Appendix to

**The Hanford Nuclear Energy
Center**

A Conceptual Study

Harold Harty, Project Manager

September 1978

Prepared for the U.S. Department of Energy
under Contract EY-76-C-06-1830

Pacific Northwest Laboratory
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Appendix to
THE HANFORD NUCLEAR ENERGY CENTER:
A CONCEPTUAL STUDY

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Pacific Northwest Laboratory
Richland, Washington 99352

PREFACE

This appendix is a compendium of topical reports prepared for the Hanford Nuclear Energy Center.

- Status Report--Conceptual Fuel Cycle Studies for the Hanford Nuclear Energy Center, BNWL-B-437, November 1975.
- Selection of Heat Disposal Methods for a Hanford Nuclear Energy Center, BNWL-2003, June 1976.
- Station Service Power Supply for a Hanford Nuclear Energy Center (HNEC), BNWL-2076, December 1976.
- Impact of a Hanford Nuclear Energy Center on Ground Level Fog and Humidity, BNWL-2058, March 1977.
- A Review of Potential Technology for the Seismic Characterization of Nuclear Energy Centers, BNWL-2396, July 1977.
- Reliability of Generation at a Hanford Nuclear Energy Center (HNEC), PNL-2474, December 1977.
- Meteorological Evaluation of Multiple Reactor Contamination Probabilities for a Hanford Nuclear Energy Center, PNL-2452, March 1978.
- Electric Power Transmission for a Hanford Nuclear Energy Center (HNEC), BNWL-B-426-REV, July 1978, Revision.
- The Impact of a Hanford Nuclear Energy Center on Cloudiness and Insolation, PNL-2638, July 1978.
- A Licensing Review for an HNEC, BNWL-2077, September 1978.

Earlier versions of reports on the HNEC concept, electrical transmission, and heat sink management are not included. One report, BNWL-B-437, contains an earlier scenario of an HNEC buildup. The scenario has been updated for the final conceptual study report (PNL-2640), but the earlier report was not reissued.

STATUS REPORT--CONCEPTUAL FUEL CYCLE
STUDIES FOR THE HANFORD NUCLEAR ENERGY
CENTER

E. T. Merrill and R. M. Fleischman
Nuclear Technology Department
Engineering Systems Analysis

November 1975

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STATUS REPORT--CONCEPTUAL FUEL CYCLE STUDIES
FOR THE HANFORD NUCLEAR ENERGY CENTER

E. T. Merrill and R. M. Fleischman

1.0 INTRODUCTION

Nuclear Energy Center (NEC) concepts have been studied throughout the world since the mid 1960s. Many of the early studies focused on nuclear energy center and agro-industrial complexes.⁽¹⁻⁶⁾ In the U. S. most of the recent studies are directed at evaluating the potential advantages and disadvantages of clustering nuclear power plants and/or supporting nuclear fuel cycle facilities on single sites.⁽⁷⁻¹⁰⁾ The principal driving forces for these concepts include perceived improvements in power plant construction schedules and special nuclear material safeguards.

In the Project Independence program⁽⁸⁾ Hanford was studied as a nuclear energy center, and a preliminary evaluation was made of fuel cycle options that might exist at a NEC. This study examines the fuel cycle in greater detail, focusing on the logistics of utilizing plutonium, in the context of a Hanford Nuclear Energy Center (HNEC).

It is generally recognized that the energy center concept may be attractive because it could provide for complete retention and productive use of plutonium within the energy center prior to the time that plutonium bearing fuels must be shipped offsite to fast breeder reactors located outside the energy center. The apparent advantages of onsite plutonium use lie in the elimination of shipments of recovered plutonium and of fresh LWR (light water reactor) mixed oxide fuel outside the energy center. This report summarizes the current status of studies to determine the logistics of onsite plutonium recycle and the timing involved in introducing the associated reprocessing and fabrication fuel cycle facilities.

Evaluating scenarios of plutonium use for the HNEC is an iterative process that must ultimately relate both to economic incentives and the

realities of Federal licensing and regulations. The current studies have evaluated the material logistics associated with various plutonium use scenarios at the HNEC to the point that reprocessing capabilities for LMFBF fuels are required. Substantial further studies will be required to evaluate the effect of LMFBF (liquid metal fast breeder reactor) plutonium on continued plutonium recycle in LWRs and to ultimately assess the economic impacts of onsite plutonium use.

2.0 STUDY GUIDELINES AND ASSUMPTIONS

The study of an evolving energy center at the Hanford site is obviously a speculative endeavor that involves not only projections of nuclear reactor growth patterns but also the consequent growth of supporting fuel cycle components such as fuel fabricating and reprocessing plants. In order to bound the current study, certain guidelines were established at the onset. These are summarized below to clarify the assumptions implicit in the results given in this report.

The conceptual HNEC fuel cycle logistics studies reported here are based on the LWR-LMFBF plutonium park concept. This concept is generally considered attractive because it would allow retention and productive use of plutonium within the energy center, thus localizing the safeguards associated with plutonium transportation and storage. For the reference HNEC, fuel reprocessing and mixed oxide fuel fabrication plants were assumed to be colocated at the Hanford site to eliminate offsite shipments of unfabricated plutonium. Moreover, plutonium use in LWRs was restricted to the HNEC, and offsite shipment of fresh LMFBF fuel was minimized by the preferential location of LMFBFs at HNEC.

The conceptual HNEC was developed in the context of regional growth. The selected HNEC growth scenario was keyed to the growth of nuclear power in the Western Systems Coordinating Council (WSCC), which was in turn keyed to a projected growth of nuclear generating capacity in the U.S. of

900 GWe in Year 2000 and 1750 GWe in Year 2010. The WSCC, shown in Figure 1, essentially covers the eleven westernmost states in the continental U. S. Under the assumed growth conditions, the WSCC capacity was estimated to be ~133 GWe in Year 2000 and 260 GWe in Year 2010. Plants located at HNEC prior to 1985 were those already planned for location at the Hanford Site. Beyond 1985 all LWRs and LMFBRs constructed in the Pacific Northwest were assumed to be located at HNEC. It was further assumed that the Hanford site could support a construction rate that would result in completion of a maximum of two reactors in a given year, and that a total of 40 reactors would comprise the completed energy center. The first commercial LMFBR was assumed to be located at the HNEC in 1993. Thereafter LMFBRs in the WSCC were preferentially located at HNEC until the growth rate of LMFBRs exceeded the assumed maximum construction rate of two reactors per year.

Spent fuel accumulations were based on the premise that there is no spent fuel now on hand and that beginning in 1975 all fuel discharged from commercial LWRs and LMFBRs located in the WSCC would be shipped to the HNEC for reprocessing. HTGR fuel was assumed to be reprocessed at an independent facility.

ERDA is currently funding the design of a pilot reprocessing plant for LMFBR fuels; however, the location, size, and startup date for this plant were not finalized at the time of this study. To estimate spent fuel accumulations and plutonium availability, it was assumed that all FFTF (Fast Flux Test Facility) and CRBR (Clinch River Breeder Reactor) fuels would be reprocessed at the pilot LMFBR separations plant, but that plutonium and fuel fabrication requirements for FFTF and CRBR would be supplied from the HNEC.

The startup of a spent fuel reprocessing plant at the HNEC was scheduled when it was projected that spent fuel sufficient for two years of operation at full plant capacity would be backlogged at the beginning of commercial operation. The initial plant was scheduled to have a 1500 MT/year capacity and capability for reprocessing LWR fuel only. These requirements reflect what is considered a commercially viable plant

FIGURE 1. National Electric Reliability Council Coordination Areas

capacity and startup schedule. The need for fuel reprocessing capability will eventually expand beyond the initial plant capacity. However, the current fuel cycle logistics was constrained to use of plutonium recovered from the first HNEC reprocessing plant. The introduction of LMFBR and additional LWR reprocessing capability is left to continuing studies.

Plutonium use was parameterized for these studies to determine the impact of various plutonium loadings in LWRs on plutonium storage and mixed oxide fuel fabrication requirements at the HNEC. Plutonium loadings in LWRs were varied from maximum recycle to recycle amounts used as a basis for preparing the Generic Environmental Statement for Mixed Oxide Fuel (GESMO).⁽¹¹⁾ Within the constraints of a given plutonium LWR recycle scheme, the recovered plutonium was distributed to 1) commercial LMFBRs and CRBR, 2) contingency storage, 3) to LWRs, and 4) to excess storage. For each plutonium use scenario, fuel cycle logistics calculations were carried out on a yearly basis until the plutonium inventory fell below the contingency storage requirements, thereby signaling the need for a second reprocessing plant.

3.0 SUMMARY AND RECOMMENDATIONS

The current fuel cycle studies indicate that for the assumed growth of nuclear power, there will be sufficient LWR spent fuel accumulated from reactors in the Western Systems Coordinating Council (WSCC) by 1988 to start operating a 1500 tonne per year separations plant at the HNEC. This plant will reprocess LWR spent fuel, provide plutonium for LWR recycle, and recover sufficient plutonium for fabrication of LMFBR fuel through approximately 1998. The addition of LMFBR reprocessing capability would be desirable in 1999 and absolutely required in 2000 to provide adequate supplies of plutonium for use as fuel in the expanding LMFBR growth component in the WSCC. Preliminary indications are that this plant should be "dual-purpose" since there is initially insufficient LMFBR spent fuel to justify an economic size "single-purpose" plant, and excess LWR fuel will be available to make up the initial reprocessing load.

The end of year plutonium inventories at HNEC for selected plutonium use scenarios are summarized in Figure 2. It was assumed that to minimize the effects of unscheduled reprocessing plant outages, a minimum fissile plutonium inventory equal to one-half of the next year's fuel fabrication requirements must be stored at all times in a facility separate from the reprocessing plant. This amounts to 4 to 8 metric tons in the 1988 to 1998 time frame. These contingency storage requirements would be increased in subsequent years concurrent with the addition of a second reprocessing plant. If full onsite use of plutonium in excess of the contingency inventory is desired, at least seven of the LWRs built at HNEC after 1985 must be capable of operation on all mixed oxide fuel. It is apparent from Figure 2 that plutonium storage requirements increase for cases in which plutonium is used in less than maximum amount in LWRs located at the HNEC.

Figure 3 shows the fabrication plant capacity requirements for each plutonium utilization case. For all cases the fabrication load tends to peak at one point and then generally declines to basic LMFBR requirements in 1997-1999. Fabrication requirements will undoubtedly increase again beyond 2000 to fuel increasing numbers of LMFBRs. Severe fluctuations in mixed oxide fabrication requirements would present business difficulties to a captive commercial plant at the HNEC. Resolution of fuel cycle logistics with a levelized fabrication load was beyond the scope of this years program.

The current studies will be continued to determine the processing schedules and plutonium utilization scenarios associated with the operation of the second reprocessing plant. The fuel cycle logistics analysis will be expanded to examine ways to levelize the mixed oxide fuel fabrication load. That is, to the extent possible, plutonium use in LWRs will be adjusted such that fabrication requirements as a function of time are either level or generally increasing. The output from studies of BWR (boiling water reactor) and PWR (pressurized water reactor) plutonium burners being performed by other contractors will be used as a refinement on the current results. Information from ongoing studies regarding LMFBR performance and associated

FIGURE 2. Effect of Recycle Policy on Plutonium Inventory

FIGURE 3. Effect of Plutonium Recycle Policy on Mixed Oxide Fuel Fabrication Requirements

fabrication and reprocessing components will be reflected in this refinement of the reference plutonium park concept.

A preliminary assessment of the impacts of onsite plutonium utilization on U_3O_8 and separative work requirements will be included in continuing studies. Fuel cycle costs for the various plutonium utilization scenarios will be calculated based upon reference costs for fuel cycle services. To the extent possible, the sensitivity of fuel cycle costs comparisons to key economic parameters will be determined.

4.0 GROWTH OF NUCLEAR POWER GENERATION AND FUEL CYCLE SERVICES AT HNEC

4.1 NUCLEAR GROWTH PROJECTIONS IN WSCC

The growth of the conceptual Hanford Nuclear Energy Center is keyed to the growth of nuclear generating capacity in the Western Systems Coordinating Council which is shown in Figure 1. Our analysis of nuclear growth in this region is shown in Figure 4. For this analysis the nuclear growth scenario was broken into three components: those units that are planned, specified and scheduled (present to ~1985); reactors that are planned, unspecified, and only tentatively scheduled (~1985-1994); and reactors that are unplanned and unscheduled but are required to meet the electrical load where economic advantages exist over fossil fuel plants (~1995-2010). The bases for determining the selected nuclear growth pattern are discussed separately in sections below.

4.1.1 Planned, Scheduled, and Specified Reactors

The projected load growth through ~1994 is based on the WSCC reply to Federal Power Commission (FPC) docket R-362 dated April 1, 1975, in which specific data are provided through 1984.⁽¹²⁾ Some reactor startup dates have been modified, based upon a report from the Subcommittee on Load and Resources to the Pacific Northwest Utilities Conference Committee dated March 28, 1975.⁽¹³⁾ The resultant startup schedule by utility, plant name, reactor type and vendor is given in Table 1.

FIGURE 4. Nuclear Capacity in Western Systems
Coordinating Council

TABLE 1. Planned and Specified Nuclear Capacity in WSCC

Principal Sponsor	Reactor		Vendor	Startup Date	Capacity, MWe	
	Name	Type			Unit	Cumulative
PG&E	Humboldt Bay	BWR	GE		68	
So. Cal. Ed.	San Onofre 1	PWR	W		430	498
SMUD	Rancho Seco	PWR	B&W	4/75	913	
PSC of Colo.	Fort St. Varain	HTGR	GGA	6/75	330	
Port. GE	Trojan	PWR	W	12/75	1130	2871
PG&E	Diablo Canyon 1	PWR	W	5/76	1100	3971
PG&E	Diablo Canyon 2	PWR	W	3/77	1100	5071
WPPSS	WNP2	BWR	GE	10/79	1100	6171
Az. PSC	Palo Verde 1	PWR	CE	5/81	1270	
So. Cal. Ed.	San Onofre 2	PWR	CE	7/81	1140	8581
Port GE	Pebble Springs 1	PWR	B&W	7/82	1260	
WPPSS	WNP 3	PWR	CE	9/82	1240	
WPPSS	WNP 1	PWR	B&W	10/82	1250	
So. Cal. Ed.	San Onofre 3	PWR	CE	10/82	1140	
Az. PSC	Palo Verde 2	PWR	CE	11/82	1270	14741
Puget PUL	Skagit 1	BWR	GE	2/83	1288	
SMUD	Rancho Seco 2	PWR		7/83	1100	
LADW&P	San Joaquin	PWR		8/83	1300	18429
WPPSS	WNP5	PWR	CE	3/84	1240	
WPPSS	WNP4	PWR	B&W	4/84	1250	
Az. PSC	Palo Verde 3	PWR	CE	5/84	1270	
PG&E	PG&E Unit A	PWR		7/84	1100	23289
Puget P&L	Skagit 2	BWR	GE	2/85	1288	
Port. GE	Pebble Springs 2	PWR	B&W	7/85	1260	
So. Cal. Ed	Vidal	HTGR	GGA	?/88	1540	

4.1.2 Planned but Unspecified Reactors

The WSCC has planned total additions of 91 GWe in the period 1985-1994, with 62.1% of the additions scheduled to be nuclear.⁽¹²⁾ For the purpose of this study the units have been scheduled as follows:

Light Water Reactors - In 1985 Skagit 2, Pebble Springs 2, plus an additional 1250 MWe PWR are assumed to come on line. In 1986 through 1994, one 1250 MWe BWR and three 1250 MWe PWRs are assumed to come on line each year.

High Temperature Gas Cooled Reactors (HTGRs) - Of the non-breeder nuclear market, 15% are assumed to be HTGRs starting with the first large commercial HTGR (Vidal) in 1988. Under these assumptions, HTGRs come on line at the rate of ~900 MWe/yr or four 1500 MWe plants in the seven-year period beginning in 1988.

Liquid Metal Fast Breeder Reactors (LMFBRs) - The first commercial LMFBR is assumed to start up in 1993. The resultant startup scheduled from 1985 through 1994 is given in Table 2.

4.1.3 Unplanned and Unspecified Reactors

Table 3 shows the projected growth of nuclear power in the WSCC for the period 1995-2010. During this time the WSCC nuclear growth was prorated from the projected growth of nuclear generating capacity in the U. S. Although U. S. nuclear power growth through the turn of the century has been intensively studied, very little published information exists regarding growth beyond that point.

1995-2000 - The national growth for the six-year period 1995-2000 was taken as the average of the "moderate-high" and "moderate-low" Office of Planning and Analysis (OP&A) projections.⁽¹⁴⁾ Under these assumptions, the Year 2000 cumulative nuclear generating capacity in the U. S. is 900 GWe, or a total growth of 356.5 GWe in the 6-year period. Projected U. S.

