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Electric Power Substation Capital Costs

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D. R. Brown

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Prepared for the U.S. Department of Energy
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Pacific Northwest National Laboratory
Richland, Washington 99352

Summary

The displacement or deferral of substation equipment is a key benefit associated with several technologies that are being developed with the support of the U.S. Department of Energy's Office of Utility Technologies. This could occur, for example, as a result of installing a distributed generating resource within an electricity distribution system.

The objective of this study was to develop a model for preparing preliminary estimates of substation capital costs based on rudimentary conceptual design information. The model is intended to be used by energy systems analysts who need "ballpark" substation cost estimates to help establish the value of advanced utility technologies that result in the deferral or displacement of substation equipment. This cost-estimating model requires only minimal inputs. More detailed cost-estimating approaches are recommended when more detailed design information is available.

The model was developed by collecting and evaluating approximately 20 sets of substation design and cost data from about 10 U.S. sources, including federal power marketing agencies and private and public electric utilities. The model is principally based on data provided by one of these sources. Estimates prepared with the model were compared with estimated and actual costs for the data sets received from the other utilities. In general, good agreement (for conceptual level estimating) was found between estimates prepared with the cost-estimating model and those prepared by the individual utilities. Thus, the model was judged to be adequate for making preliminary estimates of typical substation costs for U.S. utilities.

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Glossary of Terms

Alternate Bus. A means of providing redundant power connections, enabling maintenance without power interruptions, etc. See also transfer bus.

Bay. A portion of the substation that contains the circuit breakers, isolation switches, and all hardware associated with anything connected to the substation bus. Adjoining bays are connected by buswork.

Breaker-and-a-Half Substation Configuration. Bays with three breakers, with each bay providing two connections, typically used for high voltage transmission substations with more than three or four total connections.

Bus. Metal conductor (typically aluminum pipe) that connects substation bays together.

Bus Section Bay. A substation bay that connects segmented busses together (typically used for substations with a large number of total connections).

Buswork. Synonym for bus structure, including all insulators and support steel and footing structure that supports a bus or busses, including the bus itself. Buswork can refer to this type of hardware associated with each of the substation bays in addition to the substation busses.

Circuit Breaker. Protective device designed to isolate portions of the power system (e.g., lines and transformers) with the ability to interrupt large fault currents.

Disconnect Switch. A switch to provide isolation for various portions of the power system under normal conditions (e.g., remove portions of the system for maintenance or repair). Circuit breakers are typically provided with a pair of disconnect switches to enable maintenance of the circuit breaker. See also isolation switch.

Distribution System. Power delivery infrastructure between customers and substations.

Double Breaker Substation Configuration. A fully redundant bus configuration (two circuit breakers per substation bay). Because of its high cost, this configuration is rarely used.

Fault. Abnormal power system operation or failure, usually caused by a short circuit.

Feeder. A single distribution circuit.

Isolation Switch. See disconnect switch.

Line Bay. A substation bay that provides for the connection of a transmission line (can also be used for transformers, miscellaneous reactive power equipment, etc.).

Main and Transfer Substation Configuration. Bays with one circuit breaker connecting to the main bus and an isolation switch connecting to the transfer bus. This is a very widely used configuration.

Main Bus. In multiple-bus configurations, this is the primary means of connecting all of the various portions of the substation together.

Reclosing. Automatic scheme to restore power shortly after a fault has been cleared.

Ring Bus Substation Configuration. Provides one circuit breaker for each substation connection. Typically used for high voltage transmission substations where less than four connections are needed.

Short Circuit. The inadvertent grounding or cross-connection of energized conductor(s) caused by a variety of factors, which result in extremely high current. See also fault.

Single Bus Substation Configuration. The cheapest of all substation configurations, this simply provides connection of all portions of the substation to a common node (bus) through a single circuit breaker for each connection point.

Subtransmission. A part of the transmission and distribution infrastructure operating at voltages between that associated with the regional bulk power grid and the distribution of power from substations to customers. It is defined based on the specific voltages associated with the local infrastructure, but typically includes equipment with voltages between 69 kV and 138 kV.

Take-off Structure. Steel lattice structure, footings, and insulator strings associated with the line-substation bay interface.

Tie Breaker. Circuit breaker that connects the main and transfer buses. It replaces the functionality of any one of the normal bay circuit breakers when the line is fed from the transfer switch.

Transfer Bus. See alternate bus.

Transformer. Device to connect systems of different voltages.

Transmission System. Infrastructure associated with the regional bulk power grid.

1.0 Introduction

The displacement or deferral of substation equipment is a key benefit associated with several technologies that are being developed with the support of the U.S. Department of Energy's (DOE's) Office of Utility Technologies (OUT). This could occur, for example, as a result of installing battery energy storage or another distributed generating resource within an electricity distribution system. The application of high-temperature superconducting (HTS) fault current limiters is also expected to displace and/or defer various transmission and distribution equipment upgrades, including substation equipment. Finally, HTS transformers will be direct substitutes for conventional transformers at substations, in addition to other applications.

In each of these applications of advanced technology, the value of the advanced technology is at least partly associated with avoiding investment in conventional technologies. Therefore, knowledge of conventional technology costs is critical to determining the value of the advanced technologies. For site-specific situations, the impact of advanced technologies on substation requirements and the resulting cost avoidance can be readily estimated. For macro-level, site-generic assessments, the estimating process becomes more onerous.

