DESIGN CRITERIA

500 kV STEEL POLE STRUCTURE

TRANSMISSION LINES

A REPORT BY

TRANSMISSION ENGINEERING SECTION

BULK POWER ENGINEERING DEPARTMENT

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Forward

A major departure from the construction of conventional lattice towers which were used for the original Keystone 500 kV transmission lines to the use of steel pole structures was adopted in 1972 on the Siegfried-Wescosville 500 kV line. For aesthetic reasons, in the highly visible area in the vicinity of Route 22 and 309, a portion of the line was constructed on steel pole structures. Since that time approximately 150 miles of steel pole structure lines have been built or engineered.

This report is a documentation of the design criteria applied to these 500 kV lines utilizing steel pole structures. While this manual provides information on all aspects of the design, special emphasis is placed where the criteria used is substantially different from the Keystone criteria.

1. General

This manual documents the fundamental factors in the electrical and structural design of the PP&L 500 kV lines utilizing steel pole structures. It does not serve as an engineering design manual, but rather presents the design criteria from which detailed specifications were prepared in connection with various physical components in the construction of the lines. The manual also gives the criteria used for structure spotting and right of way clearing.

For the most part, the criteria used in the design of the lines covered in this report is similar from one line to another, however, special attention is given to areas made where the criteria is different.

2. Types of Lines

The lines are generally single circuit lines supported by 'H' frame steel pole structures, however, some of the lines have been designed for double circuit construction. A portion of the Alburtis-Wescosville line is single pole structures supporting the single circuit. The double circuit lines are supported by double circuit 'H' frame steel pole structures.

The 'H' frame configuration for the single circuit structures is two uprights with a single cross-arm with the phases arranged horizontally. The double circuit configuration utilizes a 'H' frame with two uprights and two cross-arms. The phases are arranged four on the bottom arm and two on the top arm. A circuit is arranged in a triangular configuration on each side of the structure with one phase on the top arm and two phases on the bottom arm. The single pole structure has three horizontal 'V''s arranged in a delta configuration with one on one side of the pole and two on the other side. The following is a table of the lines discussed in this report.

TABLE I

TYPES OF LINES

Line Name	Single Circuit	Type	Length Miles	Year Const.	Double Circuit H-Frame	Length Miles	Year Const.	Remarks
1. Susquehanna-Wescosville								
Susquehanna-Siegfried Section	X	H	54	78-81				
Siegfried-Wescosville Section	X	H	5	74	X	2	78-80	Portion on Towers
2. Stanton-Susquehanna #2	X	H	30	76-79				2 miles 230 kV
3. Sunbury-Susquehanna #2	X	H	40	79-82	X	4		95% owned by Allegheny Electric
4. Susquehanna-Generator #2 Leads	X	H	0.25	82				
5. South Manheim Connection					X	0.5	78	Part of 230 kV Line
6. Alburtis-Wescosville	X	H	2.8	80-81	X	5.7	80-81	
	X	Sing Pole	2.8	80-81				

Susquehanna-Wescosville Line

The Susquehanna-Wescosville 500 kV Line provides a portion of the transmission to integrate the Susquehanna SES into the bulk power system.

The line consists of two distinct line sections. The original 10 mile section from Wescosville 230 kV Substation to a point approximately 1 mile from the Siegfried 230 kV Substation is a reconstruction of the Siegfried-Wescosville 230 kV line on a combination of steel pole 'H' frames, painted green and galvanized steel lattice towers. The remaining one mile of this line section was completed as part of the Susquehanna-Siegfried line. This portion of the line utilizes double circuit 'H' frames with one circuit position initially vacant.

The line route for the conversion from 230 kV to 500 kV construction followed the original Siegfried-Wescosville 230 kV line corridor except for a small relocation in the vicinity of the Lehigh Service Center. Starting at Wescosville Substation in Upper Macungie Township, Lehigh County, the line extends 11 miles through South Whitehall Township and North Whitehall Township, Lehigh County.

The second section of line from Susquehanna to Siegfried is 54 miles long, single circuit arrangement with steel pole 'H' frame construction using corrosion resistant steel. This line section extends from the Susquehanna 500 kV Switchyard in Salem Township, Luzerne County to the Siegfried-Wescosville 500 kV line, described above, in the vicinity of the Siegfried Substation in Allen Township, Northampton County. The line route parallels the Sunbury-Susquehanna 500 kV line across the Susquehanna River, to an intersection of the existing Sunbury-Susquehanna 230 kV line. At this point, the Susquehanna-Siegfried line parallels the existing 230 kV line northeast to a point near Council Cup. At Council Cup the line leaves the existing 230 kV line, forming a new right of way, in an easterly direction across the southern portion of Luzerne County and south into Carbon County. The route then passes in a southeasterly direction across a portion of Carbon County to an intersection with the East Palmerton-Christmans 66 kV line. At this intersection, the Siegfried line and the East Palmerton-Christman line form a parallel right of way south toward East Palmerton Substation. East of the substation, the Susquehanna-Siegfried joins the Siegfried-Harwood 230 kV line and continues in a common corridor south to the Siegfried-Wescosville 500 kV line on the Lehigh River in Northampton County. The line, in general, is centered in a 200 foot right of way. Where the line is in a common corridor with other transmission lines, the right of way width varies in each case from 200 feet to 325 feet.

Stanton-Susquehanna #2 500 kV Line

The Stanton-Susquehanna 500 kV line provides one of the transmission outlets for the Susquehanna SES. In addition, it reinforces the bulk power supply to the PP&L Wyoming Valley Region.

The line is 32 miles long and is constructed on steel pole 'H' frames using corrosion resistant steel and double circuit single poles painted green. The double circuit steel pole section is approximately 2 miles long and constructed for 230 kV operation. The line will be reterminated at the Susquehanna 500 kV Switchyard when required. Starting at the Susquehanna 230 kV Switchyard in Conyngham Township, Luzerne County, the line extends to the Stanton 230 kV Substation near Pittston, Exeter Township, Luzerne County.

The line parallels the Montour-Susquehanna 230 kV line across the Susquehanna River to a point approximately 2000 feet northwest of the Susquehanna SES. Leaving the Montour-Susquehanna 230 kV line, the Stanton line traverses north to the vicinity of Schickshinny where it turns northeast extending past the UGI-Hunlock Substation and intersects a UGI-66 kV double circuit tower line. The Stanton Line parallels the UGI line in a common corridor to the vicinity of the UGI-Mountain 230 kV Substation. Near the Mountain Substation the Stanton line intersects the Stanton-Mountain 230 kV line and parallels it in a common corridor to the intersection with the Stanton-Schwoyersville and Stanton-Exeter 66 kV double circuit line. From this intersection to the Stanton 230 kV substation, all three lines are in one common corridor.

Sunbury-Susquehanna #2 500 kV Line

The Sunbury-Susquehanna line provides one of two 500 kV transmission outlets for the Susquehanna SES.

The line is 44 miles long and ownership is divided between PP&L and Allegheny Electric Cooperative, Inc. PP&L's portion is 4.3% of the line (1.9 miles) and is located at the Sunbury and Siegfried end of the line.

The first 4.2 miles from Susquehanna SES are double circuit steel pole 'H' frames. One position occupied by the Sunbury line and the other position for future system development. The structures on the north side of the Susquehanna River are painted green while the remaining structures utilize corrosion resistant steel. The balance of the line is single circuit 'H' frames utilizing corrosion resistant steel.

The line starts at the Susquehanna 500 kV Switchyard in Salem Township, Luzerne County and extends to the Sunbury Substation in Monroe Township, Snyder County. Leaving the Susquehanna Switchyard, the route crosses the Susquehanna River in a southerly direction in a common corridor with the Susquehanna-Siegfried line and intersects the existing Sunbury-Susquehanna 230 kV line. From this intersection the route parallels the existing line to the west. The two lines, in a common corridor, parallel the Susquehanna River in a southwesterly direction as they cross parts of Columbia, Montour and Northumberland Counties. At a point 1.2 miles south of Sunbury the line crosses the Susquehanna River to the Sunbury Substation on the west bank in Snyder County.

Susquehanna Generator #2 Leads

The Susquehanna generator #2 leads serves as the connection for the generator #2 output to the 500 kV substation. This short 500 kV line consists of two single circuit steel pole 'H' frames painted green and extends 1400 feet from the unit #2 dead end structure to the 500 kV switchyard. This facility is located on the Susquehanna plant site, consequently no right of way is required.

South Manheim Connections

These lines provide the present 230 kV supply to the South Manheim 230 kV Substation and the connection to the future 500 kV substation. Beginning at the South Manheim 230 kV Substation in Penn Township, Lancaster County, the line extends to the west on a 200 foot right of way 0.68 miles to the 230 kV double circuit tower line near PA Route 72. The first 0.53 miles of the line are 500 kV double circuit steel pole 'H' frames painted green and the remaining 0.15 miles are 230 kV double circuit single pole painted green.

Alburtis-Wescosville 500 kV Line

The Alburtis-Wescosville line provides system reinforcement necessary to deliver bulk power into the Pennsylvania-New Jersey-Maryland Interconnection network. In addition, the line will reinforce the power supply to the PP&L Lehigh region.

The line is 11.3 miles long and consists of three distinctly different sections of line. The first section, about 2.8 miles in length from Wescosville in Upper Macungie Township, Lehigh County to Route 100, the line is constructed on single steel poles painted green. Continuing west 2.8 miles from Route 100 to the Alburtis-Bossards right of way, the line is constructed on steel pole 'H' frames painted green. Turning south and continuing on the Alburtis-Bossards right of way, the line extends 5.7 miles to the Alburtis Substation in Lower Macungie Township, Lehigh County, on double circuit steel pole 'H' frames painted green. The second circuit position is for future system development. Right of way width varies from 140 feet in the single pole section to 200 feet in the single and double circuit H-frame section.

3. Right Of Way Clearing

To provide for the proper clearance of power conductors to surrounding vegetation, the PP&L Vegetation Management Specifications were applied to clearing the right of way corridor for 500 kV steel pole structure lines. This specification covers the initial removal or trimming of trees and brush and selective spraying of growth on the right of way.

Detailed instructions for specific clearing plans are on the Plan and Profile Construction Drawings for each line. In addition, access roads and erosion and sedimentation control measures are shown.

Erosion control plans are required by the DER wherever there is earth moving activity and require a permit whenever an activity affects more than 25 acres simultaneously. Construction practices of PP&L limit the total acres affected to less than 25 acres at one time. For PP&L Company transmission line construction, the plan and profile drawings used for constructing the line along with the specifications for Soil and Erosion and Sedimentation Control on Transmission Rights of Way (A-118231), which is made part of the plan and profile by cross reference, is considered the erosion control plan for the project.

For the three Susquehanna transmission outlets, the additional criteria of complying with the final environmental statement related to the construction of Susquehanna Steam Electric Station prepared by the NRC was imposed. To insure compliance, Environmental Audits were performed monthly by the transmission engineering section.

4. Clearance

The ground clearances for 500 kV Transmission Lines are designed to provide at all times a safe distance from the energized conductors to ground. All clearances are calculated according to Section 23 of the National Electrical Safety Code (NESC) and shown on Table II. The following 500 kV Lines are considered in this report:

1. Susquehanna-Wescosville
2. Stanton-Susquehanna #2
3. Susquehanna Generator #2 Leads
4. Sunbury-Susquehanna
5. South Manheim Connections
6. Alburtis-Wescosville

With the exception of the Alburtis-Wescosville Line, the ground clearance requirements for the above lines were based on the 6th Edition of the NESC (see Table II). PP&L Co. also practices maintaining a clearance of 41 feet at maximum thermal sag at road crossings in order to limit the current due to electrostatic effects to 5.0 milliamperes, rms, if the largest anticipated truck, vehicle, or equipment under the line were short-circuited to ground.

Clearances for the Alburtis-Wescosville Line originally were designed in accordance with the 1977 Edition of the NESC. This edition made the provision that if switching surge factors could be determined, the vertical clearance to ground could be reduced. However, as the design of the line proceeded, it was determined that the electrostatic effects of the line were not the sole governing condition for clearance. Other criteria such as corona, electric field gradient and audible noise were used to determine the ground clearance requirements on this line. The double circuit portion of the line utilizes triple bundle conductors with a clearance of 30 feet at 90°C thermal rating. This provides a maximum electric field gradient of 9.8 kV/m. The single pole single circuit portion, due to the narrow easement, utilizes the triple bundle configuration. To achieve a maximum electric field gradient of 5 kV/m, the conductors have a ground clearance of 45' thermally rated at 90°C.

TABLE II

500 kV TRANSMISSION LINE CLEARANCES IN FEET
FOR LINE CONDUCTOR TEMPERATURE OF 100°C
IN ACCORDANCE WITH THE NESC.

	6th Edition	1977 Edition	1977 Edition With Known Switching Surge factors	Alburtis-Wescosville Line
Pedestrian Travel	28	28	23.6	see note
Roads	33	33	28.6	see note
Railroads	41	41	36.6	36.6
Power Lines	15	15	15	15
Communication Lines	17	17	17	17
Future Power Lines at Roads	54	56	54	54

Note: 30' of clearance is required for triple bundled conductor, double circuit portion, at 90°C.
45' of clearance is required for triple bundled conductor, single circuit portion, at 90°C.
31' of clearance is required for double bundled conductor.

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5. Structure Location

Structure locations were determined by aesthetic, engineering design and electrical code concerns. Structures at angles are a necessity but spotting structures to reduce visual impact was considered in locating structures. A minimum distance of 200' from roads was maintained and high points were avoided unless extreme engineering conditions would have resulted.

The Keystone criteria governed the engineering design of the line except that structures were designed for specific spans as opposed to the Keystone family of towers. In addition to the aesthetic and engineering concerns, the National Electric Safety Code criteria also influenced the location of structures. The clearances specified in the code (See clearance section) were maintained. The heights of the structures were limited for economic reasons, which restricted the span lengths and structure locations. Where lines paralleled existing transmission line facilities, the location of new structures were determined by the maximum offset from existing structures to maintain NESC clearances to adjacent lines.

6. Structures

General Background

Steel pole structures were used selectively on several of the first 500 kV tower lines such as the Berks and Hosensack-Quarry lines and were mainly interspersed at locations requiring unique conductor arrangements, line crossing points, or special tension change points. Steel poles were conveniently used at those locations because they could be custom designed for the precise loadings to be applied and represented cost savings over special designed, non-standard, lattice type structures.

On later 500 kV lines, tubular steel structures were used entirely because of either (1) competitive overall steel pole installed costs which represented savings over comparable lattice tower designs or (2) environmental consideration for a more aesthetically pleasing structure compared to lattice towers. Again, all structures and foundations are custom designed for their particular application in order to realize the greatest cost savings. Loadings are developed accordingly for each structure location and provided to the selected pole manufacturer. In the case of long lines involving many structures the manufacturer generally groups loadings within the various different pole types and designs and fabricates a number of structures by the heaviest loading in a given group. This design method results in a certain percentage of overdesign on a large number of structures but optimizes overall savings by cutting down on engineering costs and manufacturing shop set up time by duplicating many fabrication units.

Since each structure is designed for actual applied loads, specific maximum allowable horizontal and vertical spans cannot be assigned to a given structure type as is the case in lattice towers designed as a family to cover a wide range of loadings.

Table "III" on page 14 summarizes the major 500 kV steel pole line which was designed by PL between 1973 and 1979. Table "IV" on pages 15 and 16 identifies the various structure types and associated outline drawings which are specified on each of the line designs.

Unswept Arms Vs. Straight Arms and Unpainted Vs. Painted Structures

A 3.0 mile segment of the Siegfried-Wescosville section of the Susquehanna-Wescosville line was the first major steel pole 500 kV line construction on PL's system. Painted structures with upswept arms were utilized on the line section in the vicinity of Routes 22 and 309 and Wescosville Substation. Tower construction was used in the remaining 8.0 mile portion of the line towards Siegfried Substation because steel pole construction could not be economically justified with the structure types being evaluated at that time.

When the time came to design the approximately 128 miles of 500 kV lines which would serve as outlets for Susquehanna S.E.S. generation (namely the Stanton-Susquehanna #2, Susquehanna-Siegfried section of the Susquehanna-Wescosville and Sunbury-Susquehanna #2 lines) the economics of different structure types were evaluated and it was determined that considerable savings could be realized over tower construction with the use of tapered straight conductor arms and OHGW arms and corrosion resistant steel. Since large portions of each of these lines are in rural or wooded areas, a corrosion resistant steel provided an improved visual impact over lattice towers. However, painted structures were purchased for the line sections in the immediate vicinity of Susquehanna S.E.S. in order to coordinate with the existing green facilities. Painted structures are used exclusively on the Alburtis-Wescosville and South Manheim Tap lines since they also are located in areas considered to be more environmently sensitive. In all cases painted structures have a higher initial cost and are more costly to maintain.

TABLE "III"
500 KV STEEL POLE LINES

Summary Of Structure Types and Configurations

Line Name	Structure Type	Single or Double Circuit	Painted on Unpainted Corten	Arm Type	General Structure Series
1. Susquehanna-Wescosville	"H" Type	Single	Painted	Upswept	5SPH1100
Siegfried-Wescosville line					5SPH1200
Susquehanna-Siegfried Section	"H" Type	Single & Double	Painted & Unpainted	Straight	5SPHT 5SHPT
2. Stanton-Susquehanna #2 Line	"H" Type	Single	Unpainted	Straight	5SPHT
3. Susquehanna-Generator #2 Leads	"H" Type	Single	Painted	Straight	____
4. South Manheim Taps	"H" Type	Double	Painted	Straight	5DPHT
5. Alburtis-Wescosville Line	"H" Type	Double	Painted	Straight	5DPHT
	"H" Type	Single	Painted	Straight	5SHPT
	Triangular Strut	Single	Painted	----	5SPT
6. Sunbury-Susquehanna #2 Line	"H" Type	Single	Unpainted	Straight	5SPHT
	"H" Type	Double	Unpainted	Straight	5DPHT
	"H" Type	Double	Painted	Straight	5DPHT

TABLE "IV"

500 KV STEEL POLE LINES
STANDARD STEEL POLE STRUCTURE OUTLINE DRAWING REFERENCE

Structure Designation	Structure Type	Insulator Type	Outline Drawings
SINGLE CIRCUIT			
5 SPH 1100 Series	Single Circuit "H", tangent (Upswept Arms)	V String Susp.	DB 1067 P.144
5 SPH 1200 Series	Single Circuit "H", 1°-15° (Upswept Arms)	V String Susp.	DB 1067 P.155
5 SP 1300 Series 5 SP 1400 Series	Single Circuit, Unguyed, Angle Deadend, 3 Pole Str.	Tension	DB 1067 P.143
5 SP 1600 Series 5 SP 1700 Series	Single Circuit, Unguyed, Angle Deadend, 3 Pole Str.	Tension	DB 1067 P.145
5 SP 202 & 203 5 SP 301 & 302	Single Circuit, Unguyed, Angle Deadend, 3 Pole Str.	Tension	DB 1066 P.813
5 SP 600 Series	Single Circuit, Single Pole, Guyed, Angle Deadend	Tension	DB 1069 P.531
5 SPHT Series	Single Circuit "H", Tangent (Straight Arms)	V String Susp.	DB 1067 P.193
5 SPHA Series	Single Circuit "H", 1°-15° (Straight Arms)	V String Susp.	DB 1067 P.194
5 SPHA Series	Single Circuit "H", 16°-30° (Straight Arms)	V String Susp.	DB 1067 P.195
5 SPHD Series	Single Circuit "H", Guyed, Angle Deadend, 0°-30° (Straight Arms)	Tension	DB 1067 P.200
5 SPD Series (Horizontal)	Single Circuit, Guyed, Angle Deadend, 3 Pole Str.	Tension	DB 1067 P.196
5 SPT Series	Single Circuit, Single Pole, Triangular Tangent Strut.	Strut Susp.	DB 1085 P.55
5 SPA Series	Single Circuits, Single Pole, Triangular Angle Strut 1°-10°	Strut Susp.	DB 1085 P.55
5 SPD Series (Triangular)	Single circuit, Guyed, Heavy Angle Deadend, 2 Pole Str.	Tension	DB 1085 P.57

Structure Designation	Structure Type	Insulator Type	Outline Drawings
5 SPD Series (Vertical)	Single Circuit, Guyed, Single Pole, Angle Deadend	Tension	DB 1085 P.58
DOUBLE CIRCUIT			
5 DPHT Series	Double Circuit "H", tangent (Straight Arms)	V String Susp.	DB 1067 P.225
5 DPHA Series	Double Circuit "H", 1°-15° (Straight Arms)	V String Susp.	DB 1067 P.226
5 DPHA Series	Double Circuit "H", 16°-30° (Straight Arms)	V String Susp.	DB 1067 P.227
5 DPHD Series	Double Circuit, "H", Guyed, Angle Deadend, 0°-30° (Straight Arms)	Tension	DB 1067 P.228
5 DPD Series	Double Circuit, Guyed, Angle Deadend, 4 Pole Str.	Tension	DB 1067 P.229

"H" Deadend Vs. Single Pole Deadend Structures

"H" type deadends were introduced in the design of the Susquehanna lines and proved a design advantage over single pole deadends in that horizontal offsets between OHGW and conductors are readily provided to obtain clearances for ice on-ice off and galloping conductor criteria. Stringing on "H" deadends is more costly due to the temporary guying that is necessary to prevent arm deflection due to stringing tension unbalances. In addition, unanticipated problems were encountered during stringing due to rotation of the conductor arm and OHGW mast which was inherent in the design tolerances provided in the pinned and bolted connections. In the end the two types of structures were nearly a trade off economically, although the use of an "H" deadend may have an aesthetic value over a typical multipole structure. Due to economics "H" deadends were limited to line break angles 30° and below.

Unguyed Vs Guyed "H" Type Structures (V-String running angles)

Cross braces are utilized on "H" structures on all lines to provide for a more rigid design and help support transverse loads in lieu of angle guys. Angle guys cannot be justified taking into consideration aesthetic impact. Rigid cross braces are specified in lieu of interpole guying due to the ease of installation and savings in labor costs. Cross braces are limited to one per structure on all lines except the Siegfried-Wescosville line; the intent is to provide space to walk the crane during erection as a one piece structure. V-string assemblies are limited to line break angles of approximately 30°, within the capacity limits of the assembly, similar to tower line construction.

Unguyed Vs. Guyed Deadend Structures

Due to the extremely large conductor tensions commonly used in the 500 kV designs it is usually cost prohibitive to purchase a self-supporting structure to sustain unbalanced tensions resulting from stringing, ice on-ice off, or broken conductor loading conditions. Therefore, most deadend structures whether they are "H" type or single pole are head and back guyed to support longitudinal loads. Guying on "H" deadends is only specified to support the typical unbalanced longitudinal loadings mentioned above. Single poles are additionally guyed to support maximum conductor deadend design loads. A total of 4 head and 4 back guys (2 per leg) are typically used on single circuit "H" deadend designs to support all conductors and OHGWs and a maximum of 4 head and 4 back guys per conductor position are typically specified on single poles. The number of guys is limited to satisfy aesthetic requirements and optimize overall installed costs.

OHGW positions typically are not guyed on "H" structures because of electrical clearance requirements and the large vertical loads that are generated in the static arms. OHGW positions on single or multipole structures are generally not guyed on line angles below 55° because of minimum electrical clearance requirements to energized conductors at the lower elevation.

Guy attachments are specified at a minimum vertical distance below conductor attachments to provide electrical clearances. This requirement generally applies to "H" deadends with large line angles and multipole structures with shallow line angles.

Single Pole Tangent Structures

A new single pole structure equipped with strut insulator assemblies on a triangular configuration was developed for the section of the Alburtis-Wescosville line out of Wescosville Substation for use on the narrow 140' wide R/W strip in that segment. Increased ground clearances and triple bundled 1590 kcmil phase conductors are incorporated on the single pole section in order to reduce RIV and audible noise interference levels.

Unequal Leg Lengths and Structure Heights

"H" type structures are typically purchased in height increments of 5' e.g. 120', 125', 130' etc. Structures on the Stanton-Susquehanna #2 and Susquehanna-Siegfried lines are not in increments of 5'. The distance from the top of structure to the conductor elevation changed from 25' to 27' during the course of design but after structural steel was purchased by the manufacturing and Steel Pole Detail and Plan Profile drawings were near completion; and it was easier to change the OHGW arm lengths and designated structure heights than change leg lengths and design drawings. Later designs compensated for this change and use height increments of 5'.

Unequal leg lengths on multilegged structures or unequal pole heights on multipole structures are utilized to limit foundation pedestal lengths to 18" below grade where cross sectional groundlines varies. Typically these unequal lengths are also in 5' increments and the remaining differences in elevation is compensated for by foundation pedestal lengths. However, one foot increments are used on the Sunbury-Susquehanna #2 and Susquehanna-Siegfried lines in order to reduce the number and length of concrete pedestals.

Structure Designation And Leg Identification

The typical 500 kV structure type designations and the definition of each character in the designations are described on pages 21 and 22. You will note that structure designations conform to the format of typical 138 kV and 230 kV structures on the earlier lines up to and including the Siegfried-Wescosville line. Designations were altered for the purchase of structures for the Susquehanna lines in order to more precisely identify the line and location where a particular

structure was to be shipped and at the same time provide at a glance additional information about configuration, insulator type, orientation, and whether or not it was to be guyed. The pole manufacturer identified the specified designation on the structure nameplate.

The pole manufacturer also labels each pole or leg section with the orientation specified on the job bill of material. The standard orientation is shown on Page 13. Physical identification is usually with beads of weld placed on baseplates, arm saddles, or flange plates and at a minimum consist of the structure number, line code letter, and orientation, e.g. $24AL_1$. Other structural members such as arms, x-braces, etc. are labelled, again with beads of weld, in accordance with the manufacturer's identification and detailed drawings. In addition, the manufacturer supplies section orientation marks on parts that are shop fitted such as flange plate connections.

Steel Pole Climbing

Step bolts and/or climbing and working ladder support brackets are installed on all steel pole structures to provide working access to all conductor and OHGW positions under both initial installation and hot line maintenance conditions. Step bolt nuts and ladder support brackets are welded to structural members by the pole manfuacturer in accordance with PP&L Steel Pole Fabrication Specification LA-50181.

Permanent step bolts were the accepted means of climbing when the Siegfried-Wescosville line was installed and therefore were the sole type of climbing assist. During the design of the later Susquehanna lines, removable climbing and working ladders became the newer means of climbing and represented cost savings over permanent steps. Step bolts are provided, however, on "H" structure OHGW arms and other structural members on all structure types where ladder provisions are impractical. High reaching aerial equipment is generally used by construction in lieu of actually climbing the structure when such equipment is available and can be readily moved to the structure site.

For specific details and location of the climbing assists provided on a given structure refer to the individual steel pole detail drawings referenced on the job Plan and Profile drawing.