TABLE 2. Nuclear Capacity (MWe) Planned but
Unspecified in WSCC 1985-1994

Year	BWR		PWR		HTGR		LMFBR		Total Cumulative
	Add	Cumulative	Add	Cumulative	Add	Cumulative	Add	Cumulative	
1985	1288 ^(a)	3 744	2510 ^(b)	23 013		330			27 087
1986	1250	3 994	3750	26 763		330			32 087
1987	1250	6 244	3750	30 513		330			37 087
1988	1250	7 494	3750	34 263	1540 ^(c)	1 870			43 627
1989	1250	8 744	3750	38 013		1 870			48 627
1990	1250	9 994	3750	41 763	1500	3 370			55 127
1991	1250	11 244	3750	45 513		3 370			60 127
1992	1250	12 494	3750	49 263	1500	4 870			66 627
1993	1250	13 676	3750	53 013		4 870	1500	1500	73 059
1994	1250	14 926	3750	56 763	1500	6 370		1500	79 559

a. Skagit 2

b. Includes Pebble Springs 2

c. Vidal

TABLE 3. Assumed Nuclear Capacity in WSCC (MWe) 1995-2010

Year	BWR		PWR		HTGR		LMFBR		Total Cumulative
	Add	Cumulative	Add	Cumulative	Add	Cumulative	Add	Cumulative	
1995	1250	16176	3750	60513	1500	7870	1500	3000	87559
1996	1250	17426	5000	65513		7870	1500	4500	95309
1997	1250	18676	3750	69263	1500	9370	1500	6000	103309
1998	1250	19926	5000	74263		10870	1500	7500	112559
1999	1250	21176	5000	79263	1500	10870	3000	10500	121809
2000	1250	22426	5000	84263	1500	12370	3000	13500	132559
2001	1250	23676	5000	89263		12370	4500	18000	143309
2002	1250	24926	5000	94263	1500	13870	4500	22500	155559
2003	1250	26176	5000	99263		13870	6000	28500	167809
2004	1250	27426	2500	101763	1500	15370	7500	36000	180559
2005	1250	28676	2500	104263		15370	9000	45000	193309
2006	1250	29926	1250	105513		15370	10500	55500	206309
2007		29926		105513	1500	16870	12000	67500	219809
2008		29926		105083		16870	13500	81000	232879
2009		29926		105083		16870	13500	94500	246379
2010		29926		105083		16870	13500	108000	259879

and WSCC nuclear growth rates between 1985 and 1994 were used as a basis for calculating the WSCC nuclear power growth from 1995-2000 as follows:

$$\frac{\text{WSCC Projected Nuclear Growth (1985-1994)}}{\text{US Projected Nuclear Growth (1985-1994)}} = \frac{56.5 \text{ GWe}}{374 \text{ GWe}} \approx 15\%$$

$$15\% \times \text{U. S. Projected Growth (1995-2000)} = .15 \times 356.5 \text{ GWe} = 53.5 \text{ GWe in WSCC (1995-2000)}$$

This culminates in about 133 GWe nuclear capacity in the WSCC in the Year 2000. Consistent with the OP&A assumption that the LMFBR will represent 10% of the generating capacity in the Year 2000, nine 1500 MWe plants were assumed to come into operation by Year 2000. One plant is brought into operation each year in 1995 through 1998 and two each year in 1999 and 2000.

HTGRs continue to account for ~15% of the nonbreeder nuclear market. The remaining ~35 GWe are assumed to be 1250 MWe LWR plants, 6 BWRs and 22 PWRs.

2001-2010 - In the absence of definitive studies, the total nuclear generating capacity in the U. S. was assumed to be 1750 GWe in the Year 2010,⁽¹⁵⁾ a total growth of 850 GWe in the 10-year period. This has been represented by a national growth rate that rises from 71 GWe per year in 2001 to 90 GWe per year in 2010. As before, the WSCC growth was assumed to account for 15% of the total U. S. nuclear generating capacity.

During this period, construction on LWRs is declining as the LMFBR begins to significantly penetrate the nuclear market. The rate of LMFBR introduction in the WSCC is assumed to expand from the 2 per year rate in the Year 2000 to 9 per year in 2008, at which point they have captured the total nuclear market. However, the scenarios for plutonium logistics must be extended to determine whether there is sufficient plutonium to sustain this growth rate.

HTGRs are assumed to continue to capture 15% of the non-LMFBR nuclear market (~4.5 GWe), and the balance of the growth is accounted for by twenty-three 1250 MWe LWRs, six BWRs and seventeen PWRs, that are all on line by 2006. In Tables 2 and 3 the column representing the cumulative

nuclear capacity reflects the retirement of Humboldt Bay after 30 years of operation. All other plants are assumed to operate 40 years.

4.2 HNEC DEVELOPMENT SCENARIO

4.2.1 Reactor Growth

The HNEC reactor growth scenario used for the purposes of this study is given in Table 4 and also shown in Figure 5. In general it was assumed that the Hanford site can not support a construction rate leading to the completion of more than two reactors in a given year and that all LWRs and LMFBRs built in the Pacific Northwest after 1985 would be located in the HNEC. The Subcommittee on Load and Resources of Pacific Northwest Utilities provided the following list of operating dates for Pacific Northwest commercial nuclear power plants through 1994.⁽¹³⁾

<u>Plant</u>	<u>Date</u>
A	July 1987
B	July 1988
C	July 1989
D	July 1990
E	January 1991
F	January 1992
G	July 1992
H	July 1993
I	January 1994
J	July 1994

For this study, plant H was assumed to be the first commercial LMFBR and the balance LWRs.

The second commercial LMFBR was assumed to come on line in 1995. In the Period 1996 through 1999 one LWR and one LMFBR were assumed to come on line each year. For startup dates beyond 1999 only LMFBRs were introduced, and the full 40 reactor park was assumed to be completed in 2008. With this growth scenario, 16 LWRs and 24 LMFBRs, representing a total of 55,850 MWe, form the complete power reactor development at HNEC.

TABLE 4. Assumed Reactor Plant Additions at HNEC (MWe)

CY	LWR		LMFBR		TOTAL	
	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative
1979	1100 ^(a)	1100			1100	1100
1982	1250 ^(b)	2350			1250	2350
1984	1250 ^(c)	3600			1250	3600
1987	1250	4850			1250	4850
1988	1250	6100			1250	6100
1989	1250	7350			1250	7350
1990	1250	8600			1250	8600
1991	1250	9850			1250	9850
1992	2500	12350			2500	12350
1993		12350	1500	1500	1500	13850
1994	2500	14850		1500	2500	16350
1995		14850	1500	3000	1500	17850
1996	1250	16100	1500	4500	2750	20600
1997	1250	17350	1500	6000	2750	23350
1998	1250	18600	1500	7500	2750	26100
1999	1250	19850	1500	9000	2750	28850
2000			3000	12000	3000	31850
2001			3000	15000	3000	34850
2002			3000	18000	3000	37850
2003			3000	21000	3000	40850
2004			3000	24000	3000	43850
2005			3000	27000	3000	46850
2006			3000	30000	3000	49850
2007			3000	33000	3000	52850
2008			3000	36000	3000	55850
2009				36000		55850
2010				36000		55850

a. WNP2

b. WNP1

c. WNP4

FIGURE 5. Reactors at Hanford Nuclear Energy Center

4.2.2 Spent Fuel Reprocessing Capabilities

The introduction of reprocessing capabilities to the HNEC is subject to several assumptions which, if altered, could have some bearing on the results of the current conceptual study:

- An initial LWR reprocessing plant will be built only when it is projected that spent fuel sufficient for two years of operation at full plant capacity will be backlogged at the beginning of commercial operation.
- The LWR reprocessing plant will serve all LWRs in the WSCC with no spent LWR fuel shipped out of the region.
- The initial LWR reprocessing plant will have a 1500 MT/year capacity.
- The LWR reprocessing plant will not reprocess LMFBR fuel.
- HTGR fuel will not be reprocessed at HNEC.

The need for additional fuels reprocessing capability will eventually expand beyond the initial plant capacity for two reasons: 1) the rate of discharge of spent LWR fuel will exceed the capacity of the first plant, and 2) the plutonium requirements for the expanding LMFBR component in the WSCC will not be met unless the LMFBR fuel is reprocessed. As the various plutonium use scenarios are discussed, the need for additional reprocessing capabilities will become apparent, and the timing and minimum requirements of a second plant will be discussed. However, the detailed plutonium utilization scenarios associated with a second reprocessing plant are left for future studies.

4.2.3 Mixed Oxide Fuel Fabrication

A mixed oxide fuel fabrication plant similar to the one proposed by Westinghouse⁽¹⁶⁾ will be required for utilization of the plutonium recovered at the reprocessing plant. To support both the LMFBR and LWR plutonium utilization programs, it must be designed for a wide range of pellet dimensions and enrichments. The size of the fabrication plant is a variable for this study since the requirements for fabrication capability depend on the scenario for plutonium use in the LWRs located at the HNEC.

The fabrication plant is assumed to start up 3 to 6 months after the reprocessing plant and will initially fabricate recycled plutonium fuels for LWRs in addition to fuel required for FFTF and/or CRBR. The plant load will gradually shift toward commercial LMFBR fuel fabrication.

5.0 FUEL CYCLE LOGISTICS

5.1 SPENT FUEL ACCUMULATIONS IN WSCC

The discussions regarding spent fuel accumulations and plutonium utilization are based on the premise that no spent LWR or LMFBR fuel will be shipped out of the WSCC. Substantial shipments out of the area could significantly affect the timing for introducing reprocessing capability and the schedule for plutonium use in LWRs unless compensating shipments are brought in from outside the WSCC. Logistics of HTGR fuel accumulation and reprocessing have not been considered in these studies.

In estimating spent fuel accumulation it has been assumed that no spent fuel is now on hand and that all fuel discharged in 1975 and later years will be stored at the reactor or at Hanford for reprocessing at HNEC.

5.1.1 LWR Spent Fuel

LWR spent fuel discharge rates are based upon manufacturer's estimates as given in Fuel Trac⁽¹⁷⁾ for the specified units or units of similar design. The quantities have been modified to represent average annual discharge rates (e.g., San Onofre discharges 19 tonnes on a 16-month cycle and is reported as 14 tonnes per year). Furthermore, to account for the lower capacity factors in the initial years of operation, the first discharge has been assumed to be 24 months after startup for PWRs and 32 months after startup for BWRs. The amount of plutonium contained in each discharge batch has been estimated based on ALTHAEA⁽¹⁸⁾ calculations of LWR discharge isotopics.

Table 5 shows the spent fuel and contained plutonium discharge in the WSCC in detail for the period 1975 through 1994. Spent fuel accumulations

through 1987 provide a sufficient inventory for introduction of reprocessing capability in 1987. The data in Table 5 are based on a capacity factor of 80%, whereas an average of 71% would be consistent with the OP&A projection.⁽¹⁴⁾ Spent fuel accumulations are summarized again more briefly in Table 6 to demonstrate that a reduction to 71% average capacity factor effects a delay of less than 1 year in the desired startup date of the initial reprocessing plant.

Table 7 presents the fuel inventories and plutonium recovered from a 1500-tonne-per-year separations plant that begins operation in 1988. In 1994 the current spent fuel discharges of 1499 tonnes meet the full capacity of the plant. Using the same initial inventory criterion while maintaining a minimum of one year inventory for the first plant, sufficient backlogged spent fuel (4990 tonnes) will have accumulated by the beginning of 2002 to justify startup of a second 1500-tonne separations plant during 2001.

5.1.2 LMFBR Spent Fuel

A rough estimate of the spent fuel discharged from LMFBRs in the WSCC is given in Table 8. If the same criterion were used to schedule the startup of a 1500-tonne/year LMFBR reprocessing plant, operation would begin in 2006 or 2007. However, depending on the scheduling of plutonium use in LWRs, the first LMFBR spent fuel should be processed in 1999 or 2000 to provide sufficient plutonium to fuel LMFBRs. A second LWR separations plant would extend these dates only about one year. Thus it seems prudent that the second plant should be a "dual-purpose" plant (i.e., an LMFBR plant capable of reprocessing LWR fuels) scheduled for startup in 1999-2000.*

Fuel inventories and discharge rates would justify a dual-purpose plant of 1500 to 2000 tonnes/year capacity. The initial process load would be 90% LWR, but by 2010 the load could shift to essentially all LMFBR

* Investigations of the technical feasibility of the "dual-purpose" concept are beyond the scope of these studies. This conclusion merely implies that from the standpoint of logistics and load it would appear to be an attractive arrangement.

TABLE 5. Spent Fuel and Contained Plutonium in WSCC

(80% Plant Capacity Factors)

Year	Reactor	Spent Fuel, Tonnes		Fissile Pu, Kg	
		Batch	Cumulative	Batch	Cumulative
1975	Humboldt Bay	3		12	
	San Onofre 1	14	17	92	104
1976	Humboldt Bay	3		12	
	San Onofre 1	14	34	92	208
1977	Humboldt Bay	3		12	
	San Onofre	14		92	
	Rancho Seco	23		94	
	Trojan	29	103	116	522
1978	Humboldt Bay	3		12	
	San Onofre	14		92	
	Rancho Seco	23		120	
	Trojan	29		150	
	Diablo Canyon 1	29	201	116	1912
1979	Humboldt Bay	3		12	
	San Onofre	14		92	
	Rancho Seco	23		142	
	Trojan	29		177	
	Diablo Canyon 1	29	328	116	1701
1980	Humboldt Bay	3		12	
	San Onofre	14		92	
	Rancho Seco	23		143	
	Trojan	29		178	
	Diablo Canyon 1	29		177	
	Diablo Canyon 2	29	455	150	2453
1981	Humboldt Bay	3		12	
	San Onofre	14		92	
	Rancho Seco	23		143	
	Trojan	29		178	
	Diablo Canyon 1	29		178	
	Diablo Canyon 2	29	582	177	3233
1982	Humboldt Bay	3		12	
	San Onofre	14		92	
	Rancho Seco	23		143	
	Trojan	29		178	
	Diablo Canyon 1	29		178	
	Diablo Canyon 2	29		178	
	WPPSS #2	37	746	114	4128
1983	Humboldt Bay	3		12	
	San Onofre	14		92	
	Rancho Seco	23		143	
	Trojan	29		178	
	Diablo Canyon 1	29		173	
	Diablo Canyon 2	29		178	
	WPPSS 2	41		168	
	Palo Verde 1	32		130	
	San Onofre 2	29	975	116	5323

TABLE 5. (contd)

Year	Reactor	Spent Fuel, Tonnes		Fissile Pu, Kg	
		Batch	Cumulative	Batch	Cumulative
1984	Humboldt Bay	3		12	
	San Onofre	14		92	
	Rancho Seco	23		143	
	Trojan	29		178	
	Diablo Canyon 1	29		178	
	Diablo Canyon 2	29		178	
	WPPSS 2	37		163	
	Palo Verde 1	32		168	
	San Onofre 2	29		150	
	Pebble Springs 1	32		130	
	WPPSS 3	32		130	
	WPPSS 1	32		130	
	San Onofre 3	29		116	
	Palo Verde 2	32	1357	130	7221
1985	Humboldt Bay	3		12	
	San Onofre	14		92	
	Rancho Seco	23		143	
	Trojan	29		178	
	Diablo Canyon 1	29		178	
	Diablo Canyon 2	29		178	
	WPPSS 2	37		190	
	Palo Verde 1	32		199	
	San Onofre 2	29		177	
	Pebble Springs 1	32		166	
	WPPSS 3	32		166	
	WPPSS 1	32		166	
	San Onofre 3	29		150	
	Palo Verde 2	32		168	
	Skagit 1	43		134	
	Rancho Seco 2	29		116	
	San Joaquin	33	1844	133	9767
1986	Humboldt Bay-	127		781	
	Diablo Canyon 2				
	WPPSS 2	37		192	1351
	Palo Verde 1	32		200	
	San Onofre 2	29		178	
	Pebble Springs 1	32		196	
	WPPSS 3	32		196	
	WPPSS 1	32		196	
	San Onofre 3	29		177	
	Palo Verde 2	32		199	
	Skagit 1	48		197	
	Rancho Seco 2	29		150	
	San Joaquin	33		172	
	WPPSS 5	32		130	
	WPPSS 4	32		130	
	Palo Verde 3	32		130	
	PG&E Unit A	29	2461	116	13107
		617		3340	

TABLE 5. (contd)

Year	Reactor	Spent Fuel, Tonnes		Fissile Pu, Kg	
		Batch	Cumulative	Batch	Cumulative
1987	Humboldt-San Onofre 2	225		1351	
	Pebble Springs 1	32		197	
	WPPSS 3	32		197	2320
	WPPSS 1	32		197	
	San Onofre 3	29		178	
	Palo Verde 2	32		200	
	Skagit 1	43		191	
	Rancho Seco 2	29		177	
	San Joaquin	33		203	
	WPPSS 5	32		166	
	WPPSS 4	32		166	
	Palo Verde 3	32		166	
	Unit A	29		150	
	Skagit 2	43		134	
	Pebble Springs 2	32		130	
	1250 MW for 1985	32		130	
		719	3180	3933	17040
1988	Humboldt Bay - Palo Verde 2	382		2320	
	Skagit 1	43		222	
	Rancho Seco 2	29		178	
	San Joaquin	33		205	
	WPPSS 5	32		196	
	WPPSS 4	32		196	
	Palo Verde 3	32		199	
	Unit A	29		177	
	Skagit 2	48		197	
	Pebble Springs 2	32		166	
	1250 MW for 1985	32		166	
	5000 MW for 1986	138		494	
		862	4042	4716	21756
1989	Humboldt bay - Palo Verde 2	382		2320	
	Skagit 1	43		225	
	Rancho Seco 2	29		178	
	San Joaquin	33		205	
	WPPSS 5	32		197	
	WPPSS 4	32		197	
	Palo Verde 3	32		200	
	Unit A	29		178	
	Skagit 2	43		191	
	Pebble Springs 2	32		196	
	1250 MW for 1985	32		196	
	5000 MW for 1986	142		661	
	5000 MW for 1987	138		494	
		999	5041	5458	27214

TABLE 5. (contd)

Year	Reactor	Spent Fuel, Tonnes		Fissile Pu, Kg	
		Batch	Cumulative	Batch	Cumulative
1990	Humboldt Bay - Unit A	612		3700	
	Skagit 2	43		222	
	Pebble Springs 2	32		197	
	1250 MW for 1985	32		197	
	5000 MW for 1986	138		742	
	5000 MW for 1987	142		661	
	5000 MW for 1988	138		494	
		<u>1137</u>	6178	<u>6213</u>	33427
1991	All ordered units	687		4120	
	1250 MW for 1985	32		197	
	5000 MW for 1986	138		774	
	5000 MW for 1987	138		742	
	5000 MW for 1988	142		661	
	5000 MW for 1989	138		494	
		<u>1275</u>	7453	<u>6988</u>	40415
1992	All ordered units	687		4120	
	1250 MW for 1985	32		137	
	5000 MW for 1986	138		776	
	5000 MW for 1987	138		774	
	5000 MW for 1988	138		742	
	5000 MW for 1989	142		661	
	5000 MW for 1990	138		494	
		<u>1413</u>	8866	<u>7764</u>	48179
1993		1551	10417	8540	56719
1994		1689	12106	9316	66035

TABLE 6. Spent Fuel and Contained Plutonium in WSCC

(Assuming 71% Average Plant Capacity Factor)

Year	Spent Fuel, Tonnes		Fissile Plutonium, Kg	
	Batch	Cumulative	Batch	Cumulative
1985	432	1636	2340	8670
1986	548	2184	2960	11630
1987	638	2822	3490	15120
1988	765	3587	4190	19310
1989	887	4474	4840	24150
1990	1009	5483	5520	29670
1991	1132	6614	6200	35870
1992	1254	7869	6890	42760
1993	1377	9245	7580	50340
1994	1499	10744	8270	58610

**TABLE 7. Spent Fuel and Recovered Plutonium Inventories
1988 Reprocessing Plant Startup**

Year	Spent Fuel, Tonnes			Fissile Plutonium, Kg	
	Beginning Inventory	Discharge	Reprocessed	Recovered*	Cumulative
1988	2822	765	750	3400	3400
1989	2837	887	1125	6600	10000
1990	2599	1009	1500	8000	18000
1991	2108	1132	1500	8100	26100
1992	1740	1254	1500	8200	34300
1993	1494	1377	1500	8300	42600
1994	1371	1499	1500	8300	50900
1995	1370	1622	1500	8500	58400
1996	1492	1744	1500	8600	67000
1997	1736	1867	1500	8700	75700
1998	2103	2017	1500	8700	84400
1999	2620	2140	1500	8700	93100
2000	3260	2290	1500	8700	101800
2001	4050	2440	1500	8700	110500
2002	4990	2590	1500	8700	119200

*Note: Lowest exposure fuels with three or more years' cooling reprocessed in the first year. Thereafter fuels reprocessed in order of discharge. Assumes mixed oxide fuel if any is stored. Spent fuel from reactors that begin operation after the full capacity of the first 1500 tonne reprocessing plant is committed are given lower priority.

