Electric Power Transmission for a Hanford Nuclear Energy Center (HNEC)

**H. Harty
W. J. Dowis, Consultant**

June 1983

**Prepared for
UNC Nuclear Industries
under Related Service Agreement
with the U.S. Department of Energy
under Contract DE-AC06-76RLO 1830**

**Pacific Northwest Laboratory
Operated for the U.S. Department of Energy
by Battelle Memorial Institute**

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

PACIFIC NORTHWEST LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
under Contract DE-AC06-76RLO 1830

Printed in the United States of America
Available from
National Technical Information Service
United States Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22161

NTIS Price Codes
Microfiche A01

Printed Copy	
Pages	Price Codes
001-025	A02
026-050	A03
051-075	A04
076-100	A05
101-125	A06
126-150	A07
151-175	A08
176-200	A09
201-225	A010
226-250	A011
251-275	A012
276-300	A013

3 3679 00047 1740

ELECTRIC POWER TRANSMISSION
FOR A HANFORD NUCLEAR
ENERGY CENTER (HNEC)

H. Harty
W.J. Dowis, Consultant

June 1983

Prepared for
UNC Nuclear Industries
under a Related Services Agreement
with the U.S. Department of Energy
under Contract DE-AC06-76RLO 1830

Pacific Northwest Laboratory
Richland, Washington 99352

CONTENTS

FIGURES	v
TABLES	vi
INTRODUCTION	1
SUMMARY AND CONCLUSIONS	3
GENERAL APPROACH	7
LOAD GROWTH	7
SITE SELECTION	8
AVAILABILITY OF RIGHTS-OF-WAY	10
TRANSMISSION SYSTEM DESCRIPTION	11
HNEC SITE	11
DESIGN CRITERIA	14
TRANSMISSION OPTIONS	14
DESCRIPTION OF TRANSMISSION SYSTEM CONCEPTS	15
LOSSES	22
REACTIVE MVA	23
TERMINAL SWITCHING ARRANGEMENTS	23
THE 50,000 MW HNEC CASE.	27
ECONOMICS	29
ECONOMIC GROUND RULES	29
CAPITAL COST	30
OPERATING AND MAINTENANCE COSTS	32
LOSSES	32
SUMMARY OF ANNUAL COSTS	32
ANALYSIS OF SYSTEM CONCEPTS	37
RELIABILITY	37
Exposure	37

Line Outages	38
Loss of All Lines in a Right-of-Way	39
Loss of an Entire Switching Station	39
Simultaneous Loss of Two HNEC Switching Stations	41
Failure to Clear High-Current Faults	41
Stability	42
RESERVES.	43
TECHNOLOGICAL DEVELOPMENT ASPECTS	44
ENVIRONMENTAL IMPACT	44
REFERENCES	R-1
REFERENCES NOT CITED	R-2
APPENDIX	A-1

FIGURES

1	Pacific Northwest Electric Power Planning and Conservation Act Service Area	12
2	HNEC Tentative Sites	13
3	Pacific Northwest Transmission System Additions for 15,000 MW Case	16
4	Pacific Northwest Transmission System as Planned Through 1991	17
5	Peak Load Power Flows for HNEC 6,000 MW Case	18
6	Peak Load Power Flows for HNEC 10,000 MW Case	19
7	Peak Load Power Flows for HNEC 15,000 MW Case	20
8	Switching Stations - HNEC 6,000 MW Case	24
9	Switching Stations - HNEC 10,000 MW Case	25
10	Switching Stations - HNEC 15,000 MW Case	26
11	EHV-UHV Tower Configuration, Capacity, and Right-of-Way Requirement	46

TABLES

1	Assumed Plant Additions at HNEC in Megawatts	.	.	.	.	.	.	9
2	Major Cross-Mountain Additions Beyond 1991	.	.	.	.	.	.	15
3	System Peak Losses	.	.	.	.	.	.	22
4	Cascade Pass Right-of-Way Capacity	.	.	.	.	.	.	28
5	Schedule of Capital Expenditures	.	.	.	.	.	.	31
6	Estimated Cost of System Losses	.	.	.	.	.	.	33
7	Total Annual Costs and Energy Transmitted	.	.	.	.	.	.	34
8	Risk of Interruption of 50% or More of the Power Flow Through a Switching Station	.	.	.	.	.	.	40
9	Summary of Land Use	.	.	.	.	.	.	45
A-1	Cost Estimating Data, 1100 kV Line	.	.	.	.	.	.	A-1
A-2	Cost Estimating Data, 500 kV Shunt Capacitor	.	.	.	.	.	.	A-1
A-3	Generic Construction Schedule for Interest During Construction	.	.	.	.	.	.	A-2
A-4	Unit Value of Losses	.	.	.	.	.	.	A-2

ACKNOWLEDGMENT

The data on the transmission system was provided by Bonneville Power Administration. The efforts of Brian Silverstein are particularly appreciated.

INTRODUCTION

A study of nuclear energy centers was conducted by the Atomic Energy Commission and reported in WASH 1288, Evaluation of Nuclear Energy Centers, January 1974. The portion of the study covering a Hanford Nuclear Energy Center (HNEC) was conducted by Pacific Northwest Laboratory, and a preliminary study of transmission of HNEC power was prepared with the assistance of the Bonneville Power Administration (BPA).

In 1975 the Energy Research and Development Administration (ERDA) requested a more detailed study of the HNEC, one aspect of which focused on the transmission system. The transmission system was developed through a series of technical discussions with BPA personnel responsible for transmission system planning. The purpose of the discussions was to further develop a concept of a system which will transmit power from HNEC to markets in the Pacific Northwest.

The original study of transmission for an HNEC, which was completed in September 1975, was updated in June 1978. The present 1983 revision takes cognizance of recent changes in the electric power situation of the PNW with respect to 1) forecasts of load growth, 2) the feasibility of early use of 1100 kV transmission, and 3) the narrowing opportunities for siting nuclear plants in the region. The purpose of this update is to explore and describe additions to the existing transmission system that would be necessary to accommodate three levels of generation at HNEC. Comparisons with a PNW system having new thermal generating capacity distributed throughout the marketing region are not made as was done in earlier versions.

The planning of a power transmission system is an iterative process developed over a considerable time period. This report is a current iteration, and substantial further studies will be required to firm up a transmission system for an HNEC, should such a generation expansion develop.

For purposes of this study of possible future transmission requirements, the base generating capacity at HNEC in 1993 is set at 5000 MW,

which is assumed to increase to 6000, 10,000, and 15,000 MW, through future capacity additions.

Cursory consideration is given to potential expansion of system capacity to transmit up to 50,000 MW from HNEC should it be required in the more distant future.

SUMMARY AND CONCLUSIONS

Approximately 75% of Pacific Northwest loads are west of the Cascade Range, and are now primarily served by hydroelectric plants east of the Range. In the future, energy will be supplied primarily by thermal plants, with peaking capacity provided by the hydro system and combustion turbines.

In this study all unprogrammed generating resources beyond 1993 are assumed to be located at HNEC except for a delayed WNP-5 unit at Satsop. Transmission requirements were determined for three levels of generating capacity at HNEC: 6,000, 10,000, and 15,000 MW. Under different load forecasts the HNEC 15,000 MW level would be reached in the year 2004, 2006, or 2017.

Although the timing of transmission system additions would depend on which load forecast is correct, the nature of the addition would be the same, unless substantial amounts of unprogrammed coal-fired generating capacity were added at sites other than Hanford. Under the study assumptions the total east-to-west peak power flow over the Cascade Range would increase from less than 18,000 MW for the 5,000 MW base to 28,900 MW in the 15,000 MW case. These flows would be accommodated by the present grid supplemented with three major 1100 kV east-west lines and some relatively minor 500 kV line additions.