Seel Pole Loading Conditions

Structure loading conditions for 500 kV line designs generally conform to Stone & Webster criteria on the Keystone lines. Loading summaries are prepared by computer for each individual structure and used by the manufacturer in their designs. The computer generates normal PP&L loadings, similar to 138 kV or 230 kV poles, but then formats those loads into the various Keystone conditions.

In the case of longitudinal loads on V-string equipped structures, Keystone loads are substituted for PP&L loads to keep loadings to a minimum. The loadings that are substituted, see Table V, are selected by comparing actual vertical and horizontal spans with lattice tower types that fall in the same range. Refer to Page 31.

Some Keystone loading conditions are also eliminated from the manufacturers summaries because they are not applicable or are readily defined as non-governing loadings. The Keystone loading conditions and an explanation of their application on steel pole structures are shown on pages 24 through 30.

The one major exception to meeting Keystone loading criteria is on the Siegfried-Wescosville line. The heavy ice loading condition on that line was limited to 1 1/4" ice, 0# wind in lieu of the normal 1 1/2" ice, 0# wind loding. A smaller condition #9E loading was selected on the basis of historical ice studies of the PP&L system and the lower U.S.G.S. elevation that the line is located.

The use of Keystone criteria on double circuit structures is similar to single circuit designs. Worst case longitudinal unbalances under the condition #5, broken conductor, condition #6, stringing, and condition #7, ice on - ice off loadings were applied.

500 KV STEEL POLE DESIGNATIONS

Example of Typical Structure Type and Definition of Each Character in the Designation
(Used on lines prior to and including the Siegfried-Wescosville Line)

5 S PH 1 1 0 1

5 – Designates Voltage

Absense of No. = 66 kV
1 = 138 kV
2 = 230 kV
5 = 500 kV

S – Letter Indicates Circuits

D = Double Circuit
S = Single Circuit

PH – Letters Indicate Structure Type

P = Single Steel Pole
PH = Steel "H" Type Structure

1101 – Use of 4 characters indicates the following:

66 kV - Designed for 556.5 kcmil ACSR, 500' avg. spans

230 kV - Designed for 1590 kcmil ACSR, 550' avg. spans

500 kV - Designed for 2493 kcmil ACAR, 1500' avg. spans.

1 (second character of the 4) – Designates Type of Framing

1 = Tangent Suspension V-String
2 = Angle Suspension V-String
3 = Unguyed Tension Deadend
6 & 7 = Guyed Tension Deadend

01 – These 2 characters distinguish the loadings by which the structure was designed.

500 KV STEEL POLE DESIGNATIONS

*** Example of Typical Structure Type and Definition of Each Character in the Designation

5 S P A 24 A L G

- **5** — Indicates 500 kV
- **S** — Letter Indicates Circuits
  - S = Single Circuit
  - D = Double Circuit
- **P** — Letter Indicates Structure
  - P - Single Steel Pole
  - PH- Steel "H" Type Str..
- **A**
  - T = Tangent V String
  - A = Angle V String
  - D = Deadend Tension
- **24** — Structure Number
- **A** — *Designates Line
  - A = Susq.-Siegfried
  - B = Susq-Stanton #2
  - C = Sunbury-Susq #2
  - D = So.Manheim Taps
  - E = Alburtis-Wescosville
  - Susq.Generator #2 Leads
- **L**
  - L = Left Pole of Multiple Pole Str.
  - M = Middle Pole of Multiple Pole Str.
  - R = Right Pole of Multiple Pole Str.
    (See Note ** below)

  (No Letter for "H" Type Structures. On Structures with more than 3 Poles, Label L_1, L_2, R_1, R_2 Etc. from the structure center)
- **G** — G For Guyed Structure (Blank for Unguyed Structure)

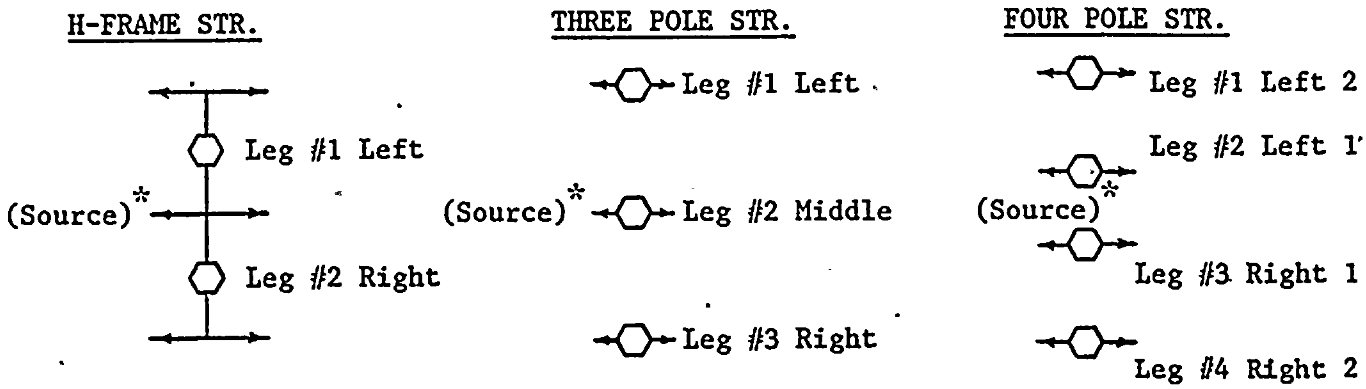
NOTE *: Most Important Code Letter of Structure Designation. Each Structure is custom designed for a specific location on a specific line. Only a structure with the proper code may be used on a given line.

NOTE**: Refer to "Steel Pole Leg Identification" section for typical orientation. Left Through right are viewed with your back to the source end of the line and the proper orientation shall be indicated on the structure bill of material and Plan & Profile drawing.

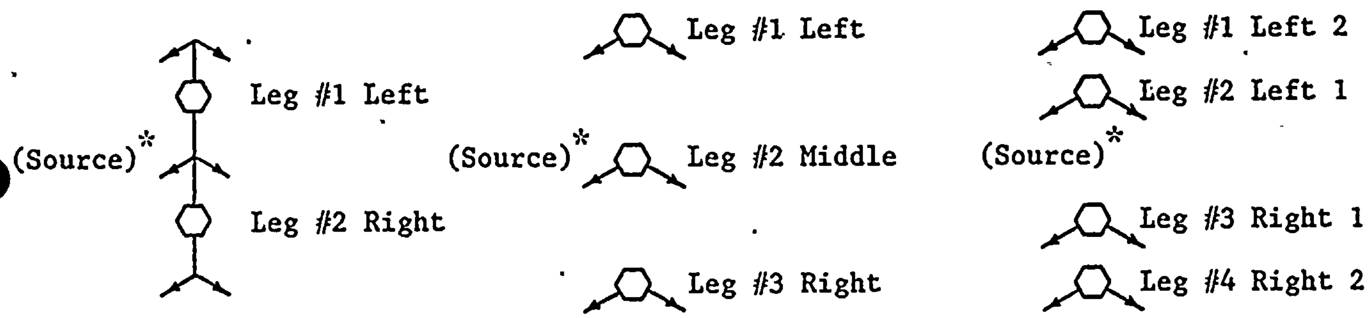
NOTE***: Standard Designation after the Siegfried-Wescosville Line.

STEEL POLE LEG IDENTIFICATION

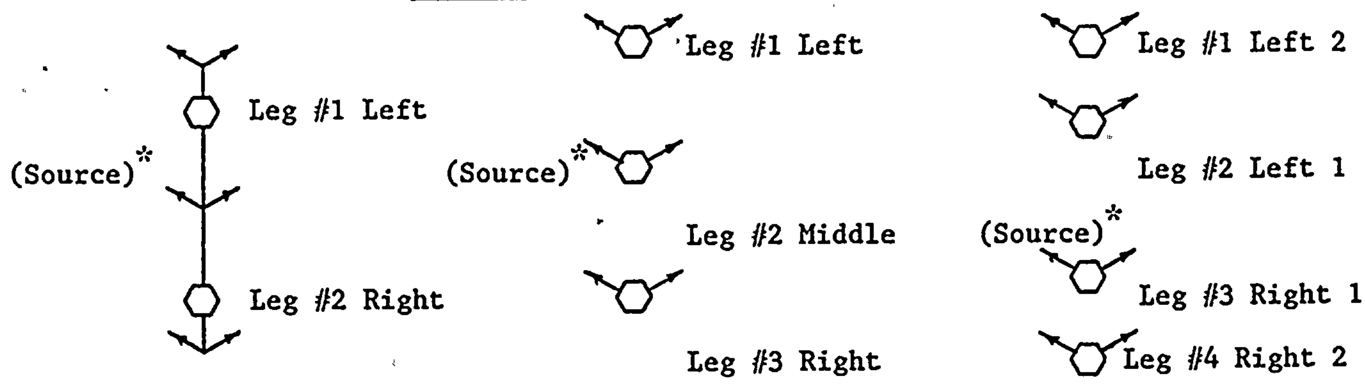
Multilegged or multipole steel structures are identified and labelled left to right with your back to the source end of the line as shown in the diagrams below.



TANGENT STRUCTURE WITHOUT BREAK ANGLE



ANGLE STUCTURE WITH BREAK ANGLE TO RIGHT



ANGLE STRUCTURE WITH BREAK ANGLE TO LEFT

* The source is the starting point of the line designated by the transmission design engineer.

Suspension Structures

All tangent and angle steel pole structures with V-strings are designed for each of the individual numbered loading conditions as follows:

1. All cables intact, NES Code heavy loading which consists of 4 psf wind on 1/2 in. radial ice, 0°F, on ground wires and conductors, and 4.0 psf wind on structure with the following overload factors:

a.	Transverse wind load and wind on structure	2.54 *
b.	Transverse and longitudinal wire pull loads	1.65
c.	All vertical loads	1.27*

   This loading condition meets the requirements of the NES Code rule 261A3a and 261A3b.

   * Overload factors on the Alburtis-Wescosville line are 2.50 and 1.50 respectively-NESC 1977 rule 250, 252, and 261A1.

2. No cables on structure, a transverse wind of 25.0 psf (1) on structure with an overload factor of 1.10 for all loads.

   This loading condition meets the requirements of NES Code rule 261A3c, 24 psf.

   (1) PP&L hurricane wind load.

3. NOTE: This condition is not applicable to steel pole structures.

   All cables intact, NES Code heavy loading which consists of 4 psf wind on 1/2 in. radial ice, 0°F, on ground wires and conductors, and 6.4 psf wind on 1.5 faces of tower with an overload factor of 2.0 for all loads.

4. All cables intact on steel pole structure in combination with a transverse hurricane wind of 25 psf (100 mph) on bare ground wires and conductors, at 60°F, and 25.0 psf wind on str. with an overload factor of 1.25 for all loads.

5. NES Code heavy loading, 0°F, combined with a longitudinal load produced by a broken subconductor in any one phase plus 100 per cent impact factor, all other phases and ground wires intact, with an overload factor of 1.25 for all loads except an overload factor of 1.0 for longitudinal long produced by a broken conductor.

6a. A longitudinal stringing load which would be produced by the ground wire binding in the stringing block and producing a longitudinal swing of the supporting bracket of 45 deg at any one ground wire attachment point, the other ground wire intact, no conductors on str., a 4 psf wind on bare wire with 4.0 psf wind on str. of 1.25 for all loads.

6b. A longitudinal stringing load which would be produced by two subconductors in any one phase binding in the stringing block and producing a longitudinal swing of the insulator of 45 deg, the other phases and ground wires intact, a 4 psf wind on bare wire with 4.0 psf wind on structure, 0°F, with an <u>overload factor of 1.25 for all loads</u>.

For "H" frames, the cantilever length of arm is designed for a camber equal to the deflection at the free end of arm calculated under loading condition.

7. A differential ice loading, incurred by ice falling from the ground wires or conductors in the span on one face of the tower, based on 1 in. radial ice to bare cable, no wind, 30°F, and producing a longitudinal load on the structure. The differential ice loading is applied to the structure as follows:

   a. Differential ice loading on one ground wire, 1 in. radial ice on the other ground wire and all three phases (see 7b)

   b. Differential ice loading on both ground wire, and 1 in. radial ice on all three phases (condition 7a was determined to control design between 7a & 7b)

   c. Differential ice loading on one outside and middle phase, 1 in. radial ice on the other phase and both ground wires.

   d. Differential ice loading on all three phases with 1 in. radial ice on both ground wires.

<u>The overload factor is 1.25 for all loads</u> and differential ice loading is always applied to the same face of the structure.

8. All cables intact, an 8 psf wind on 1 in. radial ice 0°F, on ground wires and conductors, and 8.0 psf wind on str. with an overload <u>factor of 1.25 for all loads</u>

9. All cables intact, 1 1/2 in. radial ice, no wind, 0°F, with an <u>overload factor of 1.25 for all loads</u> and combined as follows:

   a. 1 1/2 in. ice on one ground wire, the other ground wire and phases bare (see 9e.)

   b. 1 1/2 in. ice on both ground wires and all phases bare (see 9e.)

   c. 1 1/2 in. ice on both ground wires, one outside phase and the middle phase; the other phase bare (see 9e.)

   d. 1 1/2 in. ice on both ground wire and outside phases, and the middle phase bare (see 9e.)

   e. 1 1/2 in. ice on all ground wires and phases - this condition was determined to control design.

10. All steel pole structures are designed for a vertical pickup from the crossarm directly above the apex of the V-string. Condition 9e loads are used.

11. NOTE: This condition is not applicable to steel pole structure.

For the bottom chord lacing and chord angles on all tower crossarms, a 400 lb ultimate vertical load is applied at the center of these members in combination with the loading produced by the stringing conditions as specified for each of the different tower types.

All other horizontal or near horizontal redundant members are designed to withstand an ultimate vertical load of 400 lb applied to produce maximum bending.

Insulation Weight

The weight of insulator strings for use in steel pole structure design is as follows and is based on using 25 units for V-string leg:

Single V-string (50 insulators) = 900 lb

Double V-string (100 insulators) = 1,800 lb

Tension Structures

All deadend steel pole and deadend "H" frame structures are designed for each of the individual numbered loading conditions as follows:

1. All cables intact, NES Code heavy loading which consists of 4 psf on 1/2 in. radial ice, 0°F, on ground wires and conductors and 4.0 psf wind on structure with the following overload factors:

a.	Transverse wind load and wind on structure	2.54 *
b.	Transverse and longitudinal wire pull load	1.65
c.	All vertical loads	1.27 *

This loading condition meets the requirements of the NES Code rules 261A3a and 261A3b

* Overload factors on the Alburtis-Wescosville line are 2.50 and 1.50 respectively-NESC 1977 rule 250, 252 and 261 A1.

2. No cables on structure, a transverse wind of 25.0 psf (1) on strip with an overload factor of 1.10 for all loads

This loading condition meets the requirements of NES Code rule 261A3c, 24 psf.

(1) PP&L hurricane wind load

3. NOTE: This condition is not applicable to steel pole structures.

All cables intact, NES Code heavy loading which consists of 4 psf wind on 1/2 in. radial ice, 0°F, on ground wires and conductors, and 6.4 psf wind on 1.5 faces of tower with on overload factor of 2.0 for all loads.

4. All cables intact on steel pole structure in combination with a transverse hurricane wind of 25 psf (100 mph) on bare ground wires and conductors, at 60°F, and 25.0 psf wind on structure with an overload factor of 1.25 for all loads

5. NES Code heavy loading, 0°F, combined with a longitudinal load produced by a broken subconductor in any single phase plus 100 per cent impact factor, all other phases and ground wires intact, with an overload factor of 1.25 for all loads except an overload factor of 1.0 for longitudinal load produced by a broken conductor.

6a. A stringing condition resulting from the ground wires and conductors being dead ended with a 4 psf wind on bare cable, 0°F, and 4.0 psf wind on str. with an overload factor of 1.25 for all loads and combined as follows:

a. One ground wire dead-ended, no other cables on structure (see 6a-d)

b. Two ground wires dead-ended, no conductors on structure (see 6a-d)

c. Two ground wires, one outside and middle phase dead-ended; no conductors at other phase location

d. All ground wires and conductors dead-ended - this condition was determined to control design between 6a-a, 6a-b, 6a-d, 6b & 6c

e. The above combinations shall always be dead-ended on the same face of the tower.

6b. A stringing condition resulting from the ground wire being dead-ended with a 4 psf wind on bare cable, 0°F, and 4.0 psf wind on structure with an overload factor of 1.25 for all loads and combined as follows:

a. One ground wire dead-ended, no other cables on structure.

b. Two ground wires dead-ended on the same face, no conductors on structure.

NOTE: See 6a-d

6c. A longitudinal stringing load which would be produced by two sub-conductors in any single phase binding in the stringing block and producing a longitudinal swing of the insulator of 45 deg, the other phases and ground wires intact, a 4 psf wind on bare wire with 4.0 psf wind on structure 0°F, with an overload factor of 1.25 for all loads.

NOTE: see 6a-d

7. A differential ice loading, incurred by ice falling from the ground wires or conductors in the span on one face of the structure, based on 1 in. radial ice to bare cable, no wind, 30°F, and producing a longitudinal load on the structure. The differential ice loading is applied to the structure as follows:

a. Differential ice loading on one ground wire, 1 in. radial ice on the other ground wire and all three phases (see 7b)

b. Differential ice loading on both ground wires and 1 in. radial ice on all three phases (Condition 7a was determined to control design between 7a and 7b)

c. Differential ice loading on one outside and middle phase, 1 in. radial ice on the other phase and both ground wires.

d. Differential ice loading on all three phases with 1 in. radial ice on both ground wires.

The overload factor is 1.25 for all loads and differential ice loading is always applied to the same face of the structure.

8. All cables intact, an 8 psf wind on 1 in. radial ice, 0°F, on ground wires and conductors, and 8.0 psf wind on structure with an overload factor of 1.25 for all loads.

9. All cables intact, 1 1/2 in. radial ice, no wind, 0°F, with an overload factor of 1.25 for all loads and combined as follows:

   a. 1 1/2 in. ice on one ground wire, the other ground wire and phases bare (see 9e)

   b. 1 1/2 in. ice on both ground wires and all phases bare (see 9e)

   c. 1 1/2 in. ice on both ground wires and outside and middle phases; the other phase bare (see 9e)

   d. 1 1/2 in. ice on both ground wires and outside phases, and the middle phase bare (see 9e)

   e. 1 1/2 in. ice on all ground wires and phase - condition 9e was determined to control design

10. NOTE: Condition 10 not applicable because loading apply to dead end structure.

All towers with V-strings are designed for a vertical pickup from the crossarm directly above the apex of the V-string. This consists of a vertical load equal to the weight span times 2 times bare cable weight with an overload factor of 1.25 at any one phase point.

11. NOTE: This condition is not applicable to steel pole structures.

For the bottom chord lacing and chord angles on all tower crossarms, a 400 lb ultimate vertical load is applied at the center of these members in combination with the loadings produced by the stringing conditions as specified for each of the different tower types.

All other horizontal or near horizontal redundant members are designed to withstand an ultimate vertical load of 400 lb applied to produce maximum bending.

Insulator Wegiths

The weights of insulator strings for use in steel pole design are as follows:

2 Strings for each leg of the V-string = 1,800 lb per phase

3 Strings for flat leg and 2 strings for the other leg of the V-string = 2,200 lb per phase

For structures with strain insulators, the weight of insulators is 2,000 lb per phase on one face of the tower.

Special Steel Pole Structure Loadings

1. All line deadend structures at substation or switchyard terminals were designed to sustain all cables down on one face of the structure, the other side intact, NES Code heavy loading, 0°F, with an overload factor of 1.50 for all loads.

2. On single pole deadends with line break angles 55° and below an additional condition #10 and #10a were included to split the transverse loads from condition #8 into loads supported separately by pole and guys. The intent was to compensate for wind loads that would be sustained by the pole rather than the guys on shallow line angles. Guys were assumed to support deadend loads only.

TABLE V

500 KV STEEL POLE TRANSMISSION LINES

Summary of Keystone Longitudinal Loads Substituted For PL
Generated Loads on Tubular Steel Structure Loading Summaries

*** Line Angle	*** Horizontal Span Range (Feet)	*** Vertical Span Range (Feet)	Conductor Load (# Longitudinal)			OHGW Load (# Longitudinal)		
			** Condition #5	Condition #6	Condition #7	** Condition #5	Condition #6	Condition #
0°	0' to 1399	0' to 1767'	9720	7000	4200	--	*	3880
0°	1400 to 1800'	1800' to 2287'	19500	9400	10920	--	*	8940
0° - 15°	1400' to 1800'	1800' to 2287'	12260	7800	6600	--	*	3880
15° - 30°	1400' to 1800'	1800' to 2287'	10900	9260	5560	--	*	3880

NOTES:

* PL generated loads were used on OHGW position

** Keystone Condition Numbers

*** PL generated loads were used on any structure which did not fall into a range that met line angle, horizontal span, and vertical span simultaneously.

7. Electrical Characteristics

Line Impedances - ohms per mile

Name	Resistance	Reactance
Stanton-Susquehanna - single circuit		
Positive and negative sequence	0.025	0.604
Zero sequence	0.478	1.602
Susquehanna-Wescosville - single circuit		
Positive and negative sequence	0.025	0.604
Zero sequence	0.478	1.602
Susquehanna-Wescosville - double circuit		
Positive and negative sequence	0.0247	0.5821
Zero sequence	0.4699	1.750
Mutual	0.445	1.035
Sunbury-Susquehanna - single circuit		
Positive and negative sequence	0.025	0.604
Zero sequence	0.478	1.602
Sunbury-Susquehanna - double circuit		
Positive and negative sequence	0.0247	0.5821
Zero sequence	0.4699	1.750
Mutual	0.445	1.035
Alburtis-Wescosville - single circuit, twin bundle		
Positive and negative sequence	0.025	0.604
Zero sequence	0.478	1.602
Alburtis-Wescosville - double circuit, triple bundle		
Positive and negative sequence	0.0226	0.5238
Zero sequence	0.4678	1.6916
Mutual	0.445	1.035
Alburtis-Wescosville - single circuit, triple bundle		
Positive and negative sequence	0.0226	0.5137
Zero sequence	0.4985	1.5910
South Manheim Connections - double circuit		
Positive and negative sequence	0.0247	0.5821
Zero Sequence	0.4699	1.750
Mutual	0.445	1.035
Susquehanna Gen. #2 Leads - single circuit		
Positive and negative sequence	0.025	0.604
Zero Sequence	0.478	1.602

Conductor Surface Voltage Gradient-Calculated

Line Name	Maximum Kilovolts per cm line operating at 525 kV	Position of Phase
Stanton-Susquehanna	16.11	inside
Susquehanna-Siegfried		
single circuit portion	16.11	inside
double circuit portion	16.38	inside bottom
Sunbury-Susquehanna		
single circuit	16.11	inside
double circuit	17.73	inside bottom
Alburtis-Wescosville		
single circuit-twin bundle	16.11	inside
single circuit-triple bundle	15.09	bottom
double circuit-triple bundle	15.69	inside bottom
South Manheim Connections	17.73	inside bottom
Susquehanna Gen.. #2 Leads	16.11	inside

Shield Wire Configuration - Typical Suspension Structure

Two 19 No. 9 Alumoweld shield wires are installed at the top of each structure in a horizontal plane as follows:

Line Name	Ht Above Outermost Phase	Offset	Shield Angle to Outermost Phase
Stanton-Susquehanna	25'	9'	20°
Susquehanna-Wescosville (single circuit portion)	25'	9'	20°
Susquehanna-Wescosville (double circuit portion)	56'	13'	13°
Sunbury-Susquehanna (single circuit portion)	25'	9'	20°
Sunbury-Susquehanna (double circuit portion)	56'	13'	13°
Alburtis-Wescosville (single circuit - twin bundle portion)	25'	9'	20°
Alburtis-Wescosville (double circuit portion)	56'	13'	13°
Alburtis-Wescosville (single circuit - triple bundle portion)	17'4"	7.5'	23.4°
South Manheim Connections	56'	13'	13°
Susquehanna Gen. #2 Leads	25'	9'	20°

Conductor Configuration and Spacing

Name of Line	Number of Subconductors	Subconductor Configuration	Subconductor Spacing Center to Center	Conductor
Stanton-Susquehanna	2	horizontal	18"	2493 kcmil ACAR
Susquehanna-Wescosville (sc & dc portions)	2	horizontal	18"	2493 kcmil ACAR
Sunbury-Susquehanna (sc & dc portions)	2	horizontal	18"	2493 kcmil ACAR
Alburtis-Wescosville (sc H-frame portion)	2	horizontal	18"	2493 kcmil ACAR
Alburtis-Wescosville (dc portion and sc single pole portion)	3	triangular	18"	1590 kcmil ACAR
South Manheim Connections	2	horizontal	18"	2493 kcmil ACAR
Susquehanna Gen. #2 Leads	2	horizontal	18"	2493 kcmil ACAR

Phase Spacing

	Name	Description of Phase Spacing
1)	Stanton-Susquehanna	35 ft. Horizontal (flat)
2)	Alburtis-Wescosville (H-Frame portion)	35 ft. Horizontal (flat)
3)	Susquehanna-Wescosville (single circuit portion)	35 ft. Horizontal (flat)
4)	Sunbury-Susquehanna (single circuit portion)	35 ft. Horizontal (flat)
5)	Susquehanna-Siegfried (double circuit portion)	4 conductor positions on bottom arm and 2 conductor positions on top arm. Horizontal phase spacing is 33 ft. on both arms. Vertical phase spacing is 32 ft.
6)	Alburtis-Wescosville (double circuit portion)	
7)	Sunbury-Susquehanna (double circuit portion)	
8)	Alburtis-Wescosville (single circuit - single pole portion	Triangular configuration with 2 phase positions on one side of the pole and one on the other. The middle phase is located 37' horizontally and 10'8" vertically from the bottom phase. The top phase is located 25' vertically and 1'9" horizontally from the bottom phase.
9)	South Manheim Connections	4 conductor positions on bottom arm and 2 conductor positions on top arm. Horizontal phase spacing is 33 ft. on both arms. Vertical phase spacing is 32 feet.
10)	Susquehanna Gen. #2 Leads	35 ft. Horizontal (flat)

8. Foundations

Stanton-Susquehanna #2 500 kV Line

Susquehanna-Wescosville 500 kV Line

Susquehanna-Siegfried section

Siegfried-Wescosville 500 kV section

South Manheim 500 kV Connections

Sunbury-Susquehanna #2 500 kV Line

Alburtis-Wescosville 500 kV Line

General

The foundations for the above captioned lines are designed using a laterally loaded caisson design approach as developed by GAI Consultants and Duquesne Light Company except the Siegfried-Wescosville 500 kV line which is designed using the non-specific classical method for steel pole foundations. Table VI following this narrative gives specific design criteria used on each line. The purpose of this narrative is to address, in general terms, the highlights of the evolution of the laterally loaded caisson design approach. For more specific information you are directed to the appropriate DB and ER files. See the Bibliography for references.