Generically estimating substation capital cost is difficult because substation designs vary widely depending on the specific requirements of individual applications. Without being able to quantify specific design requirements, accurately determining substation cost is difficult. However, by isolating the critical design parameters associated with major cost drivers, it becomes possible to approximate generic substation capital costs. Guidance must be provided, of course, relating these parameters to key application design assumptions.

The Pacific Northwest National Laboratory (PNNL)^(a) conducted this investigation of substation capital costs for OUT. The objective of this study was to develop a model for preparing preliminary estimates of substation costs based on the key design variables that affect cost. The model would provide a consistent set of cost assumptions for OUT, and other DOE offices, that are applicable when conducting evaluations from a national or site-generic perspective. Care should be taken in applying the data in this report for site-specific analyses. In particular, specific design requirements are highly variable and need to be carefully evaluated in any application-specific study.

The balance of this report is divided into five sections that describe substation design fundamentals, the cost-estimating model, model validation and comparisons with actual data, a summary of "typical" substation costs, and conclusions and recommendations.

^(a) Pacific Northwest National Laboratory is operated for the U.S. Department of Energy by Battelle Memorial Institute under Contract DE-AC06-76RLO 1830.

2.0 Substation Design Fundamentals

Electric power substations are essentially nodes of the interconnected electric power network (grid). A typical substation contains switches and circuit breakers to isolate and protect specific components of the power system (e.g., transmission lines, transformers, and other major equipment) and to connect the various lines entering or leaving the substation with common buses.

Circuit breakers are used to provide isolation of the networked power system under faulted conditions. Circuit breakers, like fuses, are designed to safely interrupt extremely high currents associated with short circuits (also called faults). Unlike fuses, which need to be replaced, circuit breakers can be closed again once the short circuit has been cleared. Sometimes circuit breakers are equipped with logic to provide automatic reclosing for certain types of faults to provide faster restoration of service following temporary faults, such as lines brushing against trees or lightning-induced arcs.

Isolation switches are used to de-energize portions of the infrastructure for maintenance, repair, or to simply change the configuration (or topology) of a portion of the system. Most isolation switches are not designed to open under faulted conditions, and thus cannot be used in lieu of circuit breakers. In practice, isolation switches are almost always used in conjunction with circuit breakers to provide maximum flexibility and robustness.

The remaining transmission and distribution system includes a hierarchy of transmission lines and voltages providing interstate bulk power transport down to regional and local power delivery. These various systems are broadly classified into transmission, subtransmission, and distribution networks.

Because the definition of transmission and subtransmission is somewhat arbitrary, systems may fall into either category (regardless of voltage) depending on the surrounding system. A general rule of thumb is that one or two layers of subtransmission network interconnect the various distribution substations in an area, which is overlaid with one or two layers of transmission network feeding selected points of the underlying subtransmission network. The following examples illustrate this point:

- A metropolitan area is served by 69-kV and 138-kV networks, both feeding multiple distribution substations. A 230-kV network is also present, which feeds selected points within the 138-kV network. There are a couple of 500-kV nodes nearby that supply bulk-power from an interstate regional power pool. In this example, both the 69-kV and 138-kV systems are subtransmission, while the infrastructure operating at 230 kV and 500 kV is considered to be transmission.
- A largely rural area is served with a 230-kV network, in which cities and towns have 230-kV high-voltage distribution substations. There is also a 69-kV network to feed some of the smaller substations in outlying areas. The 230-kV network is the transmission network while the 69-kV network represents a subtransmission system.

- Similar to the previous example, if this area was served only by a 115-kV network, this may be considered a 'transmission' network (because there is no overlaying higher-voltage network), and it may have been designed to a higher standard than a typical subtransmission network.

It should be noted that there are many exceptions to these general design rules-of-thumb, and that it is not uncommon for a specific region to have its own unique design approach based on special circumstances.

Substations are found throughout the electric power transmission and distribution system. At all generating facilities, transformers are used to step the generator voltage up to the transmission voltage. With multiple generators and/or lines, and the need to provide power to the facility itself, most generating plants have substations with circuit breakers, switches, buswork and transformers that are similar to those found in the transmission and distribution system. Transmission (or subtransmission) substations serve as the nodes of the interconnected grid, in which two or more lines are connected to a common bus. These substations may also include transformers connecting higher-voltage transmission with a lower-voltage subtransmission network. The distribution system provides the delivery network to individual homes and businesses. Common distribution voltages include 12.5 kV, 13.2 kV and 34.5 kV. Distribution substations, which always include at least one transformer, provide for the interface between the transmission or subtransmission system and the distribution system.

2.1 Substation Configurations

There are several typical substation configurations used in the industry today. Brief descriptions of each, and the conditions under which they are applied, are given below.

2.1.1 Single Bus Substation

The **single bus** substation configuration shown in Figure 2.1 is the simplest and least expensive substation configuration. Each line is connected to a common bus through a circuit breaker to provide switching capability and protection against faults or short-circuits. Disconnect switches are also provided, which are used to isolate individual circuit breakers for maintenance or repair. While common in building medium-voltage switchgear or for the low-voltage side of a distribution substation, this configuration is seldom used at higher voltages because it is highly susceptible to prolonged outage resulting from the failure (or maintenance) of any single piece of equipment, particularly circuit breakers. Should an outage occur, there is no way to re-route the power around the unavailable component, which results in unacceptably low availability.

Source: Gönen (1986)

Figure 2.1. Single Bus Substation Configuration.