The major issues examined herein are: 1) type of transmission to be employed and an assessment of its technical feasibility, 2) availability of rights-of-way, 3) economics, 4) environmental impact, and 5) overall reliability of the transmission system.

The type of transmission selected for bulk power transfer from an HNEC for the time period studied is overhead AC, 1100 kV, which is now technologically proven.

No extensive underground transmission is contemplated during the period of this study. Conditions at HNEC terminal switching stations do not require it, and throughout the system no right-of-way contingencies are indicated that would compel any more than localized undergrounding.

The major transmission system additions for each concept studied are:

<u>Case</u>	<u>Number of Cross-Mountain 1100 kV Transmission Lines</u>	<u>Total Length km (Mi)</u>
6,000 MW	1	290 (180)
10,000 MW	2	590 (365)
15,000 MW	3	880 (545)

There are no plans to replace in-service 500 kV lines with 1100 kV lines. Only lines of 345 kV and below would be retired for replacement by higher-voltage, higher-capacity lines.

Transmission switching station bus arrangements shown in the report would accommodate line terminals and generating units up to the 15,000 MW level in three stations spaced along an 18-mile axis in the Hanford reservation. Power concentration of that level could result in fault currents near the limits of circuit breakers now available. If required, additional development to increase interrupting capacity ratings and reduce clearing times is expected to be accomplished by the time of HNEC need.

Rights-of-way are available across the mountains assuming that present ones can be utilized and widened as necessary in localized areas. By replacing existing 230 kV and 345 kV lines with 1100 kV, the transfer capacity of the corridors could be increased up to about 87,000 MW. This would accommodate more than 50,000 MW generation at HNEC.

The economics of the case studies are summarized below. The costs are for transmission facilities added after 1992, estimated in constant 1982 dollars. Capital investment required for lines, switching stations, series capacitors, and reactive compensation, is estimated to be:

<u>Case</u>	<u>Investment, \$ Million</u>
6,000 MW	415
10,000 MW	849
15,000 MW	1282

Transmission cost per kilowatt-hour delivered at load centers, for the increment of HNEC generating capacity considered herein, is estimated

at about 3 mills. This is about 7 percent of the value of the energy transmitted. Expressed differently, for an increment of 10,000 MW of thermal generating capacity at HNEC, the price of bulk power at the load centers would be expected to be about 7 percent higher than the price at the busbar, due to the costs of transmission. This unit cost is average for all HNEC plants and corresponding system loads. Individual HNEC generating plants with output wheeled to specific load centers may have greater or less unit transmission cost.

Environmental factors can be summarized as follows:

- 2767 acres in new rights-of-way required for the 6,000 MW case, 3555 acres for the 10,000 MW case, and 4623 acres for the 15,000 MW case, in agricultural, range, forest, and residential/industrial land.
- More visual intrusion in cross-mountain corridors caused by (larger) 1100 kV towers replacing 230 kV towers--one additional line for the 6,000 MW case, two additional lines for the 10,000 MW case, and three additional lines for the 15,000 MW case.

System reliability factors can be summarized as follows:

- With respect to internal failures and common hazards, up to and including loss of all lines in a corridor, the HNEC system could be designed to have a reliability essentially equal to that of the existing system.
- Several events, such as tornado, major earthquake, etc., could conceivably destroy one or more of the three switching stations at the HNEC. However, the risk of loss of generation because of switching station failure does not add significantly to the risk of generating plant outage or transmission line failure from the same event.

The heaviest power flows are in the corridor running southwest from HNEC. Reliability effects of interruptions of flow in this and other corridors have been studied, and the results of the studies have been used in developing a transmission system concept for each case which would meet the Western Systems Coordinating Council's (WSCC) and the

Bonneville Power Administration's reliability criteria. The matter of reliability as affected by disastrous events at HNEC also concerns the generating plants and is factored into those studies.

The conclusions, summarized from the above findings, are:

- Transmission of up to 15,000 MW from HNEC to markets is considered feasible from the standpoints of technology and access to rights-of-way. Technology for 1100 kV transmission should be proven by the mid-1980s.
- Additions to the HNEC transmission system would have some additional environmental impact in land use and visual effects.
- The estimate of transmission cost burden of the HNEC cases (about 3 mills per kilowatt hour) is approximately 7 percent of the estimated cost of bulk power at the generating plant busbar.
- Although overall HNEC system reliability has not been analyzed in detail nor its relative level computed, it appears to be as acceptable as that of the existing system.
- Looking to the more distant future, 50,000 MW generated at HNEC could be transmitted across the Cascade Range, assuming successful development of 1100 kV technology, utilizing available rights-of-way with widening in some places.

GENERAL APPROACH

Hydroelectric resources in the Pacific Northwest have been developed to nearly the fullest extent possible, with the exception of potential low-capacity resources at dispersed sites. Future energy load growth, beyond that offset by conservation achieved by consumers, may be served for the most part from large central station thermal plants. One scenario for locating these plants is concentrating new thermal capacity at Hanford.

Transmission facilities and investment, power and energy losses, and land requirements are examined for three stages of development at the Hanford Nuclear Energy Center (HNEC). Assumptions on rate of load growth, site selection, and availability of rights-of-way are defined at the outset of the study.

LOAD GROWTH

An energy center could serve 1) loads dispersed throughout the region, 2) industrial loads concentrated at HNEC, and 3) loads outside the region. In this study, loads in the two latter categories are ignored, except to the extent that loads at HNEC could affect transmission switching station design. Loads attracted to HNEC, which would not exist in the region otherwise, would affect only HNEC internal transmission requirements. Transmission to loads outside the Northwest is considered only to the extent of presently allowed exchanges over existing tie lines to the Southwest.

The rate of load growth determines the schedule for new generation plants, which in turn dictates transmission system additions. However, once plant site selections are made, the timing of the transmission additions can first be linked to the startup of new thermal plants and then to a load forecast. The impact of changes in load growth rate can then be readily examined.

Load forecasts used by Pacific Northwest utilities for planning have been prepared by the Pacific Northwest Utilities Conference Committee (PNUCC) for over 20 years. This type of forecast is the sum of utilities (SOU) loads, estimated by the region's utilities and by BPA for its Direct

Service Industrial (DSI) and Federal Agency customers. The total Northwest Region energy loads are forecasted in the May 1982 edition to grow to an average annual rate of 2.7% over the ten-year period 1983 to 1993. Load growth beyond 1993 can be extrapolated at the growth rate for the final year, 2%.

Pursuant to the Pacific Northwest Electric Power Planning and Conservation Act of 1982 (Regional Act), the Northwest Power Planning and Conservation Council will develop a Regional forecast to guide BPA's acquisition of major resources. The Council's plan is scheduled to be adopted in April 1983.

As part of its internal planning operations, BPA issued in April 1982 a forecast of loads for the years 1981 to 2000. A baseline forecast and alternative high and low forecasts were developed. Average annual growth rates of 1.6% and 1.8% for the first and second ten-year period, respectively, are indicated in the baseline forecast. These rates increase to 2.6% and 2.3%, respectively, in the high growth forecast.

SITE SELECTION

Resources planned by the region's utilities through 1993 are outlined in the PNUCC forecast. At the end of this time frame, WNP-2 and WNP-1 are scheduled to be in operation at Hanford, as well as two Skagit units relocated at Hanford. WNP-3 is scheduled to be in operation at Satsop, and additional coal-fired generation at Creston, near Grand Coulee, is also planned.

All unprogrammed resources beyond 1993 are assumed to be located at Hanford, except for the delayed WNP-5 unit at Satsop. Table 1 contains schedules of thermal capacity installed at HNEC for three different load growth rates. All units would be of 1300 MW gross capacity, operating at 70% plant factor.