Subsurface Related Information

- Uplift Resistance

  The cone of soil approach to uplift resistance was replaced by skin friction/adhesion because outside testing information reported the cone of soil to be applicable only for relatively shallow foundations.

- Correlation of K as f (Eh)

  Based on in-house testing it was determined that the Terzaghi equation:

$$K = \frac{E}{1.35B}$$

  was not applicable and that the spring constant, K, was more accurately represented by the Yoshida-Yoshinaka equation:

$$K = \frac{2.31E}{B} \left(\frac{B}{Bo}\right) \text{1/4 power}$$

o **Depth to first resisting medium**

As experience with the laterally loaded design concept progressed, it was discovered that by selectively ignoring the parameters of some soil strata foundation depth could be optimized.

Design Load Related Information

o **Base reactions**

As more experience with and knowledge of the computer program, used for design, grew, the deviation of base reactions changed. Originally the ABAR value was assumed to be the distance between the baseplate and the inflection point on the shaft. It was discovered later that ABAR equals ground line MOMENT divided by manufacturer's base reactions directly.

Factors of safety were applied in accordance with previously established transmission section policy. Manufacturer's base reactions were modified to account for the differences between the overload capacity factors, (olcf), and the desired factors of safety. Initially base reactions resulting from loads having an olcf of 1.25 were multiplied by .85 instead of .88 to arrive at a factor of safety of 1.1. Also at one time the uplift base reactions having an olcf of 1.25 were multiplied by 1.25 instead of 1.2 to arrive at a factor of safety of 1.5. This explanation documents the reasons for the factor of safety discrepancy between some of the lines.

For the most recent lines designed the manufacturer's calculated base reactions were appropriately modified by equations internal to the computer program.

Reinforced Concrete Design Related Information

o **Splicing**

Reinforcing for initial lines was originally ordered for tower foundations. This reinforcing was received prior to the decision to use tubular steel H-frame and augered caisson construction. Due to this, these two lines have foundation reinforcing spliced to the required length supplemented with bar ordered in 30' lengths to make up the difference.

The only splicing used on the balance of the lines is that required due to field revisions. All these splices meet the ACI Code requirements.

o **Flexural Reinforcing Design**

Flexural reinforcing was consistently designed using the working

stress equation:

$$As = \frac{ZM}{f_2 jd}$$

For the Siegfried-Wescosville section all flexural reinforcing for all diameters was designed using d = 48 which is only accurate for 5'6" diameter foundation. This resulted in conservatism. Also, for foundations on this ER the standard reinforcing cage as called out on E-118150 was used if it satisfied the above equation.

In general the balance of lines had flexural reinforcing custom designed for the individual structure base reactions and was consistent with the ACI Code.

Flexural reinforcing in foundation pedestals was originally designed as a separate cage to be spliced to the vertical caisson reinforcing. To optimize the installation, design procedures were altered to treat the pedestal flexural reinforcing as a direct extension of the vertical caisson reinforcing with no splices.

- <u>Shear Reinforcing Design</u>

Generally the minimum shear reinforcing as specified by the ACI Code was sufficient to carry shear loads.

Shear reinforcing was specifically checked and sized per the ACI Code for Sunbury-Susquehanna and Alburtis-Wescosville lines.

BIBLIOGRAPHY FOR REFERENCES

- Bulk Power Civil/Structural Files for Pressurements testing results for the following sites:

  - Bossards
  - Beach Haven
  - South Manheim Connections
  - Sunbury - Susq. #2 500 Line
  - Alburtis-Wesc. 500 Line

- ER File 121219 - Susq.-Stanton 500 Line

- ER File 121233 - Susq.-Siegfried 500 Line

- ER File 121243 - South Manheim 500 kV Tap

- ER File 122026 - Montour-Susq. 230 kV Relocation

- ER File 121242 - Susq. Generator #1 Leads

- ER File 121234 - Sunbury-Susq. 500 kV Line

- ER File 121236 - Alburtis-Wescosville 500 kV Line

- SAO File 907128 - Bossard's Foundation Testing

- Reprint of "Soils and Foundations" Vol. 12, No.3 September 1972 Issue - Japanese Society of Soil Mechanics and Foundation Engineering, by IWAO Yoshida and Ryunoshin Yoshinaka.

- Report prepared by Sargent & Lundy for PP&L dated August, 1977 "Transmission Pole Caisson Foundation Tests"

- Report prepared by General Analytics Inc. dated March, 1972 "Laterally Loaded Caisson Embedded in a Multi-Layered Elastic Media".

- Report prepared by A.M.DiGioia, Jr., T.D.Donovan, and F.J.Cortest February 1975, "A Multi-Layered/Pressuremeter Approach to Laterally Loaded Rigid Caisson Design"

- Report prepared by GAI Consultants, Inc. for PP&L, dated February, 1978. "Pressuremeter Testing and Geotechnical Design Parameter Correlations - Sunbury-Susquehanna 500 kV Line."

- Report prepared by GAI Consultants, Inc. for PP&L, dated December, 1977. "Design Approach for Laterally Loaded Drilled Piers".

- Bulk Power Civil/Structural Files for the following Design Books

  DB 1121 - Stanton-Susq. #2 500 kV - Foundation Design
  DB 1118 - Susq.-Siegfried 500 - Foundation Design
  DB 1123 - S. Manheim 500 kV Tap - Foundation Design
  DB 1124 - Montour-Susq.Relocation - Foundation Design
  DB 1122 - Susq. Generator #1 - Foundation Design
  DB 1103 - Sunbury-Susq. #2 500 kV - Foundation Design
  DB 1104 - Alburtis-Wesc. 500 kV - Foundation Design

LINE NAME/ER #	FREQUENCY OF BORINGS	BORINGS TAKEN BY	BORING SAMPLES CLASSIFI[ED] & BY WHOM	PRESSUREMETER TESTING O[F] REP. SOIL (YES/NO)	BY WHOM	PRESSUREMETER CORRELATIONS PREPARED BY	ADHESION VALUE FOR GRANDULAR SOIL	ADHESION VALUE FOR COHESIVE SOIL	ADHESION VALUE FOR ROCK	CORRELATION FOR MODULUS OF DEFORMATION BASED ON TERZAGHI(T) - YOSHIDA/YOSHINAKA(Y/Y)	FOUNDATION DESIGN COVERED BY ALLOWABLE
Susq.-Stanton 500 ER 121219 Fdns.Designed-1975-76	Center hub at Structure	BS&T	PP&L	No	-	N/A	Used Cone of uplift	Used Cone of uplift	Used Cone of uplift	Terzahi	
Susq.-Siegfried 500 ER 121233 Fdns. designed-1977-78	Center hub at structure	BS&T	PP&L &/or GAI	No	-	GAI	.75ksf.	.9ksf.	7.2ksf.	Terzaghi & Yoshida	
Sunbury-Susq. 500 ER 121234 Fdns. designed - 1979	Center hub at Structure	BS&T	GAI	Yes	GAI & BS&T	GAI	0.4ksf.	0.75 ksf.	7.2ksf.	Yoshida	
WESC. 500 ER 121236 Fdns.designed-1979	Center hub at Structure - at leg in limestone	BS&T	PP&L	Yes	STS & BS&T	PP&L	0.4ksf.	0.75 ksf.	7.2ksf.	Yoshida	
S. Manheim Sub Tap ER 121243 Fdns.designed-1978	Representative locations & Wagondrill	BS&T	PP&L	Yes	STS & BS&T	PP&L	.75ksf.	.9ksf.	7.2ksf.	Yoshida	
Montour-Susq. Reloc. ER 122026 Fdns.Designed-1977-78	Center hub at Structure	BS&T	PP&L	Yes	STS & BS&T	PP&L	.4ksf	.75ksf.	7.2ksf.	Terzahi	
Susq.Gen.#1 Leads ER 121242 Fdns.designed-1977-78	Center hub at Structure	BS&T	PP&L	Yes	STS & BS&T	PP&L	.4ksf.	.75ksf.	7.2ksf.	Terzaghi	
Siegfried-Wescosville 2019	Center hub at Structure	BS&T	←								Items of

Note: For more information see Narrative Documentation, Bibliography, and/or ER files and Desig

FOUNDATION DESIGN COVERED BY ALLOWABLE EARTH PRESSURE (AEP) DEFLECTION/ROTATION CRITERIA, OR ANCHOR BOLT LENGTH	GROUNDLINE DEFLECTION OR ROTATION CRITERIA	SPOON BLOWS MODIFIED FOR MAX. PARTICLE DIAMETER	DEVIATION OF BASE REACTIONS: SHEAR	MOMENT	ABAR	AXIAL LOAD	SOIL CLASSIFIED AS GRANULAR & COHESIVE	FACTORS OF SAFETY: SHEAR	MOMENT	AXIAL LOAD	UPLIFT	DEPTH TO FIRST RESISTING MEDIUM	REINFORCING DESIGN
Yes	1"	No	Moment ABAR	Mfgr's. Calcs.	.66 dist. between bottom of X-brace & baseplate	Mfgr's. Calcs.	No	1.06	1.06	1.25	1.25	N/A	
Yes	1" or 0.25¢ & guyed 0.5 tangent	Yes	Mfgr's. Calcs.	Mfgr's. Calcs.	Moment Shear	Mfgr's. Calcs.	Yes	1.06 or 1.1	1.06 or 1.1	1.06 or 1.1	1.56	N/A	
Yes	0.25°-¢ & guyed strs. 0.5° tangents	Yes	Mfgr's. calcs.	Mfgr's. Calcs.	Moment Shear	Mfgr's. Calcs.	Yes	1.1	1.1	1.1	1.5	Yes	
[illegible]	0.25° & 0.5°	Yes	Mfgr's. Calcs.	Mfgr's. Calcs.	Moment Shear	Mfgr's. Calcs.	Yes	1.1	1.1	1.1	1.5	Yes	
Yes	.25°¢ & guyed .5° tangent	Yes	Mfgr's. Calcs.	Mfgr's. Calcs.	Moment Shear	Mfgr's. Calcs.	Yes	1.06	1.06	1.06	1.56	N/A	
Yes	0.25°	Yes	Mfgr's. Calcs.	Mfgr's. Calcs.	Moment Shear	Mfgr's. Calcs.	Yes	1.1	1.1	1.1	1.5	Yes	
Yes	0.25°	Yes	Mfgr's. Calcs.	Mfgr's. Calcs.	Moment Shear	Mfgr's. Calcs.	Yes	1.1	1.1	1.1	1.5	Yes	

f Work Not Performed - Classical Method Used

gn Books.

SUSQUEHANNA SES
RELATED TRANSMISSION LINES
FOUNDATION DESIGN DOCUMENTATIO
TABLE VI

DEVIATION OF BASE REACTIONS					FACTORS OF SAFETY					REINFORCING DESIGN		
SHEAR	MOMENT	ABAR	AXIAL LOAD	SOIL CLASSIFIED AS GRANULAR & COHESIVE	SHEAR	MOMENT	AXIAL LOAD	UPLIFT	DEPTH TO FIRST RESISTING MEDIUM	FLEXURE FORMULA	SHEAR FORMULA	SPLICING
Moment ABAR	Mfgr's. Calcs.	.66 dist. between bottom of X-brace & baseplate	Mfgr's. Calcs.	No	1.06	1.06	1.25	1.25	N/A	As=0.0268M	Not Used	Yes
Mfgr's. Calcs.	Mfgr's. Calcs.	Moment Shear	Mfgr's. Calcs.	Yes	1.06 or 1.1	1.06 or 1.1	1.06 or 1.1	1.56	N/A	Same as Sunbury	Not Used	Yes per ACI Code
Mfgr's. calcs.	Mfgr's. Calcs.	Moment Shear	Mfgr's. Calcs.	Yes	1.1	1.1	1.1	1.5	Yes	As=.0268M 5.5 As=0.022M 6.5 As=0.018M 8.0	per ACI Code	Only in fielf revisions per ACI
Mfgr's. Calcs.	Mfgr's. Calcs.	Moment Shear	Mfgr's. Calcs.	Yes	1.1	1.1	1.1	1.5	Yes	Same as Sunbury	per ACI Code	Only in field revisions per ACI
Mfgr's. Calcs.	Mfgr's. Calcs.	Moment Shear	Mfgr's. Calcs.	Yes	1.06	1.06	1.06	1.56	N/A	Same as Sunbury	Not used	Only in field revisions per ACI
Mfgr's. Calcs.	Mfgr's. Calcs.	Moment Shear	Mfgr's. Calcs.	Yes	1.1	1.1	1.1	1.5	Yes	Same as Sunbury	Not Used	Yes revised per ACI Code
Mfgr's. Calcs.	Mfgr's. Calcs.	Moment Shear	Mfgr's. Calcs.	Yes	1.1	1.1	1.1	1.5	Yes	Same as Sunbury	Not	Yes revised per ACI Code

ssical Method Used

SUSQUEHANNA SES
RELATED TRANSMISSION LINES
FOUNDATION DESIGN DOCUMENTATION
TABLE VI

A.W.Metzer
Jan.1980

9. Insulators and Hardware

Insulators

Standard ANSI approved 5-3/4 x 10" ball and socket type porcelain suspension insulators are used on 500 kV steel pole construction. These insulators are used on 'V' strings, deadends, idler strings and horizontal 'V' assemblies. Classes of insulators used are:

ANSI Class	M&E Rating	Proof Test	Color
52-5	25,000 or 30,000 lbs.	12,500 or 15,000 lbs.	Grey
52-8	36,000 or 40,000 lbs.	18,000 or 20,000 lbs.	Royal Blue

The hardware connections for the two classes of insulators are not compatible between insulators or hardware of different classes. Color coding also helps identify the insulator class and strength to prevent intermixing.

All 'V' string leg, horizontal-'V' leg and vertical strings use 25 insulators. All deadend assemblies use 27 insulators.

Insulator Hardware Assemblies

PP&L utilizes five different types of insulator assemblies for 500 kV steel pole structures:

- Suspension, 'V' String Assembly: These assemblies are used on tangent structures or very small (less than 5°) angles. The specific assembly type is dictated by vertical and horizontal spans. Insulators in this category are Types A, B, C, C-1, D, D-1, AAA, BBB, CCC, and DDD.
- Restrained Angle 'V' String Assembly: These assemblies utilize the 'V' string shape and are used for angles up to 30° (0° to 15° and 16° to 30°). The line break angle and the vertical span dictate the strength of assembly to be used. The assemblies in this category are Types F-outside, G-center, FFF and GGG.
- Idler Assembly: These assemblies are used to support loops on deadend structures. A single string with a weight at the conductor attachment point is employed. These assemblies are Types M and MMM.
- Horizontal-'V' Assembly: These assemblies are used on tangents and small angles (less than 10°) to support conductors from a single pole structure.
- Deadend Assembly: Several deadend configurations are used for high or low tension, twin or triple bundles. Turnbuckles are

employed in each assembly coupled to each subconductor to allow for variation in assembly length to match conductor sags in a bundle. Compression fittings are used for deadends and terminal lugs. Assemblies in this category are the Types H1, HHH, JJJ and KKK.

Application of each suspension and restrained angle assembly must be determined through checking the insulator grading chart as well as checking buckling of the insulator string.

Insulator assembly hardware is purchased from several manufacturers in complete assembly units. Each assembly is made of ten or more sub-components. To achieve interchangeability of components, each supplier is required to design their assembly based on the initial Keystone design. Except for a few minor exceptions, all items are interchangeable between manufacturers. At most, two or three sub-components must be replaced at one time to achieve interchangeability. The Transmission Construction Specifications provides details for the assemblies which note the items that can be interchanged and which items must be replaced with one or two other sub-components at the same time.

Spacers

Spacers are used to stablize the bundle of conductors. Under switching conditions the sub-conductors will attract one another causing bundle collapse. To prevent collapse of the bundle, spacers are installed on specified intervals, no greater than 250' in length, along the span. Twin conductor bundles are horizontally spaced at 18". Either bolted clamps with closed spring spacers or preformed helical rod spacers are employed. The triple bundle application utilizes a configuration of an equilateral triangle with 18" spacing, two conductors on the horizontal plane at the top with one sub-conductor suspended below. The triple bundle application utilizes spacer dampers. These devices are intended to maintain the bundle spacing while reducing aeolian vibration and subspan oscillation.

Dampers

Dampers are employed on the static and twin bundle conductors. Their purpose is to reduce aeolian vibration levels. Several manufacturers have been approved for supply of these dampers. Application of each manufacturer's damper is independent of another. This means that dampers are installed per each manufacturer's recommendation. The same span will require various quantities and different placement locations of dampers dependent on the manufacturer of the damper being installed. Therefore, if two or more damper designs are used on one line, the dampers will be installed in deadend span sections. This is necessary to meet the manufacturer's recommendation for installation as closely as possible.

Armorrods

Preformed armorrods are used at all suspension points on the static and phase conductors. The armorrods are wrapped around the cable at the suspension clamp position. The rods are intended to reduce wear on the conductors due to aeolian vibration at the conductor clamp.

10. Conductor and Overhead Ground Wire Data

In the application of steel pole structures for 500 kV lines, several modifications of the Keystone design for conductors and OHGW cables have taken place. 500 kV construction is characterized by a bundle of conductors for each phase. This bundle arrangement provides for a larger effective Geometric Mean Radius (GMR) than can be obtained by a single larger conductor. The large GMR reduces the surface gradient along the phase wires which in turn reduces the audible noise, RIV, TVI and corona losses.

Lightning protection is achieved through the application of two shield wires. All lines of 500 kV construction on the PP&L system utilize Alumoweld wire for the overhead ground wire. With the exception of the Beltzville Crossing of the Susquehanna-Wescosville 500 kV line which utilizes 19 No. 5 Alumoweld, 19 No. 9 Alumoweld is used for the overhead ground wires. The appropriate electrical and mechanical characteristics of these cables are listed in Tables X and XI.

In the case of the phase conductors, there are three different conductors utilized in two configurations:

Twin bundle - 2493 kcmil 54/37 ACAR

Susquehanna-Stanton 500 kV line
Susquehanna-Wescosville 500 kV line
Susquehanna Generator #2 500 kV leads
Sunbury-Susquehanna #2 500 kV line
South Manheim 500 kV lines
Alburtis-Wescosville 500 kV line (Single Circuit H-frame Portion)

Twin bundle - 1970.7 kcmil 69/37 ACSR

Susquehanna-Wescosville 500 kV line (Beltzville Lake Crossing)

Triple bundle - 1590 kcmil 45/7 ACSR

Alburtis-Wescosville 500 kV line (Double Circuit and Single Circuit -Single Shaft Portions)

The twin bundle 2493 kcmil 54/37 ACAR is the bundle configuration developed by the Keystone Design Committee. For the long span application at the Beltzville Crossing a higher strength conductor was required. The 1970.7 kcmil 69/37 ACSR is to provide the mechanical and electrical properties required for this application. Two situations on the Alburtis-Wescosville 500 kV line necessitate the application of triple bundle conductors to achieve desirable audible noise levels. First, in the double circuit application, depending on the line phasing, a wet conductor may cause audible noise levels higher than levels which are desirable based on operating experience. Secondly, a portion of the line utilizes a 140' easement (200' is the standard 500 kV easement). To achieve desirable AN levels on this section of the line, a triple bundle conductor is required.

The accompanying Table VII, VIII, IX provide the parameters for each conductor and overhead ground wire.

TABLE VII

CABLE DATA

CONDUCTOR - 2,493 MCM, 54/37, ACAR

Physical Data	
Nominal diameter, in.	1.821
Weight per foot, lb	2.341
Area, sq. in.	1.958
Number of strands	91
EC aluminum	54
6201 aluminum allow	37
EC strand diameter, in.	0.1655
EC strand area, sq. in.	0.02151
6201 strand diameter, in.	0.1655
6201 strand area, sq. in.	0.02151
Mechanical Data	
Rated ultimate strength, lb.	63,000
Modulus of elasticity, final psi	8,286,000
Modulus of elasticity, initial, psi	6,500,000
Coefficient of linear expansion per degree F	0.0000128
Creep constants	
K	0.608×10^{-13}
M	2.10
N	0.275
EC strand wire	
Tensile strength, minimum, psi	
Individual tests	23,000
Average for lot	24,000
Minimum elongation, per cent in 10 in.	2.0
6201 strand wire	
Tensile strength, minimum psi	46,000
Stress at 1 percent extension, minimum psi	44,160
Ultimate elongation, minimum percent in 10 in.	3.0
Electrical Data	
Circular mils	2,843,000
Circular mils, 62% equivalent EC	2,345,000
EC strand wire, cm	27,390
6201 strand wire, cm	27,390
Conductivity, percent IACS, minimum	
EC aluminum	62
6201 alloy	52.5
Temperature coefficient of resistance, per deg. C at 20 C	
EC aluminum	0.00401
6201 alloy	0.00352

Electrical Data (Cont.)

Current carrying capacity, amperes, based on 50 C rise over 25 C ambient with 2 fps cross wind	1,870
Inductive reactance, Xa, 60 cycles, ohms/mile	0.34193
Capacitive reactance, Xa', 60 cycles, megohm mile. 18 in spacing	0.0322
Resistance	
D-C ohms per mile at 20 C	0.038259
A-C ohms per mile	
at 20 C	0.0451
at 50 C	0.0490
at 100 C	0.0554

Design Data

Conductor tensions are limited to the following range:

20 percent of ultimate strength at bare cable, no wind, 0°F, final sag condition

50 percent of ultimate strength with 1 in. ice and 8 lb. at 0°F

60 percent of ultimate strength at 1½ in. radial ice, no wind, 0°F, final sag condition

Reel Data

Overall diameter, in.	96
Drum diameter, in.	42
Inside width, in.	60
Overall width, in.	68.5
Hub	
Diameter, in.	5¼
Length inside, in.	3¼
Maximum cable length for full reel, ft.	6,665
Weight, lb.	
Empty	1,620
With wrapping	1,675
With wrapping and lagging	2,220
Shipping, full reel	17,823

TABLE VIII

CABLE DATA

CONDUCTOR - 1,970.7 kcmil 69/37 ACSR

Physical Data

Nominal diameter, in.	1.802
Weight per foot, lb	3.128
Area, sq. in.	1.577
Number of strands	106
EC aluminum	69
Steel	37
EC strand diameter, in.	0.1690
EC strand area, sq. in.	
Steel strand diameter, in.	0.1127
Steel strand area, sq. in.	

Mechanical Data

Rated ultimate strength, lb.	102,600
Modulus of elasticity, final psi	
Modulus of elasticity, initial, psi	
Coefficient of linear expansion per degree F	
Creep constants	
K	
M	
N	
EC strand wire	
Tensile strength, minimum, psi	
Individual tests	23,000
Average for lot	24,000
Minimum elongation, per cent in 10 in.	2.0
Steel strand wire	
Tensile strength, minimum psi	46,000
Stress at 1 percent extension, minimum psi	44,160
Ultimate elongation, minimum percent in 10 in.	3.0

Electrical Data

Circular mils	2,843,000
Circular mils, 62% equivalent EC	2,345,000
EC strand wire, cm	27,390
Steel strand wire, cm	27,390
Conductivity, percent IACS, minimum	
EC aluminum	61
Steel	8
Temperature coefficient of resistance, per deg. C at 20 C	
EC aluminum	
Steel	

Electrical Data (Cont.)

Inductive reactance, Xa, 60 cycles, ohms/mile	0.3364
Capacitive reactance, Xa', 60 cycles, megohm mile. 18 in spacing	0.0768
Resistance	
D-C ohms per mile at 25 C	0.0464
A-C ohms per mile	
at 25 C	0.0491
at 50 C	0.0535
at 100 C	0.0623

Design Data

Conductor tensions are limited to the following range:

20 percent of ultimate strength at bare cable, no wind, 0°F, final sag condition

50 percent of ultimate strength with 1 in. ice and 8 lb. at 0°F

60 percent of ultimate strength at 1½ in. radial ice, no wind, 0°F, final sag condition

Reel Data

Overall diameter, in.	96
Drum diameter, in.	42
Inside width, in.	60
Overall width, in.	68.5
Hub	
Diameter, in.	5¼
Length inside, in.	3¼
Maximum cable length for full reel, ft.	
Weight, lb.	
Empty	1,620
With wrapping	1,675
With wrapping and lagging	2,220
Shipping, full reel	

TABLE IX

CABLE DATA

CONDUCTOR - 1590 kcmil 45/7 ACSR

Physical Data	
Nominal diameter, in.	1.504
Weight per foot, lb	1.792
Area, sq. in.	1.335
Number of strands	52
EC aluminum	45
Steel	7
EC strand diameter, in.	0.1880
EC strand area, sq. in.	0.0278
Steel strand diameter, in.	0.1253
Steel strand area, sq. in.	0.0123
Mechanical Data	
Rated ultimate strength, lb.	42,200
Modulus of elasticity, final psi	11,223,690
Modulus of elasticity, initial, psi	
Coefficient of linear expansion per degree F	0.0000128
EC strand wire	
Tensile strength, minimum, psi	
Individual tests	23,000
Average for lot	24,000
Minimum elongation, per cent in 10 in.	2.0
Steel strand wire	
Tensile strength, minimum psi	190,000
Stress at 1 percent extension, minimum psi	160,000
Ultimate elongation, minimum percent in 10 in.	5.0
Electrical Data	
Circular mils	1,699,722
Circular mils, 62% equivalent EC	
EC strand wire, cm	35,343
Steel strand wire, cm	15,700
Conductivity, percent IACS, minimum	
EC aluminum	61
Temperature coefficient of resistance, per deg. C at 20 C	
EC aluminum	0.00403
Current carrying capacity, amperes, based on 40 C rise over 40 C ambient with 2 fps cross wind and emissivity factor of 0.5 without sun	1,335

Electrical Data (Cont.)

Inductive reactance, Xa, 60 cycles, ohms/mile	0.364
Capacitive reactance, Xa, 60 cycles, megohm mile. 18 in spacing	0.0822
Resistance	
D-C ohms per mile at 20 C	0.05755
A-C ohms per mile	
at 20 C	0.0623
at 50 C	0.0678
at 75 C	0.0734

Design Data

Conductor tensions are limited to the following range:

20 percent of ultimate strength at bare cable, no wind, 0°F, final sag condition

50 percent of ultimate strength with 1 in. ice and 8 lb. at 0°F

60 percent of ultimate strength at 1½ in. radial ice, no wind, 0°F, final sag condition

Reel Data

Overall diameter, in.	96
Drum diameter, in.	42
Inside width, in.	60
Overall width, in.	68.5
Hub	
Diameter, in.	5¼
Length inside, in.	3¼
Maximum cable length for full reel, ft.	6,665
Weight, lb.	
Empty	1,620
With wrapping	1,675
With wrapping and lagging	2,220
Shipping, full reel	14,163

TABLE X

CABLE DATA

OVERHEAD GROUND WIRE - 19 NO. 9 ALUMOWELD

Physical Data

Nominal diameter, in.	.572
Weight per foot, lb	.5658
Area, in sq. in.	.1954
Number of strands	19
Strand diameter, in.	0.1144
Strand area, sq. in.	0.01028

Mechanical Data

Rated ultimate strength, lb.	34,290
Modulus of elasticity, final, psi	23,000,000
Modulus of elasticity, initial, psi	20,500,000
Coefficient of linear expansion per degree F	0.0000072

Electrical Data

Circular mils	248,800
Resistance	
ra, d-c at 20 C, ohms per mile	1.098
ra, 60 cycles, a-c at 20 C, ohms per mile	1.120
Inductive reactance, Xa, 60 cycles, a-c at 1 ft. spacing, ohms per mile	0.701
Shunt capacitive reactance, x'a, 60 cycles a-c at 1 ft. spacing, megohms per mile	0.1109

Design Data

Ground wire tensions are limited to the following range:

20 percent of ultimate strength at bare cable, no wind, 0°F, final sag condition

50 percent of ultimate strength with 1 in. ice and 8 lb. at 0°F

60 percent of ultimate strength at 1½ in. radial ice, no wind, 0°F, final sag condition

Reel Data

Nominal length of strand, ft.	6,700
Net weight of strand, lb	3,791

Reel Data (Cont.)