2.1.2 Main and Transfer Bus Substation

The **main and transfer bus** substation configuration utilizes a primary bus connected with each of the lines through a circuit breaker, as illustrated in Figure 2.2. An alternate, or 'transfer' bus is available via a tie breaker as a means of providing backup power to each of the loads for any single equipment failure or unavailability. A series of disconnect switches is used to allow isolation of each of the circuit breakers. This mitigates the consequences of substation equipment failures or allows for substation equipment maintenance without requiring a power outage.

Source: Gönen (1986)

Figure 2.2. Main and Transfer Bus Substation Configuration.

2.1.3 Double Breaker Substation

A variation of the **main and transfer bus** that provides greater reliability is the **double breaker** configuration. In this scheme, each line has a separate circuit breaker connecting to each bus, thereby making the buses identical. However, this option is usually considered to be too expensive to be worth the marginal reliability improvement. The double breaker configuration is shown in Figure 2.3.

2.1.4 Breaker-and-a-Half Configuration

A compromise between the **main and transfer bus** and the **double breaker** configurations, however, is widely used because of its excellent flexibility, reliability, and cost-effectiveness. The **breaker-and-a-half** configuration includes three circuit breakers connecting two lines to two buses, as shown in Figure 2.4. Various combinations of switching sequences are available to mitigate failure consequences or to provide for equipment maintenance. Because of its relatively high cost, this bus configuration is primarily used for bulk power (345 kV and above) transmission switchyards.

Source: Gönen (1986)

Figure 2.3. Double Breaker Substation Configuration.

Source: Gönen (1986)

Figure 2.4. Breaker-and-a-Half Substation Configuration.

2.1.5 Ring Bus Configuration

The **ring bus** configuration, with one circuit breaker per line, is less expensive than the **breaker-and-a-half** configuration, but is also less flexible. Often found in transmission switchyards operating at 230 kV and above, these substations usually do not have more than three or four lines. Although more lines are possible, the scheme is too inflexible and vulnerable to 'breaks' in the ring with more than three to four lines. There are several ways in which a ring bus can be configured; an example of one configuration is shown in Figure 2.5.

2.1.6 Configuration Variations

Although actual substation applications usually follow these configurations, exceptions are common. For example, a single bus configuration might exclude circuit breakers for certain connections (perhaps substituting instead a fused disconnect switch). Breaker-and-a-half substations with an odd number of lines (and transformers) are common and specific configurations of circuit breakers and isolating switches vary. There are also many ways to implement ring buses of various sizes.

Figure 2.5. Ring Bus Substation Configuration.

2.2 Overall Substation Design and Layout

The number of substation bays are determined after the general substation configuration has been selected. These bays comprise the circuit breakers and switches, along with associated buswork that electrically connects these components. Also, bays that include a transmission line connection have additional associated structure. Each bay is connected to adjacent bays through the substation bus.

The number of substation bays is determined by how many connections are associated with each voltage (i.e., the number of lines plus transformers and other equipment such as capacitor banks, etc.). For the breaker-and-a-half configuration, each bay can accommodate two such connections. In addition, provision must be made for a tie breaker in the main and transfer configuration. Substations with more than one voltage are partitioned into sections, with each section designed with its own configuration. Transformers are used to connect these sections together.

After completing the substation layout, with appropriate configurations for each of the voltages and selection of other design characteristics (e.g., transformer ratings, etc.), the capital cost of the substation can be estimated using the model described in the following section.

3.0 Cost-Estimating Model

This section describes the model developed to estimate substation capital cost. A brief description of the origin and limitations of the model, the model itself, and a description of how to apply the model are provided.

3.1 Background

A cost-estimating model was developed to prepare substation capital cost estimates for a variety of different sizes and applications based on conceptual design information. Because substation designs vary widely depending on the specific requirements of individual applications, this estimating tool serves only to approximate capital costs based on typical design characteristics and circumstances. It should not be used, therefore, to estimate substation costs when more detailed design information is available.

The model is intended to be used by energy system analysts conducting macro-level engineering studies, particularly those less familiar with electric power design issues. Although it may be useful to practicing power engineers and cost estimators, it is not intended to replace cost-estimating tools presently used by the utility industry to estimate the cost of substation construction or additions. It should be useful, however, as a preliminary cost-estimating tool in the absence of more detailed design and cost data.

The cost-estimating model described in this section was developed by collecting and evaluating information from various federal power marketing agencies and private and public electric utilities. Because of the proprietary nature of this information, it is not appropriate to provide detail or specify its origin. The model given below summarizes a cost-estimating model obtained from one such source. Measures have been taken to validate this model using actual substation construction projects as described in Section 4. Based on the close agreement of the model to actual substation costs, the model is considered to be sufficiently valid for its intended purpose.

3.2 Cost Model

Using the procedure described in Section 3.3, a conceptual substation capital cost estimate can be developed by aggregating estimates for "per-bay" costs, transformers, and auxiliary components.

3.2.1 Per-Bay Cost

"Per-bay" costs are presented in Table 3.1 as a function of bay type and voltage. The relationships between the three bay types (line, bus tie, and bus section) are shown in Figure 3.1. These per-bay costs apply to typical main-and-transfer substation configurations. Per-bay costs for the breaker-and-a-half configuration (serves two lines per bay) are also given in the table; costs for other configurations can be estimated from the individual bay costs.