TABLE 8. Spent LMFBR Fuel in WSCC

Year	Discharge, tonnes	Cumulative, tonnes
94	23	
5	23	46
6	46	92
7	69	161
8	92	253
9	115	368
2000	161	529
1	207	736
2	276	1012
3	345	1357
4	437	1794
5	552	2346
6	690	3036
7	851	3887
8	1035	4922
9	1242	6164
2010	1445	7609
1	1656	9265

spent fuel. With a dual-purpose plant, the mix of LWR and LMFBR spent fuel reprocessed could conceivably be selected to either maximize the rate of plutonium recovery for recycle in LWRs or minimize plutonium recovery while still meeting LMFBR fuel requirements.

5.2 POLICIES AND ASSUMPTIONS AFFECTING PLUTONIUM USE AT HNEC

Three plutonium utilization scenarios have been developed for LWRs located at the HNEC: 1) plutonium recycled in GESMO⁽¹¹⁾ amounts (35% of fissile feed is plutonium); 2) plutonium recycled in 1.43 times GESMO amounts (50% of fissile feed is plutonium); and 3) maximum recycle amounts (up to 100% of fissile feed is plutonium). Investigations of these scenarios required the establishment of policies and assumptions to simulate operations within HNEC as they relate to the WSCC. The selected assumptions and policies are summarized below to clarify the conditions under which the conclusions of the current conceptual studies are valid.

5.2.1 Plutonium Logistics and Contingencies

- The inventory of stored plutonium must be equal to or greater than one-half of the next year's fuel fabrication requirements.
- First core plutonium requirements are delivered to the fabrication plant 2 years before reactor startup.
- First reload requirements are delivered to the fabrication plant at the time of reactor startup and additional reloads at one-year intervals thereafter.
- Plutonium delivered to the fabrication plant destined for reloads in BWRs at HNEC in any given year can be reprocessed and available for reuse 6 years later.
- Plutonium delivered to the fabrication plant destined for use in reloads in PWRs at HNEC can be reprocessed and available for reuse 5 years later.

- Plutonium recovered in any year plus the inventory from the preceding year is used as follows:

First: to satisfy commercial LMFBR and CRBR needs
 Second: to storage for one-half of next year's needs
 Third: any remaining plutonium may be used in LWRs to reduce their uranium and separative work requirements.

- By 1985 FFTF will have a backlog of fabricated fuel to last until 2000; thus no additional plutonium will be required.*
- By 1985 CRBR will have fabricated fuel on hand to meet reload requirements through 1988 and will require 400 kg of fissile plutonium from HNEC per year beginning in 1989. The fabrication requirement is ~2.2 tonnes of mixed oxide fuel per year.

5.2.2 Reprocessing Capabilities

- A 1500-tonne/year reprocessing plant designed specifically for LWR spent fuel begins operation in 1988.
- Mixed oxide spent fuel is stored and processed only as required to increase the plutonium recovered to meet the LMFBR, FFTF, CRBR and inventory requirements.
- The pilot LMFBR reprocessing plant will be of sufficient capacity to reprocess only CRBR and FFTF spent fuel.

5.2.3 Reactor Performance

- All LWRs at HNEC after 1985 are the CE-80⁽¹⁹⁾ design since at the time of this study this is the only reactor concept for which data were available on all plutonium operation.⁽²⁰⁾
- Table 9 shows the plutonium required or allowed in each reactor type at HNEC.

* This FFTF fuel fabrication schedule is one possibly being considered.

TABLE 9. Plutonium Required or Allowed in
Each Reactor Type at HNEC

<u>Reactor</u>	<u>Fissile Plutonium, kg</u>		<u>Mixed Oxide, tonnes</u>	
	<u>First Core</u>	<u>Reload</u>	<u>First Core</u>	<u>Reload</u>
LMFBR	2500	1100	18	8
WNP2				
GESMO		240		10
Maximum		340		13
WNP1 & WNP4				
Maximum		180		7.4
CE-80 (a)				
GESMO	440	250	24	10
1.43 x GESMO	650	385 (b)	34	14
All Pu	1900	1100 (c)	103	28
		930 (d)		
		960 (d)		

-
- a. Information in Reference 20 is based on 84.4% capacity factor, and these reload cores are scaled to 71%.
- b. First reload.
- c. Second reload.
- d. Third and later reloads.

5.3 PLUTONIUM UTILIZATION SCENARIOS AT HNEC

In Figure 1, page 4, the end-of-year fissile plutonium inventories are represented for various plutonium utilization scenarios at HNEC. Of interest are the impacts of the various LWR plutonium use schemes on plutonium inventories in the 1900 through 2000 time frame. In the sections below, the three cases for plutonium use in LWRs are discussed separately.

5.3.1 Plutonium Recycle in GESMO Amounts

The first case assumes that the LWRs at HNEC recycle plutonium in the amount used as a basis for preparing the Generic Environmental Statement for Mixed Oxide Fuel (GESMO).⁽¹¹⁾ Using this scheme, a maximum of 35% of the fissile feed is plutonium.

In Table 10 the logistics of plutonium recovery and distribution are described for this case. In 1988, the first year of separations plant operation, 3400 kg of fissile plutonium are recovered from irradiated LWR UO₂ fuel; and 1540 kg of fissile plutonium are allocated to the mixed oxide fabrication plant for LWR fuel to be charged in 1989. The remaining 1860 kg are allocated to storage, an excess of 765 kg over the contingency storage requirement of 1095 kg. Irradiated LWR mixed oxide fuel is accumulated, beginning with the first recycle discharge of 45 tonnes in 1993, until reprocessing of this fuel is required in 1999 to meet increasing plutonium demands. By the end of 1999, however, the minimum inventory requirements of 8900 kg can no longer be met. Minimum plutonium requirements for Year 2000 can be met if the first reprocessing plant operates

TABLE 10. Plutonium Use at HNEC in GESMO Amounts

Year	Recovered Fissile Pu Distribution, Kg					M.O. Spent LWR Fuel			
	Recovered From		Used In		Storage Inventory	Spent Fuel, tonnes		Contained Pu, Kg	
	UO ₂	MO	FBR	LWR ^(a)		Discharge ^(b)	Reprocessed	Inventory	Batch Inventory
1988	3400			1540	1860 (1095) ^(c)				
1989	5600		400	1790	6270 (1440)				
1990	8000		400	2480	11390 (2375)				
1991	8100		2900	1850	14740 (1815)				
2	8200		400	3230	19310 (3175)				
3	8300		4000	2350	21260 (3645)	45		45	580
4	8300		4000	3290	22270 (4195)	65		110	980
5	8500		5100	3290	22380 (4870)	95		205	1220
1996	8600		6200	3540	21240 (6795)	95		300	1290
7	8700		9800	3790	16350 (7250)	115		4151	1510
8	8700		10900	3600	10550 (7800)	115		530	1570
9	4900	8840	15600		8690 (8900)	125	655	0	1690
2000	7920	1820	17800		630 (11800)	135	135	0	1820

a. See detail in Table 11. Delivered to fabrication plant for the following year's fuel requirements.

b. Discharged and cooled ready for reprocessing.

c. Minimum inventory based upon one-half of the following year's fabrication requirements.

without unanticipated down time; however, the second reprocessing plant should be scheduled for startup in Year 2000 and must be operating by year end to meet Year 2001 plutonium requirements.

In Table 11 the distribution of fissile plutonium to LWRs located at the HNEC is given for each year beginning in 1988. For this case all sixteen LWRs located at HNEC will have participated in plutonium recycle to some degree by the time plutonium begins to run short in 1999.

TABLE 11. Individual Reactor Pu Use for GESMO Recycle Case

Year	Fissile Plutonium Used in Each Reactor (by startup date) at HNEC, Kg															
	10/79	10/82	4/84	7/87	7/88	7/89	7/90	1/91	1/92	7/92	1/94	7/94	96	97	98	99
1988	240	180	180	250	250		440									
9	240	180	180	250	250	250		440								
1990	240	180	180	250	250	250	250		440	440						
1	240	180	180	250	250	250	250	250								
2	240	180	180	250	250	250	250	250	250	250	440	440				
3	240	180	180	250	250	250	250	250	250	250						
4	240	180	180	250	250	250	250	250	250	250	250	250	440			
5	240	180	180	250	250	250	250	250	250	250	250	250		440		
6	240	180	180	250	250	250	250	250	250	250	250	250	250		440	
7	240	180	180	250	250	250	250	250	250	250	250	250	250	250		440
8	240	180	180	250	250	250	250	250	250	250	250	250	250	250	250	

- a. Year of delivery to the mixed oxide fabrication plant. First core plutonium requirements are delivered to the fabrication plant two years before reactor startup. First reload requirements are delivered at the time of reactor startup and additional reloads at one-year intervals thereafter.

About half the 2001 plutonium requirements could be met without the second separations plant if plutonium were not recycled in 1996, 1997, or 1998. Under these conditions the 1996 inventory would be nearly 25 tonnes of fissile plutonium. Construction progress on the second separations plant in relation to construction progress on the LMFBRs would have to be monitored in order to decide whether LWR plutonium recycle would be advisable in the 1996-1998 time frame.

5.3.2 Plutonium Recycle in 1.43 x GESMO Amounts

The second case assumes that the LWRs at HNEC recycle plutonium in 1.43 times GESMO amounts. Using this recycle scheme, a maximum of 50% of the fissile feed is plutonium. However, the first recycle load for reactors previously operating on uranium fuel is limited to GESMO amounts.

In Tables 12 and 13 the logistics of plutonium recovery and distribution are given for this case in the same format as was used in the previous section. By the end of 1999 the plutonium inventory of 3780 kg falls about 5 tonnes short of the required inventory despite mixed oxide fuel reprocessing in 1998 and 1999. The second separations plant should be scheduled for startup in 1999 and must be operating by mid Year 2000 to meet plutonium fabrication requirements. If plutonium were not recycled in 1997, plutonium required through the Year 2000 could be provided without additional reprocessing capability. For this case, fifteen of the sixteen LWRs located at HNEC will have participated in plutonium recycle by the time allocation of plutonium to LWRs is discontinued in 1997.

5.3.3 Plutonium Recycle in Maximum Amounts

The final case assumes that plutonium will be recycled in maximum amounts in LWRs at HNEC. For reactors previously operating on uranium fuels, the first transition batch is assumed to contain a maximum of 35% plutonium as fissile makeup, and the next batch is assumed to contain a maximum of 65% plutonium as fissile makeup.

In Tables 14 and 15 the logistics of plutonium recovery and distribution are given for this case in the same format as in previous sections. By the end of 1999 the current inventory of 7145 kg is short of the required 8900 kg contingency storage. Startup of the second reprocessing plant is desirable by late 1999 and required by the end of Year 2000. It is interesting to note that despite the higher plutonium use rate, the shortage of plutonium in Year 2000 is less than that for the 1.43 x GESMO case. This occurs because the plutonium is used early, and most of it is again available for use before the end of Year 2000. In this case only seven all-plutonium reactors are required to maintain nearly optimum plutonium inventories through 1998.

TABLE 12. Plutonium Use at HNEC in 1.43 x GESMO Amounts

Year	Recovered Fissile Pu Distribution, Kg					M.O. Spent LWR Fuel				
	Recovered From		Used In		Storage Inventory	Spent Fuel, tonnes			Contained Pu, Kg	
	UO ₂	MO	FBR	LWR(a)		Discharge(b)	Reprocessed	Inventory	Batch	Inventory
1988	3400			1750	1650 (1385) ^(c)					
1989	6600		400	2370	5480 (1970)					
1990	8000		400	3540	9540 (2763)					
1991	8100		2900	2625	12115 (2548)					
2	8200		400	4695	15220 (3698)					
3	8300		4000	3395	16125 (4408)	49		49	620	620
4	8300		4000	4815	15610 (4958)	91		140	1210	1830
5	8500		5100	4815	14195 (5700)	126		266	1730	3560
1996	8600		6200	5200	11395 (7318)	126		392	1840	5400
7	8700		9800	4835	5460 (5450)	154		546	2210	7610
8	5530	7610	10900	0	7700 (7800)	154	546	154	2290	2290
9	6830	4800	15600	0	3780 (8900)	168	322	0	2510	0
2000	7620	2690	17800	0	-3760 (11800)	182	182	0	2690	0

a. See detail in Table 13. Delivered to fabrication plant for the following year's fuel requirements.

b. Discharged and cooled ready for reprocessing.

c. Minimum inventory based on one-half of following year's fabrication requirement.

TABLE 13. Individual Reactor Pu Use for 1.43 x GESMO Case

Year ^(a)	Fissile Plutonium used in each reactor (by startup date) at HNEC, Kg														
	10/79	10/82	4/84	7/87	7/88	7/89	7/90	1/91	1/92	7/92	1/94	7/94	96	97	98
1988	240	180	180	250	250		650								
9	340	188	180	385	385	250		650							
1990	340	180	180	385	385	385	385		650	650					
1	340	180	180	385	385	385	385	385							
2	340	180	180	385	385	385	385	385	385	385	650	650			
3	340	180	180	385	385	385	385	385	385	385					
4	340	180	180	385	385	385	385	385	385	385	385	385	650		
5	340	180	180	385	385	385	385	385	385	385	385	385		650	
6	340	180	180	385	385	385	385	385	385	385	385	385	385		650
7	240	180	180	385	385	385	385	385	385	385	385	385	385	385	

a. Year of delivery to the mixed oxide fabrication plant. First core plutonium requirements are delivered to the fabrication plant two years before reactor startup. First reload requirements are delivered at the time of reactor startup and additional reloads at one-year intervals thereafter.

TABLE 14. Plutonium Use at HNEC in Maximum Amounts

Year	Recovered Fissile Pu Distribution, Kg					M.O. Spent LWR Fuel				
	Recovered From		Used In		Storage Inventory	Spent Fuel, tonnes			Contained Pu, Kg	
	UO ₂	MO	FBR	LWR(a)		Discharge(b)	Reprocessed	Inventory	Batch	Inventory
1988	3400			1900	1500	(1825)(c)				
9	6600		400	3250	4450	(3900)				
1990	8000		400	7400	4650	(4255)				
1991	8100		2900	5610	4240	(4035)				
2	8200		400	7670	4370	(4270)	28	28	280	280
3	8300		4000	4540	4130	(4100)	56	84	670	990
4	8300		4000	4200	4230	(4220)	157	241	2020	2970
5	8500		5100	3340	4290	(3928)	191	432	3080	6050
1996	8600		6200	1655	5035	(4900)	224	656	3880	9930
7	7300	2970	9800		5505	(5400)	224	241	639	4040
8	6290	6960	10900		7855	(7800)	143	415	367	2590
9	5750	9140	15600		7145	(8900)	139	506	0	2510
2000	7970	2380	17800		-305	(11800)	126	126	0	2380

a. See detail in Table 15. Delivered to fabrication plant for the following year's fuel requirements.

b. Discharged and cooled ready for reprocessing.

c. Minimum inventory based on one-half of the following year's fabrication requirements.

TABLE 15. Individual Reactor Pu Use for Maximum Plutonium Use Case

Year ^(a)	Fissile Plutonium Used in Each Reactor (by Startup Date) at HNEC, Kg									
	10/79	10/82	4/84	7/87	7/88	7/89	7/90	1/91	1/92	7/92
1988							1900			
9	240	180	180	250	250	250		1900		
1990	340	180	180	600	600	600	1100		1900	1900
1	340	180	180	960	960	960	930	1100		
2	340	180	180	960	960	960	960	930	1100	1100
3	340			600	600	600	600	600	600	600
4				600	600	600	600	600	600	600
5				600	600	600	385	385	385	385
6				385	385	385	250	250		

a. Year of delivery to the mixed oxide fabrication plant. First core plutonium requirements are delivered to the fabrication plant two years before reactor startup. First reload requirements are delivered at the time of reactor startup and additional reloads at one-year intervals thereafter.

5.3.4 Fabrication Plant Capacity

The fabrication plant capacity requirements for each plutonium utilization case are summarized by year in Table 16 and shown graphically in Figure 3, page 8. For all cases the fabrication load tends to peak at one point and then generally decline to basic LMFBR requirements in 1997-1999. Fabrication requirements will undoubtedly increase again beyond 2000 to fuel increasing numbers of LMFBRs.

Severe fluctuations in mixed oxide fuel fabrication requirements would present business difficulties for a captive commercial plant, and consequently the plutonium utilization scenarios analyzed here would not likely be implemented in practice. Attempts to levelize the fabrication load using realistic time-dependent fabrication capacities would likely dictate plutonium recycle schemes with variable LWR plutonium loadings. However, investigation of such scenarios was not within the scope of the current studies.