Weight of reel and lagging, lb	520
Total shipping weight, lb	4,311
Diameter of head, in.	56
Diameter of drum, in.	36
Traverse width, in.	39-5/16
Overall width, in.	44
Arbor hole diameter, in.	3

TABLE XI

CABLE DATA

OVERHEAD GROUND WIRE - 19, NO. 5 ALUMOWELD

Physical Data

Nominal diameter, in.	0.910
Weight per foot, lb	1.430
Area, in sq. in.	0.4940
Number of strands	19
Strand diameter, in.	0.1819
Strand area, sq. in.	0.02600

Mechanical Data

Rated ultimate strength, lb.	73,350
Modulus of elasticity, final, psi	23,000,000
Modulus of elasticity, initial, psi	20,500,000
Coefficient of linear expansion per degree F	0.0000072

Electrical Data

Circular mils	628,900
Resistance	
ra, d-c at 20 C, ohms per mile	0.4342
ra, 60 cycles, a-c at 25 C, ohms per mile	0.4507
Inductive reactance, Xa, 60 cycles, a-c at 1 ft. spacing, ohms per mile	0.645
Shunt capacitive reactance, x'a, 60 cycles a-c at 1 ft. spacing, megohms per mile	0.0971

Design Data

Ground wire tensions are limited to the following range:

20 percent of ultimate strength at bare cable, no wind, 0°F, final sag condition

50 percent of ultimate strength with 1 in. ice and 8 lb. at 0°F

60 percent of ultimate strength at 1½ in. radial ice, no wind, 0°F, final sag condition

Reel Data

Nominal length of strand, ft.	6,700
Net weight of strand, lb	9,580
Weight of reel and lagging, lb	520

Reel Data (Cont.)

Total shipping weight, lb	10,100
Diameter of head, in.	56
Diameter of drum, in.	36
Traverse width, in.	39-5/16
Overall width, in.	44
Arbor hole diameter, in.	3

11. Counterpoise & Grounding

A two step grounding and counterpoise system is applied to reduce ground resistance to approximately 25 ohms.

Prior to 1977 the steps consisted of:

1. Installation of a driven ground rod at the bottom or side of each structure foundation. Each ground rod is connected to the steel tower leg or pole. The resistance of the foundation with all piers interconnected is measured.

2. If the resistance of the foundation is greater than 25 ohms, a couterpoise, 500 feet in length (250 feet on each side of the structure) is buried along the line.

In 1977, the method of grounding the tower leg was changed to include the foundation concrete. The steps are as follows:

1. All metal components in the concrete, the anchor bolts and reinforcing cage, are bounded together and leads connected to the steel tower or pole outside the concrete. The resistance of the foundation with all piers interconnected is measured.

2. If the resistance of the foundation is greater than 25 ohms, counterpoise up to a total of 500 feet (250 feet on each side of structure) is installed.

Lengths greater than this do not have an advantage in determining the lightning outage rate. If an isolated high resistance is encountered, there is no need to reduce the resistance, other than installing the initial counterpoise. The increased outage rate of this high resistance structure has a small effect on the entire line outage rate.

If there is a large group of structures with high resistances, there may be an effect on the outage rate and this should be investigated. An increase in the number of insulators may be more economical than additional grounding.

Grounding and bonding wires are 3/8 inch high strength galvanized steel. The buried counterpoise is installed at a depth of 18" in uncultivated areas and 24" in cultivated areas. The counterpoise avoids roadways and underground facilities such as electric conduits and cables, telephone lines, sewers, water lines, storm drains, and gas and oil pipelines.

12. Electric & Magnetic Field Effects

The electric and magnetic field effects of 500 kV lines are shown in Table XII.

PP&L has operated 95 miles of single circuit 500 kV line since 1966. A portion of this mileage consists of two single circuit lines on 150 foot center lines. These circuits result in the maximum exposure to electric and magnetic field effects experienced by PP&L Company.

Magnetic Flux Density 0.96 gauss
Electric Field Gradient 9.9 kV per meter
Wet Conductor Audible Noise 55.0 dba
Heavy Rain Radio Interference 77.9 db

Experience since 1966 has resulted in few complaints. All but one consisting of complaints of spark discharges from ungrounded objects. Grounding these objects eliminated the complaints. The remaining one was a listener in a remote fringe area with poor radio reception for one station during early morning and late afternoon hours. The radio station changed its antenna pattern during these hours and as a result the signal was not as strong as during the remaining hours of the day. The transmission line did reduce the reception from Class B to Class C standards.

The steel pole transmission lines have field effects of equal magnitude to those experienced with the exception of the double circuit structures and the single circuit single poles. These structures have audible noise levels of approximately 60 dba when a two conductor bundle is used. To alleviate this condition, a three conductor bundle has been selected for the single pole structure and for double circuit structures when they are used in urban areas and areas where potential for development exists.

The phasing that gives the lowest electric field gradient for the double circuit structures shall be selected so as not to exceed 11 kV per meter.

Phasing arrangements must be checked when using these configuration on multicircuit right-of-ways. A rule of thumb is not to have like phases opposite each other.

All fences and other metallic structures on the right-of-way will be grounded in accordance with existing engineering standards.

Should a radio and television reception problem be evident, it will be investigated and corrected if it is definitely shown to be caused by the transmission line.

RJG:pd/47P-A

TABLE XII

500 KV TRANSMISSION
ELECTRIC AND MAGNETIC FIELD EFFECTS

Operating voltage 525 kV
Phase current 4600 amperes
2-2493 kcmil ACAR conductors per phase except * is 3-1590 kcmil ACSR conductors per phase.

Line Description	Ground Clearance Feet	Magnetic flux density gauss			Electric Field Gradient Kv/m			Wet Conductor AN – dBA		Heavy Rain RI – dB	
		Max	Left R/W Edge	Right R/W Edge	Max	Left R/W Edge	Right R/W Edge	Left R/W Edge	Right R/W Edge	Left R/W Edge	Right R/W Edge
Tower Line											
Single circuit	33	0.93	0.19	0.19	9.0	1.63	1.63	53.2	53.2	73.0	73.0
Single circuit (keystone)	31	1.00	0.19	0.19	9.8	1.56	1.56	53.8	53.8	74.0	74.0
Double circuit											
A A C B B C	33	0.85	0.20	0.20	10.8	1.39	1.39	58.2	58.2	78.4	78.4
A A C B A C	33	0.56	0.13	0.13	6.9	1.23	1.23	61.0	61.0	80.2	80.2
Single Pole Line *											
Single circuit	30	0.69	0.17	0.19	9.8	2.30	1.88	45.2	46.6	64.8	67.1
Single circuit "H"	30	1.01	0.19	0.19	9.8	1.56	1.56	53.7	53.7	74.0	74.0

Heavy Rain is at 1000 kHz

TABLE XII

500 KV TRANSMISSION
ELECTRIC AND MAGNETIC FIELD EFFECTS

Operating voltage 525 kV
Phase current 4600 amperes
2-2493 kcmil ACAR conductors per phase except * is 3-1590 kcmil ACSR conductors per phase.

Line Description	Ground Clearance Feet	Magnetic flux density gauss			Electric Field Gradient Kv/m			Wet Conductor AN - dBA		Heavy Rain RI - dB	
		Max	Left R/W Edge	Right R/W Edge	Max	Left R/W Edge	Right R/W Edge	Left R/W Edge	Right R/W Edge	Left R/W Edge	Right R/W Edge
Double circuit "H" One circuit initial	30	0.90	0.06	0.22	9.5	0.53	2.06	53.8	55.8	75.3	81.2
A A C B B C		1.12	0.18	0.18	13.3	1.99	1.99	55.0	55.0	81.0	81.0
A B C B A C		0.90	0.16	0.16	9.2	1.91	1.91	60.1	60.1	83.7	83.7
Double circuit "H" *	30										
One circuit initial		0.86	0.06	0.21	10.1	0.57	2.31	42.5	44.3	62.4	68.2
A A C B B C		1.08	0.18	0.18	14.1	2.24	2.24	42.1	42.1	67.9	67.9
A B C B A C		0.87	0.16	0.16	9.8	2.16	2.16	50.1	50.1	70.8	70.8

Heavy Rain is at 1000 kHz

TABLE XII

500 KV TRANSMISSION
ELECTRIC AND MAGNETIC FIELD EFFECTS

Operating voltage 525 kV
Phase current 4600 amperes
2-2493 kcmil ACAR conductors per phase except * is 3-1590 kcmil ACSR conductors per phase.

Line Description	Ground Clearance Feet	Magnetic flux density gauss			Electric Field Gradient Kv/m			Wet Conductor AN - dBA		Heavy Rain RI - dB	
		Max	Left R/W Edge	Right R/W Edge	Max	Left R/W Edge	Right R/W Edge	Left R/W Edge	Right R/W Edge	Left R/W Edge	Right R/W Edge
Multi line R/W's											
2 single circuit											
Tower Lines	31										
150' between ℄											
ABC ABC		0.96	0.22	0.22	9.9	1.63	1.63	55.0	55.0	77.9	77.9
ABC CAB		1.02	0.18	0.18	10.3	1.58	1.58	54.5	54.5	77.8	77.8
125' between ℄											
ABC ABC		0.96	0.23	0.23	9.9	1.65	1.65	55.6	55.6	78.1	78.1
ABC CAB		1.02	0.18	0.18	12.4	1.58	1.58	54.7	54.7	77.9	77.9
100' between ℄											
ABC ABC		0.96	0.24	0.24	10.0	1.66	1.66	57.7	57.7	79.2	79.2
ABC CAB		1.03	0.18	0.18	14.5	1.60	1.60	55.1	55.1	78.1	78.1

Heavy Rain is at 1000 kHz

TABLE XII

500 KV TRANSMISSION
ELECTRIC AND MAGNETIC FIELD EFFECTS

Operating voltage 525 kV
Phase current 4600 amperes
2-2493 kcmil ACAR conductors per phase except * is 3-1590 kcmil ACSR conductors per phase.

Line Description	Ground Clearance Feet	Magnetic flux density gauss			Electric Field Gradient Kv/m			Wet Conductor AN - dBA		Heavy Rain RI - dB	
		Max	Left R/W Edge	Right R/W Edge	Max	Left R/W Edge	Right R/W Edge	Left R/W Edge	Right R/W Edge	Left R/W Edge	Right R/W Edge
Multi line R/W's 125' between ℄											
Left line - single H	40										
Right line - double H	34										
C B ABC A B A C		0.64	0.15	0.20	8.0	1.68	2.44	59.3	62.0	79.6	85.0
A B ABC B C A C		0.65	0.14	0.21	8.3	1.75	2.15	59.0	61.7	79.3	84.3
B B ABC C A A C		0.73	0.12	0.14	11.0	1.63	2.06	54.7	55.6	78.1	81.3
A B ABC C B A C		0.66	0.13	0.14	10.4	1.73	2.01	57.7	60.4	78.8	83.9

Heavy Rain is at 1000 kHz

13. Lake Crossing

General Location

The line crosses the Beltzville Lake approximately 2.7 miles east of the Beltzville Dam; the lake is approximately 1500 ft wide at the crossing. (shoreline to shoreline).

Beltzville Lake is northeast of the Pennsylvania Turnpike and Route 209 intersection in Towamensing and Franklin Townships, southeast quadrant of Carbon County, eastern Pennsylvania. Location on Pohopoco Creek about 4.5 miles above its confluence with the Lehigh River. At normal conservation pool level, the lake covers over 947 acres. Recreational boating of all types is afforded by the reservoir in addition to the water supply and flood control aspects of the facility.

In relation to Susquehanna Station and Siegfried Substation, Beltzville Lake is approximately 35 miles southeast and 11 miles north, respectively.

Landscape

The topography of the land transversed by the line is illustrated on figure 3.9 - B2 in Pennsylvania Power and Light Company's Susquehanna Steam Electric Station Applicants' Environmental Report - Amendment No. 5 July 1976 (Amendment No. 5 in future references). Specifically, two miles north of the crossing the elevation approaches 1500 ft. above sea level then gradually slopes downward to approximately 800 ft. one-half mile from the center of the lake at the crossing which is 651 feet at "top of flood control pool elevation". The southern approach to the crossing is exactly the same as the north. Refer to drawing LE-83849 Sheets 6 and 7 for plan and profile of this line section.

Man-made features in the area consist of the East Palmerton-Wagners 66 kV line (see E-155884 Sheet 2 for reconstruction) built in the 1950's. The 500 kV centerline is 150 ft. west of the reconstructed East Palmerton-Wagners 138 kV centerline. In addition, two pipelines (Mobil Oil and Buckeye Co.) are located within a 1500 ft. distance east of the 138 kV centerline.

The area is mainly a forested, rural environment with land use dictated by Department of Environmental Resources for a State Park.

Transmission Line

The standard 500 kV line built by Pennsylvania Power and Light Company is a Steel Tower or Steel Pole Structure equipped with 2 static wires: 19 No. 9 AWG Alumoweld conductor, and 2-bundled Power conductors per phase: 2493 kcmil ACAR 54/37 conductor. For further details see previous sections of this report under conductor data and structure sections.

The line route was selected to minimize costs and environmental impacts. In environmentally sensitive areas, such as Beltzville State Park, appropriate engineering and construction techniques were used. Amendment 5 in Parts V and Vl discusses the route impacts.

The PP&L Standard 500 kV design was used on the 54 mile Susquehanna-Siegfried line except for the three-span (4930 ft.) section for the Beltzville crossing.

The change in design across Beltzville Lake was required, because the terrain adjacent to the Lake is not elevated and the long span would have needed structures higher then 200 feet to maintain NESC clearances.

The "Top of Flood Control Pool Elevation" of the lake is 651 ft. according to the Army Corps of Engineer's specification ER1110-2-4401 Section 4. The power conductor for the 500 kV line must be 58 ft. above the 651 ft. elevation at maximum final sag.

To achieve the necessary clearances using 2493 kcmil ACAR 54/37 would require a structure exceeding 250 ft. and 240 ft. on the south and north side of the Lake, respectively. This would require lighting and/or special painting of the structures resulting in increased environmental impacts. Therefore, a special conductor was used to permit the use of structures less than 200 ft. high in order to eliminate structure treatment and minimize environmental impacts. The basic design requirements were submitted to approved suppliers for bids:

- 3,470 amps. per phase at maximum thermal loading condition of 100°C for ACAR, 125°C for ACSR, or 200°C for SSAC conductor at 35°C, zero knots wind ambient conditions. The loading is the summer normal rating based on the PJM conductor rating method (see attached IEEE conference paper No. 74-003-0). The current shall be considered equally divided between the subconductors in the conductor bundle.

- The conductor may be composed of two or three subconductors. The minimum conductor dia. shall be 1.8" for two subconductor and .7" for three subconductor bundles.

- The maximum subconductor tension shall not exceed 60% of the ultimate strength at 1.5" ice, zero degrees F, and zero pounds wind loading condition.

- The maximum conductor sag shall not exceed 135' in the 2,620' crossing span under the above requirements.

Bids received were for the following conductor types:

- 2 subconductors of 1970 kcmil 69/37 ACSR

- 2 subconductors of 2505 kcmil 84/19 AACSR
- 2 subconductors of 2250 kcmil 84/19 AACSR
- 3 subconductors of 875.1 kcmil 54/37 ACSR
- 3 subconductors of 1138 kcmil 36/37 ACSR

Since all of the conductors listed fulfilled the specifications, other factors determined the preferred conductor type to use:

- 3 subconductors type involved greater weight & visual impact.
- 2 subconductors 2505 kcmil 84/19 AACSR and 2250 kcmil AACSR were eliminated due to manufacturing difficulty, and handling ability during construction.

Additional comments and bid prices are available in the Bulk Power Department's confidential files Purchase Recommendation EE-4930 (Sept. 7, 1977).

The conductor selected for the Crossing was 1970 kcmil (69/37) ACSR. At the time of the conductor purchase, a spare phase of 2 subconductors of 1970 kcmil (69/37) ACSR was acquired to be used in the event of a phase wire failure on the Beltzville Crossing. A sufficient length was provided to guarantee that it could also be used on the 3 Mile Island-Peach Bottom 500 kV Line river crossing for a phase wire failure, since this conductor is similar to the 2505 kcmil 84/19 AACSR used on the river crossing.

Engineering data for the 1970 kcmil 69/37 ACSR can be found in the conductor data section of this report.

Spacers and dampers were provided by the conductor manufacturer along with engineering to determine their location. Aircraft marker spheres were installed on the OHGW's according to the Federal Aviation Administrations guidelines. Design locations for spacers and marker spheres are shown on Plan and Profile print LE-83849 Sheet 6 and 7 and Damper locations are on print A-176042 (1970 kcmil 69/37 ACSR) and A-176043 (19 No. 5 AWG Alumoweld).

pd/47P-A

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Appendix A

Supporting Calculations and Information

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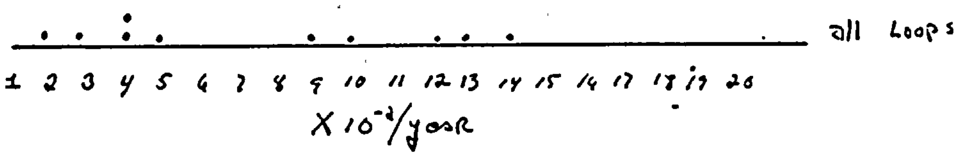
PROJECT Diesel Generator LCO extension

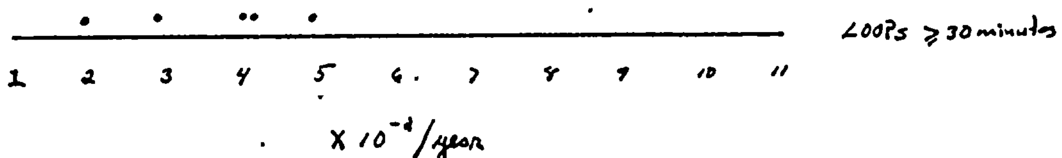
Computation of Initiating Event Frequency and Function Unavailability used in the Event Tree Quantification.

1. Loss of offsite power frequency, f_1

several references were surveyed to obtain the LOOP frequency.

ref					
6		WASH-1400	0.04/year		
5		NUREG/CR-2497	0.041/year		
4		NUREG/CR-3591	0.019/year *	5.2E-3	4.7E-2
4		NUREG/CR-3591	0.028/year **	9.0E-3	6.2E-2
1		NSAC-80	0.049/year		
1	†	NSAC-80	0.088/year		
9	†	Frank Clark ***	0.13/year		
9		Frank Clark	0.098/year		
12	†	EPRI NP-801	0.14/year	0.08	0.15
13	†	EPRI NP-2230	0.12/year	0.07	0.17





The median value of these estimates greater than 30 minutes is 0.04/year. This value is chosen for analysis.

† includes all LOOP's not just those in excess of 30 minutes

* LOOP at BWR plants only

** LOOP at PWR plants only

*** personal communication between C. Kukielka and F. Clark (1981)

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Emergency AC Power

A fault tree of the emergency power system was drawn to estimate the emergency power unavailability. Loss of onsite AC is an and gate of all the ESS buses. Inspection of the tree indicates that "Insufficient Cooling to the Diesels" is common to all buses. Also A·A = A. Therefore, the cutset of this top event are generated to estimate the Emergency Power unavailability

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Insufficient cooling to the diesel generators

1 ICTTD = ESWTAF • TF
2 ESWTAF = ESWAPF + ESWAVF + ESWACF
3 ESWAPF = NFPA • NFPC
4 NFPA = 1A201 + PAF + PDVAF + 1A201
5 NFPC = 1A203 + PCF + PDVCF + 1A201

3 =

singles	doubles
1A201	1A203 • PAF
	1A203 • PDVAF
	PAF • PCF
	PCF • PDVAF
	PAF • PDVCF
	PDVAF • PDVCF

6 ESWAVF = 1A201 + TABPVF
7 ESWACF = 1A201 + TFF
2 ESWTAF =

single	double
1A201	1A203 • PAF
TABPVF	1A203 • PDVAF
TFFA	PAF • PCF
	PCF • PDVAF
	PAF • PDVCF
	PDVAF • PDVCF

8 TF = ESWTBF + DCVTF
Train B is similar to train A ∴

ESWTBF =

single	doubles
1A202	1A204 • PBF
TBBPVF	1A204 • PDVBF
TFFB	PBF • PDF
	PDF • PDVBF
	PBF • PDVDF
	PDVBF • PDVDF

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Insufficient cooling to the diesel generators (continued)

1 ICTTD = ESWTAF · TF

doubles	triples	quad	quint
1A201 · 1A202			
1A201 · TBBPVF	24 + 18 combinations		
1A201 · TFFB			
TABPVF · 1A202			
TABPVF · TBBPVF			
TFFB · TFFA			
TFFA · 1A202			
TFFA · TBBPVF			
TFFB · TABPVF			
1A201 · TF			
TABPVF · TF			
TFFA · TF			

9 L1A201 = DGAFEB + B1A201F
10 DGAFEB = ICTTD + 1A201
9 L1A201 = ICTTD + 1A201 + B1A201F
11 L1A202 = ICTTD + 1A202 + B1A202F
12 L1A203 = ICTTD + 1A203 + B1A203F
13 L1A204 = ICTTD + 1A204 + B1A204F

14 L2A201 = ICTTD + 2A201 + B2A201F
15 L2A202 = ICTTD + 2A202 + B2A202F
16 L2A203 = ICTTD + 2A203 + B2A203F
17 L2A204 = ICTTD + 2A204 + B2A204F

note that ICTTD is common to all buses therefore it clearly dominates the failures since the top event is an and and gate.

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Insufficient cooling to the diesel generators (continued)

18 1A201 = DGAFTS + DGAFTR10 + B1A201F

19 1A202 = DGBFTS + DGBFTR10 + B1A202F

20 1A201 · 1A202 =

			ref
DGAFTS · DGBFTS	2.3×10^{-3} /d	2.3×10^{-3}	1
DGAFTS · DGBFTR10	$4.0\times10^{-2}\cdot3\times10^{-2}$	1.2×10^{-3}	3
DGAFTS · B1A202F	$4.0\times10^{-2}\times10^{-3}$	4×10^{-5}	1, 2
DGAFTR · DGBFTS	$3\times10^{-2}\cdot4.0\times10^{-2}$	1.2×10^{-3}	3
DGAFTR10 · DGBFTR10	$3\times10^{-2}\cdot3\times10^{-2}$	9.1×10^{-4}	
DGAFTR · B1A202F	$3\times10^{-2}\cdot10^{-3}$	3×10^{-5}	
B1A201F · DGBFTS	$10^{-3}\cdot4\times10^{-2}$	$.4\times10^{-5}$	1, 2
B1A201F · DGBFTR10	10^{-3} 3×10^{-2}	3×10^{-5}	
B1A201F · B1A202F	$10^{-3}\cdot10^{-3}$	10^{-6}	2
		~~2.64×10^{-3}~~ ck.	
		5.74×10^{-3}	

1. Dependent failure of diesel generators, T. Mankamo, U. Pulkkinen Nuclear Safety Vol 23 # 1, 1982.

2 NUREG-0492

3. Frank Clark correspondence.

Unavailability of a.c. power is dominated by ICTTD.

1A201 · 1A202		5.7×10^{-3}
1A201 · TBBPVF	$7\times10^{-2}\cdot10^{-3}$	7×10^{-5}
1A201 · TFFB	7×10^{-2} 10^{-5}	7.0×10^{-7}
TABPVF · 1A202		7×10^{-5}
TBBPVF · TABPVF	10^{-3} 10^{-3}	10^{-6}
TFFA · TFFB		10^{-10} ∈
TFFA · TBBPV		∈
TFFB · TABPV		∈
1A201 · TF	$7\times10^{-2}\cdot$ TF (10^{-4})	7×10^{-6}
TABPVF · TF		3×10^{-7}
TFFA · TF		∈
		5.8×10^{-3}

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Diesel generator fails to run during LOOP

No diesel failures to run were identified in the ASP work.

Frank Clark work.

cell		failure in cell	# of emissions loading at last in the cell	Total time in cell	f/t
0 ≤ t < 1		111	49	52.4 hours	0.037/hr
1 ≤ t < 2		0	19	67 hours	0
2 ≤ t < 3		0	24	70 hours	
3	4	0	14	52 hours	
4	5	0	5	89 hours	
5	6	0	4	59 hours	
6	7	0	4	41 hours	
7	8	0	3	46 hours	
8	9	0	2	36	
9	10	0	2		
10	11	0	2		
11	12	0	2		
12	13		2		
13	14		2		
14	15		2		
15	16		2		
16	17	0	2		
17	18	0	2		
18	19	0	1		
19	20	0	1		
20	21	0	1		
21	22	0	1		
22	23				

Total time on test. 198 hours.

3 failures / 198 hours = 1.5×10^{-2} / hours

NUREG 0492 3×10^{-3} / hour

all three failures were in at C.Y. during the same event. :
support work 1400 # - Failure to run 10 hrs = 3×10^{-2}/

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Consideration of Repair.

Repair was considered for cut sets if two conditions were met.

