LIFE CYCLE 2007

Connecticut Siting Council Investigation into the Life Cycle Costs of Electric Transmission Lines

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CSC
CONNECTICUT SITING COUNCIL

February 13, 2007

Citizens of Connecticut:

It is with great pleasure that I provide you the 2007 Connecticut Siting Council Investigation into the Life Cycle Costs of Electric Transmission Lines. This report compiles and analyzes the various factors that affect the total cost of ownership of overhead and underground electric transmission lines over their estimated service life. Based on data collected from the electric transmission utilities in Connecticut, this report also estimates the costs associated with constructing, operating, and maintaining transmission lines on a per mile basis.

Pursuant to Connecticut General Statutes § 16-50r (b), the life cycle cost investigation shall include, but not be limited to:

"…an inquiry of all relevant life-cycle costs, relative reliability, constraints concerning access and construction, potential damage to the environment and compatibility with the existing electric supply system. As part of the investigation the council shall hold public hearings which shall afford all interested parties opportunity to be heard. At least one public hearing shall be held after six-thirty p.m."

These subjects have been fully examined by the Council with full opportunity for public participation. The results of this process have been summarized in this report, which we hope you will find to be useful and informative.

I invite you to review this public report and challenge the analyses contained herein. With your help, I am confident that Connecticut can carefully evaluate electric transmission proposals to address our growing electric needs while taking into account the costs and possible effects on the environment.

Please feel free to contact the Council's staff or me if you seek additional information. Thank you.

Very truly yours,

Daniel F. Caruso
Chairman

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1. Background and Introduction

Pursuant to Connecticut General Statutes § 16-50r (b), the Connecticut Siting Council (Council) is required to investigate the life cycle costs of electric transmission lines every five years. The previous report, issued in 2001, investigated only the life cycle costs of 115-kV electric transmission. This report includes the life cycle costs of both 115-kV and 345-kV electric transmission.

To assist the Council in this matter, the Council retained the services of the technical consulting firm KEMA, Inc. (KEMA) of North Carolina. On January 12, 2006, the Council held a public hearing on life cycle costs and also provided an opportunity for public comment. On March 14, 2006, the Council held a technical meeting with the utilities for further investigation into life cycle costs. With the assistance of KEMA, the Council prepared a final report which was approved on October 31, 2006. The report was subsequently placed on the Council's website www.ct.gov/csc and located under "Publications." A printed version of that report has been prepared for your convenience.

The life cycle costs of electric transmission lines 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 an 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. PV 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 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 analysis 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 35 years or 40 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 25 year horizon, whether the estimated life of a transmission line alternative is 35 years or 40 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 with associated hardware
  – Site work
  – Construction management
  – 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 includes the costs of scheduled inspection and servicing of equipment and components as well as right-of-way (ROW) 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, as well as the capacity cost associated with the losses.

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 35 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 alternating current (AC) transmission lines. The four types of lines are among those 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 life cycle cost calculations include, for the purpose of estimating the cost of energy losses, an energy cost of 10 cents per kilowatt hour.) Figures 2.1 through 2.4 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

Overhead 115 kV Transmission Line
Distribution of Life Cycle Cost Elements
Energy Cost @ 10 cents/kWh
35 Year Life Cycle Cost PV = $3,890,721

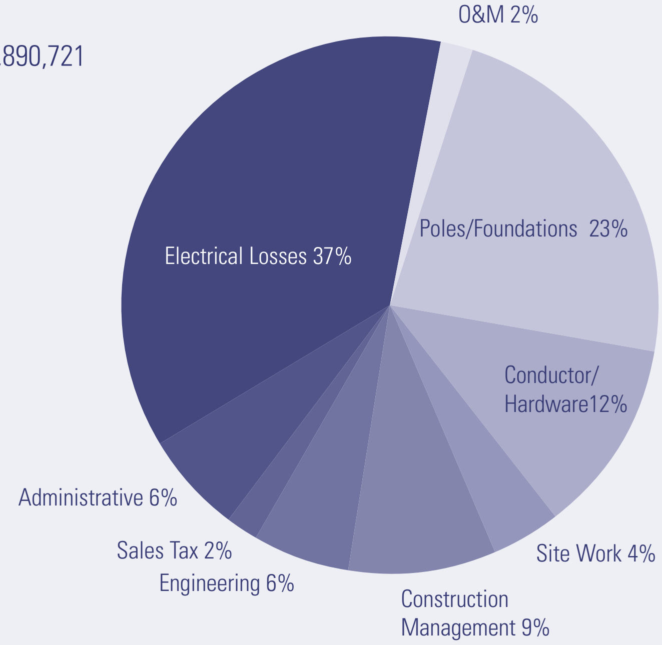


Figure 2.2 Typical Life Cycle Cost for 345 kV Overhead Line

Overhead 345 kV Transmission Line
Distribution of Life Cycle Cost Elements
Energy Cost @ 10 cents/kWh
35 Year Life Cycle Cost PV = $6,797,953

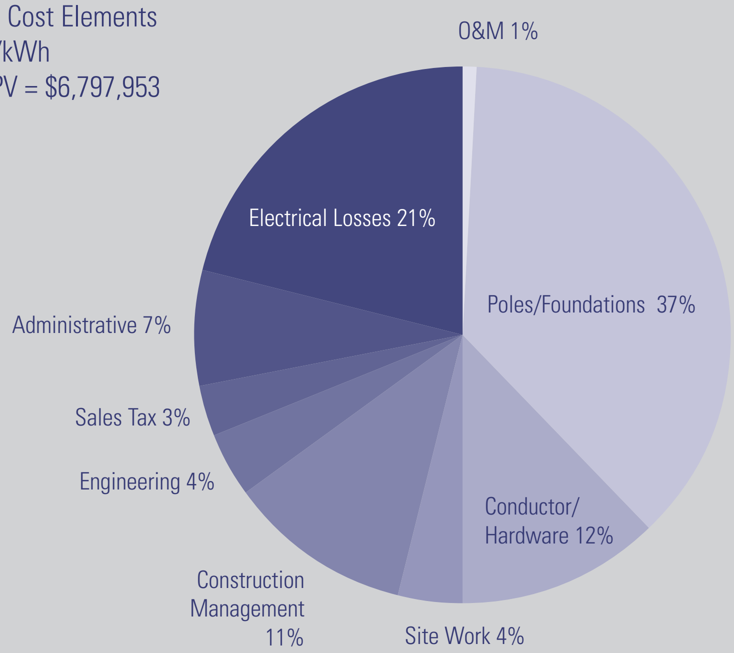


Figure 2.3 Typical Life Cycle Cost for 115 kV Underground Line

Underground 115 kV Transmission Line
Distribution of Life Cycle Cost Elements
Energy Cost @ 10 cents/kWh
35 Year Life Cycle Cost PV = $15,480,397

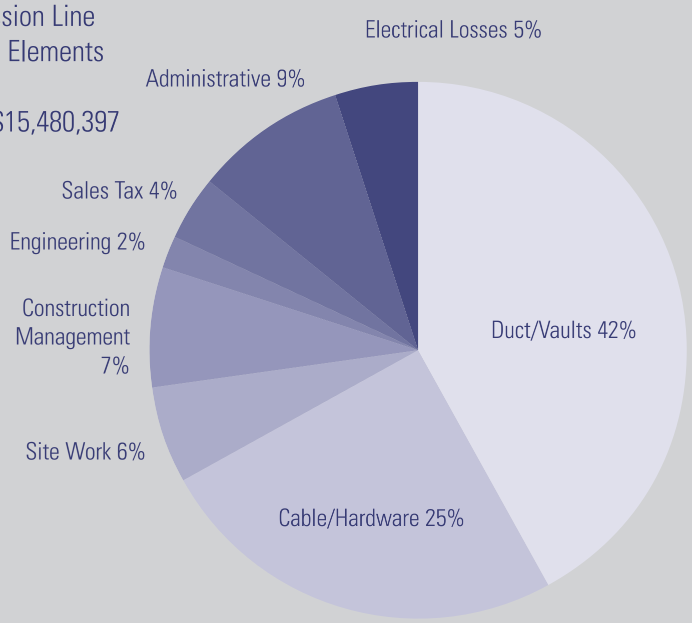
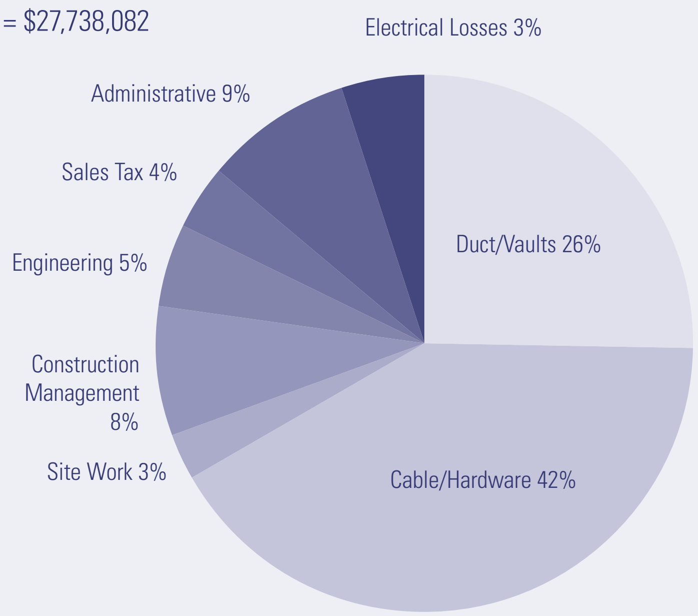


Figure 2.4 Typical Life Cycle Cost for 345 kV Underground Line

Underground 345 kV Transmission Line
Distribution of Life Cycle Cost Elements
Energy Cost @ 10 cents/kWh
35 Year Life Cycle Cost PV = $27,738,082



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 more than one transmission line is 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. Generally, a single-circuit AC transmission line, consists of three current-carrying conductors. These 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.) However, since 345-kV lines typically use two conductors per phase, known as "bundled conductors," the line-to-line voltage exists between two separate phases, not simply between any two conductors. (The voltage across two conductors of the same phase is zero because they are at the same electric potential.)
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 likely options for new overhead transmission lines in Connecticut. Therefore, this report addresses the first costs of 115 kV and 345 kV overhead transmission lines. However, the Council notes that construction of a new 69 kV line could still be an option for some locations in the CL&P system where this voltage is still in use and is too costly to change. Such a line, however, would mostly likely be pre-designed for 115 kV.

In overhead transmission lines, the current-carrying conductors are supported by insulators. 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 Connecticut, however, the major utilities have indicated that six designs 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)	Size of Conductor (kcmil)	Supporting Structure / Material	Conductor Configuration	No. of Circuits	See Drawing
115	1590	Poles/Laminate Wood	Delta	1	p. 62
115	1590	Poles/Steel	Delta	1	p. 64
345	1590 (bundled)	H-Frame/Laminate Wood	Horizontal	1	p. 66
345	1590 (bundled)	Poles/Steel	Delta	1	p. 68
115	1590	Poles/Laminate Wood	Vertical	2	p. 58
115	1590	Poles/Steel	Vertical	2	p. 60

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. A perceived increased reliability risk 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 noted in Table 3-1, the physical appearance of one overhead transmission line design may be quite different from others, even those at the same voltage level. 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. 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—includes all labor, materials, and expenses incurred in the acquisition and installation of structural components such as erecting the structures, etc.

- Cable/Hardware—includes all labor, materials, and expenses incurred in the conductors, insulators, and associated items including stringing the conductors and making cable splices. (Conductor sizes of 1590-kcmil are assumed. Smaller conductors would typically cost less.)

- Site Work— includes all labor, materials, and expenses incurred in clearing and preparing the land, etc.

- Construction Management— includes all labor, materials and expenses incurred for construction management activities.

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

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

- Project Management— includes 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 $/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

$/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 Management	157,524	247,790
Engineering	61,536	168,755
Sales Tax (4.6 percent)	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 percent 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 percent 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 $/mile	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 Management	263,045	347,130
Engineering	94,919	121,111
Sales Tax (4.6 percent)	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 percent 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 $/mile	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 Management	301,809	546,869
Engineering	104,339	176,445
Sales Tax (4.6 percent)	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, a single-circuit AC underground transmission line typically consists of three current-carrying conductors, and the magnitude of the electric potential difference between any two of them (that are of different phases) 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 consisting of a (copper) central core surrounded by electrical insulation. Different technologies for transmission cables are based on the type of insulation that surrounds the (usually) copper core. The insulation medium can be a fluid, a compressed gas, or a solid dielectric. Examples of different insulation media include: for a fluid, kraft paper impregnated with mineral oil; for a gas, sulfur hexafluoride; and for a solid dielectric, cross-linked polyethylene. Cables can be installed underground in different ways. 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 transmission line designs that are representative of underground transmission lines either currently in service or under construction. This report addresses the first costs of these four designs only. They 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. The cost categories for overhead transmission lines apply for underground transmission lines, with one exception: the “pole foundations” cost is replaced by “Duct/Vaults”, which is more appropriate for underground transmission lines. “Duct/Vaults” costing accounts includes all labor, materials, and expenses incurred in the acquisition and installation of the structural components for underground transmission lines.

Table 3-5. Characteristics of 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. 50
115*	XLPE / 1750 kcmil	Horizontal / One cable per phase	1	p. 52
345	HPFF / 2500 kcmil	Delta / One cable per phase / circuit	2	p. 54
345	XLPE / 3000 kcmil	Horizontal / One cable per phase	2	p. 56

*The 1750 kcmil underground cable size may not be typical for future use. CL&P anticipates that the 3000 kcmil cable size may be the typical size for future applications. (The 3000 kcmil underground cable is comparable to a 1590 kcmil overhead line for the purposes of LCC analysis.) However, only 1750 kcmil 115 kV underground cable cost data was available in this proceeding.

As mentioned previously, the cost of land is not included in the list of costs 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].

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 percent higher cost per mile, when compared with the XLPE cable system.

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

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

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]. The results for the 345 kV line indicate that a double-circuit 345 kV HPFF installation with six 2500 kcmil cables costs about the same to install as a single-circuit 115 kV HPFF installation with three 1750 kcmil cables. On it face, this may not seem reasonable. However, the 115 kV cost data (from UI) are likely for a considerable shorter line in a more urban setting, and these factors alone can have a significant effect on average cost. This is consistent with the much higher site work costs for the 115 kV line. Also, when one compares the very similar trench drawings for the two lines (See Appendix A, pages 50 and 54), it is not surprising that the "ducts/vaults" costs are quite similar for the two lines. Also, one would expect a greater difference in the "cable/hardware" costs for the two lines. However, these costs include all labor and expenses, as well as material costs, and the former two cost components may dominate in an urban setting. Also, the shorter line may reflect a larger share of line termination costs. This cost comparison illustrates the problems of trying to apply "system average" costs per mile for different lines in different locations.