TABLE 16. Mixed Oxide Fabrication Requirements for Pu
Utilization Scenarios at HNEC, tonnes

Year	GESMO Amounts		1.43 x GESMO		Maximum Recycle	
	LWR	FBR	LWR	FBR	LWR	FBR
1988	69		79		103	
89	79	2	90	2	158	2
90	113	2	142	2	316	2
1991	75	20	98	20	168	20
92	143	2	194	2	224	2
93	95	28	126	28	139	28
94	139	28	188	28	126	28
95	139	36	183	36	110	36
1996	149	44	202	44	62	44
97	159	70	179	70		70
98	145	78		78		78
99		112		112		112
2000		128		128		128

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SELECTION OF HEAT DISPOSAL METHODS FOR
A HANFORD NUCLEAR ENERGY CENTER

by

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SELECTION OF HEAT DISPOSAL METHODS FOR
A HANFORD NUCLEAR ENERGY CENTER

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SUMMARY

The possibility of a Hanford Nuclear Energy Center (HNEC) is currently being studied to develop an improved understanding of nuclear energy centers, their advantages and disadvantages, and to identify the research and development necessary to evaluate the nuclear energy center concept. Two cases are considered: one contains 20 nuclear power plants and one contains 40 nuclear power plants. These power plants would be built in clusters of four reactors dispersed throughout the 600 square mile Hanford Reservation in central Washington. Supporting fuel cycle facilities are also included.

Five general heat rejection systems are available for transferring the waste heat from an HNEC to the environment: (1) once-through cooling with Columbia River water, (2) cooling ponds, (3) wet cooling towers, (4) wet-dry cooling towers, and (5) dry cooling towers. These heat rejection systems can be considered relative to a balance of three factors: economics, environmental effects, and resource utilization.

Establishing an appropriate balance among these three factors is complicated by an absence of criteria and by existing or proposed regulations forbidding heat releases to water bodies. Further complications arise from an inadequate knowledge of atmospheric effects of large heat releases. Using data available, heat rejection methods have been selected to illustrate a methodology which might be used in the design of nuclear energy centers. Basically, this approach involves balancing environmental impacts to the atmosphere and to the Columbia River with conservation of resources and costs.

The most important environmental effects identified to date for HNEC cooling systems are alteration of the Columbia River aquatic life and creation of more ground fog and higher relative humidity as a result of moisture releases into the atmosphere. It should be noted that little capability exists for predicting changes in meteorological events such as icing, rain, and wind. At present only general estimates of the increases of ground fog and humidity increases can be made. Better methods for predicting the meteorological effects of wet cooling tower operation are necessary to assure that excessive adverse effects do not occur. The environmental effects for once-through cooling are mostly aquatic; while for dry-cooled systems they are almost entirely sustained in the atmosphere. The other three systems are combinations of both.

In general, the electricity generation costs for these systems are lowest for once-through cooling, 4% higher for ponds and wet cooling towers, and 10 to 15% higher for dry systems. The costs for wet-dry systems are from 5 to 15% higher in accordance with the portion of the heat transferred by the dry portion of the system.

Results of studies to date have indicated that the "optimum" heat disposal method for an HNEC is a combination of once-through cooling and wet tower cooling. The maximum number of reactors with once-through cooling depends partially on future decisions affecting the minimum river flow, but it appears to be about six reactors for a 20-reactor HNEC and ten reactors for a 40-reactor HNEC based on a Columbia River low flow rate of 54,000 cfs. The remainder of the cooling would be accomplished by tall mechanical draft towers to avoid a significant increase in ground fog formation during the winter months or relative humidity increases in the summer. Although tall mechanical draft towers have not been designed and constructed in the United States, they have been in Europe. Current natural draft towers can be adapted to a mechanical draft operation during summer low humidity conditions at Hanford.

The impacts due to ground fog formation and humidity increases are essentially independent of the locations of tall cooling towers on the Hanford

Reservation. Consequently, locations would probably be based on other factors such as aesthetic impacts, proximity to water supply, and economic costs.

Once-through cooling probably will not be permissible during the late summer in some years because the river temperature at Hanford will be 68° or above and these temperatures are detrimental to salmon. Scheduling the annual refueling outages for the once-through cooled reactors during that time should avoid economic penalties. The number of reactors with once-through cooling is also a function of the amount of generating capacity which can be shutdown and of the number of outage personnel available.

Addition of heat to the Columbia River from November to June should be beneficial to the growth rate of young salmon and as a result the probability of survival and return for spawning. A comprehensive study is necessary to quantify the benefits and adverse effects of heat additions to the Columbia River during each month of the year and for the expected ranges of river flow rates and temperature.

This aquatic analysis was based on data representative of recent operation of the Columbia River with a minimum permissible release rate of 36,000 cfs at Priest Rapids dam. This minimum flow was established when nine production reactors were operating with once-through cooling at Hanford and the 36,000 cfs flow probably is no longer optimum for current or future conditions. The optimum flow rate for the Hanford reach of the river should be determined for an HNEC case. This optimum flow rate might include increases in both the minimum permissible flow rate and in the minimum daily average flow rate.

Finally, construction of an HNEC would create a long-term commitment of land and material sources to power generation. However, once-through and wet cooling tower systems would not require more resources than would be used in power plants at other sites which probably would have similar cooling systems.

INTRODUCTION

Selection of the best method for disposal of the waste heat from a large power generation center requires a comprehensive comparison of the costs and environmental effects. The objective is to identify the heat dissipation method with the minimum total economic and environmental cost.

A 20 reactor HNEC will dissipate about 50,000 MWt of waste heat; a 40 reactor HNEC would release about 100,000 MWt. This is a much larger discharge of heat than has occurred from other concentrated industrial facilities and consequently a special analysis is required to determine the permissibility of such a large heat disposal and the best methods of disposal. It is possible that some methods of disposal will not be permissible because of excessive environmental effects or that the optimum disposal method may include a combination of several methods.

This document presents a preliminary analysis of the HNEC heat disposal problem to determine the best methods for disposal and any obvious limitations on the amount of heat that can be released. The analysis is based, in part, on information presented in the interim conceptual study (Harty, 1975), the heat sink management analysis (Laity, 1975), and the meteorological analysis (Ramsdell, 1976). The information in those documents is repeated here only as needed to assure understanding.

THE HEAT SINK PROBLEM

Release of large quantities of heat from a power center can have severe effects on the environment. Normally, large quantities of waste heat are released to nearby water bodies or directly to the atmosphere by use of cooling ponds or wet cooling towers. Cooling water withdrawals and releases to water bodies can severely affect aquatic life through mechanical abrasion in pumps and heat exchange systems or changes in water temperatures or chemical composition. Construction of large cooling ponds can heavily impact terrestrial life by reduction of habitat. Transfer of the heat to the atmosphere either from ponds or from cooling towers may increase fog or modify nearby habitats as a result of icing in the winter. Release of blowdown streams containing high concentrations of dissolved salts, biocides, and corrosion inhibitors also may adversely affect aquatic life in nearby water bodies.

Releases of heat from an HNEC must comply with the provisions of Public Law 92-500 which requires by 1983 (1) the application of the best available technology economically achievable and (2) the elimination of discharges when technologically and economically achievable. However, in the case of thermal discharges, a release is permissible whenever it can be demonstrated that the release will ensure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on that body of water.

The overall purpose of a heat sink evaluation is to identify the heat disposition methods with the best balance among economics, environmental impacts, and resource utilization. The general approach in this evaluation was to define the combination of cooling systems with the lowest total economic, environmental costs and resources utilization. The specific criteria were: (1) The economic costs should be as low as possible; (2) There should be an acceptable level of environmental effects (and preferably no significant adverse effects); and (3) Resource utilization should be as low as practicable, particularly for scarce resources.

In general, there are 24 environmental interaction parameters to consider to determine the best design for the heat dissipation facilities for a power system. Each of these parameters must be evaluated for each of the alternative heat dissipation methods, and then the sum of the effects of all parameters for each method must be compared to the sums for the other alternatives to determine the most desirable alternative.

Numerous methods have been developed for reducing the environmental effects of heat dissipation systems. However, action to reduce an adverse effect usually increases economic costs and may create new environmental problems. Selection of the best design for the best dissipation system requires a subjective balance between the economic, environmental costs, and resource utilization.

APPROACH TO THE ANALYSIS

The heat dissipation methods tentatively selected for the HNEC were determined by use of the standard environmental assessment cost-benefit analysis procedures generally used during preparation of environmental reports and statements. The general procedure as adapted to this analysis is presented schematically in Figure 1.

FIGURE 1: HNEC Heat Sink Analysis Procedure

First, the objective of the analysis was defined as: Determine the best disposal method for the waste heat from either 20 or 40 power plants built at Hanford as described in BNWL-B-458 (Harty, 1975). Then, a detailed description was prepared of the Hanford Reservation physical characteristics, in addition to a general description of the physical and social characteristics of the surrounding territory. Emphasis was placed on those characteristics expected to be significantly affected by the waste heat disposal problem. The physical characteristics of the Hanford Reservation indicated five possible methods for heat disposal:

1. Once-through cooling with Columbia River water,
2. Cooling ponds,
3. Mechanical draft wet cooling towers,
4. Mechanical draft wet-dry cooling towers, and
5. Dry cooling towers.

Twenty alternative heat dissipation cases were selected for the initial alternative analysis. These cases defined the extreme cases for the five possible heat dissipation methods (e.g., all wet cooling towers, all dry towers, etc.) and also the combinations of heat dissipation methods that represented minimum impact conditions (minimum economic costs, minimum fog formation for wet systems, etc.). They were then described and analyzed to determine the economic and environmental costs. Comparison of the cases then defined the best heat dissipation methods.

Although dry cooling has not been demonstrated on a large scale, it was assumed that it would be a reliable method soon enough to be used for most of the HNEC power plants. Natural draft wet cooling towers are uneconomical for Hanford in comparison to mechanical draft towers because of the large increase in condenser cooling water temperature that would be necessary during the summer low-humidity, high-temperature meteorological conditions. The environmental limitations on the use of each of the five cooling methods then were estimated. An example of such a limitation is the maximum permissible heat releases to the Columbia River in accordance with the applicable water quality standards.

An important part of this preliminary heat sink evaluation was to identify the available technology necessary for the evaluation and the need for new technology. Because of limitations in the ability to predict meteorological and aquatic biology effects, the estimations of environmental effects may change as additional data and analytical capability become available.

DESCRIPTION OF HANFORD

Extensive descriptions of the Hanford Reservation have been documented as a result of the ERDA facility operations (ERDA, 1975) and preparation of environmental reports for the Washington Public Power Supply System power reactors (USAEC, 1972). A summary of these characteristics was presented in the interim conceptual report for the HNEC (Harty, 1975).

The pertinent site characteristics for a heat sink evaluation are the hydrology, ecology, and meteorology. Hydrology is important because of the need for large quantities of water either as a heat sink or as a source of water evaporated during transfer of heat to the atmosphere. The ecology is important because use of water and land can have significant effects on life forms and on human recreational activities. Meteorology is important because release of large quantities of heat and moisture may affect human activities through creation of fog, increased humidity, and precipitation. These characteristics for the Hanford Reservation are summarized below.

HYDROLOGY

The only reliable source of the large quantities of water needed for wet cooling systems for large power plants is the Columbia River. Insufficient ground water is available, and all water in the Yakima River is allocated for other purposes during the low flow summer months.

The Columbia River in and near the Hanford Reservation is the last free-flowing stretch within the United States; the remainder is made up of a series of impoundments behind the 11 hydroelectric dams in the river. Average, maximum, and minimum flows are about 120,000, 690,000, and 36,000 cfs, respectively. Since 1960, the minimum average seven-day running mean flow rate has exceeded 54,000 cfs at all times. Peak flow rates occur in late spring and early summer. During late summer, fall and winter daily fluctuations in discharge may range from 36,000 to 160,000 cfs due to flow regulation by the upstream Priest Rapids Dam. This variation in flow can cause

changes in elevation of 10 feet near the upstream part of the Hanford Reservation and 5 feet in the lower reaches. Current velocities vary from less than 3 to over 10 fps.

The flow rate of the Columbia River during low flow periods is determined primarily by the amount of water released from upstream dams. These dams have over 30,000,000 acre-feet of storage capacity corresponding to an average flow of 60,000 cfs during the low-flow period from August to March of each year.

Monthly average river temperatures range from 1.5 to 20.2°C, with maximums occurring in August and September, the minimums in February. The naturally occurring temperature changes in the river between Priest Rapids and Richland range from -0.8°C in the winter to +0.8°C in the summer. River bottom substrates are typically sand, rock, and gravel. Cobbles and boulders are present in many areas and fine silt and sand are found in the slack waters. Water quality of the river is good with dissolved oxygen usually greater than 10 ppm, pH 6.5 to 8.5 and dissolved solids of 154 ppm or less (ERDA, 1975).

Less than ten percent of the Columbia River flow at Hanford is used for downstream consumption. In addition, the major use, irrigation, occurs primarily during the summer high flow period when the river flow is generally much higher than 50,000 cfs. As a result, consumption of up to 2,000 cfs at Hanford should be possible without interference with downstream consumption.

Cooling facilities must be operated at Hanford such that there is no significant effect on radionuclides currently present in the ground or in the waste storage tanks and burial grounds. Generally, this means that (1) there cannot be a significant rise in the water table evaluation underneath the ERDA production areas and burial sites, and (2) the flow rate toward the Columbia River of the groundwater containing tritium cannot be increased. Creation of a barrier to flow of groundwater containing tritium into the river would probably be considered favorable.

Since there is no Hanford generated tritium in groundwater north of the Columbia River, effects of water releases on that groundwater are of less concern. However, liquefaction and subsidence of soils always must be considered in siting large structures.

AQUATIC ECOLOGY

The effects on the aquatic environment that potentially may arise from the establishment of cooling systems for an HNEC are mainly those associated with the withdrawal of Columbia River water for power station condenser cooling and processing, and the discharge of station effluents to the river. These include loss of fish and other aquatic organisms from the following:

- Impingement on the water intake screens causing physical damage from the impact or subsequent screen cleaning operations.
- Passage through the station cooling system. Impacts may range from the death or injury of aquatic organisms due to thermal, chemical and mechanical stress in once-through cooling systems to the removal of river plants and animals in the make-up water of closed-cycle cooling systems.
- Discharge of toxic chemicals and heat to the river that may alter metabolic rates, reproductive cycles, behavior, disease resistance and food base, or cause mortalities as a result of rapid changes in temperature, i.e., heat and cold shock.

The creation of new surface waters (cooling ponds) may be conducive to the growth of nuisance algae and fish disease organisms. Benefits may also be obtained, however, through the development of new areas for sport fishing or the production of human and animal food through aquaculture.

Many of the physical, chemical and biological characteristics of the Columbia River are summarized in the document WASH-1538 (ERDA, 1975). The primary biological systems of concern are the phytoplankton, zooplankters, benthic organisms, and fish. (Appendix A lists the scientific names for the species of interest.)

The phytoplankton originates in the impoundments behind the upstream dams and from the attached algae on the river bottom. Diatoms are the dominant algal group. Biomass of net phytoplankton range from a maximum of about 2.0 g dry wt/m³ in May to less than 0.1 g dry wt/m³ in winter.

Cladocerans and copepods are the dominant zooplankters. Numbers of zooplankters in the main river channel average 600/m³ with maximums of 12,000/m³ in summer to less than 30/m³ in winter (Page, 1976). Both phytoplankton and zooplankton are nearly uniformly distributed throughout the river cross-section.

The principal benthic organisms include insect larvae, sponge, molluscs, flatworms, leeches, crayfish and oligochaetes (ERDA, 1975). Sponge, caddisfly larvae and chironomid larvae make up the bulk of the benthic organisms (Page, 1976). Greatest abundance is in the near shore areas. Maximum biomass ranges from 16 to 38 g/m² in the most productive riffle areas (USAEC, 1972).

There are over 40 species of fish in the Hanford section of the Columbia River (ERDA, 1975). About half of these are of no recognized direct value to man. Sturgeon, whitefish, catfish, perch, bass, sunfish and crappie are permanent residents of the area and provide recreational fishing; anadromous salmon, steelhead trout and shad are economically important to both commercial and sport fisheries.

The latter group use the local reach of the river as a spawning and rearing area and as a migration route to and from upstream spawning grounds. The extent to which the local section of river is used by adult anadromous upstream migrants is given in Table 1, showing the passage of fish over Priest Rapids immediately upstream from the Hanford Reservation. Although chinook salmon and steelhead trout move up the Columbia during all months of the year, the greatest numbers are present during the period from April through November.

The Hanford Section of the Columbia is one of the last main-stream river areas used for spawning by fall chinook salmon. The major sections of the

TABLE 1: Adult Anadromous Fish Passage, Priest Rapids Dam - 1965-1975

<u>Chinook Salmon</u>	<u>April*</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>October</u>
Mean	1,927	6,470	2,744	12,146	9,325	9,527	1,377
Max.	6,562	10,143	4,801	17,166	13,265	18,025	1,964
Min.	1	3,754	1,281	6,425	5,937	4,314	905
<u>Sockeye Salmon</u>							
Mean	0	3	1,669	69,575	4,250	117	18
Max.	0	9	5,020	158,352	10,210	315	54
Min.	0	0	96	32,933	1,195	19	0
<u>Coho Salmon</u>							
Mean	0	0	1	25	58	3,588	1,690
Max.	0	0	5	142	201	10,363	4,616
Min.	0	0	0	0	3	140	281
<u>Steelhead Trout</u>							
Mean	196	385	99	474	1,720	3,263	1,383
Max.	530	1,112	229	1,194	2,775	5,549	2,751
Min.	85	37	18	185	570	945	252
<u>Shad</u>							
Mean	0	16	734	2,901	435	5	1
Max.	0	172	5,243	6,543	1,405	39	11
Min.	0	0	0	147	32	0	0
<u>TOTAL MEAN</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>October</u>
	2,123	5,374	5,247	85,122	18,378	16,501	4,469

*Partial counts -- counting usually began April 15 or later.

river used for spawning are shown in Figure 2. Most of the spawning takes place near the river islands in depths of approximately 3 to 12 feet in rapidly flowing water. Spawning begins about the middle of October and is concluded by the middle of November. Egg incubation and larval fish emergence from the redds (nests) in the river bottom takes place from February through April. The numbers of fall chinook salmon redds and estimates of the local spawning population are given in Table 2. Although there is considerable variability in the Hanford chinook spawning population, it represents a significant part of the adult fall chinook in the river, 15% of the escapement over Bonneville Dam and about 30% of the fall chinook reaching the middle Columbia River (Watson, 1970).

