450	1,090	33,155	6,141,746
		5,315,895	**710,162**	**115,689**	**6,141,746**	