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

Cost Item	Line Design Supporting Structure / Material / Conductor Configuration Cable per Phase	
	HPFF -2500 kcmil / Delta One cable per phase $/mile	XLPE -3000 kcmil / Horizontal One cable per phase $/mile
Duct/Vaults	3,786,400	5,133,353
Cable/Hardware	3,686,500	8,469,288
Site Work	171,500	617,838
Construction Management	764,440	1,517,070
Engineering	252,265	950,224
Sales Tax (4.6 percent)	398,411	697,852
Project Management	905,952	1,738,562
Total Cost/Mile	9,965,468	19,124,187

Another observation to be made from Table 3-7 data is that, as opposed to 115 kV cable systems, the total cost per mile of XLPE cable is higher than HPFF for 345 kV. Indeed, the cost increase is 91 percent. Additional investigation shows that "splice vaults" and other costs related to the cable installation have a big impact on this increase. 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 excavated soil that has to be disposed of in a environmentally-friendly manner. These factors 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 for underground cables, other costs relate to 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 (While under construction)

Source: Docket No. 217 - Weekly Environmental Report dated February 23, 2005

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. Not only first costs, but a number of other factors provide the 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
- Electric and magnetic field (EMF) mitigation

These factors are all 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 corridor of land over which facilities such as highways, railroads, or other utility infrastructure 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

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 in rocky terrain
- Special foundations for water crossings
- Incremental costs of access road construction in difficult terrains

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 that are required between two contiguous towers at significantly different elevations. Steeper terrain is generally not suitable for underground cables or conduit systems, which is why underground cables are not commonly sited off road ROWs in Connecticut. Mountainous terrain, increase costs by necessitating stronger structures and foundations; also, 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, common in Connecticut, may present particular challenges. 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 on an underground route than would be required for the structure foundations on an overhead route [1]. Based on the recent Bethel-Norwalk 345 kV transmission project, more than 25 percent 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 Illuminating 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 terrain affects 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 percent of the total capital costs. As noted by, Graham McTavish, Manager of Transmission Project Planning, for Connecticut Light and Power (CL&P): "We have seen 100-200 percent 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].

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 small when compared to factors related to type of terrain. The impact that these obstacles may have on the overhead and/or underground transmission line design and the associated costs include:

- Incremental length of the transmission line to avoid 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 the presence of other utilities

To avoid private houses, schools, public buildings and parks, the transmission line length may have to increase. Rivers and streams are typically environmentally-sensitive areas, and the transmission line length may also have to increase to avoid them. If the transmission line needs to cross the rivers or streams, a number of special foundations are typically required.

Wherever an overhead transmission line needs to cross a road, stronger structures and foundations are required. Different types of structures 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 to 10 degrees); the structures, insulators and associated hardware are not designed to resist the full tension of the wires. Sharper bends (up to 45 degrees) 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 on one side. 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 unbalanced load carried in the event that all the conductors on one side go slack [6].

Underground utilities may also impact the design of underground transmission lines, since additional labor and materials may be required to avoid conflicts.

The impact that the different kinds of obstacles may have on costs will be proportional to the incremental length of the line needed to avoid them, or the incremental costs of stronger structures and foundations. Thus, cost impacts are 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 dead-end and angle structures, which in turn causes the line length to increase." Tall steel structures, and especially 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 ROW 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: 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 separately 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.

Many variables in the permitting and legal requirements for transmission lines affect transmission line costs. We have identified the most relevant government entities that affect transmission line siting designs, and associated costs. Those government entities include: the Connecticut Siting Council (Council), the Connecticut Department of Transportation (CDOT), the Connecticut Department of Public Utility Control (DPUC), the Connecticut Department of Environmental Protection (CTDEP), and the US Army Corps of Engineers (USACE).

4.3.1 Connecticut Siting Council (Council)

The Council has jurisdiction over the siting of power facilities (generally over one megawatt) and transmission lines in Connecticut (69kV and over), and evaluates utility applications for those facilities and lines. When conceptualizing the addition of a new transmission line to the power system, utility system planners perform a great many planning and preliminary engineering activities. This work ultimately leads to the development of an application to the Council for a new 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. Criteria for determining the best solution 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 Criteria." In basic terms, PA 04-246 requires the Council: 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 new 345 kV overhead and/or underground transmission line designs and associated costs include:

- Incremental length of the underground segments for 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 transmission lines
- Increased number of underground-overhead transition stations
- Potentially increased project cost due to requirements for significant magnetic field management measures

Although PA 04-246 requires the use of underground 345 kV designs only in certain defined areas where technologically feasible, utility companies seeking to build new facilities will, in fulfilling their obligation to manage costs, invest substantial effort to develop alternative designs and to evaluate the technical and financial viability of such underground construction and its 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 ROW 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 for easements over private property because construction within the highway ROW for utility facilities such as splice vaults is not permitted
- Incremental costs for horizontal directional drilling or self-supporting structures to cross water bodies and other features, when attachment of cables to bridges is not allowed
- Work schedule restrictions

Specific examples of the type of impact CDOT requirements can have on project costs, are summarized next.

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 of up to three weeks, the CDOT has decided as many vaults as possible must be built off of the roadway. (CL&P notes that most of the time spent on vault work is for splicing, not burying the vault.) This requirement imposes considerable added costs, including obtaining easements over private property adjacent to the road, the cost of turning the cable ducts off of and then back onto the road at each vault, the cost of crossing more buried utilities, and, ultimately, as cable length increases, the cost of additional vaults.

Working Schedule

In order to minimize traffic delays, CDOT has directed that contractors working on underground transmission lines in state roads are allowed to work only during the night shift. This may have impacts on costs since the working hour window for lab or at the site may be reduced to six to eight hours due to the considerable set-up and clean-up time required for each shift [2].

Cable Installations Along Bridges and Special Construction Methods

Historically, the attachment of transmission cables to highway bridges or other state structures crossing water bodies and/or railroads has not been supported by CDOT. Special construction methods such as horizontal directional drilling or "jack and bore" are the alternatives. In horizontal directional drilling, a pilot hole is drilled and then reamed out to an appropriate size, and the duct or pipe is pulled into the hole. Jack and bore involves the construction of pits on either side of the obstacle; a small tunnel is built while simultaneously a pipe is installed as the tunnel is formed [10]. These methods normally place the cables at greater depths, a minimum of 15 feet below the surface, and may require significant environmental impact controls and associated costs. Furthermore, cable capacity decreases with cable depth. This is another limiting consideration for underground cable design systems.

The degree to which these design changes imposed by CDOT affect costs is very project specific, but generally these requirements may cause an increment of 10 to 20 percent 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 Connecticut's natural resources and environment while still encouraging social and economic development [11]. When a transmission line right of way is located near an environmentally sensitive area under 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. One significant impact of CTDEP requirements on the incremental costs of construction has to do with the management of excavated soil materials.

Contaminated Soil

Since some of the soil under the local and state roads in Southwest Connecticut may be contaminated, CTDEP requires environmental measures whereby the excavated soil cannot be reused to close underground cable trenches and must be stored according to special rules. In the Bethel-Norwalk project, (CSC Docket 217), this resulted 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 percent 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 ROW is located near waterways under the USACE jurisdiction, special procedures must be followed. The impact of USACE requirements potentially includes increased project lead-time and permitting costs. Normally, for the permits required from the USACE, a final design is needed. The USACE does not allow project segmentation in this permitting process. This permit, which may take up to a year, is typically done in connection with other permits granted by the CSC and/or CTDEP. Therefore it may add to the total project time and have a direct impact on the project costs. Even though a USACE permit may be sought at the same time as other permits, the USACE process may take as long as a year, adding to the total project time and increasing 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 material and labor costs. According to the study titled "Transmission Line Capital Costs," prepared the US Department of Energy [4], 5.5 percent of the materials (cable, structures, etc) costs would be enough to cover land and land rights in a non-urban area.

According to the utilities in Connecticut, however, 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 projects 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 ROW 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 ROW, 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 ROWs 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 more expensive 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, Mr. Carberry, "… [1]f 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]".Mr. Reed 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, where as for Norwalk the cost is $350,000. In this project, one of the alternatives required widening the ROW by 40-50 feet, and the estimate for land acquisition was $50,000,000 [12, page 94]. 20 miles for fifty $50,000,000 is two and a half million a mile. Comparing this $2,500,000 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, $2,500,000 per mile of land costs become the third largest component, just after Duct/Vaults and Cable/Hardware. Applying the $2,500,000 per mile of land costs for underground transmission lines suggests that the costs for land acquisition for overhead lines are typically equivalent to underground lines, which is not the case.

4.5 Materials, Labor, and Cost Escalation

Once a transmission line design has been completed, an estimated materials list is defined. Similarly, construction estimates have detailed lists for the expected labor hours required to build the transmission line. 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 Connecticut, since the inception of the Middletown-Norwalk 345 kV transmission project, estimates for materials have increased approximately 45 percent, 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. Underground construction is significantly higher than overhead construction. See Table 4-1.

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 percent	24 percent
Materials	65 percent	76 percent
Total	100 percent	100 percent

As seen in this table, 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, cost escalation in materials will have a higher impact on underground transmission lines.

4.6 References

1. Connecticut Siting Council, Findings of Fact, 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 Fact, 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 an alternating 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 project. 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 hundreds of 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 a single circuit of one voltage 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 require the acquisition of land and sometimes increased costs for environmental impacts. 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.

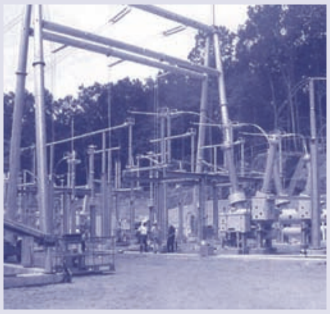


Figure 5.1 Archers Lane 345-kV Transition Station (While Under Construction)

Source: Docket 217- Weekly Environmental 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 $60,000,000 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, $20,000,000 - $25,000,000 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 Project Alternatives (all costs in 2003 dollars)

Option 1 - Overhead 345/115-kV 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 - 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 - 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 the ability to control the transmission system and increase power transfer capability. Problems created in transmission networks today by uncontrolled power flows and voltage transients have created a need for more dynamic regulation of networks to reduce the likelihood of power transfer bottlenecks and blackouts.

FACTS devices and the primary applications for them are included in Table 5-2.

Installation of FACTS devices is becoming more widespread as system capacity limitations create problems at the slightest contingency.

Table 5-2 Primary Applications of FACTS Devices

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

FACTS devices can be used for dynamic voltage control and for steady state power flow regulation. The cost of FACTS devices varies widely, depending on their technical characteristics and also on their application. A range of typical costs is 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 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 for special purposes such as, connecting AC systems of different system strengths or frequencies, and for connecting remote hydro or wind power 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
- Require only two, not three conductors sets
- 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. For overhead applications, long distance, point-to-point power transfers are an application where HVDC may be the only reasonable alternative. For underground or submarine applications the high capacitance and the resulting costs, create the possibility for HVDC to be cost competitive and operationally preferred to an AC circuit. 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. Distances required to reach a break even comparison between AC and HVDC vary widely with underground and overhead applications, but generally underground (or submarine) distances of 30 miles are required while the overhead distance required for feasibility may be ten times as much.

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. (This includes the terminals only, not the line itself.)

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 Middletown to Norwalk HVAC transmission project 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

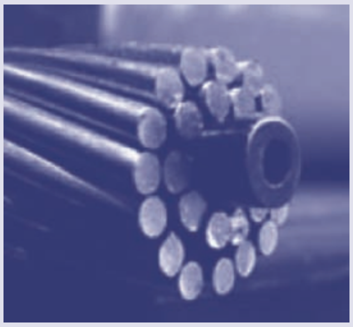
The transmission industry in recent years has seen the introduction of new conductor materials that bring the benefit of higher current-carrying capacity, lower weight and greater strength than materials generally in use for transmission lines today. Composite conductors, also known as HTLS (high-temperature, low-sag) conductors, are regarded as a potential re-conductor 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 as compared to steel core conductors include:

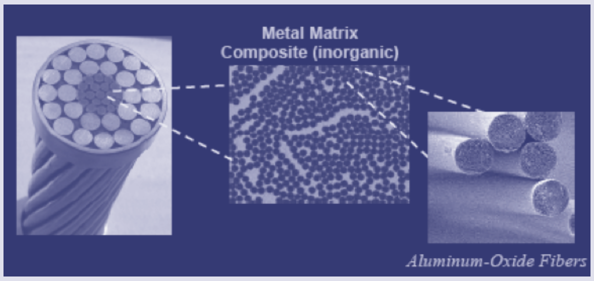
- Higher current capacity and up to 10 percent lower resistance, thereby reducing line losses. (However, it should be noted that operating composite conductors at high temperatures could cause equivalent or even greater line losses as those experienced by conventional conductors.)

- Higher strength to weight ratio (up to 50 percent lighter than conventional) may result in less conductor sag and increased reliability during heavy loading conditions (ice). (However, it should be noted that composite conductors do not stretch or sag as much as ACSR conductors. This could potentially reduce reliability in some cases.)

- Because of lighter weight, composite conductors allow the capacity of a line to be increased using existing rights-of-way and transmission structures. (However, the ability of the transmission structures to support the wind load and the conductor tension may be limiting.)

Figure 5.2 Examples of Composite Reinforced Aluminum Conductors





Source: US Department of Energy and 3M Corporation

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 conductors. 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 in a particular application might also be reduced through the use of this technology.

Composite conductors can potentially carry 30 percent to 60 percent more current than conventional ACSR conductors, according to CL&P. 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 obtain a material increase in 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. However, 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 an 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 how 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 include 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 and access ways along the right-of-way on which the line is constructed. Routine maintenance activities include such things as:

- 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.
- Wood pole inspection, 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 or older poles
- Steel pole repainting
- Infrared inspection to identify hot spots on splices and connectors

Vegetation management, or maintenance of the line right of way, is a cyclical process that provides for periodic clearing of trees, brush and other vegetation that could interfere with the 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 manholes, including the 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

Operating and maintenance (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 economic 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 analysis 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 percent per year in determining future year costs. For analysis 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 UI	2004 CL&P	2005 UI	2005 CL&P
Trans. Expenses Operation				
560 Oper Supv & Eng	$ 1,513,033	$ 4,399,082	$ 1,595,059	$ 4,711,764
561 Load Dispatch	$ 2,799,825	$ 4,695,676	$ 3,207,540	$ 5,631,543
563 OH Lines Expenses	$ 4,053	$ 764,232	$ 6,710	$ 504,649
564 Underground Lines Expenses	$ 33,330	$ 300,588	$ 27,271	$ 144,278
TOTAL OPERATION (UG + OH)	$ 2,837,208	$ 5,760,496	$ 33,981	$ 648,927
Maintenance				
568 Main Supv & Eng	$ 84,214	$ 1,196,168	$ 108,205	$ 1,935,618
571 Main of OH Lines	$ 367,814	$ 3,414,493	$ 514,945	$ 4,135,434
572 Main of UG Lines	$ 34,001	$ 115,761	$ 27,058	$ 150,000
TOTAL MAINTENANCE (UG + OH)	$ 443,922	$ 4,128,338	$ 596,106	$ 5,253,243
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	$ 28,184	$ 5,567	$ 33,307	$ 6,605
Underground	$ 28,015	$ 12,407	$ 30,744	$ 10,111
STATE AVERAGES ($ / CKT MILE)				
Overhead Construction	$6,833		$8,099	
Underground Construction	$16,809		$15,930	

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 percent 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 analysis 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 analysis.