Average annual steelhead trout spawning population estimates near Hanford for the years 1962-1971 are about 10,000 fish (Watson, 1973) and the

FIGURE 2: Hanford Chinook Salmon Spawning Area

TABLE 2: Fall Chinook Spawning - Hanford

Number of Redds (nests)*

River Kilometer

Year	560-570	586-592	597	600-608	618	633	Other	Total	Estimated No. Salmon
1947	0	15	25	10	0	75	115	240	1680
1948	120	330	38	219	0	25	53	785	5500
1949	45	50	6	195	0	1	33	330	2310
1950	24	43	38	151	3	46	11	316	2210
1951	5	10	45	151	5	95	3	314	2200
1952	73	101	40	221	3	78	23	539	3770
1953	7	5	16	38	0	83	0	149	1040
1954	4	5	8	127	0	6	7	157	1100
1955	0	12	0	47	0	4	1	64	450
1956	0	3	7	59	0	17	6	92	640
1957	27	173	55	440	43	132	2	872	6100
1958	49	249	133	520	192	258	83	1485	10400
1959	1	0	36	101	32	111	0	281	1970
1960	0	31	22	99	38	105	0	295	2070
1961	0	27	43	201	23	640	4	939	6570
1962	6	195	66	456	1	635	2	1261	8830
1963	0	283	127	506	14	370	3	1303	9120
1964	5	163	111	510	37	624	27	1477	10300
1965	4	262	211	588	54	659	11	1789	12500
1966	10	279	267	1206	37	1300	2	3101	21700
1967	28	388	273	1192	17	1340	29	3267	22900
1968	117	595	188	1069	52	1520	39	3560	24900
1969	265	820	427	1446	50	1500	0	4508	31600
1970	107	615	302	1180	72	1528	9	3813	26700
1971	182	560	416	1071	10	1361	0	3600	25200
1972	88	247	147	259	4	131	0	876	6130
1973	137	458	179	1273	62	856	0	2965	20800
1974	164	156	49	238	5	173	3	728	5100
1975	95	458	291	752	91	995	1	2683	18780

spawning areas are thought to be generally similar to those used by the fall chinook salmon. Steelhead support a fairly intensive sport fishery between Ringold and Richland.

The juvenile chinook salmon pass through the Hanford section of the Columbia from March through July (Mains and Smith, 1964), although there is some evidence that the young of populations spawning upstream of Priest Rapids may continue through August (Park, 1969). There is a tendency for the young salmon to migrate downstream near shore and near the surface of the river (Mains and Smith, 1964). In addition to the salmon produced in the river, young are released to the river from the Washington Department of Fisheries artificial spawning channel at Priest Rapids Dam and from the rearing facility at Ringold. Steelhead young are also reared and released to the river at Ringold by the Washington Department of Game.

Food of the young salmon migrating through the Hanford section of the river consists almost entirely of aquatic insects (96% of diet), most of which originate from the river benthos (Becker, 1970).

TERRESTRIAL ECOLOGY

The effects on the terrestrial environment that potentially would result from establishment of cooling systems for nuclear power stations at Hanford are mainly those associated with occupancy of land by cooling system facilities. This land occupancy would reduce the total habitat for terrestrial life. The net reduction in inhabitants would depend on the type of land occupied and the alteration of surrounding lands as a result of moisture releases from the cooling facilities. Releases of moisture could increase total populations by creation of additional habitat and watering sites which would more than compensate for the loss of land occupied by the cooling facilities. However, the new populations would consist of different species than the original inhabitants.

Natural Vegetation

The natural vegetation of the Hanford Reservation is classified as shrub-steppe (Daubenmire, 1970). The shrub component is characteristically

dominated by big sagebrush and the understory is composed of many herbaceous species, especially grasses, the most common of which are bluebunch wheatgrass, Sandberg bluegrass, and cheatgrass.

The undisturbed vegetation mosaic can be subdivided into three major vegetation types on the basis of shrub species in the overstory and the dominant herbaceous species in the understory. The big sagebrush/bluebunch wheatgrass vegetation type is confined to the Rattlesnake Hills and is entirely located within the boundaries of the Arid Lands Ecology Reserve (ALE). The big sagebrush/antelope bitterbrush/cheatgrass vegetation type occupies a triangular shaped area extending from the 100 F reactor area to the Horn Rapids bend of the Yakima River (Figure 3). The vegetation type occupying the remainder of the Hanford Reservation is classified as the big sagebrush/cheatgrass.

The three vegetation types of most concern to the construction and operation of the facilities associated with an HNEC are the big sagebrush-antelope bitterbrush/cheatgrass and big sagebrush/cheatgrass types, and the riparian plant communities associated with the Columbia River shoreline and islands. Although these latter communities occupy small acreages as compared to other communities, they are especially important to wildlife populations of mule deer, Chinese ring-necked pheasants, California quail, and to nesting populations of the Canada goose.

Special Biological Habitats

Many kinds of special habitats are recognized. One of these is an extensive area of sand dunes located north and east of the Washington Public Power Supply System's Hanford 1, 2, and 4 power stations. Typical of others are a geological formation of knob and kettle topography located near the N-Reactor (Figure 3); a series of tall, steep-walled bluffs along the eastern shore of the Columbia River known as "White Bluffs"; and a series of basaltic cliffs associated with Gable Mountain and Gable Butte, centrally located in the reservation area.

White Bluffs: The cliff faces of these bluffs provide ancestral nesting sites for thousands of cliff swallows. These birds are present for a

FIGURE 3: Hanford Reservation

few weeks in summer, raise their young, then migrate to neotropical regions with the onset of autumn weather. The birds forage on adult flying insects that are produced in the aquatic environment of the Columbia River. Cracks in the bluff face provide nesting locations for starlings and feral rock doves. The cliff faces are erodible and provide only a few ledges deep enough to provide nest sites for prairie falcons. If nuclear facilities are not built above these cliffs, there is no reason to expect that the construction and operation of nuclear energy facilities at Hanford would deleteriously affect the bird populations dependent upon the White Bluffs as nesting habitat. However, construction of facilities above the cliffs could result in water releases to the ground and destruction of the nesting sites by landslides.

Gable Mountain and Gable Butte: The basalt cliffs are remote and inaccessible and provide ledges which are used for nesting by the prairie falcon (at least one active nest is known from Gable Butte), red-tailed hawk, and great horned owl. The talus slopes provide habitat for rock wrens and canyon wrens. There is no reason to expect that the construction and operation of a nuclear energy facility at Hanford would deleteriously affect the breeding bird population dependent upon Gable Mountain and Gable Butte as nesting habitat.

Man-made Habitats: Deciduous trees planted for shade and/or fruit years ago have survived without human attention for periods as long as 35 years. Today, these trees provide nest sites for certain birds that otherwise could not be associated with the treeless vegetation of the Hanford Reservation, i.e., Swainson's hawk, red-tailed hawk, sparrow hawk, great-horned owl, raven, magpie, great blue heron, and black-crowned night heron. Many of the trees now supporting nests are senescent. Because these trees do not establish young trees from seeds, it is only a matter of time until they disappear from the Reservation. With the demise of trees, birds will have to seek nest sites elsewhere. The planting of trees around nuclear energy facilities can be expected to enhance the nesting potential of tree-nesting avifauna.

Aqueous effluents from chemical processing facilities and irrigation canals have created ponds of various ages on the Hanford Reservation. Other

ponds located east of the Columbia River have been created from seepage and waste waters from irrigation canals on the Wahluke slope. These ponds are less than ten years old and are expected to persist for an indefinite period of time. The vegetation associated with pond and shoreline environments provide habitat attractive to a wide spectrum of birds (Fitzner and Rickard, 1975). The biological problems and benefits associated with open ponds can be expected if these are contemplated for HNEC facilities.

Another kind of man-made habitat present on the Hanford Reservation is abandoned agricultural fields. For the most part, these are located near the Columbia River adjacent to the former townsites of Hanford and White Bluffs. After 30 years of abandonment, these fields support self-sustaining swards of annual plants, especially cheatgrass. These annual swards have resisted natural invasion by native perennial species for more than 30 years.

Sand Dunes: Sand dunes occupy several thousand acres of land on the western shore of the Columbia River in Benton County. For the most part, the dunes are not occupied by plants; however, a few species can become established on the nutrient-deficient and wind-mobile dune sands (Langham, 1970). The dune area is almost inaccessible to conventional vehicles and provides a sanctuary area for mule deer during the spring fawning season (Hedlund et al., 1975).

River Islands: The islands in the Columbia River located between the northern boundary of the Hanford Reservation and the City of Richland provide nesting habitat for a small population of resident Canada geese. The nesting history of this population has been studied (Hanson and Eberhardt, 1971). The islands provide critical habitat necessary for the sustainment of the Canada goose population.

Knob and Kettles: Unusual topography occurs on the western bank of the Columbia River near the N-Reactor. The origin of knob and kettle topography is believed to be a result of glacio-fluvial action. A description of the vegetation and animal populations of this area has been recorded (Rickard, 1975, and Hedlund et al., 1975).

Rock Outcrop: Rock outcrop plant communities are particularly well developed along the crest of the Rattlesnake Hills located within the Arid Lands Ecology (ALE) Reserve. The communities occupy relatively little acreage but support plants that are not found elsewhere on the Hanford Reservation. Two species found in the Rattlesnake Hills are on the Smithsonian list of endangered species, Balsamorhiza rosea and Eriogonum thymoides. Because most of the habitat supporting these plants is protected from intrusion by the ALE Reserve, the construction and operation of HNEC facilities would not be expected to deleteriously affect the status of these communities.

Gravel Bars: Gravel bars are characteristically found along fast-flowing streams and rivers. The coarse rooting substrate provided by gravel and cobbles in addition to inundation by seasonal flooding makes gravel bars difficult habitats for plant colonization. Nevertheless, some specialized plant species can invade water-washed gravel bars and maintain populations for years. Gravel bars along the Columbia River support many types of herbaceous plants. However, there have been no ecologically descriptive studies made of these communities.

Primary Productivity

Shrub-steppe plant communities are more productive than desert plant communities but less so than certain grass and forest communities (Rodin and Bazilovitch, 1975). Studies conducted on the Arid Lands Ecology Reserve in stands of the sagebrush-bluebunch wheatgrass in conjunction with the United States' contribution to the International Biological Program Grassland Biome project show that best annual production is less than 100 g/m²/year.

Wildlife Populations

Mule Deer

The mule deer is the only big game mammal on the Hanford Reservation. Although these animals roam over the entire Reservation, the major population concentration is along the Columbia River. The deer population here is at least one hundred animals (Hedlund, 1975). Critical fawning areas are

the islands in the Columbia River and the remote portions of the sand dunes. Fawn tagging has been conducted for seven consecutive years. Animals tagged on the Hanford Reservation have been killed by hunters 70 miles from their initial capture points (Hedlund, 1975).

The construction of HNEC facilities can affect the daily and seasonal patterns of movement of mule deer on the Hanford Reservation. Tall, chain-link fences are effective barriers to mule deer movements as are wide, deep concrete-walled irrigation canals. Some deer mortality can be expected from increased automobile traffic.

Although hunting has not been permitted on the Hanford Reservation, animals produced there provide game for hunters on bordering lands. The main human value of the mule deer here on the Reservation is the esthetic appeal of sighting these animals wild in their natural habitat.

Canada Goose

Nesting populations of Canada geese have been studied for many years (Hanson and Eberhardt, 1971). Over the years of study, the number of nests has declined (Figure 4). The decline is attributed to predation, changing vegetation structure on the islands, and human interference created by opening the lower section of the Hanford Reservation to public recreation.

Migrant flocks of Canada geese have historically used the Columbia River as a resting stop during spring and fall migration. These geese make foraging flights to nearby agricultural fields and rangelands that support newly germinated stands of cheatgrass. Department of Interior Wildlife refuges located in Franklin and Walla Walla Counties also attract migrant Canada geese as well as other waterfowl species.

Upland Game Birds

Chukar partridges are important game birds in steppe vegetation of eastern Washington. These birds were introduced to North America from Eurasia to provide bird hunting for sportsmen. They are especially plentiful in the Rattlesnake Hills and Saddle Mountains, although there are also a few coveys in the Gable Mountain and Gable Butte areas.

FIGURE 4: Number of Canada Goose Nests on Hanford Reservation Islands 1953-1975

California quail and Chinese ring-necked pheasants are mostly confined to the deciduous shrub vegetation associated with the shoreline of the Columbia River. Like the chukar partridge, the pheasant is an introduced species. The California quail was introduced to Washington from its native range in California.

The sagegrouse is scarce on the Hanford Reservation. A few birds are found on the ALE Reserve where they are protected from hunting.

The mourning dove is a common, summer resident of the Hanford Reservation, nesting wherever water and weed seeds are available. Birds produced on the Reservation leave in the fall and migrate south. Hunters harvest large numbers of doves during this migration period.

Small Game Mammals

The important small game mammals of the Hanford Reservation are cotton-tail rabbits and black-tailed hares. Hares are distributed throughout the steppe vegetation areas while cottontails are found in local concentrations where food and cover are available.

Black-tailed hares were studied as biological indicators of radio-iodine in the environment (Hanson, 1962) and as a biological agent for the dispersal of radionuclides in waste management areas (O'Farrell and Gilbert, 1975).

Predatory Mammals

The most important mammalian predators on the Hanford Reservation are the coyote and badger. Little is known about the population dynamics of either; however, recent studies using radiotracking techniques show that coyotes can wander many miles.

Bobcats are present on the Reservation but in low numbers. Other predators are the raccoon, skunk, mink, and weasel. These animals are mostly confined to riparian habitats associated with the Columbia River.

Other Mammals

Muskrats and beaver are present in the Columbia River. Muskrats occur in ponds and ditches elsewhere on the Reservation (Rickard et al., 1975). The most abundant small mammals are rodents, especially the Great Basin pocket mouse, deer mouse, and the Townsend ground squirrel. The population dynamics of the pocket mouse has received the most study (O'Farrell et al., 1975).

Consumer Productivity

Shrub-steppe vegetation historically did not support large herbivores such as bison and antelope. Instead, small mammals like the Great Basin pocket mouse and the Townsend ground squirrel are the abundant vertebrate herbivores. Population dynamics of pocket mice have been intensively studied (O'Farrell et al., 1975; Schreiber, 1974).

The most direct use of steppe vegetation as a food source to man is cattle grazing. Cattle grazing studies on the ALE Reserve show that one acre of sagebrush-bluebunch wheatgrass pasture can produce only about 20 pounds of cattle liveweight per year without damaging future community production.

Wildlife as a Recreational Resource

Tagging studies of mule deer show that mule deer produced as fawns on the Hanford Reservation are killed by hunters when they leave the reservation (Hedlund, 1975). Several hundred Canada geese are produced each year from the nesting populations and some of these are killed as they leave the protection of the reservation (Hanson and Eberhardt, 1970). Chukar partridges regularly nest and produce young on the ALE Reserve. Some of these are probably killed on the Washington State Department's Rattlesnake Hills Wildlife Area and private lands adjoining the reserve.

Coyotes are a permanent constituent of the wildlife resource of the Hanford Reservation and young are reared on the Reservation. Some of these animals probably leave the Reservation where they are available for predator hunting or they may also be regarded as pests by livestock raisers.

The Hanford Reservation serves as a nesting refuge for birds that are diminished throughout the western states as their ancestral habitats are usurped by man-imposed land uses. These birds - burrowing owl, long-billed curlew, great horned owl, Swainson's hawk, red-tailed hawk, and prairie falcon - all contribute to enjoyment of people who like to watch birds.

Food Webs

Diagrammatic representations of food webs in typical terrestrial and waste pond habitats are shown in Figures 5 and 6.

FIGURE 5: Food Web in Terrestrial Habitat

FIGURE 6: Food Web in Waste Pond Habitat

METEOROLOGY

Any evaluation of the impact of heat sink management alternatives on the environment must consider the climate of the region under consideration. Thus it is appropriate to describe the climate of the Hanford area in some detail.

General Climate

The basic reference on Hanford climate is the Climatography of the Hanford Area (Stone, Jenne, and Thorp, 1972). Temperature and precipitation data in this work indicate that the Hanford area borders between a steppe (BS) and desert (BW) climate using the Koppen classification scheme (Petterssen, 1958). This classification is confirmed by the vegetation types which occupy most of the Hanford Reservation.

Meteorological observations have been made at numerous locations in the Hanford vicinity, but the only extensive records for a single location are those for the Hanford Meteorological Station (HMS). The HMS is located on a plateau at about 750 ft above mean sea level and 300 ft above the Columbia River, which flows through the Reservation from the northwest to the southeast. There are several significant topographic features within 20 miles of the HMS which affect aspects of the Hanford climatology.

Prior to the establishment of the HMS in December 1944, meteorological measurements were made by U.S. Weather Bureau cooperative observers between 1912 and 1943, and by the U.S. weather Bureau in Richland for a short period at the end of 1943 and beginning of 1944.

The climatological data from these sources are summarized in Table 3. This summary gives both monthly and annual statistics for a large number of climatological variables and includes extreme values as well as mean values.