**Table 3.1. Substation Per-Bay Cost
(\$K)**

Voltage (kV)	Main and Transfer Bay Type			Breaker-and-a-Half Bay
	Line Bay	Bus Tie Bay	Bus Section Bay	
14.4	162	142	121	
34.5	198	171	144	
69	260	223	186	
115	367	319	267	
138	404	349	290	
161	468	406	340	
230	593	512	423	1484
345	961	839	701	2414
500	1532	1356	1162	3912

The differences between the bay types are the number of switches (e.g., the line bay has three switches while the bus tie bay has only two) and the amount of buswork, steel, and footings. The take-off structure for the line bays represents a significant portion of the overall steel and footings cost. Bus section bays are typically only used in large substations (usually when there are more than about 10 bays) to segment the substation into smaller sections to enhance reliability, as shown in Figure 3.1. Bus section bays are similar to bus tie bays, but with less bussing, steel, and footings.

The breaker-and-a-half bay costs were estimated by combining the costs for two bus section bays, a bus tie bay, and an appropriately scaled allocation of steel and footing cost. Each breaker-and-a-half bay is suitable for two bus connections, as shown in Figure 2.4. The costs for other substation configuration bays can be estimated using these per-bay costs by appropriately scaling the portions of the cost associated with the circuit breaker, switches, bussing, and the steel and footings. For example, individual component costs for the line bay as a function of voltage are given in Figure 3.2.

Figure 3.1. Substation Configuration Example.

Figure 3.2. Line Bay Component Costs.

3.2.2 Transformer Cost

Transformers are one of the primary cost components for virtually all substations. Transformer costs are shown in Figure 3.3 as a function of power and high-side voltage rating for the following design conditions: three-phase (3 ϕ), two-winding, and forced oil and air (FOA) cooling.

Figure 3.3. Transformer Cost.

3.2.3 Auxiliary Components

In addition to switchgear (per-bay equipment) and transformers, other major substation elements include the control building(s) and auxiliary components. The control building houses all of the various control equipment associated with the substation, including protective relays, communications infrastructure, and other hardware that is required to be installed indoors. While provisions are made for the cost of control equipment in the per-bay substation cost model, no allowance is included for the control building. If no better information is available, the control building(s) can be assumed to be about 2000 square feet and cost roughly \$100 per square foot for a total cost of \$200,000.

Voltage control is a critical function provided by distribution substations. To maintain acceptable customer voltage, some means for regulating the voltage is nearly always included at distribution substations. The options include:

- Load-tap changing (LTC) transformer: The LTC transformer changes its effective turns ratio by manipulating mechanical taps between various tap connections to the winding. This provides the ability to automatically adjust the secondary voltage to remain within preset limits independent of changes to the primary voltage.
- Voltage-regulating transformer: These transformers are connected directly to the feeder to provide a relatively small "buck" or "boost" voltage transformation which, in turn, provides automatic voltage regulation.

The choice between LTC and voltage-regulating transformers depends on the specific application. Voltage-regulating transformers have the advantage of independently regulating each feeder, while the LTC can only manipulate the distribution voltage for the entire substation. Generally, the LTC is more economic, particularly for smaller transformer ratings and/or cases with a large number of distribution feeders. A LTC adds about 45% to the base transformer cost (i.e., in addition to the cost given in Figure 3.3). Alternatively, the cost for voltage-regulating transformers (voltage regulators) is shown in Table 3.2.

Other auxiliary components not incorporated in the per-bay substation cost are reactive power compensation devices, such as capacitors and reactors. Capacitors are installed to offset the reactive demands of lagging power factor loads and the inductance of the transmission and distribution infrastructure. These capacitors serve as power factor correction devices to support voltages of the regional transmission infrastructure. Reactors, comprised of large inductors, serve the opposite function of capacitors to offset natural capacitance in the power system, particularly for the higher voltages. Capacitors and reactors are almost always switchable to enable their use as conditions warrant. For example, capacitors are typically switched in as load increases and vice versa for reactors.

Again, auxiliary components not incorporated with the per-bay or transformer costs include capacitors, reactors, and voltage regulators. Cost estimates for these components, taken from Means Electrical Cost Data (Means 1996) are presented in Table 3.2.

Table 3.2. Auxiliary Component Cost Data

<u>Capacitors (\$/MVAR)</u>	
13 to 26 kV	4,325
69 kV	4,925
161 kV	4,300
500 kV	3,800
 <u>Reactors (ea.)</u>	
13 to 26 kV	2,250
69 kV	11,500
161 kV	13,300
500 kV	85,000
 <u>Voltage Regulators (ea.)</u>	
13 to 26 kV	155,500

Source: Means (1996)

3.3 Using the Model

This section describes how to apply the model presented in the previous section to user applications using a prescriptive step-by-step method.

3.3.1 Step 1: Determine Basic Substation Design Criteria

The key information that must be specified includes: 1) the number of lines entering and exiting the substation, 2) the voltages of these lines, 3) the number of transformers, and 4) the power rating of each transformer. A one-line diagram that illustrates this basic design information should be developed.

3.3.2 Step 2: Determine Substation Configuration

Unless more specific information is available, the configuration assumptions shown in Table 3.3 can be used as default designs. Each voltage level at the substation may have a distinct configuration, connected together via transformer(s). Note that each transformer connection counts as a line.

It should also be noted that these configurations are only intended to serve as rough guidelines for estimating generic substation costs. There are many different configurations employed based on a variety of technical design and performance issues that are not reflected in Table 3.3.