7. Transmission Loss Costs

7.1 General

Since no device is 100 percent 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. (These losses only occur in substations, and are not considered part of the transmission line life cycle costs.) There also will be line insulation losses, more so for underground cables than overhead lines, but these are insignificant by comparison and seldom considered.

- Load losses are present in the windings of transformers and other devices, as well as in transmission lines and cables. Transmission line losses increase in direct proportion to the line resistance and in proportion to the square of the line current (in amperes). Because line resistance increases with temperature and conductor temperatures increase as line currents increase, the magnitude of load losses can vary greatly between peak load and light load conditions.

The reactive power demands of transmission lines and transformers also cause line currents to increase, contributing further to resistive energy losses. Such 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 net present value (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 Inc. to approximate cost of transmission losses. The loss calculations are based on an example peak load current for a line.

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

DC (Demand Cost) = $3 \times R \times I^2 \times IDC \times LIF$

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 Mitigation

Electric and magnetic fields (EMFs) 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 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 AC 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 percent 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 percent lower than those for the horizontal configuration, but they are 50 percent 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 percent 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 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 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 percent 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 Levels from the Rhode Island Study

		Distance from Centerline of Structure (ft)						
Configuration and Field	Maximum Field	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								
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. However, this assumes like phasing of the conductors and like current directions. If reverse phasing were employed instead, the result would be substantial reductions in EMF levels in comparison with the single-circuit vertical line. (See Section 8.2.3.) 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.

2) 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 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 A.

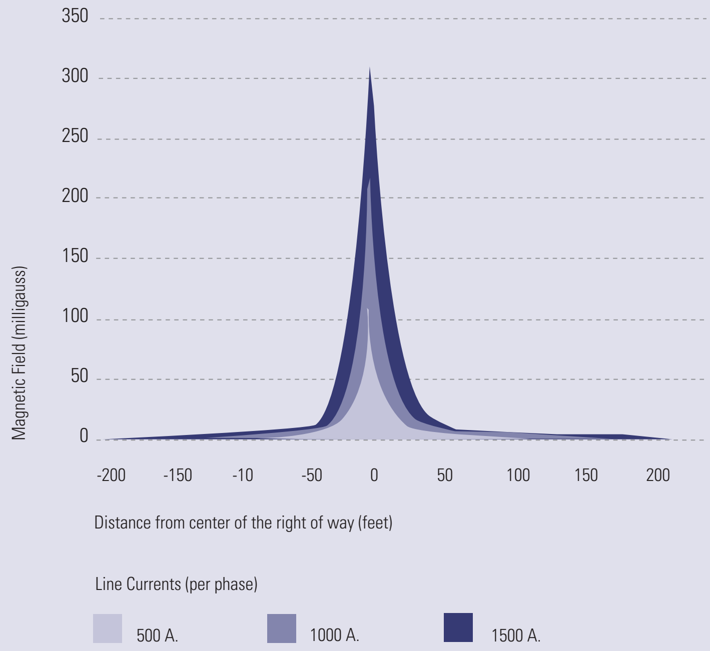


Figure 8.1 Magnetic Field Profiles for 115 kV XLPE Line with Horizontal Cable Arrangement

Source: Connecticut Siting Council and Acres International Corp., "Life Cycle Cost Studies for Overhead and Underground Electric Transmission Lines," pp. 106-111.

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. (See page 39).

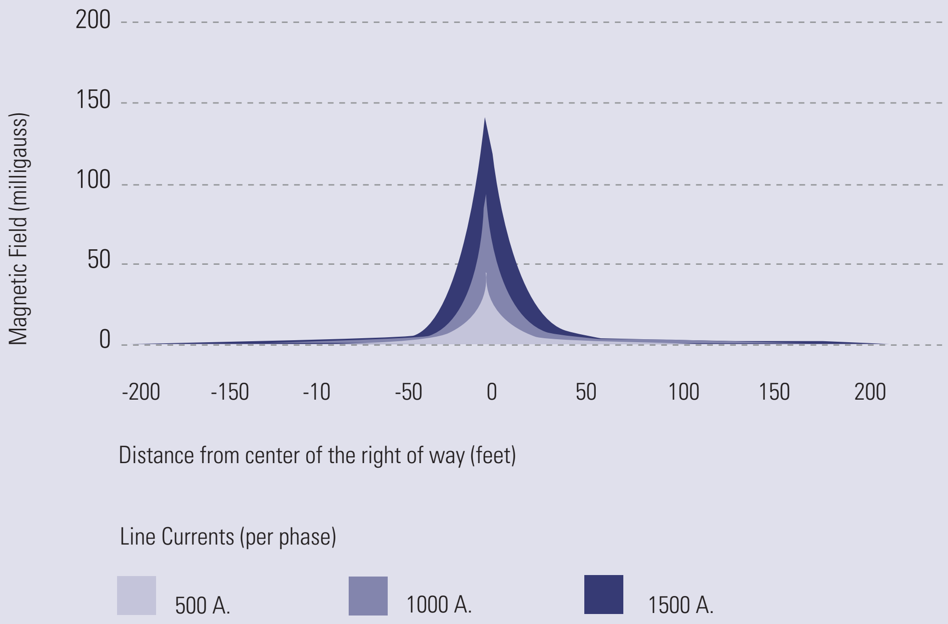


Figure 8.2 Magnetic Field Profiles for 115 kV XLPE Line with Delta Cable Arrangement

* This calculation assumes the cables are installed in separate ducts in a equilateral triangular configuration with a centerline spacing of approximately 9 to 12 inches.

Source: Connecticut Siting Council and Acres International Corp., "Life Cycle Cost Studies for Overhead and Underground Electric Transmission Lines," pp. 112-115.

8.2.3 Mitigation Alternatives

The most common method for mitigating the magnetic fields of solid dielectric cables is cable reconfiguration. One type of cable reconfiguration is the arrangement of cables in a delta configuration, as previously illustrated by the reduced fields in Figure 8-2. However, cable reconfiguration can also be 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 percent 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, there is a cost penalty because the total required length of cable is doubled. Also, the number and relative location of ground continuity conductors can be used as a mitigating method.

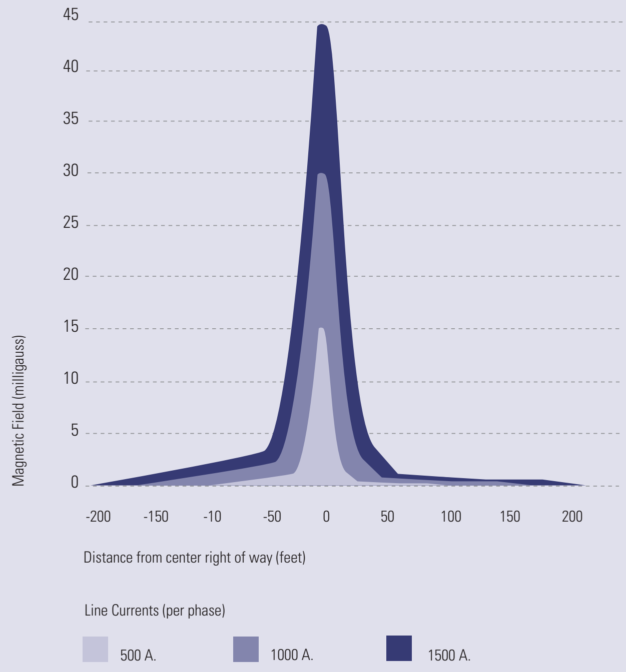


Figure 8.3 Magnetic Field Profiles for Typical 115 kV HPFF Line*

Source: Connecticut Siting Council and Acres International Corp., "Life Cycle Cost Studies for Overhead and Underground Electric Transmission Lines," pp. 96-99.

Another mitigation method for XLPE lines is the use of metallic shielding. Such shielding, which typically involves the insertion of steel plates between the cables and the ground level, has not been used previously in Connecticut. Shielding methods were considered during the Docket 272 proceedings, however. Specifically, the Docket 272 Findings of Fact conclude that steel plates installed over the top of a 345 kV cable trench could reduce magnetic fields directly over the trench by a factor of two to five. However, such steel plates also cause a "wing effect" to either side of the trench where the magnetic fields would increase somewhat. When the location of interest is a short distance away from the cable trench, therefore, such plates are generally not an effective tool for mitigating magnetic field levels.

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

* Please note that this may not fully account for the magnetic field attenuation afforded by the steel pipe.

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 (CTDEP) 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 Commission on Culture and Tourism, 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 (USACE) has the greatest influence. Specifically, the USACE 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 USACE 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 USACE permitting process.

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

Environmental Resources and the 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 Lines (Overhead or Underground)

Agency and the 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 five 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)
- Stream Channel Encroachment Permit

Connecticut Commission on Culture and Tourism
- Review of archaeological and historic resources, consistent with the National Historic Preservation Act; approval by finding no adverse effect

Department of Public Utility Control
- Method and Manner of Construction Approval
- Approval to Energize

Federal

U.S. Army Corp of Engineers, New England Division
- 404 permit for dredge and fill activities (wetlands and water-courses) or *nationwide permit approval (*These are required for most utilities. Please note that the nationwide permits have been replaced with Programmatic General Permits.)
- 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. CTDEP suggested restrictions for the Middletown-Norwalk (M-N) project line provide an illustrative example. Even though no significant watercourse impacts are anticipated from the M-N line, DEP offered the following guide lines for instream work and special habitat areas in its May 4, 2004, letter:

- "…the CTDEP Inland Fisheries Division suggests 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 M-N project 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, CL&P and UI, 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 Contaminated Substance Handling and Disposal

One might not expect that the construction of a new transmission line would incur high costs from the handling of contaminated substances. However, this has been a major cost concern for the proposed M-N project 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 CTDEP 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 CRDEP 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 contaminated 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 (LCCs) 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 percent
Operation and maintenance cost escalation:	4.0 percent
Load growth:	1.2 percent
Energy cost escalation	5.0 percent
Discount rate:	10.0 percent

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 (Fixed charge rate): This factor represents the levelized annual cost of the fixed costs of ownership in terms of percentage of the first cost. This includes the following components:
1) return on the capital investment required for construction
2) depreciation
3) federal and state income tax
4) property taxes
5) insurance

This does not include O&M since this is typically considered as variable with respect to the first cost of the facility. The value of 14.6 percent is typical for Connecticut transmission lines.

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 percent, 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 percent 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 percent per year has been assumed.

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

Using the factors outlined here, a 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 analysis. 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 percent 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 percent increase in LCC. The costs of the two 345 kV 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 percent to 80 percent of total LCC are expended during the first 17 years. This means only 20-25 percent 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

LCC Component	115 kV Wood Laminate Poles, Delta Single Circuit	115 kV Steel Poles Delta Single Circuit	345 kV Wood Laminate H-Frame, Single	345 kV Steel Poles, Delta Single Circuit	115 kV Wood Laminate Poles, Delta Single Circuit	115 kV Steel Poles, Vertical, Double Circuit
Poles & Foundations	419,633	904,156	931,247	2,445,721	456,242	1,011,337
Conductor & 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 Management	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
Losses	1,420,324	1,420,324	1,420,324	1,420,324	2,840,648	2,840,648
O&M	115,689	115,689	115,689	115,689	115,689	115,689
Total LCC	3,067,239	3,944,676	4,469,776	6,851,908	5,513,293	6,330,646

Overhead Transmission Lines
Life Cycle Cost 35 Year Cumulative PV

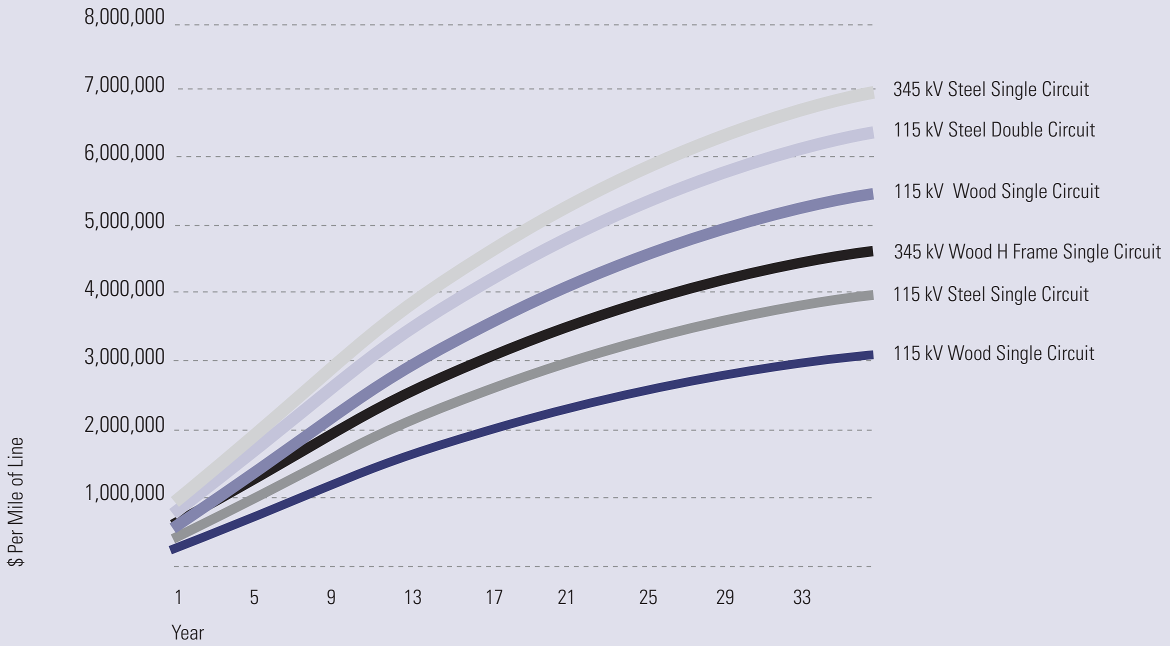


Figure 10.1. Overhead Transmission Line Life Cycle Costs

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 percent for the overhead lines, they are 5 percent 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 Management	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	756,276	756,276	1,512,552	1,512,552
O&M	54,048	54,048	54,048	54,048
Total LCC	13,134,649	14,162,631	28,494,358	15,598,449

Figure 10.2 shows the yearly growth in LCC over the assumed 35 years of line life. The relative cost difference for a 345 kV XLPE line versus a 345 kV HPFF line is quite dramatic. Also of interest is the relatively small LCC difference between a 345 kV HPFF line and either of the 115 kV alternatives.

