Report of the
Joint Legislative Audit and Review Commission
To the Governor and
The General Assembly of Virginia

Evaluation of Underground Electric Transmission Lines in Virginia

HOUSE DOCUMENT NO. 87
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In Brief

Evaluation of Underground Electric Transmission Lines in Virginia

House Joint Resolution 100 directed JLARC to study the criteria and policies used by the State Corporation Commission (SCC) in evaluating the feasibility of undergrounding transmission lines in Virginia, including the costs considered by the SCC and the impact on property values of installing transmission lines underground.

The study concludes that while technologies are available to place transmission lines underground, underground lines are typically four to ten times more expensive than overhead lines. Underground lines can be less expensive than overhead lines when land values are high because they require smaller rights-of-way.

The SCC has rarely supported the use of underground lines, primarily due to cost and reliability concerns. Improved technology may allow greater use of underground lines in the future.

The SCC seeks to address the aesthetic, environmental, and property value concerns associated with overhead lines, but uses means other than placing lines underground, such as altering routes or adjusting the type or size of overhead towers.

The study identifies areas for improvement in the process used to plan for and approve transmission lines in Virginia.

JLARC Staff for This Report

Bob Rotz, Senior Division Chief
Ashley Colvin, Project Leader
Jamie Bitz

This report is available on the JLARC website at http://jlarc.state.va.us

COMMONWEALTH of VIRGINIA
Joint Legislative Audit and Review Commission
Suite 1100, General Assembly Building, Capitol Square
Richmond, Virginia 23219

Philip A. Leone
Director

(804) 786-1258

December 27, 2006

The Honorable Thomas K. Norment, Jr.
Chairman
Joint Legislative Audit and Review Commission
General Assembly Building
Richmond, Virginia 23219

Dear Senator Norment:

House Joint Resolution 100 enacted by the 2006 General Assembly directed JLARC to study the criteria and policies used by the State Corporation Commission in evaluating the feasibility of undergrounding transmission lines in Virginia. Staff were also directed to determine the effect of transmission lines on property values and the feasibility of allowing nearby property owners to pay for the installation of underground lines.

On behalf of the Commission staff, I would like to thank the staff at the State Corporation Commission and Dominion Virginia Power and local government planning staff for their assistance during this study.

Sincerely,

Philip A. Leone
Director

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Key Findings

- Technologies are available to enable electric transmission lines to be placed underground. (Chapter 2)
- Except when there are very expensive right-of-way costs associated with an overhead line, an underground line is likely to be about four to ten times more expensive than an overhead line. (Chapter 3)
- The State Corporation Commission (SCC) has rarely supported the use of underground lines primarily due to concerns about costs and reliability. (Chapter 5)
- The SCC and Dominion Virginia Power do seek to address aesthetic, environmental, and property value concerns associated with overhead lines, but through means other than undergrounding, such as altering routes or adjusting the type or size of towers used in an overhead line. (Chapters 6-8)
- More transmission lines are planned in future years, and improved planning and availability of information could enhance transmission line decision-making. (Chapters 9-10)

House Joint Resolution (HJR) 100 from the 2006 Session of the General Assembly requires the Joint Legislative Audit and Review Commission (JLARC) to "study the criteria and policies used by the State Corporation Commission [SCC] in evaluating the feasibility of undergrounding transmission lines in the Commonwealth" (Appendix A). The SCC is the independent regulatory agency in Virginia charged with the regulation of all corporations, including utilities. These regulatory activities include reviewing transmission line proposals submitted by electric utilities. As specific parts of the JLARC review, HJR 100 requires an examination of the construction and long-term operating costs considered by the SCC. It also requires consideration of the effect on property values resulting from overhead lines and the feasibility of allowing nearby property owners to pay for underground construction.

Electric transmission lines carry power from generating plants to local substations, where they are connected to neighborhood distribution lines. Transmission lines can be built overhead on towers, or they can be buried—a process referred to as "undergrounding" (Figure 1). Overhead transmission lines are typically installed on towers that are 80 to 140 feet in height and require a cleared

Figure 1: Overhead and Underground Electric Transmission Lines in Virginia

Source: Dominion and JLARC staff photographs.

right-of-way that approximates the height of the towers. Some citizens are concerned that overhead transmission lines pose health and safety risks, or that their unsightliness may decrease property values. As a result, communities in the path of proposed overhead lines may object to their use and call for the lines to be buried instead.

Virginia regulates the need for and placement of electric transmission lines by requiring public utilities to obtain a certificate of public convenience and necessity from the SCC before constructing a transmission line of 150,000 volts (or 150 kilovolts) or more.

UNDERGROUND LINES ARE USED INFREQUENTLY FOR HIGH VOLTAGE TRANSMISSION

While underground distribution lines are fairly common in the United States, the use of underground lines for higher-voltage transmission purposes is infrequent. Underground lines constitute a small proportion of transmission lines in Virginia and throughout the United States. Although Europe is cited as having more widespread use of undergrounding, it is still by far the exception rather than the rule in European power systems.

Overhead transmission lines are generally seen as the affordable industry standard by power companies, such as Dominion Virginia Power (Dominion)—the only utility in Virginia that has underground lines. In contrast, underground lines are seen by Dominion and the SCC as more costly and as more complex to install, operate, and repair. However, underground lines are sometimes installed because there are situations in which overhead lines are impractical or infeasible. These situations include places

- where the amount of right-of-way available is limited (overhead lines require much more right-of-way than underground), such as densely populated urban and suburban residential areas;
- in the vicinity of airports, where overhead lines may interfere with flight paths; and
- where overhead lines are deemed unacceptable on visual amenity grounds, such as a national park.

Dominion's view is similar to many other power companies, which generally prefer overhead lines whenever practical.

"HPFF" and "XLPE" Are Among the Viable Technologies for Underground Lines

Although underground lines constitute a relatively low proportion of transmission lines, there are some viable technologies for undergrounding that have been and are being used with success. In the United States, the two systems that appear to be receiving greatest consideration for use (if a underground line is required) are "HPFF" systems, which use a pressurized insulating fluid, and "XLPE" systems, which use a solid (polyethylene) insulation. HPFF cable has been the cable of choice for most underground transmission projects in the United States, mainly because its pipe configuration has proven reliability, providing a lengthy cable life and low long-term maintenance requirements.

HPFF and XLPE are both viable technologies for underground transmission, at least at certain voltage levels; but there is not a complete consensus as to which technology is currently "best" at higher voltages. Some experts see XLPE as an emerging technology that may soon become or already is more widely used than HPFF. XLPE offers some advantages over HPFF, including generally lower costs (XLPE may typically cost about 20 percent less than HPFF, according to some sources), less downtime for repair and maintenance, less power loss due to heating of the line, and no potential for environmental leaks of fluid. However, other experts such as Dominion prefer HPFF, noting that XLPE's long-term reliability is not nearly as established as the long-term reliability of HPFF. The SCC has agreed with Dominion and finds use of the more-established HPFF technology to be prudent.

Overhead Line Cost Advantages Include No Need For Burial and a Free Insulating Medium

In almost all cases, underground transmission lines are more costly to install than overhead lines. The largest cost component in underground lines is materials, such as cables and insulating fluid. The thickness of underground cables, needed to provide appropriate insulation, adds to the expense of placing lines underground. (In contrast, much of the insulation for overhead lines is achieved through the use of a free insulating medium, air.) Also, the labor cost associated with installing underground structures and burying cable are higher than the cost of installing overhead towers and running wires between them.

Cost estimates indicate that underground lines typically cost between $4 million and $10 million per mile, depending on factors such as voltage levels and capacity requirements. Unless right-of-way costs for an overhead line are very high, overhead line costs typically run from somewhat less than $1 million to about $2 million per mile. The typical ratio of underground to overhead costs appears to be in the range of about four and ten to one. Cost estimates for overhead and underground lines produced by Dominion in 2005 and 2006 are largely within the cost range suggested by other sources. In instances in which right-of-way is difficult to acquire or very costly, however, underground lines may become attractive and very competitive with the cost of overhead lines.

THE SCC USES A HEARING PROCESS TO REVIEW PROPOSED TRANSMISSION LINES

Under the Virginia Utility Facilities Act, the SCC has exercised authority over both overhead and underground transmission lines in Virginia. A transmission line case commences when an electric utility submits an application for a certificate of public convenience and necessity from the SCC. Recent applications appear to conform to the *Guidelines of Minimum Requirements for Transmission Line Applications* issued by SCC staff in 1991. Information requested via these guidelines includes the need for the proposed project, a detailed description of the line, the potential environmental impact of the line, and the maximum expected electric and magnetic field levels at the edge of the proposed right-of-way. The guidelines do not request any information on undergrounding as an alternative means of construction because of the infrequency of its use.

In reviewing proposed transmission lines, the SCC may hold hearings in its capacity as a court of record. This moves the case into an adversarial process which must comply with the SCC's Rules of Practice and Procedure. The agency is empowered by the *Constitution of Virginia* to administer oaths, compel the attendance of witnesses and the production of documents, punish for contempt, and enforce compliance with its orders by levying fines or other penalties. The commissioners appear to have wide latitude in reviewing proposed transmission line projects. Commissioners are not bound by the recommendations of their staff, and the Supreme Court of Virginia has stated that they presume SCC orders to be factually correct.

The adversarial process used by the SCC can affect the outcome of a transmission line case in three ways. First, the commissioners can only consider material included in the formal record. SCC staff and hearing examiners can play an important role in completing the formal record of a case, and the commissioners appear to rely on the hearing process to develop information not provided by the utility. Second, important issues may not receive consideration unless raised by a public witness or participant in the case. Finally, the SCC process is built on rules of evidence prescribed by common law and the *Code of Virginia*. The commissioners function like judges, evaluating competing claims, and assertions must be supported by credible evidence to be persuasive.

SCC HAS ADDRESSED OVERHEAD LINE CONCERNS WITHOUT RESORTING TO UNDERGROUND LINES

The commissioners must consider several factors when evaluating proposed transmission lines, including

- need for the new line and its impact on the reliability of electric service;
- impact on the environment, including scenic assets, historic districts, and the health and safety of persons in the area;
- impact on economic development; and
- local comprehensive plans when requested by an affected locality.

A fifth factor, the estimated cost of a new line, is also given a prominent role in transmission line proceedings under current statutes.

The commissioners are routinely required to balance these competing criteria in transmission line cases. Current statutes do not provide the commissioners with guidance on how to balance these factors. Instead, the commissioners are charged with evaluating the facts of a case and finding the solution that in their opinion best balances the statutory factors. In addition, the commissioners have asserted their authority to interpret some legislative terms not defined by statute, and these interpretations may evolve over time. However, the commissioners have determined that their authority to use monetary estimates to quantify certain factors ("externalities") is limited and that their decisions should be based upon qualitative factors.

The SCC has sought to address concerns that may exist about overhead lines through methods that stop short of undergrounding. The SCC and Dominion have tended to see underground lines as overly costly and operationally complex. Additional issues, such as line reliability, environmental effects (including health and safety and historic resource issues), economic development arguments, and property value issues have not steered the SCC in the direction of calling for underground lines.

SCC and Dominion Have Considered Reliability as a Factor Favoring the Use of Overhead Lines

Section 56-46.1 of the *Code of Virginia* requires the commissioners to determine that a line is needed before approving its construction. The *Code* also emphasizes a reliable source of electricity. Section 56-234 requires all public utilities operating in Virginia to "furnish reasonably adequate service and facilities." Utilities use defined standards to determine if reliability considerations require a new transmission line. The North American Electric Reliability Council (NERC), which is charged with maintaining a reliable, adequate, and secure U.S. transmission system, has developed mandatory reliability standards for planning and operating the bulk electric system to withstand limited outages. Dominion has incorporated NERC standards for building new transmission lines into its planning process.

While utilities generally propose new transmission facilities and lines to meet growing demand for electricity, system reliability issues may also be a major factor. Projects may be undertaken to improve the overall reliability of the electrical grid and to strengthen ties with neighboring utility regions.

In addition to system issues, the reliability of a particular type of line for delivering power can become an issue. Experts and literature in the power field indicate that overhead and underground lines both have some advantages and disadvantages in terms of reliability, and in the right situations, both can be operated reliably. Underground transmission lines, for example, are far less susceptible than overhead lines to damage by the elements, such as storm damage. Furthermore, while repairs of an underground cable typically take substantially longer than for an overhead line, the fact that a cable is under repair for a long period does not necessarily mean that customers are without power as a consequence. In some cases, underground lines are part of a network, and power can be rerouted to customers. Moreover, underground lines generally have been built with two circuits in order to provide backup capacity in case of operational or maintenance problems. Dominion has developed cost estimates for underground line installations in which two spare cables are in place, offering the possibility of restoring power in about one day. However, double circuits or spare cables do increase the cost of an underground line relative to an overhead line.

On the other hand, while underground transmission lines may be less susceptible than overhead lines to lightning and high winds from storms, the benefits from this advantage can be overstated. It is important to note that most overhead lines that are damaged or fail are at the distribution level rather than the transmission level. In 2005, for example, Dominion indicates that its average customer lost power for 128 minutes. Only four minutes was attributable to transmission-related incidents. The rest of the time was because of downed distribution lines in neighborhoods. Furthermore, underground lines have been damaged by excavation activities ("dig-ins"), and can pose reliability and operational challenges by limiting the ability of a utility to restore power (re-energize) a line after a temporary fault. If the fault is in an underground portion of a line also containing an overhead segment, re-energizing the line can cause substantial equipment damage and require the utility to remove the entire line from service.

Overall, the SCC appears to be persuaded in its cases by Dominion's arguments that in addition to the cost issue, overhead lines are preferable because of reliability issues. Particular concerns pointed to by Dominion are the potential for "dig-ins," the length of repair times for underground lines, and operational issues. SCC commissioners have cited operational and reliability concerns in rejecting underground proposals in two recent cases. SCC staff have identified similar operational concerns.

Environmental Effects of Transmission Lines Have Been Addressed Without Undergrounding

Under Section 56-46.1 of the *Code of Virginia*, the commissioners are required to consider the effect of transmission lines on the environment, which is defined to include historic resources plus human health and safety. The Supreme Court of Virginia has interpreted this requirement to place a duty upon the commission to minimize the environmental impact of utility lines, and the SCC has asked utilities to address potential environmental impacts in their transmission line applications.

Residential property owners, environmental groups, and local governments have often promoted underground construction as the preferred way to address concerns regarding the environmental impact of transmission lines. However, the SCC has not found that undergrounding has been necessary in order to mitigate these concerns and has only ordered undergrounding where a viable overhead right-of-way did not exist or where the party requesting the undergrounding has borne its expense. Undergrounding has also been used if an environmental factor involves avoiding the need to demolish buildings, as may be necessary to obtain the right-of-way required for an overhead line. Instead, the commissioners have frequently taken steps short of undergrounding to address concerns regarding environmental impact. Importantly, the commissioners have determined that Section 56-46.1 requires that adverse impacts are *reasonably* minimized rather than eliminated altogether.

The commissioners have used three strategies to address the environmental impact of transmission lines:

- Consistent with statutory requirements, the commissioners have frequently determined that transmission lines built within existing right-of-way will reasonably minimize adverse impact on the environment.
- The commissioners have altered the route or design specifications of a proposed transmission line to reduce the visibility of transmission facilities.
- The commissioners have relied on other federal and State agencies to minimize impacts on wetlands and wildlife. However, these reviews may fail to protect environmental or historic features that State agencies have not yet identified.

Health and Safety Effects of Transmission Lines Have Not Justified Undergrounding

The SCC must also consider the "probable effects of the line on the health and safety of the persons in the area" before authorizing the construction of new transmission lines. This statute has been applied largely to the potential effects of exposure to the electromagnetic fields (EMF) that are generated by electric equipment, including transmission and distribution lines and home appliances. Concerns about EMF generated by transmission lines are commonly expressed during proceedings, and the predominant concern is childhood leukemia. However, scientific studies have been unable to determine if there is a *causal* link between EMF and cancer, particularly leukemia, but have noted the persistence of a statistically significant *association*.

The commissioners have not required undergrounding as a means of addressing health concerns. In past transmission line cases, the commissioners have consistently determined that the evidence does not indicate that EMF from proposed lines will threaten human health or safety. However, the commissioners have ordered route or design changes to minimize the potential impact of overhead lines on residential developments, including the impact of EMF.

Undergrounding Has Not Been Used to Protect Historic Resources

The SCC is also required to minimize adverse environmental impacts resulting from transmission lines. The term environmental has been defined "to include in meaning 'historic[.]'" The *Constitution of Virginia* also promotes historic preservation by affirming a policy of conserving historic sites and buildings in the Commonwealth. State agencies and concerned citizens have raised concerns involving historic resources during transmission line proceedings. The commission has used design and route changes rather than underground lines to protect historic resources.

Least-Cost Construction and Mitigation Are Often Used by the SCC and Dominion in Response to Statutory Factors

Cost has been an important factor in many transmission line cases before the SCC. Certain statutory provisions stress cost-efficiency in the construction of new transmission lines, and SCC guidelines require utilities to provide the estimated cost of a line in its application. Dominion has also indicated that cost is an important consideration, asserting that underground lines are generally more expensive than overhead lines and that the general body of ratepayers should not be required to subsidize underground construction when an overhead route is available. Although the company in the past has agreed to build underground lines when a third party paid the additional costs, it now states that because of reliability and operational concerns it favors underground construction only when an overhead line is not viable.

Undergrounding Has Only Been Approved When Ratepayers Would Not Pay Higher Costs

The SCC has rejected underground alternatives in cases where the underground construction is more costly and an overhead route is available. The commissioners have cited cost considerations in rejecting underground lines, specifically noting in three cases that there is no evidence that the benefits of underground construction outweigh the costs to Dominion and its Virginia ratepayers. The commission has also indicated that requiring all ratepayers to pay for the cost of underground lines could act as precedent. Generally, the commission has not approved alternative routes or construction methods (including underground lines) that would result in increased costs for all ratepayers but benefit only a subset of those ratepayers.

Underground lines may be a more cost-efficient alternative in densely developed areas with high land values. The smaller rights-of-way required for underground lines may limit the cost of acquiring easements for a line, which can be a significant cost component in transmission projects. Since 1972, the commission has approved ten underground transmission lines in Fairfax and Arlington Counties and in the City of Norfolk. In each of these cases, Dominion proposed an underground line because no overhead route was available or underground construction was more cost-efficient.

The SCC Has Approved More Expensive Overhead Routes and Designs to Minimize Adverse Impacts

Although the commissioners have generally favored the lowest cost alternatives when approving new transmission lines, they have indicated that cost alone will not determine the outcome of a case. In some cases, the commission has approved more expensive overhead routes in order to minimize the adverse impact of a line. This has involved longer routes that avoid residential developments or route designs (such as alternative types of transmission towers) that add to the cost of a project.

SCC GENERALLY RELIES ON CONSTRUCTION COSTS AND DOES NOT EXPLICITLY CONSIDER IMPACT ON PROPERTY VALUES

Current statutes provide little guidance on the application of cost considerations to proposed transmission lines. The mandate for this study directed JLARC to examine how the SCC considers the impact of transmission lines on property values. SCC staff and hearing examiners have addressed the impact of overhead transmission lines on property values in their reports, but in final orders the commissioners have not explicitly considered this factor. Instead, the commissioners have considered only construction and maintenance costs. The commissioners have declined to consider cost estimates of externalities associated with transmission lines, instead noting that legislative bodies are the appropriate place to quantify the cost of these effects. As a result, the commissioners have treated the statutory factors from a qualitative perspective when approving higher cost transmission lines.

Property valuation studies suggest that transmission lines can decrease property values, in some cases by as much as 15 percent. JLARC staff found decreases of three to five percent among single-family residences near transmission lines in Henrico County. The potential effect of transmission lines on property values may result from two factors: transmission lines often are perceived to be unattractive, and some individuals believe that EMF from transmission lines causes cancer. However, other environmental features such as highways, airports, or landfills may decrease property values more than transmission lines.

FEASIBILITY OF ALLOWING SURROUNDING PROPERTY OWNERS TO PAY FOR UNDERGROUND LINES IS LIMITED

The feasibility of allowing surrounding property owners to finance underground construction appears limited for three reasons:

- Parties advocating underground lines may face barriers to obtaining accurate cost estimates of underground alternatives in sufficient time to evaluate the desirability of paying for undergrounding. The SCC currently does not require utilities to regularly provide these estimates.
- The numbers and types of properties affected by an overhead transmission line may limit the feasibility of having surrounding landowners pay for underground construction. In some parts of the State, property values or personal incomes may not be high enough, or the number of nearby homeowners may not be large enough, to adequately spread the costs of underground construction.
- Statutory restrictions may limit the feasibility of using special tax assessments to finance the cost of underground construction. The *Code of Virginia* provides that special assessments can be levied only on "abutting" landowners, which may limit the number of homeowners who can potentially contribute to the cost of underground construction. In addition, current statutes limit the amount that can be funded by cities and towns to 50 percent of total construction costs.

THE STATE'S ROLE IN PLANNING FUTURE TRANSMISSION LINES MAY DIMINISH

Dominion's *Electric Transmission Long Term Plan* anticipates several future transmission lines in Virginia, primarily in Northern Virginia and Hampton Roads/Southside. Importantly, Dominion's plan indicates that load growth can be accommodated through several means, including upgrading existing transmission lines.

However, the growing emphasis on regional transmission planning may diminish the role of the SCC. As required by the Virginia Electric Utilities Restructuring Act of 1999, Dominion is a member of a regional transmission organization known as PJM. The need for new transmission lines in Virginia, including lines designed in part to facilitate interstate power transfers and address regional reliability concerns, have been identified by PJM in its Regional

Transmission Expansion Planning Process. Local and State agencies may benefit from greater participation in PJM's planning process in order to voice concerns or advocate for certain projects.

The passage of the federal Energy Policy Act of 2005 (EPAct) also may limit the role of the SCC in approving new transmission lines. The act allows the Federal Energy Regulatory Commission (FERC) to designate any geographic area experiencing electric energy transmission capacity constraints as a national interest electric transmission corridor (NIETC). As a result, State control over a proposed line could cease 12 months after either this designation or the case is filed with the SCC. States may be able to forestall FERC siting authority by forming regional siting compacts.

INCREASED INFORMATION ACCESS AND IMPROVED PLANNING COULD ASSIST DECISION-MAKING

Shortcomings exist in the existing process used to plan for and approve transmission lines. Improvements in the availability of information and increased coordination between planners in local governments and at Dominion could yield three benefits:

- Calls for undergrounding could be reduced and the appropriate use of underground lines could be increased. In previous situations, Dominion has requested that underground lines be built where no viable overhead corridor existed, and this often resulted from "rapid development" that prevented the use of a previously identified route.
- The feasibility of allowing surrounding property owners to pay for undergrounding could increase.
- The likelihood that the State will have a role in approving transmission lines which may be designated as NIETCs could increase.

JLARC staff also encountered difficulties obtaining information about transmission line issues because much of this information is produced by utility membership organizations and entails restrictions on access and very high costs. Additionally, JLARC staff requested data from Dominion which was not provided due to the company's concerns that confidential information could not be properly protected from public release by JLARC under its current exemptions from the Freedom of Information Act. However, in other regards, Dominion provided all requested information and offered a great deal of assistance.

Recommendations in the report include

- modifying the Virginia Freedom of Information Act to exempt confidential proprietary information provided to JLARC from disclosure to the public;
- SCC acquisition of information and computer resources necessary to conduct system planning and reliability studies to ensure that new lines are needed and determine whether undergrounding is feasible;
- increased availability of geographic information systems (GIS) information related to proposed transmission lines;
- directing the SCC to develop a record to indicate which "external" cost factors should be consistently addressed in transmission line cases and to modify commission policies and procedures accordingly;
- amending the *Code of Virginia* to clearly indicate if environmental reviews of undergrounding lines are required in accordance with Section 56-46.1; and
- amending the *Code of Virginia* to direct local governments to consider electric transmission needs in their comprehensive plans and requiring publicly regulated utilities to provide transmission plans to local governments and State agencies.

Chapter 1

Introduction

In Summary

House Joint Resolution 100 of the 2006 General Assembly requires JLARC to review the factors and criteria used by the State Corporation Commission (SCC) in evaluating underground transmission lines. JLARC addressed this mandate primarily by reviewing past transmission line cases before the SCC, and by reviewing information provided by Dominion Virginia Power, the State's largest electric utility and the only utility to build underground transmission lines. Electric transmission lines transport large amounts of power over long distances from power plants to localities. In Virginia, public utilities must receive approval from the SCC before constructing certain transmission lines. The underground construction of transmission lines has been promoted during recent cases before the commission as a means of addressing the potential adverse impacts associated with overhead lines.

House Joint Resolution (HJR) 100 from the 2006 Session of the General Assembly requires the Joint Legislative Audit and Review Commission (JLARC) to "study the criteria and policies used by the State Corporation Commission in evaluating the feasibility of undergrounding transmission lines in the Commonwealth" (Appendix A). The mandate points to whether undergrounding is a feasible alternative to the use of overhead lines and whether the SCC appears to be considering this information in choosing between underground and overhead lines.

Electric transmission lines carry power from generating plants to local substations, where they are connected to neighborhood electric distribution lines. Transmission lines can be built overhead on towers or they can be buried, a process referred to as "undergrounding" (Figure 1).

Virginia regulates the need for and placement of electric transmission lines by requiring public utilities to obtain a certificate of public convenience and necessity before constructing a line. These certificates are issued by the State Corporation Commission (SCC), an independent agency charged with the regulation of all corporations in Virginia, including utilities. In issuing these certificates, the SCC must comply with certain statutory factors.

The mandate notes that "the process of undergrounding transmission lines is not widely practiced in the Commonwealth" and that undergrounding has the potential to "mitigate many of the detri-

Figure 1: Overhead and Underground Electric Transmission Lines in Virginia

Source: JLARC staff and Dominion photographs.

mental effects arising from the construction and location of overhead transmission lines." Definitions of key concepts, an overview of past transmission line cases, and an understanding of the extent to which information on undergrounding was available to JLARC staff provide context for this review.

DEFINITION OF KEY TERMS

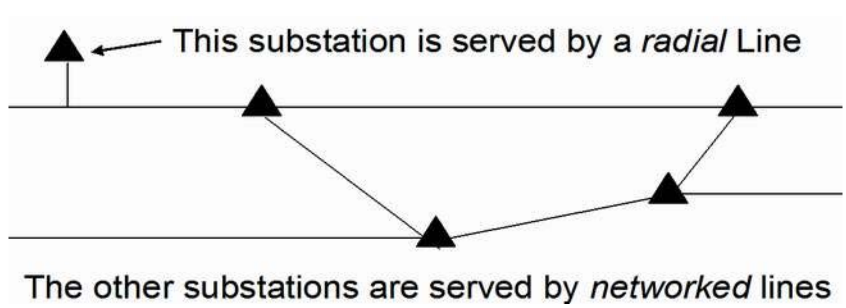
The transmission of power can be distinguished from its generation and distribution; transmission lines are distinct from distribution lines; and underground transmission lines are distinct from overhead transmission lines. Electric utilities supply their residential and commercial customers with electrical power via a three-part system:

- Generation of Power: Utility companies use various means (such as steam turbines, gas turbines, hydro turbines, nuclear units, and large diesel engines) to spin electrical generators at the power plant, producing electric power.
- Transmission of Power: Transformers at the power plant convert the power to a very high voltage level, to enable its efficient long-distance transmission. Power then flows in transmission lines until reaching a local substation.
- Distribution of Power: To distribute power to customers, the local substation "steps the power back down" via transformers to a lower voltage. Distribution lines carry the power to even smaller transformer boxes that reduce the voltage to levels appropriate for normal household electrical service.

Exhibit 1 provides additional definitions used in the report.

Exhibit 1: Electric Power Definitions

- Kilowatt – basic unit measuring the amount of electricity consumed over a given period. Electricity rates are applied to the kilowatt-hour or the number of kilowatts consumed in one hour. Also presented in a higher unit, megawatt (MW).
- Load – the amount of electric power demanded by consumers. Load is often expressed in units of megawatts, where one megawatt equals 1,000 kilowatts. The capacity of a transmission system must equal or exceed the total load in order to maintain reliable electric service.
- Kilovolt (kV) – basic unit measuring the voltage of transmission (or distribution) lines. One kilovolt equals 1,000 volts.
- MVA (megavolt ampere): Measure of electrical capacity. Electrical equipment capacities are sometimes stated in MVA.
- Circuit vs. Line – often used synonymously, a circuit consists of a distinct physical path (a group of conductors) over which electricity can flow. By contrast, a line (which connects two points, such as substations) may have one or more circuits. Additional circuits on a given line are used to increase its capacity because each circuit has physical limitations in terms of the amount of electricity that it can conduct.
- Grid – the overall network of transmission lines in a given state or region that transmit high-voltage electricity from substations at generating facilities to local substations. At local substations, transformers reduce the power to the lower voltages used on distribution lines.
- Radial/Tap Line – a transmission line that provides the sole connection from the transmission system to a substation (see graphic below). A service outage on a radial line may disrupt service.
- Loop/Network Line – a transmission line that serves as one of two or more sources of power for a substation or distribution circuit (see graphic below). This arrangement ensures that if one transmission line serving an area is out of service, then another transmission line is available.



Source: JLARC staff.

Within electric power systems, therefore, "transmission lines" are the conductors (wires or cables) which carry power at a high voltage level from the plants to local substations some distance away. "Distribution lines" are wires or cables which carry the power from a local substation to various neighborhoods and businesses at a lower voltage level. Examples of underground and overhead transmission lines used by Dominion Virginia Power are in Appendix B.

Pursuant to the study mandate, the JLARC study focused exclusively on transmission line issues. The review did not include any issues pertaining to power generation or the lower voltage distribution lines that run to and within neighborhoods.

CHARACTERISTICS OF TRANSMISSION LINES

Most transmission lines cross long distances, run overhead, and carry high voltages. Towers, usually of steel, are used to support the lines. The towers are designed to keep the electricity wires at a safe distance from the ground and each other. Since transmission lines carry high voltages, the towers supporting overhead lines are often quite tall (80 to 140 feet) and require a cleared right-of-way that approximates the height of the towers.

In Virginia, high-voltage transmission lines carry power from generating facilities such as the North Anna nuclear power plant in Louisa County to areas of demand in other parts of the state. The right-of-way for a transmission line project is obtained by co-locating the line along an existing right-of-way, such as a highway or utility right-of-way through the negotiated purchase of land or an easement, or by condemnation through the exercise of eminent domain by the electric utility. Figure 2 shows a transmission line on darkened steel towers located in the same right-of-way as a natural gas pipeline.

There are also other less-visible components of the power system. Several natural gas transmission lines carry fuel to some generating facilities. For example, an intrastate pipeline running from Fauquier County to Hanover County and then east to James City County carries fuel for use by Dominion and other generators. Electricity generation consumes a large quantity of water. Out of the 8.3 million gallons per day of water that is permitted by State agencies to be withdrawn from Virginia's ground and surface water supplies, generating plants account for 87 percent. Nationally, according to the federal Energy Information Administration, the electric power industry was responsible for 38 percent of total U.S. carbon dioxide emissions and 32 percent of total U.S. greenhouse gas emissions in 2004.

Figure 2: Overhead 230 kV Transmission Towers, With Two Transmission Lines, Along a Natural Gas Pipeline in Fairfax County

Source: JLARC staff photograph.

Transmission lines can transport power at different voltage levels depending on the conductors and equipment used. The most common voltage for transmission lines is 230 kilovolts (kV), with smaller numbers of 500 kV and 765 kV lines forming the "backbone" of the regional transmission grid. (Dominion also operates a small number of 69, 115, and 138 kV transmission lines.) By contrast, distribution lines that connect to individual neighborhoods and customers generally operate at lower voltages of 34.5 kV or less. The power in a typical home operates at 120 volts.

Higher voltage lines are ideally suited for the major transmission corridors that form the backbone of the grid. Compared to lower voltage lines, 500 and 765 kV lines can transmit larger amounts of power over longer distances with more efficiency (fewer "line losses"), and several lower voltage lines may be required to transmit the same power as one high-voltage line:

- One 765 kV line = about fifteen 138 kV transmission lines, or five 345 kV lines;
- One 230 kV line = five to twenty-five 34.5 kV distribution lines.

A small proportion of transmission lines in the United States are buried underground, including submarine cables under bodies of water. The "undergrounding" of transmission lines involves the burial of cables which carry the electricity. This method of transmission largely eliminates the need for towers and substantially reduces the width of the right-of-way on which the line is located. Undergrounding is much more expensive, however, and creates operational difficulties.

UNDERGROUND LINES ARE OFTEN ADVOCATED DURING CONTENTIOUS TRANSMISSION LINE CASES

The location (or siting) of overhead transmission lines sometimes generates controversy. For example, a 765 kV transmission line project, running from West Virginia to Wythe County, Virginia, was energized in June of 2006. It was first proposed, though, in 1990.

The lengthy process involved in the approval and siting of this line reflects the long-standing local opposition to transmission lines. The siting of power lines has often been subject to the NIMBY ("Not In My Backyard") phenomenon, in which the public wishes to use electric energy, but no segment of the public wishes to have the power lines running through or near their neighborhoods and homes.

Case Numbering

The SCC has used three systems for numbering cases since 1972. Presently, a transmission line case follows a defined format: PUE-2006-00001. PUE indicates that it is an energy-related case. Next, the year in which the case began is given, followed by the case number. JLARC staff excluded "PUE" in numbering cases, and changed older formats where possible to follow the most recent format.

In these situations, underground transmission lines are often looked upon as a solution to several perceived problems that are attributed to overhead transmission lines. To their advocates, underground lines may be a means of protecting public health and safety, protecting the environment, and preventing the reduction of property values. On the other hand, utilities and regulatory bodies express concern that underground lines are more difficult to install, operate, and maintain, and cost substantially more than overhead lines. A reflection of the interest in undergrounding is indicated by the fact that it has been advocated by citizens in three of Dominion's current transmission line cases. One of these cases, the Meadow Brook-Loudoun 500 kV line, has not yet been filed. The other two cases have been filed: the Pleasant View-Hamilton 230 kV line in Loudoun County (2005-00018), and the Garrisonville 230 kV line in Stafford County (2006-00091).

ELECTRICITY IS SUPPLIED AND REGULATED BY SEVERAL ORGANIZATIONS

Demand for electricity generally increases each year, but investments in transmission facilities have not kept pace. This may result in increasing investment in transmission lines and other electric facilities by Virginia electric utilities. In addition to the SCC, other organizations play a role in regulating and supervising electric utilities.

Electricity Usage Per Capita Has Increased

Based on data from the federal Energy Information Administration (EIA), residential sales of electricity in Virginia have increased from 28.1 megawatt hours in 1990 to 44.7 megawatt hours in 2005. Residential sales accounted for 41 percent of all electricity sold in 2005. The increase in electricity purchases may be partly explained by the increase in average house size. For example, in Chesterfield County the average house increased in size from 1,700 square feet in 1970 to 2,800 square feet in 2005. As house size increases, expenditures on heating, ventilation, and cooling increase. EIA data from 2001 indicate that these expenditures accounted for 31 percent of the electricity consumed by U.S. households.

Virginia Has Many Electric Utilities, But Only One Has Used Underground Transmission Lines

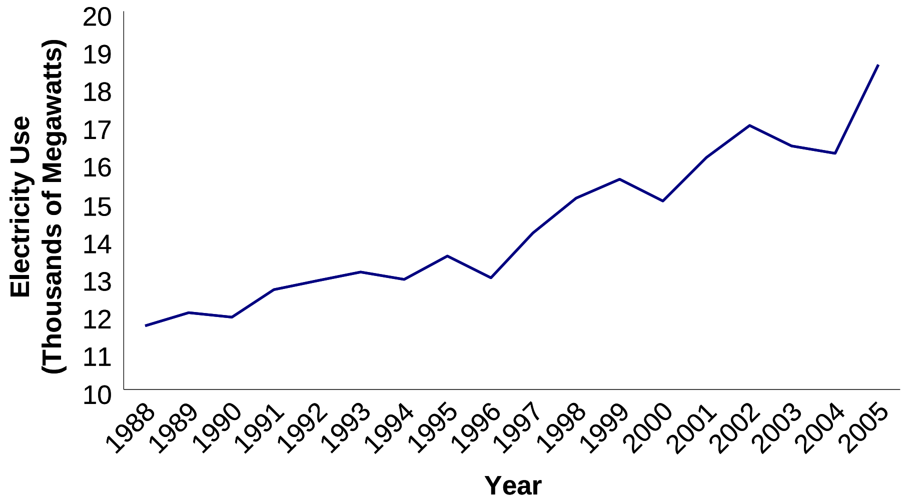
Within Virginia, electricity is sold to retail consumers by distribution providers within their assigned service area. These providers include municipalities, cooperatives, and the investor-owned utilities: Allegheny Power, Appalachian Power, Delmarva, Dominion Virginia Power, and Old Dominion Power.

The only utility in Virginia which has ever built an underground line is Dominion Virginia Power (which was previously known as Virginia Electric and Power Company, or VEPCO). Therefore, most of the information examined by JLARC staff pertains to Dominion Virginia Power's overhead and underground lines.

Dominion Virginia Power is a privately owned, publicly regulated utility that is engaged in interstate commerce. Its parent company, Dominion Resources, has energy operations in over 20 states. Dominion Resources reported an operating revenue of $18 billion and assets totaling $52 billion in 2006. In addition to its electric facilities, Dominion Resources operates a network of natural gas transmission lines and a gas storage system in several states. Dominion also operates (either directly or under contract) 84 generation facilities with an annual capacity of 17,541 MW. For the remainder of this report, the term "Dominion" refers only to Dominion Virginia Power.

Dominion is the largest electric utility operating in Virginia and it accounts for the vast majority of transmission line cases brought before the SCC. Dominion (and Dominion North Carolina Power) provides electricity to approximately 2 million customers in Virginia and North Carolina via 5,087 and 963 miles of transmission lines, respectively. In addition, the company maintains an electricity distribution system in Virginia. The highest level of electricity consumption ("peak load") on Dominion's transmission system reached 19,375 megawatts (MW) in the summer of 2006. In contrast, peak load in 1988 was 11,699 MW (Figure 3).

Figure 3: Electricity Use by Dominion's Customers Has Increased 59 Percent Since 1988



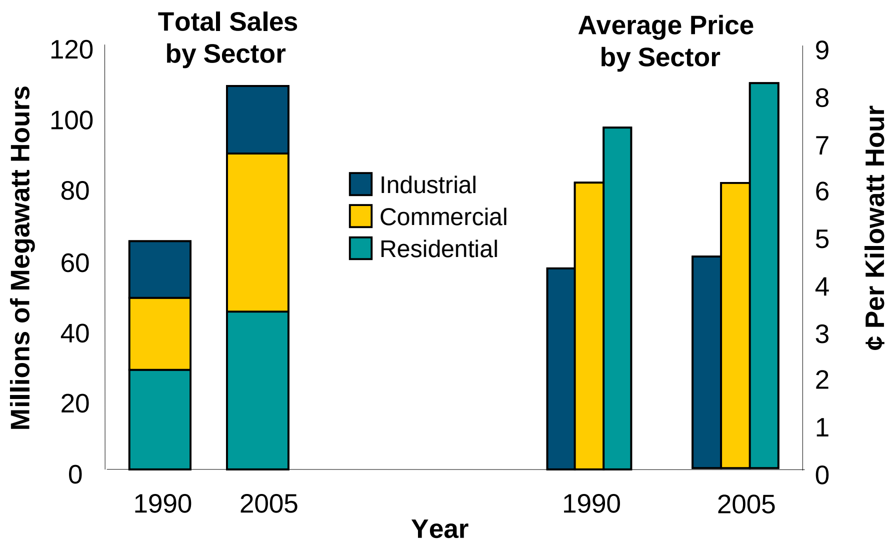
Source: JLARC staff analysis of summer peak load data provided by Dominion.

Although annual peak loads on Dominion's system have increased by 65 percent since 1988, electricity rates in Virginia as a whole have increased more slowly. As shown in Figure 4, residential rates have increased by about 12 percent, from 7.25 cents per kilowatt hour to 8.14 cents. Commercial rates have decreased by 0.6 percent, and industrial rates have increased by 5.2 percent. (These data are for all utilities in Virginia, not just Dominion.)

Organizations Outside of Virginia Also Regulate Electricity Transmission

Under the Virginia Electric Utilities Restructuring Act of 1999, electric utilities operating in the Commonwealth were required to join a regional transmission organization (RTO). The RTO that Virginia's utilities chose to join is PJM Interconnection, which operates in the Mid-Atlantic region (all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North

Figure 4: Since 1990, Electricity Use in Virginia Has Increased, But Most Electricity Rates Have Held Steady



Source: JLARC staff analysis of retail data from the federal Energy Information Administration.

Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia). PJM is designed to promote a regional approach to transmission operating, planning, and investment. PJM accomplishes its mission in part by managing the daily operation of its member utility's transmission lines and identifying the need for new lines to improve the reliability of the regional grid. Dominion has been a member of PJM since 2005.

In many cases, PJM and Dominion identify the need for new transmission lines because they must comply with mandatory reliability standards issued by NERC, the North American Electric Reliability Council. In July 2006, NERC was designated the nation's Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory reliability standards. These standards include required voltage and temperature limits that are used by electric utilities to determine when new transmission lines are needed. NERC is a wholly-owned subsidiary of FERC.

FERC is the Federal Energy Regulatory Commission, an independent federal agency charged with regulating the interstate transmission of electricity, oil, and natural gas. As indicated in its current Strategic Plan, a top priority of FERC is promoting the development of a "robust energy infrastructure." The agency is responsible for setting the rates transmission line owners such as Dominion can charge others for using their lines, and is currently implementing the Energy Policy Act of 2005 which has the potential to decrease the SCC's control over transmission lines. More information on this issue is provided in Chapter 9.

Changes Are Underway to the Planning and Approval Process for Transmission Lines

Another long-standing aspect of transmission line cases is the multi-layered approval process. Transmission lines typically require approval from several regulatory bodies. In Virginia, once the SCC has issued a certificate of public convenience and necessity in a transmission line case, there may be several subsequent steps before a line is built. These steps include completion of right-of-way acquisition, either through negotiated purchase or condemnation, and the issuance of permits from other State and federal agencies.

Growing Emphasis on Increasing the Speed at Which Transmission Lines Are Built. As noted in the 2001 report of the presidentially established National Energy Policy Development Group, "Our nation's most pressing long-term electricity challenge is to build enough new generation and transmission capacity to meet projected growth in demand." Calling the nation's transmission grid "antiquated and inadequate," the report stated that even if the nation were to achieve an adequate generating capacity, "we do not have the infrastructure to ensure reliable supply of electricity." Investment in the nation's transmission capacity was cited as an important component of the problem because it has "failed to keep pace with growth in demand."

Planning Process for Transmission Lines Is in a State of Flux. In Virginia, the electric utilities that own transmission lines now belong to a regional transmission organization known as PJM. This organization is responsible for much of the planning that used to be done wholly within the several vertically-integrated utilities. Regional planning may increase the speed at which transmission lines are built, both within and between states, because of a greater attention to the impact that infrastructure shortfalls in one state may have on other states. This may result in new lines that are proposed in order to serve not just Virginians but persons in nearby states. This appears to be the case with at least three transmission lines that Dominion has recently proposed. The approval process has also altered, and PJM now acts as a gatekeeper for many transmission line projects before the formal approval process begins at the SCC. More information on these proposed transmission lines is provided in Chapter 9.

SCOPE OF THE REVIEW

The study mandate results from a concern that the process used by the SCC to evaluate and approve transmission lines may not fully incorporate all of the relevant factors. One concern is that the SCC may not be including all of the cost factors involved in the choice between an underground and an overhead line. The mandate notes that "it is in the best interest of the public to provide for the least costly alternative in constructing electrical transmission lines," while also noting that "the costs of constructing overhead transmission lines may impact tax revenue, economic development, and property values in the immediate area of the transmission lines."

Legislative Mandate Includes Three Specific Issues

A concern with cost factors is reflected in one of the three specific issues cited in the study mandate: JLARC is directed to examine "the construction and long-term operating costs considered by the State Corporation Commission in reviewing electrical transmission line applications." This direction results from a concern that certain "external" cost factors may not be fully considered, including: a decrease in environmental values caused by harm to habitat, historic sites, or scenic assets; diminished opportunities for economic development; and the possible harm to human health resulting from the effects of radiation from overhead lines. One difficulty faced by the SCC, however, is in determining how to place a monetary value on these factors.

A second specific issue concerns "the effect on property values resulting from installing underground, as opposed to overhead, electrical transmission lines." Any decrease in property values may also result in decreased tax revenues for localities. However, because underground lines typically cost more than overhead lines, this issue also entails an assessment of how the higher incremental costs of undergrounding might be paid for, or "recovered." The mandate directs that one of these methods be assessed: "the feasibility of allowing surrounding property owners to agree to pay for the installation of underground lines."

A third specific issue identified in the mandate directs JLARC to examine the "factors considered by the State Corporation Commission in its analysis of the feasibility of installing underground electrical transmission lines." In part because of limited information on the technical aspects and costs associated with undergrounding, JLARC staff assessed the "feasibility" of undergrounding by comparing it to other alternatives.

Feasibility of Undergrounding Was Defined Technically and In Comparison to Other Means of Addressing Concerns

Undergrounding is both a method of transmitting electricity and a potential means of reducing or mitigating the effects of overhead lines. Advocates of undergrounding appear to have two main concerns: that overhead lines reduce property values and cause cancer. JLARC staff therefore reviewed the factors considered by the commissioners in their response to these concerns, and the mitigation techniques they ordered utilities to use. This review was undertaken to determine whether the commissioners and SCC staff appear to consider underground lines a feasible alternative to overhead lines.

Other potentially feasible alternatives to overhead lines include demand-side approaches and improvements in the transmission line planning process. The construction of transmission lines is a supply-side approach: a balance is achieved between electricity supply and demand by increasing supply to keep pace with demand. In contrast, demand-side alternatives attempt to create incentives for consumers to reduce demand to match supply. These incentives include electricity rates that are based on the time of day or year (to reflect changes in the market price of electricity) and devices such as updated electricity meters that allow consumers to see their usage by the hour instead of by the month. PJM operates demand-side programs, and NERC has called for more demand-side measures as one means of ensuring a reliable and adequate electricity supply.

Because of study limitations, demand-side options are not addressed in this report, but this may be a fruitful area of research in the future. Section 56-235.1 of the *Code of Virginia* states that the SCC has a "duty" to periodically investigate the practices of public utilities so as to determine whether the practices "are reasonably calculated to promote the *maximum effective conservation and use of energy* and capital resources" (emphasis added). Demand-side and conservation measures are also addressed by Senate Bill 262 of the 2006 Session, which created the Virginia Energy Plan.

This report does include staff observations on how Dominion plans for transmission lines, and information on the process used in selected localities. Undergrounding often appears to be advocated because citizens perceive it to be the best response to a newly announced overhead transmission line. However, improvements in the planning process may alleviate some of these concerns and ensure that undergrounding is used when it is appropriate. In part, this may be accomplished by coordinating utility plans and local comprehensive plans. This may also increase the feasibility of allowing surrounding property owners to pay for undergrounding or other forms of mitigation. More information on planning, and recommendations on this issue, are included in Chapter 10.

Limitations in the Availability of Information Affected the Study's Scope

JLARC staff identified 99 transmission line cases brought before the SCC since 1972 (Table 1 in Appendix C). Of this number, 23 were built to connect new generating facilities or specific businesses to the grid (Table 2 in Appendix C). The JLARC staff review was limited to the remaining 76 cases. Of the 76 transmission line cases reviewed, only 17 included a proposal by a party to the case to build a line underground (Table 1). Of these 17 cases, in ten cases an underground line was approved.

The 76 identified cases are likely a subset of all the transmission line cases heard since 1972 because in an unknown number of cases, it was the SCC's practice to approve a transmission line without publishing a final order. The record which is broadly available to the general public through the SCC's Annual Reports consists largely of final orders, which in some cases are less than two pages of text. In contrast, the final orders for very contentious cases, such as the 765 kV lines that have been built across several counties and states, are very thorough. (Hardcopy editions of the Annual Reports contain published final orders, and are available at the Library of Virginia and at the SCC's offices; published final orders are also available on-line through LexisNexis.) For cases established since 2002, the SCC's Docket Search allows on-line access to documents made a part of the record. For selected transmission line cases heard between 1991 and 2002, the SCC's website provides a portion of the record, depending on the case.

However, no information is available through the Annual Reports or on-line about the two undergrounding cases heard in the 1990s, or for earlier undergrounding cases. For these six cases, JLARC staff supplemented the final orders by requesting copies of the utility's application and any SCC staff reports from the SCC's Document Control Center. Because of cost, JLARC staff did not obtain copies of transcripts from either older cases or for on-going cases. Transcripts are created by a contractor and are not part of the record but can be obtained for $3 per page.