Table 3.3. Substation Default Configuration Assumptions

<u>Basic Substation Design Characteristics</u>	<u>Default Configuration</u>
345 kV and up	
two to four lines and transformers	Ring
five or more lines and transformers	Breaker-and-a-half
69 to 230 kV	
two to three lines and transformers	Single bus
three or more lines and transformers	Main-and-transfer
34.5 kV or less	
one feeder per transformer	Single bus
two feeders per transformer	Single bus; normally-open tie
three or more secondary feeders	Main-and-transfer

3.3.3. Step 3: Determine the Number of Bays

For each set of switchgear (i.e., for each voltage), determine the number of bays that will be necessary to provide adequate connections for each of the lines and transformers. In general, one bay is required for each connection. For the main and transfer scheme, one additional bus tie bay will be needed. Each breaker-and-a-half bay can serve two connections.

3.3.4. Step 4: Estimate Cost

Add the per-bay costs from Table 3.1, transformer costs from Figure 3.3 and the costs of special equipment (as required and if known) from Table 3.2. As a general rule-of-thumb, distribution substations **must** include voltage-regulating capability. Without knowing specific requirements, the least expensive alternative between a LTC transformer and voltage-regulating transformers for each feeder would be a reasonable assumption.

High-voltage transmission stations should include capacitor banks and reactors at the terminus of each long-length (greater than 100 km), high-voltage (345 kV and up) transmission line. Lower-voltage stations may also include capacitors, which are generally sized to provide power factor correction and are a function of the total load-carrying capacity of the substation. Without any design information, an allowance of total capacitor rating equal to one-third of the total load-handling capacity of the station is a reasonable assumption. This provides the capability to provide power factor correction from 0.85 to 0.95 under full-load conditions.

The sum of per-bay, transformer, and auxiliary costs should be multiplied by 1.15 to allow for engineering and construction management costs. Land costs should also be considered for a site-specific estimate.

4.0 Model Validation

Cost details for recent substation construction projects were collected by PNNL to validate the model. A total of 21 point designs were received from various utility sources. For each case, the utility provided actual and estimated costs. In general, good agreement (for conceptual level estimating) was found between estimates prepared with the cost-estimating model and the actual project costs. There was also reasonably good agreement between the model-generated estimates and the utility estimates provided for each of the individual projects. These results are summarized in Table 4.1.

In some cases, extensive demolition activities were included in the actual projects and, therefore, the cost model underestimated both utility-estimated and utility-actual costs. Because the cost-estimating model is intended to represent "green field" construction, these discrepancies are expected. These cases are noted in the detailed descriptions for each of the 21 point designs provided in Appendix A.

In a few cases, project bids were supplied instead of actual cost data. For these cases, the low bidder cost was used in lieu of actual project cost. Also, these cases contained several instances where key components (such as circuit breakers) were provided separately from the contractors' bids, and thus were not included as part of the cost estimate. To provide consistent comparisons, these component costs were removed from the cost calculated using the estimating model. Because of the increased uncertainty involved in making these adjustments, notations provided in Table 4.1 indicate these cases.

For 10 of the 21 cases, both utility-actual and utility-estimated costs were above those calculated with the estimating model, 7 straddled this cost (i.e., utility actual higher and utility estimate lower than model estimate or vice versa), and 4 had both utility costs below the model-estimated cost. Figures 4.1 through 4.4 present various correlations between utility- actual and utility-estimated costs compared to the model-estimated costs.

These results provide confidence that the model is a reasonably accurate tool for estimating substation costs, based on the survey sample. In fact, there was much better correlation between the model-estimated costs and the utility-actual costs than between the utility-actual costs and the utility-estimated costs. Based on these results, no "corrective" adjustments were applied to the original cost-estimating model.

Table 4.1 lists the model-estimated cost (A), utility-actual cost (B), utility-estimated cost (C), and figures-of-merit to compare between these three costs. Each case has a brief description, which includes the number of bays (in parenthesis) for each voltage; the MVA rating of the transformer (if applicable); and references to notes at the bottom of the table.

Table 4.1. Comparison of Actual and Estimated Substation Costs (\$K)

No.	Brief Description; see Appendix A for a more complete description.	(A) Model- Estimated Costs	(B) Utility- Actual Costs	(C) Utility- Estimated Costs	(B) (A)	(C) (A)
1	(1) 69 kV	238	208	198	0.87	0.83
2	(1) 115 kV	293	248	396	0.85	1.35
3	(3) 230 kV; (1) 69 kV [a,b]	1046	974	844	0.93	0.81
4	(3) 161 kV [c]	1246	1632	1365	1.31	1.10
5	(2) 115 kV; (2) 12.5 kV; 12.5 MVA	1534	1860	2230	1.21	1.45
6	(1) 161 kV + transmission line	1613	2271	1885	1.41	1.17
7	(2) 69 kV; (2) 12 kV; 25 MVA [c]	1652	1420	1900	0.86	1.15
8	(3) 161 kV; (1) 13 kV [d]	1655	2123	2039	1.28	1.23
9	(2) 115 kV; (2) 12.5 kV; 25 MVA [c]	1694	2010	2270	1.19	1.34
10	(2) 115 kV; (2) 12.5 kV; 25 MVA [c]	1696	1820	2070	1.07	1.22
11	(2) 138 kV; (4) 12.5 kV; 20 MVA	1874	2240	2410	1.20	1.29
12	(2) 138 kV; (2) 12.5 kV; 25 MVA	1877	1630	1630	0.87	0.87
13	(4) 161 kV	2040	1568	2507	0.77	1.23
14	(2) 138 kV; (4) 12.5 kV; 25 MVA [c]	2043	2140	1640	1.05	0.80
15	(5) 230 kV [a,b]	2060	2101	1961	1.02	0.95
16	(2) 50 MVA (161-13 kV) w isolation switches	2290	2333	2483	1.02	1.08
17	(2) 138 kV; (3) 12.5 kV; 25 MVA [c]	2527	3660	2810	1.45	1.11
18	(2) 230 kV; (3) 34.5 kV; 28 MVA	2530	2300	2040	0.91	0.81
19	(2) 161 kV; (6) 46 kV; 400 MVA [d]	5597	6645	7368	1.19	1.32
20	(4) 500 kV [c]	11504	14271	10151	1.24	0.88
21	(4) 500 kV; (3) 161 kV; (3) 15 kV; 1200 MVA	22690	21715	30391	0.96	1.34