Underground Transmission Lines
Life Cycle Cost 35 Year Cumulative PV

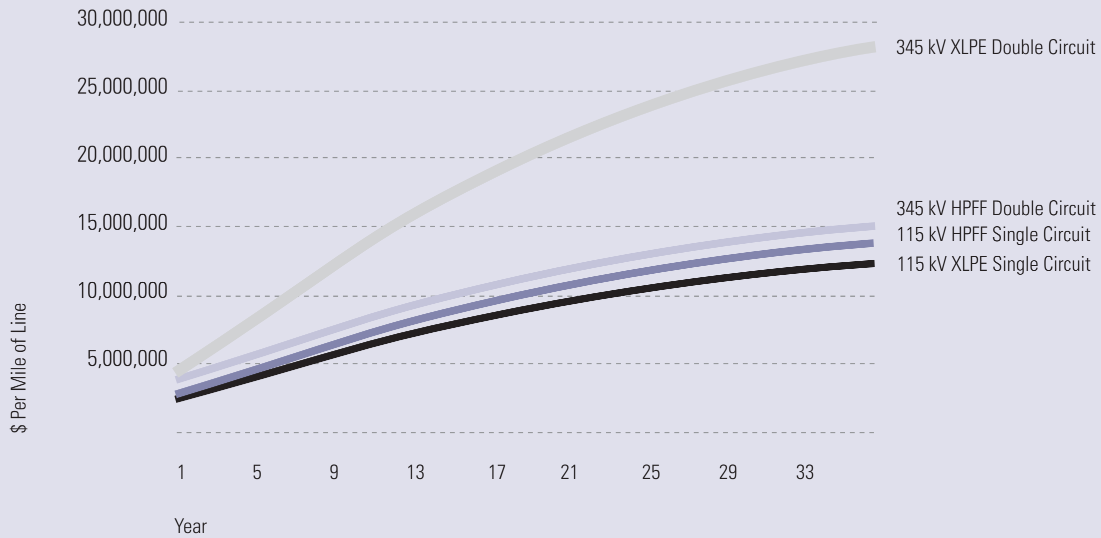


Figure 10.2. Underground Transmission Line Life Cycle Costs

Figures 10.3 through 10.6 show how the cumulative present value (PV) of LCC components vary over time for the overhead and underground lines, first at 115 kV and then at 345 kV. At both voltages, the variable components of O&M and losses are significant enough to "cross-over" the 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.

Overhead 115 kV Transmission Line
PV of Life Cycle Cost Components

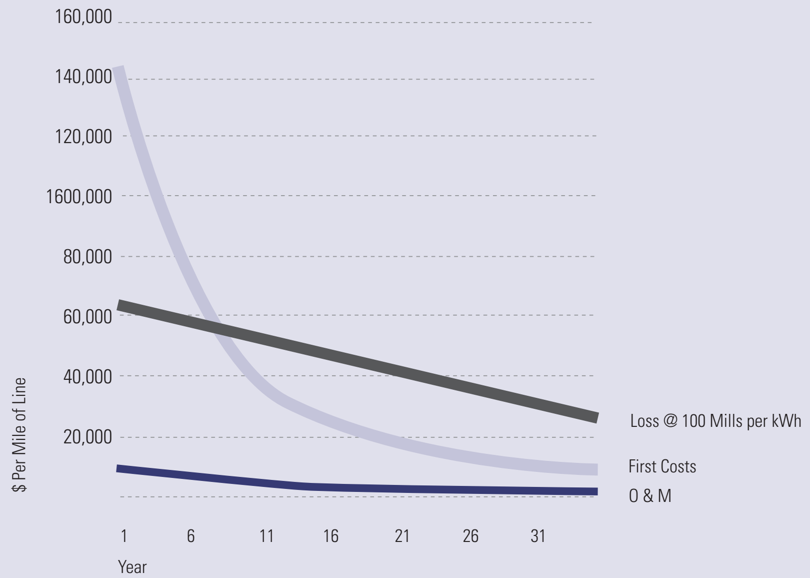


Figure 10.3. 115 kV Overhead Transmission Line Component Costs

Underground 115 kV Transmission Line
PV of Life Cycle Cost Components

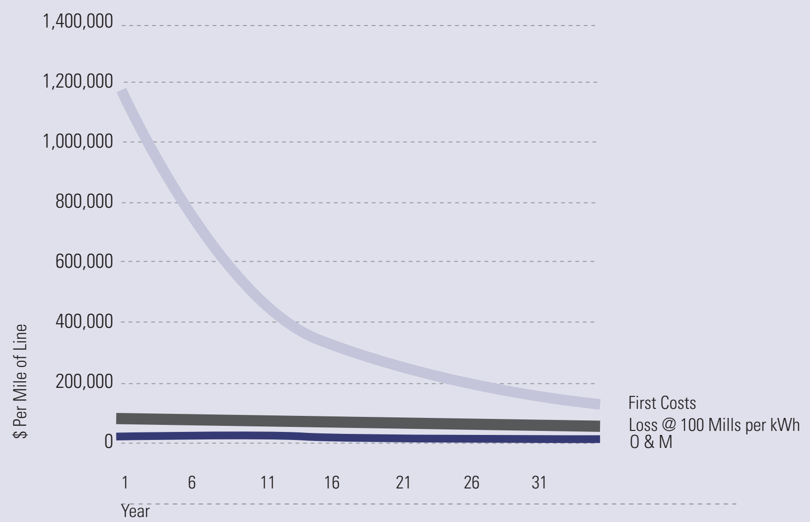


Figure 10.4. 115 kV Underground Transmission Line Component Costs

Overhead 345 kV Transmission Line
PV of Life Cycle Cost Components

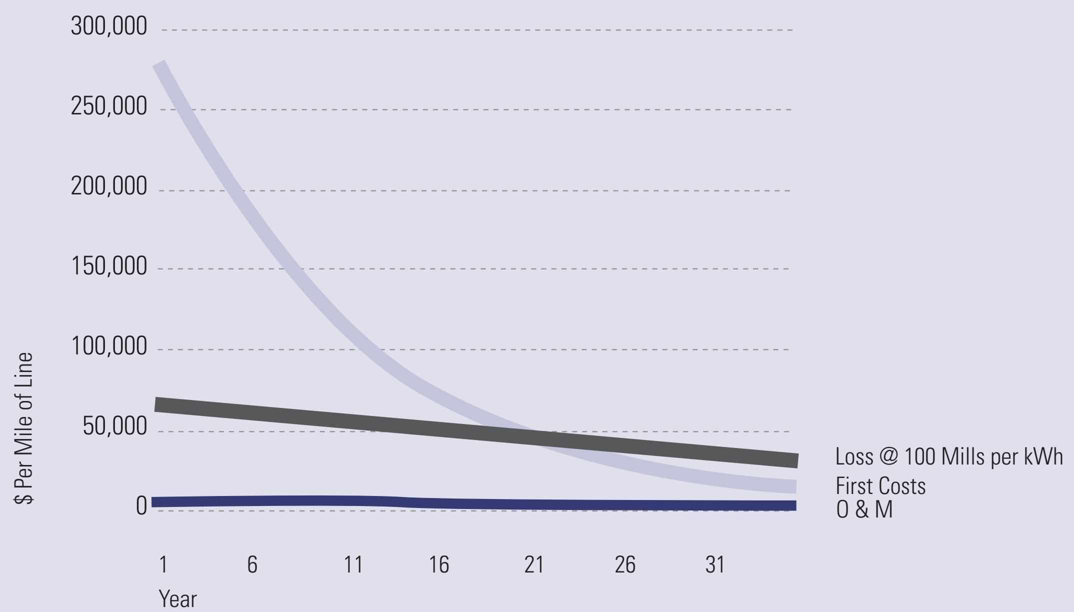


Figure 10.5. 345 kV Overhead Transmission Line Cost Components

Underground 345 kV Transmission Line
PV of Life Cycle Cost Components

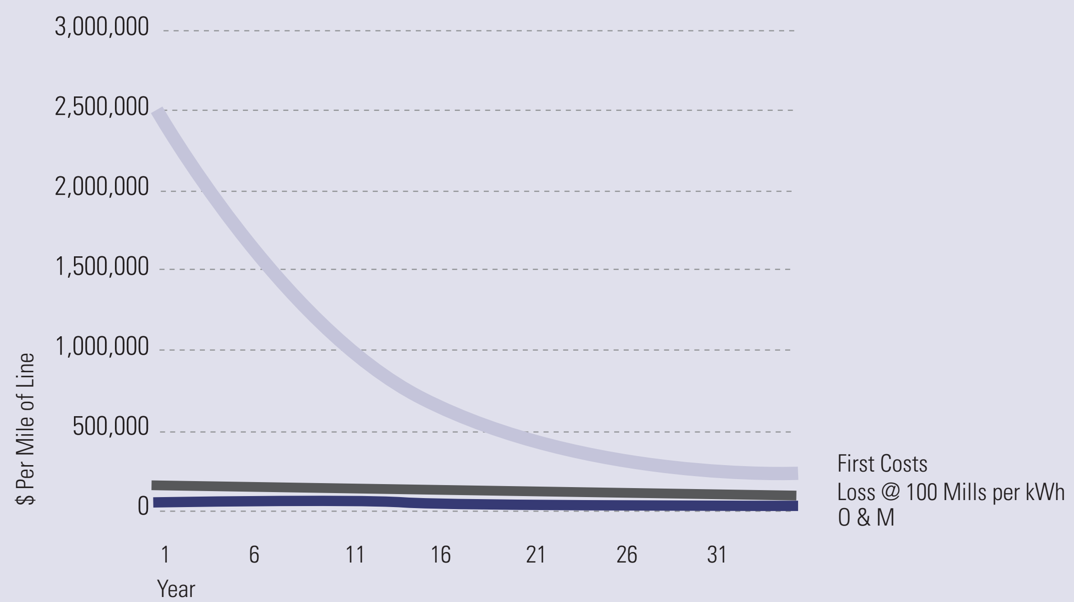
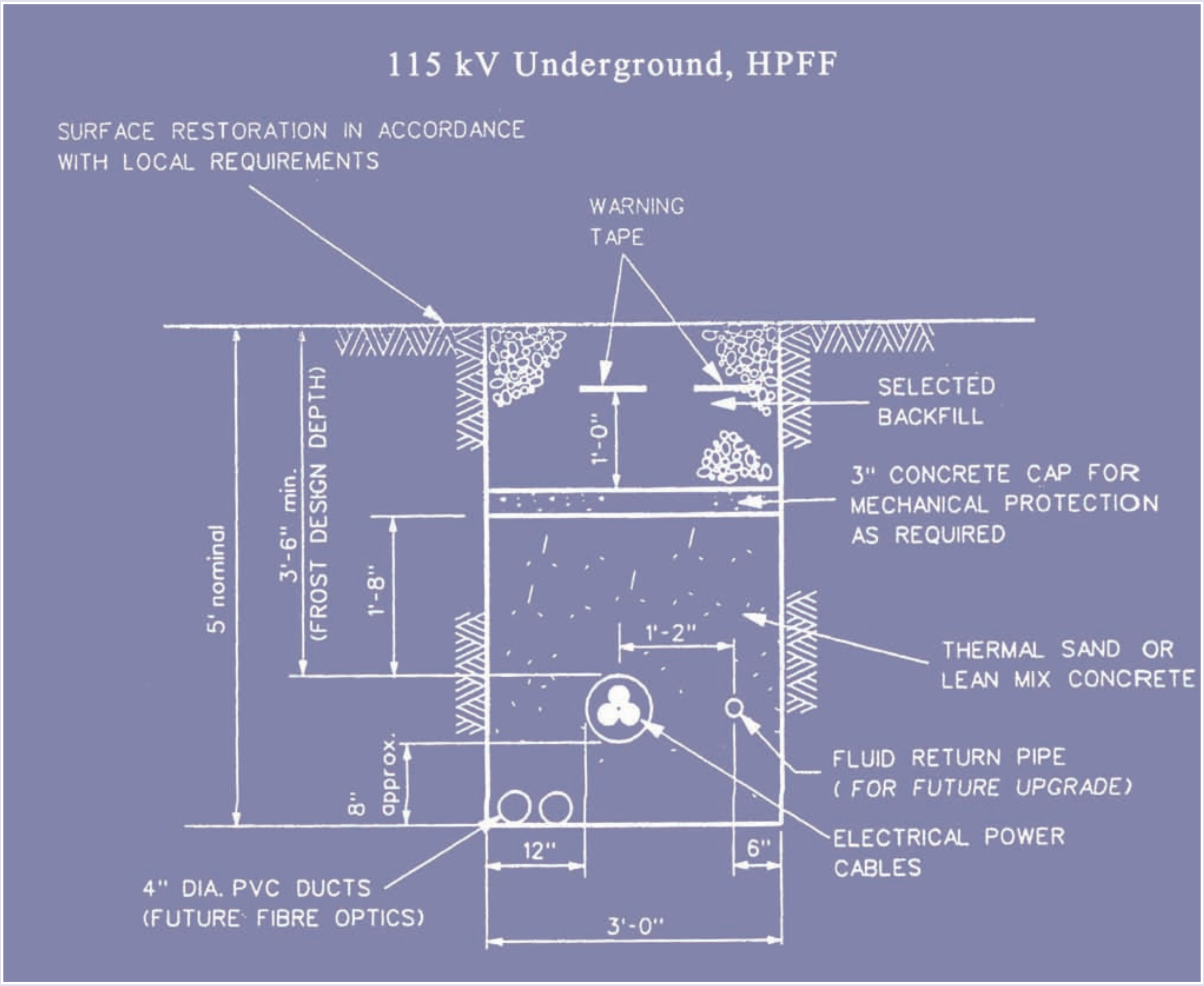


Figure 10.6. 345 kV Underground Transmission Line Component Costs

11. Appendix A – Life Cycle Cost Tables

115 kV Underground, HPFF



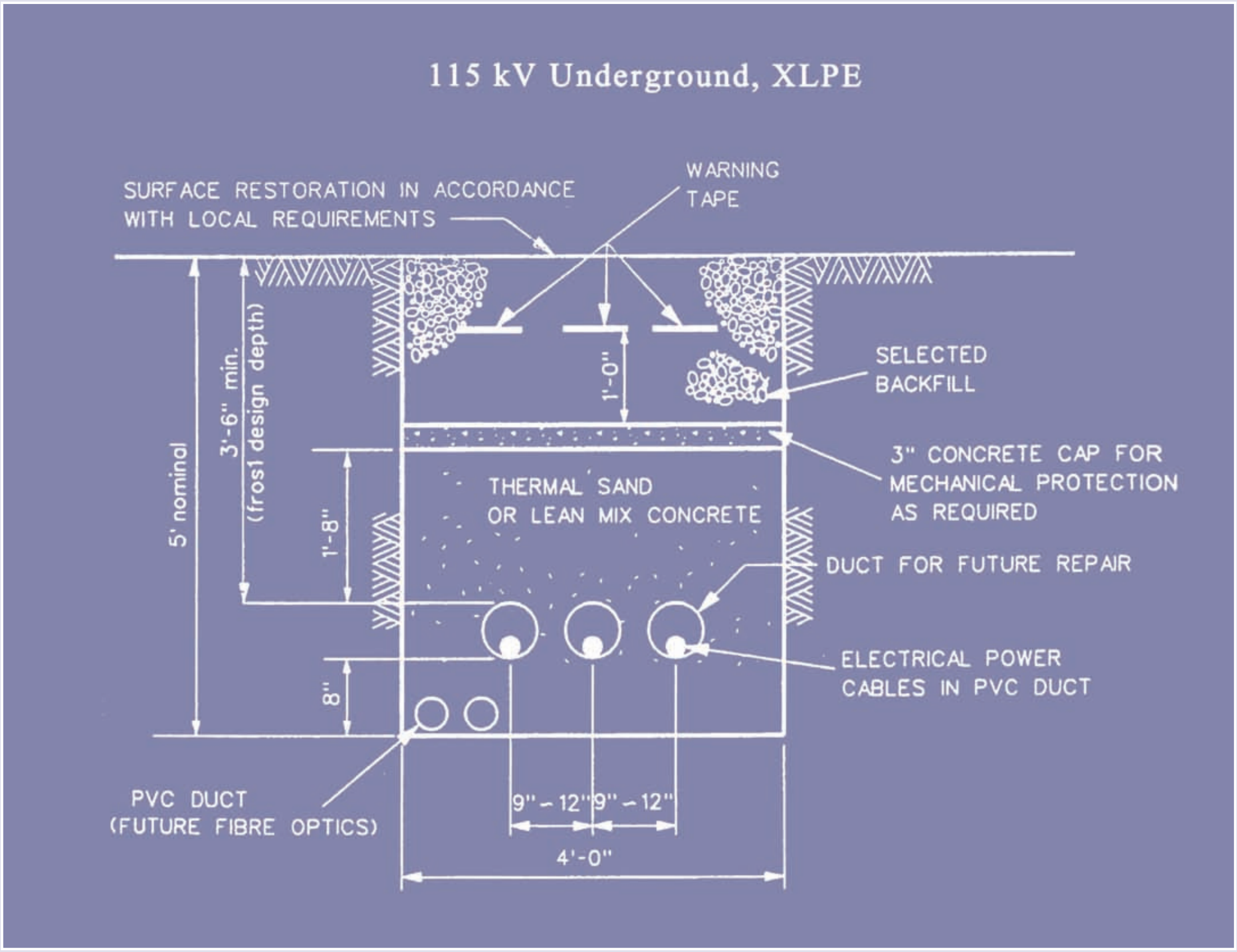
(Source: CL&P)