TABLE 3: Averages and Extremes of Climatic Elements at Hanford
(Based on All Available Records to and Including the Year 1975)

	TEMPERATURE (°F)												DEGREE DAYS (BASE 65°F)										PRECIPITATION (INCHES)																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																			
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LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST	RECORD HIGHEST	RECORD LOWEST

EXTREME AVERAGES OR TOTALS AND YEAR OR SEASON OF OCCURRENCE

1912-1975 TEMPERATURE AVERAGES (°F)				1912-1975 TEMPERATURE AVERAGES (°F)			
HIGHEST ANNUAL	56.2	1950		HIGHEST WINTER 10-11	41.1	1933	34
LOWEST ANNUAL	50.2	1929		LOWEST WINTER	24.2	1948	49
HIGHEST SPRING (MAY)	56.2	1947		HIGHEST SUMMER (JULY)	76.2	1958	
LOWEST SPRING	48.0	1955		LOWEST SUMMER	70.3	1954	
HIGHEST FALL (OCT)	56.6	1943		LOWEST FALL	49.6	1946	
1912-1975 PRECIPITATION TOTALS (IN)				1912-1975 PRECIPITATION TOTALS (IN)			
GREATEST ANNUAL	11.45	1950		GREATEST ANNUAL	11.45	1950	
LEAST ANNUAL	3.26	1967		LEAST ANNUAL	3.26	1967	
SNOW ICE PELLETS (SHEET)				SNOW ICE PELLETS (SHEET)			
GREATEST SEASONAL	43.6	1933	16	GREATEST SEASONAL	43.6	1933	16
LEAST SEASONAL	0.3	1957	58	LEAST SEASONAL	0.3	1957	58
1945-1975 WIND SPEED AVERAGE (MPH)				1945-1975 WIND SPEED AVERAGE (MPH)			
HIGHEST ANNUAL	8.3	1968		HIGHEST ANNUAL	8.3	1968	
LOWEST ANNUAL	6.3	1957		LOWEST ANNUAL	6.3	1957	
1946-1975 RELATIVE HUMIDITY AVERAGE (%)				1946-1975 RELATIVE HUMIDITY AVERAGE (%)			
HIGHEST ANNUAL	57.0	1950		HIGHEST ANNUAL	57.0	1950	
LOWEST ANNUAL	49.4	1967		LOWEST ANNUAL	49.4	1967	
1946-1975 SKY COVER AVERAGES (SUNRISE TO SUNSET, SCALE 0-10)				1946-1975 SKY COVER AVERAGES (SUNRISE TO SUNSET, SCALE 0-10)			
HIGHEST ANNUAL	6.4	1966		HIGHEST ANNUAL	6.4	1966	
LOWEST ANNUAL	5.1	1949		LOWEST ANNUAL	5.1	1949	
1951-1975 SOLAR RADIATION AVERAGE DAILY TOTAL (HOURS)				1951-1975 SOLAR RADIATION AVERAGE DAILY TOTAL (HOURS)			
HIGHEST ANNUAL	960	1973		HIGHEST ANNUAL	960	1973	
LOWEST ANNUAL	357	1967		LOWEST ANNUAL	357	1967	

	WIND (mph)												RELATIVE HUMIDITY (%)												SKY COVER (SCALE 0-10)												SOLAR RADIATION (LANGLEY'S)*											
	1945-1975 AVERAGES						PEARL GUSTS						1946-1975 AVERAGES						1946-1975 EXTREMES						1946-1975 AVERAGES (SUNRISE TO SUNSET)						1946-1975 AVERAGES						1946-1975 EXTREMES											
	PREVAILING DIRECTION	MEAN MONTHLY	HIGHEST MONTHLY	YEAR	LOWEST MONTHLY	YEAR	SPEED	DIRECTION	YEAR	MEAN	HIGHEST MONTHLY	YEAR	LOWEST MONTHLY	YEAR	HIGHEST	YEAR	LOWEST	YEAR	MONTHLY	HIGHEST MONTHLY	YEAR	LOWEST MONTHLY	YEAR	MONTHLY	HIGHEST MONTHLY	YEAR	LOWEST MONTHLY	YEAR	MONTHLY	HIGHEST MONTHLY	YEAR	LOWEST MONTHLY	YEAR															
	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR															
	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR	YEAR															
Jan	SW	6.0	10.1	1972	3.3	1955	80	SW	1972	75.2	86.8	1961	60.0	1963	100	1963	13	1963	7.8	9.0	1969	4.3	1969	120	176	1971	8.8	1973	2.7	1965	16	1971																
Feb	SW	7.1	9.4	1961	4.6	1963	65	SW	1971	70.0	86.9	1961	54.0	1963	100	1975	14	1962	7.4	8.9	1961	5.9	1964	262	218	1960	10.4	1964	4.2	1958	37	1970																
Mar	WNW	8.4	10.7	1964	5.9	1958	70	SW	1956	55.9	65.9	1950	44.0	1965	100	1974	12	1965	6.9	7.9	1950	4.9	1965	340	346	1965	8.0	1965	3.4	1968	47	1972																
Apr	WNW	9.1	11.3	1972	7.4	1954	71	SSW	1972	46.5	64.5	1963	36.9	1966	100	1973	9	1974	6.4	8.1	1963	3.7	1951	425	335	1973	10.4	1963	3.4	1972	75	1974																
May	WNW	9.9	10.5	1965	5.8	1957	74	SSW	1948	42.3	61.9	1948	31.2	1956	100	1975	7	1973	5.8	7.7	1950	4.5	1949	526	434	1970	5.1	1962	3.2	1958	67	1962																
June	WNW	9.2	10.7	1949	7.7	1950	72	SW	1957	39.5	51.5	1950	30.0	1949	100	1972	10	1964	5.3	7.0	1950	2.8	1961	620	496	1960	6.5	1953	3.1	1971	112	1965																
July	WNW	8.6	9.6	1963	6.8	1955	50	WSW	1968	31.8	40.5	1966	21.9	1959	99	1972	6	1951	2.8	4.5	1974	0.9	1953	639	714	1973	5.8	1955	0.8	1974	118	1972																
Aug	WNW	8.0	9.1	1966	6.0	1956	60	SW	1961	34.8	41.8	1963	24.5	1967	100	1972	7	1971	3.2	5.9	1962	0.6	1955	558	613	1955	6.75	1968	7.1	1957	102	1959																
Sept	WNW	7.5	9.2	1961	5.4	1957	65	SSW	1953	40.4	55.1	1959	33.2	1974	100	1962	10	1962	4.0	6.1	1959	1.4	1975	421	463	1975	19.4	1959	2.1	1970	61	1959																
Oct	WNW	6.7	9.1	1966	6.1	1952	61	SSW	1950	57.0	64.2	1962	42.5	1952	100	1975	10	1952	5.9	4.0	1975	3.9	1952	262	295	1956	21.6	1975	4.34	1973	33	1977																
Nov	SW	6.1	7.9	1965	2.8	1956	64	SSW	1949	71.5	88.1	1972	64.2	1963	100	1975	16	1979	7.6	9.1	1972	6.2	1972	132	180	1957	9.7	1964	26.5	1971	14	1967																
Dec	SW	6.1	8.3	1968	3.9	1963	71	SW	1955	80.1	90.5	1950	60.0	1968	100	1975	26	1972	8.1	9.2	1962	4.8	1954	92	114	1970	5.7	1969	19.6	1972	9	1976																
Year	WNW	7.7	11.1	1972	2.9	1956	60	SW	1972	59.9	90.5	1950	21.9	1959	100	1975	6	1951	5.9	9.2	1962	0.6	1955	372	714	1973	5.7	1969	8.23	1971	9	1976																

TABLE 3: (continued)

NUMBER OF DAYS (1945-1975)																																											
CLEAR												PARTLY CLOUDY		CLOUDY				THUNDERSTORMS				HEAVY FOG 1/4 MI OR LESS				PRECIP 0.10 INCH OR MORE				SNOW 1.0 INCH OR MORE													
MEAN MONTHLY		GREATEST MONTHLY		YEAR		LEAST MONTHLY		YEAR		MEAN		MEAN MONTHLY		GREATEST MONTHLY		YEAR		LEAST MONTHLY		YEAR		MEAN		GREATEST MONTHLY		YEAR		LEAST MONTHLY		YEAR		MEAN MONTHLY		GREATEST MONTHLY		YEAR		LEAST MONTHLY		YEAR			
Jan	4	7	1963	0	1955	7	20	27	1969	17	1963	0	0	1972	0	1975	5	14	1965	0	1969	3	8	1970	0	1972	2	10	1950	0	1967	1	1967	1	1967	1	1967	1	1967	1	1967		
Feb	5	9	1964	1	1972	7	17	26	1958	12	1964	8	1	1972	0	1975	3	11	1963	0	1971	2	5	1961	0	1972	2	4	1975	0	1974	0	1974	0	1974	0	1974	0	1974	0	1974		
Mar	6	12	1965	2	1961	9	15	22	1968	9	1965	8	1	1969	0	1975	1	5	1951	0	1975	2	8	1957	0	1973	8	2	1957	0	1975	0	1975	0	1975	0	1975	0	1975	0	1975		
Apr	7	12	1962	1	1963	11	13	21	1963	6	1954	1	3	1948	0	1975	8	1	1975	0	1974	1	5	1948	0	1973	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
May	9	14	1973	2	1960	11	11	19	1960	6	1958	2	7	1956	0	1974	1	1	1971	0	1975	2	4	1967	0	1973	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
June	10	23	1961	5	1972	10	10	15	1973	5	1960	3	8	1972	0	1963	8	1	1971	0	1975	2	8	1950	0	1973	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
July	20	26	1960	13	1974	7	3	9	1974	1	1961	2	7	1975	0	1975	0	0	1956	0	1975	1	3	1974	0	1975	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Aug	19	30	1955	11	1968	7	4	13	1968	0	1975	2	8	1973	0	1974	1	4	1975	0	1975	1	4	1975	0	1974	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Sept	15	27	1975	8	1968	8	7	13	1969	1	1975	1	4	1974	0	1975	8	1	1971	0	1975	1	5	1959	0	1975	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oct	10	14	1970	1	1975	8	13	22	1973	9	1970	1	1	1975	0	1974	1	4	1962	0	1974	2	8	1950	0	1972	8	1	1971	0	1975	0	1975	0	1975	0	1975	0	1975	0	1975		
Nov	4	10	1977	1	1973	4	19	25	1973	15	1961	0	0	0	0	1975	6	13	1965	0	1960	3	10	1973	0	1967	8	6	1955	0	1974	0	1974	0	1974	0	1974	0	1974	0	1974		
Dec	3	7	1972	1	1962	6	22	28	1967	18	1967	0	1	1971	0	1975	8	17	1950	2	1968	3	9	1964	0	1949	2	6	1964	0	1974	0	1974	0	1974	0	1974	0	1974	0	1974		
Year	112	80	Aug	0	1955	97	154	28	Dec	0	1969	11	8	1972	0	1975	24	67	Dec	0	1975	21	9	1964	0	1975	6	0	1970	0	1975	6	0	1975	6	0	1975	6	0	1975	6	0	1975

NUMBER OF DAYS				NUMBER OF DAYS			
CLEAR TO 3 TENTHS SKY COVER SR TO 551				CLEAR TO 3 TENTHS SKY COVER SR TO 551			
GREATEST ANNUAL (1966) 75				GREATEST ANNUAL (1966) 75			
LEAST ANNUAL (1966) 75				LEAST ANNUAL (1966) 75			
141				141			
85				85			
1951				1951			
CLOUDY TO 10 TENTHS SKY COVER SR TO 551				CLOUDY TO 10 TENTHS SKY COVER SR TO 551			
GREATEST ANNUAL (1966) 75				GREATEST ANNUAL (1966) 75			
181				181			
84				84			
1949				1949			
THUNDERSTORMS				THUNDERSTORMS			
GREATEST ANNUAL (1965) 75				GREATEST ANNUAL (1965) 75			
23				23			
1				1			
1949				1949			
HEAVY FOG (VIS 1/4 MI OR LESS)				HEAVY FOG (VIS 1/4 MI OR LESS)			
GREATEST ANNUAL (1965) 75				GREATEST ANNUAL (1965) 75			
42				42			
9				9			
1950-51				1950-51			
PRECIPITATION 0.10 INCH OR MORE				PRECIPITATION 0.10 INCH OR MORE			
GREATEST ANNUAL (1966) 75				GREATEST ANNUAL (1966) 75			
29				29			
10				10			
1955				1955			
SNOW 1.0 INCH OR MORE				SNOW 1.0 INCH OR MORE			
GREATEST ANNUAL (1966) 75				GREATEST ANNUAL (1966) 75			
15				15			
0				0			
1957-58				1957-58			
3 IN. OR MORE SNOW ON GROUND				3 IN. OR MORE SNOW ON GROUND			
GREATEST ANNUAL (1966) 75				GREATEST ANNUAL (1966) 75			
40				40			
0				0			
1964-65				1964-65			
PEAK GUST 40 MPH OR GREATER				PEAK GUST 40 MPH OR GREATER			
GREATEST ANNUAL (1965) 75				GREATEST ANNUAL (1965) 75			
41				41			
13				13			
1958				1958			
MAX TEMPERATURE 90 OR ABOVE				MAX TEMPERATURE 90 OR ABOVE			
GREATEST ANNUAL (1972) 75				GREATEST ANNUAL (1972) 75			
85				85			
31				31			
1964				1964			
MAX TEMPERATURE 100 OR ABOVE				MAX TEMPERATURE 100 OR ABOVE			
GREATEST ANNUAL (1972) 75				GREATEST ANNUAL (1972) 75			
32				32			
1				1			
1954				1954			
MAX TEMPERATURE 12 OR BELOW				MAX TEMPERATURE 12 OR BELOW			
GREATEST ANNUAL (1972) 75				GREATEST ANNUAL (1972) 75			
53				53			
1				1			
1975-56				1975-56			
MIN TEMPERATURE 12 OR BELOW				MIN TEMPERATURE 12 OR BELOW			
GREATEST ANNUAL (1972) 75				GREATEST ANNUAL (1972) 75			
161				161			
75				75			
1975-58				1975-58			
MIN TEMPERATURE 0 OR BELOW				MIN TEMPERATURE 0 OR BELOW			
GREATEST ANNUAL (1972) 75				GREATEST ANNUAL (1972) 75			
18				18			
0				0			
1974-75				1974-75			

REFERENCE NOTES

- * CALIBRES 5/16"
- * SKY COVER AND PRECIPITATION OBSERVATIONS NOT BEGUN UNTIL 1966
- * LESS THAN 1/2
- * ALSO ON EARLIER YEARS

LOCATION AND HISTORY

PRESENT LOCATION 25 MILES NW OF RICHMOND, WASHINGTON
 LATITUDE 40°N, LONGITUDE 119°W, ELEVATION 255 FEET
 OBSERVATIONS FROM 1912 TO 1966 WERE BY UNITED STATES
 WEATHER BUREAU COOPERATIVE OBSERVERS AT A SITE ABOUT
 10 MILES ENE OF PRESENT LOCATION. SINCE 1966 OBSERVATIONS
 HAVE BEEN MAINTAINED ON A 24 HOUR A DAY BASIS BY THREE
 DIFFERENT TRMA OPERATIONS.

In addition to the month-to-month variation in the climatological statistics presented in Table 3, there are distinct daily cycles which are superimposed on the seasonal variation. These daily cycles are most evident in temperature, humidity, and wind speed. The daily temperature cycle at Hanford ranges from about 13°F in December to 30°F in July and August.

The daily cycle of relative humidity is inversely related to the temperature cycle; that is, when the temperature decreases, the humidity increases. Conversely, when the temperature increases, the relative humidity decreases. The daily relative humidity variation at Hanford is about 25% throughout most of the year. However, it decreases to about 15% in December and January.

The daily wind speed cycle has a minimum during the morning hours and a maximum near sunset. It is most pronounced during the summer and almost imperceptible during the months of December and January. Figures 7 and 8 show these daily cycles for the months of January and July respectively.

FIGURE 7: Daily Climatological Cycles - January

FIGURE 8: Daily Climatological Cycles - July

The most frequent restriction to visibility in the Hanford area is fog which occurs on an average of 38 days per year. On 24 of these days the visibility is restricted to less than 1/2 mile. Fog is highly seasonal, although it has occurred in every month. More than 95% of the occurrences are from November through February. If the months of October and March are included this percentage increases to more than 99.5%.

Hanford fogs are generally associated with low wind speed conditions. More than 70% of the hours of fog occur when the wind speed is less than 3.5 mph, and the average wind speed during fog is 2.5 mph. Table 4 gives detailed statistics on the hours and duration of both total and dense fog by months. It should be noted that January 1976 set a record for most hours of fog in a single month, 257. During that month fog was observed on a total of 20 days, including the last 16 days of the month.

TABLE 4: Total Duration* and Maximum Persistence of Fog
Tabulated in Hours for the Period 1945-1970

ALL FOG (VIZ 0-6 MILES)	AVG TOTAL DURATION	MAX TOTAL DURATION	YEAR	MIN TOTAL DURATION	YEAR	AVG DURATION PER DAY OF OCCURRENCE	MAX. PERSISTENCE ⁽³⁾	YEAR
JAN	68.3	193.4	1965	0	1949	7.2	52.1	1955
FEB	36.4	206.2	1963	0	1967	6.2	52.0	1963
MAR	4.4	20.6	1951	0	1968+	3.1	12.2	1949
APR	0.3	2.8	1950	0	1970+	1.4	2.8	1950
MAY	0.3	2.7	1958	0	1970+	1.2	2.7	1958
JUNE	#	0.5	1948	0	1970+	0.5	0.5	1948
JULY	#	0.7	1966	0	1970+	0.7	0.7	1966
AUG	#	1.0	1959	0	1970+	1.0	0.7	1959
SEPT	0.3	5.5	1957	0	1970+	2.0	2.6	1957
OCT	7.6	63.6	1962	0	1970+	3.9	39.0	1962
NOV	55.4	148.0	1952	1.0	1960	6.8	65.4	1963
DEC	105.4	193.8	1947	6.5	1968	8.7	72.3	1947
Y	278.4	462.5 ⁽¹⁾	1964-65	147.7 ⁽²⁾	1948-49	7.0	72.3	1947-48
<u>DENSE FOG (VIZ 1/4 MI OR LESS)</u>								
JAN	20.4	52.4	1955	0	1949	3.4	15.0	1953
FEB	12.7	86.7	1963	0	1967+	3.8	16.7	1963
MAR	1.8	7.8	1949	0	1968+	2.2	5.0	1961
APR	0.1	1.3	1955	0	1970+	1.8	0	----
MAY	0.1	1.6	1958	0	1970+	1.6	1.6	1958
JUNE	0	0	----	0	----	0	0	----
JULY	0	0	----	0	----	0	0	----
AUG	#	1.0	1959	0	1970+	1.0	0.7	1959
SEPT	0.1	3.2	1957	0	1970+	3.2	1.4	1957
OCT	3.1	35.2	1962	0	1970+	3.1	15.8	1962
NOV	21.1	71.4	1952	0	1960	4.1	22.6	1963
DEC	42.0	119.8	1947	1.3	1968	5.4	47.0	1957
Y	101.4	201.5 ⁽¹⁾	1962-63	47.3 ⁽²⁾	1948-49	4.2	47.0	1957-58

* TOTAL DURATION DENOTES TOTAL NUMBER OF HOURS AND TENTHS OF HOURS IN WHICH FOG IS OBSERVED.