JLARC staff also encountered limitations in the availability of information on undergrounding itself. For example, the Electric Power Research Institute (EPRI) has published a number of reports on the topic of underground transmission. EPRI was established in 1973 as "an independent, nonprofit center for public interest energy and environmental research." Membership largely

Table 1: Since 1972, 17 Transmission Line Cases Included Undergrounding Proposals

Case Name and Number	Location	Underground Proponent	Underground Decision
Glen Carlyn-Clarendon (1982-00075)	Arlington County	Dominion	Certified
Jefferson Street-Glebe (1983-00036)	City of Alexandria	Dominion	Certified
Braddock-Annandale (1983-00059)	Fairfax County	Dominion	Certified
Ravensworth-Sideburn (1984-00028)	Fairfax County	Respondent	Rejected
Burke-Sideburn (1986-00019)	Fairfax County	Dominion	Certified
Green Run-Greenwich (1986-00035)	City of Virginia Beach	Respondent	Rejected
Glebe-Pentagon (1988-00063)	Arlington County	Dominion	Certified
Pender-Oakton (1988-00079)	Fairfax County	Dominion	Certified (Not Built)
Midlothian-Trabue (1988-00071)	Chesterfield County	Respondent	Rejected
Clifton-Cannon Branch (1989-0057)	Fairfax and Prince William Counties	Respondent	Rejected
Jefferson Street I (1995-00134)	City of Alexandria	Dominion	Certified
Jefferson Street II (1996-00071)	City of Alexandria	Dominion	Certified
Sewells Point-Navy South (2002-00180)	City of Norfolk	Dominion	Certified
Beco & Greenway (2001-00154)	Loudoun County	Respondent	Rejected
Brambleton-Greenway (2002-00702)	Loudoun County	Respondent	Rejected
Bristers-Morrisville (2004-00062)	Fauquier County	Respondent	Rejected
Churchland-Sewells Point (2004-00139)	Cities of Portsmouth & Norfolk	Dominion	Certified

Source: JLARC staff analysis of transmission facilities approved by the SCC since 1972.

consists of utilities but is also open to government agencies that fund or support energy research. (Of note, one-third of its governing board includes members of state public utility commissions.) In 1997, EPRI produced two reports on underground cable installation and system cost reductions, and in 1999, it published a report on design tradeoffs for underground cable installation and the impact on costs. In December 2004, it published a technical update, available on-line, on achieving lower costs for underground transmission cable. EPRI will also issue an updated edition in

2007 of its 1992 work *Underground Transmission Systems Reference Book*. The project will "compile the most up-to-date technical information on underground transmission systems."

JLARC staff investigated the availability of EPRI reports, some of which list for $25,000, including a request for the information from staff of Dominion Virginia Power. Dominion staff indicated that the report was available only to members of EPRI and could not be provided by Dominion; SCC staff also stated that the commission is not a member of EPRI. For other types of information, however, staff at Dominion and the SCC responded quickly and thoroughly and provided all information requested that was not limited by confidentiality concerns.

Other reports have been published by organizations which have membership restrictions. One such organization, DSTAR, has a software product for sale that compares the total lifetime costs (installation plus operations and maintenance) of overhead and underground transmission lines. However, only utilities can join this organization, and annual dues are $30,000 to $40,000. JLARC staff also corresponded with the director of the National Rural Electric Cooperative Association (NRECA), which is conducting research into the relative costs and benefits of overhead and underground transmission lines. This organization includes many Virginia cooperatives as members. Their research will culminate in a published report in 2006 that includes a detailed discussion of "differences between constructing and maintaining overhead and underground transmission lines," and a customizable economic analysis model. NRECA declined to provide the report, however, because it is only made available to dues-paying members.

JLARC staff therefore supplemented the record in transmission line cases with information that is more generally available. This information was obtained from Internet searches, interviews with staff at Dominion, the SCC, and local governments, and correspondence with other experts. Dominion staff also responded to many data requests and provided JLARC staff with tours of electric facilities and lines. JLARC staff also made independent site visits to underground and overhead lines. Information on staff research methods is included in Appendix D.

Chapter 2

Types of Underground Transmission Systems and Extent of Use

In Summary

Electricity is transmitted through the use of overhead power lines, underground cables, and submarine cables. Some transmission lines have both overhead and underground components. The vast majority of transmission line mileage in Virginia, the United States, and Europe is overhead. However, there are situations in which underground lines are seen as desirable, usually due to the siting of overhead lines either being impractical or aesthetically unacceptable.

There are a number of different types of underground systems. In the United States the two systems most often used are "HPFF," which uses a pressurized insulating fluid, and "XLPE," which uses a solid (polyethylene) insulation. HPFF is a proven technology with demonstrated reliability and a lengthy cable life. XLPE is an emerging or developing technology that offers some advantages over HPFF, including a lower cost. However, while XLPE is increasingly being used outside Virginia at higher voltage levels, some parties including Dominion are skeptical of its long-term durability.

The mandate for this study requires an examination of State Corporation Commission (SCC) criteria and policies used in assessing the feasibility of placing proposed transmission lines underground. Prior to considering the relative costs of underground and overhead lines (Chapter 3) and SCC decision-making (Chapters 4 to 8), the following questions are addressed in this chapter:

- What is the frequency of underground versus overhead line use?
- What are the different types of underground systems, and which is most used in the United States?
- Is there a consensus as to which type of underground system is "best"?

UNDERGROUND LINES ARE USED INFREQUENTLY FOR HIGH-VOLTAGE TRANSMISSION

The use of underground lines for high-voltage transmission purposes is infrequent – much less frequent than it is for the distribution of power at lower voltages to power system customers. While constituting less than half of distribution line mileage in the United States, underground distribution lines are still fairly common (one source indicates that almost one-quarter of distribution mileage is underground). However, for the high-voltage transmission of power, underground lines are used for a very small proportion of line mileage in the United States, in Virginia, and across most of Europe.

Use of Underground Lines Across the United States

There is a lack of definitive published statistics on the miles of overhead and underground lines in the United States by voltage level. The mileage figures are in a state of flux, with new lines reaching completion over time. However, the information available indicates that underground lines account for between about 0.5 percent and 3.8 percent of transmission. The variation depends in part upon the kilovolt (kV) threshold that is used to separate transmission from distribution.

More specifically, some sources have indicated that there are about 200,000 miles of overhead transmission lines in the United States and about 5,000 to 8,000 miles of underground transmission (including underwater). These sources, then, suggest that underground transmission constitutes about 2.5 to 3.8 percent of the transmission mileage. However, at least one of these sources indicates that the figures include 69 kV lines and above as "transmission."

Another source, considering the question in 2005, focused on transmission systems with voltages of 230 kV and above. This source estimated that there are about 160,000 miles of overhead line and about 750 to 1,000 miles of underground line at these voltages. Thus, at the higher voltages, the percent of underground line is about 0.5 to 0.6 percent of the total.

Connecticut has passed a bill providing that transmission lines should be placed underground when feasible to avoid having an overhead line near facilities such as schools.

Some industry observers have indicated that the underground option may be increasing in appeal in the United States due to reductions in underground costs and other concerns, such as difficulties in getting overhead lines approved. Due to concerns that a cause-and-effect relationship between overhead transmission lines and negative health effects may yet be demonstrated, Connecticut has passed a bill providing that transmission lines should be placed underground when feasible to avoid having an overhead line near facilities such as schools. Connecticut is in the process of installing several transmission lines with underground components at 345 kilovolts.

However, information from NERC, the North American Electric Reliability Council, suggests that underground lines still constitute a relatively small proportion of the new transmission lines that are currently proposed for use in the nation. NERC maintains data on the nation's electrical infrastructure including data on 338 of the 377 proposed transmission line projects (at 230 kV and above) in North America. Of these projects, almost 96 percent of the projects are overhead lines, while about four percent are underground lines. On average, the proposed overhead lines are longer than the proposed underground lines (33 miles versus 14 miles), so that underground lines constitute only about two percent of the line length that is planned.

Use of Underground Lines in Virginia

In Virginia, underground lines also constitute a small proportion of transmission lines. For example, the State's largest utility, Dominion, is the only utility in Virginia that operates any underground lines. Dominion indicates that of 6,050 miles of the "high-voltage network" operated by the company in the state, only about 50.5 miles (0.8 percent) are underground. At the 230 kV level (the intermediate voltage level used for transmission lines, and the most frequently-used voltage used for transmission in Virginia), 32.2 miles are underground, compared to 2,469 miles of overhead lines (or about 1.3 percent). Dominion states that overhead lines "have proven to be the best choice for providing safe, reliable and economical power to our customers."

Table 2 shows the number and miles of underground lines installed in Virginia and operated by Dominion. As indicated in the table, there are four localities in Virginia which have underground transmission lines, with a total of 23 lines covering 50.5 miles, or an average line length of 2.2 miles. The longest underground transmission lines in Dominion's system are about four miles in length.

Table 2: Underground Transmission Lines in Virginia

	69 kV		230 kV		Total	
Locality	**Number of Lines**	**Line Length (Miles)**	**Number of Lines**	**Line Length (Miles)**	**Number of Lines**	**Line Length (Miles)**
Alexandria	0	0	2	6.20	2	6.20
Arlington	9	18.27	6	11.07	15	29.34
Fairfax	0	0	3	9.34	3	9.34
Norfolk	0	0	3	5.59	3	5.59
Total	**9**	**18.27**	**14**	**32.20**	**23**	**50.47**

Note: In addition, 1.5 more miles of 230 kV line are planned for the future in Norfolk as a submarine segment in an overhead line.

Source: Data furnished to JLARC staff by Dominion.

Use of Underground Lines in Europe

Sometimes Europe is cited as having more widespread use of underground transmission lines at high voltages than the United States, with the further suggestion made that this may indicate that American power companies are slow to adopt underground technology. It is true that transmission projects at high voltages have been installed in Europe over the years and have received substantial attention. However, at least as recently as 2002 and 2003 underground transmission lines were still by far the exception rather than the rule in European power systems.

In most countries in Europe, transmission at 220 kV and above is defined as Extra High Voltage (EHV), and EHV comprises the main transmission networks of Europe. A December 2003 background paper on undergrounding done by the Commission of the European Communities concluded that in these networks

> the percentages of underground cables are very low, with average values around 0.5% for 380-400 kV lines and around 2.0% for 220-300 kV lines. Usually, the underground sections refer to special projects in urban areas or environmentally sensitive areas, where the construction of overhead lines is rather impossible. The considerably high cost of underground cables in respect to overhead lines of EHV . . . should be considered as the main reason for such low percentages of undergrounding achieved in various European countries.

Some European countries do use underground lines to a greater extent than the averages indicated above. For example, according to data in the Commission of the European Communities' report, about nine percent of line distance in Denmark at 380 to 400 kV is underground, and in the United Kingdom, about 5.6 percent of line distance at 220 to 300 kV is underground. As indicated in the following case study, some countries may give greater consideration than others to aesthetic issues or other factors that lead to a greater use of undergrounding, yet still largely prefer the use of overhead lines.

> ***Case Study***
>
> *In the United Kingdom, provisions of the Electricity Act of 1989 require that those who are authorized to generate or supply electricity "shall have regard to the desirability of preserving natural beauty" and shall do what can reasonably be done "to mitigate any effect which proposals would have" on natural beauty. National Grid, owners and operators of the largest power system in the United Kingdom, established a principle in its environmental policy to "incorpo-*

rate environmental considerations into all" of its activities, and states that it seeks to avoid routing new lines or siting new substations in close proximity to peoples' homes "for reasons of general amenity." However, while noting that it has had a higher proportion of its lines placed underground for amenity reasons than is the case compared to other countries, National Grid also notes that undergrounding for them "remains an exception." National Grid states that there are "strong cost and operational reasons for using overhead lines rather than underground cables . . . so in common with other transmission utilities worldwide, our preferred method of transmission is by overhead lines."

One of the countries that is sometimes cited as moving strongly away from overhead transmission in favor of underground transmission is France. In December 1999, storms caused extensive damage to power lines in the country. On the heels of this problem, an agreement was reached between the government and the electric power industry that at least 25 percent of certain transmission lines should be underground. However, two important points should be noted. First, the damage done by the storms was largely to medium voltage lines, and not lines at 225 kV and above. Second, the 25 percent figure of the reached agreement applies to lines of 63 to 90 kilovolts, and does not apply to extra high voltages of 225 to 400 kV.

Overhead Lines Are Almost Always Favored by Power Companies, But Underground Lines Are Used Occasionally

Overhead transmission lines are generally seen as the affordable industry standard by power companies. Underground lines, on the other hand, are seen as more costly and as posing more complex installation and operational issues.

Despite the general preference of power companies for overhead lines, underground lines are sometimes installed because there are situations in which overhead lines are impractical or infeasible. According to the literature reviewed for this study, some of the situations in which the impracticality of overhead lines may lead to underground solutions include

- densely populated urban and suburban residential areas, primarily due to the impracticality of running the lines along city streets,
- any place in which a line is needed but the amount of right-of-way available is very limited (overhead lines generally require more right-of-way than underground),
- river crossings,

- in the vicinity of airports, where it is judged that overhead lines may present a hazard or an unacceptable obstruction to planes,
- certain operational design situations, such as approaches to substations in congested areas, and
- locations in which overhead lines are deemed unacceptable on visual amenity grounds, such as a national park.

Dominion's view is similar to many other power companies. The manager of transmission systems for Dominion said in 2005 that Dominion prefers overhead lines. He noted that when Dominion has used underground lines, it has been in situations where overhead was not an option, such as in Crystal City, where numerous tall buildings are located closely together. Table 3 shows the local factors which Dominion cites as the rationale for underground lines in its transmission system and the extent of the underground line mileage that is due to these factors.

Table 3: Factors Explaining the Presence of Underground Lines Within Dominion's Virginia Transmission System

Undergrounding Factor	Number of Lines	Line Length (Miles)	Percent of Underground Mileage
Urban area, either very congested, or no viable overhead route	11	18.66	37
Urban area, lines installed in 1970s, Dominion acquired from PEPCO as part of a service area purchase	4	17.84	35
Conditions of railroad right-of-way agreement meant no overhead route available	2	6.20	12
Naval base – customer requested undergrounding and paid for it	4	4.00	8
Dense suburban area, no viable overhead route	1	2.18	4
Submarine segment in an overhead line, no viable overhead route for that segment	1	1.59	3

Source: JLARC staff analysis of information furnished by Dominion in September 2006.

While power companies typically have a strong preference for overhead lines, they do not have complete control of the decision. Companies are aware that a regulatory commission could decide against their wishes and require undergrounding in some situations. For example, a document of the American Transmission Company states

> We will propose the project as overhead. However, if the PSC [the Wisconsin Public Service Corporation, that state's counterpart to Virginia's SCC] chooses to examine underground construction, determines that it is justified and orders us to bury the line, we will comply...

In conclusion (and notwithstanding the underground technological developments which will be discussed in the next section of this chapter), power companies and other experts still see overhead lines as the strongly preferred option for power transmission in most situations. A line may still be placed underground, however, if there are unique and compelling countervailing local factors which make the placement of the line overhead impractical.

THERE IS NO CONSENSUS ON WHICH UNDERGROUND TECHNOLOGY IS "BEST" FOR HIGH-VOLTAGE TRANSMISSION

With regard to overhead transmission lines, the technology has changed little over recent decades. Experts indicate that "steady refinement" has occurred over the last 30 or 40 years in the design and construction of the lines, but there have been no substantial breakthroughs. In addition, the material used in construction has seen "incremental, as opposed to fundamental, change."

The picture for underground transmission lines is different. Several technologies or methods of running underground transmission lines have been employed in the United States and other countries. In addition, a recent trend, seen as a major change by some in the power industry, has been from the use of pipe-type, high-pressure fluid-filled ("HPFF") steel cables to the use of cables with solid rather than fluid insulation (known as "XLPE"). HPFF and XLPE are now the leading options in underground transmission line technology.

Several Types of Underground Transmission Lines Are in Use or Under Development

A wire, according to the definition of the Institute of Electrical and Electronics Engineers, consists of a conductor of an electrical current plus its insulation, if any. Similarly, the conductor and the insulation are critical components of electric transmission lines. Underground transmission lines vary in terms of how the conductors are run (housed in a single pipe or cable, or housed separately) and the form of insulation that is used (fluid, gas, or solid). Table 4 provides summary information about various types of underground transmission systems that are discussed in the literature.

Of the underground systems included in the table, the two systems which are seen by U.S. experts as the most viable for use for most higher voltage transmission projects are HPFF (fluid-insulated cable) and XLPE (cable insulated by a solid material, polyethylene). HPFF accounts for about 80 percent of all underground line mileage in the United States, and all of the existing underground line miles that Dominion operates at 230 kV are HPFF systems.

Another leading option for underground use is XLPE cable. With XLPE, the electrical conductor is fully coated with a solid insulating compound (polyethylene). XLPE cable is often referred to as "extruded" cable, because of the method used to apply the insulation.

HPFF Cable Has Proven Reliability While XLPE Is Seen as a Newer Technology With Increasing Use and Potential

For decades, HPFF cable was the cable of choice for most underground transmission projects. At lower voltage levels, some of these lines were installed as early as in the 1930s. There have been developments over the decades in the fluid that is used, and other advances, allowing for its use at higher voltages. According to a technical paper prepared for an IEEE conference in 2006, HPFF cables in the 200 kV to 275 kV range have been in use in the United States since the late 1950s and the first 345 kV HPFF cable went into operation in 1991. The paper also notes that HPFF cables have been installed in Japan at 500 kV.

Reasons for HPFF's dominance in the underground cable system field in the United States have included the fact that the pipe is very rugged, the system has been very reliable, and the long-term maintenance requirements have been low. A key disadvantage has been the potential for leaks of the fluid to the environment. However, the fluid used in HPFF (sometimes characterized as petroleum oil or mineral oil) has advanced considerably, meaning that leaks from current HPPF systems are much less environmentally detrimental than before. A material safety data sheet on the oil indicates that the oil has "minimal toxicity" even if ingested.

XLPE was first introduced commercially in the early 1960s. The first 225 kV extruded cable was installed in France in 1969. Europe and Japan continued to develop and install XLPE technology throughout the 1970s, 1980s, and 1990s for use at voltages above 138 kV. XLPE cable has been installed in Europe at 400 kV since 1985. In Japan, a 25-mile line of 500 kV cable was put underground in Tokyo and began operation in 2000.

Table 4: Types of Underground Systems

System	Description	Use
High-Pressure Fluid-Filled (HPFF) pipe (also referred to as just fluid-filled, or FF)	System uses pressurized dielectric fluid ("dielectric" means something that does not conduct electricity). Line consists of a steel pipe with three high-voltage conductors or "cables". Each conductor is insulated with "high-quality, oil-impregnated Kraft paper" and is surrounded by a metal shield (usually lead). Three cables in the pipe are surrounded by dielectric oil to prevent electrical discharges.	HPFF lines have been in service for 60 years or longer. HPFF is estimated to account for about 80 percent of installed underground mileage. Very common at the higher voltage levels, like 345 kilovolts.
High-Pressure Gas Filled (HPGF) pipe	A variation of HPFF. Pressurized nitrogen is used instead of dielectric fluid to insulate the conductors. Nitrogen gas is "less effective than dielectric fluid at suppressing electrical discharges and cooling." To compensate, the insulation for this type of system is usually about 20 percent thicker.	Maximum voltage use is limited to 138 kV at this time.
Gas-Insulated Lines (GIL)	Insulation in the system is achieved with the use of sulfur hexafluoride (SF_6) gas or a mixture of SF_6 and nitrogen gas. Transmission is achieved through the use of a very rigid pipe. Can be useful to transport high loads of power (above 2,000 MVA), but its installation is complex, as substantial care is needed to avoid line contamination, and joints are required at short distances.	Use has been limited. Can be a cheaper solution for a short distance, such as from a power plant to a substation, but it is not being used for lines running many miles in length.
Self-Contained Fluid Filled (SCFF) cables	Differs from HPFF and HPGF in that (1) the insulating fluid is not kept at such a high pressure, and (2) the three conductors or cables are not placed together in a pipe, but rather are kept independent of each other.	Not common in North America. Used in Europe. However, even submarine cable installation, in which SCFF was traditionally used, is increasingly done using other approaches.
Solid Dielectric Cable: EPR or XLPE	Insulation achieved through the use of a solid material which replaces the need to use a pressurized liquid or gas. EPR cable uses ethylene-propylene rubber as the solid material. In XLPE, the solid material is cross-linked polyethylene; insulation is about twice as thick as the oil insulation used in some other types of systems. As is the case with SCFF, the three cables used in XLPE technology are not housed together in a pipe. Instead, three separate cables are set in concrete ducts or buried side-by-side in soil that is specially prepared.	EPR is not used above 138 kilovolts. XLPE is increasing in transmission use. For decades, its use at 230 kilovolts or above was rare, but it is being used more and more frequently at higher transmission voltages (up to 500 kilovolts).
High Temperature Superconducting Cables (HTS)	Discovered in 1986. HTS cable can carry up to about five times as much power as copper wires of similar size. While the price to performance ratio of the cable has decreased since the 1990s, HTS cable remains very expensive. HTS cables have been used for low voltage lines in dense urban areas (Detroit, Copenhagen).	Practical use for high-voltage transmission still seen by many as well into the future, and even then, situations for use may be limited.
High Voltage Direct Current (HVDC) Technology	DC current operates at a constant polarity and intensity, and is used in transmission to move large amounts of power over large distances, or to link power systems that have differing operating frequencies.	Use is at very long distances and for underwater transmission. DC converter stations are very expensive, and the lines do not offer the ability to tap power off into areas along the way.

Sources: September 2006 telephone interview with the Director of the Electrical Insulation Research Center at the University of Connecticut; USDA briefing package, "Underground Transmission," from February 2006; ICF Consulting document from February 2003; "Underground Electric Transmission Lines" by the Wisconsin Public Service Corporation; and Dominion staff.

In the United States, during the last four decades underground transmission cable with solid insulation has been used with increasing frequency, reaching a point at which it accounted for the majority of new transmission cable installations at voltages up to and including 161 kV. However, the use of XLPE at higher transmission voltages has been slower to take hold. This may be because, as one consulting expert has noted, "the operating experience for early XLPE transmission cable systems in the United States was worse for the U.S. versus European or Japanese installations." XLPE lines installed in the United States since the mid-1980s (still at lower voltages) began to show the favorable level of reliability that was seen in other countries using XLPE. From about 2001 to the present, XLPE transmission projects at 230 kV have become more common in the United States. However, a document on undergrounding from 2006 notes that "only recently" has XLPE been used in the United States for "long 345-kV applications."

Despite its slow start in the United States, there are experts that see XLPE as an emerging technology that is gaining in popularity and use compared to the use of HPFF. An expert with Power Delivery Consultants, Inc., noted as early as June 2002 that "pipe-type cable still dominates at 345 kV and still has extensive use at 230 kV, but its percentage of new installations is diminishing." Burns and McDonnell has noted that HPFF is "most common in [the] U.S. and for 345-kV, but [the] trend is shifting." A systems operations official of ISO New England, Inc., wrote in 2005 that:

> The technology of Extra High Voltage cables, EHV, is at a crossroads. The industry is moving away from . . . HPFF, in favor of solid dielectric cables (XLPE). This is especially true for voltages of 400 kV and below. Correspondingly, the number of manufacturers of HPFF cables has dropped due to mergers, acquisitions, and the shift to alternative cables. Over the last 10-15 years, XLPE have advanced to the point where the cable can be manufactured without voids or impurities, which previously had led to premature cable failures due to high electrical stresses within the cable. In addition, the splicing and cable terminations have also seen advances. Although there are few XLPE cable systems above 300 kV, cable experts are cautiously optimistic that with proper engineering and installation methods a reliable EHV XLPE cable system can be implemented.

Some advantages of XLPE over HPFF, according to some experts, include

- absence of pressurizing systems,

- ease of splicing, resulting in a less costly installation,
- generally lower installation costs than HPFF,
- higher load-carrying capacity,
- lower dielectric loss – less power is consumed or lost from the line due to the heating effect upon the insulating material,
- unlike HPFF, no potential for environmental leaks of fluid,
- less downtime for repair and maintenance, and
- lower maintenance costs because there is no insulating fluid.

Several sources indicate that the use of XLPE may save about 20 percent in costs compared to the use of HPFF (Dominion 2006 life cycle cost estimates, Highland Council / Jacobs Babtie 2005 life cycle cost estimates, and a Terna study comparing costs in 1999-2000 as cited by ICF Consulting). While cost is often noted as an advantage of XLPE over HPFF, some experts contend that XLPE is still a less desirable option than HPFF at the 230-kV level and above. These experts, including Dominion staff, argue that XLPE's reliability is not nearly as established as the reliability of HPFF. Cost and reliability issues associated with underground and overhead transmission options are addressed further in Chapters 3, 5, and 7.

Chapter 3

Underground and Overhead Transmission Line Costs

In Summary

Cost is a key reason why most transmission lines are placed overhead instead of underground. Despite developments in underground technology, underground lines are still more expensive than overhead lines in most cases. Overhead lines have several major cost advantages—for example, insulation is achieved at a much lower price, and installing towers is less expensive than digging a trench. Dominion has generally estimated 230-kilovolt underground line costs of between about six and ten million dollars per mile. More recent estimates by Dominion have been toward the higher end of the range, with the inclusion of spare cable in the design for reliability purposes, and also taking into account increasing copper costs. Dominion's cost estimates for underground and overhead transmission lines are generally in line with estimates from other sources. Typically, the ratio of underground to overhead transmission costs is between about four and ten to one. However, it should be noted that (1) an underground line can be very cost-competitive when the right-of-way cost for an overhead line is very high, and (2) incremental use of underground lines will likely increase overall electricity costs by several percentage points (and not a manifold increase). This is because transmission costs are generally only about four to ten percent of electric system costs, and even if the proportion of underground lines is increased, they still remain only a fractional part of the system.

The mandate for this review requires an examination of the factors considered by the State Corporation Commission in assessing underground line feasibility, including the "construction and long-term operating costs considered by the SCC." The primary cost estimates that the SCC has to consider are from Dominion, although at times cost estimates are presented by other experts. To place Dominion's cost estimates into a proper context, this chapter considers the following questions:

- What are the cost advantages that power companies see in the use of overhead lines?
- What factors impact the magnitude of underground and overhead costs?
- What are Dominion's cost estimates for underground and overhead lines, and how do Dominion's cost estimates compare to estimates given by other experts and to actual project costs?
- What impact might greater undergrounding have upon the cost of the electric system?

OVERHEAD LINE COST ADVANTAGES INCLUDE NO NEED FOR BURIAL AND INEXPENSIVE INSULATION

In almost all cases, underground lines are more costly to install than overhead lines. In part, this is because of the greater quantity and higher labor costs that are associated with installing underground structures and burying cable compared to installing overhead poles or towers and running line between them. In part, it is because of the characteristics of overhead and underground lines.

Overhead lines are insulated at a low cost, in part because air surrounding the line provides substantial, free insulation, thereby reducing the extent to which the line needs designed insulation. Also, the heat that is generated by the electricity passing through the line is dissipated by the natural circulation of the air around the line. In contrast, the conductors of underground lines are surrounding with expensive insulating material. Also, costs are entailed to guard against the overheating of an underground line, as is described in a report on undergrounding done by the Highland Council of the Cairngorms National Park Authority and Scottish Natural Heritage.

> The performance achieved by current EHV cable designs is the result of many years' of cable design and manufacturing development. . . . It is, however, an unfortunate side effect that, not only are these materials highly effective electrical insulators, but they are also good thermal insulators. Thus, in normal operation, the conductors heat up, an effect made worse by burying those cables underground. The conductor heating issue becomes of further significance because the insulation material itself must not be allowed to rise beyond certain limits if it is not to sustain permanent damage. To prevent the cable from overheating, the resistance which generates heat must be reduced and this is achieved by increasing the cross-sectional area of the conductor. This means that UGC [underground cable] conductors can be up to four times larger than a similarly-rated OHL [overhead line] conductor. This is also a contributory factor to the additional costs of UGC when compared with OHL.

The magnitude of the cost difference between overhead and underground lines can vary greatly depending on the type of line and structures used and the nature of the project.

SEVERAL FACTORS IMPACT THE MAGNITUDE OF UNDERGROUND AND OVERHEAD COSTS

Typically, the construction process for underground lines involves the following steps:

- clearing right-of-way,
- digging the trench,
- installing the duct bank or conduit which will house the cable,
- installing "splice vaults" or "manholes" between every 900 and 3,500 feet or so of the right-of-way; these vaults as built by Dominion are 8 feet wide, 19 feet long, and 8 feet high, and are required to provide access to the splices and room for pulling cable,
- covering the duct bank or conduit with thermal backfill,
- pulling the cable between the vaults, and
- splicing the cable segments together, and installing termination points and other ancillary structures.

Various factors can impact the cost of the cable or the construction work that is required. These factors include, but are not limited to

- right-of-way costs,
- the size and the type of cable (which is impacted, of course, by the amount of power to be carried),
- the number of circuits to be installed,
- commodity prices at the time of cable purchase,
- the length of the line (shorter lines cost more per mile, because the termination costs are spread over fewer miles),
- labor costs, and
- the terrain and other features of the right-of-way within which the line is buried.

One of the challenges of installing underground lines is the thickness and inflexibility of the pipe or cable. This fact means that the terrain where the line is to be buried is an important factor in the project difficulty and the cost of the line. As the previously-referenced Highland Council report notes:

> A further effect of the combined thickness of insulation necessary of EHV and of the large conductor cross-sectional area required for [underground cables] is that the cables become inflexible. Care must also be taken during installation to ensure that permanent damage is not done to the insulation and sheath by 'over-bending' the cable. . . . This in turn imposes constraints on the profile of the trenches and troughs into which the cables may be installed. The radius of both horizontal and vertical bends must therefore take

account of this limitation, it being of particular importance for undulating and rocky terrain.

For overhead lines, the amount of power to be carried by the line, the type of poles or towers used, right-of-way costs, terrain, and other factors can all have substantial impacts upon project costs. For example, an overhead project using steel poles or towers to bear a 345-kilovolt line may entail costs of 2.8 to 3.7 times (or more) the costs entailed for a project using H-frame wood poles to bear a 115-kilovolt line. An overhead project over mountainous terrain may increase the cost by about 20 to 50 percent over the cost of a project on flat terrain.

DOMINION PER-MILE COST FIGURES FOR UNDER-GROUND LINES ARE SIMILAR TO OTHER SOURCES

Over the years, Dominion has prepared estimates of the costs for undergrounding transmission lines. These figures were developed for potential projects, or to reflect actual project cost experience, or for illustrative purposes based on a hypothetical scenario. These cost estimates, as compiled by JLARC staff, are shown on a per-mile basis in Table 5.

Table 5: Dominion Estimates of Underground Transmission Costs at 230 kV Have Ranged from $5.7 to $10.3 Million Per Mile

Year	Estimated Cost Per Mile ($ Millions)	Line Length (Miles)	Cable Type	Other Information
2006 (Estimates assume higher copper costs)	**10.3**	5.0	HPFF	Life cycle cost. Updated illustrative estimate (for JLARC), single circuit line with spare cable, 1035 MVA.
	10.2	5.0	HPFF	Initial cost. Updated illustrative estimate with same parameters as above.
	8.1	5.0	XLPE	Life cycle cost. Updated illustrative estimate with same parameters as above.
	7.5	5.0	XLPE	Initial cost. Updated illustrative estimate with same parameters as above.
2005	**8.2**	5.0	HPFF	Life cycle cost. Illustrative estimate (for JCOTS), single circuit line with spare cable, 1035 MVA.
	8.1	5.0	HPFF	Initial cost. Illustrative estimate, same parameters.
	6.9	5.0	XLPE	Life cycle cost. Illustrative estimate, same parameters.
	6.4	5.0	XLPE	Initial cost. Illustrative estimate, same parameters.
	5.7	1.5	HPFF	Estimated cost for double circuit line, 412 MVA, energized in 2005; final cost to be determined.
2003	**7.8**	0.6	HPFF	Approximation of costs for an actual project, with a double circuit line, 412 MVA; energized in 2003.
2001	**6.2**	3.6	HPFF	Cost estimate for line proposal filed in 2001.
1996	**6.9**	2.6	HPFF	Approximation of actual project costs for a double circuit line, 637 MVA, energized in 1996.
1988-89	**6.1**	3.5	HPFF	Estimate for double circuit line proposed in Fairfax County.

Source: SCC case files, and materials provided by Dominion to JLARC staff and to the Virginia General Assembly's Joint Commission on Science and Technology (JCOTS).

Other sources or contacts identified during this review generally indicate a range of underground costs that is similar to Dominion's estimates. For example, in an interview with JLARC staff, an underground transmission expert from Burns and McDonnell, an international engineering, architecture, and consulting firm, indicated a general cost range of about four to ten million per mile. (For further details on various underground and overhead transmission cost figures and ratios obtained during this review, see Appendix E on "Underground and Overhead Transmission Costs.") Dominion's cost estimates for XLPE from 2005 (before it increased its estimates due to rising copper prices) were below the middle of this range. Dominion's estimates from 2006, with a higher price for copper, place XLPE costs at about the middle of the range, while its HPFF estimate is just slightly above the high end of the range.

UNDERGROUND LINES TYPICALLY APPEAR TO COST FOUR TO TEN TIMES MORE THAN OVERHEAD LINES

In addition to its recent estimates of underground costs, Dominion estimated the costs for the installation of a 230-kV overhead line, with a right-of-way cost included. The underground costs could then be compared against the overhead line cost, and ratios constructed of underground to overhead costs.

Dominion's cost for overhead line installation, using steel towers with 1035 MVA capacity, equated to about $1.06 million per mile. This cost included $485,000 per mile for right-of-way. Relative to other estimates of overhead line installation costs from various sources, Dominion's overhead cost on a per-mile basis was somewhat on the lower side. For example, PJM has a cost estimate for 230 kV overhead lines that is $850,000 per mile without right-of-way costs. PJM's figure plus Dominion's right-of-way figure yields a cost of about $1.335 million per mile—higher than Dominion's estimate, but not enough of a difference to bring Dominion's overhead line estimate much closer to the cost levels of underground lines. Documents of Burns and McDonnell and the Aspen Environmental Group (a consulting firm that has prepared a number of environmental impact reviews in recent years for transmission projects) have placed the typical overhead cost range from about $1 million to $3 million and $2 million respectively, so Dominion's estimate is compatible with the low end of these ranges.

Dominion's estimates of underground and overhead initial installation costs from 2005 suggested a ratio of 7.5 to 7.7 to one for HPFF, and a ratio of 6.1 to 6.3 to one for XLPE. These ratios appear credible in relation to ratios of underground to overhead line costs compiled by JLARC staff from numerous sources. Dominion's 2006 estimates, which are higher than its 2005 figures, take into account recent copper price increases which would not have been taken into account in figures from prior years.

Analysis of the estimates compiled during the review indicated that the median ratio of underground to overhead costs for "generic" estimates (not identified in relation to a particular kV level) was about 7.0 to one for ratios from North American-based sources, and 10.0 to one with European sources included. This difference is probably in part a reflection of the fact that more projects have been done in Europe at higher kilovolt levels. For estimates at specified kV levels, there is a general relationship between the ratios given and the kilovolts assumed. Based on this relationship, average ratios are about

- 3.8 to one at 115 kV,
- 6.1 to one at 230 kV,
- 8.5 to one at 345 kV, and
- 9.7 to one at 400 kV.

UNDERGROUND LINES CAN BE VERY COST COMPETITIVE IN SOME UNIQUE CIRCUMSTANCES

The preceding discussion addresses the types of underground to overhead cost ratios that may be seen for typical projects. However, the cost of overhead projects on a per-mile basis is not always less than underground projects. In some unusual circumstances—where acquiring wide easements or right-of-way in a densely populated area is extremely expensive—an underground project may be cost-competitive with or even cost less than an overhead line.

Table 6 shows underground and overhead costs for three different scenarios, as estimated by Dominion. In each case, the underground cost per mile is about the same, but there are major differences in the overhead costs.

In the first scenario, fairly minimal right-of-way costs are assumed for the overhead line (about $0.48 million per mile), and the total cost of the overhead line was estimated at around one million dollars. In the second scenario, Dominion foresaw much higher overhead costs per mile for a 2001 project. And in the third scenario, Dominion's cost estimates for the overhead line were about double the underground line costs, and so Dominion recommended an underground route. An exhibit before the SCC at the time explained that "the high value of land and, therefore, the high costs of obtaining easements significantly increases the cost of an overhead transmission line in this area." The proposed underground project only required 25 feet of permanent and 25 feet of temporary construction easements, while an overhead project entailed a 120-foot wide permanent easement. Dominion proposed that this project be built underground, but ultimately the line was not built because a type of asbestos rock, actinolite, was discovered along the proposed underground route.

Table 6: Magnitude of Overhead Costs Has a Major Impact Upon the Cost Competitiveness of Underground Lines

Description of Estimate	Underground Cost Per Mile	Overhead Cost Per Mile	Ratio
Scenario #1: Dominion cost estimate for 230 kV line, 2005 (underground cost is initial XLPE cost)	$6.42 million	$ 1.06 million	6.1 to one
Scenario # 2: Dominion cost estimate for 230 kV line, in 2001 filing (initial costs)	$6.20 million	$ 2.60 million	2.4 to one
Scenario # 3: Dominion cost estimate for a 3.5 mile 230 kV line in Fairfax County, 1988-89	$6.06 million	$13.34 million	0.5 to one

Source: JLARC staff analysis of Dominion data and SCC case files.

TYPICALLY, UNDERGROUND LINES COST MORE EVEN AFTER ACCOUNTING FOR LIFE CYCLE FACTORS

A criticism made of underground and overhead cost comparisons is that many of the comparisons reflect the total installed costs of the line only. Questions have been raised regarding the difference that it might make in drawing cost conclusions if life cycle costs are taken into account, instead of focusing on initial installation costs.

Information reviewed for this study indicates that underground lines are likely to remain at a cost disadvantage in life cycle assessments. This is particularly clear when the difference in installation costs between underground and overhead lines amounts to millions of dollars per mile. In such cases, the magnitude of the difference in installation costs is just too large for life cycle factors to have a great impact on the cost comparison.

Table 7 shows estimated underground to overhead cost ratios from four sources which have addressed life cycle costs, including Dominion. The average underground to overhead ratio across these sources went from 9.3 to one for capital costs to 7.5 to one in the final life cycle costs given. (These average figures are based on taking one figure from each source, with a mid-point used for estimates expressed as a range or for underground estimates

Table 7: In Four Life Cycle Cost Estimates, Underground Line Costs Are Three to 11.8 Times More Than Overhead Line Costs

Type of Cost	Source 1: 1996, 2001 Acres International Corp. (115 kV)	Source 2: 2005 Highland Council, Jacobs Babtie	Source 3: 2006 Updated Cost, Dominion (230 kV)	Source 4: 1996 CIGRE Working Group (1,700 MVA circuit)
Starting point: Capital cost ratio only	5 to 6	6.4 XLPE 9.5 HPFF	7.1 XLPE 9.7 HPFF	15.3
Revised ratio with differential lifetimes assumed in figures	--	--	7.6 XLPE 9.7 HPFF	--
With maintenance / decommissioning costs included	--	6.1 to 6.3 XLPE 9.1 to 9.3 HPFF	7.4 XLPE 9.5 HPFF	--
With load losses taken into account	--	4.0 to 4.8 XLPE 5.8 to 7.1 HPFF	--	6.9 to 11.8
With outage repair costs considered	--	7.2 to 7.6 XLPE 9.1 to 9.3 HPFF	--	--
Final ratio	**3 to 5**	**7.2 to 7.6 XLPE 9.1 to 9.3 HPFF**	**7.4 XLPE 9.5 HPFF**	**6.9 to 11.8**

Notes: "—" indicates that this factor was not a factor in the particular analysis shown.
Dominion assumes that overhead lines and HPFF lines can last 70 years, but assumed replacement of XLPE at 40 years. Still, the cost Dominion estimates for XLPE replacement is only about $2.6 million, assuming that an investment of that amount could, with a real return of about five percent, produce funds to cover the cost of the replacement 40 years from now.
The 2005 Highland Council report indicated that the analysis assumed decommissioning of lines at the end of 40 years, which, it noted, "in the context of OHLs, is unduly conservative" with current practice "suggesting an asset life of 80 years for OHLs."

Sources: (1) Information on the 1996 and 2001 work by Acres International Corporation is based on a document of the Institute for Sustainable Energy at Eastern Connecticut State University entitled "Comprehensive Assessment and Report, Part I: Energy Resources and Infrastructure of Southwest Connecticut (January 2003). (2) Information based on Table 5 from the Highland Council report "Undergrounding of Extra High Voltage Transmission Lines" (2005). (3) Information on Dominion's updated (2006) life cycle costs were provided by Dominion staff to JLARC staff during the review. (4) Information on CIGRE findings is based on ICF Consulting's "Overview of the Potential for Undergrounding the Electricity Networks in Europe" (February 2003).

addressing both XLPE and HPFF). Depending on the life cycle factors taken into account, two sources show the underground to overhead cost ratio reduced considerably but by no means eliminated, while two sources show the cost ratio changing only slightly (upward for XLPE and downward for HPFF).

The low maintenance costs of underground lines are sometimes cited as a factor which can benefit underground lines in a life cycle analysis. However, some power companies report that underground line maintenance is more costly than overhead line maintenance (see gray box, next page). Regardless of the magnitude of maintenance cost that is assumed for the underground lines, the

Underground and Overhead Maintenance Costs

Dominion estimates annual maintenance costs of $3,616 per mile for underground lines, but only $2,009 per mile for overhead lines. In public utility commission proceedings in Rhode Island, an engineer with National Grid USA put annual underground maintenance costs of HPFF at $18,000 per mile and XLPE at $7,000 per mile, while indicating overhead line maintenance costs of only $3,000 per mile. (For underground lines, lower annual maintenance costs are budgeted by BC Hydro in Vancouver, however, with costs for HPFF and XLPE budgeted at $3,000 and $1,000 per mile respectively).

fact is that maintenance cost levels associated with overhead lines are simply not large enough for underground lines to close the gap in cost comparisons to overhead lines. At $2,000 to $3,000 per mile annually, an overhead line would cost $140,000 to $210,000 to maintain for 70 years. This level of maintenance cost seems quite small compare to situations where the capital cost of the underground line may be estimated at between $4 million and $10 million and the capital cost of the overhead line may be estimated at about $1 to $2 million.

Based on the analyses reflected in Table 7, however, a factor which can work to the advantage of underground lines in life cycle analyses is "load losses." The Highland Council report explains that the cross-sectional area for an underground cable is considerably larger than for an overhead line, and therefore, the loss of power from the cable can be less than the loss of power from an overhead line. While the CIGRE and Highland Council studies both saw underground lines closing the cost gap with overhead lines based on this factor, both studies nonetheless had "final" ratios in which the life cycle costs of underground lines were about 7 to 12 times greater than overhead lines.

SOMEWHAT GREATER USE OF UNDERGROUNDING COULD INCREASE POWER SYSTEM COSTS BY MANY PERCENTAGE POINTS, BUT NOT MANIFOLD

In considering the cost impact of potentially undergrounding a segment of a transmission line, a single transmission line, or even several transmission lines, it is important to recognize that the overall cost impact of that decision upon the cost of the entire power system will be far less than the underground to overhead cost ratios discussed in this chapter. There are two key reasons why. First, even with somewhat greater use of undergrounding for transmission purposes in the future, the quantity of lines that would be underground will still constitute a low percentage of the total transmission system. Second, transmission costs are only a portion of power system costs (and customer electric bills). Sources reviewed during this study generally indicate that the costs associated with transmission lines usually account for only about four to ten percent of power system costs (and transmission costs include both operating as well as capital costs).

In Virginia, underground lines constitute a small proportion of transmission lines. Undergrounding is used because there are situations in which overhead lines are impractical or infeasible. As the following chapters will discuss, the SCC has only approved underground lines when they would not pose higher costs for that utility's ratepayers, who bear the costs of all underground lines regardless of where in the utility's service area they are installed. As a result, one reason why the SCC has limited the use of undergrounding is to limit the impact on ratepayers. Therefore, unless a third party is willing to pay the costs, underground lines have only been approved when no viable overhead route existed. If this pattern holds true, then the use of undergrounding will remain limited.

Given these factors, a somewhat greater use of underground lines may be expected to increase power system costs by a few percentage points—not a two to ten-fold increase. The following case studies illustrate the point.

Case Studies

A consultant report on a transmission line project indicated that the cost for a three-mile underground line would be about five times the cost of an overhead line. However, the added cost was estimated to be about 0.8 percent of the existing transmission and distribution cost base.

***

A European power company estimated that a 15-year program of undergrounding 225 kV lines would add around 10 percent to the annual base cost. ICF consulting noted that with transmission constituting about 10 percent of electricity costs, the additional cost of electricity would be one percent.

***

An expert in undergrounding has indicated that undergrounding 25 percent of the existing extra high voltage and high voltage lines in two European countries would increase the price of electricity by three to five percent.

The magnitude of cost for any underground project(s), as well as the size of the utility or utilities undertaking the project(s), obviously influences the relative cost impact. One project in Connecticut, for example, is estimated to have more of a cost impact than indicated in the case studies above. This project is estimated to have a four percent impact upon power system costs if this line is 50 percent underground, and an eight percent cost impact if the line is 100 percent underground.

Chapter **4**

SCC Policies Affect Transmission Line Cases

In Summary

Under Virginia's Utility Facilities Act, the SCC exercises authority over both overhead and underground transmission lines in Virginia. Current statutes require the SCC to consider several factors before approving construction, including the cost and potential environmental impact of a line. Some of these terms, such as cost, are not explicitly defined in statute, and the commissioners have asserted their authority to interpret some undefined legislative criteria. SCC staff, hearing examiners, and interested individuals or groups participating in a case play an important role in supplementing the information provided by a utility in its application. The commissioners rely on the formal record developed in a case to evaluate whether a proposed transmission line satisfies the criteria prescribed by the *Code of Virginia*.

The SCC was established by the 1902 *Constitution of Virginia* as the instrument through which the State exercises its power to control corporations. In 1904, the Supreme Court of Virginia noted that the SCC was granted legislative, judicial, and executive powers in order to regulate corporations (Norfolk & P.B.L.R.R. v. Commonwealth, 103 Va. 289). The breadth of these powers is reflected in the commission's self-description, which notes that "it has been described as the 'fourth branch of government' and 'the most powerful regulatory body in America.' "

The 1971 *Constitution of Virginia* maintained the SCC as a permanent commission; its characteristics, duties, and powers are set forth in Article IX. Since the creation of the SCC, the Supreme Court of Virginia has held that the powers granted to the SCC can be changed at any time by the General Assembly.

In the absence of specific legislative direction, the SCC appears to have very broad powers. For example, in 1906 the Court construed the SCC's grant of authority as enabling the commission to determine the constitutionality of statutes which it is required to enforce (Commonwealth v. Atlantic Coast Line Railway Co, 106 Va. 61). The Court reaffirmed this power of the SCC in 1977, ruling that the commission had "the authority to, and should, pass upon the constitutionality of the statute" in question (Blue Cross of Virginia v. Commonwealth, 218 Va. 589).

At the time of the last JLARC review of the SCC, in 1986, it had 527 authorized staff positions and a biennial operating budget (1986-88) of $58.5 million. In 2006, the SCC has 653 authorized positions and a biennial operating budget (2007-08) of $179.8 million. Transmission line cases are reviewed by staff in the SCC's Division of Energy Regulation, along with staff attorneys from the Office of General Counsel. There are about 16 staff members in the Division of Energy Regulation, including clerical. Typically, one person from this division is assigned to a transmission line case, and they also have other responsibilities outside the case. In addition, a case may be assigned to a hearing examiner, who conducts the public hearings and drafts a report containing recommendations for the commissioners to consider.

COMMISSIONERS MUST CONSIDER SEVERAL FACTORS WHEN EVALUATING TRANSMISSION LINES

The Commonwealth regulates the construction and placement, or siting, of transmission lines through the Utility Facilities Act (Sections 56-265.1–265.9 of the *Code of Virginia*). Section 56-265.2(A) of the *Code of Virginia* states that it is unlawful for a public utility to construct, enlarge, or acquire a facility without first obtaining a certificate of public convenience and necessity (certificate). A certificate is not needed for "ordinary extensions or improvements in the usual course of business." This section of the *Code* further states that certificates for "overhead electrical transmission lines of 150 kilovolts or more shall be issued by the Commission only after compliance with the provisions of § 56-46.1."

Section 56-46.1 of the *Code of Virginia* includes four factors that the commissioners must consider when evaluating proposed transmission lines:

- the need for the new line and its impact on the reliability of electric service,
- impact on the environment, including scenic assets, historic districts, and the health and safety of persons in the area,
- impact on economic development, and
- local comprehensive plans when requested by an affected locality.

A fifth factor, the estimated cost of a new line, is given a prominent role in transmission line proceedings under current statutes. Section 56-235.1 requires the SCC to "investigate and monitor the major construction projects of any public utility to assure that such projects are being conducted in an economical, expeditious, and efficient manner." In addition, § 56-235.1 authorizes the SCC to "determine whether [public utilities] promote the maximum effective conservation and use of energy and *capital resources*...in rendering utility service" (emphasis added).

Commissioners Are Routinely Required to Balance Competing Criteria

The need to conserve capital resources often conflicts with efforts to minimize the adverse impacts of a line, because mitigation efforts can increase construction costs. Current statutes do not provide the commissioners with guidance on how to balance these factors, and there is no requirement that one factor receive a higher priority than another. Instead, the commissioners are charged with evaluating the facts of a case and finding the solution that, in their opinion, best balances the factors and criteria contained in the statutes.

The SCC's interpretation and application of the statutory factors can impact ratepaying customers of a utility, if the commission approves construction projects that ultimately result in higher electricity bills. An example of the SCC's awareness of this fact may be seen in their interpretation of section 56-265.2, which the commissioners have maintained is designed to prevent wasteful investments in unnecessary facilities by requiring utilities to prove that a facility is needed for the "public convenience and necessity." This interpretation of the statute was originally provided in a 1972 memo issued to all utilities by the SCC following passage of the Utility Facilities Act, and was later affirmed by a majority of the commissioners in a 1988 case (1986-00065).

The decisions made by the commissioners can also directly affect individual property owners if their land is needed for a utility right-of-way. This was observed by a commissioner in a dissenting opinion concerning the use of transmission line right-of-way for a natural gas pipeline through the Counties of Charles City, New Kent, James City, and Hanover. Here, the commissioner observed that even though 82 percent of the pipeline would be built on existing electric transmission line rights-of-way, this still left a substantial portion of land to acquire along the 118 mile route. Noting that this will occur either voluntarily or in the courts, he added that

> one of the central purposes of awarding such a certificate [of public convenience and necessity] is to give the utility the authority to exercise its powers of eminent domain with regard to the project. Though it will be easy enough for us to say that we did not directly approve the taking of property in connection with this pipeline, we must realize that our action today will be touted as eliminating most issues in the inevitable Circuit Court proceedings to follow, save that of adequate compensation. This concern is hardly a trivial one for the property owners whose land is to be taken. . . . They have a right to expect that their property will not be seized,

> and the remainder of their land burdened with a utility corridor, unless it is truly necessary (1986-00065).