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	Peak Line Current 1000 amps
Construction Management	823,186	Load Growth 1.2 percent
Engineering	242,613	Loss Factor 0.38
Sales Taxes	373,587	Energy Cost 100 mills/kWh
Administration	987,821	Energy Cost Escalation 5.0 percent

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Total PV
1	0.91	1,258,633	32,776	3,430	1,294,839	1,294,839
2	0.83	1,144,212	31,915	3,243	1,179,370	2,474,210
3	0.75	1,040,193	31,077	3,066	1,074,336	3,548,545
4	0.68	945,630	30,261	2,898	978,789	4,527,335
5	0.62	859,664	29,466	2,740	891,870	5,419,204
6	0.56	781,512	28,692	2,591	812,795	6,231,999
7	0.51	710,466	27,938	2,450	740,853	6,972,853
8	0.47	645,878	27,204	2,316	675,398	7,648,251
9	0.42	587,162	26,490	2,190	615,841	8,264,092
10	0.39	533,783	25,794	2,070	561,647	8,825,740
11	0.35	485,258	25,116	1,957	512,331	9,338,071
12	0.32	441,143	24,456	1,851	467,450	9,805,521
13	0.29	401,039	23,814	1,750	426,603	10,232,124
14	0.26	364,581	23,188	1,654	389,424	10,621,548
15	0.24	331,438	22,579	1,564	355,581	10,977,129
16	0.22	301,307	21,986	1,479	324,772	11,301,901
17	0.20	273,915	21,409	1,398	296,722	11,598,623
18	0.18	249,014	20,846	1,322	271,182	11,869,805
19	0.16	226,376	20,299	1,250	247,925	12,117,729
20	0.15	205,797	19,766	1,181	226,744	12,344,473
21	0.14	187,088	19,246	1,117	207,451	12,551,924
22	0.12	170,080	18,741	1,056	189,877	12,741,801
23	0.11	154,618	18,248	998	173,865	12,915,666
24	0.10	140,562	17,769	944	159,275	13,074,941
25	0.09	127,784	17,302	893	145,978	13,220,919
26	0.08	116,167	16,848	844	133,859	13,354,778
27	0.08	105,606	16,405	798	122,809	13,477,587
28	0.07	96,006	15,974	754	112,734	13,590,321
29	0.06	87,278	15,555	713	103,546	13,693,867
30	0.06	79,344	15,146	674	95,164	13,789,031
31	0.05	72,130	14,748	637	87,516	13,876,547
32	0.05	65,573	14,361	603	80,537	13,957,084
33	0.04	59,612	13,984	570	74,165	14,031,249
34	0.04	54,193	13,616	539	68,348	14,099,597
35	0.04	49,266	13,259	509	63,034	14,162,631
		13,352,308	756,276	54,048	14,162,631	

115 kV Underground, XLPE



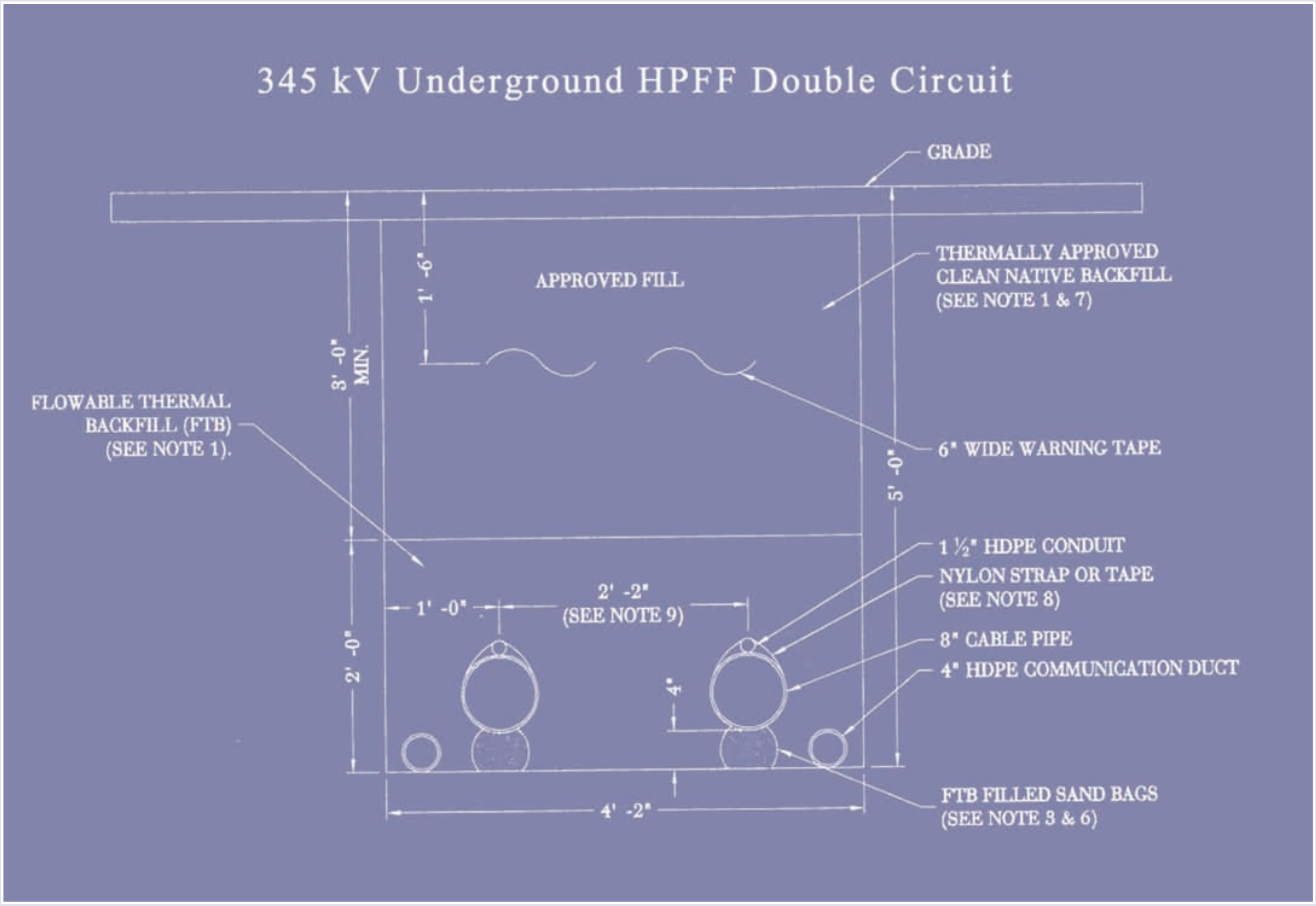
(Source: CL&P)

115 kV Underground, XLPE

First Costs		Losses
Ducts & Vaults	4,208,485	Conductor 1750 kcmil
Conductor & Hardware	1,588,244	Resistance 0.03147 ohms/mi
Site Work	611,780	Peak Line Current 1000 amps
Construction Management	823,186	Load Growth 1.2 percent
Engineering	241,667	Loss Factor 0.38
Sales Taxes	343,775	Energy Cost 100 mills/kWh
Administration	935,641	Energy Cost Escalation 5.0 percent

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Total PV
1	0.91	1,161,732	32,776	3,430	1,197,938	1,197,938
2	0.83	1,056,120	31,915	3,243	1,091,278	2,289,217
3	0.75	960,109	31,077	3,066	994,252	3,283,469
4	0.68	872,827	30,261	2,898	905,986	4,189,455
5	0.62	793,479	29,466	2,740	825,685	5,015,140
6	0.56	721,344	28,692	2,591	752,627	5,767,767
7	0.51	655,768	27,938	2,450	686,155	6,453,922
8	0.47	596,152	27,204	2,316	625,673	7,079,595
9	0.42	541,957	26,490	2,190	570,636	7,650,231
10	0.39	492,688	25,794	2,070	520,552	8,170,782
11	0.35	447,898	25,116	1,957	474,972	8,645,754
12	0.32	407,180	24,456	1,851	433,487	9,079,241
13	0.29	370,164	23,814	1,750	395,727	9,474,969
14	0.26	336,512	23,188	1,654	361,355	9,836,324
15	0.24	305,920	22,579	1,564	330,064	10,166,387
16	0.22	278,109	21,986	1,479	301,574	10,467,962
17	0.20	252,827	21,409	1,398	275,633	10,743,595
18	0.18	229,843	20,846	1,322	252,011	10,995,606
19	0.16	208,948	20,299	1,250	230,496	11,226,102
20	0.15	189,953	19,766	1,181	210,900	11,437,002
21	0.14	172,684	19,246	1,117	193,047	11,630,049
22	0.12	156,986	18,741	1,056	176,782	11,806,831
23	0.11	142,714	18,248	998	161,961	11,968,793
24	0.10	129,740	17,769	944	148,453	12,117,246
25	0.09	117,946	17,302	893	136,140	12,253,386
26	0.08	107,223	16,848	844	124,915	12,378,301
27	0.08	97,476	16,405	798	114,679	12,492,980
28	0.07	88,614	15,974	754	105,343	12,598,323
29	0.06	80,558	15,555	713	96,826	12,695,149
30	0.06	73,235	15,146	674	89,055	12,784,205
31	0.05	66,577	14,748	637	81,963	12,866,168
32	0.05	60,525	14,361	603	75,488	12,941,656
33	0.04	55,022	13,984	570	69,576	13,011,232
34	0.04	50,020	13,616	539	64,176	13,075,407
35	0.04	45,473	13,259	509	59,241	13,134,648
		12,324,325	756,276	54,048	13,134,648	

345 kV Underground HPFF Double Circuit



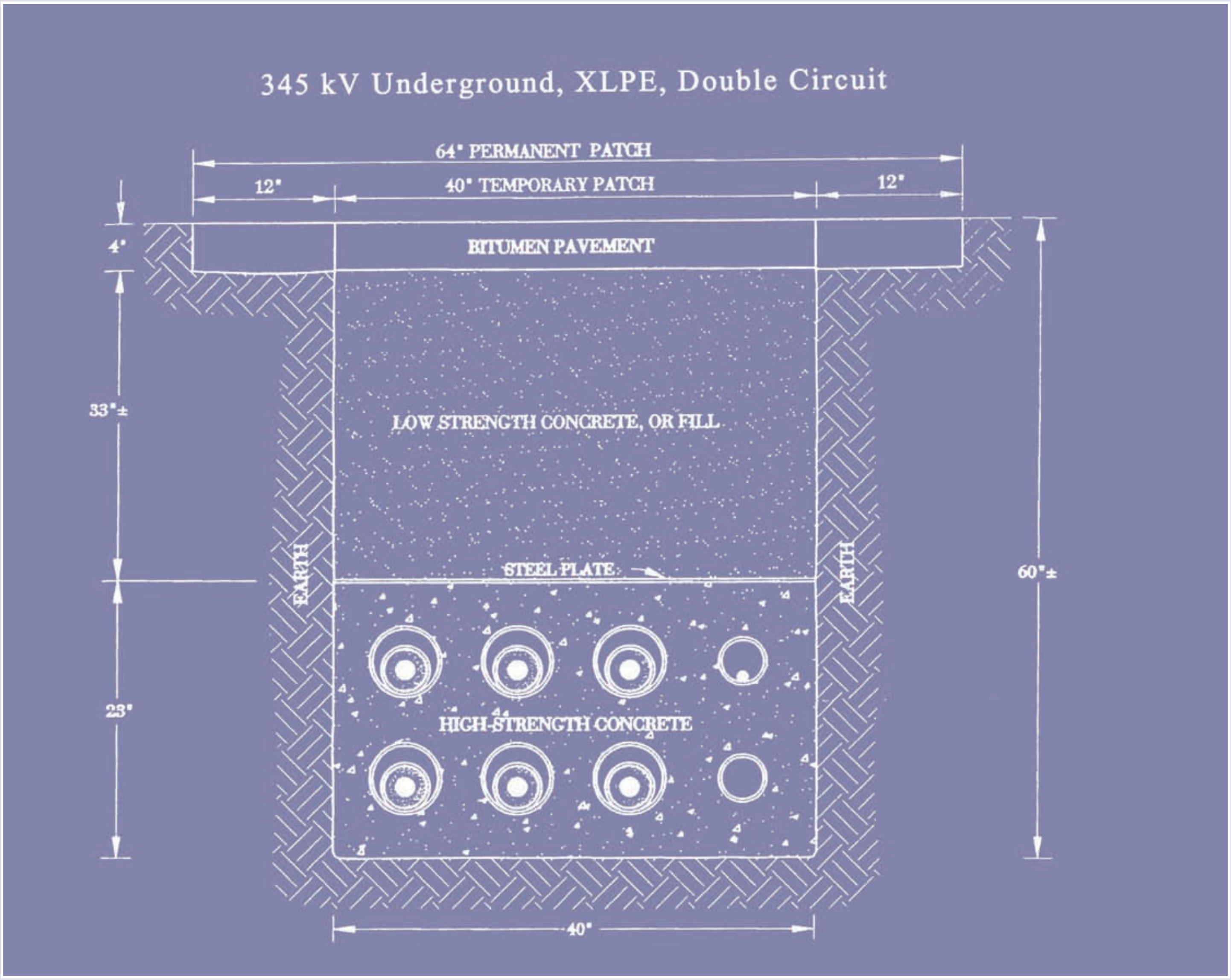
(Source: CL&P)