Both the PNUCC load forecast and the BPA high growth forecast would yield generation deficits in 1993, the last year of scheduled resources. It is assumed in the load-resource balance developed for Table 1 that the deficits are eliminated by unprogrammed resources in 1996.

TABLE 1. Assumed Plant Additions at HNEC in MW
Three Load Forecasts

<u>Calendar Year</u>	<u>PNUCC</u>		<u>BPA Base</u>		<u>BPA High</u>	
	<u>Incremental</u>	<u>Total</u>	<u>Incremental</u>	<u>Total</u>	<u>Incremental</u>	<u>Total</u>
Through 1993		5,000		5,000		5,000
1994		5,000		5,000		5,000
1995		5,000		5,000		5,000
1996	2,600	7,600		5,000	1,300	6,300
1997	1,300	8,900		5,000		6,300
1998	1,300	10,200		5,000	1,300	7,600
1999		10,200		5,000		7,600
2000	1,300	11,500		5,000	1,300	8,900
2001	1,300	12,800		5,000	1,300	10,200
2002		12,800	1,300	6,300	1,300	11,500
2003	1,300	14,100		6,300		11,500
2004	1,300	15,400		6,300	1,300	12,800
2005				6,300	1,300	14,100
2006			1,300	7,600	1,300	15,400
2007				7,600		
2008			1,300	8,900		
2009				8,900		
2010			1,300	10,200		
2011				10,200		
2012			1,300	11,500		
2013				11,500		
2014			1,300	12,800		
2015			1,300	14,100		
2016				14,100		
2017			1,300	15,400		

If, instead, load growth follows the BPA base forecast, and plants are energized as planned in the PNUCC schedule, then there will be a generation capacity surplus in 1993. Unprogrammed resources are not added in this scenario until 2002, when the surplus is eliminated by load growth. The treatment of the imbalances in load and resources may affect the timing for the HNEC 6,000 MW case somewhat, but would not have any impact on HNEC 10,000 MW and 15,000 MW cases.

If the trend is toward more use of coal-fired plants at sites other than Hanford, the dates for reaching the designated capacities of HNEC 6,000 MW, 10,000 MW, and 15,000 MW cases would be delayed. Transmission requirements for these cases may change somewhat, depending on the location of the coal-fired generation.

AVAILABILITY OF RIGHTS-OF-WAY

The power system of the Pacific Northwest may be characterized as having its major generating facilities, now mainly hydroelectric, east of the Cascade mountain range, and its major markets west of the range. Power is transmitted westward and southwestward through seven mountain passes. A concentration of new thermal generating capacity at HNEC would add to the present power flows through the passes. In forming a concept of transmission system to accommodate HNEC power flow, an important goal has been to confine the new lines to existing rights-of-way where possible, particularly in mountain crossings and other scenic areas.

This study assumed that corridors through mountain passes would be limited to those now available, but that these rights-of-way could be slightly widened as necessary.

TRANSMISSION SYSTEM DESCRIPTION

The marketing area for power generated at existing plants, and power to be generated in the future in new facilities at HNEC is the Pacific Northwest Region, as defined by the Regional Act. Utilities serving this area are Bonneville Power Administration, Idaho Power Company, Montana Power Company, Pacific Power and Light Company, Portland General Electric Company, Puget Sound Power and Light, Utah Power and Light Company, Washington Water Power Company, and 104 public agency customers of BPA. The area served is shown on the map of Figure 1.

HNEC SITE

The Hanford reservation covers approximately 570 square miles, part of which is unavailable for thermal plants, it being used for government facilities, arid land ecology studies, and similar purposes.

Tentative sites selected for nuclear plants are shown in circles on the map of Figure 2, and general areas suitable for the construction of, or expansion of, transmission switching stations are shown as squares. Corridors considered suitable for the transmission lines are also shown.

Construction of or planning for two nuclear plants by WPPSS in area No. 1 is in progress, with switching station equipment now installed at the Hanford substation and the Ashe substation. Plans are being formulated to relocate the two Skagit units to a site between Ashe and Hanford. A transmission line right-of-way has been established between the Hanford and Ashe substations, with one 500 kV line currently energized. The transmission to accommodate up to 15,000 MW at HNEC would be expanded from that already in place or planned.

As shown in Figure 2, the three substations are separated by distances of approximately 10 and 19 km (6 and 12 miles) with the end stations being 29 km (18 miles) apart. Separation of stations is an element in reliability analysis, discussed later in the report.

Figure 1. Pacific Northwest Electric Planning and Conservation Act Service Area

FIGURE 2. HNEC Tentative Sites

It is assumed that only power plant group sites No. 1 through 3 would be involved through the 15,000 MW level. Other possible locations in the Hanford reservation would be developed only if expansion beyond 15,000 MW in generating capacity were to take place. Each of these general site areas is assumed to accommodate at least six 1300 MW units. Terminal switching arrangements and capacity in outgoing lines are based on these assumptions.

DESIGN CRITERIA

Criteria used in the planning and design of the transmission system for all cases conform to the reliability criteria of the Western Systems Coordinating Council (WSCC) and BPA.

Criteria used to determine the extent, if any, to which underground transmission may be required are:

- 1) At Hanford, underground transmission would be utilized only if congestion made necessary clearances impractical, or if needed for reliability purposes, i.e., to avoid exposure to common mode failure of multiple major lines.
- 2) At receiving ends, underground transmission would be used only when rights-of-way for overhead lines would be unavailable, for environmental, zoning, or economic reasons.

TRANSMISSION OPTIONS

All transmission lines in the three cases are of overhead construction. It was assumed that in no case did application of the foregoing criteria require underground transmission. Gas insulated substation (GIS) equipment and buses may be utilized to alleviate congestion and minimize substation land requirements.

Currently, 500 kV is the highest transmission voltage level applied in the Pacific Northwest system. BPA is actively developing and testing 1100 kV transmission lines and substation equipment, with the goal of making 1100 kV available for commercial application in the early 1990s. Advantages in loss savings and maximized use of transmission corridors are offered by 1100 kV

over double-circuit 500 kV, the highest capacity transmission line currently in use. Therefore, 1100 kV is considered the long-term alternative for bulk power transmission, although BPA is evaluating both options for the next line. In this study, all future cross-mountain lines are assumed to be 1100 kV, although double-circuit 500 kV could be substituted on a one-for-one basis for the 1100 kV lines during the study period.

DESCRIPTION OF TRANSMISSION SYSTEM CONCEPTS

The transmission system of the Pacific Northwest, as planned to 1991, is shown in Figure 3. Additions and modifications to this base system to accommodate 15,000 MW at HNEC are listed in Table 2 and shown in Figure 4 over the background of the 1991 system.

TABLE 2. Major Cross-Mountain Additions Beyond 1991

<u>In Service</u>	<u>Length km (mi)</u>	<u>Description</u>
HNEC 6,000	290 (180)	Ashe-Portland Area 1100 kV
HNEC 10,000	300 (185)	Grand Coulee-Snoqualmie 1100 kV
HNEC 15,000	290 (180)	Gable Mtn-Portland Area 1100 kV

Figure 3 shows only one DC transmission line to the south. A second line has been proposed for the 1990s but it is not in the BPA budget. If it is built, the power flow diagrams to be presented herein would be modified somewhat, but the required east-west transmission lines for the three HNEC cases would not be changed. The primary use of the DC lines in the future will be for capacity exchange. At the January PNW peak load, flow would be to, rather than from, the PNW except in years in which there would be considerable excess hydro energy. This circumstance would not significantly change the cross-mountain transmission requirements.

Power flows in major transmission corridors are shown (Figures 5 and 7) under January peak load conditions for three levels of development at HNEC.

In addition to the major cross-mountain lines listed in Table 2, other sections of lines will be needed to augment local system capacity. For the period beyond 1991, the following facilities would be required:

FIGURE 3. Pacific Northwest Transmission System as Planned Through 1991.