Notes:

- a "Low bidder" cost used in lieu of actual costs. Also, selected equipment not included in estimate because it was separately supplied.
- b A tenuous estimate based on extensive material provided to the contractor.
- c Reactive component (capacitors, reactors, voltage regulators, etc.) included.
- d Utility cost includes demolition cost not captured in the model.

Comparisons between the model-estimated, utility-actual and utility-estimated costs are given in Figures 4.1 through 4.4. Figure 4.1 shows the percent difference between both utility-actual and utility-estimated to the model-estimated cost, sorted in ascending order of model-estimated cost (from Table 4.1, above). The remaining figures show these values plotted against each other for a variety of comparisons.

Figure 4.1. Percentage Difference Between Utility and Model Cost Estimates.

Figure 4.2. Utility-Actual Cost vs. Model Cost.

Figure 4.3. Utility-Estimated Cost vs. Model Cost.

Figure 4.4. Utility-Actual Cost vs. Utility-Estimated Cost.

5.0 Typical Substation Costs

The integrated North American power system is divided into nine regional electric reliability councils, voluntarily established by the electric utility industry in 1968 by the formation of the North American Electric Reliability Council (NERC). Two of these councils, the Electric Reliability Council of Texas (ERCOT) and the Western Systems Coordinating Council (WSCC), also correspond to power network (grid) physical boundaries, while the remaining seven comprise the Eastern Interconnected System, consisting of the eastern two-thirds of the United States.

The Western Interconnected System (the WSCC) was selected as the basis for determining typical substation design parameters in this report (selected out of convenience). A comparison of WSCC conditions to national averages is given below.

5.1 Typical Voltages

Common voltages in use throughout the domestic power system are shown in Figure 5.1. Total circuit miles by voltage (greater than 138 kV, with some aggregation to combine other less-common voltages into these voltage classes) are given in this figure, with a comparison between the total contiguous United States and the WSCC system.

Source: EIA 1994

Figure 5.1. Distribution of Transmission Line Circuit Miles by Voltage.

5.2 Typical Substation Voltage Combinations

Data from the WSCC region provide a basis for determining typical voltages, transformer ratings, etc. Details are provided in Appendix B, which gives numbers and sizes of transformers for various voltage classes.

In the WSCC model, about 2300 distinct transformers are represented, which have a distribution (based on primary or high-side voltage) shown in Figure 5.2. The 69-kV class includes voltages between 60 kV to 70 kV (mostly 69 kV). The 115-kV voltage class includes voltages between 100 kV and 161 kV, with common voltages of 115 kV, 132 kV, and 161 kV. The 230-kV voltage class is predominately 230 kV, but includes 287 kV and less common voltages up to 300 kV. The 345-kV voltage class includes voltages up to 360 kV, while the 500-kV voltage class contains only 500-kV systems.

5.3 Cost Estimates for Common Substation Designs

Based on the voltages in Figure 5.2, and data from Appendix B, the following substation designs are used as examples for developing typical substation cost estimates. The three examples given below represent typical designs for transmission, subtransmission, and distribution substations that would be commonly encountered in a typical power system.

Figure 5.2. Distribution of WSCC Transformers by Primary Voltage.

5.3.1 Transmission Substation Example

This substation contains five 500-kV lines (with no transformer). Based on the information in Table 3.3, a breaker-and-a-half scheme is chosen, as shown in Figure 5.3.

Although the substation nominally has three breaker-and-a-half bays (\$3912 K ea.), the third bay is incomplete and its cost can be approximated by adding a line bay (\$1532 K) and a bus tie bay (\$1356 K). Auxiliary equipment includes one 500-kV reactor per line (\$85 K for each of the five lines) and a capacitor bank rated at 750 MVAR (\$3800/MVAR). Adding provision for a 2500 square foot building at \$100 per square foot yields a total estimated cost of \$16,373 K (including 15% for engineering and construction management).

Figure 5.3. Transmission Substation Example One-Line Diagram.

5.3.2. Subtransmission Substation Example

This substation contains three 230-kV lines and five 115-kV lines connected by two 200-MVA transformers. Both high- and low-voltage sides will be main and transfer configurations as shown in Figure 5.4.

This substation has five 230-kV line bays, one 230-kV bus tie bay, seven 115-kV line bays, and one 115-kV bus tie bay for a total of \$6365 K from Table 3.1. Each of the 230/115-kV transformers has a cost of \$1750 K (see Figure 3.3). Assuming a 120 MVAR capacitor bank (\$4300/MVAR) and provision for a 2000 square foot building gives a total estimated cost of \$12,168 K (including engineering and construction management).

Figure 5.4. Subtransmission Substation Example One-Line Diagram.

5.3.3 Distribution Substation Example

The distribution substation example has three 12.5-kV feeders fed from two 25-MVA 115/12.5-kV transformers. There are two 115-kV lines feeding the substation, with the layout shown in Figure 5.5.