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	Peak Line Current 1000 amps
Construction Management	764,440	Load Growth 1.2 percent
Engineering	252,265	Loss Factor 0.38
Sales Taxes	398,411	Energy Cost 10 mills/kWh
Administration	905,952	Energy Cost Escalation 5.0 percent

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Total PV
1	0.91	1,322,689	65,553	3,430	1,391,672	1,391,672
2	0.83	1,202,445	63,831	3,243	1,269,518	2,661,190
3	0.75	1,093,132	62,154	3,066	1,158,351	3,819,541
4	0.68	993,756	60,521	2,898	1,057,176	4,876,717
5	0.62	903,415	58,932	2,740	965,087	5,841,804
6	0.56	821,286	57,384	2,591	881,261	6,723,065
7	0.51	746,624	55,876	2,450	804,949	7,528,014
8	0.47	678,749	54,408	2,316	735,473	8,263,487
9	0.42	617,044	52,979	2,190	672,213	8,935,700
10	0.39	560,949	51,588	2,070	614,607	9,550,308
11	0.35	509,954	50,232	1,957	562,144	10,112,451
12	0.32	463,595	48,913	1,851	514,358	10,626,809
13	0.29	421,450	47,628	1,750	470,827	11,097,637
14	0.26	383,136	46,377	1,654	431,167	11,528,804
15	0.24	348,305	45,159	1,564	395,028	11,923,832
16	0.22	316,641	43,972	1,479	362,092	12,285,924
17	0.20	287,856	42,817	1,398	332,071	12,617,995
18	0.18	261,687	41,693	1,322	304,701	12,922,697
19	0.16	237,897	40,597	1,250	279,744	13,202,441
20	0.15	216,270	39,531	1,181	256,983	13,459,424
21	0.14	196,609	38,493	1,117	236,219	13,695,643
22	0.12	178,736	37,482	1,056	217,273	13,912,916
23	0.11	162,487	36,497	998	199,983	14,112,899
24	0.10	147,716	35,538	944	184,198	14,297,097
25	0.09	134,287	34,605	893	169,784	14,466,881
26	0.08	122,079	33,696	844	156,618	14,623,499
27	0.08	110,981	32,811	798	144,589	14,768,089
28	0.07	100,892	31,949	754	133,595	14,901,683
29	0.06	91,720	31,109	713	123,542	15,025,226
30	0.06	83,382	30,292	674	114,348	15,139,574
31	0.05	75,801	29,497	637	105,935	15,245,509
32	0.05	68,910	28,722	603	98,235	15,343,744
33	0.04	62,646	27,967	570	91,183	15,434,927
34	0.04	56,951	27,233	539	84,722	15,519,649
35	0.04	51,773	26,517	509	78,800	15,598,449
		14,031,849	1,512,552	54,048	15,598,449	

345 kV Underground, XLPE, Double Circuit



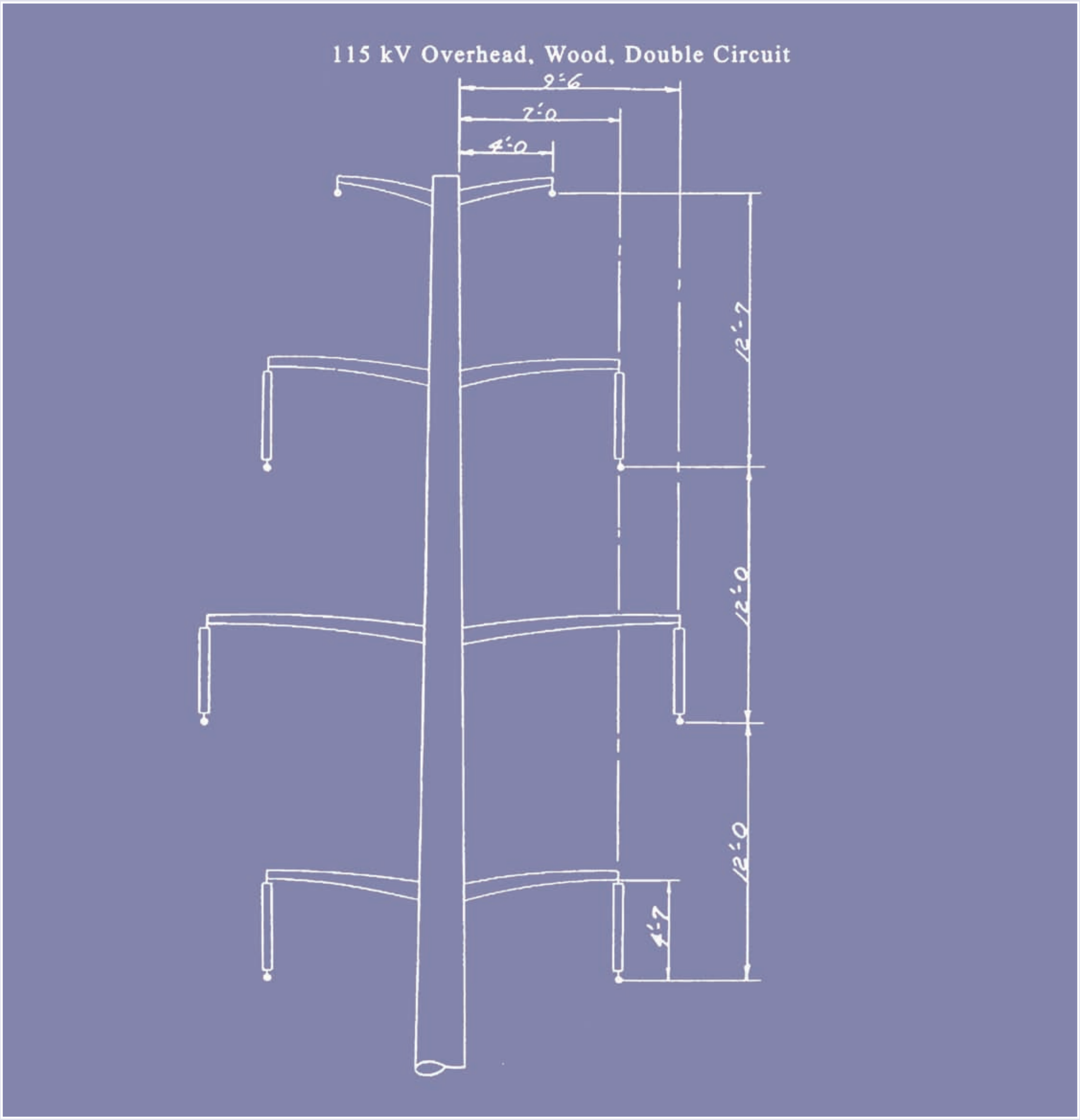
(Source: CL&P)

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	Peak Line Current 1000 amps
Construction Management	1,517,070	Load Growth 1.2 percent
Engineering	950,224	Loss Factor 0.38
Sales Taxes	697,852	Energy Cost 100 mills/kWh
Administration	1,738,562	Energy Cost Escalation 5.0 percent

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Total PV
1	0.91	2,538,301	65,553	3,430	2,607,284	2,607,284
2	0.83	2,307,547	63,831	3,243	2,374,620	4,981,903
3	0.75	2,097,770	62,154	3,066	2,162,989	7,144,893
4	0.68	1,907,063	60,521	2,898	1,970,483	9,115,376
5	0.62	1,733,694	58,932	2,740	1,795,366	10,910,742
6	0.56	1,576,085	57,384	2,591	1,636,060	12,546,801
7	0.51	1,432,805	55,876	2,450	1,491,131	14,037,932
8	0.47	1,302,550	54,408	2,316	1,359,274	15,397,206
9	0.42	1,184,136	52,979	2,190	1,239,305	16,636,511
10	0.39	1,076,487	51,588	2,070	1,130,145	17,766,657
11	0.35	978,625	50,232	1,957	1,030,815	18,797,471
12	0.32	889,659	48,913	1,851	940,423	19,737,894
13	0.29	808,781	47,628	1,750	858,159	20,596,053
14	0.26	735,255	46,377	1,654	783,287	21,379,339
15	0.24	668,414	45,159	1,564	715,137	22,094,476
16	0.22	607,649	43,972	1,479	653,100	22,747,576
17	0.20	552,408	42,817	1,398	596,624	23,344,200
18	0.18	502,189	41,693	1,322	545,204	23,889,403
19	0.16	456,536	40,597	1,250	498,383	24,387,786
20	0.15	415,033	39,531	1,181	455,745	24,843,531
21	0.14	377,302	38,493	1,117	416,912	25,260,443
22	0.12	343,002	37,482	1,056	381,540	25,641,983
23	0.11	311,820	36,497	998	349,316	25,991,299
24	0.10	283,473	35,538	944	319,955	26,311,254
25	0.09	257,703	34,605	893	293,200	26,604,453
26	0.08	234,275	33,696	844	268,815	26,873,268
27	0.08	212,977	32,811	798	246,586	27,119,854
28	0.07	193,616	31,949	754	226,319	27,346,172
29	0.06	176,014	31,109	713	207,837	27,554,009
30	0.06	160,013	30,292	674	190,980	27,744,989
31	0.05	145,466	29,497	637	175,600	27,920,589
32	0.05	132,242	28,722	603	161,567	28,082,156
33	0.04	120,220	27,967	570	148,757	28,230,913
34	0.04	109,291	27,233	539	137,062	28,367,976
35	0.04	99,355	26,517	509	126,382	28,494,358
		26,927,758	1,512,552	54,048	28,494,358	

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	Peak Line Current 1000 amps
Construction Management	263,045	Load Growth 1.2 percent
Engineering	94,919	Loss Factor 0.38
Sales Taxes	72,600	Energy Cost 100 mills/kWh
Administration	165,087	Energy Cost Escalation 5.0 percent

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Total PV
1	0.91	241,027	123,111	7,341	371,480	371,480
2	0.83	219,116	119,877	6,941	345,934	717,413
3	0.75	199,196	116,728	6,562	322,487	1,039,900
4	0.68	181,087	113,662	6,204	300,954	1,340,854
5	0.62	164,625	110,676	5,866	281,167	1,622,021
6	0.56	149,659	107,769	5,546	262,974	1,884,995
7	0.51	136,054	104,938	5,243	246,235	2,131,230
8	0.47	123,685	102,182	4,957	230,824	2,362,054
9	0.42	112,441	99,498	4,687	216,626	2,578,680
10	0.39	102,219	96,884	4,431	203,534	2,782,214
11	0.35	92,926	94,339	4,190	191,455	2,973,669
12	0.32	84,479	91,861	3,961	180,301	3,153,970
13	0.29	76,799	89,448	3,745	169,992	3,323,961
14	0.26	69,817	87,098	3,541	160,456	3,484,417
15	0.24	63,470	84,810	3,348	151,628	3,636,045
16	0.22	57,700	82,583	3,165	143,448	3,779,493
17	0.20	52,455	80,413	2,992	135,860	3,915,353
18	0.18	47,686	78,301	2,829	128,816	4,044,169
19	0.16	43,351	76,244	2,675	122,270	4,166,439
20	0.15	39,410	74,241	2,529	116,180	4,282,619
21	0.14	35,827	72,291	2,391	110,509	4,393,128
22	0.12	32,570	70,392	2,261	105,223	4,498,351
23	0.11	29,609	68,543	2,137	100,290	4,598,641
24	0.10	26,917	66,743	2,021	95,681	4,694,322
25	0.09	24,470	64,989	1,910	91,370	4,785,692
26	0.08	22,246	63,282	1,806	87,334	4,873,026
27	0.08	20,224	61,620	1,708	83,551	4,956,577
28	0.07	18,385	60,001	1,615	80,001	5,036,578
29	0.06	16,714	58,425	1,527	76,665	5,113,244
30	0.06	15,194	56,890	1,443	73,528	5,186,772
31	0.05	13,813	55,396	1,365	70,573	5,257,345
32	0.05	12,557	53,941	1,290	67,788	5,325,133
33	0.04	11,416	52,524	1,220	65,159	5,390,293
34	0.04	10,378	51,144	1,153	62,675	5,452,968
35	0.04	9,434	49,801	1,090	60,325	5,513,293
		2,556,956	2,840,649	115,689	5,513,293	

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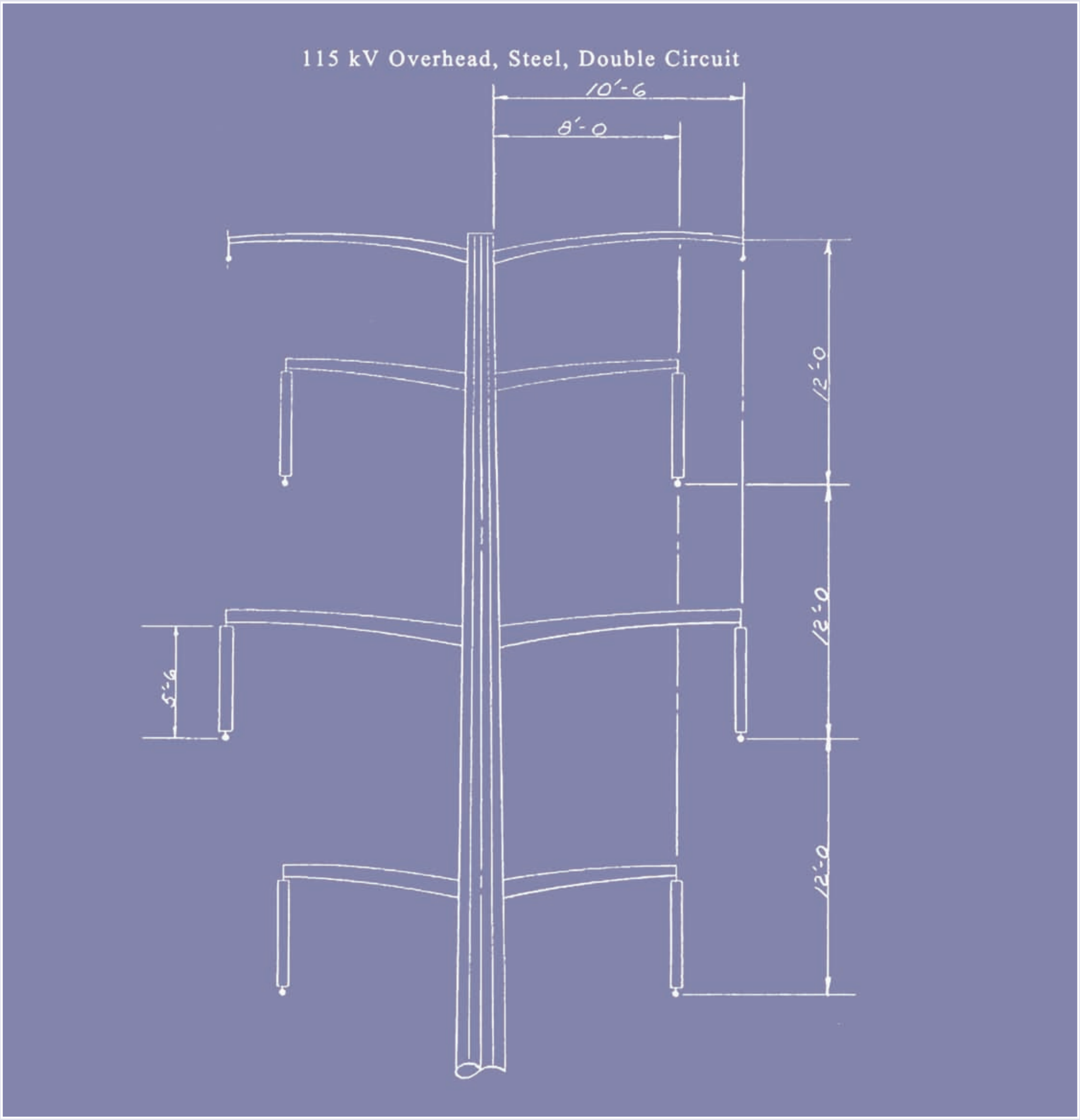
115 kV Overhead, Steel, Double Circuit