In light of the need to balance cost concerns with the statutory requirement to minimize adverse impacts on the environment, the commissioners have indicated that only reasonable or limited mitigation measures are required. In a 1991 opinion approving a new 230 kV line through Fairfax and Prince William Counties, the commissioners rejected a proposal to place underground a portion of the proposed line through the Manassas Historical District. As the commissioners explained,

> the law requires that we find the proposed transmission line reasonably minimizes adverse impact on the environment. It does not require that the line avoid any such impact. A policy of no impact would, in many situations, bar construction of necessary facilities (1989-00057).

The commissioners have also indicated in past opinions that no single factor can determine the outcome of a case. Instead, the statutes require that all legislative criteria are weighed before approving new transmission facilities. Furthermore, the commissioners affirmed in a 1995 opinion that the need for a line cannot be considered separately from an evaluation of environmental impact and alternative routes (1991-00050). As the commissioners have stated in several opinions, the statutory criteria "are, to a large extent, interrelated and overlapping." This position was recently affirmed in a case in Loudoun County in which the commissioners observed that "individual criteria . . . are not dispositive," and that each statutory criterion is considered "on an individual basis and as part of the whole" (2001-00154).

SCC Interprets Terms Not Defined in Statute

Some statutory provisions governing the approval of transmission lines include specific legislative instructions regarding their application to a proposed line. For example, Section 56-46.1 requires the commissioners to minimize adverse impacts on the environment. This section defines the term environment to "include in meaning 'historic,' as well as a consideration of the probable effects of the line on the health and safety of the persons in the area concerned." Other statutory criteria do not include definitions or legislative instructions. For example, the statute provides no definition of 'cost.'

The commissioners have approached the application of some factors with more hesitation than others. For example, the commissioners have noted that their authority to **quantify** externalities is limited. Externalities are those effects of an action, such as the construction of a transmission line, that are not included in the cost. For example, an externality occurs when the cost of constructing a transmission line does not include the cost of reductions in environmental values. This may occur if the presence of a transmission line harms habitat, historic sites, or scenic assets, or potentially harms human health or safety. Placing a monetary value on these potential reductions can be contentious, and the commissioners render decisions based upon **qualitative** factors instead.

In contrast to the decision to avoid quantitative analysis, the commissioners have asserted their authority to interpret some legislative terms not defined by statute. The commissioners discussed their approach to determining the need for new facilities in a 1988 opinion involving a natural gas pipeline, noting that

> there are no legislative constraints or instructions as to the meaning of public convenience and necessity contained in § 56-265.2. Consequently, we must exercise our discretion in determining when construction of proposed facilities will serve the public interest (1988-00065).

The commission has also indicated that its application of statutes which lack legislative "constraints or instructions" may evolve. In the previous gas pipeline case, the commissioners explained that its interpretation of the public convenience and necessity standard had emerged from the judicial process: "through time and practice, certain factors have been judicially crafted and applied to applications submitted under § 56-265.2." As a result, the application of some statutes governing the certification of new transmission facilities, including the criteria established in Section 56-46.1, may change over time.

SCC USES A HEARING PROCESS TO REVIEW PROPOSED TRANSMISSION LINES

The SCC acts as a court of record, and transmission line cases must comply with the SCC's Rules of Practice and Procedure. The *Constitution of Virginia* allows the commission to "prescribe its own rules of practice and procedure" and also states that the "General Assembly shall have the power to adopt such rules, to amend, modify, or set aside the commission's rules, or to substitute rules of its own." The SCC's Rules are promulgated in Sections 5-20 et. seq. of the *Virginia Administrative Code*. As a court of record, the SCC is empowered by the *Constitution* to

- administer oaths,
- compel the attendance of witnesses and the production of documents,
- punish for contempt, and

- enforce compliance with its orders by levying fines or other penalties.

Utility Applications Routinely Conform to SCC Guidelines

Majority of Cases Reviewed Were Decided Largely Based On Information Provided by the Utility

A review of transmission proceedings since 1972 indicates that respondents other than the utility participated in hearings for only one-third of the cases. Respondents have included affected property owners, environmental advocacy organizations, and localities. In the other two-thirds of cases reviewed, SCC staff or a hearing examiner may have filed a report, but it does not appear that hearings were held.

A transmission line case commences when an electric utility submits an application for a certificate of public convenience and necessity from the SCC. Recent applications appear to conform to the *Guidelines of Minimum Requirements for Transmission Line Applications* issued by SCC staff in 1991. These guidelines updated a 1972 memo issued by the commissioners to all electric utilities operating in Virginia, and ask utilities to provide basic information regarding the proposed transmission line. As noted in the cover letter to the guidelines, the information would normally be requested by SCC staff in the course of its review of the application.

Of note, the guidelines do not request any information on undergrounding as an alternative means of construction. This appears to result from the fact that utilities propose underground lines very infrequently, and information on undergrounding has therefore not been seen as needed in the vast majority of transmission line cases.

The Hearing Process Can Affect the Review of a Case in Three Ways

The commissioners rely on the hearing process to develop information not provided by the utility in its application. In a 2001 opinion approving a 765 kV line in southwestern Virginia, the commissioners explained that while the utility "may not have developed some information that the Protestants believe should have been considered, the hearing process corrects any shortcomings" (1997-00766). In practice, it appears that the hearing process can affect a transmission line case in three important ways.

Commissioners Can Only Consider Material Included in the Formal Record. Information not introduced into the record in accordance with SCC procedural rules cannot be considered. For example, in a 1990 opinion approving construction of a 230 kV line through Hanover, Henrico, New Kent, and Charles City Counties, the commissioners ruled that an article submitted by a respondent and attached to comments on the hearing examiner's report was not part of the record, which had been closed, and therefore could not be considered (1989-00017). In a more recent case involving a 500 kV line in Fauquier County, the hearing examiner stated that written comments on Dominion's application submitted by the Board of Supervisors "do not have the same weight as evidence submitted at the hearing by the parties to this proceeding" (2004-00062).

SCC staff and hearing examiners can play an important role in completing the formal record of a case. A review of past transmission line cases indicates that staff routinely submit written analyses for consideration by the hearing examiner and the commissioners. Staff have also sought additional information from a utility when its application or other supporting materials did not address a relevant issue. In 2003, Dominion proposed a 230 kV transmission line in the Chesapeake region but provided no alternatives to the proposed project in its application. SCC staff requested additional information from the company and developed a feasible alternative for consideration by the commissioners (2004-00064). The hearing examiner assigned to a case can also contribute to the formal record. In an ongoing case in Loudoun County, the hearing examiner has proposed an alternative route for consideration (2005-00018).

Issues May Not Receive Consideration Unless Raised by a Public Witness or a Participant in the Case. In following a judicial process model, the commissioners can only consider material in the formal record. For example, the commissioners may not consider the potential impact of a transmission line on nearby homeowners if those homeowners do not express their concerns during the proceedings. The testimony of public witnesses can affect the commissioners' decision. In the final order for a case involving a natural gas line in Prince William County, the commissioners observed that twenty-six public witnesses testified at two public hearings, and that "those participating provided valuable information about the communities adjacent to the pipeline, safety concerns, proximity of the pipeline to homes, schools, and other occupied buildings, and the need for a tree buffer adjacent to the pipeline route." This information prompted SCC staff to investigate these issues further and to request the commissioners' permission to file supplemental testimony that addressed the citizens' concerns (2000-00741).

The Record Developed by the Hearing Process Is Built on Rules of Evidence. Persons who disagree with the information submitted by the utility must offer credible evidence to support their position. This need for evidence was illustrated in a 1978 opinion approving construction of a 765 kV line in southern Virginia. In addressing complaints made by property owners near the proposed route, the commissioners explained that

> while several witnesses alluded to...alleged undesirable "side-effects" of a 765 kV line, no expert witnesses were offered by any participating party, and no evidence was oth-

> erwise offered tending to impugn our earlier findings that a 765 kV line, as proposed, is safe within the determination of present technology (10848-A, later renumbered as case 1985-00021).

The commission has determined that protestants in a transmission line case are responsible for providing evidence that rebuts that offered by the utility in the application. In a 2004 case involving a 500 kV line in Fauquier County, the hearing examiner addressed an argument advanced by the County Board of Supervisors that Dominion should be required to prove that the line will not harm residential and agricultural areas. The hearing examiner determined that

> the burden is not on Dominion to prove there will be no future negative impact from its proposed transmission line. On the contrary, the burden lies with other parties in the case to submit evidence of some future negative impact. The burden then shifts to Dominion to rebut that evidence.

In recommending approval of the line, the examiner noted that no evidence of future negative impact was presented during the proceedings (2004-00062).

Commissioners Are Not Bound by Staff Recommendations

Since the passage of the Utility Facilities Act, the commissioners have generally issued a written opinion in transmission line cases. The opinion states the decision of the commissioners and may provide a rationale for their decision and any relevant factual findings. While the commissioners are limited to material contained in the case record, they are not bound by recommendations from SCC staff or the hearing examiner. For example, in a recent case from Loudoun County, the commissioners rejected a recommendation by the hearing examiner to install underground part of a 230 kV line in order to minimize impact on surrounding property owners (2002-00702). In 1990, the Supreme Court of Virginia held that the commissioners are not bound by the actions of SCC staff, and that anything they propose can be no more than recommendations to be adopted or rejected by the commissioners (Roanoke Gas Co. v. Division of Consumer Counsel, 219 Va. 1072).

The Virginia Supreme Court Presumes That SCC Orders Are Correct

Respondents involved in a transmission line case before the SCC have the right to appeal final orders issued by the commissioners to the Supreme Court of Virginia. The Court has indicated that it will not review the facts of a transmission line case but will only consider whether the commissioners made an error in the application of the law. As noted by the Court in an unpublished decision from November 2005 that involved a transmission line in Loudoun County,

> The Commission's findings are regarded by this Court as prima facie just, reasonable, and correct and will not be disturbed in the absence of a showing of abuse of discretion. . . Therefore, we will not reverse the Commission's findings unless they are based on inherently incredible evidence or a mistake of law or are unsupported by the evidence.

Indeed, in a 1976 case the Court held that the SCC order did not fail to comply with the statutory mandate to furnish a statement of reasons for its action even though "the opinion is nonspecific and inadequately documented in many respects, and is lacking in the detail and quality ordinarily observed in Commission opinions" because the Court was able to "ascertain, albeit with some difficulty, the evidentiary basis" for the order (APCO v. Commonwealth, 216 Va. 617).

Chapter 5

Reliability Concerns Affect Reviews of Underground Lines

In Summary

While utilities generally propose new transmission facilities to meet growing demand for electricity, system reliability may also be a major factor. Projects may be undertaken to improve the overall reliability of the electrical grid and to strengthen ties with neighboring utility regions. In addition to system-wide concerns, the reliability of a particular type of line for delivering power can be an issue. Experts and the literature in the power field indicate that both overhead and underground lines have advantages and disadvantages in terms of reliability and both types can be operated reliably. However, the SCC appears to be most persuaded in cases by Dominion arguments that in addition to the cost issue, overhead lines are preferable to underground lines because of the reliability issue. Dominion's concerns include the potential for damage from excavation ("dig-ins"), the length of repair times for underground lines, and operational issues.

The need for new transmission lines is closely related to service reliability factors. The need to provide a reliable source of electricity is emphasized in Section 56-234, which requires all public utilities operating in Virginia to "furnish reasonably adequate service and facilities." In addition, the reliability of the type of line—overhead or underground—that is proposed for a project can be an issue. Specifically, SCC staff and Dominion argue that underground lines are inherently less reliable than overhead lines and that they also impose operational constraints on the overall transmission network. Further, when considering the types of underground lines that could be used, SCC staff and Dominion state their preference for the more established but costlier HPFF technology, maintaining that the newer and less expensive XLPE cables are problematic.

SOME TRANSMISSION LINES ARE BUILT TO ENSURE THE RELIABILITY OF A UTILITY'S GRID

Utilities use defined standards to determine if reliability considerations require a new transmission line. The most prominent organization that issues reliability standards is the North American Electric Reliability Council (NERC), which seeks to maintain a reliable, adequate, and secure U.S. transmission system. Toward that end, NERC has developed mandatory voltage and temperature limits that are used by electric utilities to determine when new transmission lines are needed. NERC has been granted au-

Peak Electricity Use Occurs for Only a Few Hours Per Year

The 100 hours with the highest electricity usage per year account for two percent of the total consumption of electricity all year. These 100 hours also account for 16 percent of the total variation between lowest and highest hourly usage.

thority by the Federal Energy Regulatory Commission (FERC) to levy monetary fines for violations of NERC reliability standards.

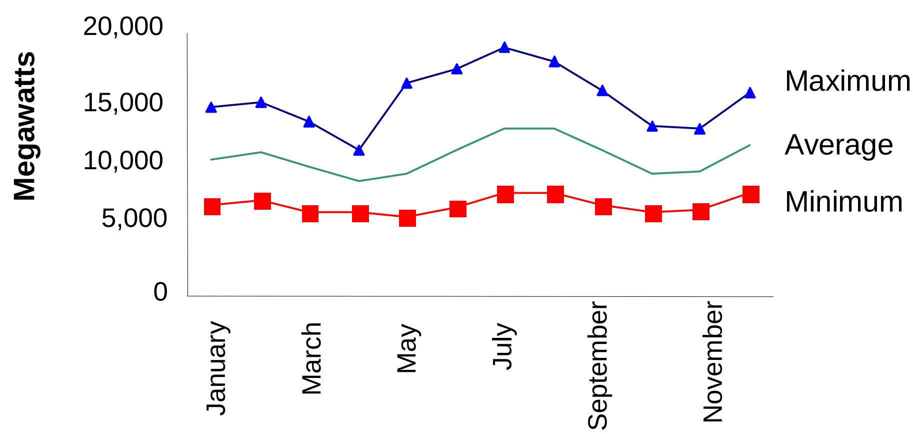
Utilities Plan for Peak Demands and Contingencies

A new transmission line may be needed to address overloading associated with unusually hot summer days when the demand for energy increases substantially, and lines may also be more prone to reaching their thermal limits. As indicated in Figure 5, electricity use over a 12-month period varies considerably. Electricity usage also varies over a 24-hour period, with the highest loads in Dominion's territory occurring between 1:00 and 7:00 P.M.

Many of Dominion's recent transmission lines have been proposed to meet increases in electricity demand in the "Northern Piedmont" region of Virginia, which Dominion defines as the Counties of Arlington, Caroline, Culpeper, Fairfax, Fauquier, Fluvanna, Goochland, Hanover, Henrico, Loudoun, Louisa, King George, Orange, Prince William, Spotsylvania and Stafford, plus the City of Alexandria. The size of this area indicates that transmission line projects are built in many cases because of demands placed upon the system by many localities.

Many of the localities in the Northern Piedmont region—areas where recent transmission lines have been proposed—are projected to grow much more slowly than other parts of the State. As

Figure 5: Electricity Use Varies By Month Within Dominion's Service Territory



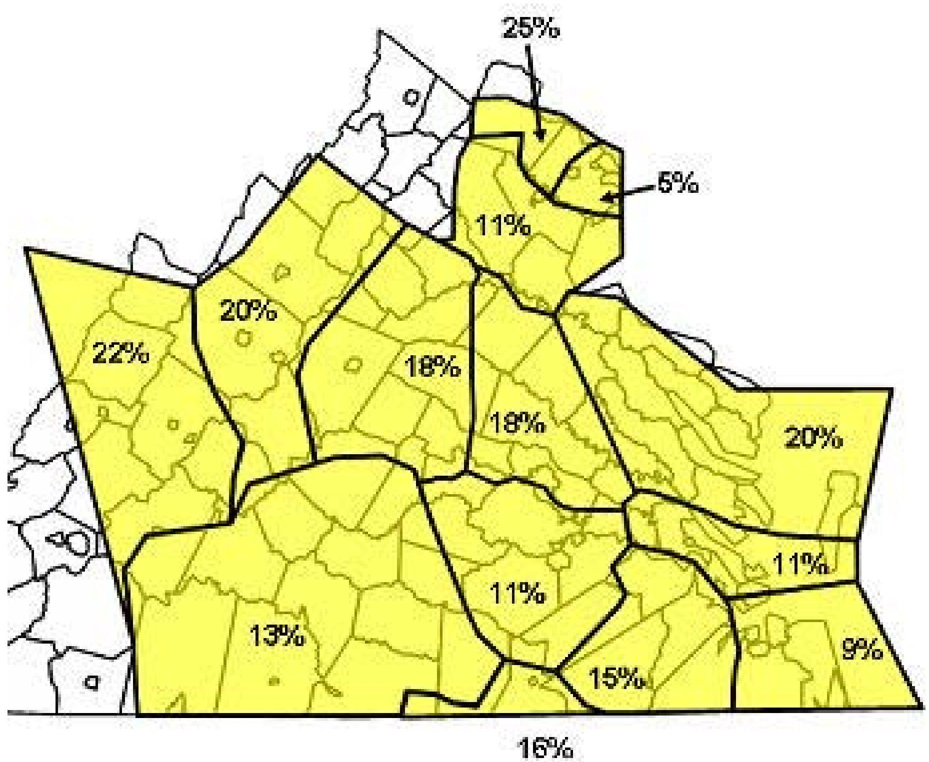
Source: JLARC staff analysis of Dominion peak load data posted by PJM.

indicated in Figure 6, between 2006 and 2015 the largest percentage growth in summer peak loads will be in Loudoun County and western Fairfax County, as well as in the Shenandoah Valley. Peak loads will increase in these areas by more than 20 percent over that time. In contrast, peak loads are projected to grow by eleven to fifteen percent in Fauquier, Stafford, and Prince William Counties. In eastern Fairfax County, Arlington County, and Alexandria, peak loads will grow by only five percent by 2015.

A transmission system must also be able to withstand power failures caused by storms, fallen tree limbs, or other unanticipated events. When a line is affected by these events or has reached its voltage or thermal limits this event is referred to as a "contingency."

In some cases, the loss of a transmission line may force one or more remaining lines to exceed their thermal or voltage limits. During the summer of 2006, some 500 kV lines in Virginia reached the limits of safe operation. For example, line 569A from Morrisville (Fauquier) to Loudoun (Loudoun), and line 575A from Lady-

Figure 6: Percentage Growth in Electricity Usage by 2015 Is Projected to Vary Among Dominion's Planning Regions



Source: JLARC staff analysis of projected summer peak load data from 2006 to 2015 provided by Dominion.

smith (Hanover) to North Anna Generating Station (Louisa) both acted as constraints on several dates in July and August. This required Dominion to shift power flows to other lines, and may result in system upgrades in future years. These upgrades could occur to these lines, or to other parts of the system.

Building Additional Transmission Lines Is a Common Solution to Reliability Concerns

NERC reliability standards guide long-range plans by requiring utilities to design their grid to operate within certain limits if one or more components of the transmission system were to fail. Contingency studies, which look at how power flows on the system after components fail, designate the failure of a single component as an N-1 event (such as when one transmission circuit is forced out of service at the same time that the largest local generator is unavailable). A double-contingency event occurs when two transmission circuits are forced out of service at the same time.

NERC standards also help explain why underground lines are built with two circuits (or a spare cable) while overhead lines generally consist of a single circuit. A second circuit allows an underground line to remain operational if problems occur with one set of cables: an N-1 event.

An additional factor, one that is distinct from reliability, is *congestion.* This term refers to the extent to which the cost of electricity varies from region to region, in part because voltage or thermal limits on existing lines prevent the transmission system from delivering the least-cost electricity to all parts of the system.

It is also important to note that in many cases, a new transmission line may be designed to improve both the local distribution network and the utility's overall transmission network. Table 8 gives examples of how some recent transmission lines have been designed to meet both distribution and transmission needs.

SCC Guidelines Request Information on Need. A review of recent transmission line cases before the SCC indicates that applications for new lines routinely address the need for a proposed project. Electric utilities have established the need for new transmission facilities by using

- past and projected increases in load for regions, localities, and individual lines, including comparisons to State or regional averages,
- NERC reliability standards, and

Table 8: Some Recent Lines Are Designed to Meet Both Distribution and Transmission Needs

Transmission Line and Case Number	Transmission and Distribution Needs Indicated by Utility
Virginia Beach (2006-00040)	New 230 kV line provides additional bulk power to the area. New 230-34.5 kV substation allows for an additional distribution circuit, reducing the length and improving the reliability of an existing circuit.
Bristers-Gainesville (2006-00048)	New 230 kV line keeps Dominion's transmission system in compliance with NERC reliability standards. Line also allows Dominion and NOVEC to build new substations to support their distribution networks.
Stafford (2006-00091)	Transmission line and substation address overloads on local distribution lines and transformers. Circuit breaker and ring bus support development of 230 kV transmission system.
Pleasant View-Hamilton (2005-00018)	New 230 kV line and 230-34.5 kV substation relieve overloading on Purcellville distribution system and strengthen the transmission system by laying the foundation for a future network configuration in western Loudoun County.

Source: JLARC analysis of transmission line applications filed with the SCC since 1972.

- the statutory requirement that utilities must provide reliable and adequate electric service.

NERC Reliability Criteria Appear Especially Important During SCC Review of a Proposed Line. The commissioners have approved at least three recent transmission lines designed to maintain compliance with NERC reliability standards. For example, in a 2004 application for a new 500 kV line in southern Fauquier County, Dominion asserted that the new line was needed to meet NERC standards and the growing demand for electricity in the northern part of the State (2004-00062). The application detailed seven scenarios in which the loss of a transmission line or generation source in the region would cause one or more remaining lines to exceed their thermal limits. The commissioners have also cited these standards in approving several 230 kV lines in Loudoun County and the Chesapeake region.

The commissioners may accord NERC reliability standards substantial weight because they were designed to ensure the reliability of the overall transmission system. The northeastern blackout of 2003 underscored the interdependent nature of the transmission system and the potential for outages to cascade across multiple transmission regions.

EXPERT OPINIONS VARY AS TO THE RELIABILITY OF UNDERGROUND COMPARED TO OVERHEAD LINES

The term “reliability” has been used by Dominion and other experts to include at least five different factors:

- frequency of power outages,
- length of time for line repairs,
- overall availability of the line for use,
- length of customer service interruption, and
- long-term durability of the line.

SCC staff and Dominion maintain that underground lines are not reliable, citing several of these factors. In contrast, other experts interviewed by JLARC staff, as well as expert opinions in the literature, indicate that the reliability of underground lines compares favorably with overhead lines. One area of agreement is clear, however: underground lines typically take longer to repair.

Frequency of Power Outages: Underground Lines Appear to Have an Advantage Over Overhead Lines

In general, distribution lines are more likely to experience an outage than transmission lines. One power company indicates that transmission outages only account for about two percent of the annual number of customer interruptions. According to Triangle Power Systems Consulting, ten-year electricity service interruption data indicate that only about 12 percent of the hours that customers are without service are due to transmission line problems.

The American Transmission Company states that “failures in underground transmission lines are infrequent.” Underground cables are rarely impacted by storm damage. Although overhead transmission lines are exposed to the elements, even these lines are infrequently the cause of power outages, in part because of their physical design. High-voltage transmission, poles or towers are designed to withstand higher wind speeds, and the height of the poles makes them less vulnerable to falling trees. Although storm damage can remove an overhead line from service by damaging overhead transmission towers, if the line is networked then electricity service may not be interrupted.

Dominion staff indicate that overhead transmission line structures have failed ten or fewer times in the past 20 years. The failure of a 230 kV line north of Hopewell in September 2006 illustrates an extreme example of this kind of situation (Figure 7). This line, which

Figure 7: Overhead 230 kV Line in Chesterfield County Damaged By Wind Storm in 2006

Source: JLARC staff photograph of 230 kV transmission tower north of Hopewell, Virginia, in September 2006.

was suspended on 250-foot tall towers, fell into the Appomattox River due to high winds. Other examples offered by Dominion include damage caused to towers from being struck by a train or heavy equipment, and winds from a tornado. In the latter example, four wooden towers on a 115 kV line in Shenandoah County were damaged by a tornado on April 28, 2002, at 5:07 pm. New steel structures were installed and power restored on April 30th at 8:18 pm.

Indeed, it appears that the vast majority of overhead lines that fail are at the distribution level in neighborhoods, and underground transmission lines would not address these failures. In addition, it does not appear that a single underground transmission line would provide greater reliability in the case of weather-related incidents or sabotage. For example, if a new substation were served by an underground line, but an overhead line connected the underground line to a generating station, then a failure on the overhead line could cause the underground line to lose power as well.

Industry Reports Indicate that Underground Lines Are Less Vulnerable To Forced Outages. Dominion staff have testified that "outages of transmission lines, both overhead and underground, are not common" (2005-00018). However, underground lines appear to have some advantage in this aspect of reliability, as they are less vulnerable than overhead lines to forced outages. For example, a May 2005 report by a power industry consultant indicates that the outage rate for 225 kV XLPE cable "compares favorably with typical forced outage rates for overhead lines." The figure given for

XLPE in the report is a rate of 0.1 failures per 100 miles per year. The report compares this rate to a rate of about one forced outage per 100 miles per year for overhead lines, or a failure rate ten times greater.

The 2005 report, developed by an expert with Power Delivery Consultants, was received by Dominion and provided to JLARC staff during the review. It calls the source of the cited XLPE outage rate data "one of the most comprehensive documents concerning the reliability" of 225 kV XLPE, noting that the data are "in a technical publication prepared by engineers employed by Electricite of France (EDF)." The report states that this publication "is particularly relevant because EDF is one of the major users of this technology and has the longest operating history."

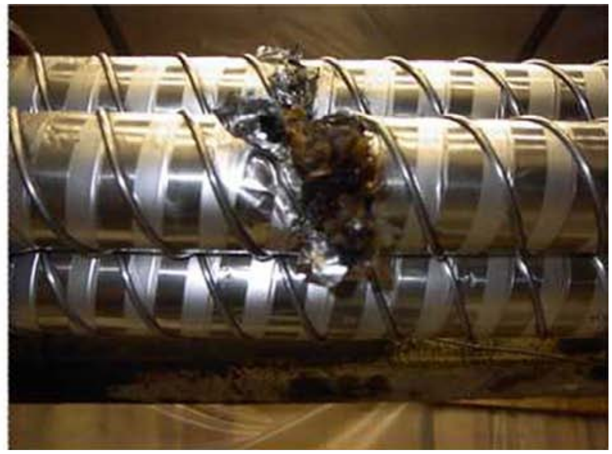
While the data cited in the report reflected 20 years of operating experience with XLPE, the data may actually understate the potential level of performance of XLPE today. That is because the data were published in 1990, and XLPE technology has made some improvements since that time.

Outage Concerns Arise In Part from the Possibility of a "Dig-In." One specific issue that surrounds the frequency of power outages is the extent to which damage from excavation ("dig-ins") may compromise underground lines. The report of the Power Delivery Consultants expert explains dig-ins as "a result of the excavation contractors that do not take the time to coordinate with utilities or that do not observe or respect warning signs." While dig-ins are considered more likely for underground distribution lines than for underground transmission lines, the possibility of dig-ins is sometimes cited as an argument against the use of undergrounding.

Underground lines that are encased in concrete, a common practice in the United States, have some protection from dig-ins. While it is possible that the concrete can be broken up with repeated blows by an excavator, dig-ins of transmission lines that are so protected seem to be regarded as low probability but not impossible events. Dominion staff informed JLARC staff that the use of a four-inch protective concrete slab (used on part of one underground line in Arlington) would not be sufficient to resist a pile-driver, the cause of a 2004 dig-in in Alexandria (Figure 8). However, Dominion staff have testified that XLPE "cables are protected from dig-ins with heavy concrete slabs in the trench above the cables, and they are identified with marker tapes" (2002-00702).

Figure 8: "Dig-In" of a 230 kV HPFF Transmission Line in Alexandria (2004)

Fluid Leak After Pile Driver Struck Cable



Damaged Insulation on Same Cable

Source: Dominion.

Length of Time for Repairs: Underground Lines Take Longer to Repair than Overhead Lines

There is a consensus that overhead lines can be repaired more quickly than underground lines. Comments by a New England power company official summarize the reasons for this:

> It is relatively easy to locate and repair the problem in an overhead line, all of which can generally be accomplished in a day or two. It may take many days to locate the break in an underground cable, since it is buried and inaccessible, and the repair itself, which may require splicing of cables, is also more complicated and time-consuming.

Experts differ as to the difficulty of locating the fault in a underground line. While some indicate that finding the fault can take days, others indicate that there are state-of-the-art pinpointing devices that "will find faults in less time and with less risk of damaging good cable than classical techniques." It has been asserted that through advanced techniques, about 95 percent of the time, cable analysis can get a power company within 10 to 20 feet of the fault in the line. This enables further efforts to pinpoint the fault within a small section of the line. However, experts generally agree that overhead lines typically take less time to repair.

Table 9, for example, shows the length of time for repairs that is reported by various sources. Generally, the time spent to accomplish repairs is reported to be hours or about a day for overhead lines, but five to ten or even 20 days for underground lines. There is a reported difference in the time period for repairs between XLPE and the HPFF lines favored by Dominion, which are said to take months to repair, compared to about five to ten days for XLPE. For either type of cable, however, it has been typical practice in Virginia to place these lines alongside or underneath roadways. As a result, repairs to underground lines will frequently require excavation activities in streets, which can potentially increase the time it takes to access a fault and also disrupt traffic.

Table 9: Length of Time for Overhead and Underground Line Repairs

Source	Overhead	Underground Generally	XLPE	HPGF[1]	HPFF
Booth and Associates	Typical: 1/2 to 1 day Catastrophic: Upwards of one week	Typical: Within one week Catastrophic: Up to two weeks	--	--	--
Burns and McDonnell	A few hours to several days	--	5 to 9 days	8 to 12 days	2 to 9 months
Cooperative Research Network	A few hours to several days	--	5 to 9 days	8 to 12 days	2 to 9 months
Dominion / JLARC staff	Hopewell line, 2006: 31 days[2]	Jefferson Street Glebe line: 36 days	--	--	--
Hydro Quebec	Minor repair: 1 day Major repair: 7 days	Minor repair: 5 days Major repair: Up to 20 days	--	--	--
Orton Consulting Engineers Int’l	One day	7 to 10 days	--	--	--
National Grid	Typical: 1 to 2 days	Typical: 12.5 days	--	--	--
Power Delivery Consultants, Cooper	4.4 hours average forced outage repair time	7.9 days average forced outage repair time	--	--	--
Williams	--	Direct buried lines: Can be more than one month	--	--	--
Wisconsin	--	--	5 to 9 days	8 to 12 days	2 to 9 months

[1] High Pressure Gas Filled.
[2] According to Dominion staff, one circuit was restored in five days, and the second circuit was restored 14 days later. It took a total of 31 days to restore the towers and conductors to pre-event condition.

Source: JLARC staff review of sources on electric transmission.

Availability for Use: Overhead Lines May Rate Somewhat Better, But Both Types Rate Well

The availability of a transmission line for use is a function of the frequency with which the line is out-of-service and the time that it takes to repair the line. As previously noted, a May 2005 report by a consultant for Power Delivery Consultants indicated that underground XLPE lines have a substantial advantage over overhead lines in terms of the frequency of line failure, but overhead lines have a substantial advantage in the length of time required to repair the line. Overall, the report states that the "availability" for overhead lines is 99.9 percent of the time, which is "slightly better" than the 99.8 percent rating for 230 kV underground XLPE. Thus, both overhead and underground applications have high availability ratings at 230 kV.

Length of Customer Service Interruption: Utilities Can Limit Interruptions for Both Overhead and Underground Lines

The length of time that an overhead or a underground line is out of service is not necessarily equal to the length of time during which customers are without power. In fact, the previously referenced May 2005 report by Power Delivery Consultants asserts that "transmission cable system failures rarely cause loss of electrical service to the utility's customers." The length of customer service interruption is likely to be less—and in the case of underground transmission, possibly far less—than the length of time it takes to repair the line.

System Design Enhances Reliability of Underground Lines. Utilities almost always design transmission systems so that the loss of any single circuit or line has no negative effects upon customers. If the overhead or underground line is part of a networked or looped configuration, power can be rerouted to flow to customers from a different direction.

Because of NERC standards, underground lines in Virginia generally have been built with two circuits (instead of the single circuit typically present in overhead lines) in order to provide backup capacity in case of operational or maintenance problems. This increases the cost of an underground line relative to an overhead line. Three examples of this type of configuration exist in Arlington County: Braddock-Annandale (1983-00059), Glen Carlyn-Clarendon (1982-00075), and Crystal-Glebe. In addition, an underground line in Fairfax County, Burke-Sideburn (1986-00019), is in the middle of a "loop" that extends from the Bull Run substation to the Ravensworth substation. In the event of a failure along the underground portion between Burke and Sideburn, these two substations would still be powered by overhead lines.

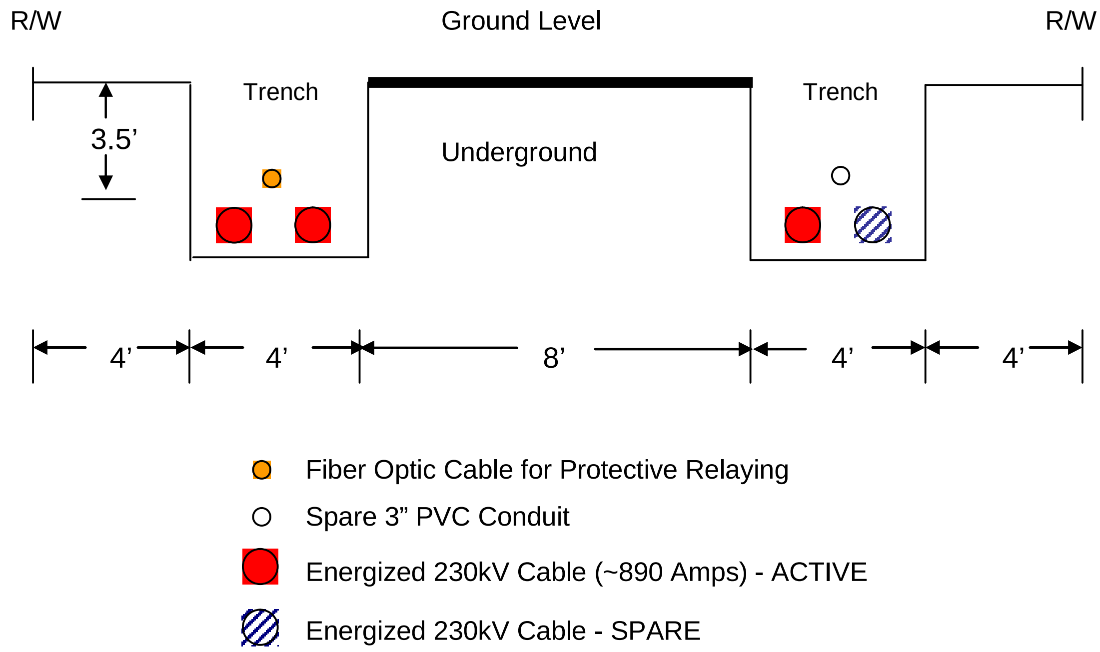
Dominion Expresses Concern Regarding the Ability to Restore Power to Underground Lines. One problem that Dominion associates with underground transmission lines is the ability to restore power by "reclosing" circuit breakers after a fault occurs. When a fault occurs on an overhead transmission line, the line may not have been damaged and can be restored to service immediately. For example, if a tree limb brushes against a line and is detected by line sensors, this "fault" may last for just a few seconds and then the situation returns to normal. During these few seconds, circuit breakers open to protect the line but then automatically "reclose" immediately. Dominion indicates that this can be done safely on an overhead line because a fault event (like the tree limb) is usually a temporary condition and does not usually do significant damage. However, Dominion does not allow automatic reclosing on underground transmission lines because the faults they are prone to (such as dig-ins) have likely damaged the cable and its insulation. Therefore, were power automatically restored then more extensive damage could be done.

As a result, when a fault occurs on an underground transmission line, Dominion keeps the line out of service until tests can be performed to determine the cause of the fault and ascertain the extent of damage to the cable. Dominion states that while automatic reclosing may not have caused damage, there is no way to determine this without performing tests that typically take several days to complete. As a result, on a radial line Dominion would need to open the circuit breaker until the fault was determined and in the meantime service would be discontinued. As a result, in testimony for the Pleasant View-Hamilton line, Dominion stated that "underground circuits therefore preclude the possibility of regaining service to customers for *any* disturbances." (2005-00018).

Spare Cables Can Also Enhance Reliability. Although reclosure may be a concern, underground projects can be designed so that power delivery is not dependent upon one cable alone. Power can be transmitted through a secondary or spare cable (Figure 9). For example, in estimating costs for JCOTS for a five-mile 230 kV line (see Chapter 3 of this report), Dominion included the use of a spare cable that could be used in the event of the failure of another cable. While the inclusion of this spare cable increased Dominion's cost estimate, Dominion staff stated that with this spare cable it could re-establish power for customers served by the underground line within just one day.

The approach of using a redundant or spare cable in an underground project appears to provide a reasonable safety net for the provision of power to customers. The report by Power Delivery Consultants indicates that a fault in one cable is not likely to cause a fault in the second:

Figure 9: Example of Underground 230 kV HPFF Line With Spare Cable (1,035 MVA)



Source: Dominion Virginia Power.

> Cable faults rarely cause damage to other cables of the same circuit or a parallel circuit. With the possible exception of cables that are directly buried and touching, the concrete or earth between cables protects them during faults. A typical ductbank has a quarter-inch thickness of PVC duct plus three inches of high-strength concrete surrounding each cable.

Of course, if an external event, such as a dig-in, were to damage all of the cables, then the repair times could become more extensive. In addition, if a transmission line that malfunctions is the sole supplier of power to some customers, power companies may expedite the repairs to an extent that is not reflected in typical repair times. For example, one expert testified in a Rhode Island transmission line proceeding that because of the urgency of transmission line repairs, most underground line repairs are handled within one week rather than the 12.5 days which another expert had suggested was typical.

Long-Term Durability: There Is Some Concern About XLPE’s Life, But Trend Is Toward XLPE

Dominion staff indicate in their cost analyses that its OH lines can be expected to last 70 years. In these analyses, Dominion staff assume the same long life for HPFF. However, for XLPE cable, Dominion assumes a life of 35 years. A key argument used by Dominion staff in favoring HPFF over XLPE is that HPFF has a long track record of proven reliability, while the long-term durability of XLPE is not well-established.

Statements by other sources in the power industry indicate that Dominion's expectations or assumptions regarding the life of overhead lines and HPFF lines may be reasonable. For example, a document of the Public Service Commission of Wisconsin states that overhead lines in the northern part of that state are assumed for accounting purposes to last about 32 years, but the lines have actually been lasting about twice as long. The Georgia Transmission Company states that "overhead cable easily can last 70 years." Several sources indicate that HPFF lines have lasted 50 years and more.

Regarding XLPE, national and international experts share the same potential concern expressed by Dominion about the long-term reliability or durability of XLPE. For example,

- PJM (the regional transmission organization) has design and application technical requirements which state that "Underground transmission lines 230 kV and above should generally be pipe type [HPFF]. Pipe type systems are preferred due to their extremely high reliability. Solid dielectric cables and self-contained fluid-filled cables may also be used. Solid dielectric cable may be preferred over pipe type for circuit lengths under 600m, and for circuits 138 kV and below."
- According to a recent European consulting group report on undergrounding, a major power company expressed the view that it would prefer to use fluid-filled cable if a proposed project was to be underground, in part due to the "relative immaturity of XLPE technology."
- The same consulting report quoted the following from another cable consulting firm: "History has taught us that the success of a new type of high-voltage cable is not secure until at least 20 years of service experience is at hand." The report goes on to conclude that "there is likely to remain a question mark over the reliability of XLPE-insulated cables which will only be removed as successful operating experience grows. The uncertainty relates not only to the cable but also the performance of the jointing and terminating systems."
- A 2006 briefing package on underground transmission, prepared by a field staff member of the electric program of the United States Department of Agriculture's Rural Development program, notes that "useful life questions" regarding XLPE "are more unknown compared with previous systems."

On the other hand, a power company engineering expert in undergrounding contacted by JLARC staff indicated a general comfort level with the durability of XLPE, noting that the design life of XLPE and HPFF is the same (40 years). A second power company engineering expert from another state also noted the XLPE design life of 40 years and expressed confidence that it would last longer.

In addition, the issue of long-term durability has not prevented an apparent rise in the use of XLPE in the United States at higher voltages. An underground cable expert with a company which manufactures XLPE stated to JLARC staff that since 2003, XLPE has become "the default technology" in the United States at 230 kV. The next step for XLPE, he indicated, is 345 kV. Until recently, he said, XLPE was only used in three power plant-related, short hookups at that voltage.

However, there are now several major 345 kV projects in the United States, including projects of Northeast Utilities in Connecticut and Com Edison in Chicago, and a project on Long Island. (In Connecticut, a 345 kV project with 10 miles of HPFF and two miles of XLPE was just energized in October 2006). The success of these cables may influence perceptions in the United States of XLPE's use at voltages above 230 kV. Internationally, the use of XLPE at 345 kV is not particularly unusual. For example, XLPE is being used at 380 and 400 kV in Europe and at 500 kV in China and Japan.

A 2005 report by the consulting firm KEMA presented findings from a short survey of literature from "three major recent conferences on EHV power cables." According to the report,

> Most countries agreed that due to maintenance problems with fluid-filled cables they were adopting XLPE. They agreed that overall there are very few problems relative to the performance of new XLPE cables but some very significant concerns by a number of countries in regards to the remaining life and performance of early XLPE cables. . . . Reliable data over a long period of application is not available [for XLPE], such cables are too short in service, with most projects realized in the last 10 years.

In sum, despite lingering concerns for some experts about its lifespan, there appears to be a trend to the greater use of XLPE. This type of cable is generally less expensive to install, has additional advantages, and is approaching the same design life as HPFF.

SCC HAS CITED OPERATIONAL AND RELIABILITY CONCERNS IN REJECTING UNDERGROUNDING

Reliability considerations have played an important role in the review of underground lines by the SCC. In 1990, the commissioners noted the operating and maintenance problems experienced by Dominion resulting from a 230 kV line that contained overhead and underground components (1988-00071). In 2004, the commissioners cited reliability concerns raised by Dominion in rejecting a recommendation by the hearing examiner to place underground part of a proposed 230 kV line in Loudoun County (2002-00702).

SCC staff have also identified operational concerns associated with underground transmission lines. In a 2001 report analyzing an underground proposal in eastern Loudoun County, staff concluded that burying part of the line would cause substantial power flow imbalances in nearby transmission lines. Load along the underground line would increase 15 percent while falling by 13 percent on a nearby overhead corridor. These imbalances would intensify in the event of an outage in the transmission system (2001-00154). Imbalances could apply both to the existing network and to the future network after planned transmission line expansions are installed. The hearing examiner noted these concerns in rejecting consideration of undergrounding in this case.

These concerns are not unique to Dominion and SCC staff. The director of an ongoing 345 kV undergrounding project in Connecticut undertaken by Northeast Utilities told JLARC staff that non-regular equipment may be needed to offset the effects an underground line has on a network, especially when HPFF is used or there are long runs of underground cable. She added that this equipment should be considered during project planning. This statement reflects an aspect of Virginia's process that affects transmission line cases: when a utility does not propose an underground line, it is up to other participants in the case to be aware of how the line could affect the overall transmission grid and what compensating equipment will be needed.

Operational Concerns Result From Both the Characteristics of the Line and Its Location

Underground lines differ from overhead lines in two key areas that affect their operation and the cost of their installation. Although techniques and equipment appear to be available to address these concerns, their use adds cost and may decrease system reliability.

Underground Lines Must Contend With Voltage Issues. Underground lines have a higher capacitance than overhead lines, and this affects system operation. Capacitance refers to the ability of a conductor (a cable or wire) to store an electric charge. As this charge increases, the voltage on the cable increases and requires corrective measures. There appear to be at least two types of corrective measures used by Dominion: adding electrical components that will offset the capacitance (shunt reactors, Static VAR Compensators, and phase shifting transformers) or by switching the line out of service. Dominion has testified that it has to regularly switch out an underground line in Alexandria, but because that line is networked, power is not interrupted. In a radial configuration, switching a line out of service is not an option because doing so would interrupt power (2005-00018).

On the radial underground lines that Dominion operates in Northern Virginia, two parallel circuits are in operation. This redundancy assists with reliability concerns but also appears to create operational concerns. Dominion has noted these concerns in testimony in response to a proposed underground line from Pleasant View to Hamilton in Loudoun County that would have two parallel circuits (2005-00018). As noted by Dominion staff, "paralleling underground cables (which has been suggested as a means of adding incremental additional circuit capacity) makes the problem of voltage rise worse." Advocates of the underground option in the Pleasant View to Hamilton case also suggested that the presence of parallel cables would allow for one circuit to be switched off, thus addressing the voltage issue. In response, Dominion staff testified that "switching cables on and off repeatedly is not a reasonable solution. Switching-induced transient over voltages are hard on both the cables and the switching equipment. In addition, if cables are switched off, the full capacity of the circuit is no longer available."

As a result, in a radial configuration Dominion must use the electrical components noted above and this adds both cost and reliability concerns. A consultant retained by Dominion in the Pleasant View to Hamilton case (KEMA) estimated that the most cost-effective means of compensating the voltage rise would be the installation of a shunt reactor, at a cost of about $3 million. KEMA added that "with the appropriate compensation, all voltages can be returned to an acceptable level." KEMA observed that "HPFF cables would require higher compensation than XLPE cables, due to their inherently higher capacitance levels." The addition of a shunt reactor may create additional reliability problems, because it is an additional component that might fail and thus violate NERC contingency standards. Yet Dominion has plans to add additional reactors in Northern Virginia in 2008, in order to reduce the need to switch out the underground line in Alexandria.

Underground Networked Lines Can Create Power Flow Problems. In a network configuration, the lower resistance of an underground line results in imbalances in power flows. This is not a concern in radial lines because power cannot flow to another transmission line. The presence of power flow imbalances requires compensation, and this can add to the cost and complexity of a project.

Imbalances in power flows occur when there are differences in the characteristics of the conductors in different circuits. Because power will take the path of least resistance, if an overhead and an underground line are both connected to the same point, more power will flow along the underground line. This is because underground lines have less resistance to power flow. (Underground lines are made of copper, have a wider cross-section, and often have more than one circuit connecting two points.) These imbalances, and the higher capacitance of an underground line, can affect the entire system.

Dominion staff have testified that these imbalances create sufficient operational concerns that the use of undergrounding is not preferred. However, techniques appear to be available to address this issue, although this may increase the cost of a project. For example, Dominion's Long Range Plan indicates that it may be able to respond to overloads on overhead lines by making adjustments to power flows. (This is accomplished by using phase shifting transformers.) The plan notes that phase-shifting, as a means of directing power flows, was done successfully in 2000 to protect an overhead line. However, if a phase-shifting transformer had to be added as part of an underground line, this would likely increase the project cost and create reliability concerns.

Dominion Plans Overhead Transmission Line Projects in Order to Offset Reliability Concerns on Underground Lines. Dominion's Long Range Plan includes two projects in which improvements will be made to overhead lines to compensate for potential violations of NERC reliability standards caused by underground lines. The plan also includes a new underground line project to further insulate the system from the potential reliability problems created by existing underground lines.

To illustrate the type of project Dominion anticipates needing to undertake, the plan indicates a need to upgrade an existing 230 kV overhead line in Arlington County in 2008. This upgrade is required because "an outage on one underground cable could force the failed [underground] circuit to be out for repairs for a six-week period." If this occurs, the overhead line will be overloaded.

Overhead lines may also be subject to this same condition. Dominion's plan also includes upgrades to overhead lines because of other overhead transmission line projects. As illustrated in one recent case, the addition of a new 230 kV line will cause load flows in the surrounding transmission circuits to be redistributed (2006-

00048). On one nearby line, the increased power flows would, under peak load conditions, exceed the capacity of the conductor. Hence, Dominion included the cost of upgrading this nearby line in the cost of the new 230 kV line for which it sought approval.

This inclusion of this cost illustrates the need to include the cost of addressing potential reliability problems—whether associated with underground or overhead lines—in the total estimated cost of a project.

The SCC and Dominion Are Hesitant to Adopt XLPE

In two recent transmission line cases in Loudoun County, opponents of the overhead line have argued in favor of using XLPE. Dominion has always used HPFF, which has a longer track record but is also more expensive than XLPE. Both SCC staff and Dominion appear to place a premium on using proven technology, which may reflect a desire to ensure the highest degree of reliability rather than an intent to not embrace new technologies.

Dominion's testimony from cases since 2003 indicates the company's concerns with XLPE and the desire to continue using HPFF. Dominion witnesses testified that HPFF has "thousands of circuit-mile-years of experience in the United States and is well suited for installation in a variety of environments." In contrast, Dominion does not want to use XLPE because "performance and reliability have not been as good as required for 230 kV lines." Dominion has stated that given the "limited historical operating record for 230 kV XLPE cables, it is very difficult to have the confidence to call this a mature technology." Dominion also noted that there have been quality control issues, and that there is only one domestic supplier of XLPE cables (2002-00702). Dominion staff have reiterated these concerns to JLARC staff.

SCC staff have agreed with these concerns. In testimony from 2006, SCC staff have noted their concern with "directing the Company to employ an unfamiliar technology for an application with which there is a lack of a significant track record" (2005-00018). SCC staff also testified in 2003 that they view Dominion's policy of adhering exclusively to HPFF, "a mature technology that it has working experience with, to be very prudent." Hence, SCC staff argue that "any discussion of underground 230 kV on the Virginia Power system ought to be restricted to a discussion of using oil-filled cable" (2002-00702).