DENOTES LESS THAN 0.05 HOUR

(1) DENOTES THE GREATEST NUMBER OF HOURS IN A SEASON

(2) DENOTES THE LEAST NUMBER OF HOURS IN A SEASON

(3) MAXIMUM PERSISTENCE OF DENSE FOG IS BASED ON THE PERIOD 1953-70

The climatological data for the HMS are generally assumed to be representative of the entire region although local variations in the climate are known to exist. Important variations are those associated with the Columbia River and the major topographic features which form the sides of the basin. Differences between the northern and southern portions of the Hanford reservation are primarily small differences in temperature, humidity and wind.

Diffusion Climatology

The major impact of an HNEC on the atmosphere will come as a result of the release of waste heat. The extent of the impact will be further related to the ability of the atmosphere to disperse the heat. The primary factors which govern the dispersion or diffusion of the waste heat are atmospheric stability and the wind. The stronger the wind or less stable the atmosphere the more rapid the dispersion of the heat.

Results of numerous atmospheric diffusion experiments at Hanford indicate that four categories adequately describe atmospheric stability variations for the purpose of the diffusion modeling. Figure 9 shows wind roses for Hanford for each of these stability categories and for all categories combined. These wind roses clearly show that the prevailing wind direction at Hanford is from the west-northwest and northwest.

If the Hanford area were the Great Plains with no significant topographic features, the major impact of an HNEC would be expected to occur to the east-southeast and southeast. However, the influence of the topographic features in the Hanford area make this a very tenuous assumption. Air flow measurements made over the Reservation in the past few years indicate there are frequent local circulation patterns which are not adequately described by the wind direction at the HMS. Evidence of these local circulations is seen in Figure 10 which shows wind roses at several locations on and surrounding the Hanford Reservation. In some cases these circulations would act to increase the rate at which the waste heat is dispersed, and in other cases they would have the opposite effect. Figures 11 and 12 further demonstrate the differences in wind which can be observed at two places in relatively close promimity. The physical separation between the FFTF and the WNP-2 sites is about 2 miles, with the FFTF to the west of WNP-2. The large frequency of winds from south-southwest through west at the FFTF can be attributed to local circulations related to Rattlesnake Mountain or the west edge of the Hanford Reservation which do not affect WNP-2.

FIGURE 9: Wind Roses as a Function of Stability and Wind Speed at HMS Based on Winds at 200 Ft and Air Temperature Stability Defined Between 3 Ft and 200 Ft for 1955 through 1970 (The points of the rose represent the directions from which the winds come.)

FIGURE 10: Surface Wind Roses for Various Locations on and Surrounding the Hanford Site (The points of the rose represent the direction from which the winds come.)

FIGURE 11: Wind Rose for the FFTF Site (At 13 ft, January 1, 1971 - July 1, 1973)

FIGURE 12: Wind Rose for the WNP-2 Site (At 23 ft, April 1972 - March 1973)

A detailed evaluation of the transport and diffusion of thermal effluents from a HNEC would be a complex and relatively expensive process as a result of the local circulations referred to above. Therefore a relatively simple dispersion model which uses HMS wind and stability data and assumes straight line transport has been used to examine the impact of various HNEC heat sink management alternatives on fog and humidity. The results of this evaluation are discussed later.

THE HEAT SINK ALTERNATIVES

Study of the physical characteristics of the Hanford Project reveals that there are five possible methods for releasing large quantities of waste heat to the environment:

1. Once-through cooling using Columbia River water,
2. Cooling ponds,
3. Wet cooling towers,
4. Dry cooling towers, and
5. Wet-dry cooling towers.

Definite physical and administrative limits exist for some of these cooling methods (e.g., maximum permissible heat releases to the Columbia River) and may exist for all methods if there are stringent atmospheric limitations. Consequently, the first step in analyzing these alternatives is to determine the limitations on each cooling method. The second step then is to select and describe the several alternative cases for the HNEC cooling systems. These case descriptions then become the bases for the final comparison of the alternatives to determine the best cooling methods.

PHYSICAL LIMITATIONS ON COOLING METHODS

Operation of twenty power reactors would require release of about 50,000 MWt to the environment. The three general choices for release of that heat are: to the Columbia River, to the atmosphere by use of cooling ponds, or to the atmosphere by use of cooling towers.

The amount of heat that can be released for each of these methods is limited by administrative restrictions on the heat releases to the Columbia River, the availability of cooling pond land, or by the effects on the atmosphere. This section examines each of these modes to determine the obvious limitations on the amount of heat that can be disposed of by use of these methods.

Heat Releases to the Columbia River

The maximum permissible heat release to the Columbia River near Hanford as established by the Washington State Water Quality Standards is defined by the formula:

$$\Delta t = \frac{110}{T-15}$$

where Δt is the permissible average daily temperature rise and T is the river temperature after all heat additions. No heat releases are permitted that would increase the river temperature above 68°F (20°C). In addition, heat releases must comply with the provisions of Public Law 92-500 which require that no releases be made after 1983 or releases be made such that they assure a balanced, indigenous population of shellfish, fish, and wildlife.

During the winter months when maximum generation is desirable, the average daily river flow at Hanford varies from 36,000 to over 100,000 cfs. From 1960 to 1974, the minimum seven-day running mean flow rate varied from 54,000 to 103,000 cfs and averaged 70,000 cfs. The minimum flow occurred only in August or September. At minimum river temperature when about a 5°F Δt is permissible and the river flow often is close to the minimum, the maximum permissible heat release would be about 24,000 Mwt at 70,000 cfs. This corresponds to 12,000 MWe (10 reactors). At 54,000 cfs flow, the permissible heat release is about 19,000 MWe, corresponding to eight reactors.

The minimum required flow at 36,000 cfs in the Hanford reach was established when nine production reactors were operating at Hanford with once-through cooling. Since only one production reactor now is operating, this minimum required flow should be reevaluated with consideration of the future construction of an HNEC, current knowledge of effects of heat releases on the Columbia River aquatic ecology, and the effects of the additional storage reservoirs and hydroelectric capability in comparison to the time when the minimum flow requirement was established. Establishment of different minimum and average flows would affect the number of power plants that could have once-through cooling.

During August and September, the river temperatures are higher ($>50^{\circ}\text{F}$) so that the maximum permissible heat release generally is less. As an example, in August, when the minimum flow rate is expected to be about 70,000 cfs and the river temperature is at 65°F , the permissible Δt is about 2.2°F , corresponding to a maximum permissible heat release of 10,000 MWt or a generation of 5,000 MWe (4 reactors). In actuality, the number of reactors that could be operated in the summer in compliance with these standards probably would be lower than shown here because of river heating by other industries and by nature.

The amount of heat that can be released to the Columbia River without a significant effect on the aquatic life is not known. Historical data indicate that as much as an annual average of 23,000 MWt has entered the river from all causes between Priest Rapids and the City of Richland without evidence of a significant effect on the aquatic life (Jaske and Synoground, 1970). This occurred in 1965 when most of the Hanford production reactors were operating.

Therefore, it appears that up to ten reactors could operate with once-through cooling during the winter months, but many of these reactors would have to be shut down during the August to October period when the river temperatures are high. During some years when the river temperatures reach 68°F (20°C), all reactors would have to be shut down during the high temperature period.

Heat Releases to Cooling Ponds

The possible heat releases from cooling ponds is determined primarily by the land area available for ponds. At Hanford about 2.5 acres of pond are needed per MWe of generating capacity in order to have condenser inlet temperatures near the temperatures of the Columbia River during the period from August to February (Jaske, 1971). A smaller pond area per MWe would result in higher condenser inlet temperatures, a lower power plant thermal efficiency, a higher power plant capital cost, and a higher annual fuel cost.

A survey of available cooling pond sites identified the ponds that probably could be built without major effects on the Hanford Reservation water table or major expenditures such as pond lining (Table 5). (Construction of slurry trenches or intercept ditches might be necessary in some cases to prevent detrimental water table effects.)

In addition, several ponds might be built with liners to prevent water table effects (Figure 13 and Table 6). Most of these lined ponds are south of the 200 Areas and are not close to the selected HNEC power plant sites, but they might be operated as a single system connected by canals to provide a large circular flow of cooling water.

These data indicate that the maximum capacity for cooling ponds would be about 16,000 MWe (13 reactors, maximum).

Heat Releases from Cooling Towers

Heat releases at cooling towers generally are limited by the maximum permissible atmospheric effects due to heat and moisture releases. The normal amount of water loss by evaporation is about 30 cfs for a 1250 MWe power plant or about 1200 cfs for 40 Hanford reactors. Although this is a large amount of water, it represents only one percent of the annual average flow of the Columbia River. Removal of that amount from the river probably would have an insignificant impact on the river as long as it is removed by use of intake pump structures designed for minimum impact.

Analysis of fog and humidity effects indicates that the atmospheric effects for cooling towers at Hanford will not limit the total heat releases from over 20 reactor plants if the types for the towers are correctly selected. However, there may be a noticeable increase in fog on the Hanford Reservation. This is discussed in greater detail later in the atmospheric analysis for the several alternatives.

At Hanford, cooling towers must have mechanical draft. During high temperature, low humidity, summer conditions, natural draft towers do not

TABLE 5: Unlined HNEC Cooling Ponds

<u>Pond Site</u>	<u>Pond Elevation (ft)</u>	<u>Pond Area (acres)</u>	<u>Capacity (MWe)</u>
Wahluke West	540	5,000	2,000
Wahluke East	440	2,800	1,100
White Bluffs	420	4,800	2,000
100 F	420	5,900	2,400
Riverland	460	2,500	1,000
		<u>21,000</u>	<u>8,500</u>
TOTAL		21,000	8,500

TABLE 6: Lined HNEC Cooling Ponds

<u>Pond Site</u>	<u>Pond Elevation</u>	<u>Pond Area (acres)</u>	<u>Capacity (MWe)</u>
Gable Mountain	480	6,500	2,600
NP	440	3,000	1,200
300 Area	440	1,800	700
300 Area Northwest	440	2,000	800
Horn Rapids	500	2,300	900
Cold Creek	520	2,200	900
Wye-West	540	2,200	900
		<u>20,000</u>	<u>8,000</u>
TOTAL		20,000	8,000

FIGURE 13: Potential Reactor Cooling Ponds

generate sufficient air flow for satisfactory operation without a large increase in the condenser cooling water temperature.

SELECTION OF THE COOLING METHOD CASES

Twenty cases were compared to determine the best heat disposal methods for an HNEC. These cases covered various combinations of the available cooling methods and reactor sites, plus both 20 and 40 reactor HNECs. Selection of the cases for analysis was based on several general rules concerning the economic and environmental costs of cooling systems:

1. Once-through systems have the lowest economic costs.
2. Unlined cooling ponds and wet towers have intermediate economic costs.
3. Dry towers and lined cooling ponds have the highest economic costs.
4. Once-through cooling has the largest effects on aquatic ecology.
5. Pond cooling has the largest effects on terrestrial ecology.
6. Cooling pond operation results in maximum fog formation.
7. Increasing the elevation of the moisture release reduces the occurrence of ground fog.

Eleven cases then were selected for the analysis of the 20 reactor HNEC (Table 7)*. Figure 14 shows the HNEC plant sites. Eight of these cases were designed to describe extreme cases for specific environmental or economic effects as follows:

Cases I to IV	Maximum moisture releases to the atmosphere
Case XI	Highest construction and operating costs
	Maximum release of dry heat
	Zero water use
Cases VI & VII	Maximum land use

*In all cases it was assumed that the three planned reactors at the WPPSS site will have short wet towers. A fourth reactor at that site would have either a short wet tower or a dry tower.

TABLE 7: HNEC Heat Sink Alternatives Analysis Cases - 20 Reactors

Case No.	Case Characteristics	Number Reactors at Specified Sites						Cooling Tower Height*
		Wet Towers	Dry Towers	Wet-Dry Towers	Once-thru Cooling	Closed Cycle Ponds	Helper Towers	
I	Wet Tower	4 @ 1,2,3,4,&5						75
II	Wet Tower	4 @ 1,5,11,13&14						75
III	Wet Tower	4 @ 1,2,3,4&5						75*, 500
IV	Wet Tower	4 @ 1,5,11,13&14						75*, 500
V	Wet-Dry Tower	3 @ 1	1 @ 1	4 @ 2,3,4,5				75
VI	Partial Once-thru	4 @ 1; 3 @ 3			1@3,8;4@5	3@8;4@4		75*, 500
VII	Partial Once-thru	4 @ 1			1@4,8;4@5,10	3@4,8		75
VIII	Partial Once-thru	4 @ 1,3; 2@4			2@4;4@5,6			75*,500
IX	Helper	4 @ 1					4@4,5,6,8	75*, 500
X	Full Once-thru	4 @ 1			4@4,5,8,10			75
XI	Dry Tower	4 @ 1	4@2,3,4,5					75

* Only wet towers at site 1 are 75 ft. in height.

FIGURE 14: HNEC Plant Sites

Case IX & X Maximum water use

Cases II & IV High elevations for moisture releases

The helper case IX was defined as once-through cooling with a tall wet cooling tower of the same design as is used for closed cycle wet towers. These towers would transfer 72% of the waste heat to the atmosphere. They could be bypassed during winter conditions as necessary to obtain optimum river temperatures.

Case V was added to cover the possibility that use of only wet cooling towers would cause an excessive fog formation. For that case, use of 50% dry cooling was assumed to illustrate the costs and effects of wet-dry towers. The other cases are typical combinations of cooling systems.

In addition to the 11 cases for the 20 reactor HNEC, nine were also developed for the 40 reactor HNEC (Table 8). These cases are essentially the same as the cases for the 20 reactor HNEC.

No cases were included for lined cooling ponds in the southern portion of the project because of excessive economic and environmental costs in comparison to wet cooling towers. The economic cost would be much higher than for the wet towers because of the requirement of essentially zero leakage to prevent detrimental effects on the water table. The environmental effects are also expected to be larger than for wet towers because of (1) more land use, (2) more water evaporation in the summer causing a larger increase in relative humidity in Richland, and (3) increases of ground fog in the winter in Richland because the source of moisture is at ground level.

DESCRIPTION OF HEAT SINK ALTERNATIVES

Selection of Cost and Environmental Interaction Parameters

There are 24 general cost and environmental interaction factors that should be considered in a cost-benefit comparison (Table 9). Each of these is studied to determine if a significant impact may result and if a

TABLE 8: HNEC Heat Sink Alternatives Analysis Cases - 40 Reactors

Case No.	Case Characteristics	Number Reactors at Specified Sites					Cooling Tower Height*
		<u>Wet Towers</u>	<u>Dry Towers</u>	<u>Wet-Dry Towers</u>	<u>Once-thru Cooling</u>	<u>Helper Towers</u>	
XII	Wet Tower	4 @ 1-10					75
XIII	Wet Tower	4@1,3,5,6,7,8,11,12,13,14					75
XIV	Wet Tower	4 @ 1-10					75*, 500
XV	Wet Tower	4@1,3,5,6,7,8,11,12,13,14					75*, 500
XVI	Wet-Dry Tower	3 @ 1	1 @ 1	4@3,5,6,7,8,11,12,13,14			75
XVII	Partial Once-thru	4@1,4,8,10			8@4,5,8		75*, 500
XVIII	Helper	4 @ 1				4@6;8@4,5,8,10	75*, 500
XIX	Full Once-thru	4 @ 1			4@6;8@4,5,8,10		75
XX	Dry Tower	4 @ 1	4@3,5,6,7,8,11,12,13,14				75

* Only wet towers at site 1 are 75 ft in height.

TABLE 9: General Evaluation
HNEC Cooling System Environmental Interaction Parameters

<u>Parameter</u>	<u>Significant?</u>	<u>Reason</u>
Capital Costs	Yes	Large cost differences between alternatives
Operating Costs	Yes	Large cost differences between alternatives
Fuel Costs	Yes	Large cost differences between alternatives
Human Displacement	No	No permanent residents at sites
Land Use	Yes	Reduction of recreational and wildlife use
Agricultural Effects	Yes	Potential changes in meteorology
Water Use	Yes	Large water uses necessary
Water Quality	Yes	Releases of chemicals in blow-down streams
Noise	No	No noise effects expected off project
Odors	No	No generation of odors expected
Employment	No	Probably trivial difference in operating and construction employment in comparison to total labor force
Taxes	No	Secondary effect. Differences in taxes expected to be small
Social Attitudes	Yes	Societal reaction to changes in meteorology
Navigation	No	No effect on navigation expected
Aquatic Biology	Yes	Effects of river water use
Terrestrial Biology	Yes	Effects of land use
Meteorology	Yes	Effects of heat and water releases
Radiation Doses	No	No difference between alternatives
Fuel Shipments	No	Insignificant difference between alternatives
Waste Disposal	Yes	Same as water quality
Esthetics	Yes	Cooling tower plumes
Recreation	Yes	Loss of recreational lands
Historical	No	No important historical sites
Archaeological	Possibly	Additional information may be obtained from discovery or excavation of archaeological sites

detailed evaluation should be made. If a detailed evaluation appears desirable, each factor is evaluated in depth for each of the alternatives for the system being considered.