1. Enough time existed to perform the repair, and
2. Repair of the component had an impact on the calculation.

The onsite a.c. power system unavailability is dominated by insufficient cooling to the diesels. Cut sets of this failure mode were examined to identify repairable items.

	cut set	component MTTR	allowable	$1-e^{-\frac{T}{MTTR}}$	repairable
1.	DG_FT_ · DG_FT_ (A/B, S/R, A/B, S/R)	20 hours	1 hour w/o HPM 8 hours w HPM	4.88×10^{-2} 3.3×10^{-1}	no
2.	B1A201F · B1A202F (A/B)	1.32 hours	1 hour w/o HPM 8 hours w/ HPM	5.31×10^{-1} 9.5×10^{-1}	
3.	TADPVF · TBDPVF	6 hours	1 hour w/o HPM 8 hours w HPM	1.54×10^{-1} 7.36×10^{-1}	

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Repairable Component.

cut set	failure probability	probability component won't be repaired HPM failure	HPM summer	revised failure probability HPM failure	HPM summer
DGAFTS·DGBFTS	2.3×10^{-3}	1	1	2.3×10^{-3}	2.3×10^{-3}
DGAFTS·DGBFTR10	1.2×10^{-3}	0.95	0.67	1.14×10^{-3}	8.0×10^{-4}
DGAFTS·B1A202F	4.0×10^{-5}	0.47	0.02	1.88×10^{-5}	8×10^{-7}
DGAFTR10·DGBFTS	1.2×10^{-3}	0.95	0.67	1.14×10^{-3}	8×10^{-4}
DGAFTR10·DGBFTR10	9.0×10^{-4}	0.95	0.67	8.55×10^{-4}	6×10^{-4}
DGAFTR10·B1A202F	3.0×10^{-5}	0.47	0.02	1.41×10^{-5}	6×10^{-7}
B1A201F·DGBFTS	4.0×10^{-5}	0.47	0.02	1.88×10^{-5}	8×10^{-7}
B1A201F·DGBFTR10	3.0×10^{-5}	0.47	0.02	1.41×10^{-5}	6×10^{-7}
B1A201F·B1A202F	10^{-6}	0.47	0.02	4.7×10^{-7}	2×10^{-8}
				5.45×10^{-3}	4.5×10^{-3}

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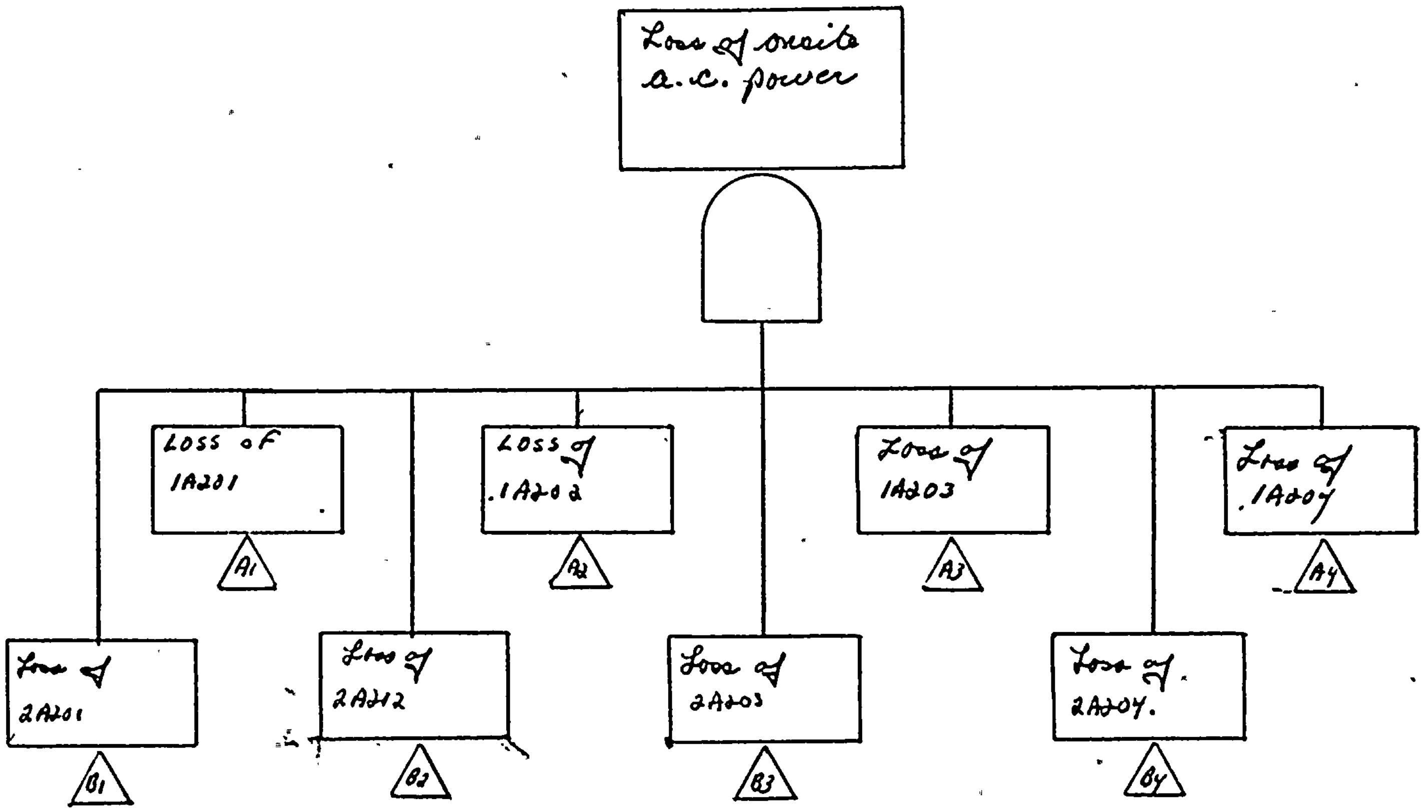
The situation of LCO must also be considered. Since the emergency power system is divisional, only one division will be examined and it is assumed this number also describes the other division

cut sets	failure probability	probability component will be required: HPM failure	probability component will be required: HPM success	resulting probability: HPM failure	resulting probability: HPM success
DGAFTS	4.0×10^{-2}	1	1	4.0×10^{-2}	4.0×10^{-2}
DGAFTR10	3.0×10^{-2}	0.95	0.67	2.85×10^{-2}	2.0×10^{-2}
B1A201F	1.0×10^{-3}	0.05	0.002	5×10^{-5}	2×10^{-6}
TABPVF	1.0×10^{-3}	1	1	1.0×10^{-3}	1.0×10^{-3}
TFFA	3.0×10^{-4}	1	1	3.0×10^{-4}	3.0×10^{-4}
				ck ~~6.8~~ 7.0 $\times 10^{-2}$	6.1×10^{-2}

The unavailability of emergency power then becomes

Emergency power	Normal	LCO
HPM success	4.5×10^{-3}	6.1×10^{-2}
HPM failure	5.4×10^{-3}	6.8×10^{-2}



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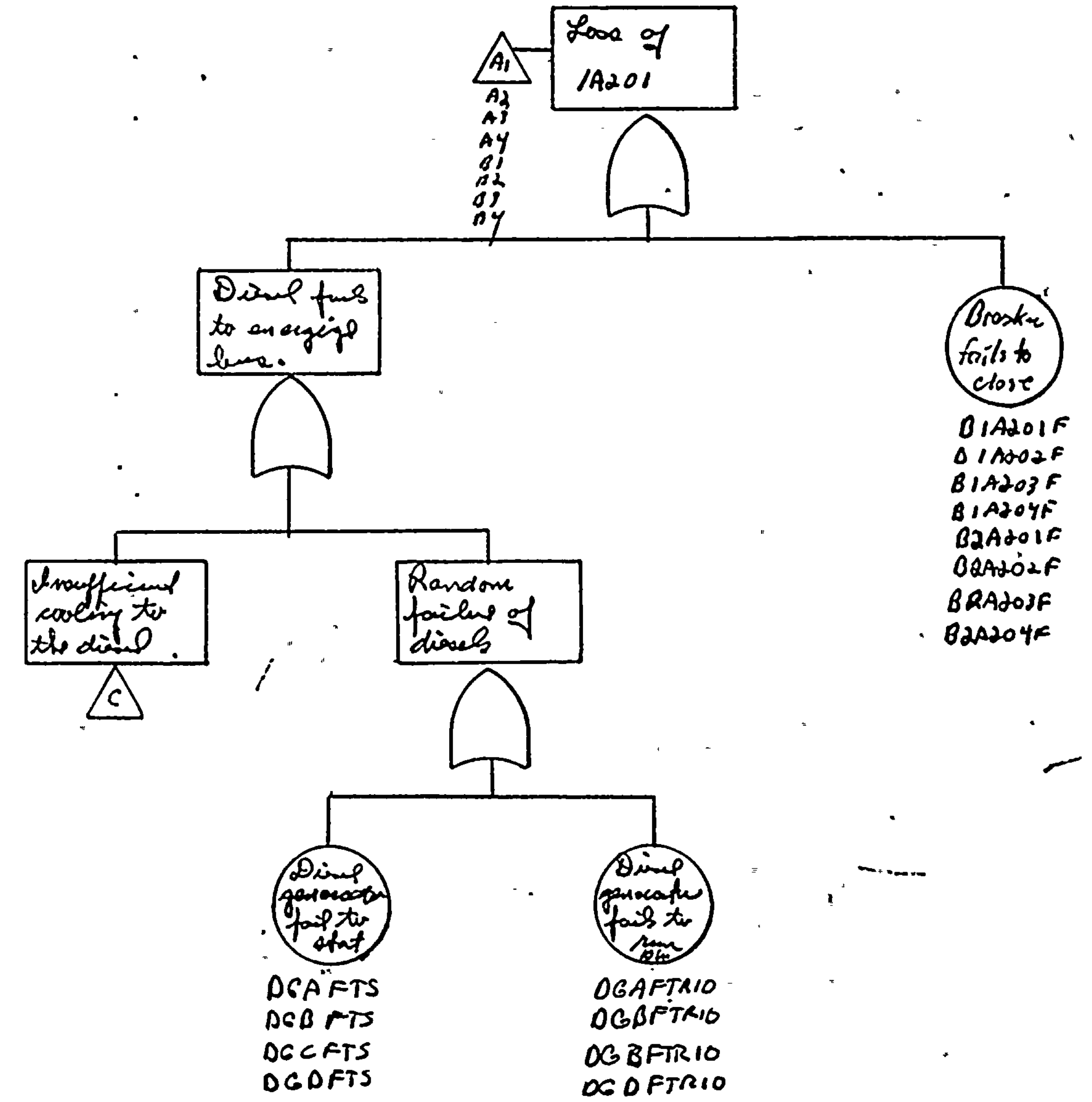

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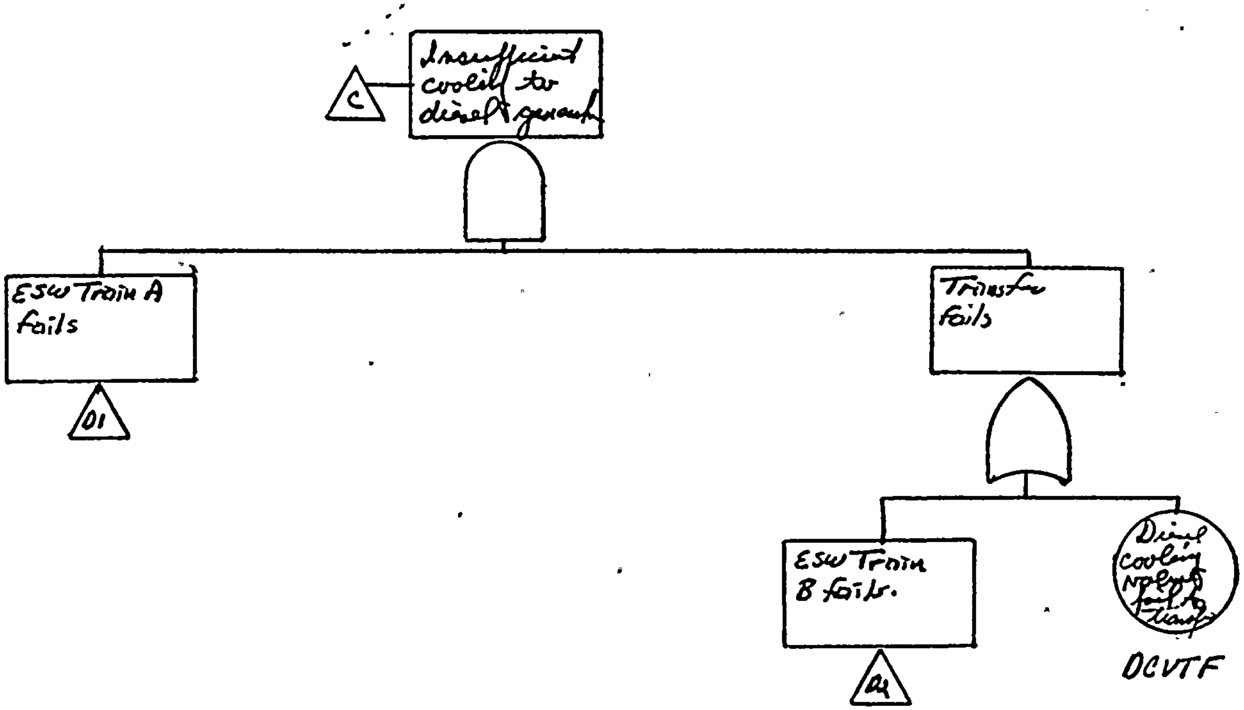
Insufficient cooling to diesel generator
C
ESW Train A fails
D1
Transfer fails
ESW Train B fails
D4
Diesel cooling not transferred
DCVTF

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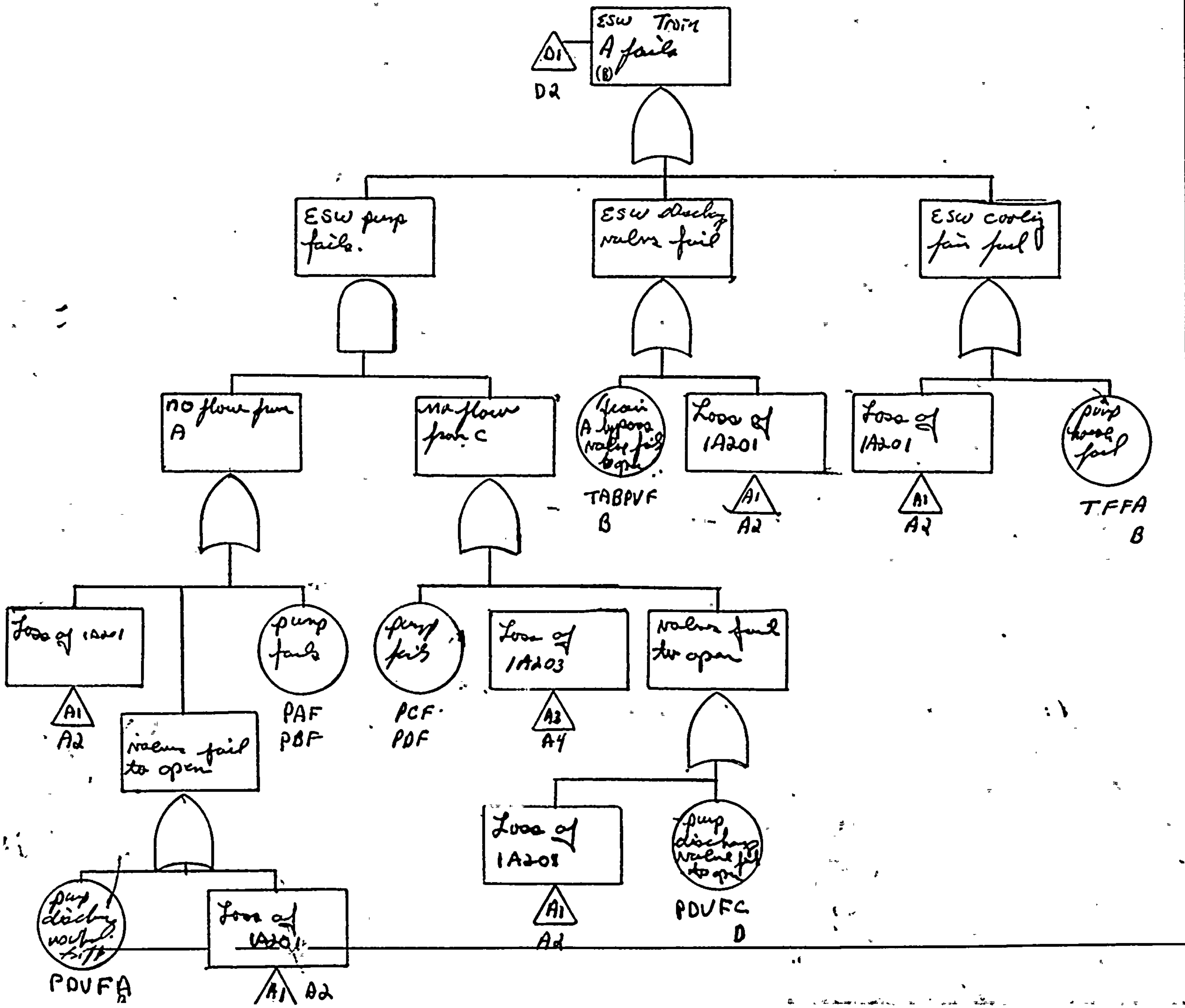

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3 High Pressure Make Up.

The high pressure make up system consist of two systems. HPCI + RCIC. The litterature was review and the following ~~numbers~~ unavailabilities obtained.

NSAC survey: HPCI × RCIC = $7.0 \times 10^{-2} \cdot 7.3 \times 10^{-2} = 5.11 \times 10^{-3}$ /d

fault tree: HPCI × RCIC = $4.6 \times 10^{-2} \cdot 4.5 \times 10^{-2} = 2.07 \times 10^{-3}$ /d

ASP: 2.2×10^{-3} /d.

2.2×10^{-3} is the ASP value. This value ~~accounts~~ for repair or restart and is derived from actual demand and is thus the used.

note: Both HPCI and RCIC recieve power from 1D264. It supplies a valve to the suppression pool.

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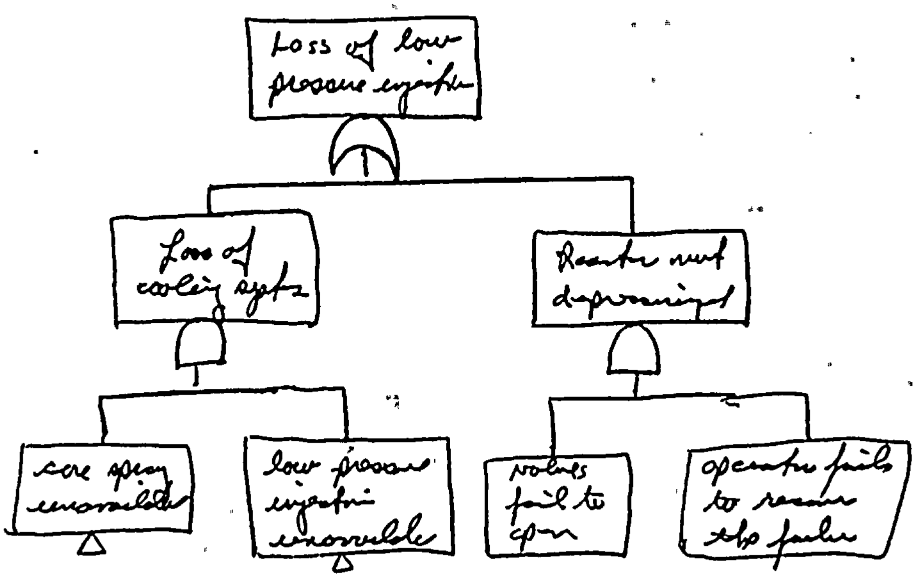
4. Low Pressure Make Up.

The low pressure make up system for this study consist of automatic depressurization, low pressure injection, and low pressure core spray. The simple tree below shows the arrangement



Three source of data were examined. These are:

1. Wash-1400 $5 \times 10^{-3}/d$
2. NSAC-DATA $1.6 \times 10^{-3}/d$.
3. ASP. $6.7 \times 10^{-3}/d$.

Each document identified failure to depressurize as the dominant contributor to system failure.

Susquehanna utilizes ~~[illegible]~~ crosby not target rock valves. This data may not be applicable. The ASP events were examined to identify failures that didn't involve the valve itself, but other common mode problems. Three events were identified.

115870,
124222
158231

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115870 - Failure of air operator on 3 of 4 relief valves

124222 - 4 of 6 valves failed to lift during testing the remaining two lifted at deflated pressure.

158231 - Air operator air leak off line to small on the ADS line.

Only one of these failures is unique to the ADS valves, The others are general valve failures. The ADS failure rate in this set is

1 failure in 192 BWR demands = 5.21×10^{-3} /d.

Wash-1400 estimated the ADS failure rate at 5×10^{-3}/d. This failure rate is based on logic failures.

The other two valve failures involve general valve failures and could involve all 16 safety relief valves. It is conservatively assumed these failures affected all 16 valves. This translates to a general valve failure rate of

2 failures in 192 BWR demands = $1. \times 10^{-2}$/d

This information and the following tree is used to estimate the failure rate of reactor depressurization. A simplified order of magnitude tree is constructed on the next page to estimate the low pressure makeup unavailability.

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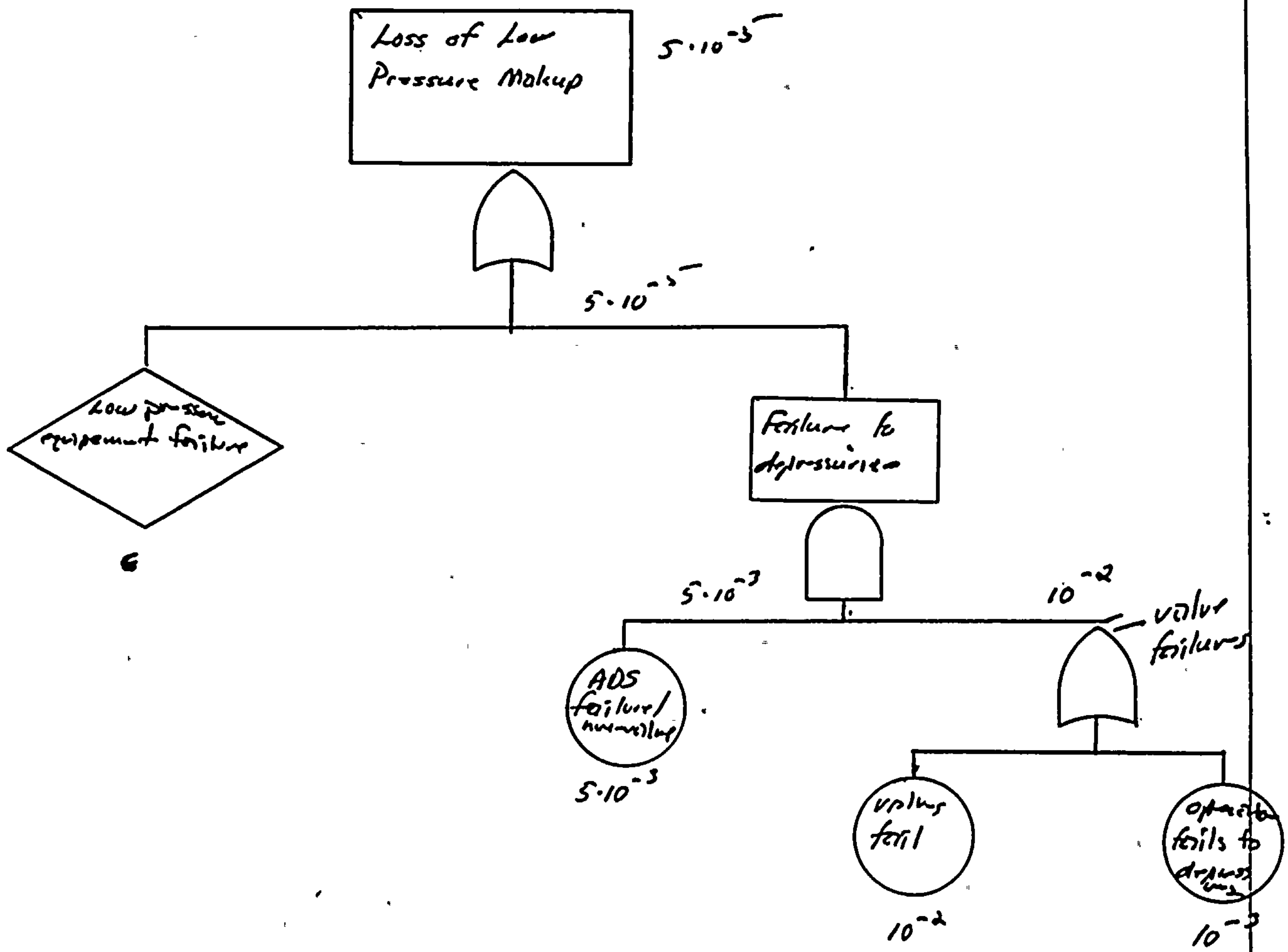

€ - all the following subsystems must fail

LPCI-A	7.4×10^{-3}	with -1400 valves.
LPCI-B	3.4×10^{-3}	
CS-A	7.4×10^{-3}	
CS-B	7.5×10^{-3}	

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5 Long Term Heat Removal

Three documents were used to estimate loss of long term heat removal. These are

Wash-1400	10^{-4}
ASP	10^{-4}
NSAC	10^{-5}

The ASP estimate is based upon one common mode failure of both RHR heat exchangers. The Wash-1400 value is based upon common mode failure of high pressure service water. The derivation of the NSAC number is unknown. 10^{-4} therefore seems reasonable and it is used as the estimate of the unavailability of Long Term Heat Removal when a.c. power is available.

When station blackout exist the ~~probability of~~ long term heat removal is consequently failed due to loss of a.c. power. The unavailability of long term heat removal is then estimated by restoring a.c. power. Two references are examined.

1. the Frank Clark data
2. letter from D.C. Cole to Paul Hill.

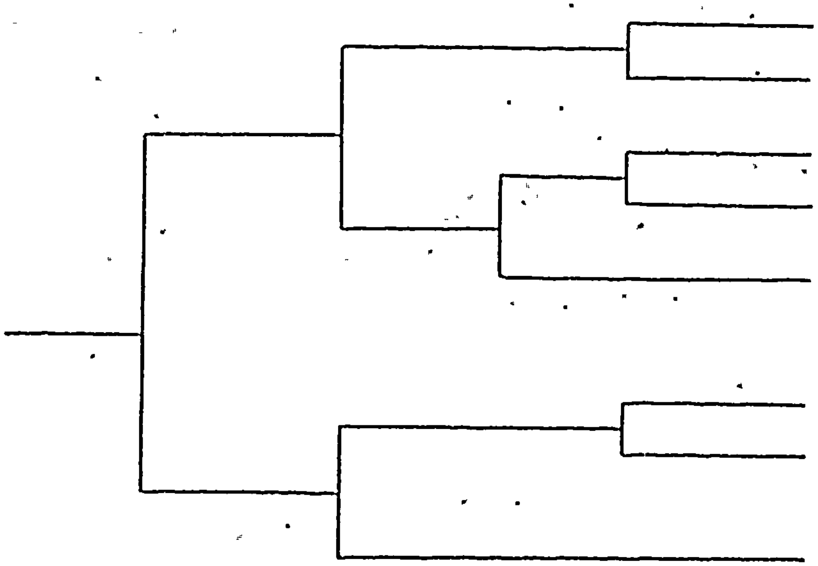
The time to restore offsite a.c. power is estimated to be within ~~to~~ 2 hours in ref 2 and 1 hour in ref 1. The mean time to repair is estimated to be the arithmetic average between these ~~two~~ numbers

or $\frac{1+2}{2} = 1.5$. The probability of not restoring

a.c. power hours $e^{-\frac{10}{2}} = 1.27 \times 10^{-3} \sim 2 \times 10^{-3}$

note 8 hours to HPCI failure + 2 hours to boil down.