Because the 115-kV bays do not include circuit breakers, approximately \$80 K needs to be deducted from the per-bay cost. Adding three 12.5-kV bays (approximated by using the 14.4-kV voltage classification in Table 3.1), yields a total of \$1060 K for the aggregated per-bay cost totals. Transformer cost is \$450 K each, and 15 MVAR of capacitor capacity (\$4325/MVAR) is included for power factor correction purposes.

Voltage regulation may either be provided by adding LTC capability to the transformers (an additional \$203 K per transformer) or three voltage-regulating transformers (\$156 K each). Because the LTC option is cheaper, it is chosen for this example.

The total estimated cost for this example is \$2909 K (including a 1000 square foot building at \$100/square foot, engineering, and construction management).

Figure 5.5. Distribution Substation Example One-Line Diagram.

6.0 Conclusions and Recommendations

This report documents the development and validation of a substation cost-estimating model. The model is applicable for preparing preliminary estimates of substation capital costs based on rudimentary conceptual design information. The model is intended to be used by energy systems analysts who need "ballpark" substation cost estimates to help establish the value of advanced utility technologies that result in the deferral or displacement of substation equipment. More detailed cost-estimating approaches are recommended whenever design information is available that exceeds the minimal inputs required for this model.

7.0 References

EIA. 1994. *Electric Trade in the United States 1992*. Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, U.S. Department of Energy, Washington DC.

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Appendix A

Description of Sample Case Studies

This appendix contains a brief synopsis of each of the 21 cases (sorted in order of ascending cost as calculated by the cost-estimating model described in Section 3). Note that in several cases, more detailed, but proprietary information provided by the utilities was used to prepare the estimate with the cost-estimating model.

Case 1

Install one 69-kV circuit breaker and associated equipment.

Used low bidder cost in lieu of actual project cost.

Case 2

Install one 115-kV breaker (provided).

Used low bidder cost in lieu of actual project cost.

Case 3

Install three 230-kV, 3000-A circuit breakers and one 69-kV, 3000-A circuit breaker (major equipment provided).

Prorated per-bay cost for 230-kV and 69-kV single line breaker bays with circuit breaker and switches removed, prorated an additional factor of 2/3 to account for other materials provided. Used low bidder cost in lieu of actual project cost.

Case 4

Install:

- two 24-MVAR, 161-kV capacitor banks
- one 161-kV, 2000-A, 40-kA SF₆ circuit breaker
- two 161-kV, 1200-A, 7-kA circuit switches (suitable for cap bank switching)
- five 161-kV, 800-A isolating switches
- two 800-A, 1600-μH reactor banks.

Estimated by:

- one 161-kV, 1600-A single breaker bay

two 161-kV, 1200-A single breaker bay
Means (1996) for capacitor and reactor costs.

Case 5

Install:

two 115-kV, 1200-A line bays (total 1 circuit breaker, 7 switches)
one 10/12.5-MVA, 116/12.47-kV transformer
one three-phase 1.0/1.25-MVA, 13.2-kV voltage regulator
three 12.5-kV, 1200-A line bays (total 2 circuit breakers, 12 switches)
21 ft x 15 ft service building.

Case 6

Install:

two 161-kV, 800-A circuit breakers
2.73 miles of double circuit 161-kV, 636-kcmil ACSR transmission line.

Estimated by:

two 161-kV, 1200-A single line breaker bay
overhead transmission, assuming 161-kV, 636-kcmil ACSR, double circuit steel pole structures, is estimated to be \$240K/mile.

Case 7

Install:

three 69-kV, 1200-A line bays (total no circuit breakers, 7 switches)
one 15/20/25-MVA, 67/12.47-kV transformer
one three-phase 2.0/2.667-MVA, 13.2-kV voltage regulator
three 12.5-kV, 1200-A line bays (total 2 circuit breakers, 13 switches)
2.4-MVAR, 12.5-kV capacitors
22 ft x 16 ft service building.

Case 8

Install:

three 161-kV, 2000-A, 40-kA circuit breakers
ten 161-kV, 2000-A switches
three 13-kV, 600-A vacuum switches
supervisory control.

Estimated by:

three 161-kV, 1600 A single breaker line bays
one 14.4-kV, 1200-A single breaker line bay less circuit breaker.

Demolition costs not captured in cost estimating tool. Items removed include switchgear and several motor-operated disconnect and oil switches.

Case 9

Install:

two 115-kV, 1200-A line bays (total 1 circuit breaker, 7 switches)
one 15/20/25-MVA, 67/12.47-kV transformer load-tap changer
three 12.5-kV, 1200-A line bays (total 2 circuit breakers, 12 switches)
3.6-MVAR, 12.5-kV capacitors
22 ft x 16 ft service building.

Case 10

Install:

two 115-kV, 1200-A line bays (total 1 circuit breaker, 7 switches)
one 15/20/25-MVA, 69/12.5-kV transformer load-tap changer
three 12.5-kV, 1200-A line bays (total 2 circuit breakers, 12 switches)
4.2-MVAR, 12.5-kV capacitors
23 ft x 15 ft service building.

Case 11

Install:

two 138-kV, 1200-A line bays (total 1 circuit breaker, 7 switches)
one 12/16/20-MVA, 138/12.47-kV transformer load-tap changer
four 12.5-kV, 1200-A line bays (total 3 circuit breakers, 16 switches).

Case 12

Install:

two 138-kV, 1200-A line bays (total 1 circuit breaker, 7 switches)
one 15/20/25-MVA, 116/13.2-kV transformer load-tap changer
three 12.5-kV, 1200-A line bays (total 2 circuit breakers, 11 switches)
33 ft x 15 ft service building.