FIGURE 4. Pacific Northwest Transmission System Additions for HNEC 15,000MW Case.

FIGURE 5. Peak Load Power Flows for HNEC 6,000 MW

FIGURE 6. Peak Load Power Flows for HNEC 10,000 MW

FIGURE 7. Peak Load Power Flows for HNEC 15,000 MW

Seattle Area

Loop the 500 kV Monroe-Maple Valley-Raver line and the second 500 kV Monroe-Raver line into a new 500 kV substation at Snoqualmie. Construct a second 500 kV line from Snoqualmie to Maple Valley (25 km)(16 miles).

Portland Area

Construct a second 500 kV line from Ostrander to Pearl (32 km)(20 miles).

The transmission facilities are all operating within their capabilities for the January peak conditions depicted in Figures 5 through 7. Nominal maximum capacities have been established by BPA for transmission lines 250 km to 325 km (155 miles to 200 miles) in length in an interconnected network.

<u>Nominal Maximum Capacity</u>			
	1100 kV	single-circuit	10,000 MW
	500 kV	double-circuit	5,000 MW
	500 kV	single-circuit	1,500 MW

<u>Standard Line Design</u>		
<u>Design</u>	<u>Conductors Per Phase</u>	<u>Series Compensation</u>
1100 kV	8 x 4.24 cm AAC (2097 kCM)	30% (including 500/1100 kV transformers)
500 kV dbl circuit	3 x Seahawk (1869 kCM)	30%
500 kV sgl circuit	3 x Seahawk (1869 kCM)	none

Line loadings will not, however, reach the nominal maximum capacities during the study period. The loss-savings realized by adding cross-mountain transmission lines, as described in the following section, will lead to the construction of these lines before they are required to meet the Reliability Criteria. A line is economically justified the year that the annual costs, including interest, amortization, operations and maintenance, equals the value of losses saved on the transmission grid. The schedule of transmission additions for the three HNEC levels is based on powerflow studies of the base cases and outage cases, and a cursory analysis of potential loss savings.

Transmission line outages, or simultaneous outages of a line and a large generator in the load area, may produce temporary line flows greater than the nominal values tabulated above. However, thermal limits and receiving end voltages would be within limits established by the Reliability Criteria. Preliminary studies indicate no stability problems.

LOSSES

Transmission system losses are significantly reduced when a new cross-mountain line is energized. For example, with 6,000 MW (5 units) at HNEC, an 1100 kV line will decrease January peak losses by 160 MW, while a double-circuit 500 kV line will effect a 110 MW loss savings. With 7200 MW (6 units) at HNEC, the loss savings for an 1100 kV line increases to 210 MW. Total system peak losses for the three HNEC levels are tabulated in Table 3.

TABLE 3. System Peak Losses

<u>Case</u>	<u>PNW Loss (MW)</u>	<u>Unscheduled Reactive (MVAR)</u>
HNEC 6,000	1250	700
HNEC 10,000	1480	2300
HNEC 15,000	1870 ^(a)	6000 ^(a)

(a) Estimated - Values for the HNEC 15,000 power flow are adjusted for estimated effects in lower voltage portions of the system.

Peak loads, and hence, peak losses, are experienced only for a short period during the year. The ratio of average load to peak load is called the load factor, which is approximately 65 percent on the total PNW system. Cross-mountain line load factor is expected to be somewhat lower due to the operation of the hydro system to supply peak loads. The load factor should approach the system average as more base-loaded thermal plants are built at HNEC. This deviation must be considered when evaluating cross-mountain transmission alternatives. Losses are approximately proportional to the square of the line load. For 65 percent load factor, a loss-factor adjustment of 45 percent is applied to the peak losses in Table 3 to obtain annual energy losses.

REACTIVE MVA

New thermal plants are expected to supply part of the reactive power (MVAR) needs of the PNW system. Additional reactive support, supplied by shunt capacitors, will be required in the load areas. Unscheduled reactive requirements for the three levels at HNEC are listed in Table 3. It is assumed that that buildup of MVAR requirements will follow a smooth curve from zero in 1991 to the designated values at the HNEC 15,000 MW level.

TERMINAL SWITCHING ARRANGEMENTS

Conceptual bus arrangements at the HNEC substation sites are shown in Figures 8 through 10 for development of 6,000 MW, 10,000 MW, and 15,000 MW. Lines to existing 500 kV stations and lines to other generating stations at HNEC can originate at each substation, and 500/1100 kV step-up transformers for the new cross-mountain lines can be located there. In addition, each station allows for one or two generating plants to supply possible local industrial load. Generating units up to a total of eight (including one or two for local loads) could be accommodated in each station, assuming that interrupting duty can be held within acceptable limits. Beyond that, more concentration of power in the switchyard would aggravate problems in handling fault currents; it would also be inadvisable to expose too great a portion of the system generating capacity to complete failure of a switching station.

It is likely that gas-insulated substation (GIS) equipment will, at least in part, be used at the HNEC terminals, as well as at the receiving end of the cross-mountain lines. Switching arrangements would be the same whether the station is air insulated or GIS, although the physical layout would change considerably.

One alternative to the arrangements shown is generator step-up transformation directly to 1100 kV. This option is especially attractive if an 1100 kV tie line is established between Coulee and HNEC.

Safety requirements for nuclear plants specify that two independent offsite sources of power for in-house use be available to each reactor. In modern power plant design, the normal source is the generator bus. When the generator is down, power can flow from the 500 kV station to the station

FIGURE 8. Switching Stations - HNEC 6,000 MW Case

FIGURE 9. Switching Stations - HNEC 10,000 MW Case

FIGURE 10. Switching Stations - HNEC 15,000 MW Case

service transformers via the generator bus. At HNEC the alternate source can be the 230 kV system lines in the vicinity of the plants, or the 500 kV system, when two or more lines terminate in the switching station. The alternatives are discussed in Reference 2, in which it was concluded that "Either of the two alternate circuit concepts, Concept A or B (230 or 500 kV), studied in detail would be acceptable, based on safety and operability." (Although Figures 8 through 10 do not contain detailed information on station service arrangements, such detail can be obtained from Reference 2.)

THE 50,000 MW HNEC CASE

In a long-term examination of an energy center, it is necessary to judge the limitations of the transmission system that would have evolved, specifically with respect to continuing growth of the energy center beyond 15,000 MW in generating capacity. To this end, some consideration is given in the report to expansion or adaptation of the system to accommodate net power export of up to 50,000 MW from an HNEC in the more distant future.

If 75% of the added thermal generation would flow to the west, the total flow over the Cascade Range from thermal and hydroelectric sources at peak load would be about 60,000 MW plus flow from any added eastern peaking generation.

Table 4 gives the potential capacity of rights-of-way available over the Cascades if 4 of the 12 rights-of-way are occupied by high-capacity double-circuit 500 kV lines and if the remaining 8 rights-of-way are occupied by single-circuit 1100 kV lines.

A transfer capability of 87,000 MW is shown in the table, against the somewhat lesser requirement of the HNEC 50,000 MW case, indicating ample potential for transfer capacity in available rights-of-way. The total system capability for transfer of power east to west allows a 20% reduction in the summation of pass capacities for imbalance in loading and for reliability. In this analysis the need for the 1100 kV lines would come late enough that the technology may be expected to be well advanced and tested.