LOOP f_1	ESS buses Energized P_1	High Pressure Makeup P_2	Low Pressure Makeup P_3	Long Term Heat Removal P_4



Adequate Core Cooling	Yearly Frequency of Inadequate Core Cooling: Normal f_2	Yearly Frequency of Inadequate Core Cooling: LCO f_3
yes	-	-
no	3.9×10^{-6}	3.7×10^{-6}
yes	-	-
no	8.6×10^{-9}	8.2×10^{-9}
no	4.4×10^{-9}	4.4×10^{-9}
yes	-	-
no	3.6×10^{-7}	4.7×10^{-6}
no	4.8×10^{-7}	6×10^{-6}
Total	4.8×10^{-6}/year	1.5×10^{-5}/year

Figure 1: Event Tree for Loss of Offsite Power at SSES

Event tree quantification

Sequence	manual arrangement		LCO arrangement	
$f_1 \beta_1 \beta_3$	$4.0\times10^{-2} \times 5.5\times10^{-3} \times 2.2\times10^{-3}$	4.8×10^{-7}	$(4.0\times10^{-2})(6.8\times10^{-2})(2.2\times10^{-3})$	6×10^{-6}
$f_1 \beta_1 (1-\beta_3) \beta_4$	$4.0\times10^{-2} \times 4.5\times10^{-3} \times 2\times10^{-3}$	3.6×10^{-7}	$(4.0\times10^{-2})(6.1\times10^{-2})(.99)(2.0\times10^{-3})$	4.8×10^{-6}
$f_1 (1-\beta_1) \beta_2 \beta_3$	$4.0\times10^{-2} \times 0.94 \times 2.2\times10^{-3} \times$ ~~10^{-4}~~ 5×10^{-6} ck 11/11/84	~~8.8×10^{-9}~~ 4.4×10^{-9} ck 11/11/84	4.0×10^{-2} .94 2.2×10^{-3} ~~$.5\times10$~~ 5×10^{-5} 11/11/84	~~2.4×10^{-9}~~ 4.4×10^{-9}
$f_1 (1-\beta_1) \beta_2 (1-\beta_3) \beta_4$	$4.0\times10^{-2} (.94)(.99) 2.2\times10^{-3} \cdot 10^{-4}$	8.8×10^{-9}	$4.0\times10^{-2} (.94)(.99) 2.2\times10^{-3}\ 10^{-4}$	8.2×10^{-9}
$f_1 (1-\beta_1)(1-\beta_2) \beta_4$	$4.0\times10^{-2} (.94)(.99) 10^{-4}$	3.9 3.9×10^{-6}	$4.0\times10^{-2} (.94)(.99)\ 10^{-4}$	3.7×10^{-6}
		4.8×10^{-6}		1.5×10^{-5}

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Estimation of unavailability.

Probability of Inadequate Core Cooling $= \frac{365.25 - \text{days in an LCO}}{365.25} f_2 + \frac{\text{days in an LCO}}{365.25} f_3'$

here,

f_2 = the unavailability of the system necessary to maintain adequate core cooling during normal standby alignment.

f_3' = the unavailability of the system necessary to maintain adequate core cooling ~~during a~~ with a diesel in LCO.

Tech spec allowed days in LCO is 3 days.

For the sake of analysis it is assumed 2 LCO is entered per year and that this LCO requires 3 days. Perhaps a greater number of LCO will be entered, however this situation will minimize the effect of the LCO situation.

case 1 normal LCO arrangement

$\bar{q}_1 = \frac{(365.25 - 6)}{365.25} 4.8\times10^{-6} + \frac{6}{365.25}$ ~~1.3×10~~ 1.5×10^{-5} (ck 11/11/89)

$q_1 = 4.72\times10^{-6} + 2.46\times10^{-7}$ (~~1.23×10^{-7}~~) $= 4.97\times10^{-6}$ (~~4.88×10^{-6}~~) $= 5\times10^{-6}$ (ck 11/11/89)

case 2 extended LCO arrangement

$\bar{q} = \frac{365.25 - 30}{365.25} 4.8\times10^{-6} + \frac{30}{365.25} 1.5\times10^{-5}$

$q_2 = 4.41\times10^{-6} + 1.23\times10^{-6} = 5.64\times10^{-6}$

$\delta q_{30} = 5.64 \times 10^{-6} - 4.88 \times 10^{-6} = 7.58 \times 10^{-7}$ ~ 8 parts in 10 million.

note: 30 days ~~was~~ is chosen as the time for the extended LCO time since only 2 buses are critical to the ~~mean~~ of adequate core cooling. It is assumed each diesel will require 15 day to tie in.

Since 4 buses must be tied in ~~as~~ a conservative estimate of all 4 buses being tied in can be obtained by assuming all 4 buses were critical. Thus choose 3 days for the normally LCO and 60 for the ~~emergency~~ extended case. Case 1 is unchanged however case 2 becomes

case 2

$$q_2 = \frac{365.25-60}{365.25} 4.8 \times 10^{-6} + \frac{60}{365.25} 1.5 \times 10^{-5}$$

$$4.01 \times 10^{-6} + 2.46 \times 10^{-6} = 6.48 \times 10^{-6}.$$

The change in unavailability for the 60 day case becomes

$$\delta q_{60} = 6.48 \times 10^{-6} - \cancel{4.88 \times 10^{-6}}\ 5.0 \times 10^{-6} = \cancel{1.6 \times 10^{-6}}\ 1.48 \times 10^{-6} \sim$$ ~~16 parts in 10 million~~

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<u>Quantification of Uncertainty.</u>

Three methods are employed to estimate the uncertainty or more precisely an estimate of the imprecision of this analysis. These methods are:

1. use a poisson distribution to estimate the confidence bounds given no cases of loss of adequate core cooling given SBO and loss of HPM.

2. recognize that much of the failure probabilities are linear combination of binomial data; estimate the variance in

$$\frac{p(1-p)}{N},$$

then propagate the variance as prescribed by the event tree.

3. reduce the system to a signal component and then estimate the uncertainty or the upper confidence bound using equivalent test and equivalent failure.

(Margin note beside items: Insufficient time to complete this part.)

Method 1 is straight forward. There have been no loss of adequate core cooling as a result of ~~SBO~~ LOOP and inadequate core cooling this translates into the following confidence limits:

~~.05 — .9~~

~~.025 — .95~~

	Lower	Upper
0.05 - .90	0	5.8×10^{-3}
0.025 - 0.95	0	7.1×10^{-3}
0.005 - 0.99	0	1.0×10^{-2}

Method 2

This method involves propagating moments of distributions. The following propagation rules are employed.

1. Sums of distributions

$$\mu_1 = \sum_{i=1}^{n} \mu_{1i}$$

$$\mu_2 = \sum_{i=1}^{n} \mu_{2i}(x_i)$$

2. Products of distributions

$$\mu_1 = \prod_{i=1}^{n} \mu_i$$

$$\mu_2 = \sum_{i=1}^{n} \left(\frac{\mu_1}{X_i}\right)^2 \mu_2(X_i) + \sum_{i=1}^{n-1} \sum_{j=i+1}^{n} \mu_2(X_i)\,\mu_2(X_j)$$

In applying these propagation rules it is assumed the covariance between the distributions is zero.

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The propogation rules are applied to these sequences

$$S^2 = \sum_i^N S_i^2 \prod_{j \neq i} \bar{X}_j^2$$

special cases used

$N = 2$

$$S_2^2 = S_1^2 \bar{X}_2^2 + S_2^2 \bar{X}_1^2$$

$N = 3$

$$S_3^2 = S_1^2 \bar{X}_2^2 \bar{X}_3^2 + S_2^2 \bar{X}_1^2 \bar{X}_3^2 + \bar{S}_3 \bar{X}_1^2 \bar{X}_2^2$$

$N = 4$

$$S_4^2 = S_1^2 \bar{X}_2^2 \bar{X}_3^2 \bar{X}_4^2 + \bar{S}_2^2 \bar{X}_1^2 \bar{X}_3^2 \bar{X}_4^2 + \bar{S}_3 \bar{X}_1^2 \bar{X}_2^2 \bar{X}_4^2 + \bar{S}_4 \bar{X}_1 \bar{X}_2 \bar{X}_3$$

The sums or differences of distributions are represented as

$$\bar{S}_3^2 = S_1^2 + \bar{S}_2^2$$

Estimate of each parameter is first made followed by the sequence propogation.

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Only sequence that are significant contributor to the risk estimate. The following symbols are used to describe the sequence.

f_1 = LOOP frequency.

P_{11} = two diesels fail to start.

P_{12} = one diesel fails to start.

P_{13} = one diesel fails to run

P_2 = failure of high pressure make up.

P_3 = ~~failure of~~ to restore ac power in 10 hours.

P_4 = failure of both RHR heat exchanger.

The following sequence are major contributor to the estimate.

1. $f_1 P_{11} P_2$
2. $f_1 P_{12} \cdot P_{13} P_2$ (twice)
3. $f_1 P_{13} P_{13} P_2$
4. $f_1 P_{11} P_3$
5. $f_1 P_{12} P_{13} P_3$ (twice)
6. $f_1 P_{13} P_{13} P_3$
7. $f_1 P_4$

Calculation of Uncertainty

1. LOOP frequency

Estimate : 0.04 /y

σ^2 0.04 /y

poisson distribution assumed.

2. Emergency Power

2.a. 2 diesels fail to start (ρ_{11})

Estimate : 2.3×10^{-3}

σ^2 : $\frac{(2.3 \times 10^{-3})(.99)}{11,000} = 2.1 \times 10^{-7}$

binomial distribution

2.b 1 diesel fails to start. (ρ_{12})

Estimate : 4×10^{-3}

variance : $\frac{(4.0 \times 10^{-3})(.996)}{11,000} =$ ~~3.96×10^{-6}~~ ck 11/11/88

binomial distribution

2.c 1 diesel fails to run (ρ_{13})

Estimate : 3×10^{-3}

variance : 3×10^{-3}

poisson distribution assumed.

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3. High Pressure Make Up (p_2)

Estimate: 2.2×10^{-3}

Variance: $s^2 = \frac{p(1-p)}{N} = \frac{(2.2\times10^{-3})(0.99)}{1633} = 1.33\times10^{-6}$

Distribution: a binomial distribution was assumed.

4. Restoration of a.c. power within 10 hours (Loss of ultimate heat sink). (p_3)

Estimate: 2×10^{-3}

Variance: $\lambda^2 = (2\times10^{-3})^2 = 4\times10^{-6}$

Distribution: an exponential Distribution was assumed.

5. Common Mode Failure of 2RHR Heat Exchangers (Loss of Ultimate Heat Sink)

(p_4) Estimate: 10^{-4}

Variance: $\frac{p(1-p)}{N} = \frac{10^{-4}}{1633} = 6.12\times10^{-8}$

Propogation of Variance.

1. $Var(f_1 \, p_{11} \, p_2) = S_{f_1}^2 \cdot p_{11}^2 \cdot p_2 + f_1^2 S_{p_{11}}^2 p_2^2 + f_1^2 p_{11}^2 S_{p_2}$

$= (0.04)(2.3\times10^{-3})^2 \cdot (2.2\times10^{-3})^2 + (0.04)^2 (2.1\times10^{-7})(2.2\times10^{-3})^2 + (0.04)^2 (2.3\times10^{-3})^2 (1.3\times10^{-6})$

$9.4\times10^{-13} \quad + \quad 1.6\times10^{-15} \quad + \quad 1.1\times10^{-14}$

$=$ ~~9.5×10^{-13}~~ 10^{-12} ck 11/18/84

2. $Var(f_1 \cdot p_{12} \cdot p_{13} \, p_2) = S_{f_1}^2 p_{12}^2 \cdot p_{13}^2 \cdot p_2^2 + f_1^2 S_{p_{12}}^2 \cdot p_{13}^2 \cdot p_2^2 + f_1^2 \cdot p_{12}^2 \cdot S_{13}^2 \cdot p_2^2 + f_1^2 \cdot p_{12}^2 \cdot p_{13}^2 S_{p_2}^2$

$= (0.04)(4\times10^{-2})^2 (3\times10^{-3})^2 (2.2\times10^{-3})^2 + (0.04)^2 \cdot (4\times10^{-6}) \cdot (3\times10^{-3})^2 (2.2\times10^{-3})^2 +$

$\sim$ ~~$10^{2} \cdot 10^{-18}$~~ ck 11/11/84 $3 \cdot 10^{-15}$ $\qquad 10^{2} \cdot 10^{-22}$

$(4\cdot10^{-2})^2 (4\cdot10^{-2})^2 (3\cdot10^{-3})(2.2\cdot10^{-3})^2 \quad + \quad (4\cdot10^{-2})^2 (4\cdot10^{-2})^2 (3\cdot10^{-3})^2 (1.3\times10^{-6})$ ~~$(4\cdot10^{-2})^2(4\cdot10^{-2})^2(3\cdot10^{-3})^2(1.3\times10^{-6})$~~ $3\cdot10^{+3} \cdot 10^{-20}$

$2\cdot10^{3} \cdot 10^{-17}$

$= 10^{-16} + 10^{-20} + 2\cdot10^{-14} + 3\times10^{-17} = 2\cdot10^{-14}$

3. $Var(f_1 \, p_{12} \, p_{13} \, p_2) = S_{f_1}^2 p_{12}^2 p_{13}^2 p_2^2 + = (0.04)(3\cdot10^{-3})^2 (3\cdot10^{-3})^2 (2.2\times10^{-3})^2 = 1.6\cdot10^{+3} \cdot 10^{-20} = 3\cdot10^{-17}$

$f_1^2 S_{p_{12}}^2 p_{13}^2 p_2^2 + = (0.04)^2 (3\cdot10^{-3})(3\cdot10^{-3})^2 (2.2\times10^{-3})^2 = 2\cdot10^{+3} \cdot 10^{-19} = 2\cdot10^{-14}$

$f_1^2 p_{12}^2 S_{13}^2 p_2^2 + = (0.04)^2 (3\cdot10^{-3})^2 (3\cdot10^{-3})(2.2\times10^{-3})^2 = \qquad 2\cdot10^{-14}$

$f_1^2 p_{12}^2 p_{13}^2 S_2^2 \quad + \quad (0.04)^2 (3\cdot10^{-3})^2 (3\cdot10^{-3})^2 (1.3\cdot10^{-6}) \qquad 1.3\cdot10^{-3} \cdot 10^{-22} \quad 1.3\cdot10^{-15}$

$4\cdot10^{-14}$

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4. $Var(\lambda_1 \rho_{11} \rho_3) = S_{\lambda_1}^2 \cdot \rho_{11}^2 \rho_3^2 \; + \; (4\cdot10^{-2})\cdot(2.3\cdot10^{-3})^2\cdot(2\cdot10^{-3})^2 = 8\cdot10^1\cdot10^{-14} = 8\cdot10^{-13}$

$\lambda_1^2 \cdot S_{\rho_{11}}^2 \cdot \rho_3^2 \; + \; (4\cdot10^{-2})^2(2.1\times10^{-1})(2\cdot10^{-3})^2 \quad 1.3\cdot10^2\cdot10^{-17} = 1.3\cdot10^{-15}$

$\lambda_1^2 \cdot \rho_{11}^2 \cdot S_{\rho_3}^2 \quad (4\cdot10^{-2})^2(2.3\cdot10^{-3})^2(4.0\cdot10^{-6}) \quad 2\cdot10^2\cdot10^{-16} = 2\cdot10^{-14}$

8.2×10^{-13}

5. $Var(\lambda_1 \rho_{12} \rho_{13} \rho_3) = S_{\lambda_1}^2 \cdot \rho_{12}^2 \cdot \rho_{13}^2 \cdot \rho_3^2 \; + \; (4\cdot10^{-2})(4\cdot10^{-3})^2(3\cdot10^{-3})^2(2\cdot10^{-3})^2 = 2\cdot10^3\cdot10^{-20} = 2\cdot10^{-17}$

$\lambda_1^2 \cdot S_{\rho_{12}}^2 \cdot \rho_{13}^2 \cdot \rho_3^2 \; + \; (4\cdot10^{-2})^2(4\cdot10^{-6})(3\cdot10^{-3})^2(2\cdot10^{-3})^2 = 1.5\cdot10^3\cdot10^{-22} = 1.5\cdot10^{-19}$

$\lambda_1^2 \rho_{12}^2 \cdot S_{\rho_{13}}^2 \cdot \rho_3^2 \; + \; (4\cdot10^{-2})^2(4\cdot10^{-3})^2(3\cdot10^{-5})(2\cdot10^{-3})^2 = 3\cdot10^3\cdot10^{-19} = 3\cdot10^{-16}$

$\lambda_1^2 \cdot \rho_{12}^2 \cdot \rho_{13}^2 \cdot S_{\rho_3}^2 \; + \; (4\cdot10^{-2})^2(4\cdot10^{-3})^2(3\cdot10^{-3})^2(4\cdot10^{-6}) = 10^4\cdot10^{-23} = 10^{-18}$

3.2×10^{-16}

6. $Var(\lambda_1 \rho_{13} \rho_{13} \rho_3) = S_{\lambda_1}^2 \rho_{13}^2 \rho_{13}^2 \rho_3^2 \; + \; (4\cdot10^{-2})(3\cdot10^{-3})^2(3\cdot10^{-3})^2(2\cdot10^{-3})^2 \quad 1.3\cdot10^3\cdot10^{-20} \quad 1.3\cdot10^{-17}$

$\lambda_1^2 S_{\rho_{13}}^2 \rho_{13}^2 \rho_3^2 \; + \; (4\cdot10^{-2})^2(3\cdot10^{-5})(3\cdot10^{-3})^2(2\cdot10^{-3})^2 \quad 1.7\cdot10^3\cdot10^{-19} \quad 1.7\cdot10^{-16}$

$\lambda_1^2 \rho_{13}^2 S_{\rho_{13}}^2 \rho_3^2 \; + \; (4\cdot10^{-2})^2(3\cdot10^{-3})^2(3\cdot10^{-5})(2\cdot10^{-3})^2 \quad 1.7\cdot10^{-16}$

$\lambda_1^2 \rho_{13} \rho_{13} S_{\rho_3} \quad (4\cdot10^{-2})^2(3\cdot10^{-3})^2(3\cdot10^{-3})^2(4\cdot10^{-6}) \quad 5\cdot10^3\cdot10^{-20} \quad 5\cdot10^{-17}$

$4\cdot10^{-16}$

7. $Var(q_1 \cdot p_4) = S_{q_1}^2 p_4^2 + q_1^2 S_{p_4}^2$

$(4\cdot10^{-2})(10^{-4})^2 \qquad 4\cdot10^{-10} \qquad 4\cdot10^{-10}$

$(4\cdot10^{-2})^2(6\cdot10^{-8}) \qquad 10^2\cdot10^{-2} \qquad 1\cdot10^{-10}$

$5\cdot10^{-10}$

The variance in the estimate of containment core cooling is

$$Var(q) = 5\times10^{-10}.$$

The best estimate of the standard error becomes

$$\sigma = \sqrt{Var(q)} = \sqrt{5\cdot10^{-10}} = 2.3\cdot10^{-5}$$

$1s = 2.3\cdot10^{-5}$
$2s = 4.5\cdot10^{-5}$
$3s = 6.7\cdot10^{-5}$

$q = 5\cdot10^{-6}$

or

$\bar{X} + 1s = 2.8\times10^{-5}$
$\bar{X} + 2s = 5.0\times10^{-5}$
$\bar{X} + 3s = 7.2\times10^{-5}$

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List of Drawings Used.

Electric Power

E-107150 SH-1,2
E-107153 SH 1-3
E-107154 SH 1-4

Emergency Service Water.

E-106216 SH 1-2
E-162640 SH 1
B-103401 SH 3-5,
B-103402 SH 7

High Pressure Coolant Injection

FF127250P5901-5911 SH-1-11
FF127250P6901-5911 SH-1-11
FF114570P9801-9807 SH 1-11

Reactor Core Isolation Cooling.

E-106257
FF129010P0401-0404 SH 1-4
FF129010P8001-8004 SH-1-4
FF129010P001-9011 SH-1-11

All drawings were controlled copy stick file.
Casimir Kulbaba 10/29/84

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Appendix B

Comments and their Resolution

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Comment	Resolution
Oct. 16, 1984	
1. Reference Tech Spec & Reg Guide 1.93	was included
2. Discuss importance of 1A201 & 1A202	was discussed
3. Discuss why buses must load in 4 minutes	included
4. RCIC can take stuck open SRV	incorporated
5. Examine for LPCI a. common mode failure of pumps and valves b. common mode failure of valves to open c. human error	these were included
6. Use 1 LCO per quarter	not justified. 6 LCO day for present core 60 for extended core
7. Discuss uncertainty	Uncertainty was included

8 Reference site years — Referenced.

9 Delete Ratio in actual experience — Deleted.

10. Change test to tech spec # — Changed.

11. Look at all LER's and see if any HPCI/RCIC failure to run occurred — non-occurred.

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Comment	Resolution
Oct. 29, 1984	
1. Reference all numbers.	All numbers were referenced.
2. Include an event tree legend	An Event Tree legend was included.
3. Make the analysis for 60 not 30 days.	This was done.
Nov 11, 1984	
1. Fault tree for ESW didn't include any contribution from maintenance.	Maintenance is not allowed by the tech specs for a LCO. Therefore it doesn't have to be included in the fault tree
2. The SRV/ADS failure appears to double count.	The discussion isn't clear. It is rewritten to clear up the matter.
3. Explain how 6 days is developed for normal operation.	This is explained in the report.
4. Define equations.	The uncertainty section was rewritten.

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Comment	Resolution
Comment of Nov 15/1994	
Are both units treated	Yes, through the ESW tree. See Appendix D.
Comments on computations	
1. Repair calculation $1-e^{-T/MTTR} = 1.54\cdot10^{-1}$ not $1.54\cdot10^{-2}$ at 1 hour for repair of TADDVF·TDDDVF ~~not included~~	Corrections were made. These components were not included in the repair calculation.
2. Repair of HPM is $5.5\cdot10^{-3}$ not $5.45\cdot10^{-3}$	Recognized but not significant.
3. For sequence $f_1(1-p_1)p_2p_3$ $(1-p_1)=0.9945$ not 0.94	Acknowledged and corrected. Does not impact the results
4. Case 2 of the availability calculation, $q_2 = 6.47\cdot10^{-4}$ not $6.48\cdot10^{-6}$	not significant.
5. Case 1 of the availability calculation $q_1 = 7.6\times10^{-7}$ not $7.58\cdot10^{-7}$	" "

Comment	Resolution
6. Uncertainty Calculations	
a. 2b var(1 diesel fail to start) $= 3.45 \cdot 10^{-4}$ not $7.56 \cdot 10^{-6}$	corrected.
b. $S_{f_i}^2 \cdot p_{11}^2 \, p_{13}^2 \, p_{14}^2 = 2.8 \cdot 10^{-15}$ not 10^{-4}	Order of magnitude approach used. Correction made but does not impact the result.
c.	

Appendix C

Summary of Key Assumptions.

Summary of Key Assumptions

Assumption	Impact of Assumption
1. The two gross valve failure events effects all 16 SRVs at SSES.	This is not the case. It is a conservative assumption to aid in the unavailability estimate. The valve failure rate is actually lower, however the estimate in operators failure probability becomes important and the significance of this assumption diminishes.
2. Operator fails to manually depressurize the reactor after failure of automatic depressurization in 30 minutes.	It is assumed the operator will properly perform his duty once he has realized the need to do it. The depressurization procedures are clear and he is well trained. The 30 minutes is chosen to correspond to the time HPCI/RCIC allowed to be unavailable. This time frame is obtained from discussion of the station Blackout report. The probability of 10^{-3} is obtained from NUREG 3010 for 30 minutes. The results of the analysis show the operator fails ~~fro~~ event is in to be insignificant.

3. Event tree branches are independent.

This assumption is made so the covariance can be taken as zero. This assumption is justified since their is good reason to believe the data and branch points are independent. Each estimate was take from a different data source, and the dominate contributor to system failure is independent of any other system. As an example LPM failure is estimated using failure to depressurize. This failure includes failure to automatically depressurize or to manually depressurize. These item are independent of a.c. power. HPM and LPM are connected by D.C. power, however failure estimate for these systems ~~is independent of~~ have no contribution from d.c. power. The attached Matrix covers all system combinations.

4. Success of Scram is tacitly assumed.

Scram failure doesn't add much insite to the analysis and its contribution is small. Consider the following sequences that lead to inadequate core cooling given ATWS:

1. LOOP·FTS·EPF
2. LOOP·FTS·HPI
3. LOOP·FTS·SLC
4. LOOP·FTS·LTHR.

The failure probability (or frequency) for each is

LOOP 4x10⁻²
FTS —

Assumption 4 continued.

FTS ⇒ Failure to scram.

There has been one failure to scram in the BWR population. During 1980 there were 209 scrams at the 22 BWRs going critical after 1968, (this year is picked because these represent a more homogeneous population. plants like Dresden 1, Big Rock Point, LaCross etc are excluded). This translates to

$209/22 = 9.5$ scrams per year.

Between 1965 - 1980 there were 191.79 BWR Years
Between 1981 - Present there is ~76.8 BWR Years
OR 268.6 BWR Years. This translates to

$$268.6 \text{ BWR years} \times 9.5 \frac{\text{scrams}}{\text{year}} \doteq 2.6\times10^{3} \text{ scrams}$$

or $1 \text{ failure} / 2.6\times10^{3} \text{ scram} = 3.9\times10^{-4}/d$.

The B.F. 3 failure was rectified and NUREG/CR-3591 suggest a probability of rectification of 0.66 or failure of 0.34. Therefore the failure to scram probability becomes

$$3.9\times10^{-4}/d \times .34 \sim 1\times10^{-4}$$

$EPF = 4\times10^{-3}$
$HPCI = 3\times10^{-2}$
$SLC = 10^{-3}$ (two trains 10^{-2} per train & $\beta = .1$)
$LTHR = 10^{-4}$

Assumption 4. continued

Combining these probabilities yeilds

LOOP·FTS·EPF = $0.04 \cdot 10^{-4} \cdot 4 \cdot 10^{-3} = 16 \cdot 10^{-9} = 1.6 \cdot 10^{-8}$

LOOP·PTS·HPI = $0.04 \cdot 10^{-4} \cdot 3 \times 10^{-2} = 12 \cdot 10^{-8} = 1.2 \times 10^{-7}$

LOOP·FTS·SLC = $0.04 \cdot 10^{-4} \cdot 10^{-7} = 4 \cdot 10^{-8}$

LOOP·FTS·LTHI = $0.04 \cdot 10^{-4} \cdot 10^{-4} = 4 \cdot 10^{-10}$

Total = $1.2 \cdot 10^{-7}$

This represents $1.2 \cdot 10^{-7} / 4.8 \times 10^{-4} < 2.5\%$.