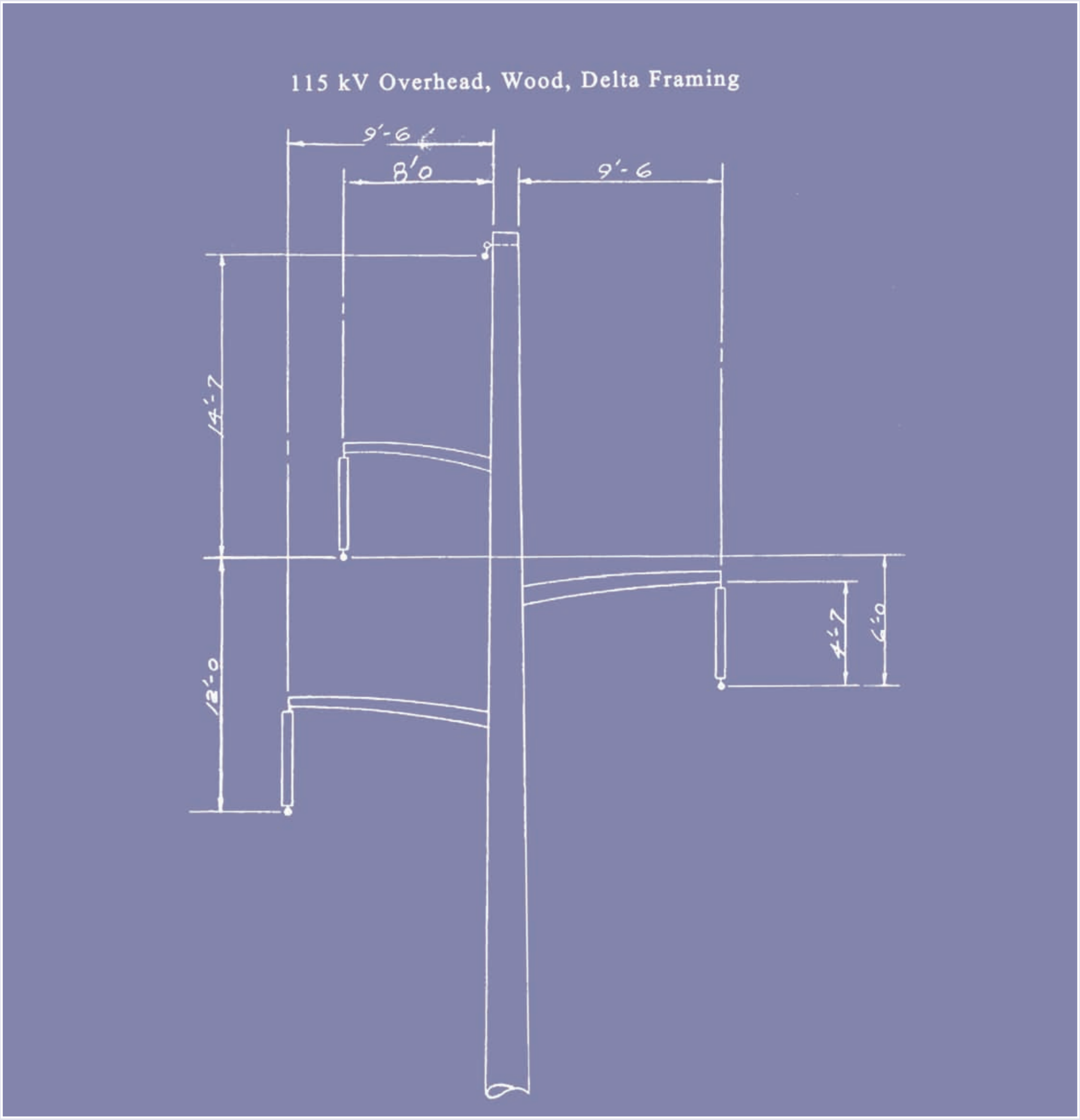
(Source: CL&P)

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	Peak Line Current 1000 amps
Construction Management	347,130	Load Growth 1.2 percent
Engineering	121,111	Loss Factor 0.38
Sales Taxes	95,808	Energy Cost 100 mills/kWh
Administration	217,859	Energy Cost Escalation 5.0 percent

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Total PV
1	0.91	318,074	123,111	7,341	448,526	448,526
2	0.83	289,158	119,877	6,941	415,976	864,502
3	0.75	262,871	116,728	6,562	386,161	1,250,664
4	0.68	238,974	113,662	6,204	358,840	1,609,503
5	0.62	217,249	110,676	5,866	333,791	1,943,294
6	0.56	197,499	107,769	5,546	310,814	2,254,108
7	0.51	179,544	104,938	5,243	289,726	2,543,834
8	0.47	163,222	102,182	4,957	270,361	2,814,195
9	0.42	148,384	99,498	4,687	252,568	3,066,763
10	0.39	134,894	96,884	4,431	236,210	3,302,973
11	0.35	122,631	94,339	4,190	221,160	3,524,133
12	0.32	111,483	91,861	3,961	207,305	3,731,438
13	0.29	101,348	89,448	3,745	194,541	3,925,979
14	0.26	92,135	87,098	3,541	182,774	4,108,752
15	0.24	83,759	84,810	3,348	171,917	4,280,669
16	0.22	76,144	82,583	3,165	161,892	4,442,561
17	0.20	69,222	80,413	2,992	152,628	4,595,189
18	0.18	62,929	78,301	2,829	144,059	4,739,248
19	0.16	57,208	76,244	2,675	136,127	4,875,375
20	0.15	52,008	74,241	2,529	128,778	5,004,153
21	0.14	47,280	72,291	2,391	121,962	5,126,115
22	0.12	42,981	70,392	2,261	115,634	5,241,749
23	0.11	39,074	68,543	2,137	109,754	5,351,503
24	0.10	35,522	66,743	2,021	104,285	5,455,789
25	0.09	32,293	64,989	1,910	99,192	5,554,981
26	0.08	29,357	63,282	1,806	94,445	5,649,426
27	0.08	26,688	61,620	1,708	90,016	5,739,442
28	0.07	24,262	60,001	1,615	85,878	5,825,320
29	0.06	22,056	58,425	1,527	82,008	5,907,328
30	0.06	20,051	56,890	1,443	78,385	5,985,713
31	0.05	18,228	55,396	1,365	74,989	6,060,702
32	0.05	16,571	53,941	1,290	71,802	6,132,504
33	0.04	15,065	52,524	1,220	68,808	6,201,312
34	0.04	13,695	51,144	1,153	65,993	6,267,305
35	0.04	12,450	49,801	1,090	63,341	6,330,646
		3,374,309	2,840,649	115,689	6,330,646	

115 kV Overhead, Wood, Delta Framing



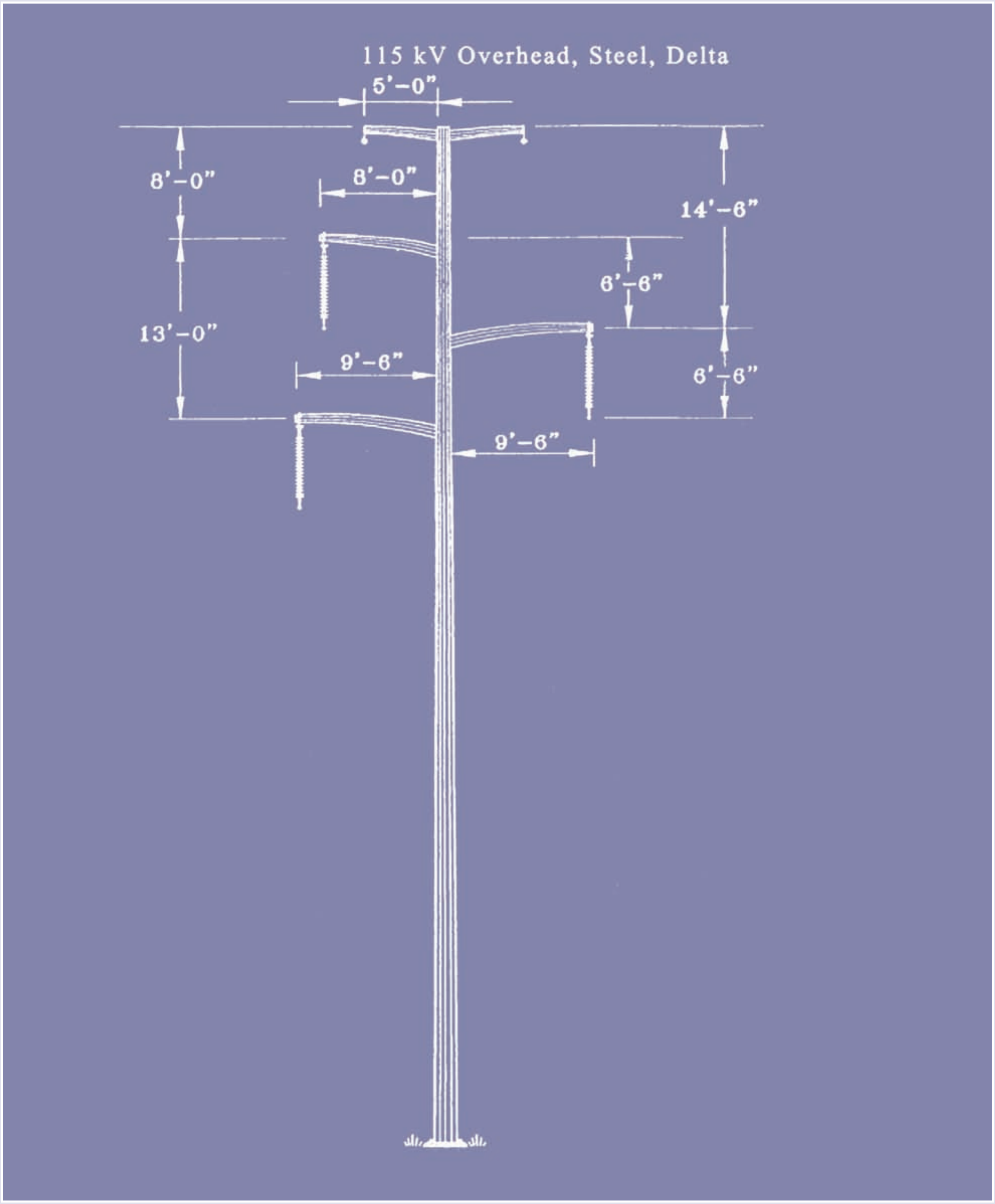
(Source: CL&P)

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	Peak Line Current 1000 amps
Construction Management	157,524	Load Growth 1.2 percent
Engineering	62,536	Loss Factor 0.38
Sales Taxes	43,477	Energy Cost 100 mills/kWh
Administration	98,862	Energy Cost Escalation 5.0 percent

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Total PV
1	0.91	144,339	61,556	7,341	213,235	213,235
2	0.83	131,217	59,939	6,941	198,096	411,331
3	0.75	119,288	58,364	6,562	184,214	595,546
4	0.68	108,444	56,831	6,204	171,479	767,025
5	0.62	98,585	55,338	5,866	159,789	926,814
6	0.56	89,623	53,885	5,546	149,053	1,075,867
7	0.51	81,475	52,469	5,243	139,188	1,215,055
8	0.47	74,068	51,091	4,957	130,117	1,345,172
9	0.42	67,335	49,749	4,687	121,771	1,466,942
10	0.39	61,214	48,442	4,431	114,087	1,581,029
11	0.35	55,649	47,170	4,190	107,008	1,688,037
12	0.32	50,590	45,930	3,961	100,481	1,788,518
13	0.29	45,991	44,724	3,745	94,460	1,882,978
14	0.26	41,810	43,549	3,541	88,900	1,971,878
15	0.24	38,009	42,405	3,348	83,762	2,055,639
16	0.22	34,553	41,291	3,165	79,010	2,134,649
17	0.20	31,412	40,207	2,992	74,611	2,209,260
18	0.18	28,557	39,150	2,829	70,536	2,279,796
19	0.16	25,961	38,122	2,675	66,757	2,346,554
20	0.15	23,601	37,121	2,529	63,250	2,409,804
21	0.14	21,455	36,146	2,391	59,992	2,469,795
22	0.12	19,505	35,196	2,261	56,961	2,526,757
23	0.11	17,731	34,272	2,137	54,140	2,580,897
24	0.10	16,119	33,371	2,021	51,511	2,632,408
25	0.09	14,654	32,495	1,910	49,059	2,681,467
26	0.08	13,322	31,641	1,806	46,769	2,728,237
27	0.08	12,111	30,810	1,708	44,628	2,772,865
28	0.07	11,010	30,001	1,615	42,625	2,815,490
29	0.06	10,009	29,213	1,527	40,748	2,856,238
30	0.06	9,099	28,445	1,443	38,987	2,895,226
31	0.05	8,272	27,698	1,365	37,334	2,932,560
32	0.05	7,520	26,970	1,290	35,780	2,968,341
33	0.04	6,836	26,262	1,220	34,318	3,002,658
34	0.04	6,215	25,572	1,153	32,940	3,035,599
35	0.04	5,650	24,900	1,090	31,640	3,067,239
		1,531,226	1,420,324	115,689	3,067,239	