Contrary to the opinions of SCC staff and Dominion's witnesses, the hearing examiner in one of the recent Loudoun County cases recommended that a portion of the proposed line be placed underground. Protestants favored an underground line using XLPE and the hearing examiner concluded that

> Underground installation would appear very feasible based on the record here. With 29 miles of 230 kV line underground, the Company clearly has the experience and capability to install and operate a small portion of this 230 kV line underground (2002-00702).

However, Dominion took issue with this conclusion, noting in its response to the hearing examiner's call for undergrounding: "Whether it is simply 'possible' to build a project has never been a standard adopted by the Commission." In the final order, the commissioners cited reliability concerns were given as one of the reasons for not using an underground line: "In the instant case, Dominion has established that there are sufficient reliability concerns to reject underground installation of a portion of the new line."

Chapter 6 Environmental, Health, and Historic Resource Concerns

In Summary

Environmental impact is an important part of most transmission line proceedings before the SCC. The *Code of Virginia* requires the commission to minimize the adverse impacts of transmission lines, and utilities must address potential impacts in their initial application. Although underground construction has been promoted as the preferred way to preserve natural and historic resources and protect individuals from the potential health effects of electromagnetic fields (EMF), with one exception the commission has consistently rejected underground construction as a means to addressing environmental concerns. Undergrounding has been approved in those circumstances where a viable overhead route did not exist, which may be viewed as a recognition of the environmental consequences of the demolition necessary to obtain an overhead route. Instead, the commissioners generally have ordered steps short of undergrounding to address environmental concerns. These steps have included the use of existing rights-of-way, transmission line routes that avoid residential areas, design changes that reduce the visual impact of overhead structures, and State environmental reviews to identify sensitive historic or natural resources.

A common concern during transmission line cases is the potential negative impact of a line on the surrounding environment. Under the Utility Facilities Act, environmental impacts are broadly defined to include the natural and historic resources of the Commonwealth as well as health and safety considerations. Considerable time during transmission line proceedings may be devoted to determining these impacts and identifying reasonable mitigation measures. Opponents of overhead transmission lines often argue that the utility should undertake additional steps to address these impacts. Underground construction has often been promoted as the preferred way to minimize these impacts, but has never been ordered in response.

CONSTITUTIONAL AND STATUTORY PROVISIONS EMPHASIZE ENVIRONMENTAL PROTECTION

The *Code of Virginia* gives environmental impact an important role in SCC reviews of proposed transmission lines. The Utility Facilities Act (Section 56-265.2) states, “The certificate for overhead electrical transmission lines of 150 kilovolts or more shall be issued by the Commission only after compliance with the provisions of § 56-46.1.” Section 56-46.1 (A) requires the commissioners to “give consideration to the effect of [transmission facilities] on the environment and establish such conditions as may be desirable or necessary to minimize adverse environmental impact."

The commissioners interpreted this requirement in their 1972 memo, stating that SCC approval "is conditioned on the Commission's determination that the route the line is to follow will reasonably minimize adverse impact on the scenic, environmental and historic assets of the area concerned."

Statute Places Duty Upon SCC to Minimize Environmental Impact

Section 56-46.1 has been interpreted by the Supreme Court of Virginia to place a duty upon the commission to minimize the environmental impact of utility lines. Indeed, language in a 1975 case makes clear the importance that the Court believes the statute places upon environmental considerations:

> It was in the 1971 revision of the Constitution of Virginia that a provision was inserted which established the policy of the Commonwealth to 'conserve, develop, and utilize its natural resources, its public lands, and its historical sites and buildings. . . . to protect its atmosphere, lands, and waters from pollution, impairment, or destruction, . . .' In 1972 the General Assembly enacted Code § 56-46.1. . . . This represented an increased emphasis in environmental concerns by the legislature (Board of Supervisors of Campbell County V. Appalachian Power Company, 216 Va. 93).

Although the Court held in 1975 that Section 56-46.1 imposes a "duty" upon the SCC to "minimize the environmental impact of construction of utility lines," the Court held three years later that this duty was satisfied through the SCC's adoption of federal guidelines through the 1972 memo (Citizens for the Preservation of Floyd County, Inc. v. Appalachian Power Company, 219 Va. 540).

Guidelines Request Information on Potential Environmental Impacts

The SCC has asked utilities to address potential environmental impacts in their transmission line applications. Guidelines issued by SCC staff in 1991 ask utilities to list a variety of potential impacts near the proposed right-of-way, including

- the number of residences within 500 feet of the route and the general character of the area (rural, urban, agricultural),
- any sites in the Virginia Natural Area Preserves System,

- any scenic rivers, scenic byways, and wildlife or recreational preserves designated by the State, and
- any areas subject to conservation easements established through the Virginia Conservation Easement Act or designated as important farmland under § 3.1 et seq. of the *Code of Virginia*.

A review of recent transmission line applications indicates that utilities routinely provide this information when proposing new facilities.

ENVIRONMENTAL EFFECTS OF TRANSMISSION LINES ARE ADDRESSED WITHOUT UNDERGROUNDING

In cases where the potential impact of a transmission line upon scenic, recreational, or agricultural resources has been raised—as distinct from impacts upon health or historic resources—the commission has often taken steps to mitigate these concerns. Some of these steps have increased the initial estimated cost of a transmission line, but it appears that the commissioners have never required undergrounding solely as a means of mitigating an environmental concern. The avoidance of demolition, however, may be viewed as a recognition of an environmental concern, and this has resulted in undergrounding where no viable overhead route existed.

The single instance in which environmental factors are mentioned in a final order was a 2002 decision to approve an underground line that connected to a substation on the Norfolk Naval Station. The commissioners noted that "the new underground line will enhance views of the area and will avoid the need for tall transmission towers above the proposed extension of Interstate Route 564" (2002-00180). However, the commissioners went on to note that "the towers could pose a hazard to aircraft operating from the base," and that "the customer [U.S. Navy] is paying for the facilities, and that the general body of Virginia Power ratepayers will not bear the direct costs or risk of construction." These observations suggest that, at best, the improved aesthetics were one of several considerations and were likely a secondary factor.

Citizens and Agencies Have Raised Environmental Concerns

Residential property owners have often cited the environmental impact of transmission lines during local public hearings on a proposed line. For example, at a 2005 public hearing for a proposed 500 kV line in Fauquier County, witnesses complained about Dominion's methods for clearing rights-of-way, and expressed concern that additional tree-clearing will expose the transmission line to their view.

Environmental groups and local governments have raised concerns regarding scenic and recreational impacts. For example, the Northern Virginia Regional Park Authority has participated in each of three recent cases in Loudoun County, arguing that building additional overhead lines along the Washington & Old Dominion Trail would harm its scenic, recreational, and historic qualities.

State agencies regularly identify potential environmental impacts during reviews coordinated by the Department of Environmental Quality (DEQ). Construction of overhead or underground transmission lines can impact wetlands, wildlife, and other natural resources in the surrounding area. For instance, in a 2004 case involving an overhead 230 kV line in northwestern Chesterfield County, the Department of Mines, Mineral and Energy (DMME) noted during the DEQ review that abandoned coal mines were located within the proposed right-of-way. DMME subsequently recommended that Dominion perform geotechnical testing to determine their precise location before building the line (2004-00041).

Environmental Concerns Have Been Cited as a Reason to Avoid Undergrounding

The SCC has not found that undergrounding has been necessary in order to mitigate the environmental concerns expressed by witnesses. For example, in two recent cases, the commissioners have concluded:

> Our explanation for rejecting underground proposals in previous proceedings is applicable here as well: "There is no evidence that benefits will accrue to the Company or its ratepayers which outweigh the increased costs and risk of reliability problems associated with the underground installation of a portion of the proposed transmission line." [Quoted section is from case number 1988-00071; this statement appears in cases 2002-00702, 2004-00062.]

In a recent case in Loudoun County, the commissioners cited the incompleteness of the record as a reason to not place the lines underground: "The record is incomplete regarding the environmental impacts of underground installation and the impacts of the facilities that would need to be built in order to transition from overhead to underground construction" (2002-00702).

Although the final order does not provide any more information about the commission's reasoning, a review of the record in that case suggests that it involves the lack of a review by State environmental agencies of the effects of a proposed underground alternative. According to Dominion's August 2004 response to the hearing examiner's report, no environmental review was conducted with respect to undergrounding any portion of the line. This likely occurred because Dominion's application did not propose an underground line, as a preferred route or as an alternative, and as a result, State agencies did not consider it during their environmental review. It may have been possible, however, for the hearing examiner to request such a review once protestants offered an underground alternative.

Dominion Raises Environmental Concerns With Respect to Underground Lines. In the Loudoun County case referenced above, Dominion's response to the hearing examiner's report noted that "very different impacts aris[e] from digging a linear trench several miles long, tunneling under roads, etc, compared to overhead construction," and that these impacts require that State environmental agencies conduct a review. Dominion also noted the following specific environmental concerns:

- The duration of the construction phase of the underground line are estimated four to five times that of an overhead line, which could impact traffic.
- For overhead lines, excavation activity is limited to a small-diameter drilled hole for each structure every 700-800 feet, whereas an underground installation requires a continuous open trench for several hundred to a thousand feet at a time.
- Dust and noise associated with the underground construction activities are significantly greater than for overhead line work. Many truckloads of material excavated for the underground line must be hauled away and disposed of offsite (Dominion's August 2004 response to the hearing examiner report in case number 2002-00702).

When State Agencies Have Reviewed Underground Lines, Concerns Have Focused on Construction Activities. The environmental concerns of State agencies have not resulted in a request by them for undergrounding, or in an order from the commission that a line be buried. Instead, the environmental reviews have focused on mitigating the effects of construction activities of the type noted by Dominion staff.

Based on the final orders for several earlier undergrounding cases, it is not apparent whether an environmental review was undertaken (1982-00075, 1983-00036, 1983-00059, 1986-00019 and 1988-00063). In one earlier case, the final order notes that "the Commission did receive correspondence from the Commonwealth's

Department of Conservation and Historic Resources advising that the proposed underground transmission line affected no historical sites" (1988-00079).

For two Alexandria cases in the mid-1990s, DEQ coordinated a review with other agencies (1995-00134 and 1996-00071). For these two cases, the final order indicates that DEQ "determined that the proposed transmission line removal and underground installation should not have a significant impact on natural resources," provided that Dominion followed the environmental recommendations provided by various agencies:

- DEQ noted that if the project impacted wetlands, then permits from the U.S. Army Corps of Engineers and the Virginia Marine Resources Commission would be required.
- The Department of Historic Resources (DHR) reported the probable existence of a 19th century cemetery, and asked Dominion to work with archaeologists to document the site.
- The Department of Conservation and Recreation (DCR) determined that no significant communities, species, or habitats were documented in the area.

In two recent cases in Norfolk involving a submarine cable (2002-00180) and the installation of an underground line on the Norfolk Naval Station (2004-00139), DEQ submitted a report that summarized the potential impact of the lines on natural resources, and also provided recommendations for minimizing those impacts. The recommendations were similar to those provided for the Alexandria lines, including the need for a contingency plan in the event wetlands do not re-vegetate and that the Company should

- follow pollution prevention principles to the extent practicable,
- observe time-of-year restrictions (prohibitions on activity) with respect to beach disturbance, island activities, and any in-stream work, and
- coordinate with the Virginia Department of Game and Inland Fisheries and the U.S. Fish and Wildlife Service concerning potential impacts to birds.

SCC Has Taken Other Steps to Mitigate Potential Environmental Impact of Overhead Lines

The commissioners have frequently taken steps short of undergrounding to address concerns regarding environmental impact. The commissioners have determined that § 56-46.1 requires that adverse impacts are *reasonably* minimized rather than eliminated altogether. Environmental impact has been addressed by requiring the use of existing rights-of-way, ordering specific route or design modifications, and adopting recommendations developed by DEQ during its environmental impact review.

SCC Has Required the Use of Existing Rights-of-Way. The commissioners have frequently determined that transmission lines built within existing right-of-way will comply with its interpretation of the statutory need to "reasonably minimize adverse impact on the environment" (1989-00057). More than half of the transmission line cases reviewed by JLARC staff included the use of existing right-of-way along all or part of the route. In most of these cases, the commissioners have cited the use of existing rights-of-way to explain how an approved route complies with the statutory criteria in Section 56-46.1:

- In 2004, the commissioners approved a 12-mile 230 kV line in northwestern Chesterfield County. The application filed by Dominion proposed building the line entirely along an existing right-of-way containing a 230 kV line. In approving the line, the commissioners stated that the proposed route "uses existing right-of-way and is located completely on [Dominion's] property or existing right-of-way and, thus, reasonably minimizes any adverse impact on the scenic assets, historic districts, and environment of the concerned area" (2004-00041).

Use of Existing Transmission Corridors May Alter Habitat. The use of existing right-of-way can alter the landscape if vegetation must be removed to accommodate a new transmission line. This can occur when an easement permits the construction of additional transmission lines but the corridor has been cleared to accommodate only a single line, as occurred in a 2004 case:

- In 2004, Dominion sought SCC approval to build a 500 kV line on right-of-way already containing an identical line in southern Fauquier County. The company owned a 235 foot easement but had cleared only 140 feet. Adding the second 500 kV line required removing an additional 95 feet of trees, generating opposition from nearby homeowners. In approving the new project, the commissioners noted that alternative routes would have involved new easements that affected other property owners (2004-00062).

In other cases, a utility may propose a transmission line on right-of-way it already owns but which does not contain any transmission facilities. In these situations, the new line may require the removal of trees, potentially exposing a view of the transmission line to nearby residents. An ongoing case in Stafford County illustrates this situation:

- In August 2006, Dominion filed an application with the SCC to build a 230 kV line connecting an existing north-south transmission corridor east of Interstate 95 to a proposed substation near Garrisonville. The company has proposed building the first of three lines on an uncleared 335-foot right-of-way which it has owned since the 1960s. In some places, residential developments have been built up to the right-of-way (2006-00091).

SCC Has Used Route and Design Changes. The commissioners have commonly addressed public concerns regarding the potential impact of transmission facilities by altering the route or design specifications of a proposed line. A review of available records from past cases identified that route or design modifications were ordered in at least 17 of the 76 transmission line cases. In five of these cases, respondents advocated underground construction in order to minimize the impact of an overhead line on nearby property owners. As Table 10 indicates, the commissioners have commonly ordered modifications in response to complaints from property owners about the potential impact of transmission lines.

Route and design changes reflect an intent expressed by the commissioners in 1994 to consider a broad array of environmental impacts resulting from transmission lines, with special emphasis on residential dwellings. While Section 56-46.1 defines environmental impacts to include natural and historic resources as well as impacts on health and safety and economic development, the commissioners appear to pay particular attention to the potential impact on residential property. In a 1994 opinion approving a 500 kV line in southern Virginia, the commissioners explained:

> We consider environment in the broadest sense, and we must be satisfied that the proposed transmission line will minimize adverse effects on historic and natural resources, as well as existing and proposed land uses. The Commission is particularly concerned about impact on occupied or habitable residences (1992-00058).

The commissioners have also sought to minimize impact on nearby residences by using design changes and natural vegetative screens to reduce the visibility of transmission facilities. For example, in a 1996 opinion the commissioners ordered similar steps to minimize the visual impact of a 230 kV line on nearby residences in Goochland County. The commissioners relied partly on their personal inspection of the proposed route to identify measures that

Table 10: The Commissioners Have Routinely Ordered Design and Route Changes to Minimize the Potential Impact of Transmission Lines

Case and File Number	Design / Route Changes Approved By the Commissioners
Jackson Ferry-Axton 765 kV (10848-A)	Approved four modifications to the original route.
Ravensworth-Sideburn (1984-00028)	Approved a settlement agreement reached between Dominion and the Fairfax County Board of Supervisors.
Green Run-Greenwich (1986-00035)	Altered the portion of the route through a mobile home park.
Bull Run-Burke (1988-00004)	Routed the line across Braddock Road to accommodate future VDOT plans and avoid a nearby gas station and residences.
Loudoun-Clark (1988-00042)	Routed the line around the Sully Historic Site in Fairfax County.
Elmont-Chickahominy (1989-00017)	Routed the line across Totopotomy Creek and away from nearby residences.
Chesterfield-Chickahominy (1989-00073)	Routed the line "as far west as possible" to minimize impact on Curles Neck Swamp.
Basin-Midlothian (1991-00019)	Approved an alternative route agreed to by Dominion.
Clifton-Cannon Branch (1989-00057)	Routed the line one block south of the historic district in the City of Manassas.
Timberville Substation and 115 kV Line (1992-00004)	Relocated the line approximately 60 feet to bypass a mobile home.
138 kV (1994-00022)	Routed the line around the perimeter of a residence to avoid bisecting private property and a nearby lake.
Clover-Carson 500 kV (1992-00058)	Altered the route to accommodate two farms and two homes under construction.
Tap to Proposed Motorola Substation (1995-00088)	Ordered the use of modified towers, non-reflecting conductors, and the establishment of a permanent vegetative buffer.
Chickahominy-Darbytown (1997-00422)	Routed the line away from areas adjacent to White Oak Swamp.
Wyoming-Cloverdale (1997-00766)	Gave SCC staff authority to review the placement of towers, and required the use of non-reflecting conductors.
Beco-Greenway (2001-00154)	Approved an alternate route that avoided two residential developments and made better use of terrain and vegetation.
Brambleton-Greenway (2002-00702)	Ordered the use of shorter towers and moved one tower away from a nearby residential development.

Note: All cases involved 230 kV transmission lines unless otherwise noted. Cases in bold involved proposals to build an underground line.

Source: JLARC analysis of transmission line opinions issued by the SCC since 1972.

would reasonably minimize adverse impacts. These measures included requiring Dominion to use non-reflecting conductors, preserving a vegetative buffer by purchasing the land or acquiring an easement, and working with the SCC's Division of Energy Regulation on the height, design, and location of the towers (1995-00088). Other cases illustrate the use of alternative tower designs to reduce the visual impact of a transmission line.

SCC Relies on Other Federal and State Agencies to Minimize Potential Impacts on Wetlands and Wildlife. The commissioners have routinely incorporated DEQ recommendations into their final orders since the agency began coordinating environmental impact reviews of transmission lines in 2003. A common recommendation is for the electric utility to comply with all federal and State environmental permits.

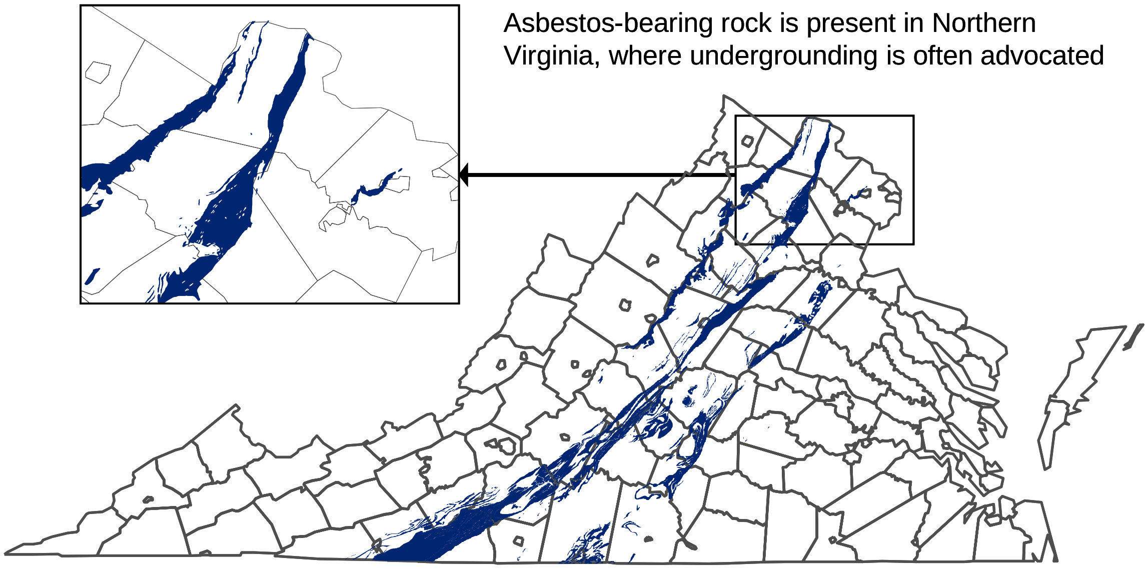
Although the reviews coordinated by DEQ have often highlighted potentially vulnerable environmental features, they may not identify all existing features near a proposed route. It appears that State agencies investigate the potential impact of a transmission line by reviewing their databases for the location of environmental or historic features and reporting to the SCC what is known to be present in the vicinity. This has been aided recently by the use of geographic information system (GIS) maps of the proposed routes provided by Dominion, and in some cases DEQ has recommended (and Dominion has agreed to) archaeological surveys of sensitive areas prior to construction.

However, important environmental factors may be found only after construction has begun, as when an asbestos-bearing rock (actinolite) was discovered in 1988 during construction of the Pender-Oakton underground line in Fairfax County. That line was not built, because of the cost of controlling the contaminants, but Dominion's Long Range Plan lists the project as planned in 2014. Figure 10 shows the location of actinolite in the Commonwealth.

SCC HAS NOT FOUND THAT HEALTH AND SAFETY EFFECTS JUSTIFY UNDERGROUNDING

Section 56-46.1 of the *Code of Virginia* requires the SCC to consider the "probable effects of the line on the health and safety of the persons in the area" before authorizing the construction of new transmission lines. Although this statute appears sufficiently broad to encompass a variety of health and safety effects, it has been applied largely to the potential effects of human exposure to electromagnetic fields (EMF). A consideration of the potential health and safety effects of transmission lines on animals were beyond the scope of this review because Section 56-46.1 specifically states that the SCC shall consider human health and safety.

Figure 10: Presence of Asbestos-Bearing Rock (Actinolite) May Hinder Use of Underground Lines



Source: JLARC staff analysis of data from the Department of Mines, Minerals and Energy.

Guidelines Ask Utilities to Provide the Maximum EMF Levels Associated With a Proposed Transmission Line

A review of recent applications indicates that utilities routinely calculate the new EMF levels expected at the edge of a right-of-way as a result of a proposed line. In addition, utilities calculate the maximum EMF levels resulting from any transmission lines already within the right-of-way.

As indicated in Table 11, the estimated maximum EMF readings (in milli Gauss, mG) reported by Dominion in the applications reviewed by JLARC staff are 0.1 to 4.3 for 230 kV underground lines and 1.5 to 271 for 230 kV overhead lines. For 500 kV, the values have ranged from 36 to 183.

SCC guidelines also state that if a utility "is of the opinion that no significant health effects will result from the construction and operation of the line," that the utility should "describe in detail the reasons for that opinion and provide references or citations to supporting documentation." A 2004 application filed by Dominion is typical of how the company has responded to these guidelines. In applying for SCC approval to build a 500 kV line in southern Fauquier County, Dominion stated its position regarding the potential health effects of EMF:

Table 11: Estimated Magnetic Field Levels Reported by Dominion for 230 kV Transmission Lines

Case Number	Location	Type of Line	EMF Value Maximum (mG)	EMF Value Normal (mG)
2006-00091	Stafford	Overhead	1.5 – 72	0.4 – 35
2005-00018	Loudoun	Overhead	108 – 213	unknown
2004-00139	Norfolk	Underground	0.1 – 0.1	unknown
2004-00139	Norfolk	Overhead	62 – 135	unknown
2004-00041	Chesterfield	Overhead	49 – 104	unknown
2003-00064	Chesapeake	Overhead	143 – 202	59 – 63
2002-00702	Loudoun	Overhead	109 – 181	21 – 30
2001-00154	Loudoun	Overhead	187 – 271	30 – 66
1996-00071	Alexandria	Underground	4.3 – 4.3	2.7 – 2.9
1995-00134	Alexandria	Underground	2.2 – 2.2	1.2 – 1.6

Note: EMF values are for the edge of the right-of-way. For cases in bold, the values include the magnetic field generated by an existing line. Underground lines use HPFF technology.

Source: JLARC staff analysis of applications submitted to the SCC.

> The Company is aware of no demonstrated causal relationship between observed biological responses to EMF and adverse human health effects. Decades of concentrated research have failed to establish a cause and effect relationship between power line fields and human health risks.

Dominion went on to provide the citations and abstracts for three recent scientific studies addressing possible links between EMF and cancer (2004-00062). In that case, Dominion also noted that Section 56-46.1(A) requires that the commission consider the "probable" effects of a line on health and safety.

EMF Is a Common Citizen Concern During Proceedings

JLARC staff review of transmission line cases indicates that concern about the potential health effects of transmission lines is one of the two primary concerns expressed by citizens. Specifically, citizens express concern that the EMF generated by an overhead line will cause cancer, of which the predominant concern is childhood leukemia. The other major concern expressed by citizens is that transmission lines will reduce their property values, and concerns over EMF are frequently cited as a reason that property values may decrease.

Like electric fields, the strength of magnetic fields decreases with distance from the source. However, unlike electric fields, most common materials do not block magnetic fields. Magnetic fields are measured in units called Gauss, and for the levels encountered near transmission lines the unit of measure is the milli Gauss (mG), which is one thousandth of a Gauss. (Another unit, the tesla, is sometimes used in European studies. One mG is equal to 0.1 microtesla, or μT.)

Concerns expressed by homeowners during recent transmission line cases have included the possibility that future research would reveal that EMF in fact causes cancer and other diseases (2001-00154), and unease because of the proximity of transmission lines to schools. At a 2005 hearing for a Fauquier County 500 kV line (which was proposed to parallel an existing 500 kV line), two witnesses expressed concern regarding the potential EMF effects on an elementary school. One witness cited a World Health Organization (WHO) finding that EMF is a possible human carcinogen and a 1994 engineering study recommending that either the existing transmission line or the elementary school be moved. As noted in the hearing examiner's report, another witness "contended that Dominion has never denied or refuted that EMF is associated with childhood leukemia." (The school was built after the first 500 kV transmission line was in place.)

Scientific Research Has Not Found a Causal Link Between Magnetic Fields and Cancer

In Virginia, the SCC and the Virginia Department of Health (VDH) have been involved in reviewing EMF research. In 1985, the General Assembly directed these agencies to monitor ongoing health and safety research relating to high voltage electric transmission lines and to report these findings on an annual basis. In 1998, the annual reporting requirement was terminated and a final report was submitted to the General Assembly in 2001.

The final report from VDH observed that "exposure to EMF is universal and unavoidable" and that a typical American home has a background magnetic field of between 0.5 to 4 mG. Based on research conducted through 1999, VDH concluded that

> there is no conclusive and convincing evidence that exposure to extremely low frequency EMF emanated from nearby high voltage transmission lines is causally associated with an increased incidence of cancer or other detrimental health effects in humans.

It appears that the primary reason why many researchers conclude that no causal link can be established is the fact that laboratory studies have not supported this conclusion. As noted by the National Institutes of Health in 1999, data on humans gathered from epidemiological studies

> have serious limitations in their ability to demonstrate a cause and effect relationship whereas laboratory studies, by design, can clearly show that cause and effect are possible. Virtually all of the laboratory evidence in animals and humans and most of the mechanistic work done in cells fail to support a causal relationship between exposure to ELF-EMF [extra-low frequency electromagnetic fields] at environmental levels and changes in biological function or disease status.

NIH added that the lack of connection between the human data from epidemiological studies and the experimental data from laboratory studies "complicates the interpretation of these results. The human data are in the 'right' species, are tied to 'real life' exposures and show some consistency that is difficult to ignore." However, NIH added that any definitive conclusions are "tempered by the observation that given the weak magnitude of these increased risks, some other factor or common source of error could explain these findings."

Since VDH last reported in 2001, new studies have been unable to determine if there is a causal link between EMF and cancer, particularly leukemia, but have noted the persistence of a statistically significant association. In March 2001, a report was published in England by an advisory group to the National Radiological Protection Board. This report, known as the "Doll Report" after the group's chair, Sir Richard Doll, observed that laboratory and animal studies have provided no evidence that magnetic fields affect biological processes; however, the report noted that residential studies

> suggest that relatively heavy average exposures of 0.4 μT or more [equivalent to 4 mG] are associated with a doubling of the risk of leukemia in children under 15 years of age. The evidence is, however, not conclusive.

The report noted, however, that "in the UK, very few children (perhaps 4 in 1000) are exposed to 0.4 μT or more."

Two reports issued in 2005 also looked at the potential connection between magnetic fields and leukemia. An overview of past research published by the National Cancer Institute (NCI) observed that although magnetic fields near many electrical appliances are higher than near power lines,

> appliances contribute less to a person's total exposure to magnetic fields. This is because most appliances are used only for short periods of time, and most are not used close to

the body, whereas power lines are always emitting magnetic fields.

The second report issued in 2005, which appeared in the *British Medical Journal*, investigated whether the distance between a child's home address at birth and a transmission line was associated with childhood cancer. The report concluded that "there is an association between childhood leukemia and proximity of home address at birth to high voltage power lines, and the apparent risk extends to a greater distance than would have been expected from previous studies." However, this was a very cautious finding, and the report noted that "there is no accepted biological mechanism to explain the epidemiological results; indeed, the relation may be due to chance or confounding."

If the transmission lines were the cause of the cancer, the findings indicated that "1% of childhood leukemia in England and Wales would be attributable to these lines, though this estimate has considerable statistical uncertainty." Commentary published in the same journal observed that in 2002, more than 200 children in England and Wales were killed in road accidents and another 32 died in house fires. In contrast, even if EMF causes childhood leukemia, the result would be an increase of five cases annually.

In the United States, for children age four and under, the national incidence of leukemia is six cases per 100,000 each year. This decreases to about two cases per 100,000 annually for children ten and older. In Virginia, the rate is lower. JLARC staff obtained data from the Virginia Cancer Registry for the most recent five years (Table 12). Staff at the Registry caution that these data are conservative because not all hospitals, outpatient facilities, and private pathology laboratories report cases, and cancer data for areas primarily in Southwest Virginia may be under-reported.

The most recently available data from VDH indicate that ten children under age 20 died from leukemia in 2004, the same number that died from accidental poisoning. In contrast, 150 children died

Table 12: Childhood (Age 19 and Under) Leukemias Diagnosed in Virginia, 1999 - 2003

Year	Rate per 100,000	Number of Persons
1999	3.4	66
2000	4.0	78
2001	3.0	58
2002	3.3	65
2003	3.9	77

Source: Virginia Cancer Registry, September 2006.

of motor vehicle accidents, 50 died as a result of assault by firearms, and 26 died by accidental drowning. There are also more deaths attributed to diseases other than leukemia: 21 children died of heart disease, 17 died as a result of respiratory disease, and 15 died from septicemia.

Magnetic fields have been classified as "possibly carcinogenic" by the International Agency for Research on Cancer, an agency of WHO. This assignment needs to be placed in context, however, because the classification is the lowest—and, as WHO points out, the "weakest"—of the three categories.

The highest classification, carcinogenic to humans, includes asbestos and tobacco. The middle classification, probably carcinogenic to humans, includes agents such as diesel engine exhaust and sun lamps. EMF is classified in the lowest tier, possibly carcinogenic to humans, along with welding fumes and coffee.

The published studies also indicate that there is an association between the strength of the magnetic field and the risk of developing leukemia. The reports point to a magnetic field of 3 mG (0.3 μT) as a dividing line, below which there is no association with the risk of leukemia. However, magnetic fields of 3 mG or more appear to be relatively common, and Table 13 presents data on EMF readings conducted by JLARC staff. As those observations indicate, the level of the magnetic field can vary from one side of the right-of-way to another. (Magnetic fields also vary with current, which varies from hour-to-hour and day-to-day.) Appendix F presents information on magnetic field readings taken along two transmission line rights-of-way.

Although undergrounding has been suggested as a means of reducing exposure to EMF, it appears that there is a substantial differ-

Table 13: Magnetic Field Levels Observed by JLARC Staff

Object Producing Magnetic Field	Observed Level (mG)
Retail Cash Register	1.5, 1.8, 4.4
Underground Distribution Line	4.5 – 12.3
Laptop Computer (Power On)	8 – 20
Same Laptop Computer (Power Off)	1
Car Console Between Front Seats (Power On)	9.4
Same Car (Power Off)	0.6
Sewing Machine (Power On)	11 – 121
Same Sewing Machine (Power Off)	0.4

Note: Reported values were recorded at the closest proximity to the measured object, except for the distribution line, for which a range of ambient values is reported.

Source: JLARC staff measurements, taken with Teslatronics Model 70 Triaxial milliGaussmeter, provided and calibrated by Dominion Virginia Power.

ence in the magnetic field generated by HPFF and XLPE cables. As indicated in Table 11, the types of cables used by Dominion (HPFF) produce magnetic field readings that are very low. However, there are indications that XLPE cables have higher magnetic field readings, and that these readings can be higher than those of overhead lines.

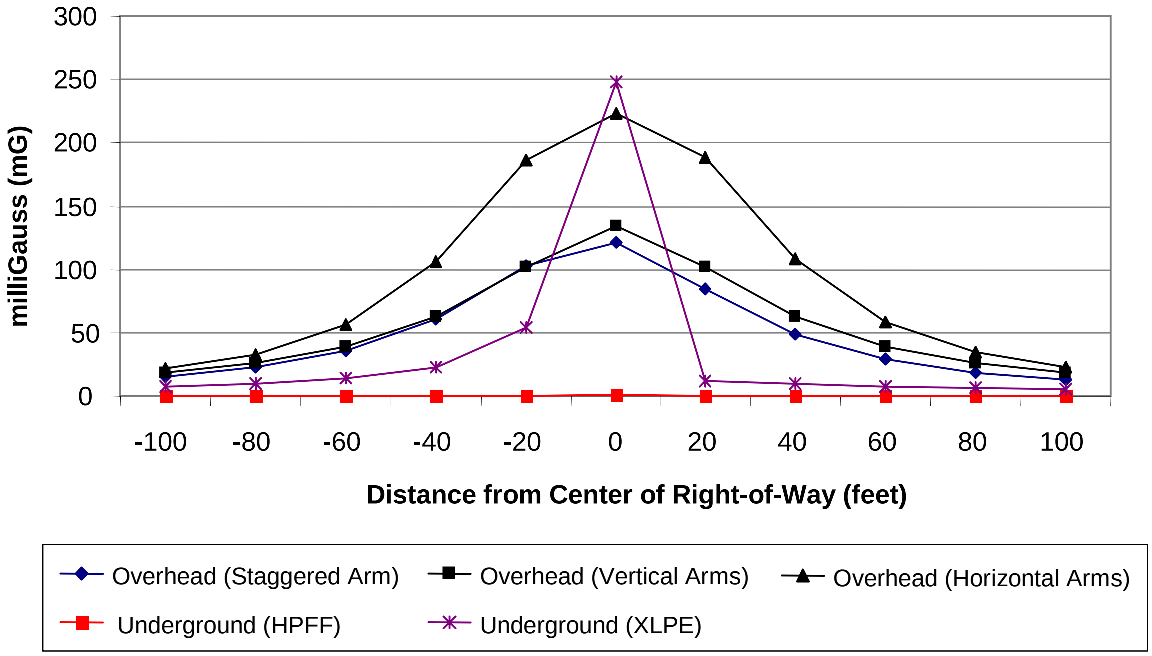
Information on the estimated magnetic field strength of different types of underground cables was presented to the Virginia Joint Commission on Technology and Science (JCOTS). In 2005 testimony, a presenter provided JCOTS with a graph that illustrated the magnetic field strength of overhead lines, XLPE cables, and HPFF cables. At the center of the right-of-way, the magnetic field strength of overhead wires was approximately 165 mG, the XLPE cable was about 145 mG, and the HPFF was about 2 mG. (These estimates were made assuming a load of 700 Amps.) Dominion provided JLARC staff with estimated magnetic field levels for different types of overhead and underground lines (Figure 11). These data also indicate that HPFF has negligible magnetic field readings, but Dominion's data indicate that XLPE has a higher magnetic field than any overhead line.

The differences in magnetic field levels are especially important to consider if the transmission line will be installed in a manner such that the right-of-way will be used by pedestrians. The underground lines currently installed in Virginia are placed underneath sidewalks or in roadways: places where the magnetic field is in close proximity to the surface. Some advocates of undergrounding have also suggested that they be placed underneath recreational trails. If XLPE does generally produce higher magnetic fields than HPFF cables or overhead wires, then its placement near pedestrians could be a concern.

Commissioners Have Not Required Undergrounding as a Means of Addressing Health Concerns

In past transmission line cases, the commissioners have consistently determined that the evidence does not indicate that EMF from proposed lines will threaten human health or safety. As reported in a 1986 opinion approving a 500 kV line in Fairfax and Prince William Counties, the hearing examiner assigned to the case concluded that "there is not sufficient evidence which would give rise to a concern that the health and safety of Virginia residents is imperiled" (1985-00013 and 1985-00020). As a result, undergrounding has not been required. Based on the final orders issued by the commission, none of the ten underground lines approved by the commissioners since 1972 were intended to minimize exposure to EMF.

Figure 11: Magnetic Field Levels Vary Depending On the Type of Overhead or Underground Line Used



Note: Levels are based on 400 megavolt amperes.

Source: Dominion.

The SCC has approached the scientific debate surrounding a possible association between EMF and cancer by relying on literature reviews compiled by VDH and evidence presented during case proceedings. In most of the 12 cases in which the commissioners explicitly discussed EMF concerns, the final orders stated only that the utility had found no evidence that the proposed line would pose a hazard to human health. In other cases, the commissioners addressed issues that had emerged during the public hearings. In at least four of the 76 cases since 1972, the commissioners have concluded that high-voltage transmission lines pose no known health risks to humans. (This conclusion was also reached in seven of the 23 cases involving the connection of a generator or other facility.)

- In a 1991 opinion approving a new 230 kV line through Fairfax and Prince William Counties, the commissioners addressed concerns among homeowners that EMF was dangerous. The commissioners rejected these concerns, noting that scientific studies and EMF estimates presented by Dominion had not been challenged and that some residents moved into the area after construction of the existing transmission line (1989-00057).

- In 1994, the commissioners noted that while epidemiological studies are the best source of information currently available, these studies are subject to "inherent limitations." Epidemiological research, they reasoned, is not an experimental science but is based on observation and reviews of health records. As a result, the cause of a disease cannot be proven experimentally but must be inferred (1992-00058).
- In a 2004 order, the commissioners concluded: "Based on the facts presented in this case, we find that the claims of EMF impacts were refuted by evidence presented by the Company" (2004-00062).

The commissioners have also rejected a recommendation to establish standards for maximum allowable electric fields. The commissioners agreed with a finding by the hearing examiner that "there is not sufficient evidence which would give rise to a concern that the health and safety of Virginia residents is imperiled by the proposed high voltage transmission lines" (1985-00013 / 1985-00020). At least six other states (Florida, Minnesota, Montana, New Jersey, New York, and Oregon) have set standards for the electric fields on transmission line rights-of-way, and four states have standards for edge-of-right-of-way magnetic field levels:

- Connecticut: 100 mG
- Florida: 150 mG (230 kV); 200 mG (500 kV)
- Massachusetts: 85 mG
- New York: 200 mG

However, the commissioners have indicated that some of the other measures they employ to reduce environmental impact, such as routing a line away from homes, also serve to reduce any potential EMF effects.

SCC Has Taken Other Steps to Minimize the Potential Effects of EMF

While the commissioners have ruled that current scientific research does not identify EMF as a health threat, they appear to have determined that the possibility of health effects can justify route or design changes to minimize potential impacts on residential developments. In a 1994 opinion approving a 500 kV line extending across the southern part of Virginia, the commissioners noted that, in light of the scientific uncertainties surrounding EMF,

> Some scientists, therefore, advocate taking all steps in the design, location and construction of transmission lines to

> avoid exposing people to magnetic fields. This approach is frequently referred to as "prudent avoidance." While the Commission is not now adopting prudent avoidance as a policy, we note that our approach to routing this particular 500 kV line incorporates many elements which reduce extended exposure of humans to the line (1992-00058).

The commission then added that their "policy of avoiding homes also minimizes the impact on residences from magnetic fields associated with transmission lines." Consistent with this approach, in at least three cases since 1972 the commissioners have cited the health and safety concerns of nearby homeowners to explain route or design changes (1988-00004, 1989-00057, and 1994-00022).

EMF Concerns in Connecticut Recently Led to Legislation Requiring Undergrounding

In Connecticut, proposed transmission lines are reviewed by the Connecticut Siting Council. The council has used the policy of prudent avoidance since 1993, and has recently adopted a threshold of 100 mG at the edge of the right-of-way as an indicator that transmission lines will receive increased regulatory attention. In reviewing new lines, the council adheres to Public Act 04-246, adopted in 2004, which requires that transmission lines of 345 kV or greater should be buried when the lines are located "adjacent to residential areas, private or public schools, licensed child day care facilities, and licensed youth camps or public playgrounds."

As a result of this legislation, overhead lines cannot be placed next to these facilities. However, overhead lines are permissible if an applicant can demonstrate to the council that it is technologically infeasible to bury the line. The definition of feasibility includes consideration of the effect that the underground line could have on the reliability of the transmission system. Similar legislation was introduced this year in Vermont, but it did not become law.

In Virginia, several transmission lines are located in close proximity to schools. GIS analysis performed by JLARC staff indicates that 72 schools are within 500 feet of a transmission line (115 kV and above), including 48 elementary schools. A partial explanation for this may be that EMF concerns did not receive much attention until the 1980s, and prior to 1972 all transmission line locations were approved by local governments. Moreover, since 1972 some localities have built schools next to existing transmission lines or uncleared rights-of-way.

However, the desirability of Connecticut's approach has been questioned by the chair of the Connecticut Siting Council. In testimony before JCOTS, she advised Virginia to not adopt or recommend legislation that would require all new transmission lines to be underground, but to instead review options for less visible overhead lines. Another option may be to increase the distance between new structures and rights-of-way ("setbacks"), a practice followed in California (*Code of Regulations*, Title 5, Section 14010(c)).

UNDERGROUNDING HAS NOT BEEN USED TO PROTECT HISTORIC RESOURCES

As previously discussed, Section 56.46.1 of the *Code of Virginia* requires the SCC to minimize adverse environmental impacts resulting from transmission lines and defines the term environmental "to include in meaning 'historic[.]'"Article XI of the *Constitution of Virginia* also promotes historic preservation by affirming a policy of conserving historic sites and buildings in the Commonwealth.

Overhead and underground transmission lines each can affect nearby historic resources. Overhead lines appear most likely to impair the view shed or historic context of a resource rather than destroying the resource itself. In most cases, transmission towers can be placed to leave a resource such as a cemetery or historic home intact. However, the sight of towers and wires may detract from the historical appeal of a resource. By contrast, underground transmission lines appear more likely to impact archaeological resources such as historic artifacts or unmarked burial grounds.

SCC Guidelines Reflect Statutory Emphasis on Protecting Historic Resources

The guidelines issued by SCC staff ask utilities to list in their application any historic sites within or adjacent to the proposed right-of-way. According to the guidelines, these sites may include places on the National Register of Historic Places or the Virginia Landmarks Register, historic districts designated by a locality, and archaeological sites designated by the Virginia Department of Historic Resources (DHR).

Electric utilities appear to address potential impacts on historic resources in their transmission line applications. For example, in its application for a 230 kV line near Leesburg, Dominion noted that an alternate route would potentially impact Rokeby Manor, listed on the National Register of Historic Places; the Washington & Old Dominion Trail, eligible for the Virginia Landmarks Register; and the historic districts of Paeonian Springs and Leesburg (2005-00018).

State Agencies and Concerned Citizens Have Raised Concerns Involving Historic Resources

A review of past transmission line cases indicates that State agencies have raised concerns regarding historic assets during SCC proceedings. DHR and other State agencies routinely participate in the environmental impact reviews coordinated by DEQ. These agencies have reviewed their databases to identify any historic resources that could be impacted by a new transmission line.

One recent case in Loudoun County illustrates how State agencies can raise potential historic impacts that may otherwise not be considered. In its 2002 application for SCC approval of a 230 kV transmission line, Dominion did not identify any historic resources within or near its proposed right-of-way. However, during the environmental impact review coordinated by DEQ, DHR identified several archaeological sites in the project area and recommended that Dominion avoid these sites when locating transmission structures. DEQ subsequently recommended that the company work with DHR to determine the impact of the line on historic resources (2002-00702).

State agencies or concerned citizens cannot protect historic resources which have not yet been identified. Moreover, protecting known resources can be difficult when their historic value has not been fully determined. For example, in an ongoing case in Loudoun County, the Northern Virginia Regional Park Authority (NVRPA) has asserted that placing a new 230 kV line along the Washington & Old Dominion Trail is problematic because detailed natural and cultural resource studies have not been conducted. The NVRPA concluded that, for this reason, it could not identify the most sensitive areas of the trail (2005-00018).

SCC Has Used Design and Route Changes to Protect Historic Resources

A review of 76 SCC opinions since 1972 identified at least five transmission line cases in which impact on historic districts was a significant issue. As indicated by Table 14, in three of these cases the commissioners ordered steps short of underground installation to protect historic resources near the proposed lines. A 1989 case illustrates the willingness of the commissioners to approve a more expensive route in order to protect a historic asset. The commissioners granted a request by Dominion to convert an existing 115 kV line in Fairfax County to 230 kV, but rerouted the new line around the Sully Historic Site in order to minimize impact on the historic home (Figure 12).

Table 14: Commissioners Have Ordered Steps Short of Underground Lines to Protect Historic Resources

Transmission Line and Case Number	Design / Route Changes Approved By the Commissioners
Charlottesville-Remington (1980-00006)	Denied an application to rebuild an existing 115 kV line near Monticello in Albemarle County.
Loudoun-Clark (1988-00042)	Routed the line around the Sully Historic Site in Fairfax County.
Clifton-Cannon Branch (1989-00057)	Routed the line one block south of the historic district in the City of Manassas.
Carson-Clover 500 kV (1992-00058)	Noted that the line bordered Reams battlefield but would not affect its historic interpretation.
Loudoun-Morrisville/Gainesville 500/230 kV (1994-00036)	Relocated an existing line to accommodate the Manassas National Battlefield.

Note: All cases involved 230 kV transmission lines unless otherwise noted. The case in bold involved a proposal to build the line underground.

Source: JLARC analysis of transmission line cases reviewed by the SCC since 1972.

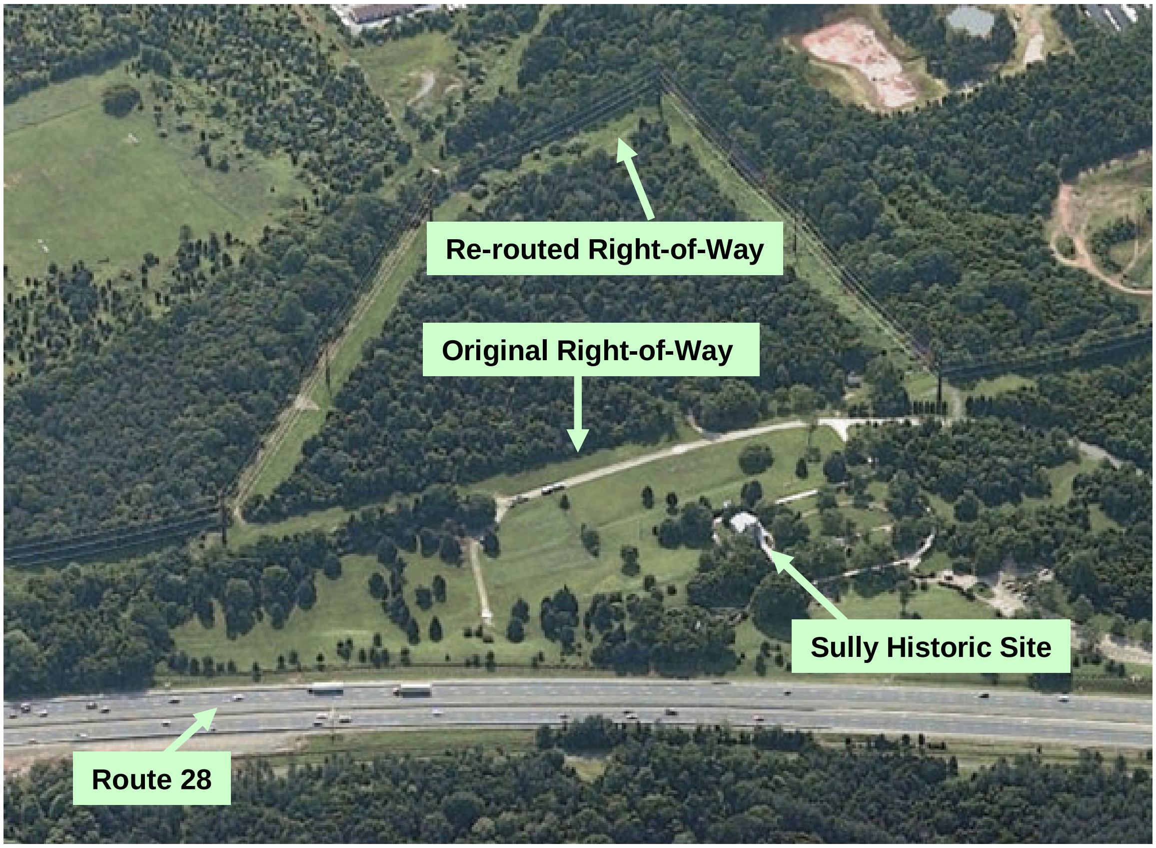
The proposed route would have traversed the Sully property on an easement owned by the company. The commissioners explained that while the route change "will increase the expense of this project to [Dominion] and to ratepayers… this additional expense is warranted in light of the value of Sully Historic Site" (1988-00042).