TABLE 4. Cascade Pass Right-of-Way Capacity

Pass	1976 MW	Convert Cross-Mountain Lines (345 kV and below) to:	
		Total Capacity	
		12- 5 GW Lines MW	4-5 GW Lines 8-10 GW Lines MW
Stevens	2,600	6,500	11,500
Snoqualmie	550	5,000	10,000
Stampede	3,700	17,700	22,700
Columbia River	2,250	11,500	16,500
Lolo	1,950	11,200	21,200
Mt. Wilson	1,500	11,500	16,500
Breitenbush	<u>500</u>	<u>5,000</u>	<u>10,000</u>
Total Capacity	13,050	68,400	108,400
System Transfer Capability ^(a)	10,500	55,000	87,000

(a) Includes margin for reliability

Handling that amount of power from one general area would involve many questions of system design. However, no absolute technological barrier to the accommodation of 50,000 MW at HNEC is apparent from a transmission standpoint. Growth of transmission capability along the lines discussed above would be compatible with the system visualized for 15,000 MW, and could progress without disruption of system operation.

ECONOMICS

Additional hydro capacity and some pumped storage east of the mountains are expected to come on line during the 1993 to 2000 period. The transmission system concepts for HNEC cases would serve both the new hydro capacity and the new thermal capacity at HNEC.

In this analysis no attempt is made to allocate new transmission capital or operating costs to such generating capacity; to determine or allocate unused capacity in the transmission system at the beginning or end of the growth stage; to place a value on the existing base transmission system; or to derive the system-wide average cost of transmission per unit of energy transmitted. The purpose is only to measure the incremental transmission costs resulting from a decision to add generating capacity at HNEC, to give some perspective on such costs relative to the value of the energy transmitted, and to provide a basis for comparison of incremental transmission cost estimates for any other prospective siting of generating capacity in the region.

The capital cost estimates include major transmission lines, transformers, switching stations, series compensation, and shunt reactors. They exclude those other additions to the system which are needed but are of relatively minor economic significance.

In all cases the estimates are for a series of costs that come from the system additions described above, incremental to the base system costs of the transmission plant in place in 1992, and that would be incurred to accommodate the series of new thermal generating plants to be installed in the HNEC concepts. The analysis makes use of the BPA base load forecast. The significance of the analysis applies also to the other load forecasts in which both load and generating capacity grow more rapidly.

ECONOMIC GROUND RULES

The transmission system required for the three levels of development at HNEC will be built over a period of years. In this study, conducted

in a period of changing inflation and interest rates, no effort was made to predict cost escalation rates due to general inflationary or other effects, or to use discount rates incorporating inflationary or deflationary expectations. Rather, a real discount rate of 4 percent was used, with no escalation of costs applied to estimated capital requirements or operating expense beyond the 1982 dollar value level.

Tables containing the base data used in the economic analysis are in Appendix A.

CAPITAL COST

The incremental transmission facilities required for an additional 10,000 MW of capacity at Hanford (from the 5,000 MW assumed to exist in the late 1990s to the 15,000 MW of the largest case) consist of three major 1100 kV transmountain lines and two 500 kV relatively short lines. The latter are not included in the economic analysis since they would have a relatively minor effect on the overall costs of accommodating the assumed capacity growth at Hanford.

Under the BPA base load forecast, major new lines would be required in the years 2001, 2009, and 2016. Capacitors for the control of reactive KVA on the system would be added from 1992 on. The cost of these facilities is estimated at:

Ashe Portland	\$411 million
Grand Coulee Snoqualmie	424 million
Gable Mountain Portland area	411 million
6,000 MVAR Capacitors	<u>36 million</u>
	\$1282 million

Table 5 contains the schedule of transmission capital funding requirements as capacity at Hanford increases from 5,000 to 15,000 MW.

TABLE 5. Schedule of Capital Expenditures*

<u>Year</u>	<u>\$Million</u>
1992	0.4
1993	0.4
1994	2.0
1995	3.6
1996	3.6
1997	30.5
1998	45.6
1999	247.6
2000	81.0
2001	0.4
2002	2.8
2003	4.5
2004	4.5
2005	32.3
2006	47.9
2007	256.2
2008	84.2
2009	2.8
2010	6.4
2011	6.4
2012	33.2
2013	48.4
2014	250.4
2015	83.7
2016	3.2
	<hr/>
	1282.0

*BPA Base Load Forecast

OPERATING AND MAINTENANCE COSTS

Operating and maintenance costs are estimated at:

Ashe-Portland	\$2.7 million/year
Grand Coulee-Snoqualmie	2.8 million/year
Gable Mountain-Portland area	2.7 million/year
Capacitors	\$425/MVAR/year

These values are used in the computations of annual costs to follow.

LOSSES

The value of losses is based on BPA "time-differentiated long-run incremental cost analysis". The expression for the annual cost of losses per peak kW, C_L , is:

$$C_L = \$0.042 (8760) (L_0 F) + \$54 (1-L_0 F)$$

where $L_0 F$ is the loss factor, in this case 0.45.

Year-to-year losses as loads build up and as additional transmission lines are added are given in Table 6.

Three major effects may be seen. First, the addition of the Ashe-Portland 1100 kV line reduces system losses, and results in a loss credit for a few years. Second, since losses are a function of the square of the current carried in the lines, the losses build up rapidly as the lines become more fully loaded. Third, the curve of losses is sawtoothed, with stepped decreases occurring as new transmission lines come into service. A third effect, not shown in the table, is the reduced losses in an 1100 kV line for a given level of power transmission, relative to those in alternative 500 kV lines.

The losses shown in Table 6 are included in the overall costs of energy delivery.

SUMMARY OF ANNUAL COSTS

Table 7 contains estimates of year-to-year fixed charges on capital, operation and maintenance costs, and cost of losses.

TABLE 6. Estimated Cost of System Losses
Resulting from Load Growth and Transmission Line Additions

<u>Year</u>	<u>Peak System Losses, MW</u>	<u>Δ Losses^(a) MW</u>	<u>Value of Δ Loss^(b) \$ Million</u>
2000	1410	0	0
2001	1250	(160)	(31.2)
2002	1301	(109)	(21.3)
2003	1352	(58)	(11.3)
2004	1403	(7)	(1.4)
2005	1455	45	8.8
2006	1507	97	18.9
2007	1559	149	29.1
2008	1661	201	39.2
2009	1480	70	13.7
2010	1562	152	29.7
2011	1644	234	45.7
2012	1726	316	61.7
2013	1809	399	77.9
2014	1892	482	94.1
2015	1975	565	110.3

(a) From 1410 MW Base

(b) Based on BPA TDLRIC Unit Power Value

TABLE 7. Total Annual Costs and Energy Transmitted,
System Additions Through 2015

Year	Fixed Charges 10^6 \$	O&M Costs 10^6 \$	Losses 10^6 \$	Total Costs 10^6 \$	Energy Transmitted to Load Center, 10^9 kWh
1992	0.03	0.03		0.06	
1993	0.05	0.06		0.11	
1994	0.08	0.09		0.17	
1995	0.10	0.12		0.22	
1996	0.13	0.15		0.28	
1997	0.15	0.18		0.33	
1998	0.18	0.21		0.39	
1999	0.20	0.24		0.44	
2000	0.23	0.27		0.50	
2001	21.74	3.00	(31.2)	(6.46)	
2002	21.81	3.08	(21.3)	3.59	8.64
2003	21.89	3.17	(11.3)	13.76	8.33
2004	21.96	3.25	(1.4)	23.81	8.01
2005	22.03	3.34	8.8	34.17	7.69
2006	22.10	3.42	18.9	44.42	15.35
2007	22.17	3.51	29.1	54.78	15.03
2008	22.25	3.59	39.2	65.04	22.68
2009	44.55	6.48	13.7	64.73	23.48
2010	44.74	6.70	29.7	81.14	30.95
2011	44.93	6.93	45.7	97.56	30.45
2012	45.12	7.15	61.7	113.97	37.92
2013	45.31	7.38	77.9	130.59	37.41
2014	45.50	7.60	94.1	147.20	44.87
2015	45.18	7.85	110.3	163.81	52.34

These estimates are for an increment of two major lines to the transmission system to accommodate an increment of 9100MW of generating capacity at Hanford.