Case 13

Install:

four 161-kV, 2000-A, 40-kA SF₆ circuit breakers
thirteen 161-kV, 2000-A disconnect switches.

Estimated by:

four 161-kV, 1600 A single breaker line bays.

Case 14

Install:

two 138-kV, 1200-A line bays (total 1 circuit breaker, 7 switches)
one 15/20/25-MVA, 132/12.5-kV transformer load-tap changer
four 12.5-kV line bays (total 4 circuit breakers, 14 switches)
3.6-MVAR, 12.5-kV capacitors.

Case 15

Install (circuit breakers provided):

five 230-kV, 2000-A circuit breakers with 10 disconnecting switches and nine single-phase current transformers.

Estimated by:

two 230-kV, 2000-A breaker-and-a-half bays (reduced by 1 bus section bay) subtracting five circuit breakers.

Used low bidder cost in lieu of actual project cost. Some big ticket items (transmission line spans and service building) subtracted from itemized "estimated" and "actual" project costs to compare with the calculated cost.

Case 16

Install:

two three-phase 30/40/50-MVA, 161/13-kV transformer banks
switches for isolation.

Estimated by:

two three-phase, 50 MVA, 115 kV two-winding transformers
two 161-kV bays (no circuit breakers, 3 switches total)
two 14.4-kV bays (no circuit breakers, 5 switches total).

Case 17

Install:

three 138-kV, 1200-A line bays (total 1 circuit breaker, 6 switches)
one 15/20/25-MVA, 138/12.47-kV transformer load-tap changer
five 12.5-kV, 1200-A line bays, one bus section bay (total 4 circuit breakers,
17 switches)
3.6-MVAR, 12.5-kV capacitors.

Case 18

Install:

one line bay 230-kV, 1200-A; one bus tie bay 230-kV, 1200-A (total 2 circuit breakers,
4 switches)
one 15/20/25/28-MVA, 230/34.5-kV transformer load-tap changer
three 34.5-kV, 1200-A line bays (total 2 circuit breakers, 11 switches)
16 ft x 15 ft 8 in. service building.

Case 19

Install:

two 161/46/13-kV, 120/160/200-MVA transformers
two 161-kV, 2000-A circuit breakers
six 46-kV, 2000-A circuit breakers (6-bay main-and-transfer configuration).

Estimated by:

two three-phase 115/34.5-kV, 200 MVA transformers
two 161-kV, 1600-A single breaker line bays
six 46-kV, 2000-A single breaker line bays.

Extensive refurbishment/removal of old equipment and other work not included in estimated cost.

Case 20

Install:

one 500-kV breaker-and-a-half bay
one 500-kV single breaker line bay (with 4 switches)
two 500-kV single breaker line bays (with 2 switches)
two 386.4-MVAR, 500-kV capacitor banks.

Case 21

Install:

four, single-phase 500/161/13-kV, 400-MVA autotransformer with load-tap changer
four 500-kV, 3000-A, 40-kA circuit breaker
two 161-kV, 4000-A, 50-kA circuit breaker
one 161-kV, 2000-A, 50-kA circuit breaker
three 15-kV vacuum circuit breakers.

Estimated by:

autotransformer cost estimated directly
four 500-kV single breaker line bays
three 161-kV, 1600-A single breaker line bays.

Estimates exclude extensive reactive components (three 84-MVAR 161-kV capacitor banks, 9 single-phase 13-kV shunt reactors).

Appendix B

WSCC Representative Data

This appendix contains data for the Western North American power system. A transmission planning model, representative of standard models used by the entire U.S. utility industry, was used to determine common voltage combinations for deriving "typical" substation designs. This 5000-bus model includes detailed representation of the transmission and sub-transmission system and nearly all large generating facilities. Although the distribution system is not specifically represented, all system load is aggregated at the buses representing actual substations in the power system and all main substations are represented.

Figures B.1 through B.5 show the relationship between transformer rating (MVA) and secondary voltage for each of the primary voltage classes given in Figure 5.2. Common transformer primary/secondary voltage combinations can be imputed from this figure, although it should be pointed out that multiple transformers with the same voltage and power (MVA) rating can be represented as a single point in these figures. This is illustrated in Figures B.6 through B.10, where the cumulative numbers of transformers in each primary voltage class are shown for progressively increasing secondary voltages. The transformer rating for one of the most common primary/secondary voltage combinations (230/115 kV) is shown in Figure B.11.

Figure B.1. Transformer Rating vs. Voltage (69-kV primary voltage class).

Figure B.2. Transformer Rating vs. Voltage (115-kV primary voltage class).

Figure B.3. Transformer Rating vs. Voltage (230-kV primary voltage class).

Figure B.4. Transformer Rating vs. Voltage (345-kV primary voltage class).

Figure B.5. Transformer Rating vs. Voltage (500-kV primary voltage class).

Figure B.6. Cumulative Transformers by Secondary Voltage (69-kV primary voltage class).

Figure B.7. Cumulative Transformers by Secondary Voltage (115-kV primary voltage class).

Figure B.8. Cumulative Transformers by Secondary Voltage (230-kV primary voltage class).

Figure B.9. Cumulative Transformers by Secondary Voltage (345-kV primary voltage class).

Figure B.10. Cumulative Transformers by Secondary Voltage (500-kV primary voltage class).

Figure B.11. Transformer MVA Rating (sorted) For All 230/115-kV Transformers.

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