There is much unknown about how the plant will respond during ATWS. These estimates are considered conservative. The RPS scram failure could have cut the power to perhaps RCIC capacity which lowers the $\bar{q}$ to ~~2.4×10^-7~~ 2.4×10^{-8}. The chance of a full failure to scram is probably an order of magnitude less than what's estimated here also. To include Loop with ATWS would increase the $\bar{q}$ marginally, increase the uncertainty and add little to the result & was ∴ excluded.

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Matrix of Independency

	LOOP	ESS Buses Energized	High Pressure make up	Low Pressure makeup	Long Term Heat Removal
LOOP	X				
ESS Buses Energized	Redundant to offsite lines. Dominated by the diesels	X	Symmetric		
High Pressure Make up	a.c. power independent $p(HPM) = \bar{q}$(HPCI/RCIC)	same	X		
Low Pressure Make up	powered from ESS buses	failed without a.c	LPM failure independent of HPCI-RCIC, components independent of each other.	X	
Long Term Heat Removal	Probability to recover independent of offsite power if grid up. ~~Hx failure is a.c. independent~~	Hx a.c independent	Hx & other components independent of HPM,	LHM uses fn of ADS as failure mode independent of common elements.	X

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Appendix D

Consideration of Two Units

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AC power serves both units, therefore a total loss of AC power can result in both units experiencing inadequate core cooling. One sequence is identified in the event tree, f, $p_1 p_4$. The p_4 here is failure of "Long Term Heat Removal" which is calculated as failure to recover offsite AC power. This sequence doesn't include use of the fire protection system. The SBO procedures explains how to tie in the fire system into RPV and it is likely that it would be accomplished. This cooling of the reactor with the fire system greatly extends the time the station can exist without a.c. power. No credit was taken for it in the analysis. The probability of inadequate core cooling in both units becomes

$$P(u_1,u_2) = P_{\text{independent}}(u_1) \cdot P_{\text{independent}}(u_2) + P(u_1 \cdot u_2)_{\text{common mode}}$$

$$= 4.4\times10^{-6} \cdot 4.4\times10^{-6} + 3.6\times10^{-7}$$

$$= \sim 3 \cdot 10^{-11} + 3.6 \cdot 10^{-7} = 3.6 \cdot 10^{-7}$$

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This represents $3.6 \cdot 10^{-7} / 4.8 \cdot 10^{-6} = 0.075$ or 7.5% of the computed risk which conservatively overestimates the risk associated with this extension.

PP&L

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W. Barberich	N-4
H.R. Clarke	N-5
T.M. Crimmins	N-5
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S.B. Kuhn	N-5
D.J. Morgan	N-5
H.V. Oheim	N-5

May 27, 1982

Mr. P. R. Hill - N5

SUSQUEHANNA STEAM ELECTRIC STATION
STATION BLACKOUT ANALYSIS
RE: YOURS OF FEBRUARY 12, 1982

This letter presents an evaluation of the frequency of loss of off-site power at Susquehanna and is a complete response to your letter and to the additional points of interest raised at our March 30, 1982 meeting and subsequent discussions. In order to clearly and adequately address the frequency of loss of off-site power issue for Susquehanna, our response is provided in report format.

DESCRIPTION OF OFF-SITE POWER SYSTEM

A detailed description of the Susquehanna off-site power system and its connections to the PL transmission system is presented in the attached copy of Section 8.2.1 of the Susquehanna FSAR (See Appendix 1). In brief, off-site power at Susquehanna is provided by Startup Transformers #10 and #20 and their transmission connections to the bulk power system. The transformers are physically and electrically remote from each other and each one is connected to a 230 kV transmission line. The transmission lines which supply Transformers #10 and #20 occupy separate corridors and do not terminate in the same switching station. With all facilities initially in service, the total loss of any one of the four switching stations, which terminate the two transmission lines from which Transformers #10 and #20 are tapped, will not result in the loss of both Startup Transformers. If terminal problems occur on one of the transmission lines supplying a Startup Transformer, the problem can be isolated, in most cases automatically, by opening the breaker(s) at that terminal. This would permit the Startup Transformer to remain in service via supply from the remaining terminal.

DEFINITION OF LOSS OF OFF-SITE POWER

Loss of off-site power (LOOP) is defined, for the purpose of this analysis, as the simultaneous loss or unavailability of power supply to Startup Transformers #10 and #20. Therefore, the determination of frequency of LOOP takes into account the availability of the transmission system which supplies Transformers #10 and #20 and the availability of the transformers themselves. This analysis does not take into account plant induced outages of the 13.8 kV and 4.16 kV startup busses which could result in isolating the plant from the off-site power system.

FREQUENCY OF LOOP AND ANTICIPATED RESTORATION TIME

The total frequency of LOOP at Susquehanna is conservatively estimated to be .049 occurrences per year. The components of the total frequency of LOOP include: LOOP due to independent outage events (.009/year) and LOOP due to common mode outage events (.04/year). The frequency of LOOP value is dominated by common mode outage events (disasters and system blackout).

The time required to restore off-site power after LOOP is dependent on the extent of damage, if any, to the electric supply system caused by the LOOP initiator event. In most cases, off-site power is expected to be restored within 6 hours of LOOP. If there is no damage to system facilities, off-site power can be restored within several minutes by automatic or supervisory switching operations. On the other hand, if there is extensive damage to the off-site power system, the restoration time would be many days.

DETERMINATION OF FREQUENCY OF LOOP

The determination of frequency of LOOP includes both the "sustained" and "transient" occurrences of LOOP expected on the PL system. Transient occurrences of LOOP are less than 3 minutes duration. The components considered in determining the frequency of LOOP at Susquehanna include:

- Simultaneous forced outage of both 230 kV sources to the off-site power system due to independent events.
- Forced (independent) outage of one 230 kV source while the other source is scheduled out for maintenance.
- Natural and man-made disasters - unusually severe weather events, earthquake, airplane crash, sabotage and war.
- System blackout (widespread or local).
- Simultaneous forced outage of both 230 kV sources to the off-site power system due to dependent events (neither blackout nor disaster related).

Since the 230 kV transmission lines supplying the off-site power system do not share the same switchyard sources and are on separate corridors, the non-blackout non-disaster related dependent outage consideration was assumed to be negligible. The frequency of LOOP due to independent events was calculated using historical data for the PL system. An estimate of the frequency of LOOP due to common mode outage events (disasters and blackouts) was derived from an analysis of weather data and PL historical outage data. A detailed discussion of the determination of frequency of LOOP caused by independent events and by common mode outage events is presented below.

LOOP CAUSED BY INDEPENDENT EVENTS

The calculation of the annual frequency of LOOP caused by independent events is based on the simultaneous and independent forced outage of both 230 kV sources to the off-site power system due to independent events, and the independent forced outage of one 230 kV source while the other source is scheduled out for maintenance. The forced and scheduled outage hours used in the calculation are based on PL historical outage data (1975-1981). It is important to note that these data do not reflect the urgency associated with restoring an outaged off-site source at Susquehanna. Since the frequency of LOOP is a function of the restoration time (see Appendix 2), the calculated value for frequency of LOOP using historical data will tend to be conservative.

Based on PL historical outage data, the calculated value for frequency of sustained LOOP caused by independent events is approximately .003 occurrences per year. The calculation technique is presented in Appendix 2. This value corresponds to outage durations lasting longer than 3 minutes. It is generally expected that, on the bulk power system, a transient line fault will have been cleared and the outaged line restored to service within 3 minutes by automatic reclosures. In general, a sustained outage is one which cannot be restored within this approximate 3 minute interval. Based on PL historical outage data, the frequency of LOOP due to transient interruptions - less than 3 minutes duration - is approximately .006 occurrences per year.

The curve shown in Appendix 3 illustrates the "annual frequency of LOOP > T hours duration" as a function of "T hours duration". This curve, for independent events only, was developed using available PL historical outage data. The 6-hour point highlighted on the curve is the average time to restore one of the off-site power sources in the event that construction personnel are required to isolate a faulted section of one of the 230 kV lines which supplies Transformer #10 or Transformer #20.

LOOP CAUSED BY COMMON MODE OUTAGE EVENTS

Since the 230 kV transmission lines supplying the off-site power system do not share the same switchyard sources and are situated on separate

corridors, the common mode outage events which could reasonably cause LOOP are disasters (natural or man-made) and blackouts (widespread or local). Previous occurrences of disasters and blackout were reviewed and the likelihood of such occurrences in the Susquehanna electrical area was estimated.

The disaster component of common mode outages - earthquake, airplane crash, sabotage, war, hurricane, tornado, flood, unusual hail, ice or wind storms -- is dominated by unusually severe weather events. There have been several instances of multiple 230 kV line outages caused by unusually severe weather events. In March 1958, a severe snow storm occurred in the Lancaster Region and caused the collapse of two transmission structures - one on each of two adjacent 230 kV lines (Manor-Westport and Manor-Riverside). One of the two circuits was restored in 4 hours by making temporary connections between the usable portions of both circuits. In June 1972, the rains associated with Hurricane Agnes caused severe flooding in the Susquehanna River basin. The flooding resulted in the loss of both generating units at the former Stanton generating plant, the loss of the three generating units at Brunner Island, the loss of the Brunner Island 230 kV switchyard and the seven 230 kV lines terminated there. In January 1978, unseasonably warm weather and persistent rain resulted in an ice jam and severe flooding at Safe Harbor Hydroelectric Station on the Susquehanna River. The ice jam destroyed a double circuit 230 kV river crossing structure located on an island near the down-river side of the dam. For postulated disaster scenarios similar to the 1972 flood and the 1978 ice jam, there would not be a LOOP concern at Susquehanna. The loss of any one of the source switchyards or the loss of any section of 230 kV line would not result in LOOP.

The development of a multi-interconnected bulk electric supply system began after World War II. Therefore, there are less than 40 years of history upon which to base a prediction of the impact of adverse weather on the continuity of bulk electric supply. Weather records, however, date back more than 100 years. Based on climatological data from the Wilkes Barre-Scranton airport located approximately 30 miles north-northeast of the Susquehanna plant, there have been several severe storms worthy of note. The blizzard of 1888 began on March 11 as rain with winds up to 65 miles per hour, changed to snow and resulted in 15 inches of accumulation with 15 to 20 foot drifts. Although the incidence of tornados is very low, two tornados did occur, August 1890 and August 1914, causing several deaths in the Wilkes-Barre area. In November, 1969, a freak storm characterized by heavy wet snow, severe icing and gusty winds caused extensive damage to 69 kV and 12 kV electric supply facilities in the PL Pocono Region. Hurricane Agnes (1972), previously mentioned, was the worst natural disaster in the history of Pennsylvania causing record flooding and several deaths.

In order to minimize the impact of severe weather on the reliability of the electric supply system, all PL transmission lines are designed to

conform with or exceed the rules set forth in the National Electrical Safety Code (NESC). This conformance applies to mechanical strength as well as electrical clearance. For the specific case of mechanical strength, all 230 kV lines in the vicinity of the Susquehanna plant are designed for 1 inch ice loading with an applied 8 pound per square foot wind. The NESC specifies a 1/2 inch ice loading with an applied 4 pound per square foot wind design requirement. In addition to complying with the NESC, PL transmission design also provides for adequate lightning protection, adequate clearance over flood levels (as designated by the Army Corps of Engineers), and minimal environmental impact.

Extensive disruptions to the bulk power system resulting in LOOP can be caused by the unpredictable but real occurrence of major floods, hurricanes, tornados, unusually severe ice storms and by possible occurrences of earthquakes, sabotage, airplane crashes, and war. The occurrence of LOOP due to earthquakes, sabotage, airplane crashes, and war is expected to be considerably less frequent than LOOP due to severe weather. With regard to airplane crashes, a review of the Federal Vortac map indicates that, as of January 1, 1982, there are no major scheduled airline flights within 8 miles of the Susquehanna plant. Considering all of the possible instances of unusually severe weather and other disasters, loss of off-site power at Susquehanna due to disasters is conservatively estimated to occur once every 50 years (.02 occurrences per year).

The blackout component of common mode outages is not readily predictable from historical data. There has been only one incident of a blackout on the PL system. The incident occurred on June 5, 1967 and resulted in a blackout of the eastern portion of the PJM Interconnection. Since there is only one recorded occurrence in 36 years of post-war history, it is impossible to statistically predict the frequency of occurrence of a blackout. For the purpose of this analysis, a blackout can be either a widespread condition such as occurred in 1967, or a localized electrical disruption affecting only a relatively small part of the bulk power system. A turbine-generator trip which results in LOOP would be considered a localized blackout occurrence. In order for the sudden generation loss resulting from a turbine-generator trip to cause LOOP, the transient stability limit of the local grid would have to be exceeded causing all four 230 kV switchyard sources supplying the offsite system to be outaged.

Based on the PJM blackout experience and blackout experiences of other utilities, a greater understanding of the causes of blackout has resulted in subsequent improvements in equipment design, systems engineering and operator training. In addition, procedures and guidelines have been developed to unload and unstress the electric supply system in order to minimize the exposure to widespread outages, cascading, and blackout. LOOP due to either a widespread or a local blackout is conservatively estimated to occur once every 50 years (.02 occurrences per year).

The estimated value, therefore, for frequency of LOOP due to disasters and blackouts is .04 occurrences per year.

RESTORATION OF OFF-SITE POWER AFTER LOOP

The time to restore off-site power after LOOP is dependent on the extent of damage, if any, to the electric supply system. In most cases, off-site power can be restored in less than one day if there is only minor damage to the system. Obviously, if one postulates the simultaneous and catastrophic physical failure of both Transformers #10 and #20 or of the 230 kV lines supplying them, the restoration time for an off-site source would be on the order of many days. The restoration time would be a function of the status of the remainder of the electric supply system, the availability of spare equipment, and weather conditions.

For a more reasonable LOOP scenario, without catastrophic failures of multiple components of bulk power related facilities, it is expected that one of the off-site sources can be restored either within a few minutes by performing remote switching operations or within 6 hours by isolating a faulted section of transmission line. The specific work involved in isolating a faulted section of line involves the removal of bolted jumper loop connections on the 230 kV transmission structure at or near the point where the 230 kV tap line supplying the Startup Transformer is connected to the grid. By removing the appropriate loops at the tap point, the faulted section of line is isolated and the affected Startup Transformer can be re-energized from the remaining 230 kV source switchyard.

After a blackout, the restoration of the electric supply system follows established PJM restoration procedures. Following an event which causes a blackout, less than 1 hour would be required to determine the extent of the blackout and initiate the restoration procedure. A 230 kV supply line would be provided at Susquehanna from Yards Creek Pumped Storage Hydroelectric Station in New Jersey. It is expected that an energized 230 kV circuit, capable of providing off-site power at Susquehanna, would be available within 2 hours after a blackout.

D. G. Cole

G. Laczo

By: G. Laczo

GL:mg
LA-23

Attachments

8.2 OFFSITE POWER SYSTEM

8.2.1 DESCRIPTION

8.2.1.1 Transmission System

The bulk power transmission system of PP&L operates at 230 KV and 500 KV. Unit #1 of the Susquehanna Steam Electric Station supplies power to the 230 KV system through a 230 KV switchyard and Unit #2 supplies power to the 500 KV system through a separate 500 KV switchyard. The offsite power system for the plant is supplied through the 230 KV portion of the bulk power system.

Figure 8.2-1 shows the Susquehanna 230 KV and 500 KV switchyards and the transmission lines associated with each yard and in the vicinity of the plant. The figure shows the line arrangement with both units in operation. The two switchyards are physically separate and are tied together by a 230 KV yard tie line with a 230-500 KV transformer in the 500 KV yard.

Two independent offsite power sources are supplied to the Susquehanna plant. One source is established by tapping the Montour-Mountain 230 KV line north of the plant and constructing 1300 ft. of 230 KV line on painted steel pole structures to startup transformer #10. The Montour-Mountain line shares double circuit steel pole structures with the Stanton-Susquehanna #2 230 KV line in the vicinity of the plant. The double circuit line extends to a point 1.5 miles east of the transformer #10 tap at which point the two circuits split as shown in Figure 8.2-1. The Montour-Mountain line extends 16.8 miles north on double circuit lattice towers with the Stanton-Susquehanna #1 230 KV line and terminates in the Mountain Substation. The Stanton-Susquehanna #2 circuit extends southward on double circuit towers with the Stanton-Susquehanna #1 circuit and terminates in the Susquehanna 230 KV Switchyard.

To the west of the tap into the Susquehanna plant the Montour-Mountain 230 KV circuit extends 1500 feet on double circuit steel pole structures at which point the Stanton-Susquehanna #2 circuit separates and extends northward to Stanton Substation. The Montour-Mountain 230 KV circuit then joins the Montour-Susquehanna 230 KV circuit on double circuit steel lattice towers and extends 29.0 miles to the Montour Switchyard. The total distance to Mountain Substation from the tap into the plant is 18.7 miles. The distance from Montour to the tap is 29.7 miles.

Several lines feed the Montour Switchyard and Mountain Substation, as can be readily seen in Figure 8.2-3. These lines

offer a multitude of possible supplies for the tap into Susquehanna startup transformer #10. Montour Switchyard is supplied directly by generation from the Montour Steam Electric Station. Other generating stations are indirectly linked by the bulk power grid system. The conductors for the transformer #10 tap and the Montour-Mountain line are 1590 kcmil 45/7 ACSR and are supported by single string insulator assemblies. Maximum conductor tension is limited to 16,000 pounds on steel pole line sections and 21,900 pounds on lattice tower sections under maximum anticipated loading conditions.

The second offsite power source is supplied at 230 KV from the yard tie circuit between the Susquehanna 500 kV and 230 kV Substations south of the Susquehanna Steam Electric Station. The source is provided by a single 400 ft. span tap from the 230 KV yard tie circuit to startup transformer #20.

The yard tie line consists of 230 KV double circuit tubular steel pole structures supporting two parallel circuits of 1590 kcmil 45/7 ACSR conductors on single string insulator assemblies. The circuits are tied together to form a two conductor per phase single circuit line. The 400 ft. tap to transformer #20 consists of one 1590 kcmil 45/7 ACSR conductor per phase. The distance from the tap point west to the 500 KV yard is 1500 ft. The distance from the tap point east to the 230 KV yard is 1.6 miles. Maximum conductor tension is limited to 16,000 pounds in the yard tie line under maximum loading conditions.

The second offsite power supply is furnished by the multiple sources throughout the bulk power grid system through the 230 KV and 500 KV lines emanating from the Susquehanna 230 KV and 500 KV switchyards. See Figure 8.2-3.

All transmission lines meet or exceed design requirements set forth by the National Electric Safety Code. One or two overhead ground wires are employed on the transmission lines above the phase conductors to provide adequate lightning flashover protection. All lines meet the Army Corps of Engineers requirements for clearance over flood levels. All bulk power transmission lines are designed to withstand 100 mph hurricane wind loads on bare conductors.

The Montour-Mountain 230 KV line is crossed by the Stanton-Susquehanna #2 230 KV line. No transmission lines cross over the Susquehanna 500 KV to 230 KV yard tie line or the two tap lines supplying transformers #10 and #20.

No single disturbance in the bulk power grid system will cause complete loss of offsite power to the Susquehanna SES. This is a basic system design criteria.

8.2.1.2 Transmission Interconnection

PP&L is a member of the Pennsylvania, New Jersey, and Maryland Interconnection which permits economical exchanges of power with neighboring utilities and provides emergency assistance. Direct bulk power ties are between PP&L and Philadelphia Electric, Luzerne Electric Division of UGI, Metropolitan Edison, Pennsylvania Electric, Jersey Central Power and Light, Public Service Electric and Gas, and Baltimore Gas and Electric Companies.

8.2.1.3 Switchyards

8.2.1.3.1 Startup Transformers #10 and #20

The Montour-Mountain 230 KV line and the 230 KV yard tie line supply power to startup transformers #10 and #20, respectively, through motor operated air break switches. High speed positive ground switches are installed between the motor operated air break switches (MOABs) and the startup transformers. The startup transformers and low side bus connections are discussed in Section 8.3.1. The startup transformer yards are physically separated from each other, the Unit #1 and #2 main transformer yards and the 230 KV and 500 KV switchyards as can be seen on figure 8.2-1. 1590 kcmil 45/7 ACSR conductors connect the air switches to the startup transformers. 13.8 KV cables are installed in underground conduit between the startup transformers and the turbine building. Non-segregated phase bus ducts establish the tie to the 13.8 KV startup buses within the turbine building. See Figure 8.2-4 for a one line diagram of the offsite power system.

Line relay protection for the Montour-Mountain 230 KV line and the 230 KV yard tie circuit is provided by two independent directional comparison carrier blocking pilot relaying and two zone directional distance backup systems which ensure adequate line protection in the event of a malfunction. These relaying schemes detect faults on the transmission line and isolate the power sources to the transformers by tripping the power circuit breakers (PCBs) at the line terminals. Breaker failure relaying, applied at each line terminal, detects a failure to trip or failure to interrupt condition at the line terminal and trips all associated PCBs necessary to isolate the line. Power to the line relaying facilities is supplied from the local switchyard power sources.

Startup transformers #10 and #20 are protected by high speed percentage differential, sudden pressure and overcurrent

relaying. Direct transfer trip facilities are utilized as the primary relaying scheme to open the PCBs at the transmission line remote terminals in the event of transformer trouble. Backup protection is provided by the high speed ground switch on the 230 KV side of the startup transformer. This switch is closed to place a positive fault on the 230 KV transmission line which will be detected by the remote line terminal relaying systems if the primary direct transfer trip scheme fails to function correctly. The motor operated air switch automatically opens after the 230 KV system is de-energized to isolate the startup transformer from the transmission system and permit reclosing of the transmission line terminal PCBs.

A time delay undervoltage relay monitors the 13.8 KV startup bus voltage. On loss of offsite power the relay trips the startup bus incoming feeder breaker and initiates transfer of the bus loads to the other startup transformer through closure of the startup bus tie breaker. The time delay undervoltage relay also prevents unnecessary automatic trip of the incoming feeder breaker for short duration disturbances on the transmission line.

Power to transformer #10 and #20 switchgear, motor operated air break switches, and high speed ground switches is supplied from the station 125 V DC power supplies.

8.2.1.3.2 Susquehanna Unit #1 230 KV Main Transformer Leads

Overhead 1590 kcmil 45/7 ACSR conductors, bundled two per phase, tie the Unit #1 main stepup transformers, through a high voltage Disconnect switch-Synchronizing PCB-Disconnect switch arrangement, to the 230 KV switchyard. The synchronizing breaker and disconnect switch arrangement is provided at the Susquehanna SES site to improve reliability in synchronization and flexibility of operating Unit 1. Steel pole structures support the strain bus and the 2.2 mile 230 KV tie with single string insulator assemblies. The tie line is capable of transmitting the full 1280 MVA output of the Unit #1 generator.

Relay protection between the Unit #1 transformer and the synchronizing breaker is provided by high speed percentage differential relays which trip Unit #1 and the synchronizing breaker by the unit master trip lockout relays. A second protection scheme is provided by the Unit #1 overall differential relaying which also detects fault conditions between Unit #1 transformer and the synchronizing breaker. Two directional comparison carrier blocking pilot and two zone directional distance backup relaying systems provide fault protection between the 230 KV synchronizing PCB and the Susquehanna 230 KV Switchyard. Breaker failure protection relaying is applied at

each terminal to detect a failure to trip or failure to interrupt condition and to electrically isolate the faulty component.

Control power to the synchronizing power circuit breaker and power to the onsite relaying equipment are provided by the plant 125 V DC power supplies.

8.2.1.3.3 Susquehanna 230 KV Switchyard

The 230 KV switchyard is an outdoor steel structure, comprised of 6 bay positions containing 14-230 KV power circuit breakers arranged in a breaker and one half scheme. Terminating positions are provided for seven lines, one generator lead, and a yard tie to the 500 KV switchyard. The switchyard breakers can be operated by remote supervisory control from the PP&L System Operating Offices.

Service power to the 230 KV switchyard is provided by a local 12 KV distribution line with a backup diesel generator in the 230 KV switchyard. An automatic throwover scheme is employed in the event of one source failure. Line protection equipment power is provided by a single 125 V DC switchyard service battery equipped with two full capacity chargers.

8.2.1.3.4 Susquehanna Unit #2 500 KV Main Transformer Leads

Unit #2 generator output is connected to the 500 KV switchyard by a 1400 ft. overhead 500 KV transmission line. 2493 kcmil 54/37 ACAR conductors bundled two per phase are supported by V-string insulator assemblies on steel pole H-frame structures. The tie is capable of transmitting the full 1280 MVA generator output of Unit #2 to the 500 KV switchyard.

Relay protection for the connection between the Unit #2 transformer and the Susquehanna 500 KV switchyard is provided by high speed bus differential relays which trip Unit #2 and the three 500 KV switchyard generator breakers by the master trip lockout relays for a fault in the connection. An overall differential protection scheme provides a second system to trip Unit #2 and the three PCBs connected to the generator in the 500 KV switchyard for a fault on the transformer leads. Breaker failure protection is applied at each terminal to detect a failure to trip or failure to interrupt condition and to electrically isolate the faulty component.

8.2.1.3.5 Susquehanna 500 KV Switchyard

The 500 KV switchyard is an outdoor steel structure, comprised of three bays containing five 500 KV power circuit breakers arranged in a modified ring bus configuration. The switchyard provides for ultimate future expansion to 5 bays in a breaker and one half scheme. Terminating positions are provided for two lines, one 500 KV generator lead circuit and a circuit to a bank of three single phase 500-230 KV autotransformers. Manual operation of the 500 KV generator lead synchronizing circuit breakers is by the plant control room operator. The remaining PCBs can be operated by PP&L's remote supervisory control or by the plant supervisory control.

Service power to the 500 KV switchyard is provided by two sources: one from the generating station, and the second from the tertiary winding of the yard tie autotransformers with an automatic low voltage throwover scheme in the event of one source failure. Line protection equipment is powered by a single 125 V DC switchyard service battery equipped with two full capacity battery chargers.

8.2.1.3.6 Montour and Mountain 230 kV Switchyards

Figure 8.2-5 shows a one line diagram of the off-site power system for Startup Transformer #10.

The Montour Switchyard is an outdoor steel structure comprised of four bay positions containing 11-230 kV power circuit breakers arranged in a breaker and one half scheme. Two generating leads from the Montour Steam Electric Station and five transmission lines are terminated in the yard. The switchyard breakers can be operated by remote control from the PP&L System Operating offices.