Fixed charges on capital expenditures and interest-during-construction were computed for the various types of equipment. Fixed charges begin the year the line goes into service. These were added to the O&M and loss cost estimates to obtain total annual costs.

Energy delivered to load centers is computed by subtracting incremental transmission system losses from the rated output of the HNEC plants, year by year during the period. Energy deliveries, based on an average 70% generating plant load factor, are also shown in Table 7. In the Table, it is assumed that revenue from the sale of electricity delivered to load centers must cover all costs of transmission, including capacity and energy losses in the transmission system (losses as shown in the Table).

The estimated unit cost of transmission for the increment of generation being studied is 3.0 mills per kilowatt hour, which is about 7% of the estimated value of the energy at the generating plant busbar.

The sensitivity of the 7% figure to the estimated value of energy is:

<u>Variance in Energy Value, %</u>	<u>Transmission Cost/ Energy Value Ratio</u>
0	7.0
+15%	6.5
-15%	7.7

This does not reflect the total system average cost of transmission, since the figures do not include the base system facility costs or energy deliveries.

In conclusion, for an increment of approximately 10,000MW of thermal generating capacity at HNEC (from the 5,000MW assumed to exist at the beginning of the period to 15,000MW), the price of bulk power at the load centers would be expected to be from 6.5 to 7.7% higher than the price at the busbar, due to the costs of transmission from the Hanford site. This increase may be compared with the estimated incremental costs of transmission from alternative generating sites.

ANALYSIS OF SYSTEM CONCEPTS

This section of the report briefly examines the reliability, reserve, technological development and environmental aspects of the growth of generating capacity at HNEC up to 15,000 MW.

RELIABILITY

The reliability of the PNW transmission system as it would be affected by the concentration of thermal generating capacity at HNEC, as epitomized in this study, can be assessed by examining the probability and consequences of system disturbances, i.e., the probable frequency of outages, the amount of load to be dropped, and the duration of the service interruption.

The economy of system design requires that although many kinds of disturbances and equipment failures can be accommodated without any loss of load, other kinds would involve temporary loss of load in certain areas in the process of isolating the troubled area and thereby protecting the rest of the system. Criteria governing the design of the system determine where the line is drawn between accepting some loss of load and investing in more capital plant to avoid any loss of load. The reliability criteria now in effect would apply to the transmission system additions.

Technology of 1100 kV transmission is now available and proven. Substation equipment design basically is scaled up from that of 500 kV equipment. While power flow on an 1100 kV line is greater than that on a 500 kV line the system is designed to meet present Reliability Criteria. If 1100 kV facilities are added for loss savings before they are needed for reliability, then operating experience can be gained in the interim period.

Exposure

Exposure to transmission system outages, which may or may not involve load outages, would be somewhat greater with 10,000 to 15,000 MW of generating capacity at HNEC than it is presently, because of (a) more miles of transmission line, (b) more power carried over certain rights-of-way, and (c) a

considerable concentration of both switching station equipment at HNEC and of transmission lines in the general vicinity of the Center. Category (a) could add some exposure to line equipment failure, but such failures would normally be accommodated without load dropping and may be eliminated as a source of potential downgrading in reliability.

Exposure to damage from external causes is of more concern. Possible causes that could act upon exposure categories (b) and (c) are listed below:

<u>Possible Cause of Failure</u>	<u>All Lines in Rights-of-Way</u>	<u>Switching Stations</u>
Tornado	X	X
Flood		X
Avalanche	X	-
Brush fire	X	
Icing from storms	X	
Earthquake		X
Aircraft crash	X	X
Sabotage	X	X
Ashfall from Cascade volcanoes	X	X
Abnormal conditions at adjacent nuclear plants; radioactive dis- charge as affecting accessibility	X	X
Military attack ^(a)		X

(a) Consequences of military acts are to be considered in other studies.

As mentioned previously, in the current economic climate additional lines can be justified by reduction in losses before they are required for reliability. This trend tends to offset the negative effects of added exposure on system reliability by providing additional alternate flow paths in the network. Other considerations follow.

Line Outages

Line outages as discussed here include both circuits of a double-circuit line. The following statements refer to steady-state conditions with load

shifts made under stable conditions. Transient stability effects are discussed in a latter section on stability.

In the simulated system tests the HNEC design concepts respond to the loss of any line without interruption of service to loads on any part of the system. The most heavily loaded line will carry about 5,000 MW just before a second 1100 kV line is added to the Portland area for the 15,000 MW case. Load on that line, or on any other line considered crucial, would be shifted to other lines of the network without any loss of load. Although a particular line may be more heavily loaded than presently, more spare capacity is provided in other lines in the network, and the consequences (no load loss) would be unchanged.

Loss of All Lines in a Right-of-Way

The design criteria permit some controlled dropping of interruptible and firm load in the event of loss of all lines in a right-of-way. This could cause loss of more load in the future when east to west transfers would be greater than at present. However, if a single right-of-way would have only one major line, along with one or two 230 kV single-circuit lines, 80% of the capacity in the right-of-way would be in the major line. If system design is such that the loss of the major line could be accommodated without any loss of load, the chances are that in most situations simultaneous loss of the minor lines could also be accommodated.

If the major lines described heretofore were placed in separate rights-of way, the difference in reliability of the two concepts for loss of all lines in a right-of-way would probably be insignificant.

Loss of an Entire Switching Station

Under the design criteria, loss of an entire switching station could entail dropping of some interruptible and firm load, and dropping of generators. In the HNEC cases, since a large amount of generating capacity is connected to a single switching station substantial load may be dropped.

However, here again extenuating circumstances exist in that the two adjacent thermal generating groups and the hydro plants in the eastern part of the state with their reserve capacity may be able to pick up most or all of the generating deficit. All generators on one switching stations would constitute from 10 to 14% of total on-line system generating capacity depending on the stage of development and the point in the loading condition at the time.

Although loss of an entire switching station could have serious reliability consequences with the HNEC concepts, the probability of such a loss is very low. The switching structure and apparatus would be spread over many acres, and under ordinary conditions it is highly unlikely that a section in trouble could not be isolated; thus, the amount of generation lost in a specific incident may not be highly disruptive.

The risk of interruption of up to 8.4 GW power flow at an HNEC switching station serving seven generating units, because of a disastrous event affecting the station, is evaluated in Reference 4. The probability of occurrence of such events is given in Table 8 taken from the referenced document. From the table, the probability of a major power interruption at a switching station because of the occurrence of any of these events is 4.3×10^{-6} per year, or once in 230,000 years. The estimated probable time in which the station could be returned to service following such an event is 25 days.

TABLE 8. Risk of Interruption of 50% or More of the Power Flow through a Switching Station

	<u>Probability, Events/Year</u>	<u>Probable Outage Time, Days</u>
Tornado	4.0×10^{-6}	25
Aircraft crash	1.7×10^{-7}	40
Flood	1.0×10^{-7}	15
Earthquake ^(a)	--	--
Radioactive release ^(a)	--	--
Ashfall ^(a)	--	--

(a) Failure of a switching station from such events would add nothing to the risk of loss of generation on the system arising from the impact of the same event on the generating plants feeding into the switching station.

From these estimates, HNEC switching station exposure to external events would not significantly reduce the reliability of the transmission system.

Relay misoperation and operator error are more likely causes of loss of part or all of a switching station, but the probabilities of such events have not been estimated.

Simultaneous Loss of Two HNEC Switching Stations

As analyzed in Reference 4, single events that are sufficiently widespread to impinge on two switching stations simultaneously (limited to earthquake, ashfall, and flood from a Grand Coulee Dam failure) would also cause failure of the generating plants. Therefore, the switching station risk adds nothing to the overall risk of loss of generation to the system. Conceivably a single tornado could strike two switching stations without affecting the generating plants, but the probability is very low, of the order of 1×10^{-7} events per year (once in 10 million years).