115 kV Overhead, Steel, Delta



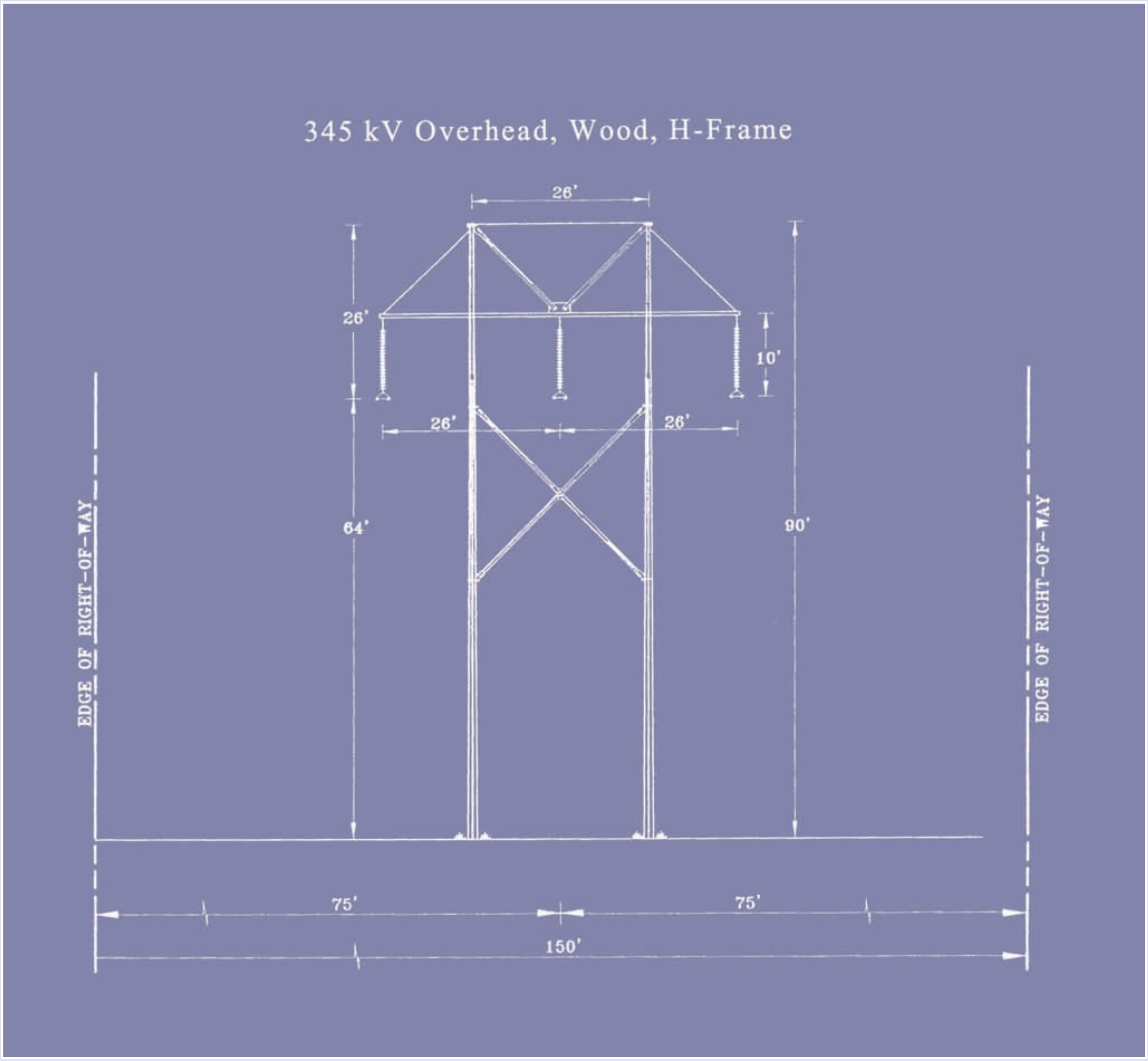
(Source: CL&P)

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	Peak Line Current 1000 amps
Construction Management	247,790	Load Growth 1.2 percent
Engineering	168,755	Loss Factor 0.38
Sales Taxes	68,390	Energy Cost 100 mills/kWh
Administration	155,513	Energy Cost Escalation 5.0 percent

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Total PV
1	0.91	227,049	61,556	7,341	295,945	295,945
2	0.83	206,408	59,939	6,941	273,287	569,233
3	0.75	187,644	58,364	6,562	252,570	821,803
4	0.68	170,585	56,831	6,204	233,620	1,055,423
5	0.62	155,077	55,338	5,866	216,281	1,271,704
6	0.56	140,979	53,885	5,546	200,410	1,472,114
7	0.51	128,163	52,469	5,243	185,876	1,657,990
8	0.47	116,512	51,091	4,957	172,560	1,830,550
9	0.42	105,920	49,749	4,687	160,356	1,990,905
10	0.39	96,291	48,442	4,431	149,164	2,140,069
11	0.35	87,537	47,170	4,190	138,896	2,278,966
12	0.32	79,579	45,930	3,961	129,471	2,408,436
13	0.29	72,345	44,724	3,745	120,814	2,529,250
14	0.26	65,768	43,549	3,541	112,858	2,642,108
15	0.24	59,789	42,405	3,348	105,542	2,747,650
16	0.22	54,354	41,291	3,165	98,810	2,846,459
17	0.20	49,412	40,207	2,992	92,611	2,939,071
18	0.18	44,920	39,150	2,829	86,900	3,025,971
19	0.16	40,837	38,122	2,675	81,634	3,107,604
20	0.15	37,124	37,121	2,529	76,774	3,184,378
21	0.14	33,749	36,146	2,391	72,286	3,256,664
22	0.12	30,681	35,196	2,261	68,138	3,324,802
23	0.11	27,892	34,272	2,137	64,301	3,389,103
24	0.10	25,356	33,371	2,021	60,748	3,449,851
25	0.09	23,051	32,495	1,910	57,456	3,507,308
26	0.08	20,956	31,641	1,806	54,403	3,561,711
27	0.08	19,051	30,810	1,708	51,568	3,613,279
28	0.07	17,319	30,001	1,615	48,934	3,662,213
29	0.06	15,744	29,213	1,527	46,483	3,708,696
30	0.06	14,313	28,445	1,443	44,201	3,752,898
31	0.05	13,012	27,698	1,365	42,074	3,794,972
32	0.05	11,829	26,970	1,290	40,089	3,835,062
33	0.04	10,754	26,262	1,220	38,235	3,873,297
34	0.04	9,776	25,572	1,153	36,501	3,909,798
35	0.04	8,887	24,900	1,090	34,878	3,944,676
		2,408,663	1,420,324	115,689	3,944,676	

345 kV Overhead, Wood, H-Frame



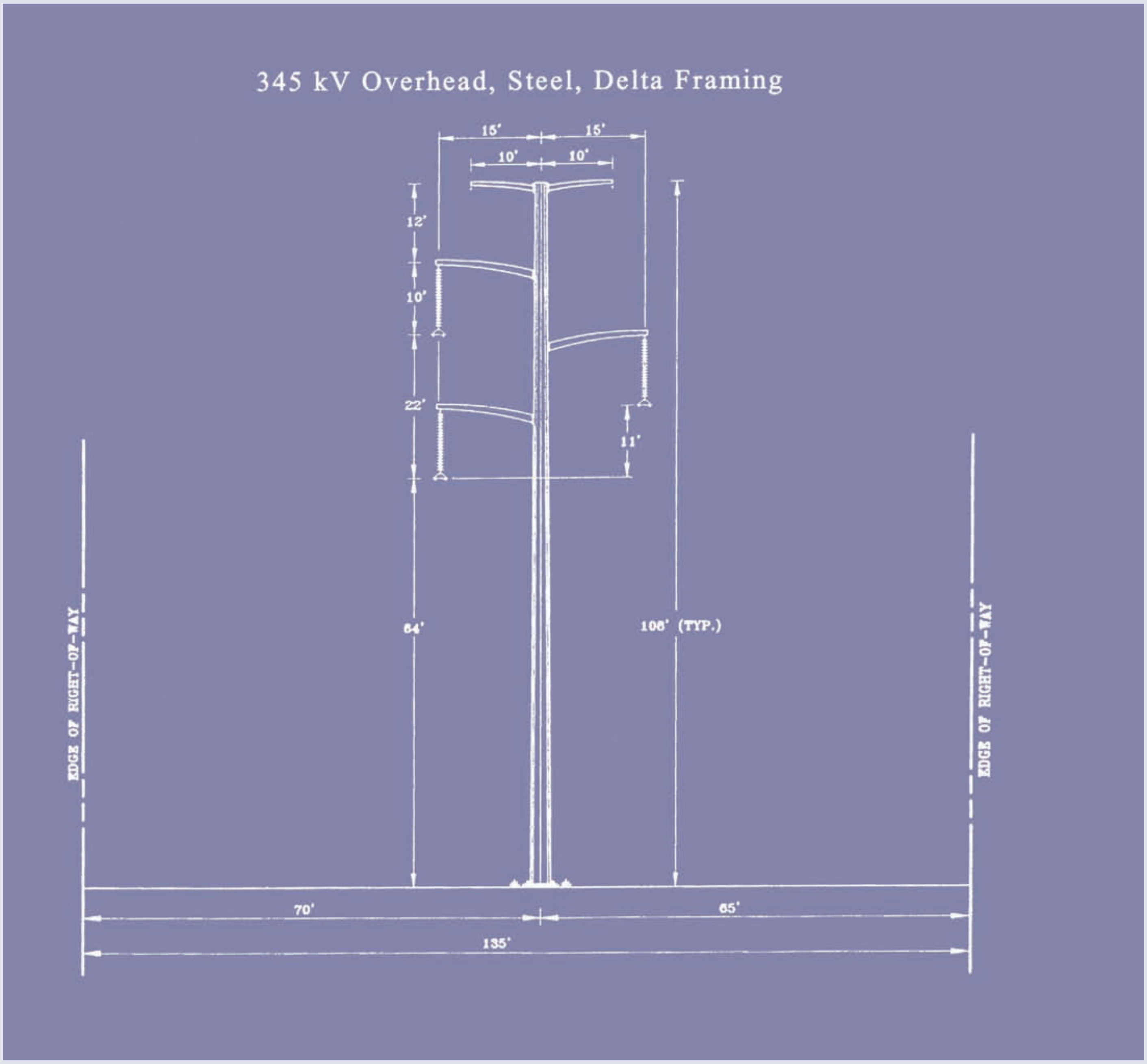
(Source: CL&P)

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	Peak Line Current 1000 amps
Construction Management	301,809	Load Growth 1.2 percent
Engineering	104,339	Loss Factor 0.38
Sales Taxes	83,299	Energy Cost 100 mills/kWh
Administration	189,415	Energy Cost Escalation 5.0 percent

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Total PV
1	0.91	276,546	61,556	7,341	345,443	345,443
2	0.83	251,406	59,939	6,941	318,285	663,728
3	0.75	228,551	58,364	6,562	293,477	957,205
4	0.68	207,773	56,831	6,204	270,809	1,228,014
5	0.62	188,885	55,338	5,866	250,089	1,478,103
6	0.56	171,714	53,885	5,546	231,144	1,709,247
7	0.51	156,103	52,469	5,243	213,816	1,923,063
8	0.47	141,912	51,091	4,957	197,960	2,121,023
9	0.42	129,011	49,749	4,687	183,447	2,304,470
10	0.39	117,283	48,442	4,431	170,156	2,474,626
11	0.35	106,621	47,170	4,190	157,980	2,632,605
12	0.32	96,928	45,930	3,961	146,819	2,779,425
13	0.29	88,116	44,724	3,745	136,585	2,916,010
14	0.26	80,106	43,549	3,541	127,195	3,043,205
15	0.24	72,823	42,405	3,348	118,576	3,161,781
16	0.22	66,203	41,291	3,165	110,659	3,272,441
17	0.20	60,185	40,207	2,992	103,384	3,375,824
18	0.18	54,713	39,150	2,829	96,693	3,472,517
19	0.16	49,739	38,122	2,675	90,536	3,563,053
20	0.15	45,218	37,121	2,529	84,867	3,647,920
21	0.14	41,107	36,146	2,391	79,643	3,727,564
22	0.12	37,370	35,196	2,261	74,827	3,802,390
23	0.11	33,973	34,272	2,137	70,381	3,872,772
24	0.10	30,884	33,371	2,021	66,276	3,939,048
25	0.09	28,077	32,495	1,910	62,482	4,001,530
26	0.08	25,524	31,641	1,806	58,972	4,060,501
27	0.08	23,204	30,810	1,708	55,721	4,116,223
28	0.07	21,094	30,001	1,615	52,710	4,168,932
29	0.06	19,177	29,213	1,527	49,916	4,218,848
30	0.06	17,433	28,445	1,443	47,322	4,266,170
31	0.05	15,848	27,698	1,365	44,911	4,311,081
32	0.05	14,408	26,970	1,290	42,668	4,353,749
33	0.04	13,098	26,262	1,220	40,580	4,394,329
34	0.04	11,907	25,572	1,153	38,633	4,432,961
35	0.04	10,825	24,900	1,090	36,815	4,469,776
		2,933,764	1,420,324	115,689	4,469,776	

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	Peak Line Current 1000 amps
Construction Management	546,869	Load Growth 1.2 percent
Engineering	176,445	Loss Factor 0.38
Sales Taxes	150,936	Energy Cost 100 mills/kWh
Administration	343,215	Energy Cost Escalation 5.0 percent

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Total PV
1	0.91	501,094	61,556	7,341	569,991	569,991
2	0.83	455,540	59,939	6,941	522,420	1,092,410
3	0.75	414,127	58,364	6,562	479,054	1,571,464
4	0.68	376,479	56,831	6,204	439,515	2,010,979
5	0.62	342,254	55,338	5,866	403,458	2,414,437
6	0.56	311,140	53,885	5,546	370,570	2,785,007
7	0.51	282,855	52,469	5,243	340,567	3,125,574
8	0.47	257,141	51,091	4,957	313,189	3,438,763
9	0.42	233,764	49,749	4,687	288,200	3,726,963
10	0.39	212,513	48,442	4,431	265,386	3,992,349
11	0.35	193,193	47,170	4,190	244,553	4,236,902
12	0.32	175,630	45,930	3,961	225,522	4,462,424
13	0.29	159,664	44,724	3,745	208,133	4,670,557
14	0.26	145,149	43,549	3,541	192,239	4,862,796
15	0.24	131,954	42,405	3,348	177,707	5,040,502
16	0.22	119,958	41,291	3,165	164,414	5,204,916
17	0.20	109,053	40,207	2,992	152,252	5,357,168
18	0.18	99,139	39,150	2,829	141,118	5,498,286
19	0.16	90,126	38,122	2,675	130,923	5,629,210
20	0.15	81,933	37,121	2,529	121,582	5,750,792
21	0.14	74,484	36,146	2,391	113,021	5,863,813
22	0.12	67,713	35,196	2,261	105,170	5,968,983
23	0.11	61,557	34,272	2,137	97,966	6,066,949
24	0.10	55,961	33,371	2,021	91,353	6,158,302
25	0.09	50,874	32,495	1,910	85,279	6,243,581
26	0.08	46,249	31,641	1,806	79,696	6,323,278
27	0.08	42,045	30,810	1,708	74,562	6,397,840
28	0.07	38,222	30,001	1,615	69,838	6,467,677
29	0.06	34,748	29,213	1,527	65,487	6,533,164
30	0.06	31,589	28,445	1,443	61,477	6,594,641
31	0.05	28,717	27,698	1,365	57,780	6,652,421
32	0.05	26,106	26,970	1,290	54,367	6,706,788
33	0.04	23,733	26,262	1,220	51,215	6,758,002
34	0.04	21,575	25,572	1,153	48,301	6,806,303
35	0.04	19,614	24,900	1,090	45,605	6,851,908
		5,315,895	1,420,324	115,689	6,851,908	

Prepared for the
Connecticut Siting Council
by KEMA Inc.

Brochure Design by
Jeff Lin Advertising and Design

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