In a 1991 case, the commissioners altered the proposed route for a 230 kV line through the historic district of Manassas City instead of approving an underground section in the city. Historic Manassas, Inc., a respondent in the case, sought to place underground this portion of the line, citing the potential for transmission towers to clash with the two-story buildings in the historic district and isolate the district from the City of Manassas Museum.

The commissioners noted in an interim order that Dominion could seek authority to place underground part of the line if a local source of funding could be found. However, in a final order authorizing overhead construction, the commissioners rejected the underground alternative and routed the line one block south of the historic district, stating: "We do not find that minimization of the environmental impact as required by the statute requires construction of a portion of the transmission line underground" (1989-00057).

The commissioners also cited impact on historic resources in initially dismissing an application filed by Dominion to convert a 115kV line in Albemarle County to 230 kV. Although the new line would have occupied existing right-of-way along the entire route,

Figure 12: Relocation of Transmission Line to Protect Historic Site



Source: JLARC staff analysis of SCC final order in case 1988-00042. Imagery used with permission of Pictometry.

the commissioners cited the impact of replacing 55-foot wooden structures with 90-foot steel towers on the "unique historical quality in the area near Charlottesville" that included Monticello. The commissioners noted that Dominion did not adequately address potential impacts on historic resources, and concluded that the proposed line would not reasonably minimize adverse impact on the scenic and environmental assets. As a result, the commission dismissed the company's application (1980-00006). The reconstruction project was approved by the commissioners in 1984 after Dominion resubmitted its application (1982-00091).

Chapter 7

Higher Costs Have Typically Discouraged Use of Undergrounding

In Summary

The SCC has interpreted the statutory requirements in the Utility Facilities Act to require the least costly means of installing a transmission line which can be achieved while balancing other statutory factors. In recognition of factors besides costs, the SCC has taken steps in some cases to require the use of a more expensive route or other measures to mitigate the impacts of an overhead line.

Undergrounding, however, has not been used as mitigation tool. The SCC has only approved the use of underground lines in situations in which it would not add to the costs borne by ratepayers. In some instances, undergrounding has been approved because it was less expensive due to high right-of-way costs for overhead options. In three of the ten cases where undergrounding was approved, the approval was largely based on the availability of a third party that was willing to pay the costs, so there was no cost impact upon ratepayers.

Typically, however, underground lines are seen by Dominion and the SCC as costing substantially more than overhead lines. In most cases, therefore, underground alternatives are not presented by Dominion nor considered by the SCC, and have been rejected when raised as a mitigation alternative by parties to a case.

The cases reviewed by JLARC staff indicate that the higher costs typical of an underground line is one of the most frequently cited reasons for not allowing undergrounding. Transmission line construction costs are paid by all of a utility's ratepayers, and this is one reason given by the commissioners to avoid undergrounding. The commission has endorsed other mitigation efforts, however, such as longer routes, modified towers, or tree buffers.

STATUTORY FACTORS EMPHASIZE COST-EFFICIENCY, BUT COST ALONE DOES NOT DETERMINE CASES

Cost considerations have played an important role in transmission line cases before the SCC because of statutory provisions that stress cost-efficiency. As stated by SCC staff in testimony before the Joint Commission on Technology and Science, two of the "Criteria and Policies for Transmission Line Applications" used by the SCC are

- Section 56-234, which requires electric utilities to provide electric service at "reasonable" rates, and

- Section 56-235.1, through which the SCC is empowered to investigate public utilities to determine whether they "promote the maximum effective conservation and use of energy and *capital resources*" [emphasis added].

Section 56-46.1 also promotes cost-efficiency by requiring a utility to show that an existing right-of-way cannot be used before it acquires new easements.

Although economic development considerations are not strictly considered to be a cost factor, their consideration is also included in section 56-46.1. The commissioners are required by this section to "consider the impact of a proposed [transmission line] on economic development within the Commonwealth" before granting a certificate of public convenience and necessity. However, the statute provides no further definition of "economic development" or instructions on its application to transmission line cases.

Agency guidelines for transmission line applications ask utilities to provide the estimated cost of a project, and this estimate has been routinely included in recent applications. However, transmission line applications generally do not contain more detailed cost information, such as a breakdown of total cost, or the assumptions used to estimate the cost of material or labor. Additionally, the information routinely provided by utilities does not include cost information on undergrounding or on the impact that the line will have on economic development. This appears to result from the fact that the guidelines are intended only to request information that would be needed by the SCC to evaluate a typical transmission line application.

The commissioners have often sought to minimize construction costs when evaluating proposed and alternative transmission lines. This appears to be the main reason why undergrounding proposals have been rejected. A review of past SCC proceedings identified 27 cases since 1972 in which the commissioners cited cost factors to explain their decision. These cases are listed in Table 15. Cost discussions have been especially common when there was opposition to a line or alternative routes were proposed. Indeed, in nearly half of the 27 cases listed in the table, the commissioners rejected route or project alternatives that would have resulted in higher costs. In some of these cases, alternative routes were designed to minimize adverse impacts on the environment.

Although statutory provisions emphasize the need to minimize the cost of new transmission facilities, the commissioners have indicated that cost alone will not determine the outcome of a case. Other factors, such as the need to minimize environmental impact

Table 15: The Commissioners Have Routinely Cited Cost Factors When Reviewing New Transmission Facilities

Case and File Number	SCC Decision
Jackson Ferry-Axton 765 kV (1977-10848-A)	Rejected an alternative route because it would have required more land and cost more.
West Staunton-Harrisonburg (1979-20084)	Rejected a route change in part due to its higher costs.
Winterpock-Midlothian/ Chesterfield (1986-00060)	Cited cost savings of designing towers to accommodate a future line.
Bull Run-Burke (1988-00004)	Cited taxpayer savings of $30,000 from accommodating VDOT road expansion.
Occoquan-Ogden Martin System (1988-00074)	Noted that Ogden Martin would fund the project and ratepayers would not bear the cost of construction.
Loudoun-Clarke (1988-00042)	Additional costs were justified to protect the Sully Historic Site.
Pender-Oakton (1988-00079)	Noted that overhead construction would have been double the cost of an underground line.
Hopewell-Firestone Plant (1989-00050)	Noted that Firestone would fund the project and ratepayers would not bear the cost of construction.
Midlothian-Trabue (1988-00071)	Rejected undergrounding in part because of higher cost.
Chesterfield-Chickahominy (1989-00073)	Rejected an alternative because it would not have addressed need and ratepayers would ultimately bear the cost.
Clifton-Cannon Branch (1989-00057)	Rejected an alternative substation site because it would have required additional land and increased costs.
North Pole-Oilville-Short Pump (1991-00027)	Rejected alternative routes in part because of their higher costs.
Clover-Carson 500 kV (1992-00058)	Rejected a 230 kV line due to the estimated $66 million in line losses that would have resulted.
Southern Virginia (1994-00022)	Cited the benefits of avoiding $50,000 in litigation costs.
Goshen-Low Moor (1995-00057)	Rejected alternatives in part due to higher costs.
Jefferson Street-Glebe (1995-00134)	Noted that the City of Alexandria would reimburse Dominion for the costs of underground installation.
Tap to Proposed Motorola Substation (1995-00088)	Determined that while mitigation measures would increase the project's costs, this increase would not be excessive.
Chickahominy/Darbytown-White Oak (1996-00115)	Rejected an alternative route due to higher costs.
Moore Substation (1996-00360)	Noted the project would reduce wholesale power costs.
Dulles-Reston (1999-00009)	Rejected an alternative due to its higher costs.
Sewells Point-Navy South (2002-00180)	Noted that the Navy would pay the $9 million cost of underground installation.
Beco and Greenway Lines (2001-00154)	Rejected placing a line along the southern edge of the W&OD Trail in part due to the need to buy additional right-of-way.
Dooms/Elmont-Tenaska Power Plant 500 kV (2001-00663)	Noted that Tenaska would fund construction of the new line.
Fentress-Shawboro (2004-00064)	Noted that the proposed project was the least costly alternative.
Brambleton-Greenway (2002-00702)	Rejected an underground alternative due in part to the higher cost of construction.
Bristers-Morrisville 500 kV (2004-00062)	Rejected alternative routes due to their higher costs.
Churchland-Sewells Point (2004-00139)	Noted that an underground line was cheaper than generation and comparable to overhead construction.

Note: All cases involve 230 kV transmission lines unless otherwise noted.

Source: JLARC analysis of transmission facilities approved by the SCC since 1972.

or ensure service reliability, must be considered and may justify more expensive transmission facilities. The commissioners appear to have sought a balance of these factors, approving measures that have a substantially smaller financial impact on a new transmission line than underground construction.

SCC HAS APPROVED SOME ADDITIONAL EXPENDITURES TO MINIMIZE ADVERSE IMPACTS OF OVERHEAD LINES

In at least four transmission line cases since 1972, the commissioners approved overhead routes that were more expensive than the original route proposed by the utility. These additional costs were required in order to minimize the adverse impact of a proposed line, and the commissioners explicitly discussed why a more costly alternative was justified. In three of these cases, the mitigation efforts—the costs of which were borne by all of Dominion's customers—were designed to minimize the visual impact of overhead lines on nearby homeowners:

- maintenance of a tree buffer through a permanent easement or outright purchase of the land (1995-00088),
- approving a route one mile longer and $1.6 million more expensive than the route proposed by Dominion (2001-00154), and
- approving a route in Loudoun County more than twice as long and approximately 70 percent more expensive ($4.7 million) than the shortest possible route, the use of which may have required the demolition of homes (2002-00702).

However, cost concerns sometimes outweigh the potential benefit that could be obtained, as illustrated in a recent case in Loudoun County where the commission approved a route that protestants said would require elimination of a tree buffer. The final order indicated that this action was taken because the alternative route would have required additional right-of-way at a cost of approximately $3 to 3.5 million (2001-00154).

TRANSMISSION LINE PROJECT COSTS ARE PAID BY ALL RATEPAYING CUSTOMERS OF THE UTILITY

For many years there appears to have been a concern among the commissioners and SCC staff that the high cost of underground construction places an unfair burden on ratepayers. This results from the SCC's interpretation of Section 56-234, which requires electric utilities to provide electric service at "reasonable" and also "uniform" rates. The uniformity requirement has been interpreted by the SCC to require that transmission line costs need to be borne by all of a utility's customers. This interpretation has been raised when undergrounding has been advocated. In a 1991 case, the hearing examiner wrote that the costs of a proposed underground line would be paid by every electric customer of the utility (1989-00057). This concern was echoed in a 2004 case in Fauquier, where the hearing examiner stated that "Dominion's ratepayers as a whole should not be burdened with the expense of an underground transmission line unless there is no reasonable overhead option available" (2004-00062).

Virginia's Restructuring Act Has Temporarily Frozen Electricity Rates

The Virginia Restructuring Act of 1999 capped and effectively froze Dominion's base electricity rates. In addition, Dominion's fuel factor – the portion of rates used to recover fuel costs from customers – was frozen for the period from January 1, 2004, through July 1, 2007, and Dominion cannot recoup these costs. Dominion will be able to receive annual fuel factor adjustments from July 1, 2007 through July 1, 2010.

Starting January 1, 2011, the Restructuring Act calls for rates for electricity supply service to be based on market prices. Under the Act, the SCC will set default rates for electric supply for customers who do not buy power from competitive providers. The Act directs the SCC to base these rates on prices in competitive regional electricity markets (such as PJM), and to consider factors such as customers' need for rate stability and protection from unreasonable rate fluctuations.

In response to a question posed by JLARC staff about commission policy on electricity rates, the commissioners noted that they have

> rejected alternative routes or alternative construction method for which the benefits did not, in the Commission's evaluation of the evidence, outweigh the increased costs that would be borne by all ratepayers. Conversely, the Commission has also approved alternative routes that satisfy this analysis. In other words, the Commission has not approved alternative routes or construction methods that would (1) result in significantly increased costs for all ratepayers, but (2) benefit only a particular subset of ratepayers (by, for example, reducing environmental externalities for those particular ratepayers).

This concern results from the manner in which utilities used to recover transmission line costs. Historically, it appears that the typical practice of the SCC has been to certify construction of a transmission line and associated facilities, not to approve cost-recovery. As noted in a 1996 underground case in Alexandria,

> Our approval of the Company's project does not constitute authorization for Virginia Power to recover the cost of its construction project in rates. The Company remains subject to the burden of proof articulated in Va. Code § 56-234.3, and other statutes in Title 56 of the Virginia Code (1996-00071).

Prior to restructuring, the commission did not determine that a utility could recover the funds it expended on a project until a subsequent rate hearing, where the costs of that project were subject to examination. If these costs were determined to be prudent and necessary, they would be considered along with all of the utility's costs to determine if a change in electricity rates was warranted.

This recovery mechanism appears to have changed for the time being. Presently, the costs associated with most transmission line projects undertaken by Dominion while electricity rates are capped are not borne by retail customers (such as homeowners) in the same manner as they were prior to restructuring. As noted by SCC staff and Dominion in a recent Loudoun County case, at the present time the higher costs resulting from underground projects are borne by Dominion's shareholders. However, because project costs are repaid over many years, after the rate cap expires the general body of retail customers (ratepayers) will become responsible for paying the remaining balance of the costs—which is a far larger amount than will be paid by shareholders (2002-00702).

Although Dominion's shareholders will shoulder these costs until the rate caps expire, SCC staff note that Dominion may be able to recover some or all of these costs through other means. This may occur, for example, through increased electricity sales if a new transmission line results in the addition of new customers. New transmission lines, therefore, may not only serve existing customer demands but also allow development to generate new customers and thus increased electricity sales.

Because the rate caps limit the ability of Dominion to recover costs from Virginia retail ratepayers, the company has the option of recovering these costs through other means. Dominion could pass on the costs of transmission line projects by renegotiating contracts with wholesale customers in Virginia (municipalities, State agencies, electric cooperatives), wholesale customers in other states, or to retail customers in its North Carolina service area. Other options available to Dominion appear to include petitioning the Federal Energy Regulatory Commission (FERC) to increase Dominion's transmission rates (although the caps would limit the usefulness of this option) or to defer its transmission project costs until after Virginia's rate caps expire. Dominion has already taken the latter step with regard to certain expenditures associated with joining PJM (the regional transmission organization), and has requested permission from FERC to defer the recovery of $240 million until after the caps expire.

UNDERGROUNDING HAS BEEN APPROVED WHEN LESS COSTLY OR WHEN RATEPAYERS ARE NOT AFFECTED

In 17 transmission line cases, underground construction has been proposed. In ten of these cases Dominion proposed an underground line in its application, and the company's proposals were approved in each case. In these ten cases, the underground proposal was seen as cost-efficient for ratepayers because either (1) the undergrounding option was less expensive, or (2) there was a third party willing to pay the cost of undergrounding.

In the remaining seven cases, respondents promoted undergrounding in order to avoid the potential impacts of an overhead line. Undergrounding was rejected in each of these cases, and cost concerns were cited by the commissioners in three instances. The commissioners concluded in these cases that the disadvantages of underground construction outweighed the potential benefits:

> There is no evidence that benefits will accrue to the Company or its ratepayers which outweigh the increased costs and risk of reliability problems associated with the underground installation of a portion of the proposed transmission line (quoted in cases 1988-00071, 2002-00702, and 2004-00062).

Undergrounding Can Be Less Expensive Where Land Values Are High Due to Right-of-Way Costs

Obtaining new easements for a transmission line can be a significant expense, especially when real estate values are high or condemnation proceedings are required. Because underground lines require smaller rights-of-way, undergrounding may be less costly than overhead lines in areas with high land values.

As Table 16 indicates, in eight cases the commissioners have approved underground lines in Northern Virginia, where the density of urban development and land prices have been higher than other regions of the State. In each of these cases, Dominion proposed underground construction because it had determined that no viable overhead route was available or that an underground line was more cost-effective.

Although the expense of acquiring right-of-way was likely a major factor that resulted in the lack of an overhead route, cost was explicitly cited as a factor by the commissioners in only two of the ten cases. However, in one of these cases the line runs through several apartment complexes (Figure 13), which could have resulted in the displacement of many individuals who were not landowners. This fact suggests that a desire to not displace residents—an environmental factor—is also a strong consideration.

A case from Fairfax County illustrates how land values can influence the use of underground transmission lines. In a 1989 opinion approving a 3.5-mile underground line, the commissioners noted that an overhead line would cost approximately $46.7 million, more than double the $21.2 million cost of building an underground line. Dominion attributed these costs to high land values and the 120-foot right-of-way required for overhead construction compared to 25 feet for the underground alternative (1988-00079). As discussed in Chapter 10, in some cases urban development may preclude overhead construction even though easements for an overhead line have already been obtained.

Table 16: The Commissioners Have Approved Underground Lines in Areas With High Land Values

Transmission Line and File Number	Locality	Line Length (Miles)	ROW Width (Feet)
Glen Carlyn-Clarendon (1982-00075)	Arlington County	2.0	35
Jefferson Street-Glebe (1983-00036)	City of Alexandria	0.34	17
Braddock-Annandale (1983-00059)	Fairfax County	3.6	Unavailable
Burke-Sideburn (1986-00019)	Fairfax County	2.2	20
Glebe-Davis (1988-00063)	Arlington County	2.4	30
Pender-Oakton (1988-00079)[1]	Fairfax County	3.5	25
Jefferson Street I (1995-00134)	City of Alexandria	0.32	24
Jefferson Street II (1996-00071)	City of Alexandria	2.4	8

Note: All transmission lines are 230 kV. Some of these lines also may have included temporary construction easements.
[1] The Pender-Oakton line was not built.

Source: JLARC analysis of transmission line applications filed with the SCC.

Figure 13: Undergrounding May Be Preferable Where An Overhead Line Would Displace Many Residents

Note: Parallel lines in photograph are shadows cast by overhead distribution lines and do not indicate route of underground line.

Source: JLARC staff photograph showing location of an underground 230 kV line under a sidewalk in Fairfax County.

However, an overhead line may be required in areas with high land values if the available right-of-way is not conducive to underground construction. Rocky terrain can increase construction costs substantially, potentially eliminating some of the savings associated with smaller land acquisitions. Unanticipated developments, such as the discovery of pollutants or sensitive environmental resources, can also increase the cost of underground construction and may require overhead lines instead.

Undergrounding Has Been Approved If Costs Paid By Third Party, But Dominion No Longer Favors This Practice

In three cases, Dominion has requested permission to use an underground line because a third party was willing to pay for the costs. The willingness of a third party to bear these costs appears to have been motivated by economic development considerations in two of these cases. Economic development also played a role in three other cases involving undergrounding, and these cases confirm the rule that undergrounding has only been used when a third party is available or if an overhead route cannot be found.

The earliest instance of this arrangement occurred in 1982, when the company built an underground line after Arlington County agreed to purchase the right-of-way from Dominion and also "contribute to the cost of installing the overhead line underground." This information is in the company's application but is not in the final order, so it is unclear why this arrangement was made or if Arlington paid the total additional cost of undergrounding (1982-00075).

Dominion articulated its position during a 1991 case in the City of Manassas (1989-00057). In this case, a 230 kV overhead line was proposed to pass through the historic district. Respondents argued for undergrounding, stating that the overhead line would harm the local business community by making the historic downtown district less appealing for tourists. As noted in the hearing examiner's report, Dominion stated that it would use underground lines in three situations:

- where no viable overhead route was available,
- when the cost of an overhead line exceeded the cost of underground installation, and
- if the incremental cost of underground construction was paid by a third party.

In their opinion authorizing overhead construction, the commissioners stated that Dominion could seek SCC approval to build the line underground if a local source of funding was identified, but no third party was ever identified.

Dominion has agreed to underground a line twice since that time when a third party paid the additional costs:

- In December 1995 agreed to bury 1,700 feet of an existing overhead 230 kV transmission line near Jefferson Street in the City of Alexandria. As noted above, this line already included an 1,800-foot section buried in 1983 as a result of the Richmond, Fredericksburg, & Potomac Railroad Company (RF&P) easement, and Dominion would later seek authority to bury an additional 13,000 feet of the overhead line in May 1996. The City was seeking to place the 1,700-foot section underground in order to permit construction of a planned hotel, convention center, and African-American heritage park and agreed to finance the project.
- In 2002, the U.S. Navy agreed to pay for placement of a 0.5-mile section of new 230 kV line underground. The underground line would "enhance views of the area" and avoid the need for tall transmission towers that could pose a hazard to aircraft (2002-00180). Dominion staff note that any potential reliability problems resulting from this line would only affect the naval base and as such did not justify avoiding the use of undergrounding.

In a more recent case from Loudoun County, the commissioners declined to order undergrounding—even though some parties argued that it would benefit economic development activities—because no third party was willing to bear the costs. The hearing examiner cited continued economic development as a benefit of installing a three-mile section of a 230 kV line underground, concluding that undergrounding would "clearly mitigate the adverse impact of the line on economic development and the environment of this area" (2002-00702). However, no third party was identified and a viable overhead route was available. The commissioners rejected underground construction in their 2004 opinion.

In two other cases that involved economic development considerations undergrounding was requested by Dominion even though no third party was identified. However, undergrounding was necessary because no viable overhead route was available. Dominion had two 230 kV overhead lines that crossed property owned by RF&P. RF&P notified Dominion of a planned hotel and convention center in 1983 (1983-00036), and subsequent retail, residential, and warehouse developments in 1996 (1996-00071). These lines served major portions of Fairfax and Arlington Counties, and the City of Alexandria, and had to be kept in service. However, under a 1969 right-of-way agreement with RF&P, Dominion agreed to relocate the overhead lines if they interfered with the development of the property.

During interviews for this report, however, Dominion staff indicate that the company has changed its position on this matter. Dominion staff state that their increased experience with the problems associated with underground lines mean that they no longer prefer undergrounding, even if a third party will bear the costs.

SCC AND DOMINION HAVE POINTED TO HIGHER COSTS OF UNDERGROUNDING AS A REASON TO AVOID ITS USE

A 2005 SCC staff report noted that one of the key reasons that transmission lines "are not customarily built underground" is that "underground transmission is extraordinarily costly." The extraordinary nature of the expense appears to be a key factor in why the SCC has used various means to mitigate the impact of overhead lines, but has not approved the use of undergrounding for this purpose.

In most transmission cases before the SCC, undergrounding is not presented by Dominion as an option nor considered by the SCC. In a recent case, the SCC noted that the absence of undergrounding alternatives in the case was not surprising, given the issue of ratepayer expense.

> [The company includes] no alternatives that are underground routes. This is not surprising, given that the line can be built overhead. No utility in Virginia has ever built a transmission line underground at ratepayer expense, unless there were extraordinary technical difficulties to building it overhead. Neither has any transmission line been built underground in Virginia at ratepayer expense for aesthetic purposes.

In all seven cases in which respondents to a case promoted undergrounding as a means to avoid the potential impacts of an overhead line, undergrounding was rejected, with cost concerns cited by the commissioners in three instances. The commissioners concluded in these cases that the disadvantages of underground construction outweighed the potential benefits:

> There is no evidence that benefits will accrue to the Company or its ratepayers which outweigh the increased costs and risk of reliability problems associated with the underground installation of a portion of the proposed transmission line (1988-00071, 2002-00702, 2004-00062).

In some instances, experts on behalf of respondents to Dominion's applications before the SCC have presented cost estimates that are lower than Dominion cost estimates. However, there have not been dramatic differences between the costs as seen by respondent experts and Dominion's underground cost estimates. Respondent experts have confirmed the point that undergrounding would be several times more expensive. Differences seem to center on whether the ratio of underground to overhead costs is closest to four or five or six to one.

For example, in 2004, an expert for respondents to a Dominion application estimated a cost for a 230 kV XLPE line of 3.25 miles that equated to about $6.55 million per mile. Relative to Dominion's estimate of overhead costs of about $1.57 million per mile, respondents were in effect indicating that the underground line would be about 4.2 times as expensive as an overhead line. Dominion staff indicated a belief that the respondent's estimate was understated, however, and instead indicated that if all appropriate costs were included the ratio would be closer to five to one.

In 2005, another expert for respondents to a Dominion application estimated an installation cost for a 230 kV XLPE line that equated to about $4.7 million per mile. This cost did not include right-of-way costs and other miscellaneous costs not categorized as material and labor costs for installation. Similarly in 2005, Dominion presented a cost estimate for a 230 kV XLPE underground line for JCOTS. Excluding the types of costs not addressed by the respondent expert, Dominion's 2005 estimate was $5.96 million per mile, and its full installation cost estimate (with right-of-way) equated to about $6.4 million per mile. Compared to the cost figure Dominion gave to JCOTS for a 230 kV overhead line—which was about $1.06 million—the estimate of the respondent's expert produces a ratio of underground to overhead costs of about 4.4 to one. Use of Dominion's estimate without right-of-way produces a ratio of 5.6 to one, and use of Dominion's estimate with right-of-way produces a ratio of about six to one.

Chapter 8

Impact on Property Values and Feasibility of Payment by Surrounding Landowners

In Summary

One cost factor that the SCC does not appear to explicitly consider is the impact of an overhead line on property values. In recent transmission line cases, the available record indicates that the hearing examiner reviewed evidence on property values and in two recent cases found that overhead transmission lines diminished property values. However, instead of explicitly incorporating diminished property values into a calculation of how to best mitigate the effects of transmission lines, the commission appears to qualitatively weigh this factor with the other factors under consideration. The commission has in many instances ordered other types of mitigation—use of tree screens, re-routing of lines, or alternate tower designs—but has never ordered undergrounding as a result of an impact on property values.

The feasibility of allowing surrounding landowners to pay for underground lines is limited. Salient factors include the difficulty of obtaining timely estimates of underground costs, the characteristics of the land along the selected route, the potential impact of anticipated increases in electricity rates on willingness to pay for undergrounding, and statutory restrictions in the use of special assessments.

Landowners near the routes proposed or selected for overhead transmission lines have often expressed concern that the lines will negatively affect the value of their property. These concerns result from the potential unsightliness of the lines as well as concerns about health risks. These issues are examples of externalities: costs that may not be included in the estimated cost of proposed lines. If these external costs are not included in the cost estimates, then certain property owners may bear unreimbursed costs resulting from the physical location of the line. Residents of some communities have expressed the desire to pay for the burial of a transmission line themselves in order to avoid what they perceive as negative characteristics of an overhead line.

Dominion and the SCC do not appear to have a consistent and uniform policy of using the estimated cost impact of overhead transmission lines on property values in determining the overall cost of a project. Instead, Dominion and the SCC have at times responded to these concerns by adjusting the proposed route of the line or taking other measures to mitigate the line's impacts. However, to date in Virginia, undergrounding has not been used as a means of addressing the potential impact on property values.

PROPERTY VALUES DO NOT APPEAR TO BE EXPLICTLY CONSIDERED AS A FACTOR BY THE COMMISSION

Although the SCC has clearly considered cost as a primary factor in its review of transmission line applications, the final orders issued by the commissioners have not specifically noted property values. In contrast, reports by SCC staff and hearing examiners have devoted substantial attention to property values.

The lack of explicit consideration should not be taken as an indication that property values are not included in the commission's analysis. Many of the mitigation measures ordered by the commission (some of which were proposed by the utility) result from an effort to lessen the impact of the line upon the environment. These measures include the use of existing right-of-way, the maintenance of tree buffers, and the use of shorter or non-reflective towers. These steps likely lessen the impact upon property values because the literature indicates that proximity to a line and its impact upon the view shed are two factors that affect a transmission line's effect on property.

There is no written evidence from the cases reviewed that property values are explicitly considered by the commission, nor does the *Code of Virginia* include the impact on property values as a defined component of "cost." These issues may have prompted the call for JLARC to investigate property values as a factor. The legislative mandate for this study notes that "the costs of constructing overhead transmission lines may impact tax revenue, economic development, and property values in the immediate area of the transmission lines" while also noting that "it is in the best interest of the public to provide for the least costly alternative in constructing electrical transmission lines." Moreover, the mandate specifically calls for an examination of "the effect on property values resulting from installing underground, as opposed to overhead, electrical transmission lines."

Property Valuation Studies Appear to Indicate that Transmission Lines Decrease Property Values

JLARC staff reviewed literature on the effects that various features of the landscape have on property values. The studies reviewed were typically published in *The Appraisal Journal* and the *Journal of Real Estate Research*. Staff were not able to locate any studies that specifically considered the effects on property values from underground transmission lines.

JLARC staff focused on more recently published studies largely because studies from the 1960s and 1970s, some of which concluded that there was no negative effect from transmission lines, were published before electromagnetic field (EMF) concerns became widespread. In the intervening years, various state supreme courts and federal circuit courts have found that the public's belief that EMF is harmful is an adequate basis for compensation in a condemnation proceeding even though there is no conclusive scientific evidence. As noted by the Florida Supreme Court in a 1987 case that involved 500 kV transmission lines, public fear may be considered even without scientific justification so long as it affects property values (Florida Power & Light Co. v. Jennings, 518 So.2d 895). It does not appear that Virginia courts have adopted this position, however.

Literature Indicates That Effects on Property Values Result from Two Features. First, transmission lines are in many cases not perceived to be attractive. Second, the public belief that EMF causes cancer can decrease demand for properties near transmission lines and in turn lower property values. The extent to which some buyers may place a premium on avoiding transmission lines is indicated by a 1994 article in the *Washington Post*, which described how some home buyers were adding EMF contingency clauses to their purchase contracts, where the sale would be nullified if EMF levels exceeded a specified threshold.

The studies reviewed conclude that there is an effect on property values of up to 15 percent. For example, a 1992 review of previous studies by the Edison Electric Institute (EEI), an association of investor-owned electric companies, concluded that "overhead transmission lines have the potential to reduce the sales price of residential and agricultural property," and that "the effect, especially for single family homes, is generally small (from zero to 10 percent), but has been estimated to be greater than 15 percent in some specialized cases in rural areas." The EEI review noted that two of the 57 studies analyzed indicated that the effect on property values diminishes over time. EEI added, however, that "impacts appear to last for several years at least, affecting property owners who expect to sell within the first few years following transmission line construction."

In a 2006 *Journal of Real Estate Research* article, the authors concluded from their analysis of 58 peer-reviewed journal articles that proximity to a detrimental feature (such as transmission lines, power plants, railroad tracks, landfills, shopping centers, and animal feeding operations) produced an average loss in property value of 9.5 percent; this applied to properties located within two miles of the site. The authors made several other observations that may be relevant when considering the potential effects of transmission lines on property values:

- Losses may be higher in areas where the rate of appreciation is lower.
- Different buyers may place a higher premium on avoiding certain detrimental features: a person who is concerned with EMF may not dislike living near a busy highway.
- Properties may be affected in ways other than a decrease in sales price, such as a longer time on the market or difficulty obtaining certain types of financing.
- The extent of the impact is driven by factors such as the type of property, its distance from the detrimental features, and the length of time that the feature has been present in the landscape.
- Negative effects may be offset by positive effects, such as presence of parkland on transmission line rights-of-way.
- Many factors can reduce property values, such as landfills and highways, and these may have a larger effect than transmission lines.
- The extent of the impact may depend on the extent to which other detrimental features are in the same area: the presence of several transmission lines may have a different impact than the presence of a single line.

Assessors Express Divergent Opinions Regarding Effect on Property Values. JLARC staff also contacted organizations in Virginia that may have knowledge of the potential impact of transmission lines. Staff spoke with a representative of the Virginia Association of Assessing Officers (VAAO), who stated that transmission lines may affect property values but that it depends upon the nature of the property and its location. The representative, who is a local assessor, also added that many subdivisions are built close to detrimental features, such as interstate highways, but that people keep buying the houses and the values keep increasing. In other words, "A ruckus over construction doesn't always translate into a loss of value." He concluded, however, that transmission lines probably do have an effect.

In contrast, another local assessor stated that he has "not seen any value impairment" and that this results from the fact that an assessor "can never prove that there is an effect in the market." He attributed this to the fact that in his locality, there are always enough people willing to buy a house, and as a result, there is not a discernible effect on property values.

These divergent opinions are important because they indicate that the impact on assessed values—and hence on local real estate tax revenues—may differ from locality to locality. In other words, if assessors in one locality do not believe that transmission lines have an effect or feel that they could not establish an effect, then assessed values may not be affected. However, as indicated by the VAAO representative, assessors may "make a presumption that even though they are looking for the market to tell them what the impact is, they may take a conservative approach and assume that there is an effect." As a result, the representative cautioned that sale prices, not assessed values, should be relied on as the most accurate indication of a marketplace effect.

In addition to local assessors, staff twice contacted the Home Builders Association of Virginia, and the Virginia Association of Realtors, but neither organization provided a response.

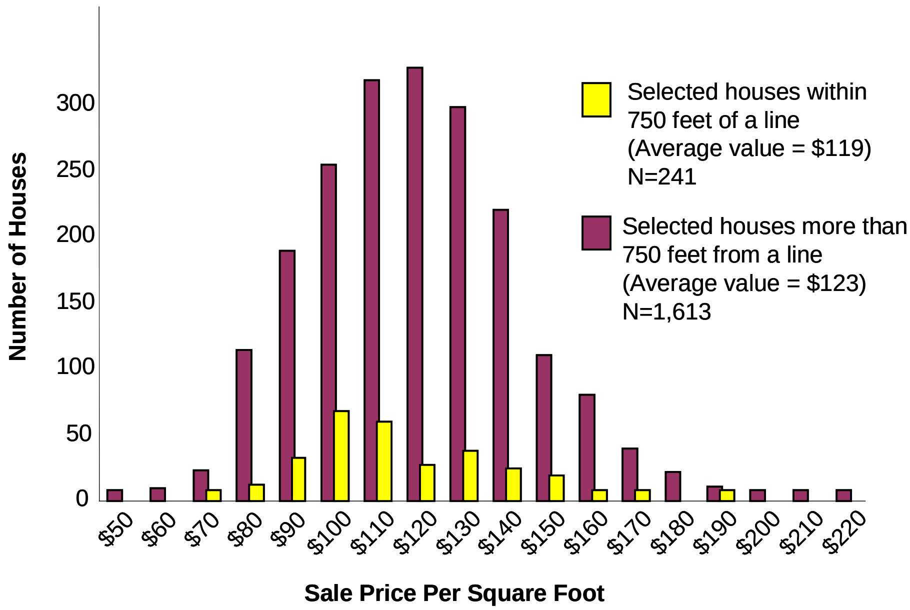
Case Example Indicates that Proximity to a Transmission Line Is Associated With a Decrease in Property Values

JLARC staff explored the use of geographical information system (GIS) data to address the mandate's question regarding the impact on property values. GIS data on the location of transmission lines was requested from Dominion but was not provided for the reasons indicated in Chapter 10. JLARC staff instead used information available from federal and State agencies, local governments, and other published information.

To conduct the analysis, JLARC staff examined assessment data from the County of Henrico. As advised by the assessors contacted for the study, the analysis focused on houses that were as similar as possible and also used sale prices instead of assessed values. As of June 2006, Henrico had 108,148 parcels of land, of which 6,187 had a single-family residence that was sold (for a non-zero price) in 2005. Of this group, 1,854 of the houses were built from 2000 to 2005.

GIS was then used to construct a buffer 750 feet wide around the overhead transmission lines (voltages of 115 kV and greater), and parcels were selected that had their center within this buffer. This resulted in the selection of 241 houses. As indicated in Figure 14, the average sale price per square foot (of finished area) of the 241 houses within 750 feet of the transmission line was $119, compared to an average price of $123 for the other 1,613 houses. This is a decrease of 3.25 percent. JLARC staff next looked at specific types of houses, and the results changed slightly. For example, among colonial style houses, 109 were in the buffer and 1,140 were not. Colonial houses within the buffer had an average value of $117 per square foot compared to $123 for the other colonial houses. This represents a decrease of 4.88 percent. In all of these calculations, excluding extreme values, based on standard

Figure 14: Proximity to a Transmission Line Is Associated With a Decrease in Property Values (Top) and New Houses Are Sometimes Built Next to Transmission Lines (Bottom)



Source: JLARC staff analysis of assessment data from County of Henrico, and JLARC staff observations of the location of 115-, 230-, and 500-kV transmission lines using data from the Virginia Department of Economic Development, the County of Henrico, the Virginia Department of Transportation, and the United States Geological Survey.

deviation or other means, did not change the results. Figure 14 also illustrates another aspect of this debate: many houses have been built right next to transmission line rights-of-way.

Concerns Over EMF and the Visual Impact of Lines Have Been Noted in Some Transmission Line Cases

Based upon the record available to JLARC staff, six cases were identified in which property values played a role. In one case, 1994-00022, that role was very limited; the other five cases reveal a mixed picture, in which transmission lines are deemed to affect property values in some cases but do not appear to be a deciding factor in others. Where property values appear to affect the outcome, the result is that changes are made to the route or type of transmission structure. Property values do not appear to have been used by the hearing examiner or the commissioners, however, as a factor in determining the cost of an overhead line in comparison to an underground line.

One Case Suggests the Commission Did Not Believe It Had to Consider Property Values. The commission took notice of property values as a concern in one case, but did not find that factor to be a sufficient reason to deny the application. The case involved two 230 kV lines in Halifax County, and only one person objected to the lines. In the final order, the commissioners observed that the landowner was concerned about the impact of the line upon a farm she owned, but noted that

> her concerns relate primarily to the impact of the lines on property value. While this is a legitimate concern, [she] has identified no adverse impact on environmental or cultural attributes of the area which the Commission must consider (1992-00043).

Concerns Over Adequacy of Compensation in Eminent Domain Proceedings Was Noted in One Case. One of the most contentious cases reviewed by the SCC was the $306 million, 90-mile Wyoming to Jackson Ferry 765 kV transmission line built by Appalachian Power Company (AEP). In its consideration of this line, the SCC considered—among several other factors—the potential impact of the line upon property values. Several public witnesses testified, and expressed two particular concerns regarding the extent to which eminent domain proceedings would fully compensate them for lost value. First, witnesses noted that many families in the area live on land that has been passed down for generations and as such attach a value to the land that a "fair market price" may not include. Second, witnesses argued that payment for a right-of-way through a portion of the property would not account for the loss of value to the rest of the property, an occurrence termed consequential damage.

In rebuttal testimony, an expert witness concluded that "no consistent or systematic impact on real estate prices of properties within one-fourth of a mile of a 765 kV transmission line was found, except for properties actually traversed by the right-of-way." The hearing examiner noted that this testimony was not cross examined.

In his report from October 2000, the hearing examiner noted that the "impact of a transmission line on property values is a consideration in this proceeding" and that although "the impact on property values cannot be avoided, it can be minimized with the shorter route and final right-of-way siting." It does not appear, however, that the potential monetary impact upon property values was included in the cost estimate for the line. This would be in keeping with the commission's reluctance to quantify externalities, particularly if doing so would give greater weight to those factors over others that are not quantified.

Another distinguishing feature of this case is AEP's policy of offering to purchase—at 100 percent of fair market value—any parcel on which a primary residence or structure used for daily business is located within 100 feet of the edge of the right-of-way. This policy is in place for up to one year after the line is energized. The commission's decision making appears to have considered this policy because the final order of May 2001 stated that approval of the application was conditioned on AEP's commitment to implement mitigation measures, and this policy was included as one of several mitigation measures attached to the order.

Recent Case in Loudoun County Involved the Link Between EMF Concerns and Decreased Property Values. More recently, health concerns resulting from EMF exposure have been identified by public witnesses and the hearing examiner as a reason why property values will likely be diminished (2001-00154). This case was the first of three recent cases in Loudoun County and is known as "Phase I." In this instance, Dominion filed an application in March 2001 for two 230 kV lines (1.6 and 2 miles long, respectively). Another reason offered for a reduction in property values was the visual impact of the lines, and the hearing examiner made note that one subdivision did not have a tree barrier and had "no other way of mitigating the effects of the proposed transmission line."

At public hearings, the record indicates that 14 witnesses testified about the possible adverse health effects of EMF and the adverse impact of the proposed transmission line on property values. One group of homeowners retained an expert witness, who compared the selling prices of homes affected by the transmission lines with the selling prices of otherwise similar homes that were not affected. The witness adjusted for other quantifiable differences between the two groups, such as differences in square footage, and subsequently attributed the 15 percent difference in selling price to the impact of the transmission lines.

Based on the testimony of this witness, homeowners offered estimates of the impact on property values that could result if the transmission line followed the route segment (number 19) that they opposed:

- One homeowner was "worried about the effects of EMF and the loss of between $67,500 and $100,000 in value for his house."
- Another homeowner estimated that the proposed transmission line would "reduce the value of her home by between $50,000 and $75,000."
- A third witness argued that the segment opposed by the homeowners "was the most expensive route if the estimated $1.5 million to $2.25 million in lost property value for residential homeowners is considered."

As a rebuttal witness, Dominion offered the testimony of another expert, who found fault with the valuation methodology used by the other expert and argued that the results were inconsistent with other studies. The specific fault identified was the method of determining market value by comparing a single sale price for two individual homes and subsequently attributing the difference in sale prices to a single factor. In addition, the rebuttal witness pointed out that the resulting estimates were "inconsistent with published studies regarding the impact of transmission lines on property values, which usually peg the effects within + or – 10%."

In his report of January 25, 2002, the hearing examiner wrote that the testimony of the homeowner's witness was "more compelling," noting that this paired sales analysis was consistent with other residential property valuations he had seen. However, the hearing examiner observed that the paired sales analysis used a limited sample size (only six sales of homes without transmission lines to six sales of similar homes with transmission lines) and that the estimate of a 15 percent reduction was not in line with published studies. After taking these factors into account, the hearing examiner concluded:

> I find that the record in this case supports a finding that the 35 most affected homes in Regency and Cameron Chase will likely suffer a diminution in value of 5% to 10% and

> that 80 other homes in these neighborhoods will suffer a diminution in value of 1% to 5%.

The hearing examiner also noted that concerns about the health effects of EMF likely is one of the reasons why property values decrease:

> The testimony related to the effects or lack of effects of EMF, at a minimum, demonstrates why construction of the Greenway Line likely will reduce the property values of some of the homes in the Regency and Cameron Chase neighborhoods. In sum, though there is insufficient proof to link EMF from transmission lines with specific cancer risks, concerns continue.

In the final order in this case, which granted approval and remanded the case for further proceedings, the commissioners appear to agree with the hearing examiner's conclusions: "As found by the Examiner, Segment 19 will have a significant and detrimental visual impact on existing homes and businesses." The commissioners found that the line was needed and that an alternate route—one that differed from the segment protested by homeowners—should be used.

Subsequent Loudoun County Case Involved Whether Property Owners Should Have Known the Line Was Planned. Another policy issue is apparent from the record of a second transmission line case in Loudoun County: whether knowledge of the proposed line would have affected the decisions of landowners to purchase their property. In this case, known as Phase II, Dominion filed an application in December 2002 for a 230 kV transmission line of approximately 8 miles in length. In its application, Dominion noted that residents were concerned about the impact that various routes might have upon property values and it appears that these factors were taken into consideration.

In her report, the hearing examiner included the testimony of several witnesses whose statements indicate that a lack of information about the proposed line was a common concern. Three witnesses stated that they were unaware that a line would be built when they purchased their property. In addition, a member of the General Assembly testified about the foreknowledge of landowners. According to the hearing examiner's report, the delegate

> had been contacted by several of his constituents. They informed him that although the contractors that built their homes may have realized a power line may be built, the purchasers were not notified and purchased with the un-

> derstanding that they were going to have a community with a certain appearance.

These statements indicate that some members of the general public were not aware that the line was under consideration. It is beyond the scope of this report to assess the reasons for this, or whether homeowners should have known about the proposed line. But the requirement that a utility use existing rights-of-way may help to ensure that persons who own property in areas away from existing easements will not unexpectedly suffer a potential decrease in property values. This issue would resurface in a later case in Fauquier, as discussed below.

As in Phase I, testimony was offered that indicated properties near the transmission line would be diminished in value. A paired sales analysis indicated a diminution of market value of 1 to 15 percent. Dominion offered rebuttal testimony, which indicated that there would be no impact on property values. One of Dominion's experts produced visual impact simulations and concluded that although the woods would be thinner for 50 to 100 feet, a tree buffer 300 to 500 feet thick would remain. The hearing examiner concluded that the simulations and residents' concerns over EMF risks indicate that there may be an impact on property values but that the tree buffer would greatly mitigate the impact.

In its final order, the commissioners appear to have considered the impact of the proposed and alternative routes upon property values. Although property values were not explicitly discussed, the commission did note the impact that various routes would have on the properties involved. As in earlier cases, the commissioners used a combination of routing and changes to pole heights and placements to mitigate impact. The final order did not discuss EMF, however, in contrast to the hearing examiner's report.

The Most Recent Case Rejected EMF Concerns and Suggested Homeowners Should Be More Aware of Planned Lines. In a 2004 case in Fauquier County, the issue of knowledge of a proposed line by property owners was used to counter claims that their property values would be unfairly diminished. In this case, Dominion filed an application in May 2004 for a new 500 kV transmission line, approximately eight miles long, which would be constructed entirely within existing right-of-way and paralleling an 500 kV line (2004-00062).

In filed comments, the Fauquier County Board of Supervisors indicated their concern that the proposed line would affect property values. The record reflects that many citizens filed comments, including information on the effect of EMF on health and the effect that the original line had upon property values at the time.

One witness provided some background about how the existing right-of-way was obtained. According to this witness, Dominion acquired its 235-foot wide easement in 1973 by instituting an eminent domain proceeding in the Circuit Court of Fauquier County (Virginia Electric and Power Company v. Danlon Associates, Et Al.) During this proceeding, the value of the 17.41 acres that would be condemned needed to be determined, as well as the extent of damages to the rest of the subdivision. In the condemnation proceeding, an expert witness testified that the value of the subdivision before the taking was $1,170,000, and after the taking it was valued at $598,441. It was also noted that EMF was not mentioned in the 1973 case and that the focus was on visual pollution.

SCC staff and Dominion stated that property owners had "been on notice" since the condemnation proceeding was filed in 1973. The fact that property owners should have known about the line was used as an indication that there would not be a new impact. Dominion pointed out that

> Virtually all of the 40 residents in Coventry purchased their properties after the existing line was built in the southern side of the right-of-way and could see that the northern side was open and could have checked the public records to determine the status of the open side. . . . The incremental impacts of the proposed new line were, or should have been, foreseeable by the residents in Coventry before they decided to live there, and are no different from those experienced by other landowners adjacent to transmission lines in other locations on the Company's system.

Dominion further argued that any property value impact of the new line was addressed in the condemnation proceeding, when the then-owner of the property was awarded damages for the right-of-way, "which included the right to construct not just the now existing line but additional lines as needed." Dominion added that the claims by current owners that the transmission line affects property values "are belied by the actual proximity of their residences to the existing and proposed lines." Noting that one resident of the subdivision recently acquired an additional property on the edge of the right-of-way, about 450 feet from the existing line, Dominion observed that "Clearly, impacts from proximity to the existing power line were not a deterrent to that transaction."

The hearing examiner appears to have agreed with Dominion's reasoning, noting that the homeowners "chose voluntarily to build next to a major transmission line corridor. In property law parlance, they moved to the nuisance." The hearing examiner also pointed out that the other alternatives considered by Dominion would require the acquisition or condemnation of additional rights-of-way, thereby affecting other property owners.

Unlike the cases in Loudoun County, in this case the potential effect on property values resulting from EMF was not included as a factor: the hearing examiner wrote that the vast majority of studies have not found a causal relationship between EMF and detrimental health effects. Instead, the hearing examiner stated that Dominion's offer to design and purchase vegetative buffers on the property of affected homeowners, as a result of clearing vegetation from the right-of-way, was "a reasonable response to the homeowners' concerns raised in this case."

The commissioners appear to have adopted the hearing examiner's reasoning, noting that alternative routes would require the acquisition or condemnation of additional rights-of-way, and that "based on the facts presented in this case, we find that the claims of EMF impacts were refuted by evidence presented by the Company." The commissioners also agreed with the hearing examiner that Dominion's offer to place vegetative buffers was a reasonable response, and directed the company to comply.

FEASIBILITY OF ALLOWING SURROUNDING PROPERTY OWNERS TO PAY FOR UNDERGROUND LINES IS LIMITED

In addition to an examination of property values, the mandate specifically calls for an analysis of "the feasibility of allowing surrounding property owners to agree to pay for the installation of underground lines."

There appear to be four broad issues to consider. First, the existing process used to certify transmission lines does not require the utility to provide cost estimates as part of the application, which may hinder an evaluation of the additional costs. Second, the route chosen for an underground line may not have a sufficient number of property owners to bear the costs. Third, anticipated increases in electricity rates may diminish the desire of ratepayers to incur the additional costs associated with undergrounding. Fourth, there appear to be some legal restrictions on the extent to which the most likely mechanism—a special tax assessment—can be used.

Obtaining Accurate Cost Estimates for Consideration by Surrounding Property Owners May Be Problematic

The property valuation literature and testimony in recent transmission line cases indicate that property values may be decreased by about 10 percent. As a result, it may be in the best financial interest of homeowners to pay for undergrounding if the cost of doing so is equal to or less than the cumulative decrease in property values.

A possible barrier to making this determination is the need for an accurate cost estimate of the overhead and underground alternatives. The party which is likely in the best position to make this determination is the utility, which may have staff with expertise in undergrounding or could use the services of an outside consultant as part of the necessary route selection process. Utilities are not required to submit this information, however.

The one utility in Virginia that has installed underground lines, Dominion, has maintained its opposition to the use of undergrounding, even if another party is willing to pay the costs. This does not indicate that underground lines could not be installed, however, if the commissioners order their use. As noted in the SCC's report *Implications of a Requirement to Consider Undergrounding of Electric Transmission Lines*, under the commission's Rules of Practice and Procedure any locality can request that the commission consider undergrounding by filing a notice of participation in a case as a respondent. The report also stated that the commission already has the authorization to condition approval of a transmission line upon the line being located underground.

Once this information is obtained, in some cases it may indicate that the additional cost of undergrounding a line exceeds the total decrease in property values. In the first Loudoun case (2001-00154), a public witness testified that the total decrease in property values (in a given area) would range from $1.5 million to $2.25 million. This potential decrease, while not insubstantial, is much less than the estimated cost of undergrounding. Dominion's prefiled testimony indicated that an underground alternative would increase the cost from $10.2 million to $26.1 million.