Failure to Clear High-Current Faults

As noted under a following section on "Technological Development Aspects," the high fault currents of an HNEC with the bus arrangements shown would be close to the limit of present state-of-the-art interrupting capacity. It is assumed that future development effort will further increase the capacity ratings and reduce clearing times. If so, the reliability of fault clearing equipment would presumably be adequate. If adequate development results have not been achieved by the time of need, the design would have to be such as to limit fault currents by subdivision of buses, use of reactance, or other measures, at added cost.

The extent to which an HNEC might be vulnerable to major power interruptions from failure to clear high-current faults is explored in Reference 4. The major concern is that the first two circuit breakers in the protective sequence would fail to clear the fault thus precipitating system instability. The probabilities entering into an assessment of risk are:

1. The probability of occurrence of the causative event, i.e., a heavy short circuit or ground on the transmission system,
2. The probability of successive failure of two breakers for any reason (some failures are not due to high fault currents), and

3. The probability of the system becoming unstable before further backup breakers have cleared the fault.

In the comparative positions of HNEC 15,000 MW and the present system with respect to these probabilities, there is no clear difference in Items 1 and 2, but there is some disadvantage to the more highly-developed HNEC in Item 3. The disadvantage would be with the uncleared fault being near a larger block of generation. Estimates of the numerical value of probabilities 1 and 3 were not available. The value of Item 2, the failure rate of modern circuit breakers, is 0.005 (once in 200 attempts) for each breaker.

Even though HNEC, 10,000 to 15,000 MW, is at some disadvantage in the above comparison, the frequency of a failure-to-clear event would be very low as determined by the presence of the factor $(0.005)^2 = 0.000025$. It can be concluded that under the above assumptions the reliability of the transmission system would not be significantly downgraded by HNEC exposure to greater fault currents.

Stability

The Pacific Northwest system of 1993 with its "distributed" hydro and thermal generation will be a closely coupled system, with internal inter-connecting transmission lines of relatively high capacity, thus enhancing internal system stability. The greatest stability problems would be those concerned with angular swings between the Pacific Northwest and Interconnected adjacent systems, those of California, Canada, Idaho, and Montana.

In the HNEC case of maximum development internal system stability will be maintained if the total capacity of the ties between HNEC and existing generating stations are proportionately as great as that which now exists in the interconnections between Grand Coulee and other generating plants. Preliminary studies indicate that the requirement would be met by the systems described heretofore for both cases.

Although thorough stability studies have not been conducted on the HNEC cases, preliminary studies indicate that the angular swings occurring when major loads or lines are lost would not be excessive and could be kept within

acceptable limits by means now employed in various places on the system. These include fast fault clearing (one cycle breakers), dynamic braking resistors, fast relaying, and controlled dropping of generators and/or loads.

The results of the preliminary study on stability are summarized below:

- Internal system stability could probably be maintained without great difficulty in the HNEC concepts.
- Stability between the PNW and adjacent systems will be affected in much the same way as at present, the major consideration being the total increase in generating capacity relative to the capacity and loading of tie lines with other systems.

To summarize the foregoing section on reliability:

- HNEC 10,000 to 15,000 MW would be exposed to a very low-probability class of events that could affect reliability adversely relative to present system reliability and that class of events could not be compensated reasonably by system design measures.
- In other exposure classifications the HNEC concept has reliability essentially equal to that of the present system.

RESERVES

The existence of a nuclear energy center conceivably could affect the amount of the reserves that would be necessary because of 1) a transmission pattern that would be different than for a system with more distributed generation, and 2) a potentially better situation in which to maintain generating plants and make emergency repairs on them. Only the first of these possible influencing factors is considered here, the second being a part of the larger HNEC study.

The Pacific Northwest Utilities Conference Committee (PNUCC), in which the Bonneville Power Administration is a participant, has adopted a criterion of determining reserve requirements based on the larger of either 1) a reserve margin of 12% of estimated peak loads for the coming year of a resource schedule, increasing by 1% each year until a 20% margin is reached, or 2) the reserves required to maintain an annual probability of load loss equivalent

to 0.5 plus one-half year's load growth. In the first method, the lower reserve levels in the early years reflect the predominance of inherently more reliable hydro generating units in the system. The higher levels in the later years are intended to reflect the impact of adding large thermal plants with higher outage factors to the present system.

It is expected that in the future the reserves will be provided largely by hydro plants and pumped storage installations, but that under certain conditions reserves will also be maintained in thermal plants. The reserve capacity has been and will be available to loads throughout the system under the same transmission conditions prevailing normally.

The amount and placement of reserve capacity are therefore largely independent of the placement of thermal generation for both spinning and other operating reserves.

TECHNOLOGICAL DEVELOPMENT ASPECTS

In the HNEC concept, in which 4 to 8 generating units may feed into one switching station, and with adjacent groups of plants that could make important contributions to current at a fault near the switching station, fault currents could exceed the ratings of circuit breakers now available.

The HNEC 15,000 MW case allows an available fault current of 50 to 60 kA which is within the interrupting capacity of modern circuit breakers. Within the last two decades the interrupting time of circuit breakers has been reduced from 8 cycles of the power frequency to two cycles, and at 500 kV the standard rating is 40 kA and two cycles. Breakers capable of interrupting up to 100 kA in two cycles at voltages up to 800 kV are available. Additional research is proceeding in the development of relay-breaker combinations at above rating capable of interrupting faults within one cycle after initiation.

ENVIRONMENTAL IMPACT

The environmental effects of the HNEC transmission concept presented herein would be mainly in the categories of visual impact and the amount of land used for rights-of-way. Study of the biological effects of the electrostatic and electromagnetic fields near 1100 kV lines is continuing. Voltage

gradients in space at the edge of the right-of-way can be kept to the values for existing lower voltage lines by conductor design and possible use of shield wires.

Differences in visual impact would occur wherever 1100 or 500 kV towers were added or where they would replace 230 or 345 kV line towers. These towers are larger than the lower voltage towers (Figure 11). In the HNEC cases there would be one additional cross-mountain line of approximately 180 miles in length for each of the three stages of capacity growth. Although the higher voltage towers are larger, they have only minor added visual impact on most observers when seen in open countryside without a frame of reference for size.

Amounts of land that would be required over and above that already in use for transmission rights-of-way are listed in Table 9. After the construction of the Ashe-Portland line at the 6000 MW stage of HNEC development, the new land requirements of the additional lines to accommodate the 10,000 and 15,000 MW cases are relatively small.

TABLE 9. Summary of Land Use
Additional Rights-of-Way
for Cross-Mountain Lines

<u>Land Use</u>	<u>Incremental Right-of-Way</u>		
	<u>HNEC 6,000</u>	<u>km² (Acre)</u> <u>HNEC 10,000</u>	<u>HNEC 15,000</u>
Agricultural	6.27 (1550)	0.99 (245)	0.05 (12)
Rangeland	3.76 (930)	0.91 (225)	3.93 (971)
Forest Lane	1.04 (257)	1.29 (318)	0.22 (54)
Residential/Industrial	0.12 (30)	0.00 (0)	0.13 (31)
Total	11.19 (2767)	3.19 (788)	4.33 (1068)

Note: 1. Assumes utilization of existing right-of-way by replacing existing lower voltage lines with higher capacity lines.
2. Lolo Pass ultimate capacity is for two 1100 kV lines (HNEC 6,000). Second line, HNEC-Portland, assumed to use Satus Pass (HNEC 15,000).

FIGURE 11. Configurations of typical BPA Transmission Line Towers. Heights given are averages for level terrain. Actual heights vary depending on environmental and engineering factors.