The Mountain Switchyard is owned and operated by UGI Corporation, Luzerne Electric Division. It is an outdoor steel structure with two bay positions each containing one 230 kV PCB. The two PCBs are arranged back to back between the Montour-Mountain and Mountain-Lackawanna Lines. Between the two PCBs is a normally open MOAB to the Susquehanna-Stanton #1 line. The PCBs and MOAB can be operated by remote supervisory control from the UGI Corporation System operator's office. PCB and MOAB status is monitored by PP&L's System Operating offices.

8.2.1.4 Offsite Power System Monitoring

PP&L's transmission lines are patrolled approximately three times throughout a year to ensure that the physical and electrical integrity of the transmission line supports, hardware, insulators, and conductors is maintained for safe and reliable continuity of service.

The periodic transmission line patrol is conducted by helicopter. Less frequent foot patrols and selective structure inspections are performed depending on the age of the line.

Monitoring of the Unit #1 and Unit #2 offsite power sources in the plant control room is via a hardwired mimic bus arrangement which shows startup transformers #10 and #20, the transformer #10 and #20 motor operated air break switches, the 13.8 KV start-up buses, the 13.8 KV bus feeder breakers, and the 13.8 KV bus tie breaker. Annunciation signals abnormal tripping to the control room operator. Control and status indication are provided for the 230 KV MOAB switches and the 13.8 KV breakers. Potential indication for the PP&L grid and 13.8 KV bus and status indication of the 230 KV high speed ground switches are provided.

A cathode ray tube (CRT) display is provided by the plant computer system which provides the operator with additional information about the offsite power sources. The display is a mimic bus arrangement, similar to the hardwired mimic bus, and includes the status of the PCBs at the remote terminals of the transformer #10 and #20 supply lines.

Monitoring of the Unit #1 main generator output leads to the 230 KV switchyard is provided in the control room. A hardwired mimic bus arrangement provides control and status indication of the synchronizing PCB. Potential indication and monitoring of current, watts, vars, watt hours and voltage are provided. Annunciation signals an abnormal change in status of the synchronizing PCB. The computer CRT display system provides the operator with the status of all PCB's in the 230 KV switchyard and the synchronizing PCB via input from PP&L's supervisory control system. Annunciation accompanies a failure of the supervisory system. Manual control of the 230 KV switchyard is by a supervisory system from selected PP&L System Operating facilities.

Monitoring of the Unit #2 main generator output leads and the 500 KV switchyard is provided in the control room via a mimic bus arrangement. PCB open-close status indication and control are provided for all PCBs in the 500 KV switchyard. Except for the main generator synchronizing breakers which are hardwired directly to the control room along with potential indication, all 500 KV PCB control and status indication in the control room is

provided through a supervisory system. Digital displays monitor output current, watts, vars, watt hours, and voltage. Annunciation accompanies uncommanded PCB status changes, loss of potential, transformer trouble, fire protection system actuation, carrier equipment failure, and fault recorder failure. Control of the 500 KV switchyard fault recorder and tap change control on the 500-230 KV transformer are made available to the operator. Similar information is provided to the control room operator via the computer CRT mimic bus arrangement display through the supervisory system. Primary control of the 500 KV switchyard is via the System Operating supervisory control system except for the main generator synchronizing breakers which can be controlled only by the plant operator.

Preoperational and initial startup testing of all apparatus, equipment, relaying, and PCBs is conducted at transformers #10 and #20 and the 500 KV and 230 KV switchyards to ensure compliance with design criteria and standards.

PCB protective relay testing, maintenance, and calibration in the 230 KV and 500 KV switchyards, Montour switchyard and at transformers #10 and #20 will be conducted approximately once every two years. PCB protective relay testing, maintenance and calibration at Mountain switchyard is performed approximately every year.

8.2.1.5 Industry Standards

The requirements, criteria and recommended practices set forth in the following documents are implemented in the design of the transmission system:

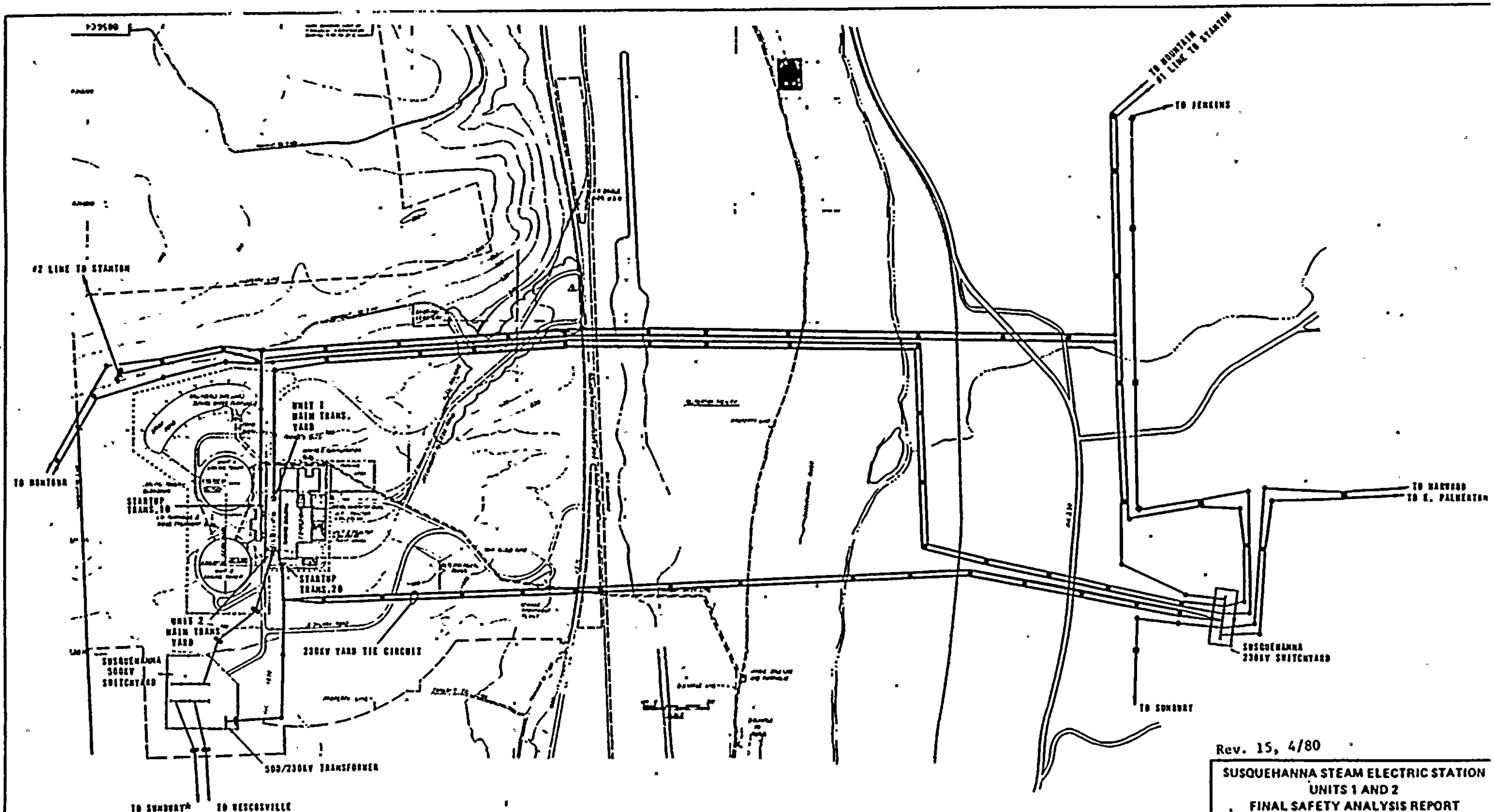
A National Electric Safety Code, 7th Addition.

B. PJM Interconnection Protective Relaying Philosophy and Design Standards

C. MAAC Group Reliability Principles and Standards for Planning Bulk Power Electric Supply System of MAAC Group, July 18, 1968 (Appendix 8.2A)

D. In general, high voltage circuit breakers are manufactured and tested in accordance with the latest recommendations and rules of the ANSI, IEEE, NEMA, and AEIC.

E. Pennsylvania Power & Light Company Substation and Relay and Control Engineering Instruction Manuals, Engineering and Construction Standards, Operating Principles and Practices; Relay and Control Facilities 3/3/76 and sound engineering principles. The design criteria include consideration of aesthetics, reliability, economics, and safety.



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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

TRANSMISSION LINE ARRANGEMENT

FIGURE 8.2-1

* Sunbury line to be installed in 1982.

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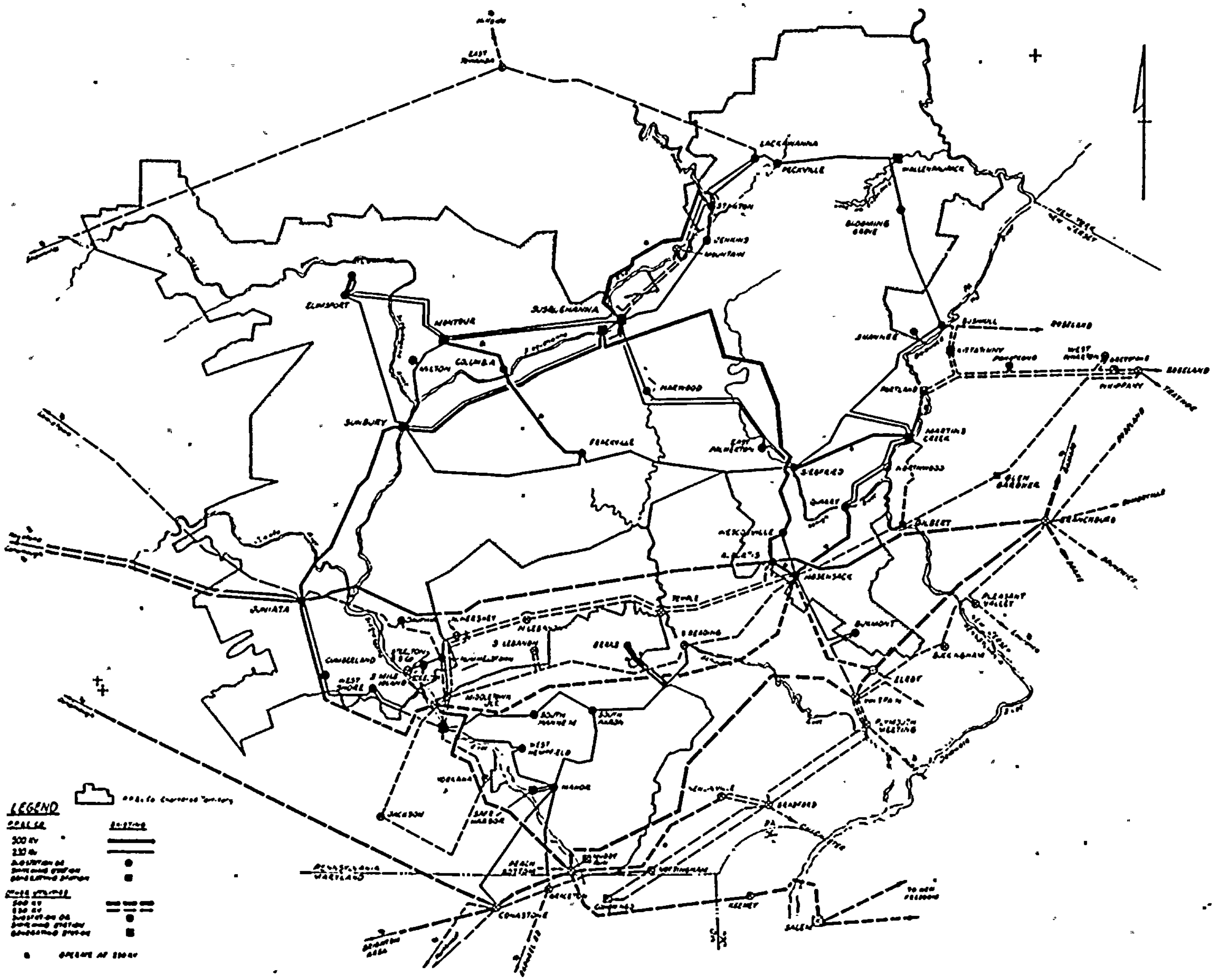
FIGURE 8.2-2



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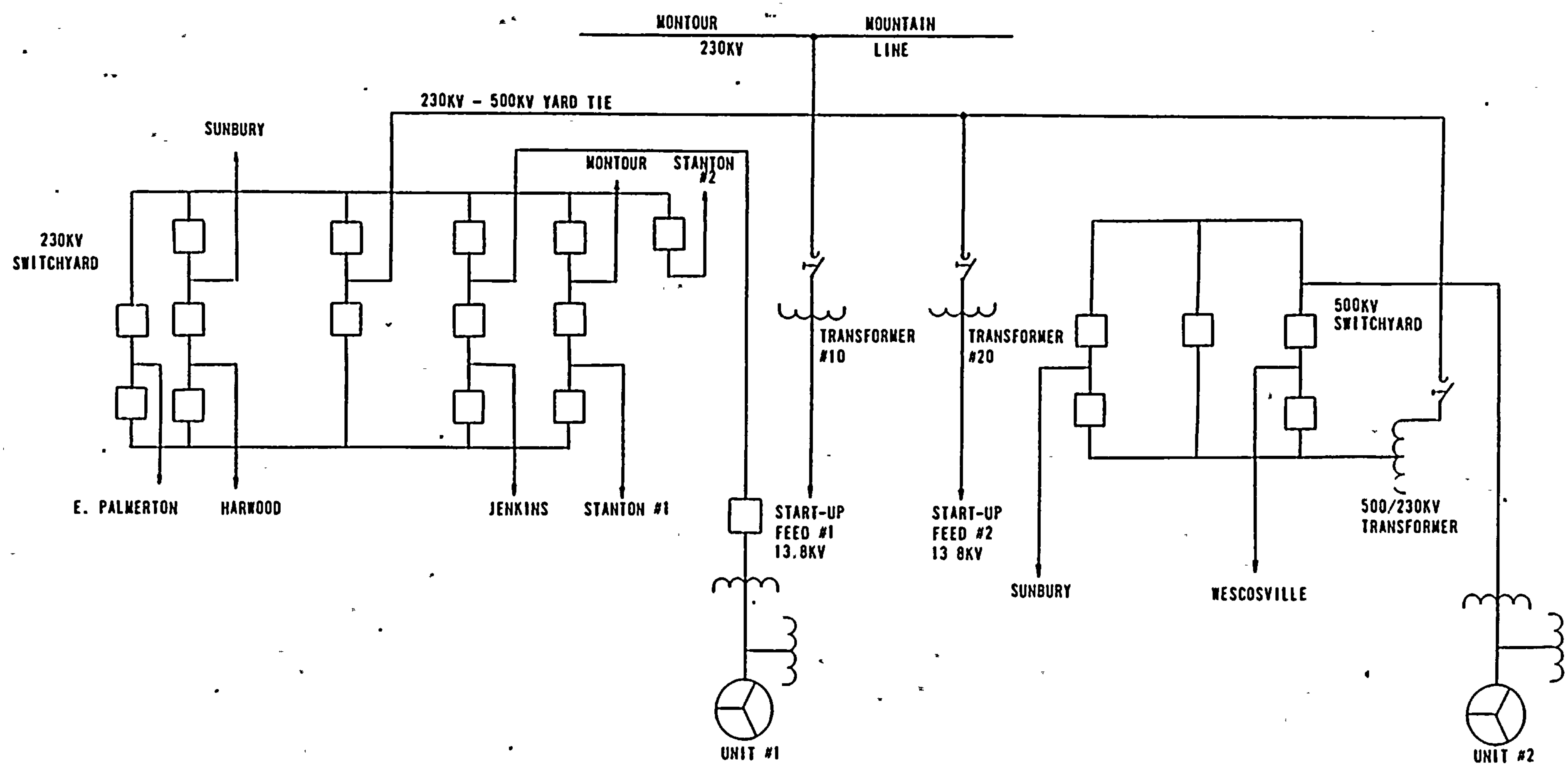
BULK POWER SUPPLY SYSTEM OF PP&L AND ADJOINING SYSTEMS PLANNED THRU 1982

FIGURE 8.2-3



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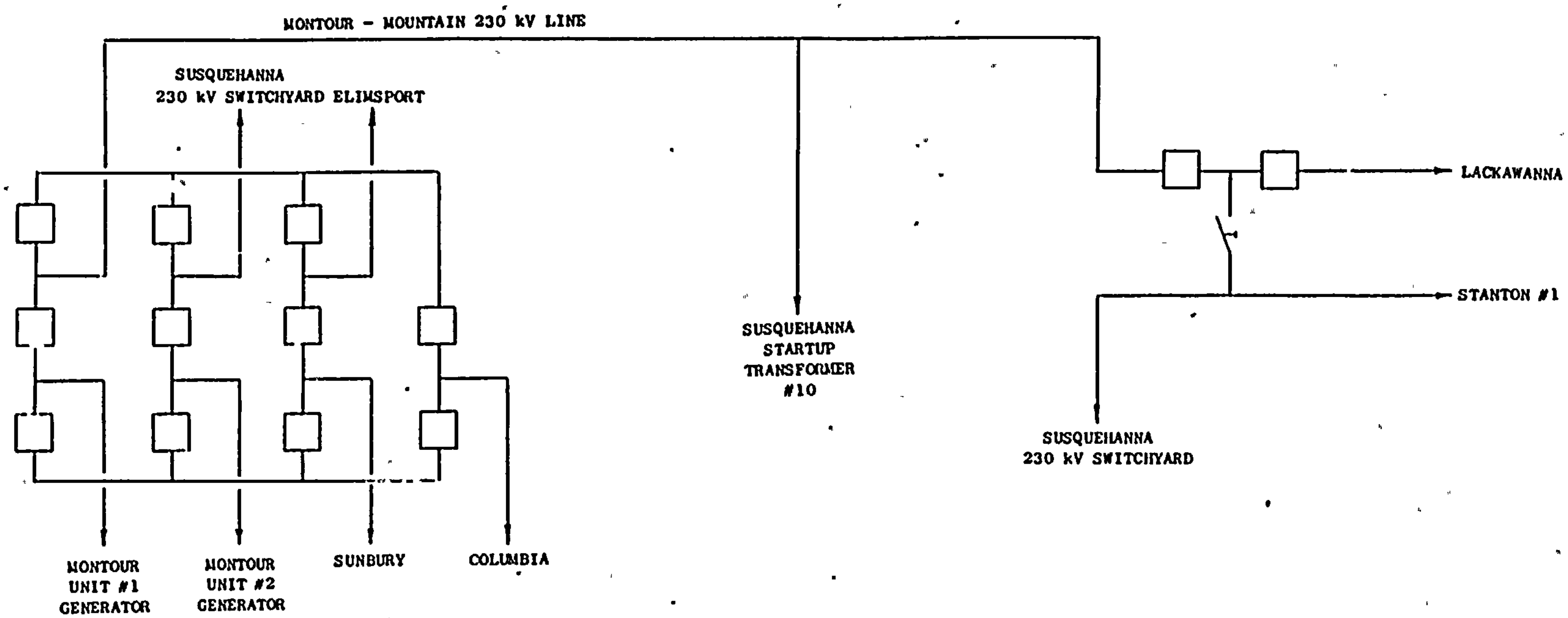
TRANSMISSION SYSTEM

FIGURE 8.2-4



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SUSQUEHANNA STEAM ELECTRIC STATION
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MONTOUR AND MOUNTAIN
SWITCHYARDS
ONE LINE DIAGRAM

FIGURE 8.2-5

APPENDIX 2

CALCULATION OF FREQUENCY OF LOOP DUE TO INDEPENDENT EVENTS

The PL historical outage data (1975-1981) show that for approximately 1200 miles of monitored 230 kV transmission lines, there were approximately 30 instances of forced 230 kV line outages annually. The average duration associated with each forced outage was approximately 8 hours. So as not to skew the Susquehanna LOOP calculation, the historical data were adjusted so that none of the forced outages exceeded 48 hours. This adjustment was made in recognition of the physical and electrical independence of the Susquehanna off-site power system and PL's commitment to the top priority restoration of an outaged off-site source at Susquehanna.

Since the Montour-Mountain 230 kV line, including the Transformer #10 tap, is approximately 50 miles in length, the forced outage frequency for this line is predicted to be:

(50 mi ÷ 1200 mi) x (30 per year) = 1.224 occurrences per year.

Similarly, for the 2.5 mile line supplying Transformer #20, the forced outage frequency is predicted to be :

[(2.5 mi x 10) ÷ 1200 mi] x [30 per year] = .612 occurrences per year.

The length of the short line, 2.5 miles, was increased by a factor of 10 to reflect the assumed higher frequency of terminal induced forced outages for short lines.

The predicted frequency of Transformer #10 and #20 failures is .005 per transformer per year. Since a spare Startup Transformer will be located on site, a 3 day outage duration was assumed for postulated failures of Transformer #10 or #20.

The annual frequency of sustained LOOP (λ_{S1}) at Susquehanna due to having both 230 kV sources in a simultaneous forced outage condition is:

$$\lambda_{S1} = \frac{\lambda_1 \lambda_2(r_1+r_2)}{8760}$$

λ_1 = combined annual frequency of loss of Transformer #10 and its 230 kV source (.005 + 1.224 = 1.229).

λ_2 = combined annual frequency of loss of Transformer #20 and its 230 kV source (.005 + .612 = .617).

r_1 = equivalent outage duration for λ_1:

$$\left(\frac{1.224x8 + .005x72}{1.229} = 8.3 \text{ hours}\right)$$

r_2 = equivalent outage duration for λ_2.

$$\left(\frac{.612x8 + .005x72}{.617} = 8.5 \text{ hours}\right)$$

Therefore, $\lambda_{S1} = \frac{(1.229)(.617)(8.3+8.5)}{8760}$ = .0015 occurrences per year

Using a similar approach, the frequency of sustained LOOP at Susquehanna with one of the two 230 kV sources scheduled out for maintenance is:

$$\lambda_{S2} = \frac{(\lambda_{1m}\ \lambda_2\ r_{1m}) + (\lambda_{2m}\ \lambda_1\ r_{2m})}{8760}$$

λ_{1m} = annual frequency of scheduled maintenance outage for Transformer #10 and its 230 kV source (1 occurrence per year).

λ_{2m} = annual frequency of scheduled maintenance outage for Transformer #20 and its 230 kV source (1 occurrence per year).

r_{1m} = outage duration for λ_{1m} (8 hours).

r_{2m} = outage duration for λ_{2m} (8 hours).

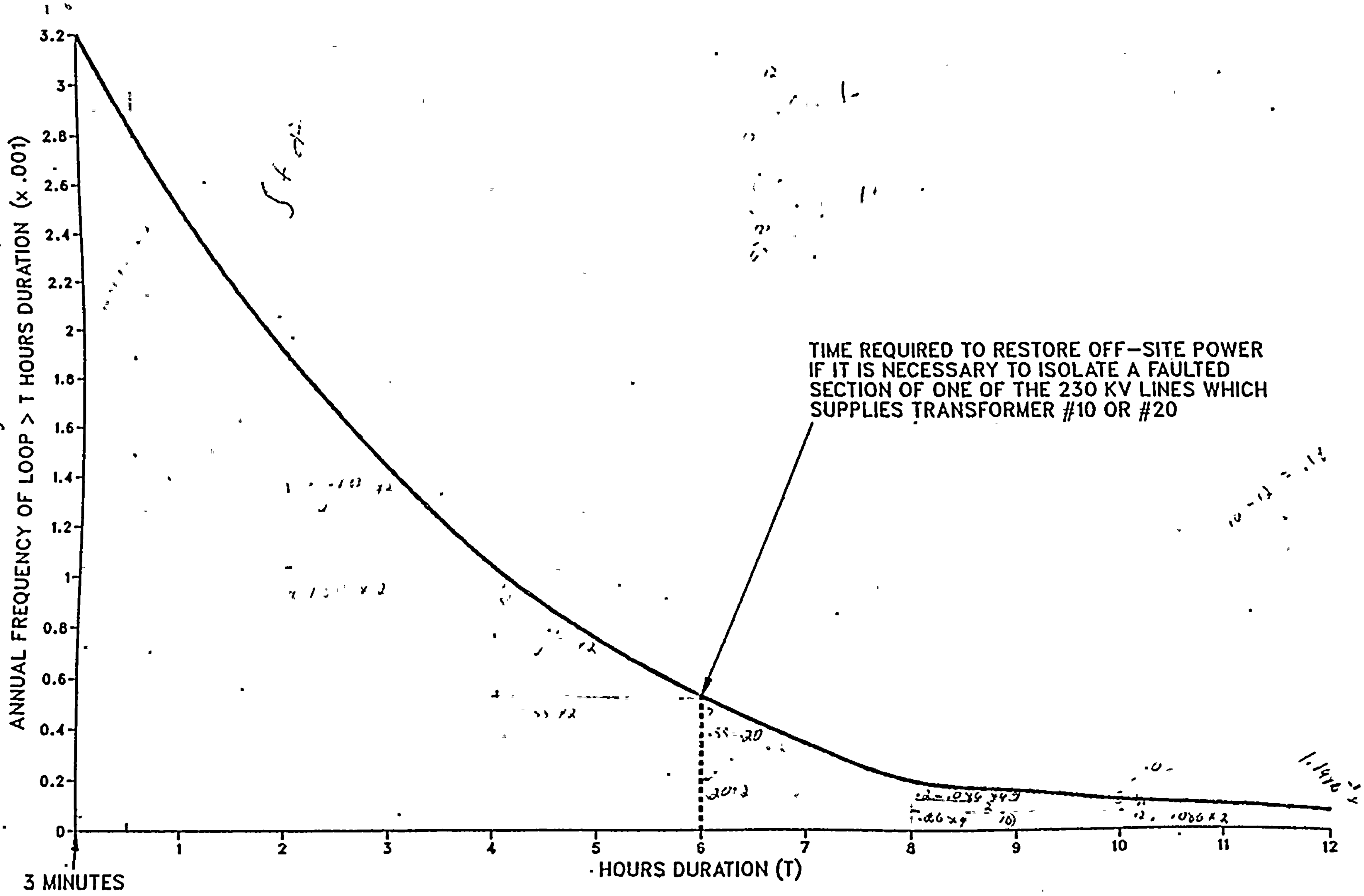
Therefore, $\lambda_{S2} = \frac{(1)(.617)(8)+(1)(1.229)(8)}{8760}$ = .0017 occurrences per year.

Combining the above two components of the independent event calculation yields a value of .0032 (.0015 + .0017) predicted occurrences of sustained LOOP per year. The calculation for transient interruptions of off-site power is similar to the one above and is not presented.

The calculation technique used above is based on the IEEE paper "Power System Reliability I - Measures of Reliability and Methods of Calculation". This paper was published in the July 1964 issue of the IEEE Transactions on Power Apparatus and Systems.

(MG/LA-23)

ANNUAL FREQUENCY OF LOOP > T HOURS DURATION VS. HOURS DURATION (T). FOR LOOP CAUSED BY INDEPENDENT EVENTS



APPENDIX 3