Characteristics of the Property Affected May Affect Willingness or Ability to Pay

Leaving aside the matter of the actual cost of installing an underground line, the kinds of situations in which an underground line may be installed is an important factor. To date, underground lines have been approved by the SCC for relatively short distances, in dense urban settings, or where a submarine crossing of a water body is required. In those cases, existing rights-of-way were not suitable or were not available. However, where an existing right-of-way is available, it does not appear likely that homeowners would obtain much benefit from a new line being constructed overhead when an existing overhead line is present. Similarly, in situations where a new 230 kV line is proposed to occupy the same right-of-way as a future 500 kV line, undergrounding the smaller line may not be a satisfactory solution if the 500 kV line will be built overhead.

As a result, undergrounding will more likely be desirable in cases where new right-of-way is required. It is in these situations where an overhead line may be more intrusive if its installation requires clearing trees and is done in an area where other transmission lines are not and will not be present. The commissioners have not required the use of undergrounding in two cases where a historic site was affected by the line: the Sully Historic Site (1988-00042) and the Manassas Battlefield (1994-00036). However, the feasibility of allowing surrounding property owners to pay for undergrounding will likely depend, in part, upon the number of people affected by the newly cleared right-of-way, the value of their property, and other characteristics that may affect their willingness to pay for undergrounding.

In some parts of the State, property values may be sufficiently high that homeowners would be willing to pay for undergrounding. Even so, there would need to be a sufficiently large number of people affected, relative to the cost of undergrounding, for the additional payment to be desirable. It is on this point that past commission policies on routing a line may work against payment by surrounding property owners.

The commissioners have indicated a desire to route lines such that they come close to as few houses as possible. To this end, the staff guidelines request information on the number of houses that will be within 500 feet of a line. If this routing is successful, the number of nearby property owners is decreased. The chosen route may also pass through a mix of neighborhoods: some with relatively high home values or personal income, others with relatively less. As a result, some homeowners may not find the additional expenses to be affordable or reasonable.

Transmission lines that are routed in part through industrial or commercial areas may be less intrusive, and property owners in those areas may not desire undergrounding. A “hybrid” line, one that is partially overhead and partially underground, may be offered as a solution in these cases but this type of approach would require that a 7,500 square foot parcel of land be available for transition structures, where an underground line is connected to overhead towers.

Anticipated Increase in Electricity Rates May Affect Ability to Pay

Relatively low electricity rates in Virginia result from the rate caps implemented as part of the Virginia Electric Utility Restructuring

Act. Rates have been capped since 1998, and apart from annual adjustments for the cost of fuel beginning in July 2007 customers of Dominion Virginia Power will not see an increase in overall electricity rates through 2010 under current law. Yet these increases—and the market prices that will follow the expiration of rate caps—may be sufficient to limit the willingness of some property owners to incur additional costs.

The SCC is of the opinion that electricity prices will likely increase. According to the latest status report by the SCC, *The Development of a Competitive Retail Market for Electric Generation within the Commonwealth of Virginia*, "Virginia retail customers could see precipitous increases in their electric bills" prior to the expiration of capped rates on January 1, 2011. Moreover, the SCC warns that "post rate cap prices could be significantly higher than today's capped rate levels." An increase in electricity prices may be especially challenging for some older Virginians.

In contrast, Dominion notes that "the SCC's opinion that post-capped rate prices will be precipitously higher is not a universally held view." Dominion refers to the benefits of well-functioning competitive markets and argues that despite high electricity prices (which are driven by high fuel costs), robust competition will continue to benefit consumers, especially if policy makers continue to support an effective restructuring process.

Statutory Restrictions May Hinder the Use of Special Assessments as a Mechanism

If cost estimates could be obtained and public support warranted such an investment, then the locality would have to observe certain legal requirements. One mechanism that may be used is for the locality to levy a special assessment. Authority for the creation of these assessments is found in Sections 15.2-2404 – 15.2-2413 of the *Code of Virginia*, and Article X, Section 3 of the *Constitution of Virginia*. A key feature of this mechanism is that the cost of a project is borne by those who benefit from it. Procedurally, these districts are created after a petition by a majority of the landowners in the proposed district (60 percent in counties; 75 percent in cities) or by a two-thirds vote of the governing body.

Section 15.2-2404 specifies the improvements for which assessments may be levied: sidewalks, paving existing alleys, sanitary or storm water management facilities, retaining walls, curbs, gutters, waterlines, street lights, canopies, benches, waste receptacles, and "permanent amenities." Additional types of improvements are allowed in specific localities, including the installation of underground transmission lines in Loudoun County.

Because these assessments produce a revenue stream that may need to be collected over many years, an underground project may require an additional form of financing, such as the issuance of a bond, to pay for up-front costs of the project. If this is the case, the resulting bond issues would be moral obligation, and hence could be more difficult to market and may carry a marginally higher interest rate than general obligation bonds. In some localities, these issues may count against the locality's debt capacity ceiling. JLARC staff inquired about these concerns with local development officials and were informed that a bond attorney would need to be consulted about any specific project.

Two aspects of current law that may prove problematic to the feasibility of this approach are the statutory requirements that these assessments be made only on "abutting" landowners and that the assessments "shall not be in excess of the peculiar benefits resulting from the improvements" (Section 15.2-2404). There is a constitutional basis for these restrictions: Article X, Section 3 of the *Constitution of Virginia* provides that

> The General Assembly by general law may authorize any county, city, town, or regional government to impose taxes or assessments upon abutting property owners for such local public improvements as may be designated by the General Assembly; however, <u>such taxes or assessments shall not be in excess of the peculiar benefits resulting from the improvements to such abutting property owners</u> [emphasis added].

According to bond attorneys contacted by JLARC staff, these requirements may mean that specific measures of cost and benefit be used, such as increases in property value.

There are also statutory limits on the amount that can be funded through these assessments in cities and towns. The assessment may not exceed 50 percent of the total cost in cities or towns (unless otherwise agreed) with certain exceptions based on population thresholds (Section 15.2-2406). Moreover, the other 50 percent of the cost would have to be obtained by other means.

Chapter 9

The State's Role in Approving Transmission Lines May Diminish in the Future

In Summary

Dominion, like other utilities, is planning several new transmission lines. These lines are designed to respond to projected increases in the demand for electricity and also to ensure the reliability of the transmission grid. Some of the new projects planned by Dominion indicate that the company uses several methods other than building new lines to respond to load growth and reliability concerns. Moreover, some of the plans suggest that overhead lines may allow for greater flexibility than underground lines. One aspect of future transmission lines that may differ from those approved and built in the past is the increasing focus on regional planning. As required by the Virginia Restructuring Act, Dominion is a member of a regional transmission organization. This organization has identified new lines in Virginia that it states must be built in order to ensure the operation of the regional grid. This change raises questions about the extent to which undergrounding or other forms of mitigation will be used. In addition, one of these lines may be the first instance of a new federal approval process, whereby lines that are deemed to be of national importance are approved by federal authorities rather than the SCC.

Like other utilities, Dominion is planning to build several new transmission lines. The October 2006 Long-Term Reliability Assessment published by the North American Electric Reliability Council (NERC) indicates that utilities in the southern part of the U.S., including Virginia, plan on adding 1,624 miles of 230 kV, 270 miles of 345 kV, and 345 miles of 500 kV transmission lines in the 2006–2015 time period. This equates to more than $6.75 billion in expenditures over the next five years. In Virginia and North Carolina specifically, planned transmission additions include 647 miles of 230 kV lines and 105 miles of 500 kV lines.

The role of the SCC in approving some of these new lines, particularly at the 500 kV level, may change as a result of recent federal legislation that would allow the Federal Energy Regulatory Commission (FERC) to designate certain future transmission lines as being of national importance. One such line has been proposed in Northern Virginia, and if it is designated as a National Interest Electric Transmission Corridor (NIETC), then State control could cease 12 months after either this designation or after the case is filed with the SCC.

DOMINION'S LONG-RANGE PLAN ANTICIPATES MANY NEW TRANSMISSION LINES

Dominion updates its *Electric Transmission Long Term Plan* annually and posts portions of it on the company's website. Information about Dominion's plans may also be found in PJM's Regional Transmission Expansion Plan, as discussed below. According to the information in these public documents, Dominion plans many new transmission lines over the next 17 years, primarily in Northern Virginia and Hampton Roads/Southside. Information on these lines is presented in Table 17 and Figure 15.

Although new transmission line are planned, Dominion's plan indicates that it accommodates load growth by several means. In some cases, new lines can be avoided or delayed by improving (uprating) existing lines. Improvements to a line in Chesterfield County, combined with the addition of a second line to existing

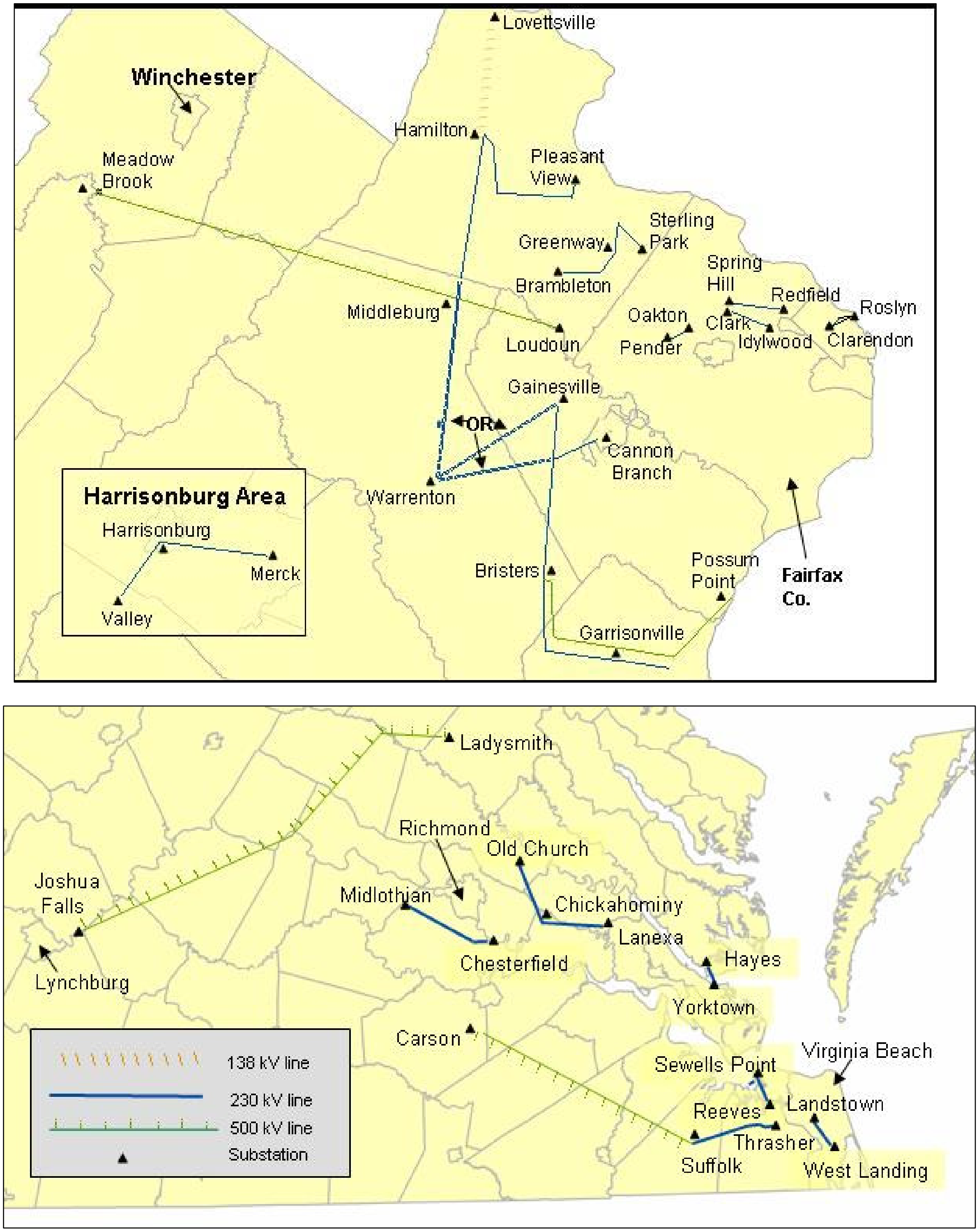
Table 17: Dominion's Long Range Plan Lists New Transmission Lines Statewide

Substation (Locality)–Substation (Locality)	Voltage	Planned Date
Landstown (Virginia Beach)–West Landing (Virginia Beach)	**230**	**2007**
Clarendon (Arlington)–Rosslyn (Arlington)–Ballston (Arlington)	69 & 230	2008
Brambleton (Loudoun)–Greenway (Loudoun)	**230**	**2008**
Pleasant View (Loudoun)–Hamilton (Loudoun)	230	2008
Old Church (Hanover)–Chickahominy (Charles City)	**230**	**2009**
Bristers (Fauquier)–Gainesville (Prince William)	230	2009
Garrisonville (Stafford) loop line	230	2009
Harrisonburg (Rockingham)–Valley (Augusta)	*230*	*2010*
Suffolk (Suffolk)–Thrasher (Chesapeake)	230	2011
Carson (Dinwiddie)–Suffolk (Suffolk)	500	2011
Chickahominy (Charles City)–Lanexa (New Kent)	230	2011
Bristers (Fauquier)–Garrisonville (Stafford)	230	2011
Meadow Brook (Shenandoah)–Loudoun (Loudoun)	500	2011
Harrisonburg (Rockingham)–Merck (Rockingham)	230	2012
Hayes (Gloucester)–Yorktown (York)	230	2012
Pender (Fairfax)–Oakton (Fairfax)	**230**	**2014**
Midlothian (Chesterfield)–Chesterfield (Chesterfield)	*230*	*2015*
Clark (Fairfax)–Idlywood (Fairfax)	*230*	*2015*
Reeves (Norfolk)–Sewells Point (Norfolk)	230	2015
Bristers (Fauquier)–Possum Point (Prince William)	500	2016
Joushua Falls (Amherst)–Ladysmith (Hanover)	500	2016
Brambleton (Loudoun)–Sterling Park (Loudoun)	230	2018
Bristers (Fauquier)–Cannon Branch (Manassas)	230	2019
Middleburg (Loudoun)–Hamilton (Loudoun)	230	2020
Hamilton (Loudoun)–Lovettsville (Loudoun)	138	2022
Warrenton (Fauquier) networking alternatives	230	2023
Redfield (Fairfax)–Spring Hill (Fairfax)	230	2023

Notes: Lines in **bold** have already been approved by the SCC. Lines in *italics* are proposed for installation on existing overhead towers.

Source: Dominion Electric Transmission Long Term Plan, October 2006. http://www.dom.com/about/elec-transmission/

Figure 15: Transmission Lines Planned By Dominion in Northern Virginia (Top Map) and Southside and Hampton Roads (Bottom Map)



Note: Transmission line routes illustrate the locations to be connected, not the actual route.

Source: JLARC staff analysis of Dominion's October 2006 Electric Transmission Long Term Plan.

towers, will meet load growth in Chesterfield without having to acquire new right-of-way. Similarly, by improving a 230 kV line that runs from Chuckatuck to Newport News, Dominion can avoid building a new 500 kV line from Chickahominy to Williamsburg (Skiffes Creek).

In other situations, a new project will accommodate load in one area, thereby delaying the need for a project in a second area. For example, the proposed Hamilton substation in central Loudoun County will take some of the load now served by the Middleburg substation, possibly delaying the need for new transmission projects in the Middleburg area.

Projects included in the plan also suggest that overhead construction provides more flexibility than undergrounding. For at least three new transmission line projects (indicated in Table 17 by italics), Dominion proposes to add a second line to existing transmission towers. To achieve the same result on an underground line, during initial construction a second trench would be required and pipes or a ductbank would need to be installed. In at least two other cases listed in Table 17, a portion of the line can be placed on existing structures, although new right-of-way will be needed for the remainder.

Interstate considerations also affect local transmission planning. Projects planned for Northern Virginia are affected by the fact that some of the 230 and 500 kV transmission lines in that area are used to import and export power.

Interstate considerations also affect local transmission planning. Projects planned for Northern Virginia are affected by the fact that some of the 230 and 500 kV transmission lines in that area are used to import and export power. When a new project is proposed, Dominion gives consideration to whether it would affect power flows between Virginia and other states. In addition, planners look at whether a project built for **intrastate** distribution or transmission needs could also accommodate **interstate** needs. As a result, power flows have affected the types of alternatives proposed by Dominion. For example, construction of the Pleasant View-Hamilton line is intended to be the first step in creating a 230 kV network that runs south to Middleburg and then east to Loudoun. This network is needed in order to reduce power flows on the existing corridor from Loudoun to Pleasant View, which is used for interstate power imports and exports in addition to supplying local distribution needs. Power is imported into Northern Virginia because the region does not generate enough power to meet demand.

REGIONAL PLANNING AND THE FEDERAL ENERGY POLICY ACT MAY CHANGE THE ROLE OF THE SCC

The role of the SCC and the Commonwealth in general in regulating electric utilities is changing, and this could affect the process used by the SCC in all transmission line siting cases. The role of the SCC began to change with the passage of the Virginia Electric

Utilities Restructuring Act in 1999, which had two pertinent changes: utilities were required to allow other electricity generators to use their transmission lines, and the utilities were required to join a regional transmission organization (RTO). More recently, the passage of the federal Energy Policy Act of 2005 altered the incentives and requirements for the transmission grid.

The restructuring act required Virginia's utilities to join an RTO in order to ensure the success of deregulation. The RTOs are overseen by FERC and are designed to allow for a regional approach to transmission operating, planning, and investment. This is accomplished in part by having the RTO manage the daily operation of each utility's transmission lines, including the setting of rates for the transfer of wholesale power between utilities. Virginia's largest utilities decided to join an RTO known as PJM, which is located in the mid-Atlantic area. Electric utilities in several other states are also members of PJM.

PJM's Regional Transmission Line Planning Has Identified the Need for Several New Lines in Virginia

As a result of FERC's encouragement of RTOs and Virginia's requirement that its utilities join an RTO, the role of the SCC appears to be changing. This may be seen in part by looking at the role that PJM plays in planning for new transmission lines. One of the activities undertaken by PJM is its Regional Transmission Expansion Planning Process (RTEP), which will likely result in increased transmission construction in future years. As noted in PJM's 2006 RTEP, the electricity needs of customers in New Jersey, Delaware, eastern Pennsylvania and Maryland (including Baltimore and Washington, D.C.) are supplied in part by wholesale power transfers along interstate extra-high voltage (EHV) lines in Northern Virginia, northern West Virginia, western Maryland, eastern Ohio and southwestern Pennsylvania. These growing transfers "are driving the need for transmission upgrades" which PJM is responsible for addressing.

A review of Dominion's planned transmission lines indicates that several projects in the northern part of Virginia are identified as resulting from, or being affected by, transmission needs outside of Virginia. Dominion's plan indicates that several projects (such as transmission lines or transformers) are included in PJM's regional plan. Of the 124 projects in Dominion's plan, 18 are required by PJM. However, it is not clear whether these regional considerations will affect the role of the SCC or its decisions.

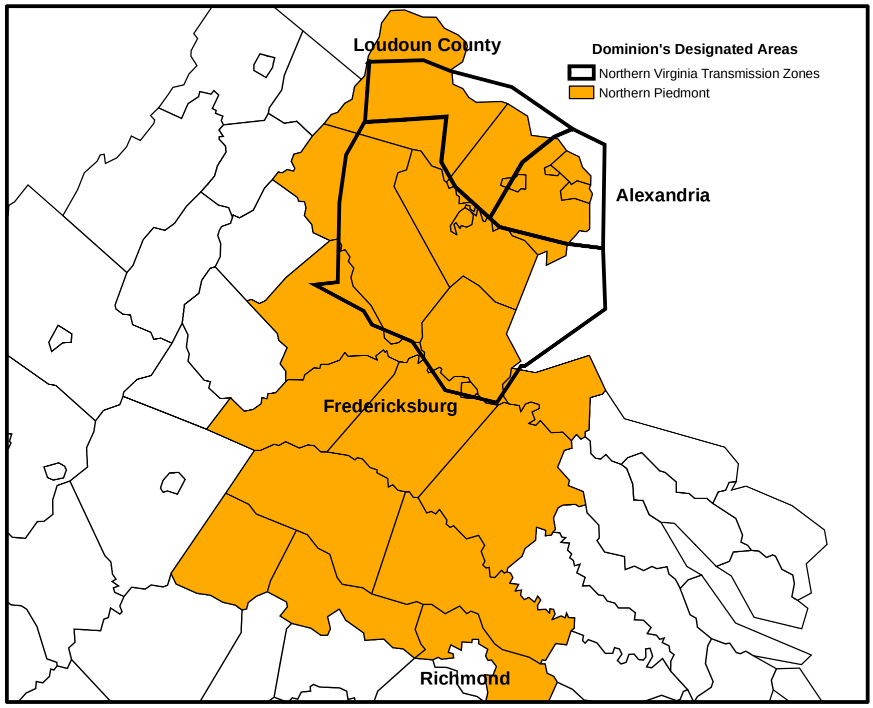
The results of this regional approach to transmission line planning may be seen in two recently announced projects, and an apparently unannounced project, which appear to be designed to address regional needs:

- The 230 kV Bristers-Gainesville line, running for 16 miles between Fauquier and Prince William Counties, and associated substations will help alleviate stress "on the critical EHV interfaces north of Pleasant View substation." These stresses are caused in part by a new wind farm in West Virginia. Dominion filed an application for certification of this line in May 2006 (2006-00048).
- New lines near Harrisonburg, such as the 230 kV Harrisonburg-Valley line, will also be needed in part because of "heavy west to east transfers across the EHV interfaces to the north."
- The 500 kV Meadow Brook-Loudoun line is proposed as a solution to contingency analyses which indicate that lines in West Virginia and Maryland could overload under certain conditions. Dominion's responsibility consists of 30 miles between the termination of Allegheny Power's responsibility in Frederick County and Dominion's substation in southeastern Loudoun County.

Dominion states that these lines, including the Meadow Brook-Loudoun line, are needed to ensure the reliable delivery of electricity to Virginia consumers. According to the company, Northern Virginia will face severe reliability problems by 2011 if these lines are not built. This results in part from the fact that power must be imported into Northern Virginia because it is "generation deficient." Specifically, in Dominion's three Northern Virginia transmission zones (illustrated in Figure 16), peak load in the summer of 2007 is expected to be 6,031 megawatts, but generation within this area is expected to be only 2,926 megawatts. Additionally, Dominion states that electrical demand in Northern Virginia has grown by 40 percent in the past ten years and is expected to grow an additional eight percent by 2011.

However, the regional or multi-state nature of these lines may be seen in the fact that PJM's proposals to FERC indicate that Dominion may recover most project costs from other utilities. This allocation, however, is currently before FERC and has not yet been endorsed by that body. As required by Schedule 6 of PJM's Operating Agreement (Section 1.5.6), PJM allocates cost responsibility for a transmission line based on the extent to which load in one or more utility service areas (such as Dominion's) causes the need for the upgrade. This cost assignment is necessary, according to PJM, because "in a large, integrated transmission system such as PJM, demand in one area can and does contribute significantly to congestion and overloads on facilities in other areas." PJM notes

Figure 16: Location of Dominion's Northern Virginia Transmission Zones and its Northern Piedmont Region



Source: JLARC staff.

that the allocations "are a reasonable approximation of the long-term benefits of the upgrades." In contrast, the costs for Dominion's planned 500 kV line across southern Virginia, from Dinwiddie County to the City of Suffolk, is currently assigned completely to Dominion. The cost allocations for these lines are listed in Table 18.

It is important to note that a line which is built to relieve congestion or address regional reliability concerns may also improve Dominion's overall system reliability in Virginia by providing alternate pathways on which power can flow. JLARC staff asked whether the proposed Bristers-Gainesville line serves this purpose, given that PJM has assigned the costs to other utilities. Dominion staff indicated that the utility still needs the line to serve its load in Northern Virginia, even if this load is smaller relative to the load that will be served in other states. Dominion staff also pointed to the fact that the line was originally included in their 2005 long-term plan. This plan, which was issued in October 2005, does include the line. The October 2004 plan, published before Dominion joined PJM in May 2005, does not.

Table 18: PJM's Preliminary Recommended Cost Allocations for Planned Transmission Lines in Virginia

Utility	Planned Transmission Line			
	Meadow Brook-Loudoun	Harrisonburg-Valley	Bristers-Gainesville	Carson-Suffolk
Atlantic City Electric	4	2	4	0
Allegheny Power	0	20	3	0
Baltimore Gas and Electric	19	8	17	0
Delmarva Power and Light	6	3	6	0
Dominion	**0**	**33**	**0**	**100**
Jersey Central Power & Light	9	5	9	0
Metropolitan Edison	4	2	4	0
Long Island Power Authority	1	0	1	0
PECO Energy	12	6	12	0
Pennsylvania Electric	1	1	2	0
Potomac Electric Power	21	8	19	0
PPL Electric Utilities	9	5	9	0
Public Service Electric & Gas	14	7	13	0
Rockland Electric	0	0	1	0

Source: JLARC staff analysis of material submitted by PJM to FERC, and presentations by PJM's Transmission Expansion Advisory Committee.

Although SCC staff noted that the Bristers-Gainesville line is the first Dominion project submitted to the SCC that has been authorized by PJM, the staff report in this case did not discuss the relationship between the needs identified by PJM and those identified by Dominion. As noted by SCC staff, Dominion's application stated that the proposed line is needed in order to continue to provide reliable service within its Northern Piedmont region (Figure 16), which includes 20 localities. SCC staff observe that "the proposed line would deliver power into Prince William County, which lies at the edge of the Washington, D C. metropolitan area, and is experiencing rapid business and residential development." The SCC staff report, like Dominion's application, was silent on the multi-state need for the line.

If these changes alter the role of the SCC, they may also affect the use of undergrounding. It would not be unusual if undergrounding was proposed for these lines during the transmission line proceedings before the SCC. The more likely scenario, if these line are approved, is that some alternative form of mitigation will be required, such as the maintenance of a tree buffer or changes to the proposed towers. A question therefore arises as to whether Dominion will be required to pay for undergrounding or any other type of mitigation effort if a project's costs are borne by utilities outside Virginia. In response to this question, the commissioners informed JLARC staff that "any requirements placed by the Commission on a certificate of public convenience and necessity, in the form of conditions or otherwise, must be met by the applicant."

Under State law, the SCC retains the authority to certify all new transmission lines proposed for construction in Virginia. The exact nature of how the SCC's certification process may change, if at all, as a result of PJM's planning process is not yet known. PJM is making several changes to the RTEP process, which will now be done over a 15-year horizon, and will result in "a new level of approval which will require the affected Transmission Owners to proceed with preliminary siting, environmental impact assessment, and potential right-of-way acquisition." Consequently, as planning shifts in part to a regional process, local or State agencies in Virginia may not be involved in the designation of transmission line corridors or in a discussion of the appropriate technology. Of note, a review of membership lists for the two PJM groups most closely involved in developing the RTEP indicates that the only members from Virginia are utilities. In contrast, both Pennsylvania and the District of Columbia have government representation.

Local and State agencies may benefit from greater participation in PJM's planning process, in order to voice concerns or advocate for certain projects. In some cases, the shift to a regional process may mean that local and State agencies may need to participate in proceedings before FERC. For example, several members of PJM have questioned the assumptions used by PJM to approve certain transmission lines, and the resultant cost allocations. Among the projects questioned by other utilities is the proposed Meadow Brook-Loudoun line. For example,

- Public Service Electric & Gas (PSEG) of New Jersey argues that "PJM has made certain planning assumptions, which we contend are flawed. For example, PJM's long-term portion of the plan does not properly consider what new generation resources or demand side resources will be in place in those later years." PSEG then pointed to five specific issues in the process used to approve several projects, including the Meadow Brook-Loudoun line, noting: "In some instances, changes to even one of these items could alleviate the need for one or more of these projects."
- The Long Island Power Authority specifically questioned the Meadow Brook-Loudoun line, noting that it echoed concerns similar to those raised by other stakeholders "regarding the sufficiency of analysis and justification" for this project. One concern identified was that "PJM has not described whether less costly alternatives to the projects were considered, and, if so, provided any background information and explanations as to why the alternative projects have been rejected."
- FirstEnergy made more general comments about the RTEP. (FirstEnergy includes Jersey Central, Met-Ed, Ohio Edison,

Penelec, and Penn Power.) FirstEnergy asked for additional explanation as to why the projects are needed, and why the alternatives were discarded. FirstEnergy noted that it "does not dispute the fact that the proposed RTEP projects will resolve the [reliability] criteria violations identified. [But that the] issue is whether they 'all' are required to meet the long term security goals of the transmission system."

Changing Authority of Federal Regulators May Affect the SCC's Role

Under a federal law passed in 2005, a federal entity (FERC) can designate national interest electric transmission corridors, and potentially supersede State regulators in approving transmission projects in these corridors.

The passage of the federal Energy Policy Act of 2005 (EPAct) allows FERC to designate any geographic area experiencing electric energy transmission capacity constraints as a national interest electric transmission corridor (NIETC). According to the language of Section 1221, FERC would then have "backstop" authority to issue permits for construction of transmission lines in the NIETC if

- the State does not have authority to approve the facilities or to consider interstate benefits of the facilities;
- the applicant does not qualify to apply to the State for construction authority;
- the State has withheld approval for more than one year after the filing of an application seeking approval or one year after the designation of the NIETC, whichever is later; and
- the State has conditioned its approval in such a manner that the proposed construction will not significantly reduce transmission congestion in interstate commerce or is not economically feasible.

FERC's authority includes the ability to grant utilities the power of eminent domain along the route. States may be able to forestall FERC siting authority by forming regional siting compacts, which has been the subject of discussion by the National Governors Association.

The designation of NIETCs appears to be attractive to utilities as a means of lowering state regulatory barriers. For example, a New York company has proposed a privately financed 200-mile transmission line, and has asked FERC to designate its proposed route as a NIETC even though it does not cross a state boundary. Dominion provided formal comments to FERC on the EPAct, including the use of NIETCs, and the comments indicate a desire to bypass the SCC's authority:

> We applaud the section of the Federal Energy Policy Act of 2005 giving the FERC backstop authority over transmission

> siting. The process today involves costly and time-consuming reviews by multiple county, city and state agencies. While it would have been preferable to give the FERC the same authority it now holds in the siting of gas transmission facilities, the backstop provisions of the new Energy Policy Act are a good step forward. We also applaud the Act's efforts to set enforceable federal reliability standards for the transmission grid and to encourage investment in transmission facilities . . . .

One of the two Virginia utilities responsible for constructing the Meadow Brook-Loudoun line, Allegheny Power, has indicated its desire to seek NIETC designation:

> Construction of over 200 miles of 500 kV line from 502 Junction to Loudoun within 5 years calls for an extremely aggressive schedule. . . . AP urges PJM to . . . work with AP to obtain any necessary NIETC designation for this project from DOE.

Dominion has not requested this designation.

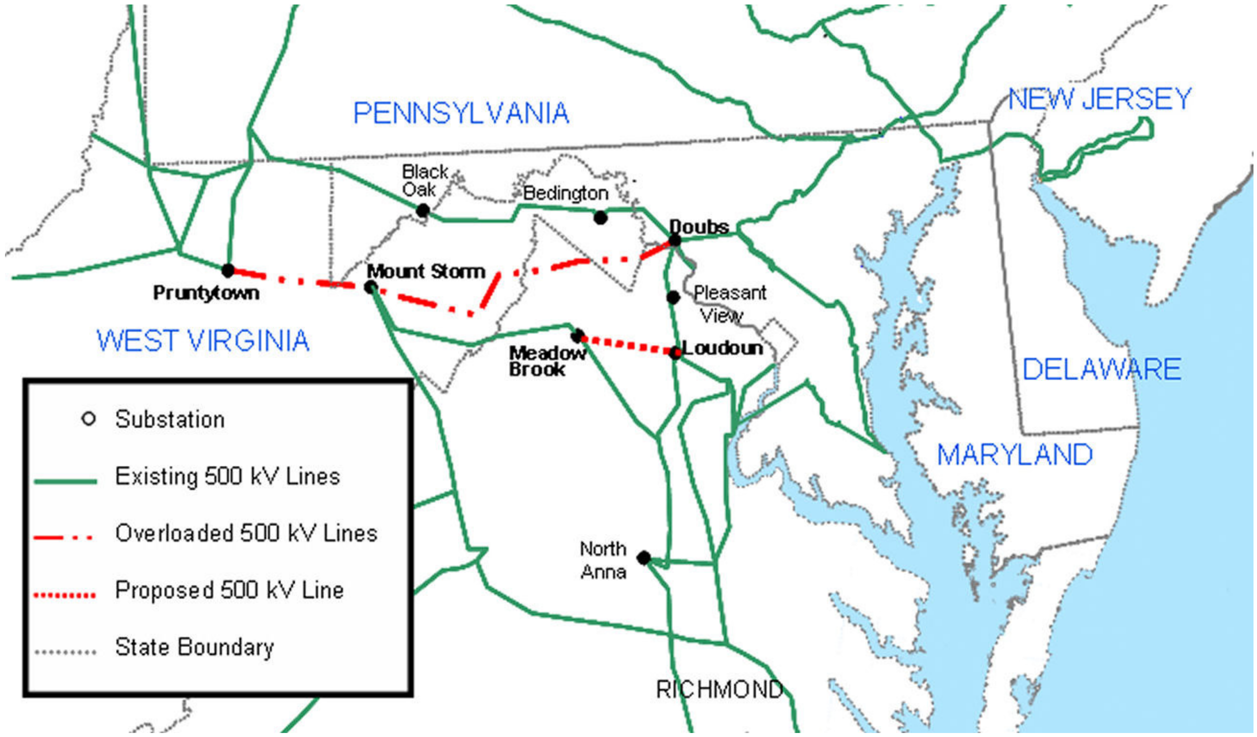
The indication that this line serves interstate needs, although it will likely strengthen Virginia's grid as well, is indicated in PJM documentation of the need for the line, which will be built to address reliability issues (contingencies) on transmission lines in West Virginia and Maryland (Figure 17):

> The recommended solution to the Mt. Storm-Doubs 500 kV and Pruntytown-Mt. Storm 500 kV overloads is to build a new 502 Junction-Mt. Storm-Meadow Brook-Loudoun 500 kV circuit. The cost is estimated at $850 million with a June 2011 in-service date.

As noted above, the electricity needs of customers in New Jersey, Delaware, eastern Pennsylvania and Maryland (including Baltimore and Washington, D.C.) are supplied in part by interstate transmission lines. However, these needs are also supplied by local generation, and the likely retirement of these generating plants may lead to the need for additional interstate lines. This can already be seen in the case of the potential closure of Mirant's Potomac River generating plant in Alexandria. According to PJM,

> Shutting down Potomac River of itself imposes additional contingency loading on the Bedington-Black Oak and Mt. Storm-Doubs 500 kV transmission lines, exacerbating the constraints already experienced on those lines.

Figure 17: New Transmission Line in Virginia Proposed to Address Overloaded Lines in West Virginia



Source: JLARC staff analysis.

PJM indicates that the closure of this plant alone could advance the date by which the Meadow Brook-Loudoun line (or another alternative) is needed by as much as two years. This is a further indication of the value of regional cooperation among Virginia localities in the siting of not just transmission lines, but generating plants as well.

As indicated earlier, the commissioners have stated that the utility applying for a line would be responsible for meeting any requirements ordered by the commission. Although it is unlikely that a 500 kV line, such as the Meadow Brook-Loudoun line, would be undergrounded, as technology advances it is not inconceivable that this may become possible. As noted in Chapter 2, a 26-mile 500 kV line has been installed in Japan. Therefore, the manner in which the Meadow Brook-Loudoun line is approved may serve as an important precedent.

JLARC staff asked the commissioners how they anticipate that the designation of any NIETCs in Virginia will affect their current role in transmission siting. In response, the commissioners indicated that under Virginia statutes, the commission is required to find that the new line is needed and that in previous cases applicants "have provided evidence to show that the new lines are necessary to provide reliable **intrastate** service to Virginia consumers" [emphasis added]. The commissioners added that although they have "not considered interstate needs to be dispositive in applying Virginia statutes on this matter," evidence could be introduced that establishes a proposed **interstate** line's "overall system benefits."

The commissioners also provided information as to the steps that are necessary in a transmission line case in order to afford due process, noting that "it is not unusual for more than 12 months to pass prior to reaching a final resolution in complex transmission line proceedings before the Commission." As indicated in Table 19, for cases filed in the past five years, Dominion has sought approval between six and 23 months prior to the date by which the company needed to begin construction. For example, the Morrisville-Bristers 500 kV line (2004-00062), which is being built on existing right-of-way, was filed in May 2004. Dominion's application indicated that construction would take 24 months, and that the line needed to be complete by May 2007. This indicates that approval was needed by May 2005, or 12 months after the case was filed.

Lastly, the commissioners stated that they will continue to fulfill their statutory obligations and will continue to provide the public participation and analyses directed by Virginia statutes, but that they "obviously cannot speak as to how FERC, or applicants before the Commission, may attempt to invoke the new federal permit provisions contained in EPAct 2005."

Dominion expressed confidence that "the State Corporation Commission will deal with this case [Meadow Brook-Loudoun] in a fair and impartial manner, carefully considering all issues and concerns raised during the review process." In addition, Dominion feels that "the Commission's record of fair and impartial consideration of transmission cases makes uncertain the relevance of the NIETC designations and FERC backstop siting authority to Virginia."

Table 19: In Recent Cases, Dominion Has Filed An Application Between Six and 23 Months Prior to the Anticipated Construction Date

Case Number	Date Filed With SCC	Date Line Needs To Be Completed	Construction Time (Months)	Anticipated Construction Date[a]	Date Approved by SCC
2001-00154	March 2001	May 2002	6	Nov. 2001	June 2003[b]
2002-00702	Dec. 2002	May 2005	8	Sept. 2004	Oct. 2004
2003-00064	Feb. 2003	June 2005	18	Dec. 2003	Oct. 2003
2004-00041	April 2004	Nov. 2006	8	March 2006	Sept. 2004
2004-00062	May 2004	May 2007	24	May 2005	July 2005
2004-00139	Dec. 2004	May 2007	24	May 2005	Aug. 2005
2005-00018	April 2005	June 2008	12[c]	June 2007	Pending
2006-00048	May 2006	May 2009	24	May 2007	Pending
2006-00091	Aug. 2006	June 2009	24	June 2007	Pending

[a] Completion date minus construction time.
[b] Final order issued in June 2002 granted approval but remanded the case to determine specific placement of transmission towers.
[c] Also requires 24 months for preconstruction activities (right-of-way acquisition and clearance, and additional permitting).

Source: JLARC staff analysis of transmission line cases.

Chapter 10

Need for Improved Information Availability and Planning in Transmission Line Cases

In Summary

In the past, underground transmission lines have accounted for a very low proportion of transmission lines in the United States and Virginia. However, some experts indicate that in the future, greater use of underground transmission lines may be seen for several reasons, including increasing difficulties in finding appropriate right-of-way for overhead lines. This may be especially true in areas that are densely populated and that have high land values.

A review of prior transmission cases in Virginia indicates that improvements could be made in the availability of information and planning. Presently, there is little coordination of planning activities between Virginia's local governments and Dominion. In some cases, a consequence is that lines may be built underground because of rapid and uncoordinated development. In other cases, a surprised public may oppose a new overhead line and advocate undergrounding, while lacking good information about the factors involved. Moreover, even if surrounding property owners were able to pay for undergrounding, the present lack of coordination limits the feasibility of this option.

Some information that may have affect policymaking, and the SCC's review of transmission lines, is not presently available to the SCC, local and State agencies, or the general public. This information includes electric utility industry reports on the latest research into undergrounding and the software required to confirm that a new transmission line is needed. The lack of this information affects the hearing process used by the SCC because some parties are at a disadvantage when a transmission line is proposed and potentially operate with an information deficit during the adversarial proceedings before the SCC. In light of these concerns, JLARC staff recommend statutory amendments that may improve policymaking and the SCC's review of transmission lines.

There are also existing limitations in the process used to plan transmission lines, namely a lack of coordination between utilities and local governments. Some of the existing underground lines were built because rapid growth at the local level eliminated previously available overhead transmission routes. Improvements to this process could help ensure that undergrounding is used appropriately.

LIMITED ACCESS TO INFORMATION HAS IMPORTANT POLICY IMPLICATIONS

JLARC staff encountered difficulty obtaining certain information that may have proved useful during this review. As discussed in Chapter 1, some of this information was unavailable because it can only be obtained by utilities. In other instances, Dominion declined to provide requested information due to concerns that information it deems confidential could subsequently be requested from JLARC under Virginia's Freedom of Information Act (FOIA).

A larger consideration, however, is the policy implications resulting from the lack of information available to SCC staff, local governments, or the general public regarding undergrounding specifically and transmission line planning generally. Utilities and their membership organizations have access to a much larger array of information and expertise than other organizations. At present, the SCC does not have access to this information, although it may be eligible for membership in some of the organizations. Local governments and property owners would likely have much more difficulty obtaining this information, and some consultants contacted by JLARC staff indicated they are disinclined to work for anyone other than a utility.

Additionally, SCC staff presently do not have routine access to information that would allow them to analyze the factors used by a utility to indicate the need for a transmission line—or that undergrounding is not feasible in certain instances.

Certain Information Was Restricted by Dominion Because of Concerns It Could Become Publicly Available

Although Dominion staff provided a great deal of information during this review, certain data requested by JLARC staff were not provided, and Dominion staff cited confidentiality concerns. Specifically, Dominion was concerned that the exemption for JLARC in Virginia's FOIA would not prohibit the release of confidential data, and their general counsel suggested that the exemption reflect the wording in Chapter 132-1.2 of the *North Carolina General Statutes.*

For example, JLARC staff requested information at the substation level on projected increases in demand, in order to determine where future lines may need to be built and if the locations may be suitable for undergrounding. Dominion declined to provide this information, instead providing information for large regions of Virginia. Dominion staff noted that the release of detailed information may aid their competitors who would then be better able to determine where a generating facility should be located, or could breech agreements Dominion has on non-disclosure of electricity consumption by certain parties.

JLARC staff also explored the use of Dominion's geographic information system (GIS) data to answer the mandate's question regarding the impact of transmission lines on property values. Dominion again declined to provide this information because of FOIA. JLARC staff instead used information available from State agencies, local governments, and other published information. The accuracy of the GIS information created by parties other than Dominion is not known, and time constraints also prevented a complete analysis of the potential impact on property values. A more complete analysis could be conducted if there is legislative interest, and this would be aided by the use of the GIS information maintained by Dominion if their confidentiality concerns can be addressed.

Recommendation (1). The General Assembly may wish to amend Section 2.2-3705.3 of the *Code of Virginia* to include confidential proprietary business data, records, and other information provided to the Joint Legislative Audit and Review Commission pursuant to a study or investigation as exempt from disclosure either during or after the completion of a study or investigation.

Greater Access to Information May Benefit SCC Staff During Reviews

SCC staff play a very valuable role during transmission line cases. Staff have analyzed utility applications and suggested alternate routes and other modifications. Staff also provide information in response to questions from the hearing examiner and in some cases produce staff reports. The role of staff could be augmented by ensuring that they have routine access to certain types of information.

SCC Does Not Appear to Use Industry Reports on Undergrounding. The Electric Power Research Institute (EPRI) has published a number of reports on the topic of underground transmission. Membership largely consists of utilities, but is also open to government agencies that fund or support energy research. EPRI will issue an updated edition in 2007 of its 1992 *Underground Transmission Systems Reference Book*, which will "compile the most up-to-date technical information on underground transmission systems." Dominion engineers referred to the requirements of this book in a recent case in Loudoun County (2002-00702).

Similarly, the National Rural Electric Cooperative Association is publishing a report this year on the costs and benefits of undergrounding. JLARC staff asked if the SCC was a member of these organizations and had access to their reports. SCC staff informed JLARC staff that the commission does not belong to these organizations, and as such would not have access to their reports and data. Instead, it appears as though the commission would only have access to this information if a utility or other participant in a transmission line case introduced it into the record.

SCC Staff Do Not Have the Routine Access to Computer Resources Used to Replicate Utility Analyses. Although SCC staff have played an active role in evaluating the need for new facilities, staff have also testified that the commission does not possess the internal computer resources necessary to independently execute the reliability models used by utilities to justify new transmission lines.

The mandatory standards set by NERC (the North American Electric Reliability Council) require utilities to ensure that the transmission system is able to operate during peak loads and also be capable of responding to contingencies. (A contingency is an unexpected failure of a critical transmission system component, such as a transmission circuit or substation transformer.) NERC standards help explain why underground lines are built with two circuits (or a spare cable), because a second circuit allows the underground line to remain operational even if problems occur with one circuit. In addition, Chapter 5 discussed the unique characteristics of underground lines and why additional equipment may be required to address potential reliability concerns or the effects that underground lines may have on the operation of a network.

Utilities analyze the effect that new lines or generators will have on other circuits by using software that models load flows. For example, in the Bristers-Gainesville 230 kV case (2006-00048), Dominion's load flow studies identified three single contingency violations, and four double contingency violations that result from increased load growth. Dominion stated that all seven contingencies would be eliminated by the proposed line.

Utilities also use this software to determine what equipment may be needed to counter the unique effects that underground lines have on load flows. The director of a 345 kV undergrounding project in Connecticut undertaken by Northeast Utilities told JLARC staff that "transmission planners must take all the information on cable systems into account when modeling the proposed additions," including the need for additional equipment to offset the effects of underground cables.

Presently, the SCC does not use this software, and it appears likely that the lack of access to this software affects the SCC's review of cases where underground lines are proposed. When a utility does not propose an underground line, it is up to other participants in the case to be aware of how the line could affect the overall transmission grid and what compensating equipment may be needed. Dominion has pointed to the fact that witnesses opposed to a transmission line have not performed modeling as a reason to discount their testimony. In a recent Loudoun County case, a Dominion engineer testified that a witness in favor of undergrounding "has made no attempt to perform any load flow analysis to show what happens to load flows on the transmission system in eastern Loudoun County if the proposed line is installed underground" (Rebuttal testimony volume 1, part 3, 2002-00702).

SCC staff have indicated that the commission will review the question of need in greater detail for major transmission lines or when need has been questioned. However, during 2005 proceedings for a 500 kV line in Fauquier County, SCC staff stated that it "does not have the software or computer resources to replicate the studies conducted by Dominion, and in fact would have to contract with a consultant to perform those studies" (2004-00062).

In response to a question from JLARC staff regarding the availability of these resources, the commissioners stated:

> The Commission would, on occasion, need to hire additional Staff or permit its Staff to engage outside experts to address thoroughly certain matters - such as performing detailed load flow modeling and contingency analyses in opposition to those presented by the applicant. The Commission has previously permitted its Staff to engage outside experts in various energy matters that present sufficiently complex issues to merit the devotion of additional resources.

SCC staff indicated to JLARC staff that in many cases it is possible to determine if load projections are reasonable based upon the experience they have developed in prior cases. However, it does not appear that contingency analyses that are used to establish the need for a line could be conducted without access to the requisite software and information. It further appears that these analyses would also allow the SCC to determine if a utility's reliability concerns regarding the impact of undergrounding on a network are valid.

As a result, it does not appear that the SCC can independently verify a utility's arguments that undergrounding is not feasible. This could be accomplished by retaining consultants in each case, or by acquiring the necessary software resources for internal use (such as software from PowerWorld Corporation). Verification of a utility's modeling could range from an independent analysis of reliability needs to the ability to execute the models created by utilities to justify a new line and its method of installation.

Recommendation (2). The General Assembly may wish to direct the State Corporation Commission to acquire the resources and information necessary to replicate utility load projections, load flow studies, and contingency analyses in every transmission line case.

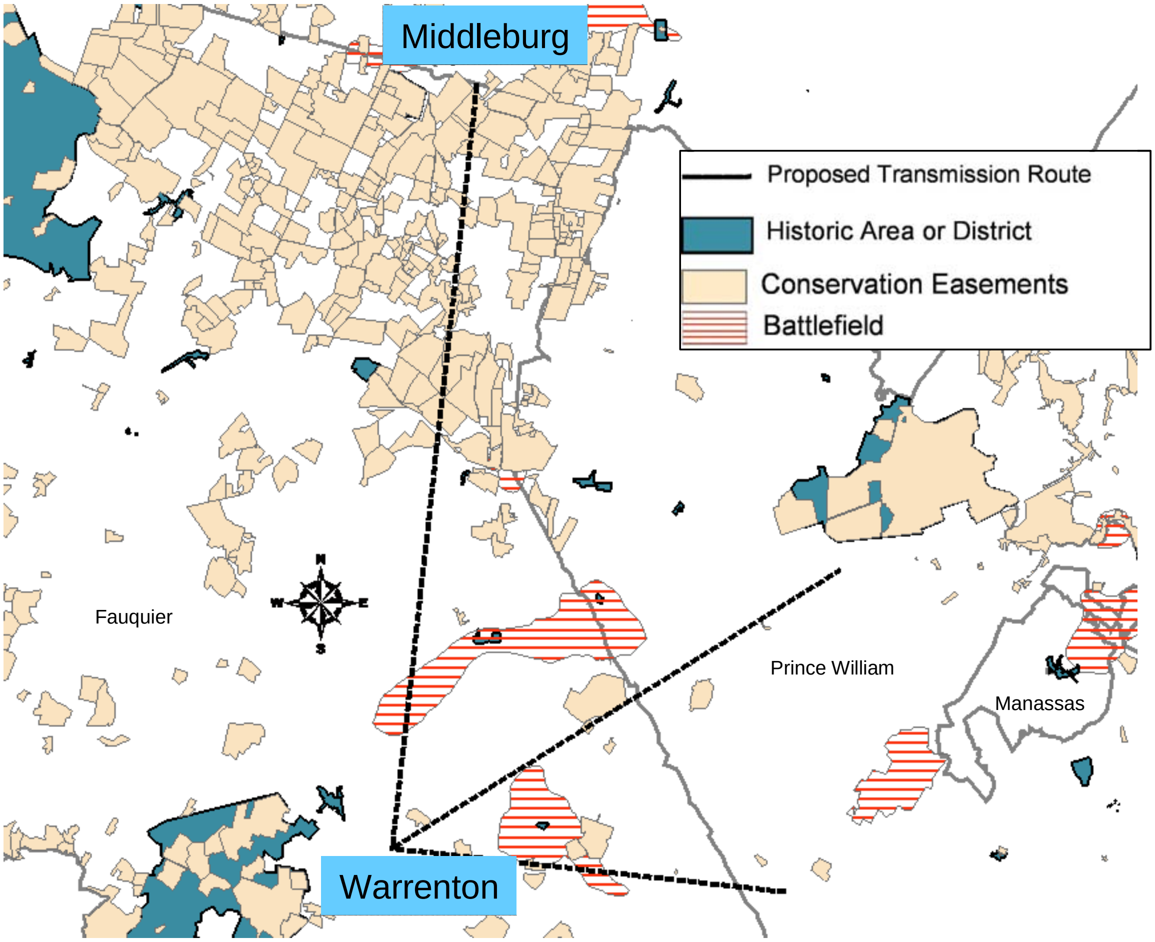
Greater Availability of GIS Resources Would Benefit All Parties. The review of proposed transmission lines would also be aided by greater use of GIS information. Figure 18 illustrates how GIS can assist policymakers and planners, by indicating each of the three routes Dominion is considering for a transmission line from Warrenton in the year 2023.