The use of the large towers will result in increased risk to migratory birds. Mortality resulting from collision with radio and television towers located along migration routes has been well documented but has not been shown to significantly affect population levels. These collisions normally occur at greater heights than the planned transmission towers. The role of transmission facilities in the electrocution of birds is difficult to evaluate since there is little quantitative information available concerning mortality. Electrocution involves simultaneous touching of two conductors or one conductor and ground. Large hawks and owls are more susceptible to electrocution than smaller birds. Recent studies have shown that there is little danger of electrocution for even large birds of prey on steel towers since these towers have widely spaced conductors.

The prairie falcon and American peregrine falcon are two species threatened with extinction (U.S. Fish and Wildlife, Resource Publ. 114) that are likely to come in contact with the proposed transmission corridors. The prairie falcon nests in the bluffs along the Columbia River and forages out over nearby grassland areas in search of prey. The American peregrine falcon also nests along bluffs and cliffs, but it is more secretive. There are no known peregrine nests in the vicinity of the transmission corridors but adults may cross them during migration and while foraging. Several pairs of nesting prairie falcons have been seen near Hanford along the Columbia River. Construction and maintenance activities along the transmission line corridors are not expected to have any adverse effects on either species.

The potential exists for some environmental degradation associated with the removal of existing 230 kV circuits and construction of 1100 kV single circuit or 500 kV double-circuit lines. Erosion can occur as a result of vegetation removal and road construction activities. Generally, erosion is more of a problem in forested areas with heavy rainfall, but the slow rate of vegetation recovery in semi-arid regions can result in significant wind erosion problems. Both soil erosion and increased exposure to direct sunlight can adversely affect aquatic environments by increasing turbidity and sediment load which lowers overall stream productivity. The clearing of cover along stream banks exposes the stream to direct sunlight resulting in increased water temperatures. Higher water temperatures reduce the oxygen-holding

capacity of the water and increases the metabolic rate of water-dwelling organisms. These effects are minimized by maintaining suitable cover along stream beds.

Maintenance of transmission line right-of-way would be expected to have only a minimal effect as compared to the original construction impact as long as vegetation is permitted to become reestablished beneath the lines. Vegetation control beneath the lines serves to maintain the plant community in a permanent successional stage but does not greatly reduce the availability of suitable wildlife habitat.

Little environmental impact is anticipated. Some additional potential exists for adverse impact from the greater transmission line mileages in agricultural, rangeland, and forestland habitats associated with system growth. There are no rare or endangered species that would be adversely affected by construction of the HNEC transmission design.

REFERENCES

1. United States Nuclear Regulatory Commission, NUREG-001, Nuclear Energy Center Site Survey, 1975, January 1976.
2. R. L. Richardson, W. J. Dowis, BNWL-2076 Station Service Power Supply for a Hanford Nuclear Energy Center (HNEC).
3. R. D. Dunlop, R. Gutman, and P. P. Marchenko, Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines, IEEE PES Winter Meeting, January 29, 1978.
4. R. G. Clark, W. J. Dowis, BNWL-2474 Reliability of Generation at a Hanford Nuclear Energy Center (HNEC), Pacific Northwest Laboratory, June 1978.

REFERENCES NOT CITED

Biological Studies Task Team, Bonneville Power Administration, Electrical and Biological Effects of Transmission Lines: A Review, June 1977.

Garver, L. L., J. J. LaForest, and S. C. Robison. October 1975. Transmission Costs as Affected by Energy Center Size. General Electric Company, Schenectady, New York. Electric Utility Systems Engineering Department. Preliminary Report.

GPU Service Corporation. December 1974. Energy Park Development, Transmission Study.

National Electric Reliability Council, April 1975. Nuclear Energy Centers: An Assessment of Impact on Reliability of Electric Power Supply. Technical Advisory Committee, Interregional Review Subcommittee. Princeton, New Jersey.

Reister, D. B. and L. W. Zelby, "A Comparison Between Dispersed Nuclear Power Stations and a Nuclear Energy Center at a Hypothetical Site on Kentucky Lake, Tennessee," Vol. II, Transmission of Power, ORNL-TM-5014.

Ringlee, R. J. and J. W. Beck, December 1974. An Assessment of Policies and Technical Factors Affecting the Degree of Interconnection of Electric Utilities in the U.S. Power Technologies, Inc., Schenectady, New York.

APPENDIX

Unit Cost Estimates
Used in the Economic Analysis Section

TABLE A-1. Cost Estimating Data
1100 kV Line Ashe-Portland
1982 Dollars x 10⁶

<u>Item</u>	<u>Investment</u>	<u>Annual O&M</u>	<u>Service Life (Yr)</u>
1. Line 290 km (8 x 4.24 cm AAC)	318	0.3	50
2. Transformers (4 x 3000 MVA banks)	40	0.5	35
3. Shunt Reactors (1920 MVAR)	30	1.2	35
4. Series Capacitors (1100 MVAR)	17	0.6	35
5. Switching (2 1100 kV PCBs)	6	0.1	35
Total	411	2.7	

Note: 1. Items 1, 3, and 4 are 3.4% higher for Coulee-Snoqualmie
(300 km/290 km = 1.034)
2. Annual O&M costs are estimated for 1100 kV equipment based on
500 kV experience. Direct and indirect maintenance operations,
administrative and general included.
3. Equipment service lives in the BPA cost of service analysis (COSA)
are: steel lines - 39 yrs, substation - 28 yrs. Longer lives are
assumed for 1100 kV based upon no replacement due to obsolescence.

TABLE A-2. 500 kV Shunt Capacitors
for Unscheduled Reactive

Investment	\$6000/MVAR
Annual O&M	\$425/MVAR
Service Life	28 years

TABLE A-3. Generic Construction Schedule
for Interest During Construction (IDC)

<u>Year</u>	<u>Percent Funds Expended</u>	
	<u>Line</u>	<u>Substation</u>
1	0.5	
2	1.0	
3	1.0	
4	9.4	0.2
5	11.7	8.6
6	58.0	67.5
7	<u>18.4</u>	<u>23.7</u>
	100.0	100.0

TABLE A-4. Unit Value of Losses

Energy	42 mills/kWh
Capacity	\$54/kW

These values are based on the BPA Time-Differentiated Long-Run Incremental Cost (TDLRIC) analysis (March 1982).

If L_0F = Loss factor, then the annual cost of losses, in dollars per peak kW, C_L , is found as:

$$C_L = 0.042 (8760) (L_0F) + 54 (1-L_0F)$$

DISTRIBUTION

No. of
Copies

No. of
Copies

OFFSITE:

ONSITE:

W. F. Savage, Chief
Advanced Concepts
Evaluation Branch
Mail Stop F-309
Washington, DC 20545

DOE Richland Operations Office

H. E. Ransom
K. W. Bracken
O. J. Elgert
F. R. Standerfer

Arlee Holm
Bonneville Power Administration
P. O. Box 3621
Portland, Oregon 97208

UNC Nuclear Industries

W. R. McSpadden
R. L. Richardson

Ricky Poon
Bonneville Power Administration
P. O. Box 3621
Portland, Oregon 97208

Rockwell Hanford Operations

C. M. Salina

Brian Silverstein
Bonneville Power Administration
P. O. Box 3621
Portland, Oregon 97208

34 Pacific Northwest Laboratory

F. W. Albaugh
C. E. Diamond - consultant
W. J. Dowis - consultant
S. J. Farmer
H. Harty (20)
A. M. Platt
W. D. Richmond
L. D. Williams
Publishing Coordination (2)
Technical Information (5)

Library
Bonneville Power Administration
P. O. Box 3621
Portland, Oregon 97208
3 Files
Bonneville Power Administration
P. O. Box 3621
Portland, Oregon 97208

27 DOE Technical Information Center