Presently, SCC guidelines request paper copies of highway maps that indicate where a proposed transmission line will be routed. During proceedings, these maps may be supplemented with aerial photographs and other exhibits. In one recent case in Loudoun County, Dominion provided DEQ with a GIS map of the proposed and alternate routes. However, this map was a rough illustration of the various routes, and was of poor accuracy and completeness in comparison to the GIS maps used to create the paper exhibits. The GIS map also does not appear to have been generally available, in contrast to the paper maps which were published by Dominion on their website.

Dominion planning staff described to JLARC staff how they are making greater use of the GIS resources that are provided by localities. GIS data enables planners to overlay current and future developments with existing transmission and distribution networks. Dominion staff stated that their planning activities could be improved substantially if they had greater access to updated GIS data from around the State. However, while this point is reasonable, it needs to be balanced with the concerns expressed by local officials who stated that Dominion does not provide data they request as part of their local economic development activities.

Recommendation (3). The General Assembly may wish to amend Section 56-265.2 (C) of the *Code of Virginia* to state that a digital geographic information system (GIS) map showing the location of any electrical utility facility shall be filed with the State Corporation Commission. The General Assembly may also wish to direct the State Corporation Commission to make these GIS maps publicly available on their website.

Figure 18: GIS Maps, Which Show Location of Significant Features, Can Assist Planners In Determining Where Transmission Lines Should Be Routed



Note: Transmission line routes illustrate the locations to be connected, not the actual route.

Source: JLARC staff analysis of GIS data from the Department of Historic Resources, the Department of Conservation and Recreation, and other data from Dominion.

STATUTORY CLARIFICATION MAY IMPROVE THE SCC'S REVIEW OF TRANSMISSION LINES

Current statutes do not provide guidance on the application of cost considerations to proposed transmission lines. In addition, the commissioners have indicated a willingness to interpret some legislative terms that are not defined in statute, and have applied the cost criterion differently depending on the circumstances of a case. As a result, there is some ambiguity about whether the definition of "cost" is limited to construction and maintenance costs, or can be broadened under current statutes to include other factors such as lost property value. Under the current framework, the commissioners do not appear to consider the impact of a transmission line on property values unless the issue is raised by a participant in the case, nor does the SCC use monetary estimates of other "external" environmental costs. There is also some statutory ambiguity as to whether the General Assembly intends for the SCC to consider environmental factors when reviewing underground transmission lines.

Commission Does Not Routinely Use Certain External Costs In Reviewing Transmission Lines

In the cases reviewed by JLARC staff, the commissioners have not routinely indicated the cost factors on which their decision was based. When final orders contain explicit cost discussions, the commissioners have limited their discussion to construction costs. These costs frequently include the expense of obtaining right-of-way, along with materials and labor. Although the commissioners have cited some cost estimates beyond construction costs they do not appear to routinely consider these additional costs or discuss them in final orders.

The commissioners have also noted that their authority to consider quantitative environmental externalities is limited. Externality costs are those effects of constructing a transmission line that are not included in the cost of the project. For example, an externality may occur if the presence of a transmission line harms habitat, historic sites, scenic assets, or human health or safety, and these potential effects are not included in the cost of a project.

Placing a monetary value on these potential costs can be contentious, and it may not be possible to account for these impacts by developing monetary estimates. As a result, although a strict definition of externality costs would include any cost that is not included in the price of a project, the term is often applied to issues for which reliable dollar estimates are not available. For instance, the effect of a transmission line on property values is frequently estimated, but placing a value on human or animal life is more difficult. As such, certain factors which have been considered in some cases, such as property value effects, may not be strictly considered to be environmental externalities but a lack of uniform consideration of these factors means that they are not consistently "internalized."

The policy to not consider quantitative environmental externalities was established by the commission in a case involving an investigation of the conservation and load management programs of utilities (1990-00070). In the final order, the commissioners noted that their authority to quantify externalities is limited and that they instead render decisions based upon qualitative factors. The final order observed that the conditions imposed upon utilities in certification cases may affect rates, and that Section 56-235.1 requires "cost-based" rates. As a result,

> We believe that it would be speculative, and thus contrary to our legal authority, to include adjustments in rates for external environmental factors. Moreover . . . incorporating selected externalities, but ignoring the impact of others, could distort the balancing process and lead to economic inefficiency, resulting in higher utility rates for all customers. We therefore agree with our Staff and a number of the parties, who suggested that incorporation of environmental externalities should be dealt with from a broader perspective than utility ratemaking. Congress and the General Assembly are the proper bodies to provide this perspective. When and if we are directed by legislation to incorporate quantified environmental externalities into the regulatory process, we shall do so, of course.

JLARC staff asked the commissioners whether this case represents current commission policy. In response, the commissioners stated, "As there has been no statutory change on this matter, such analysis remains as Commission precedent on this question."

However, since the adoption of that policy the final orders indicate that the commissioners have at times considered costs other than construction costs, but the final orders do not indicate whether they are routinely and uniformly considered. For example,

- The commissioners have accounted for "line losses" in approving certain types of transmission lines. (Line losses occur due to the conversion of electricity to heat and electromagnetic energy, which means that not all of the power introduced into a transmission line reaches the other end.) In a 1994 opinion approving construction of a 500 kV line in southern Virginia, the commissioners cited a monetary estimate of the "line losses" associated with a lower voltage alternative. Because a higher voltage line was said to have lower line losses, the opinion reasoned that a lower-voltage (230 kV) alternative would require the generation of more electricity and cause additional air emissions. According to an estimate provided by Dominion, the net present value of these line losses over the life of the project would total over $66 million (1992-00058). Line losses were also cited in approving a 765 kV line, where the commissioners noted, "In essence, line loss savings produced by the line will offset much of its cost" (1991-00050).
- In some cases, information on the impact that overhead lines will have on the value of nearby property has been consid-

ered. This information indicated a specific percentage reduction in the value of houses close to the transmission line. The hearing examiner and commissioners considered this information and found that mitigation techniques other than undergrounding would satisfy the statutory factors. (In at least one of these cases, it appears that the cost of undergrounding exceeded the total decrease in property values.)

- In a recent case in Virginia Beach, Dominion provided compensation for unavoidable impacts to wetlands by purchasing mitigation credits (2006-00040). This method relies on third parties (neither the regulating agency nor the company) to produce replacement wetlands (credits) in exchange for payment. These credits can then be used to offset wetlands that are degraded during construction activities. This approach may therefore provide a means of internalizing some environmental externalities.

JLARC staff further inquired as to whether the commission would be in a position to develop a sufficient record, at the request of the General Assembly, that would quantify externalities such as the potential impact of electric transmission lines on (1) human health and safety and (2) the value of private property. The commissioners responded:

> If the General Assembly directs the Commission to quantify specific environmental externalities, the record will be built by those who choose to participate on such issue. As noted above, in transmission line cases the Commission is required to consider all reports from state agencies concerned with environmental protection (see Va. Code § 56-46.1 A). The Commission's Staff currently would need to engage outside experts to address quantification of environmental externalities, unless those agencies charged with administering Virginia's environmental laws sponsor testimony quantifying environmental externalities.

Recommendation (4). The General Assembly may wish to direct the State Corporation Commission to develop a record to indicate which cost factors should be consistently addressed whenever the commission is required to approve the construction of any electrical utility facility, and to modify commission policies and procedures accordingly. Cost factors that the commission should consider include (1) the monetary effect of an electric facility on the value of land and structures within and immediately adjacent to the proposed location or corridor; (2) the cost of energy lost during the transmission of electricity (line or load losses); and (3) the potential for increased use of wetland mitigation credits.

Statutory Basis for Environmental Reviews of Underground Lines Is Not Clear

During a recent case in Loudoun County (2002-00702), Dominion argued that the commissioners could not follow the hearing examiner's recommendation that the line be undergrounded "and also comply with its own obligations under § 56-46.1." As noted at the beginning of this chapter, the Utility Facilities Act states that "The certificate for **overhead** electrical transmission lines of 150 kilovolts or more shall be issued by the Commission only after compliance with the provisions of § 56-46.1" [emphasis added].

The original language in this statute was modified by the General Assembly in 1985 to add the modifier "overhead." By adding this modifier, it appears that there is not a clear statutory basis for requiring that an **underground** transmission line of 150 kV or more be approved in accordance with § 56-46.1.

In practice, this statutory modification may not have had an effect, because it appears that utilities and the SCC have usually considered all underground lines to be extraordinary, and as such have reviewed them in accordance with § 56-46.1. Indeed, in its 2005 report to the General Assembly on the *Implications of a Requirement to Consider Undergrounding of Electric Transmission Lines*, the commission stated that § 56-46.1 is applicable to "all transmission lines capable of carrying 150 kilovolts." Stated as such, however, this would exclude underground lines of 69, 115, and 138 kV—the voltages in use below 230 kV. Moreover, in at least one instance Dominion requested that the commissioners declare that a proposed 230 kV underground transmission did not require certification pursuant to the Utility Facilities Act (2002-00180). These ambiguities suggest that legislative clarification may be warranted.

Recommendation (5). The General Assembly may wish to amend Section 56-265.2 of the *Code of Virginia* to add the language in bold: "The certificate for overhead electrical transmission lines of 150 kilovolts or more**, and underground transmission lines of any voltage,** shall be issued by the Commission only after compliance with the provisions of § 56-46.1."

IMPROVED COORDINATION BETWEEN UTILITIES AND LOCALITIES MAY ADDRESS SOME PUBLIC CONCERNS

As the previous chapters have discussed, the SCC has only approved underground lines when they would not pose higher costs for ratepayers. This has occurred when no viable overhead route existed or when a third party was willing to bear the costs. In instances in which no viable overhead route has been found, there are generally two inter-related reasons for this: the expense associated with acquiring the land or an easement (through purchase or condemnation), or the need to demolish houses, apartments, and other buildings on the potential transmission route. Under these circumstances, underground lines have been requested and approved because the approach best satisfies two of the statutory factors: the need to minimize cost and the need to avoid the "environmental" harm associated with demolition, especially of dwellings.

If this pattern holds true, it suggests that future underground lines will be certified only if population density makes an overhead route too expensive or environmentally insensitive. Moreover, if Dominion's operational and reliability concerns are valid, then it would appear to be to the company's and ratepayer's benefit to avoid undergrounding. This may be aided by improving the coordination of Dominion's transmission planning and locality comprehensive plans.

Yet Dominion has previously agreed to undergrounding lines if a third party paid for the costs, and the SCC has approved this outcome. If operational and reliability concerns can be successfully addressed, and a third party payer can be found, then undergrounding may be feasible. At present, however, the lack of prior coordination and other forms of cooperation between Dominion and local governments makes this outcome unlikely. This situation, combined with the lack of readily available information on Dominion's planned transmission lines, limits the feasibility of allowing surrounding property owners or local governments to pay for undergrounding. This is compounded by the relatively short time frame given by Dominion to decision makers. As indicated in Table 19 (Chapter 9), for cases filed in the past five years Dominion has sought approval between six and 23 months prior to the date by which the company needed to begin construction.

As a result of the lack of prior coordination and the limited time frame for decision making, the SCC will likely receive cases in the future in which the need to build a line within one or two years may cause lines to built overhead that might reasonably be placed underground, or lead to the use of routes in which undergrounding becomes necessary but might have been avoided.

The feasibility of greater coordination to address these concerns is indicated by examples from at least two prior cases. In these instances, undergrounding was requested by local citizens or governments but their concerns were satisfied in stipulated agreements by other means. This suggests that improved coordination prior to transmission line hearings may have another tangible benefit: judicial economy.

Improved planning may be especially important if State and local policymakers wish to retain control over the siting and approval of certain future transmission lines, which the federal government may designate are of national importance. One such line has been proposed in Northern Virginia, and if it is designated as a National Interest Electric Transmission Corridor (NIETC), then State control could cease 12 months after either this designation or after the case is filed with the SCC.

Dominion's Planners Consider a Variety of Factors

Dominion staff state that the need for new transmission lines is generally driven by increased electricity usage at the local (distribution) level. In addition, new lines may be needed to relieve congestion by allowing cheaper electricity to reach areas of high demand and to improve the reliability of the transmission system.

As a result of these considerations, Dominion staff indicate that their planning process attempts to incorporate the needs of both their distribution and transmission network. Dominion has about 11 planners who study annual changes on its distribution circuits. The load changes on the distribution lines that serve a particular area are then summed at the substation level. In evaluating annual load changes, Dominion includes

- percentage changes, which are a function of population changes and increases in the per capita consumption of electricity, and
- block changes, such as zoning changes or new subdivisions, additional manufacturing and industrial plants, and abrupt changes in the economy. Distribution planners cited the example of Rt. 288 in Chesterfield County as a block change.

The horizon for detailed distribution planning is two years, and five years for higher level planning. Transmission planners stated that the horizon for transmission planning is longer—five years for detailed plans and 10 for higher level—because the process of obtaining certification from the SCC and then constructing the line requires more time. Dominion begins evaluating potential routes as soon as the need for a new line is identified. The company also plans further into the future—15 to 20 years—by purchasing rights-of-way.

Dominion Staff Report Challenges in Staying Abreast of Changing Local Conditions

Dominion staff report that they stay abreast of local comprehensive plans and regularly attend planning commission meetings. In addition, they are often in the field and observe where new development is occurring. Distribution planners use several strategies to identify these block changes, including speaking with developers, monitoring the local newspapers, and working with a locality's economic development officials. The challenge, as they see it, is determining when growth is likely versus merely possible.

However, Dominion's planners indicated that their efforts are complicated by the need to account for the demands of electric cooperatives, and the changing nature of local planning. Dominion staff indicated that localities do a good job with transportation, sewer, and other locally-provided utility services, but they give very little attention to electric transmission needs. They pointed out that many localities do not discuss existing transmission line rights-of-way in their comprehensive plans, nor do they address how the need for future right-of-way could change with new development.

JLARC staff inquired about the feasibility of communicating with localities with greater frequency or working with local officials to identify potential transmission line corridors. Dominion staff agreed that more dialogue with localities is needed. However, they expressed a concern that open discussion could encourage land speculation and ultimately increase the cost of right-of-way acquisition. Staff described their ongoing efforts to coordinate with certain Northern Virginia localities, by sharing twice annually their distribution and transmission planning, and speaking with economic development officials to identify areas rezoned for mixed-use and other anticipated changes.

As an example of the kind of information that could be more regularly exchanged between Dominion (or other utilities) and local governments, Dominion plans on networking a 115 kV line that now connects to a substation in Middleburg (Loudoun County) by building a new line from Middleburg north to the Leesburg area. Dominion will need to build this line when the load it carries exceeds 100 MVA, which it anticipates will occur within the next ten to fifteen years. However, Dominion notes that the date that this new line between Middleburg and Leesburg will be needed depends upon the rate and size of development in the area around Middleburg, a factor over which the Counties of Loudoun and Fauquier have some control. However, Dominion could assist local planners and citizens by informing them of the effect that new development has upon the power grid. Information that may be useful includes data on the current load carried by existing transmission circuits, and how close it is to the need for upgrades, including additional lines. For instance, Dominion's Long Range Plan states that the load on the 115 kV line to Middleburg is expected to be 77 MVA by the summer of 2007—or 77 percent of its capacity.

SCC Staff and Dominion Assert that Localities Need to Incorporate Utility Plans into Local Planning

In recent transmission line cases, SCC staff have emphasized the importance of long-range planning by utilities. SCC staff have also discussed two aspects of long-range planning that affect local governments and property owners. First, SCC staff have argued that purchases of land or easements by a utility "serve to provide advanced notice to the public about where lines and stations will eventually be built so that the public [can] make informed land development decisions." Second, SCC staff have added that "local planning officials would well serve their citizens by including the long-range bulk power expansion plans of electric utility companies in their information systems." Dominion has stated that it "agrees with the Staffs comment that local planning officials would serve their citizens by considering Dominion's long range expansion plans in their planning processes."

SCC Staff and Dominion Suggest That a Utility's Ownership of Easements Constitutes Public Notice of Intentions. As part of a transmission line proceeding, the SCC issues an "order for notice" requiring the utility to publish notice of the proposed route in the local newspapers of affected localities. In addition to the formal notice requirements set forth in statute, SCC staff appear to believe that the ownership of easements by a utility constitutes a form of public notice. During 2004 hearings for a 500 kV line in Fauquier County, Dominion staff explained that the planning for Dominion's 500 kV system dates back to the 1970s (2004-00062). At that time, the company purchased right-of-way across Stafford and Fauquier Counties to allow for the construction of 500 kV lines to the Possum Point Generation Station in Prince William County. As noted by the hearing examiner,

> Since 1970, the Board, the Fauquier County Planning Commission, and the landowners adjoining the transmission line right-of-way have been on notice that at some point in the future a second transmission line might be built. That time has come.

Dominion also appears to take this stance, noting that all of the property owners "have been on notice at least since the condemnation proceeding was filed in 1973." It is not clear if this position is endorsed by the commissioners since in this same case the commissioners did not take a position on this issue. It may be instructive to note, however, that the final order advised that "portions of the Hearing Examiner's Report only are adopted if explicitly done so herein."

JLARC staff asked local planning staff how an individual would find utility easements on land they were planning to purchase. In all three counties, planners indicated that the information was available for viewing in their offices. In one county, online maps indicate some easements, but not all, nor do they indicate the owner or intended use.

In response to questions about the role of the local government in reducing conflicts between homeowners and a utility's planned use of an easement, one locality stated that they have recently adopted a 200-foot setback requirement from the edge of the transmission right-of-way for the location of new houses. Planning staff in another locality said they have traditionally relied on the developers to warn homeowners of nearby easements. JLARC staff also asked Dominion for information on easements which it owns but has not used, and this information is presented in Appendix H.

SCC Staff Have Also Argued That Dominion Should Change Certain Aspects of Its Planning Process. In at least two recent cases, SCC staff argued that Dominion should extend its long-range planning horizon beyond ten years. (Of note, Dominion's long-term plan includes certain projects with an anticipated date beyond 2020, but it is unclear to what extent detailed planning is undertaken for these projects.) In arguing for an extended horizon, SCC staff pointed to the potential to mitigate the negative effects of transmission lines in high-growth areas:

> Virginia Power's bulk power system planning process formally looks no further than 10 years. While this may produce acceptable results in low-growth areas, this case clearly demonstrates that waiting too long to begin building transmission lines in areas with rapid growth creates unnecessary public opposition, limits route choices, increases necessary mitigation, and increases costs. To a great extent, these problems can be reduced by locating lines before, rather than after, rapid development begins in an area. The building of new transmission lines would be less contentious and less expensive if both Virginia Power and the local governments worked together on long-range planning for bulk power system expansion, and utilized a planning horizon beyond the 10 years currently used by Virginia Power.

The commissioners considered the merits of this argument in a recent case involving a transmission line in Loudoun County. In the final order, the commissioners adopted the hearing examiner's finding that Dominion "should work more closely with the Staff on long-term transmission planning in areas such as Northern Virginia where projected load growth is significant" (2002-00702). However, local planning officials report that they do not regularly communicate with Dominion, which suggests that the company may need to more closely cooperate with local staff and not just SCC staff.

Local Planning Staff Desire More Information and Coordination

JLARC staff visited three counties in Northern Virginia in which Dominion is planning on building new transmission lines in the next few years. In all three of these counties, local planning staff indicated that the amount of information provided by Dominion was minimal and focused on where to route a new line or site a substation. In other words, the information did not indicate that alternatives were available to an overhead line, nor was the information provided sufficiently far in advance to allow the locality to assist in designating transmission line corridors or ensure that the land use around an existing corridor was compatible with Dominion's plans. However, it also appears that local officials would benefit in future years from asking more extensive and direct questions about Dominion's plans.

In each of these counties, there are concrete examples of how the current lack of coordination between localities and Dominion affects transmission line cases and results in calls for undergrounding:

- Planning staff in one locality stated that Dominion discussed the location of a new substation for five years but had not provided information about the associated transmission lines. However, it does not appear that local staff asked about these plans. Moreover, as a result of accepting proffers from developers, schools were built on the edge of a transmission line right-of-way. Currently, local citizens are protesting a proposed line and calling for alternate routes or alternatives—including undergrounding. Planning staff were receptive to sharing the county's development plans with Dominion and stated that Dominion could be more forthcoming with its long-term plans.
- In a second locality, planning staff indicated that Dominion had been a good partner and had agreed to mitigation efforts associated with a new substation and other facilities. How-

ever, local staff appeared to be unaware of Dominion's plans to build several new lines to the substation and noted that the locality has never discussed long-term plans or projects with Dominion because the company "is always close to the chest." A more open approach, staff said, would improve the public's understanding of the need for transmission lines. Lastly, staff expressed a desire to work more closely with the company to better understand how they develop their growth projections and indicated a willingness to work with Dominion to designate a corridor for needed lines.

- Staff in the planning department of the third locality took issue with Dominion's claims that utility planners attended planning meetings and met with local staff. Staff were also unaware of a new line proposed by Dominion that may cross their county, or of Dominion's future plans, and indicated that knowledge of Dominion's plans could greatly influence ongoing rezoning activities. Specifically, if an existing right-of-way was a more desirable option, the locality needed to know this before it allowed new developments alongside that would prevent the right-of-way from being widened.

In addition, it appears that there may be a benefit to greater regional cooperation between localities. Planning staff in one locality expressed their frustration that they serve as the location for electric facilities that serve the needs of neighboring localities. Residents in some localities also have made greater use of conservation easements, and some localities have gone to greater lengths to preserve a rural landscape. As a result, a transmission line may be routed through one locality because of land use decisions in a neighboring locality. Planning among localities could assist with these issues.

It is important to note, however, that many of the existing electric facilities were built in the 1960s or 1970s, when they would have had much less impact than at present. Moreover, the statutory requirement that existing right-of-way be used—which may favor the purchase or condemnation of new land alongside an existing corridor—means that future lines are more likely to be built where existing lines now stand. And if any of the existing lines were built prior to 1972, the approval was granted at the local level. In light of these factors, if the use of undergrounding follows historical patterns, then overhead lines will continue to be a feature of the landscape.

Insufficient Planning and Coordination May Have Resulted in Previous Need to Underground Lines

Greater coordination between local governments and utilities may be beneficial to all parties, as evidenced by prior cases where a lack of advanced coordination resulted in the need to use underground lines.

Undergrounding Is Primarily Used When No Viable Overhead Route Exists. The main reason for Dominion's use of undergrounding seems to result from the lack of viable overhead routes, which is closely tied to cost because of the larger right-of-way required by an overhead line. A lack of viable overhead routes appears to have resulted from three factors:

- the need to remove overhead lines as a condition of the easement granted by a railroad;
- the need to avoid posing a hazard to aircraft and ships, such as aircraft carriers; and
- the presence of rapid development.

Earlier Cases Indicate That Rapid Development Has Eliminated Viable Overhead Routes. Rapid development has two consequences that result in the use of undergrounding. First, changes in land use or further increases in population density result in a need for transmission in an area in which viable overhead routes are no longer present. Dominion has requested permission to build two lines for these reasons.

The Glebe-Davis line in Arlington County (1988-00063) was built underground because of increasing density:

> The transmission system to Crystal [City] Substation was installed in the early 1970's and at that time, because of the high density, the 230 kV transmission line was installed underground. Then, and now, there is no viable overhead transmission route available for this new line.

The Glen Carlyn-Clarendon line, which crosses under Glebe Road north of Fairfax Drive in Arlington County, was built as a result of changes in land use: "Construction and operation of the rapid transit system is expected to accelerate development in the Clarendon area." Underground construction was selected as the "most practical" on the basis of "land use in the area and available rights-of-way." As Figure 19 illustrates, additional transmission lines in this area could not reasonably be built overhead.

Figure 19: Underground Line Was Used Under a Street in Arlington County Because No Viable Overhead Route Was Available

Source: JLARC staff photograph.

Rapid development also appears to require undergrounding when a lack of coordination between Dominion and localities eliminates a previously viable overhead route already identified by Dominion. The effect that rapid development can have on transmission line cases, when a locality and a utility do not coordinate their plans, is seen in two cases in Fairfax County.

In 1986, Dominion filed its application for the Burke-Sideburn line in Fairfax County, south of George Mason University (1986-00019). In the application, Dominion indicated that the line was originally planned to be an overhead 115 kV line between Burke and Ravensworth, and that right-of-way acquisition began in 1969 and was completed in 1975. The project was delayed in 1978 for unspecified reasons, but would never have been reviewed by the SCC because it was less than 150 kV. Dominion further stated:

> Increased residential development in this area prompted a reactivation of the project for 230 kV transmission to provide adequate service. Because development was so rapid, an additional substation [Sideburn] was needed by this time. . . . The density of residential development between Burke and Sideburn substations is such that our original overhead route no longer exists. . . . The Company has retained a right-of-way but it is not environmentally feasible to consider overhead construction in this area. . . . [O]ne section is located between townhouses which were built after the right-of-way was obtained [Figure 20]. *Because of*

> *the rapid development of the Burke area, no viable overhead corridor exists* [emphasis added].

Subsequently, in 1988, Dominion requested permission to put another 230 kV line underground, from the Pender substation to the planned Oakton substation. According to Dominion's application, the transmission line

> was originally considered in 1973 as an overhead line. Rapid development and the rise in land value in the Fairfax area has changed what may have been a viable option in 1973 into an unacceptable alternative today. The project was deferred in 1976 due to an increase in the demand for electricity. However, renewed growth and load projections showing existing circuits exceeding their normal loading capabilities in 1990 necessitates construction of the above project.

Dominion noted that the underground project would require a 25-foot-wide permanent easement and would cost $21 million. (An

Figure 20: Underground 230 kV Line in Fairfax County Was Built Because Rapid Development Eliminated Viable Overhead Route

Source: JLARC staff analysis of case 1986-00019; aerial imagery used with permission of Pictometry.

additional 25 feet of temporary construction easement would be required as well.) The overhead alternative, with a 120-foot-wide easement, would cost $47 million. As noted, Dominion's discovery of asbestos (actinolite) along the proposed route raised the cost of an underground line. Of note, information from the Department of Mines, Minerals and Energy indicates that data on the location of this actinolite schist in the Oakton area was first published in 1981, suggesting that the environmental reviews conducted today by State agencies may also play a valuable role in planning before a case is formally initiated. To this point no transmission line has been built, but Dominion's long-range plan includes this line plus another possible line beginning at Oakton.

Undergrounding Has Been Avoided Through Stipulated Agreements. Two earlier cases also indicate the value of advanced planning, and how it could reduce the need for contested transmission line proceedings. In these cases, stipulated agreements were reached between Dominion and other parties following SCC hearings in which undergrounding was advocated. The fact that these agreements were reached suggests that advanced planning may have allowed an amicable solution to have been achieved prior to the hearings.

In 1985, Dominion and Fairfax County submitted a settlement agreement to the SCC that become the basis for building the Sideburn-Ravensworth line overhead (1984-00028). In this agreement, Dominion agreed to several steps, including using a specific type of transmission tower, planting flowering trees, and correcting any radio or television interference caused by the line. Similarly, in 1990 Dominion reached an agreement with protestants that modified Dominion's preferred route. Chesterfield County maintained their desire for undergrounding, but agreed that the changes were satisfactory (1988-00071).

These cases suggest that improved coordination between planners at Dominion and local governments would be beneficial for several reasons:

- First, if undergrounding should be limited to only those circumstances where no viable overhead route is available, then improved coordination and planning would assist in the determination of suitable transmission line corridors. This would also assist localities in determining the proper location of schools and subdivisions. Such notice may also allow localities to modify planned growth, in its extent or location, if so desired.
- Second, if undergrounding is viable in an area, but a third-party source of payment is required, then advanced notice of

the need to build a line and potential route would assist in the determination of whether it is feasible to allow surrounding property owners to pay for the line. Advanced notice in this case would require that Dominion advise localities before a situation is reached where the need for a line is "acute," as the new Stafford line is described.

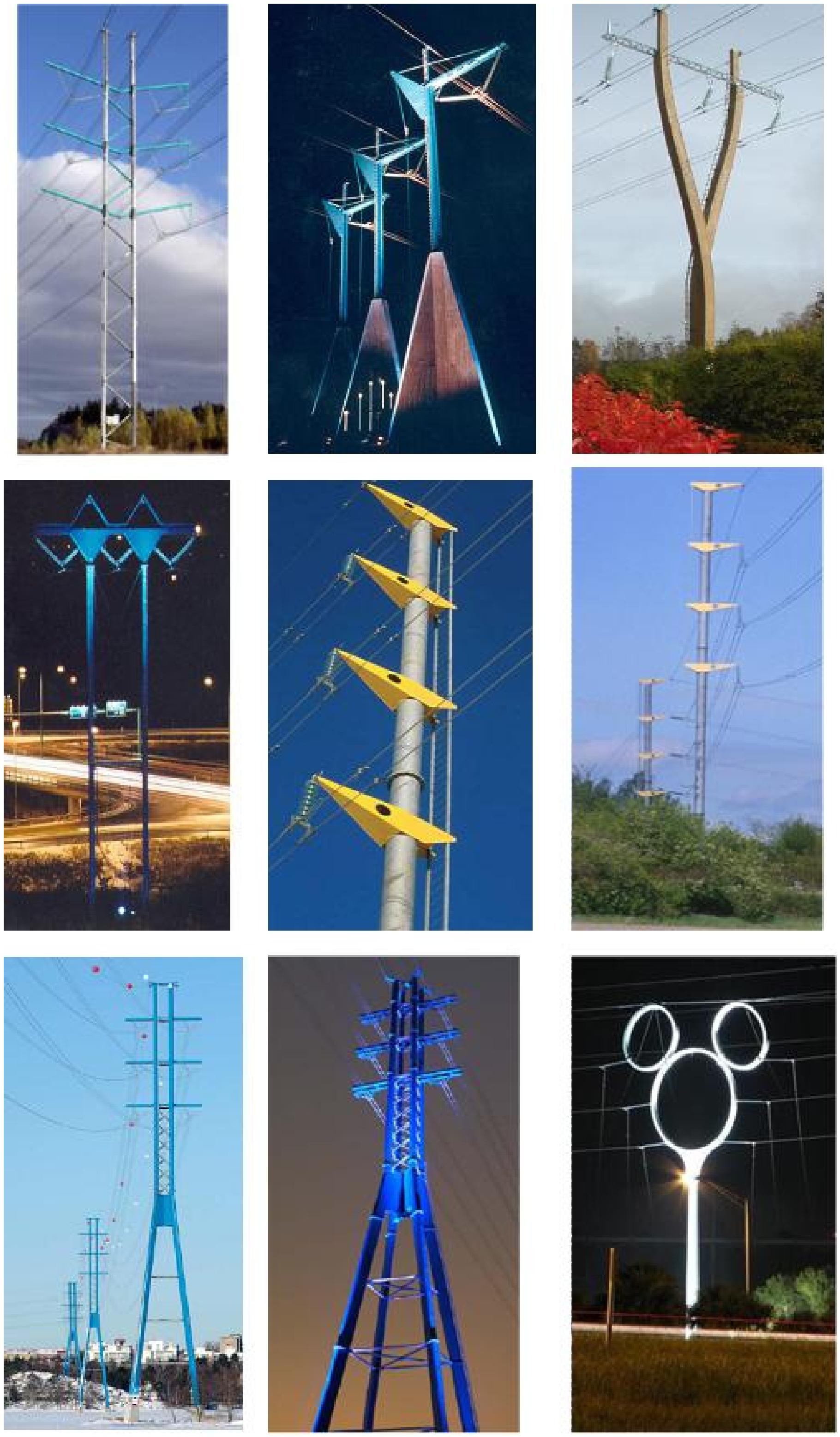
- Third, if undergrounding is not feasible, or if a transmission line cannot be routed such that it does not affect the viewshed or property values, then another option may be to have surrounding property owners pay for alternative tower designs, as depicted in Figure 20. Alternative tower designs may also aid economic development or tourism, as illustrated by the Walt Disney tower in Orlando, Florida (bottom right photograph, Figure 21).

Improvements in coordination could be voluntary, or they could take the form of legislative direction. In recent years, the General Assembly has considered several bills which recognized the importance of advanced planning:

- HB 2407 passed during the 2005 Session, in recognition of the long-term impact of an aging population and the needs of persons with disabilities, directed localities to include their requirements in their comprehensive plans.
- SB 699 passed during the 2006 Regular Session requires localities to submit their comprehensive plans or amendments to the Virginia Department of Transportation for comment and review.
- HB 5094 from the 2006 Special Session, which did not pass, would have required every county to amend its comprehensive plan to incorporate urban development areas with the intention of improving transmission planning.

Recommendation (6). The General Assembly may wish to amend Section 15.2-2223 of the *Code of Virginia* to direct local governments to include electric transmission and other utility infrastructure needs that are not presently included in their comprehensive plans. The General Assembly may also wish to direct publicly regulated utilities to provide their long-range plans in sufficient detail to local governments and State agencies upon request.

Figure 21: Alternative Transmission Tower Designs Could Be Considered



Source: Photographs presented at a 2006 meeting of the Towers, Poles, and Conductors subcommittee of the Institute of Electrical and Electronics Engineers.

Appendix A Study Mandate

HOUSE JOINT RESOLUTION NO. 100

Directing the Joint Legislative Audit and Review Commission to study the criteria and policies used by the State Corporation Commission in evaluating the feasibility of undergrounding transmission lines in the Commonwealth. Report.

Agreed to by the House of Delegates, March 2, 2006
Agreed to by the Senate, February 28, 2006

WHEREAS, it is the duty of the State Corporation Commission to consider environmental, economic, and service reliability factors in issuing certificates of public convenience for the construction of electrical transmission lines; and

WHEREAS, the relative environmental, economic, and service reliability factors considered by the State Corporation Commission vary with respect to the proximity of the transmission lines to densely populated areas; and

WHEREAS, the long-term implications of placing overhead transmission lines near densely populated areas must be carefully evaluated; and

WHEREAS, the costs of constructing overhead transmission lines may impact tax revenue, economic development, and property values in the immediate area of the transmission lines; and

WHEREAS, it is in the best interest of the public to provide for the least costly alternative in constructing electrical transmission lines; and

WHEREAS, the process of undergrounding transmission lines may mitigate many of the detrimental effects arising from the construction and location of overhead transmission lines; and

WHEREAS, the process of undergrounding transmission lines is not widely practiced in the Commonwealth; now, therefore, be it

RESOLVED by the House of Delegates, the Senate concurring, That the Joint Legislative Audit and Review Commission be directed to study the criteria and policies used by the State Corporation Commission in evaluating the feasibility of undergrounding transmission lines in the Commonwealth.

In conducting its study, the Joint Legislative Audit and Review Commission shall examine (i) the factors considered by the State Corporation Commission in its analysis of the feasibility of installing underground electrical transmission lines; (ii) the effect on property values resulting from installing underground, as opposed to overhead, electrical transmission lines, and the feasibility of allowing surrounding property owners to agree to pay for the installation of underground lines; (iii) the construction and long-term operating costs considered by the State Corporation Commission in reviewing electrical transmission line applications; and (iv) such other issues as it deems appropriate. This study shall not be conducted unless funding is provided in the appropriation act for such purpose.

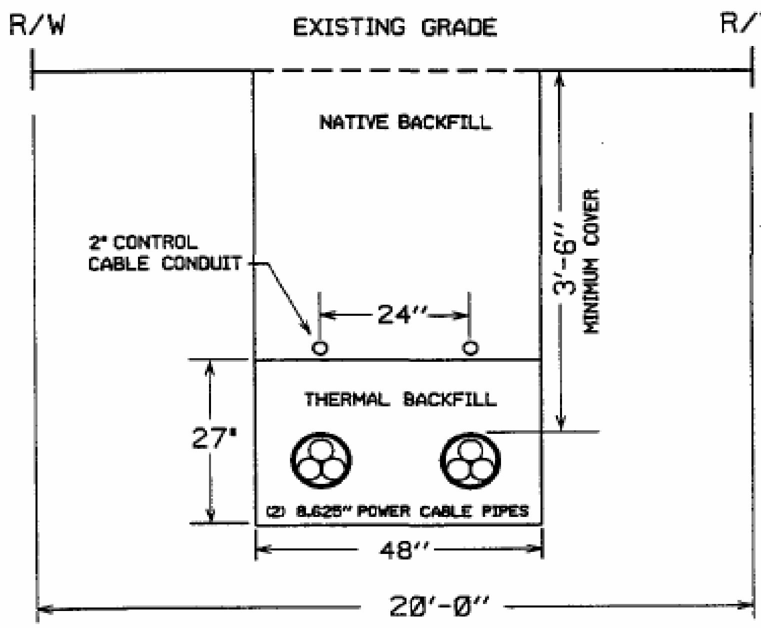
All agencies of the Commonwealth shall provide assistance to the Commission in the preparation of this report, upon request.

The Joint Legislative Audit and Review Commission shall complete its meetings for the first year by November 30, 2006, and for the second year by November 30, 2007, and the Chairman shall submit to the Division of Legislative Automated Systems an executive summary of its findings and recommendations no later than the first day of the next Regular Session of the General Assembly for each year. Each executive summary shall state whether the Commission intends to submit to the Governor and the General Assembly a report of its findings and recommendations for publication as a document. The executive summaries and reports shall be submitted as provided in the procedures of the Division of Legislative Automated Systems for the processing of legislative documents and reports and shall be posted on the General Assembly's website.

Appendix B

Underground and Overhead Transmission Structures Used By Dominion

Figure 1: Dominion Proposed an Underground 230 kV Transmission Line in 2002 for the Naval Base in Norfolk

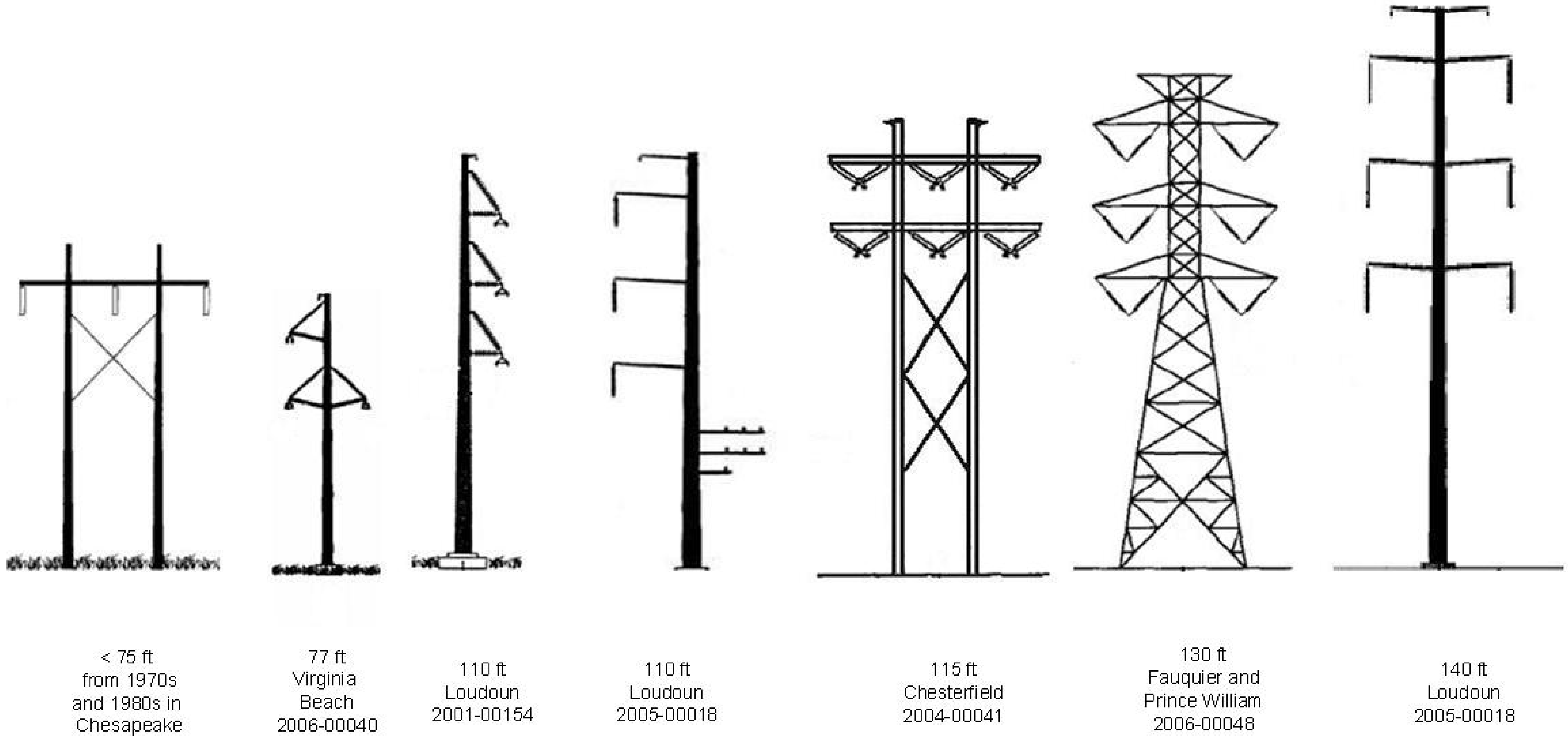


TYPE OF CONSTRUCTION:	230 kV DOUBLE CIRCUIT UNDERGROUND
TRENCH CHARACTERISTICS:	48 IN. WIDTH X 56.825 IN. MINIMUM DEPTH
FACILITIES IN TRENCH:	TWO 2 IN. PVC CONDUIT FOR CONTROL CABLE TWO FIBER OPTIC CONTROL CABLES TWO 8.625 IN. STEEL PIPES FOR POWER CABLE SIX 230 kV 2500 KCMIL COPPER CABLES (3 PER PIPE)
AAPROXIMATE LINE LENGTH:	3000 FEET

Note: The SCC approved the underground line in 2002.

Source: SCC staff report for case 2002-00180.

Figure 2: Dominion Has Proposed a Variety of Overhead Structures For Recent 230 kV Transmission Lines



Source: JLARC analysis of recent transmission line applications filed with the SCC.

Appendix C

Supplemental Tables

Table 1: JLARC Staff Reviewed 76 Transmission Line Cases Considered by the SCC Since 1972

File Number	Location	Voltage (kV)	SCC Outcome
1974-10848-A	Carroll, Floyd, Franklin, Henry, and Wythe Counties	765	Approved
1975-11655/10758	Fairfax, Fauquier, Louisa, and Warren Counties	500/230	Approved
1979-20084	Augusta and Rockingham Counties; Town of Mt. Crawford	230	Approved
1980-00006	Albemarle, Louisa, and Orange Counties	230	Denied
1980-00104	Fairfax County	230	Approved
1981-00007	Alleghany, Botetourt, and Rockbridge Counties	230	Approved
1981-00049	City of Suffolk	500	Approved
1982-00035	Cities of Chesapeake and Norfolk	230	Approved
1982-00075	Arlington County	230	Approved
1982-00091	Albemarle County	230	Approved
1983-00024	City of Suffolk	500	Approved
1983-00036	City of Alexandria	230	Approved
1983-00059	Fairfax County	230	Approved
1984-00007	Albemarle, Madison, and Orange Counties	115	Approved
1984-00009	Shenandoah County	138	Approved
1984-00028	Fairfax County	230	Approved
1985-00013/00020	Loudoun and Prince William Counties	230	Approved
1985-00024	Campbell, Halifax, and Pittsylvania Counties	230	Approved
1986-00019	Fairfax County	230	Approved
1986-00026	Fairfax County	230	Approved
1986-00035	City of Virginia Beach	230	Approved
1986-00060	Chesterfield County	230	Approved
1986-00066	King George, Richmond, Stafford, and Westmoreland Counties; City of Fredericksburg	230	Approved
1987-00035	Chesterfield and Fluvanna Counties	230	Approved
1987-00047	Prince William County	230	Approved
1988-00004	Fairfax County	230	Approved
1988-00016	Chesterfield County	230	Approved
1988-00023	Middlesex County	230	Approved
1988-00042	Fairfax, Loudoun, and Prince William Counties	230	Approved
1988-00063	Arlington County	230	Approved
1988-00071	Chesterfield County	230	Approved
1988-00072	Fairfax County	230	Approved
1988-00079	Fairfax County	230	Approved
1988-00094	City of Chesapeake	230	Approved
1988-00095	Caroline, Hanover, and Spotsylvania Counties; City of Fredericksburg	230	Approved
1989-00005	Fauquier and Prince William Counties	230	Approved
1989-00017	Charles City, Hanover, Henrico, and New Kent Counties	230	Approved
1989-00026	Chesterfield, Goochland, and Powhatan Counties	230	Approved

1989-00044	Shenandoah County	115	Approved
1989-00057	Prince William County; City of Manassas	230	Approved
1989-00073	Charles City, Chesterfield, and Henrico Counties	230	Approved
1989-00088	Dinwiddie County	115	Approved
1990-00003	Mecklenburg County	115	Approved
1990-00012	Rockbridge County	115	Approved
1990-00040	Rockbridge County	115	Approved
1991-00014	City of Virginia Beach	230	Approved
1991-00027	Goochland and Henrico Counties	230	Approved
1991-00043	Appomattox, Buckingham, Campbell, Caroline, Cumberland, Fluvanna, Goochland, Louisa, and Spotsylvania Counties	500	Approved
1991-00050	Botetourt, Craig, Giles, and Roanoke Counties	765	Withdrawn
1991-00059	City of Emporia	115	Approved
1992-00004	Rockingham County	115	Approved
1992-00024	Charles City and New Kent Counties	230	Approved
1992-00035	Albemarle County	115	Approved
1992-00058	Brunswick, Charles, Dinwiddie, Halifax, Lunenburg, and Mecklenburg Counties	500	Approved
1994-00022	Campbell County	138	Approved
1994-00036	Prince William and Loudoun Counties	500/230	Approved
1994-00044	Bedford, Franklin, and Pittsylvania Counties	138	Approved
1995-00057	Alleghany and Rockbridge Counties	230	Approved
1995-00134	City of Alexandria	230	Approved
1996-00071	City of Alexandria	230	Approved
1996-00099	Pittsylvania County; City of Danville	230	Approved
1996-00360	Fairfax County	230	Approved
1997-00766	Bland, Botetourt, Craig, Giles, Montgomery, Roanoke, and Tazewell Counties	765	Approved
1999-00009	Fairfax County	230	Approved
2000-00286	Prince William County	230	Approved
2001-00154	Loudoun County	230	Approved
2002-00180	City of Norfolk	230	Approved
2002-00702	Loudoun County	230	Approved
2003-00064	City of Chesapeake	230	Approved
2004-00041	Chesterfield County	230	Approved
2004-00062	Fauquier County	500	Approved
2004-00139	City of Norfolk	230	Approved
2005-00018	Loudoun County	230	Pending
2006-00040	City of Virginia Beach	230	Pending
2006-00048	Fauquier and Prince William Counties	230	Pending
2006-00091	Stafford County	230	Pending

Note: Cases exclude 23 transmission lines connecting a new generator or customer to the grid. Cases 1983-00024, 1987-00047, 1988-00004, 1988-00016, 1994-00036, 1995-00134, and 1996-00071 involved route or tower alterations to previously approved lines.

Source: JLARC analysis of transmission line cases reviewed by the SCC since 1972.

Table 2: Another 23 Transmission Line Cases, Intended to Connect a Generator or Individual Customer to the Grid, Have Been Considered by the SCC Since 1972

File Number	Location	Voltage (kV)
1984-00031	Greensville County	115
1986-00045	City of Hopewell	230
1987-00043	City of Portsmouth	230
1988-00008	City of Hopewell	230
1988-00074	Fairfax County	230
1989-00050	Prince George County	230
1989-00059	Chesterfield County	230
1990-00039	Campbell and Pittsylvania Counties	115/138
1991-00001	City of Chesapeake	230
1991-00019	City of Richmond	230
1991-00040	King William County and Town of West Point	230
1992-00043	Halifax County	230
1992-00046	Louisa County	230
1993-00052	King George County	230
1993-00073	Pittsylvania County	69
1994-00035	Halifax County	230
1995-00088	Goochland County	230
1996-00115	Henrico County	230
1997-00422	Henrico County	230
1998-00060	Dinwiddie County	230
1999-00351	Fauquier County	230
2000-00009	Caroline County	230
2001-00663	Fluvanna County	500

Note: Case 1997-00422 involved route modifications to a previously approved line.

Source: JLARC analysis of transmission line cases reviewed by the SCC since 1972.

Appendix

D Research Activities and Methods

JLARC staff addressed the study mandate by completing several research activities. Factors considered by the SCC in transmission line cases were examined. This review of all transmission line cases was conducted in part to ascertain how the SCC has responded to legislative direction on how to approve transmission lines, as embodied in statute. Staff reviewed the final orders of past transmission line cases before the SCC. Staff identified at least 99 cases since 1972 using the SCC's Annual Reports and Docket Search as well as online LexisNexis searches. Of these, 23 lines were built to connect new generating facilities or specific businesses to the grid. As a result, in this report, references to the total number of transmission line cases since 1972 have excluded the 23 lines in these two categories.

JLARC staff also reviewed cases involving underground transmission lines in greater depth. Only 17 cases since 1972 included a proposal by a party to the case to build a line underground. In nine of the 17 cases, staff reviewed available reports by SCC hearing examiners or SCC staff. In the remaining eight cases, JLARC staff relied upon the information contained in the application (when available) and the final order issued by the commissioners. These 17 cases are listed in Table 1 in Chapter 1.

The review of transmission line cases was supplemented with information obtained through other research activities. These activities included

- Internet searches,
- interviews with staff at Dominion Virginia Power, the SCC, and local governments,
- correspondence with transmission and undergrounding experts,
- data requests submitted to Dominion staff,
- site visits of electric facilities and lines with Dominion staff as well as independent site visits to underground and overhead lines, and
- the use of geographical information system (GIS) data provided by State agencies, local governments.

Appendix E

Underground and Overhead Transmission Costs

Tables 1 to 6 of this appendix show transmission line cost information that was compiled during this review.

Table 1 and Table 2 show estimates of underground and overhead line costs, respectively, on a per-mile basis.

Table 3 shows ratios of underground to overhead line costs that are based on Dominion estimates of costs in 2005 and 2006. The ratios vary depending on the use of initial installation and life cycle costs for XLPE and HPFF. The 2006 ratios are higher than corresponding 2005 ratios due to increases in the price of copper that is applied in estimating the costs for the underground lines.

Tables 4, 5, and 6 show estimated ratios of underground to overhead line costs that were identified during this review from sources other than Dominion. Table 4 shows ratios found during the review that did not include a specific identification of the kilovolt (kV) level assumed. This table presents the cost ratios in descending order. Tables 5 and 6 show ratios that were accompanied by a specific statement regarding the kV level assumed. These tables present the information based on ascending kV levels. A brief description of the information source for each ratio is given in a column of the tables in this appendix.

Table 1: Estimates of Underground Cost Per Mile by Dominion and by Other Sources

Estimated Cost Per Mile ($ millions)	Line Length	kV	Cable Type	Other Information (Assumptions, Sources)
13 to 15	2 miles	345	XLPE	Northeast Utilities, Bethel-Norwalk line. Higher cost includes transition station cost.
10 - 11.5	10 miles	345	HPFF	Northeast Utilities, Bethel-Norwalk line. Higher cost includes transition station cost.
10.2	0.5 mile	345	XLPE	1,500 MVA line. Estimate by expert testimony in Vermont.
10.2	5 miles	230	HPFF	Initial costs, single circuit line, Dominion estimate, July 2006
9.7	--	230	--	Double circuit line. Excludes ROW, engineering and design, and contingencies. Estimate for Ontario Power Authority.
8.2	27 miles	230		Jefferson-Martin line in California, 2006. Three of the 27 miles of the project were overhead.
8.2	0.5 mile	345	XLPE	500 MVA line. Estimate by expert testimony in Vermont.
8.1	5 miles	230	HPFF	Initial costs, single circuit line, Dominion estimate, July 2006.
7.9	Not specified	345	SCFF	Single circuit, 2002 dollars, Institute for Sustainable Energy
7.8	0.58 miles	230	HPFF	Dominion approximation of actual project costs for a double circuit line, 412 MVA, energized in 2003.
7.5	5 miles	230	XLPE	Initial costs, Dominion estimate, July 2006.
5 to 10	--	--	--	Aspen Environmental Group.
4 to 10	--	230	--	Burns and McDonnell staff, 2006
6.9	2.55	230	HPFF	Dominion approximation of actual project costs for a double circuit line, 637 MVA, energized in 1996.
6.5	1.5 miles	345	XLPE	1,500 MVA line. Estimate by expert testimony in Vermont.
6.4	Not specified	345	XLPE	Single circuit, 2002 dollars, Institute for Sustainable Energy
6.4	5.0 miles	230	XLPE	Initial costs (including ROW and miscellaneous costs). Dominion estimate, July 2005
6.3		345		Est. capital costs, Bethel-Norwalk project in Connecticut, without ROW and substation costs
6.2	3.6 miles	230		Dominion cost estimate as part of a transmission line proposal that was filed in 2001.
5.8	2.6 miles	138		Double circuit line through challenging terrain.
5.7	1.5 miles	230	HPFF	Dominion estimated project cost for a double circuit line, 412 MVA cables, energized 2005; final actual costs TBD.
5.6	Not specified	345	HPFF	Single circuit, 2002 dollars, Institute for Sustainable Energy.
5.0	Not specified	115	--	Single circuit, 2002 dollars, Institute for Sustainable Energy, mean of XLPE, SCFF, and HPFF/HPGF costs.
4 to 6	--	345	--	PJM per unit cost estimate, posted July 2004.
4.8	5.6 miles	230	XLPE	Project costs, California, 2002-04.
4.7	15.7 miles	230	XLPE	Loudoun County expert, 2005; excludes ROW costs and miscellaneous costs not directly involved in installation.
4.5	1.5 miles	345	XLPE	500 MVA line. Estimate by expert testimony in Vermont.
3.5 to 4.9	1.9 to 4 miles	150	--	Estimate for Nantucket Project, Cape Wind Associates, LLC.
3.5	--	230	--	PJM per unit cost estimates, posted July 2004.
2.9	--	115	--	Single circuit, 2002 dollars, Institute for Sustainable Energy, mean of XLPE, SCFF, and HPFF/HPGF costs.
2 to 3 plus	--	230	--	USDA Rural Development electric programs staff, 2006.
1 to 1.5 plus	--	115	--	USDA Rural Development electric programs staff, 2006.

Note: "--" means not specified.

Source: JLARC staff compilation.

Table 2: Estimates of Overhead Cost Per Mile by Dominion and by Other Sources

Estimated Cost Per Mile ($ millions)	kV	Other Information (Assumptions, Sources)
4.0	345	Northeast Utilities, Connecticut Bethel-Norwalk project.
2.9 to 4	500	Double circuit line. Estimate for Ontario Power Authority.
1.9 to 2.6	230	Double circuit line. Estimate for Ontario Power Authority.
1 to 3	--	Burns and McDonnell document.
2	500	From a capital cost analysis of energy transmission done by the Bonneville Power Administration and the Northwest Gas Association.
1.7 to 2.2 plus	345	Steel pole / tower. Institute for Sustainable Energy.
1.80	765	Seppa 1999 estimate, capital costs only.
1.71	345	Double circuit. National Council on Electricity Policy.
1.70	500	PJM. Cost does not include ROW.
1.4 to 1.9	115	Double circuit. Estimate for Ontario Power Authority.
1 to 2	--	Aspen Environmental Group document.
1.50	345	PJM. Cost does not include ROW.
1.20	500	Seppa 1999 estimate, capital cost only.
1.06	230	Dominion estimate, 5 mile 1035 MVA capacity line with steel towers. Includes $0.485 million per mile for ROW.
0.94	230	Double circuit, 16-mile line. APS transmission.
0.92	345	Single circuit. National Council on Electricity Policy.
0.70 to 1.10 plus	115	Steel pole / tower. Institute for Sustainable Energy.
0.90	345	H-frame pole. Institute for Sustainable Energy.
0.90	345	Seppa 1999 estimate, capital costs only.
0.85	230	PJM. Cost does not include ROW.
0.70	138	PJM. Cost does not include ROW.
0.70	115	Laminated wood or steel pole. Institute for Sustainable Energy.
0.60	115	Wood pole H-frame. Institute for Sustainable Energy.
0.54	138	Double circuit. National Council on Electricity Policy.
0.48	230	Seppa 1999 estimate, capital costs only
0.39	138	Single circuit. National Council on Electricity Policy.

Source: JLARC staff compilation.

Table 3: Ratios for 230 kV Underground to Overhead Transmission, 2005 and 2006 Dominion Estimates

Cost Ratios, Underground to Overhead	Cost Assumptions or Type of Cost	Year
9.7	Initial installation costs, use of HPFF underground cable.	2006
9.5	Life cycle costs, HPFF underground cable.	2006
7.7	Initial installation costs, HPFF underground cable.	2005
7.5	Life cycle costs, HPFF underground cable.	2005
7.4	Life cycle costs, XLPE underground cable.	2006
7.1	Initial installation costs, XLPE underground cable.	2006
6.3	Life cycle costs, XLPE underground cable.	2005
6.1	Initial installation costs, XLPE underground cable.	2005

Note: Information sorted from high to low based on the ratio of underground to overhead cost. Where the ratio is a range, the mid-point of the range is used in sorting from high to low.

Source: JLARC staff analysis of Dominion data.

Table 4: Ratios of Underground to Overhead Costs, No Specific kV Level Given

Cost Ratios, Underground to Overhead	Cost Assumptions or Type of Cost	Information Source	Year
15 to 25		UK TSOs, cited by ICF consulting	2004
10 to 25		Union of the Electricity Industry (Eurelectric)	2005
15.3	Capital cost only, 1,700 MVA circuit	National Grid, cited by ICF	1996
14		Ofgem (UK reg agency), cited by ICF	2004
10 to 15	Cost of high-voltage line installation	Paper, Demetrios Tziouvaras	2005-06
11.8	Capital plus low load loss cost, 1,700 MVA circuit	National Grid, cited by ICF	1996
10 to 12		ETSO, cited by ICF	2004
5 to 15	Cost range indicated on web site	Florida Power and Light	2006
5 to 15	General range given	Idaho Power, web site FAQ sheet	2006
8 to 10	Cost of copper has gone up, increasing the ratio	Burns & McDonnell transmission staff	2006
4 to 10	General range given	Wisconsin Public Service Commission	
6.9	Capital cost plus high load loss cost	National Grid, cited by ICF	1996
3 to 10	Capital cost, general range	USDA Rural Development staff	2006
2 to 10	Broad range	Burns & McDonnell	
2 to 10	General range given	Georgia Electric, website document	2006
4	Single circuit lines	American Transmission Company	2003

Note: Information sorted from high to low based on the ratio of underground to overhead cost. Where the ratio is a range, the mid-point of the range is used in sorting from high to low.

Source: JLARC staff compilation.

Table 5: Ratios of Underground to Overhead Costs—Transmission at 115 to 230 kV (Sources Other Than Dominion)

Kilovolt (kV) Level	Other Cost Notes / Assumptions	Information Source	Cost Ratios, Underground to Overhead
115	Underground double circuit versus wood pole H frame	Institute for Sustainable Energy	**6.7 to 9.8**
	Colorado projects	USDA Rural Development	**4 to 6**
	Underground single circuit versus wood pole H frame	Institute for Sustainable Energy	**3.7 to 5.8**
	Underground double circuit versus steel pole	Institute for Sustainable Energy	**3.6 to 5.4**
	Underground single circuit versus steel pole	Institute for Sustainable Energy	**2.0 to 3.2**
132	Total installed cost	Orton Consulting Engineers Int'l	**5.7**
	Lifetime cost	Orton Consulting Engineers Int'l	**2.6**
138	Cost without terminals.	Wisconsin Public Service Commission	**5.1**
	Overhead proposal is double circuit steel poles	Appalachian, in the *Roanoke Times*	**3**
110 to 219	Single value of 7, with range from 3.4 to 16	CIGRE, as cited by the Commission of the European Communities (CEC)	**7**
150 / 200	Not stated	ESB Nat. Grid, Ireland, cited by ICF	**7.7**
	150 kV	Europowercab, cited in CEC report	**4.5**
150 / 220	Not stated	Terna, Italy, cited by ICF	**5**
	Not stated	Statnett, Norway, cited by ICF	**4.5**
	Not stated	RTE, France, cited by ICF	**1.6 to 3**
225 / 230	225 kV	Europowercab, cited by CEC	**7.5**
	225 kV, installation cost	Orton Consulting Engineers Int'l	**5 to 10**
	Experts on behalf of Loudoun County, 230 kV	Torben Aabo (2004) & Gerry Sheerin (2005)	**4.2 & 4.4**
	230 kV double circuit lines	Ontario Power Authority	**3.7 to 5.1**
	225 kV	ICF Consulting	**3**

Note: Information sorted from high to low by kV level first, and then by the cost ratio. Where the kV level or the cost ratio is expressed as a range, the mid-point of the range is used in sorting from high to low.

Source: JLARC staff compilation.

Table 6: Ratios of Underground to Overhead Costs—Transmission at Above 230 kV

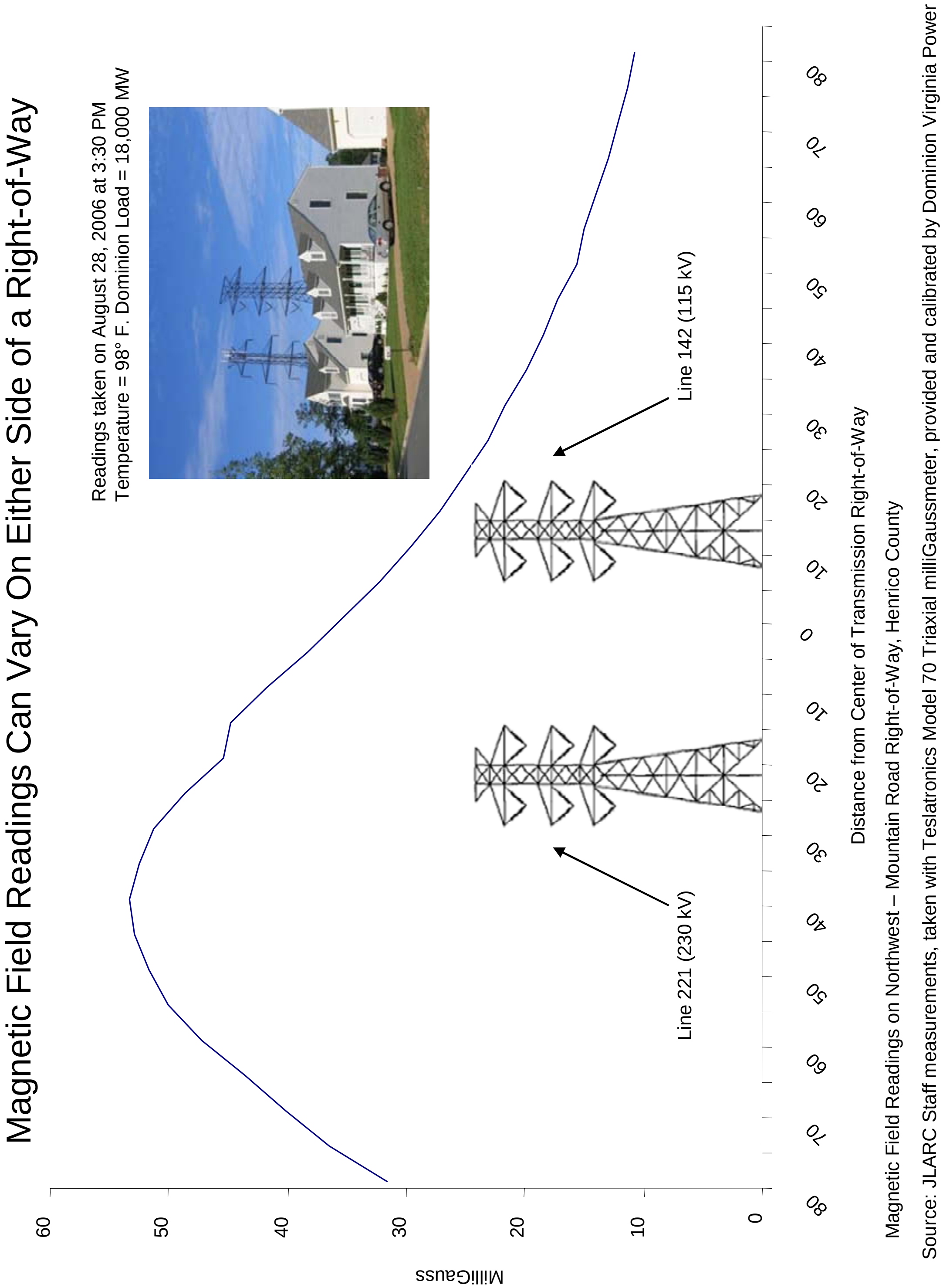
Ratios for Transmission at Above 230 kV			
Kilovolt (kV) Level	**Other Cost Notes / Assumptions**	**Information Source**	**Cost Ratios, Underground to Overhead**
220 to 362	Single value of 13, with range from 5.1 to 22.1	CIGRE, as cited by the Commission of the European Communities (CEC)	**13**
275	Double circuit	SHETL, cited by Highland Council	**12 to 15**
345	SCFF single circuit compared to H-frame	Institute for Sustainable Energy	**8.8**
	XLPE single circuit compared to H-frame	Institute for Sustainable Energy	**7.1**
	Ratio given as part of discussion of proposed 345 kV line	American Transmission Co. staff	**7.0**
	HPFF single circuit compared to H-frame	Institute for Sustainable Energy	**6.2**
	SCFF single circuit compared to steel pole	Institute for Sustainable Energy	**3.6 to 4.6**
	Bethel-Norwalk, 2 miles of XLPE	Northeast Utilities	**3.2 to 3.8**
	XLPE single circuit compared to OH steel pole	Institute for Sustainable Energy	**2.9 to 3.8**
	HPFF single circuit compared to OH steel pole	Institute for Sustainable Energy	**2.5 to 3.3**
	Bethel-Norwalk, 10 miles of HPFF	Northeast Utilities	**2.5 to 2.9**
380 / 400	Not stated	REE, Spain, cited by ICF	**25**
	Not stated	National Grid, UK, cited by ICF	**15 to 25**
	400 kV double circuit line	SHETL, cited by Highland Council	**14 to 25**
	Not stated	RTE France, cited by ICF	**10 to 20**
	Not stated	UK Regulator OFGEM, cited by ICF	**14**
	Capital cost, 1 km 400 kV double circuit fluid-filled	The Highland Council	**12**
	400 kV	ICF Consulting	**10**
	Capital cost, 5 km 400 kV double circuit fluid-filled	The Highland Council	**9.5**
	Life cycle cost, 5 km 400 kV fluid-filled	The Highland Council	**9.1 to 9.3**
	Capital cost, 10 km 400 kV double circuit fluid-filled	The Highland Council	**8.9**
	Capital cost, 1 km of 400 kV double circuit XLPE	The Highland Council	**8.9**
	Not stated	APG, Austria, cited by ICF	**8**
	Not stated	Terna, Italy, cited by ICF	**8**
	400 kV	Europowercab, cited by CEC	**7.5**
	400 kV, installed cost	Harry Orton	**5 to 10**
	Not stated	GRTN, cited by ICF	**5 to 8**
	Not stated	Fingrid, cited by ICF	**5 to 8**
	Life cycle cost, 5 km line, 400 kV, XLPE versus OH	The Highland Council	**7.2 to 7.6**
	Not stated	Statnett, Norway, cited by ICF	**6.5**
	Capital cost, 5 km, 400 kV, double circuit XLPE	The Highland Council	**6.4**
	380 kV, lifetime cost	ICF report on Italian regulated tariff	**5.9**
	Capital cost, 10 km, 400 kV double circuit, XLPE	The Highland Council	**5.8**
	Estimate for 400 kV project	ICF report, Beauly Scotland line	**5**
	400 kV project in Denmark	ICF Consulting	**4.5**
500	Range of ratios given in EIS for four 500 kV projects	U.S. DOE EIS documents	**10 to 16**
363 to 764	Single value of 20, with range from 14.6 to 33.3	CIGRE, as cited by the Commission of the European Communities (CEC)	**20**

Note: Information sorted from high to low by kV level first, and then by the cost ratio. Where the kV level or the cost ratio is expressed as a range, the mid-point of the range is used in sorting from high to low.

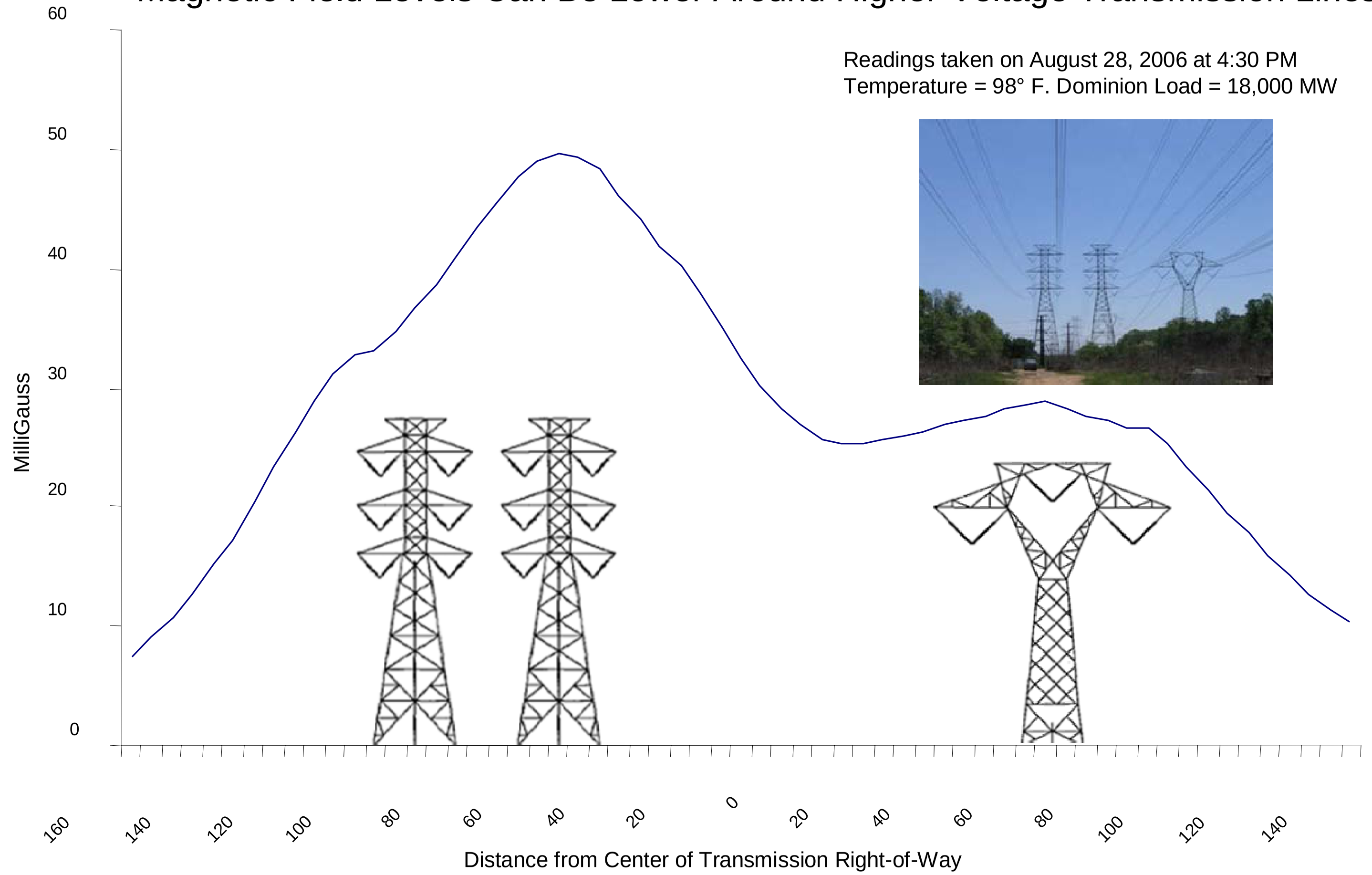
Source: JLARC staff compilation.

Appendix **F**

Magnetic Field Readings



Magnetic Field Levels Can Be Lower Around Higher-Voltage Transmission Lines



Magnetic Field Readings on Midlothian-Carson Right-of-Way, Chesterfield County

Source: JLARC Staff measurements, taken five feet above ground with Teslatronics Model 70 Triaxial milliGaussmeter, provided and calibrated by Dominion Virginia Power

Appendix G

Unoccupied Transmission Corridors Owned by Dominion Virginia Power

Pender /Oakton UG R/W – 24’ permanent underground r/w in Fairfax County that extends from Pender Substation to the proposed Oakton substation site.

Fredericksburg / Quantico R/W – Company owns a 100’ wide transmission r/w in Stafford County that has been abandoned due to re-routing of the line (252/ 29). The original route crosses residential properties and is currently used by Distribution. There are currently no transmission structures on this corridor.

Ox / Occoquan / Pohick / Van Dorn R/W – Company acquired r/w in the 1970’s in Woodbridge but did not construct transmission line because Company could not justify a new independent right-of-way until the existing r/w was developed to its maximum capability. It does not appear that all acquisitions for this line were obtained.

Stafford / Elmont / Loudoun – Company acquired a 500’ width r/w for a portion of the corridor and will only require a 150’ width r/w. Portions of the 500’ width r/w have been quitclaimed but the Company has maintained 150’ for future use. The Company also acquired a 335’ r/w for approximately 11.6 miles in this corridor, which has not been compromised by quitclaims.

Old Church / Chickahominy – Portions of this r/w have been acquired. Real Estate Department is actively acquiring remaining parcels.

Landstown / West Landing – Portions of this r/w have been acquired. Real Estate Department is actively acquiring remaining parcels.

Hayes / Yorktown – R/W from Hayes Substation to Yorktown, including 120’ underground r/w across the York River, was acquired in 1985-86. Proposed line has not been constructed.

Joshua Falls / Ladysmith T/L – Company purchased 20 acres for transmission r/w in a residential subdivision in Louisa County to ensure its ability to extend the line. Project was initiated in 1992 but was delayed because of coordination issues with AEP and required regulatory approvals.

Possum Point / Weaver Road T/L – 225' Corridor in Prince William County, Virginia.

Richmond / Portsmouth T/L (Locks / Centralia) – 100' Corridor currently used by Distribution.

Appendix H Agency Responses

As a part of the extensive validation process, State agencies and other entities involved in a JLARC assessment effort are given the opportunity to comment on an exposure draft of the report. Appropriate technical corrections resulting from comments provided by these entities have been made in this version of the report. This appendix includes written responses from the State Corporation Commission and Dominion Virginia Power.

MARK C. CHRISTIE
CHAIRMAN

THEODORE V. MORRISON, JR.
COMMISSIONER

JUDITH WILLIAMS JAGDMANN
COMMISSIONER

COMMONWEALTH OF VIRGINIA

JOEL H. PECK
CLERK OF THE COMMISSION
P. O. BOX 1197
RICHMOND, VIRGINIA 23218-1197

STATE CORPORATION COMMISSION

November 7, 2006

Philip A. Leone, Director
Joint Legislative Audit and Review Commission
Suite 1100, General Assembly Building
Capitol Square
Richmond, Virginia 23219

Dear Dr. Leone:

The Virginia State Corporation Commission ("SCC") thanks you and the JLARC Staff for the opportunity to review the Exposure Draft ("Exposure Draft" or "Draft") of your report entitled *SCC Review of Underground Electric Transmission Lines* dated October 31, 2006.

The SCC Staff has suggested several technical and clarifying changes to the Draft, and these have been furnished to your Staff, via e-mail. Please do not hesitate to contact us should there be any questions regarding these changes or if you need any further documentation or clarification.

During the past several months, the SCC and its Staff were pleased to assist JLARC and its Staff in the course of its study of electric transmission line undergrounding pursuant to House Joint Resolution 100 approved by the 2006 Session of the Virginia General Assembly. We commend this study team for its thoroughness in exploring this technically and legally complex topic.

The Exposure Draft explores many issues and sub-issues associated with the SCC's review of utilities' transmission line cases. In response to your invitation to do so, we offer several brief comments on the draft. In the main, these comments concern practice and procedure before the SCC in the context of these cases; the draft's legislative proposal concerning transmission line need analysis replication by the SCC Staff; and the draft's legislative proposal concerning quantification of environmental and other externalities in the Commission's review of transmission line applications.

Procedures and practice before the Commission.

First of all, the SCC and its Staff are sensitive to the impact of any proposed electric transmission line on the communities through which a line route is proposed. Consequently, and beyond requiring the applicant utility to comply with the notice requirements contained in § 56-46.1, the SCC makes every effort to establish and implement proceedings that maximize participation by homeowners and landowners along a proposed line route.

Moreover, through both the direct-mailed landowner notices and the public notices of proposed line routes given by the applicant utility pursuant to § 56-46.1 of the Code, affected homeowners and landowners are informed that they have the opportunity to express their views and concerns as public witnesses (through both live testimony and in written comments). Thus, citizen participation in these proceedings is encouraged and facilitated to the fullest extent possible. To that end, the Commission conducts public hearings in or near communities affected by proposed construction as a matter of standard practice.

The Exposure Draft states that the records in transmission line cases are generally developed by a hearing process built on the rules of evidence. Draft at 45-46. We would emphasize, however, that the Commission is in a "legislative" (versus judicial) mode when it conducts transmission line cases, and thus the rules of evidence are greatly relaxed to ensure that all information that may be useful to the Commission is introduced and made part of the record. This is particularly so as regards comments, testimony and other information offered by public witnesses for the Commission's consideration.

Every utility proposing to construct a transmission line has the statutory burden imposed by the Virginia General Assembly, to establish, through competent, probative evidence that such a line is needed (§§ 56-265.2 and 56-46.1), and that that the proposed routing will minimize adverse impact on "scenic assets, historic districts, and environment of the area concerned." § 56-46.1. This burden remains upon the applicant throughout the entire proceeding. Concurrently, the SCC has a statutory obligation to ensure that any such line proposed will be constructed in an "economical, expeditious and efficient manner." § 56-234.3. Thus, Virginia's electric utilities must do far more than simply file an application with this Commission to obtain approval of a proposed transmission line. They must satisfy the requirements of the laws of the Commonwealth described above, as administered by this Commission.

We also emphasize that the SCC's hearing examiners assigned to these cases do not limit the development of the evidentiary record in transmission line cases simply to testimony and exhibits offered and admitted in the SCC's courtrooms. For example, in a recent transmission line case[1] the hearing examiner assigned to that case traveled to Loudoun County on three separate occasions to view primary and alternate line routing proposals, and did so in the company of affected property owners and/or their representatives. The Commission itself exercises final oversight authority concerning the development and completeness of evidentiary records in every case before it. The Commission can, and has, directed hearing examiners to conduct additional evidentiary proceedings in order to ensure the completeness of the evidentiary record in some cases.

Thus, transmission line dockets before the Commission are designed to provide the fullest possible procedural and substantive protections for landowners and residents in the vicinity of proposed transmission lines.

<u>Role of the Commission Staff in Transmission Line Cases.</u>

The Exposure Draft recognizes the role of the Commission Staff in these cases—principally as a source of information and expertise on significant issues affecting the public interest. In the recent case involving a line proposed by Dominion Virginia Power to be sited in Loudoun County[2], for example, the Commission's Staff offered the pre-filed written testimony, and live testimony of a member of the Commission Staff who holds degrees in electrical and electrical power engineering. His testimony provided an assessment of the need for the proposed transmission line and issues associated with its siting. This testimony reflects the historical role that the Commission Staff has played in these cases, i.e., to assist the Commission in its development of the evidentiary record in such cases.

We note the Exposure Draft's recommendation that the Commission "acquire the resources and information necessary to replicate utility load projections, load flow studies and contingency analyses in every transmission line case." The recommendation is directly related to the Exposure Draft's conclusion that "the commission does not have the internal computer resources necessary to independently verify the reliability models used to justify new transmission lines." The Draft goes on to conclude that with the requisite analyses enabled by such new resources, the SCC could independently verify the backdrop for a utility's opposition to undergrounding a transmission line on the basis of reliability concerns. Draft at 136.

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1 *Application of Virginia Electric and Power Company for a certificate of public convenience and necessity for facilities in Loudoun County: Pleasant View – Hamilton 230 kV Transmission Line and 230 kV-34.5 kV Hamilton Substation,* Case No. PUE-2005-00018.

2 Id.

Such a recommendation, as drafted, would impose significant costs on the Commission. Beyond costs, however, there is the larger issue of creating meaningful information via replication of Virginia utilities' reliability analyses backing transmission planning and siting applications. Increasingly, the "modeling" for major transmission lines reflects transmission planning at the regional level. Virtually all of Virginia's investor owned utilities are members of PJM. In fact, Regional Transmission Entity participation by Virginia's transmission-owning utilities is directed by § 56-579 of the Virginia Electric Utility Restructuring Act.

Thus, the future transmission needs and requirements of Virginia's transmission-owning utilities reflect not only reliability issues in the Commonwealth of Virginia, but also the needs of the entire PJM footprint in the states now interconnected to Virginia through this regional transmission organization. Additionally, this regional planning process may increasingly focus in the future on economic, as well as reliability, issues associated with transmission improvements allowing greater access to lower-cost generation facilities.

At this time, neither the Commission or its Staff could replicate PJM's reliability and economic modeling implicit in its regional transmission expansion planning processes. Such modeling depends on inputted data from utilities throughout the 14 state region that PJM serves, not just from Virginia utilities. Moreover, it is impossible to know whether the Staff would be permitted access to the proprietary system data of all of these utilities—data that would be essential to conduct (or replicate) such load flow and contingency studies.

With respect to those cases that fall outside regional transmission planning conducted by PJM, the Commission Staff would, consistent with past practice in all transmission line cases, explore and analyze applicant utilities' assertions of need through (i) meetings between utility representatives and the Commission Staff, (ii) review and analysis of the utilities' applications, as filed, and (iii) discovery conducted by the Staff and other parties subsequent to applications' filing. Need-related information and data developed through this process has historically provided the Commission Staff sufficient information to review utilities' needs analysis offered in support of transmission line applications. As and when needed, the Commission Staff has employed consultants to assist it in analyzing proposed transmission lines of unusual length or complexity.

In summary, the Commission believes that replicating utility load projections, load flow studies, and contingency analyses should be done, if at all, on a case-by-case basis, and then only when the time invested and costs associated with doing so would produce information reasonably necessary to the Commission's determination of need for a proposed transmission line.

Quantifying Externalities.

The Exposure Draft correctly reports that that the SCC does consider costs—as it must by statute—in its assessment of a proposed transmission line, and any proposed construction or routing alternatives. The Draft also emphasizes that the SCC does not currently quantify costs external to the construction and maintenance costs of a proposed transmission. However, and as noted in the Draft, the SCC *does* consider these costs from a qualitative viewpoint, and gives full consideration to any qualitative evidence offered by the parties to a transmission line proceeding.

Specifically, to the extent that properties—including, significantly, homes—are affected by a proposed transmission line and its routing, the Commission does consider these impacts in its overall consideration of a proposed transmission line. As noted in the Draft, the Commission has frequently directed modifications to utilities' proposed transmission line routing in an effort to mitigate the impact on property owners.[3] For example, in conjunction with a transmission line sited in Loudoun County,[4] the Commission approved a routing along a portion of the W&OD Trail to avoid two subdivisions.

In this regard, we note that the Exposure Draft recommends, for consideration, potential legislation that would direct the Commission to "indicate which cost factors should be consistently addressed whenever the Commission is required to approve the construction of any electric utility facility, and to modify Commission policies and procedures, accordingly. Cost factors that the Commission should consider include (A) the monetary effect of an electric facility on the value of land and structures within and immediately adjacent to the proposed location or corridor...." Draft at 141. In short, this recommendation is suggesting legislation requiring the Commission to quantify the externality of property value impact, and then taking that into consideration as part of the costs of a transmission line.

Concerning that proposal, it is our view that adopting such legislation would effectively mandate an enlargement of the Commission Staff to include qualified real property appraisers for

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3 In addition to alternative routes, other methods to reduce visual impact may arise in proceedings. These include: height of the line's supporting structures (towers); structure design (single shaft versus lattice); structure material (galvanized versus self-protecting rust), tower location, use of topography to minimize visibility, type of conductor (reflective versus non-specular); use of natural visual barriers (trees).

4 *Virginia Electric and Power Company d/b/a Dominion Virginia Power - For a certificate for facilities in Loudoun County: Beaumeade-Beco 230 kV Transmission Line and Beaumeade-Greenway 230 kV Transmission Line,* Case No. PUE-2001-00154.

these cases, or require the Commission to make substantial investments in retaining independent experts to assist the Staff for the purpose of quantifying these property value impacts. Procedurally, this represents a substantial departure from current practice before the Commission where only those parties with an interest in quantifying property value impacts in these cases do so—frequently through public witness testimony, and often through real estate experts. Moreover, how such quantification should or could be weighted as part of the Commission's considerations is not addressed in this recommendation, or the draft, generally.

In our September 29, 2006, letter to you, we, *inter alia,* responded to your question about the Commission's view of quantifying environmental externalities. A copy is attached for convenient reference. In that letter, we made clear, however, that should the General Assembly direct the incorporation of quantified environmental externalities into the regulatory process, the Commission would carry out the law. In the meantime, however, we do not believe we currently possess statutory authority to do so.

We also wish to emphasize that until any such change in the law, the Commission will continue to do what it has done historically, and that is to take land owners' and homeowners' concerns about property value impacts of proposed transmission lines into consideration when reviewing the proposed construction and siting of transmission lines. Moreover, the Commission will continue to do everything in its power to reasonably mitigate the impacts of proposed electric transmission lines

In summary, we appreciate the opportunity to respond to the Exposure Draft. Please let us know if we can be of any further assistance to you, the members of your Staff, or the legislative members of JLARC.

Sincerely,

Mark C. Christie

Mark C. Christie, Chairman
State Corporation Commission.

MCC/nel
Attachment

COMMONWEALTH OF VIRGINIA

MARK C. CHRISTIE
CHAIRMAN

THEODORE V. MORRISON, JR.
COMMISSIONER

JUDITH WILLIAMS JAGDMANN
COMMISSIONER

JOEL H. PECK
CLERK OF THE COMMISSION
P. O. BOX 1197
RICHMOND, VIRGINIA 23218-1197

STATE CORPORATION COMMISSION

September 29, 2006

Philip Leone
Director
Joint Legislative Audit and Review Committee
Suite 1100
General Assembly Building
Richmond, Virginia 23219

House Joint Resolution 100 Study

Dear Mr. Leone:

Attached are responses to the four written questions included in your letter dated September 22, 2006 regarding the above-referenced study. If, after reviewing the responses, you would like us to respond to additional questions and/or you or your staff wish to meet with us, we will be happy to do so.

Respectfully submitted,

Mark C. Christie | Theodore V. Morrison, Jr. | Judith Williams Jagdmann

Mark C. Christie
Theodore V. Morrison, Jr.
Judith Williams Jagdmann

* * *

1. *According to the Federal Energy Regulatory Commission (FERC), the federal Energy Policy Act of 2005 grants FERC the new responsibility of "supplementing state transmission siting efforts in national interest electric transmission corridors," or NIETCs. At this time, how does the Commission anticipate that the designation of any NIETCs in Virginia will affect the Commission's current role in transmission siting?*

The Energy Policy Act of 2005 (EPAct 2005) allows FERC to issue a permit for construction of transmission facilities in an NIETC in a number of instances. These include: (1) if the State does not have authority to approve the facilities; (2) if the State does not have the authority to consider interstate benefits of the facilities; (3) if the applicant does not qualify to apply to the State for construction authority; (4) if the State has withheld approval for more than one year after the filing of an application seeking approval or one year after the designation of the NIETC, whichever is later; and (5) if the State has conditioned its approval in such a manner that the proposed construction will not significantly reduce transmission congestion in interstate commerce or is not economically feasible (*see* EPAct 2005 § 1221(a)).

Under Virginia statutes, the Commission is required to find that the new line is "needed" (*see* Va. Code §§ 56-46.1 B and 56-265.2). In asserting that transmission facilities are "needed," applicants before the Commission have provided evidence to show that the new lines are necessary to provide reliable *intrastate* service to Virginia consumers. The Commission has not considered *interstate* needs to be dispositive in applying Virginia statutes on this matter. Evidence has been adduced, however, in particular cases involving interstate line construction as to the proposed line's overall system benefits, including those realized in Virginia, and nothing precludes the presentation of such evidence in subsequent cases.

In addition, it is not unusual for more than 12 months to pass prior to reaching a final resolution in complex transmission line proceedings before the Commission. These cases involve procedures such as published notice, direct notice to affected landowners and localities, receipt of written and electronic public comment, multiple rounds of discovery, multiple rounds of pre-filed testimony, recommendations from state agencies concerned with environmental protection, consideration of local comprehensive plans, local public hearings to receive testimony from public witnesses, evidentiary hearings to receive evidence and argument from formal participants, briefing, and reconsideration requests.

The above procedures, which are necessary to afford due process, also are not limited to one siting route, but may encompass the evaluation of multiple siting alternatives. Indeed, such indepth evaluation may reasonably lead to consideration of routes that are significantly different from those proposed by the applicant. The General Assembly has recognized this and, in such instances, has directed the Commission to cause notice of any such new route to be published and mailed the same as for the original routes and to give interested parties in the newly affected areas the same protection afforded those affected by the originally noticed routes (*see* Va. Code § 56-46.1 E).

The Commission will continue to fulfill its statutory obligations regarding applications requesting certificates of public convenience and necessity for the construction of transmission facilities – and will continue to provide the public participation and analyses directed by Virginia statutes (*see* Va. Code §§ 56-265.2 and 56-46.1). We obviously cannot speak as to how FERC, or applicants before the Commission, may attempt to invoke the new federal permit provisions contained in EPAct 2005.

* * *

2. *In the case of transmission line projects submitted for approval under the Utility Facilities Act and § 56-46.1, and for which responsibility for all or a portion of the costs of the project have been assigned by the PJM Board of Managers to utilities outside of Virginia, which utility or other party does the Commission anticipate would be responsible for any additional costs associated with mitigation activities the Commission requires as a condition of certification?*

The Commission's authority regarding construction of transmission facilities in Virginia extends to the "public utility" that files the application requesting a certificate of public convenience and necessity (*see* Va. Code §§ 56-265.1 and 56-265.2). Any requirements placed by the Commission on a certificate of public convenience and necessity, in the form of conditions or otherwise, must be met by the applicant.

* * *

3. *In the Final Order for Case Number PUE-1990-00070, the Commission stated that "environmental externalities should be dealt with from a broader perspective than utility ratemaking. Congress and the General Assembly are the proper bodies to provide this perspective." Does the Commission still maintain this opinion? If yes, is the Commission in a position to develop a sufficient record, at the request of the General Assembly, that would quantify externalities such as the*

potential impact of electric transmission lines on (A) human health and safety, and (B) the value of private property?

On March 27, 1992, the Commission issued a Final Order in Case No. PUE-1990-00070. This case was initiated by the Commission to investigate conservation and load management (CLM) programs of electric and natural gas utilities. The Commission explained that the "first critical question which we must address is which test or tests should be applied to judge whether a [CLM] program is cost effective." (1992 SCC Ann. Rep. at 263.) In this regard, the Commission found that environmental externalities should not be *quantified* in evaluating the costs associated with a CLM program: "We believe that it would be speculative, and thus contrary to our legal authority, to include adjustments in rates for external environmental factors." (*Id.* at 264.) The Commission found that it lacked statutory authority to increase rates based on offsetting quantitative environmental externalities and agreed with parties "who suggested that incorporation of environmental externalities should be dealt with from a broader perspective than utility ratemaking." (*Id.*) Thus, the Commission concluded that "Congress and the General Assembly are the proper bodies to provide this perspective. When and if we are directed by legislation to incorporate *quantified* environmental externalities into the regulatory process, we shall do so, of course." (*Id.* (emphasis added).) As there has been no statutory change on this matter, such analysis remains as Commission precedent on this question.

In that same Final Order, the Commission further explained the difference (for our regulatory purposes) between quantitative and qualitative environmental externalities: "This Commission clearly considers environmental factors in rendering our decisions, but these factors are taken into account from a *qualitative*, not quantitative, standpoint." (*Id.* (emphasis added).) As an example, the Commission cited Va. Code § 56-46.1. This statute directs the Commission to consider, in transmission line cases, factors such as the effect of the facility on the environment, adverse environmental impact, reports from state agencies concerned with environmental protection, local comprehensive plans, the effect on economic development, and adverse impact on scenic assets, historic districts and the environment of the area concerned.

In transmission line cases the Commission must rule based on the record before it – including the record developed on qualitative environmental externalities. In reference to undergrounding, in ruling on prior transmission line applications the Commission has explained its rejection of underground proposals as follows: "There is no evidence that benefits will accrue to the Company or its ratepayers which outweigh the increased costs and risk of reliability problems associated with the underground installation of a portion of the proposed transmission line." (*See* 1990 SCC Ann. Rep. 269; 2004 SCC Ann. Rep. at 350-351.)

The Commission has rejected alternative routes or alternative construction methods for which the benefits did not, in the Commission's evaluation of the evidence, outweigh the increased costs that would be borne by all ratepayers. Conversely, the Commission has also approved alternative routes that satisfy this analysis. In other words, the Commission has not approved alternative routes or construction methods that would (1) result in significantly increased costs for all ratepayers, but (2) benefit only a particular subset of ratepayers (by, for example, reducing environmental externalities for those particular ratepayers).

The Commission views the decision to have ratepayers in a service area pay for more expensive transmission line alternatives that do not benefit those ratepayers as a legislative policy decision. If the General Assembly enacts legislation speaking to that policy – such as directing the Commission on how to allocate those extra costs that provide specific benefits to particular, identifiable subsets of Virginians that are uniquely burdened by the line – the Commission will faithfully implement the same. As one example, we note that the General Assembly has permitted certain localities to create a special rate district to cover additional costs of constructing, operating, and maintaining certain transmission lines underground rather than overhead (*see* Va. Code § 15.2-2404).

In response to the final part of Question 3, above, the record in Commission proceedings is developed by all who participate, such as the applicant, respondents, Commission Staff, and public witnesses. If the General Assembly directs the Commission to quantify specific environmental externalities, the record will be built by those who choose to participate on such issue. As noted above, in transmission line cases the Commisson is required to consider all reports from state agencies concerned with environmental protection (*see* Va. Code § 56-46.1 A). The Commission's Staff currently would need to engage outside experts to address quantification of environmental externalities, unless those agencies charged with administering Virginia's environmental laws sponsor testimony quantifying environmental externalities.

* * *

4. *Are there any additional resources which would aid the Commission or its Staff in reviewing applications for transmission lines? For example, in the Staff report for Case Number PUE-2004-00062, Staff expressed uncertainty "whether, and under what circumstances, a utility could be directed to construct new generation." In that same case, the Hearing Examiner's report indicated that*

Staff would need to retain a consultant to perform the contingency analysis conducted by the utility.

In response to your first example, the Commission has never directed a public utility to build generation in lieu of constructing a transmission line. Current statutes do not explicitly give the Commission that authority. We also have not evaluated any practical or legal impediments that may thwart the statutory implementation of a forced-generation-in-lieu-of-transmission alternative.

As noted above, issues in Commission proceedings are developed, for example, by the applicant and by respondents (who are frequently, but not invariably, opposed to the applicant). The Commission's Staff is a participant in cases but does not always provide testimony on all issues raised in a case. The Commission would, on occasion, need to hire additional Staff or permit its Staff to engage outside experts to address thoroughly certain matters – such as performing detailed load flow modeling and contingency analyses in opposition to those presented by the applicant. The Commission has previously permitted its Staff to engage outside experts in various energy matters that present sufficiently complex issues to merit the devotion of additional resources.

*   *   *

Dominion Resources Services, Inc.
P.O. Box 26532, Richmond, Virginia 23261

Dominion[SM]

November 7, 2006

Mr. Philip A. Leone, Director
Joint Legislative Audit and Review Commission
Suite 1100
General Assembly Building
Capitol Square
Richmond, Virginia 23219

Dear Mr. Leone:

Dominion thanks JLARC for the opportunity to review the draft of your report on the policies and criteria used by the State Corporation Commission to evaluate the feasibility of undergrounding transmission lines.

We found the report to be objective and responsive to the issues presented by the General Assembly through its passage of House Joint Resolution 100.

Please contact us if we can be of further assistance.

Sincerely,

John D. Smatlak

John D. Smatlak
Vice President – Electric Transmission

JLARC Staff

Executive Staff

Philip A. Leone, Director
Glen S. Tittermary, Deputy Director

Division Chiefs

Robert B. Rotz, Senior Division Chief
Harold E. Greer III, Division Chief

Section Managers

Patricia S. Bishop, Fiscal & Administrative Services
Gregory J. Rest, Research Methods
Walter L. Smiley, Fiscal Analysis

Project Leaders

Aris W. Bearse
Justin C. Brown
Ashley S. Colvin
Martha L. Erwin
Eric H. Messick
Nathalie Molliet-Ribet
Kimberly A. Sarte

Project Staff

Janice G. Baab
Jamie S. Bitz
Jennifer K. Breidenbaugh
Eileen T. Fleck
Paula C. Lambert
Brad B. Marsh
Ellen J. Miller
Jason W. Powell
Pinki N. Shah
Tracey R. Smith
Elisabeth M. Thomson
Christine D. Wolfe
Kent S. Wyatt

Administrative and Research Support Staff

Joan M. Irby
Betsy M. Jackson

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Joint Legislative Audit and Review Commission
Suite 1100
General Assembly Building
Capitol Square
Richmond, Virginia 23219
804-786-1258 Fax 804-371-0101
http://jlarc.state.va.us