A general evaluation of each of the 24 parameters is presented in Table 9. Included are the reasons why these parameters are considered significant or insignificant for a comparison of HNEC cooling system alternatives. This general evaluation showed that 15 of these parameters should be considered in greater detail during the evaluations. However, three of these are duplicates and one cannot be evaluated at this time, thereby reducing the total to 11. The four that can be eliminated are as follows:

Waste Disposal - The only waste disposal of importance is chemical releases in blowdown streams. This can be evaluated as water quality and aquatic biology effects.

Esthetics - The esthetic effects are primarily due to cooling tower plumes and can be evaluated as part of the general social attitude parameter.

Recreation - The only recreational effect probably is loss of lands on the Wahluke Slope for recreation. This is part of the land use evaluation.

Archaeological - There is no way to tell ahead of time if new archaeological sites will be discovered or if construction of power plants will result in excavation of known sites. More than 100 sites have been identified to date.

The 11 environmental effect parameters that were evaluated in the cooling system comparison are:

Capital Costs	Aquatic Biology
Operating Costs	Terrestrial Biology
Fuel Costs	Meteorology
Land Use	Agricultural Effects
Water Use	Social Attitudes
Water Quality	

Development of Specific Interaction Parameters

Capital Costs

The base reactor plant capital costs for this analysis were based on the estimated costs in the environmental statements for five four-unit nuclear power plants currently under construction or proposed by private utilities (Barton, Hartsville, North Anna, Shearon Harris, and Vogtle). The construction costs for the five example four-unit nuclear power plants are given in Table 10.

TABLE 10: Typical Four-Unit Nuclear Power Plant Capital Costs

	<u>Barton</u>	<u>Hartsville</u>	<u>North Anna</u>	<u>Shearon Harris</u>	<u>Vogtle</u>
Total Power (MWe)	4836	4980	3854	3600	4636
Construction Cost					
(\$ x10 ⁶)	3059	2150	1033	1058	2196
(\$/kW)	633	432	268	294	474
Startup Dates					
Unit 1	9/83	12/80	12/74	10/79	4/80
Unit 2	9/84	6/81	7/75	10/80	4/81
Unit 3	9/85	12/81	3/77	10/81	4/82
Unit 4	9/86	6/82	3/78	3/82	4/83
Cooling System	Natural draft towers	Natural draft towers	13,000 acre lake	Natural draft towers plus 4000 acre lake	Natural draft towers

Correlation of the construction costs for these plants shows an average cost escalation of ten percent per year and a construction cost of about \$290/kW for startup of the first unit late in 1975. (The Shearon Harris costs were not included in the correlation because they appear to be anomalously low -- see Figure 15.) The resultant total capital cost for a 5,000 MWe cluster starting operation of the first reactor on January 1, 1976, would be about \$1.5 billion.

Although construction costs for nuclear power plants have escalated rapidly since the original estimates, and future costs will probably escalate at a similar rate, use of these costs is not expected to affect the

FIGURE 15: Cost Correlation for Four-Unit Nuclear Power Stations

conclusions of this document. The relationship between the economic and environmental costs should remain the same because the environmental values presumably will escalate at the same rate as for the economic costs.

Although the power plants correlated on Figure 15 have somewhat different types of cooling systems, the general correlation of that figure still appears valid. Four of the five have natural draft towers and the cost of the North Anna lake is similar to the cost of cooling towers for that plant.

The capital cost data for the four-unit stations (\$290/kWe) is for natural draft towers. Since a mechanical draft tower costs about \$2/kWe less than a natural draft tower, the capital cost for a HNEC reactor plant using short mechanical draft towers is estimated to be \$288/kWe. Similarly, based on

information in the literature and the construction conditions at Hanford, the capital costs for other cooling modes were estimated to be:

Once-through	\$275/kWe
Unlined cooling ponds	285/kWe
Helper cooling towers	300/kWe
Lined cooling ponds	316/kWe
Unlined helper cooling ponds	295/kWe
Lined helper cooling ponds	326/kWe
Dry cooling towers	330/kWe

These unit capital costs include the effects of differences in the thermal power level of the reactors because of differences in the condenser cooling water temperatures. The assumed thermal efficiencies and reactor thermal power levels are shown in Table 11.

TABLE 11: Power Plant Efficiencies

<u>Cooling Mode</u>	<u>Net Thermal Efficiency (%)</u>	<u>1250 MWe Reactor Thermal Power Level (MWt)</u>
Once-through	33	3,790
Ponds	32.5	3,850
Wet Towers	32	3,900
Dry Towers	30	4,170

In those cases where tall fan-assisted mechanical draft cooling towers are used, a separate tower system is assumed to be constructed for each reactor. The additional shell cost is expected to add about 20 percent to the tower construction cost, resulting in a total plant capital cost of \$290/kWe.

Operations and Maintenance Costs

The operation and maintenance (O&M) costs for a power plant can be considered to have two components: (1) the cooling system costs and (2) all other costs. All other costs can be treated as a constant when cooling system alternatives are compared.

The cooling system O&M costs vary between alternatives primarily because of differences in equipment and maintenance costs. Typical power requirements and costs assumed for the various alternatives are given in Table 12.

TABLE 12: Typical O&M Costs

<u>Cooling System</u>	<u>Power Requirement (MW)</u>	<u>O&M Cost (Mills/kWh)</u>
Once-through	5.0	2.0 (Base)
Mechanical Draft Tower (wet)	15.1	2.1
Mechanical Draft Tower (dry)	27.8	2.3
Ponds	6.8	2.1

The difference in power requirements for the various alternatives was considered during determination of the net thermal efficiencies, the power plant thermal power levels, and the gross electricity generations.

Fuel Costs and Plant Factors

The fuel cost was assumed to be 1.32 mills/kWh (i.e., typical CY 1976 costs). The plant factor was assumed to be 70 percent of all alternatives.

HNEC Land Areas

A survey of five nuclear power plant clusters containing four reactors (Barton, Hartsville, North Anna, Shearon Harris, and Vogtle) revealed that the main plant systems, including cooling towers, occupy about 300 acres. The total site areas varied from 1,000 to 19,000 acres, most of which was unoccupied or occupied by cooling ponds. Use of once-through cooling (on lakes) appears to require about the same amount of land as use of cooling towers. However, this conclusion probably results more from the use of available land areas than from an attempt to use a minimum amount of land.

Because large low-cost land areas are available at Hanford, all four-reactor plant sites are assumed to occupy one square mile (except for cooling pond cases), regardless of the type of cooling system used. This allows

ample room for all facilities (reactors, cooling towers, substations, etc.) at optimum locations for economic and operational reasons. Because of the low land costs at Hanford, attempts to define the exact land areas required for specific cooling systems would be futile because differences in construction costs as the land areas are minimized probably would be much larger than the change in land values.

Material Use

The primary materials used in cooling systems are concrete and steel. Much smaller quantities of other materials are generally used. A survey of the literature and discussions with utilities and cooling tower vendors indicates that typical quantities of materials for the various types of cooling systems are as shown in Table 13.

TABLE 13: Cooling System Materials

<u>Cooling System</u>	<u>Material per 1,250 MWe Reactor</u>	
	<u>Concrete (cubic yards)</u>	<u>Steel (tons)</u>
Once-through	13,000	3,300
Unlined cooling ponds	14,500	3,700
Short mechanical draft cooling towers	36,000	4,000
Tall mechanical draft cooling towers	40,000	4,000
Dry cooling towers	37,000	10,000

Water Utilization

All water used in the cooling systems is obtained from the Columbia River and then evaporated or returned to the river. The quantity depends on the time of year and the final optimization of the plant designs. Based on current industrial practices and Hanford meteorological conditions, the water utilization per reactor is as shown in Table 14.

TABLE 14: Water Use for Various Cooling Systems

<u>Cooling System</u>	<u>Intake from River (cfs)</u>	<u>Evaporation Rate* (cfs)</u>	<u>Discharge to River (cfs)</u>
Once-through	1,500	**	1,500
Helper towers	1,500	22	1.478
Cooling ponds	60	45	15
Wet towers	40	30	10
Dry towers	0	0	0

*Full power operation.

**Not determined. Evaporation will occur downstream of the reactor plant. The amount will depend on the number of reactors with once-through cooling and whether a surface or submerged discharge is used, but it is expected to be smaller than for closed cycle systems.

Chemical Releases

The two types of chemical releases from cooling systems are the drift from wet cooling towers and the biocides and corrosion inhibitors in the blowdown stream from closed cycle cooling systems. The amount of chemicals in the drift from the wet tower for one reactor is estimated to be about five tons per year or an average of up to 200 lb per acre per year deposited on nearby lands. The chemicals in the blowdown streams for one reactor are estimated in Table 15.

TABLE 15: Chemical Releases from Wet Towers and Cooling Ponds

<u>Chemical</u>	<u>Quantity (tons/year)</u>	
	<u>Wet Towers</u>	<u>Cooling Ponds</u>
Total dissolved solids*	700	6,300
Copper	7	10
Free available chlorine	3.5	5
Total phosphorus	7	10

*Primarily derived from dissolved solids in makeup water from the river.

Aquatic Ecological Effects

The possible impacts of power stations on the economically important fish population, both resident and migratory, and their supporting food base obviously will be influenced by a number of design features, including the condenser cooling methods (once-through or closed cycle), location of the water intake and discharge structures, and the chemical characteristics of the liquid effluents discharged to the river. For these reasons the analysis of potential impacts on aquatic organisms will be based on assumed sets of power plant conditions and are subject to change or refinement with further plant development.

Once-through Cooling. Because of the large volume of water withdrawn and discharged by once-through units and the increased temperatures of their effluents, they could have a significant impact on the river biota. These power stations probably will be upstream from some of the major salmon spawning areas and on the opposite side of the river (Figures 2 and 14). Careful design of the thermal discharge system will be required to (1) minimize the exposure of the salmon spawning areas to the plant effluents and (2) reduce the possibility of creating a thermal block to the upstream movement of anadromous fish. The movement of chinook salmon and steelhead trout and possibly other salmon is along the north shore in the Hanford reach of the river; and there is a clear avoidance response by these fish to heated effluent discharged along the shore, but not to the main center-channel outfalls. Shoreline zones receiving heated water also produced mortalities to juvenile salmon drifted slowly through these areas (Becker and Coutant, 1970). Passage of young salmon through the mid-channel thermal discharges produced no mortalities.

The most critical period for possible thermal effects on the local race of salmon is during the first three weeks in October at the start of spawning and continuing for about one month thereafter. River temperatures at this time average about 60°F (range 56 to 65°F) (Watson, 1970). An increase above these temperatures may produce a delay in spawning and possible mortality in the adult population and reduce the survival of the

spawn. The recommended optimum temperatures for certain stages of the salmon life cycle are as follows (EPA, et al., 1971):

Migration routes	45-60°F (7.2 to 15.6°C)
Spawning route	45-55°F (7.2 to 12.8°C)
Rearing areas	50-60°F (10 to 15.6°C)

Temperatures of the Columbia historically have exceeded the desired temperature ranges, particularly for migration and spawning. In laboratory studies chinook salmon eggs were spawned in October at a base river temperature of 56°F and incubated at 2°F increments above the river ambient. These tests showed increased embryonic and larval mortalities at temperatures greater than 4°F above that of the river as shown in Table 16 and Figure 16 (Nakatani, 1969). Thermal additions to salmon eggs that started incubation in late November and December, when river temperatures were 54 to 48°F, resulted in a much lower increase in mortality. The fish hatched from these spawns had a much better growth rate when maintained at up to 12°F above ambient river temperatures. Warming the river during the winter may be beneficial to embryonic and early larval development.

In the past, the salmon spawning areas downstream from the proposed once-through cooled power plants received the heated effluents from up to nine plutonium production reactors with no observed changes in the local salmon population or other river biota attributable to that discharge (Watson, 1970). The temperatures of these effluents were in "excess of 185°F" (Derouin, 1972). The volume of effluent discharge from these reactors is classified, but did include 1256 cfs discharge at an average Δt of about 34°F from the Washington Public Power Supply System (WPPSS) steam plant at 100-N Area. The fact that these past heated discharges have produced no measurable changes in the river ecosystem lends support to the feasibility of establishing a limited number of once-through cooled plants along the Columbia in the interest of a balanced environmental impact.

Recent research on the ecological effects of the WPPSS Hanford-N steam plant provides a basis for estimating possible changes that may be expected for once-through cooling. Some of the observed biological effects are:

TABLE 16: Mortality and Growth of Young Chinook Salmon Reared Under Elevated River Temperatures

Date Spawned	10/30/66	11/14/66	11/23/66	12/8/66					
Date Terminated	4/24/67	5/9/67	5/18/67	6/2/67					
Initial Base Temp.									
°F	56	54	53	48					
Lot	Temperature Condition	% Mor- tality	Mean wt,g	% Mor- tality	Mean wt,g	% Mor- tality	Mean wt,g	% Mor- tality	Mean wt,g
1	Control (a)	4.6	0.95	10	0.63	5.5	0.64	4.8	0.63
2	+ 2°F	3.6	1.40	11	0.96	9.3	0.97	5.5	0.97
3	+ 4°F	11	1.92	16	1.53	12	1.37	7.5	1.42
4	+ 6°F	28	2.72	19	2.55	9.4	1.96	7.3	1.79
5	+ 8°F	60	4.28	17	4.17	6.9	2.61	17	2.31
6	+ 10°F	97	-	43	5.52	10	3.82	14	3.18
7	+ 12°F	100	-	93	5.65	37	5.28	12	4.24

(a)°Similar to temperature at Priest Rapids Dam

FIGURE 16: Salmon Embryonic and Larval Mortalities

1. Passage of phytoplankton through the cooling system reduced primary productivity within the system. No decrease in primary productivity downstream of the plant discharge could be measured.
2. About half of the zooplankton were killed in passage through the cooling system.
3. Benthic organism production in areas receiving warm effluents was increased and remained active longer into the winter.
4. There was no fish survival after passage through the cooling system.

Particular care must be given to the design of the water intakes to reduce fish loss from impingement and entrainment. Studies of the shoreline water intake at the WPPSS steam plant (Page, et al., 1975; Gray, et al, 1975) show that up to 18 percent of the juvenile salmon produced between the intake and Priest Rapids Dam are lost through impingement; and up to 9 percent are killed by passage through the cooling system. If proportionally similar losses, based entirely on water intake volume, are projected for six once-through cooled plants, most of the salmon production between Priest Rapids and the power plants would be destroyed. This could be as much as 35 percent of the total salmon production in the Hanford section of the river. Resource loss of this magnitude could not be accepted without good justification. The intake structures for once-through systems should remove water only from the central portion of the river or other locations with low juvenile salmon populations.

If six reactors have once-through cooling, approximately 10 percent of the zooplankton and drift organisms passing the plant intakes would be destroyed or lost to the river. No significant changes in phytoplankton production are expected and there may be some very localized enhancement of benthic productivity in the winter.

Operation of more than ten reactors with once-through cooling probably is unacceptable from an ecological standpoint. At minimum river flows over half the entire river would be diverted through the power plant cooling systems. This would 1) expose over half the entire populations of planktonic and drift organisms and some larval fish to the chemical and mechanical stress of passage through plant cooling systems, and subject the entrained organisms to a temperature rise of 25°F or greater; 2) possibly overheat

the river water locally by recycling the effluents from one cluster of plants through the cluster immediately downstream; and 3) create near-shore increases in temperature that may impede fish migration.

Wet Cooling Towers. Total water intake and blowdown for 40 cooling towers is 1600 and 400 cfs, respectively; and the Δt of the blowdown is 12°F. Less than five percent of the minimum river flow would be used for cooling.

No measurable aquatic impacts are envisioned for this case. Off-shore water intake and blowdown discharges should be considered to reduce impingement-entrainment of river organisms in the cooling water system and to reduce exposure of the shoreline areas to undiluted blowdown discharge. The provisions of Public Law 92-500 probably can be met without blowdown treatment. The cases with less than 40 towers would have proportionately smaller impacts.

Cooling Ponds. With proper management ponds could be beneficial for recreational fishing or aquaculture. Very intensive aquaculture of fish produces annual yields up to 1,500 tons/acre (Bardach, 1968). Less intensive management (no supplemental feeding; some fertilization) more appropriate to the cooling pond size and use would produce about 100 to 200 lb/acre/yr. Care would be necessary to prevent the introduction of radionuclides into the cooling ponds if sport fish or aquaculture is intended.

The creation of cooling ponds may provide new habitat for nuisance algae and fish disease organisms. Prediction of the degree of these undesirable effects is difficult. Much depends upon the kinds of biota that are established in these ponds and the intensity of management. They are not viewed at this time as sources of uncontrollable problems. The necessary cooling ponds for 12 reactors will create about 40,000 acres of new surface water.

The makeup and blowdown water for the worst case of 12 reactors using ponds is only 720 and 180 cfs, respectively. No measurable effects on the river aquatic life would be expected from use of that water.

Aquatic Effects of Specific HNEC Cases. For cases I through V, XI, XII through XVI and XX (wet towers, wet-dry towers, dry towers), the expected impacts from the withdrawal of river water and the discharge of tower blowdown will be slight and probably imperceptible.

Case VI (once-through, wet towers, cooling ponds) may have an adverse effect on the river organisms, particularly the salmon and trout, during the late summer and early fall (August through October). Approximately 25 percent of the minimum river flow of 36,000 cfs would be heated to a temperature of 25°F above ambient. At this minimum river flow the temperature of the river would be raised approximately 6°F after complete mixing with the heated condenser discharge. For a fifteen-year minimum seven-day average river discharge of 54,500 cfs, the river temperature would be increased about 4°F above ambient. Since river temperatures at this time of year normally approach the upper thermal tolerance limits of salmon and trout, the addition of heat would be expected to have an adverse effect on these fishes. Chinook salmon eggs and larvae exposed in October to 4°F above a starting incubation temperature of 56°F in laboratory studies shows an increased mortality (Figure 12). The Columbia River thermal maximum of 68°F should not be exceeded by the discharge of heated effluents if the anadromous salmonoids in the river are to be protected; and as indicated in the previously cited laboratory study on chinook salmon, this temperature may seasonally be too high for the well-being of these fish.

Case VII (once-through, wet towers, cooling ponds) will withdraw 42 percent of the minimum river flow of 36,000 cfs and about 28 percent of the 15-year, seven-day minimum. The discharge from this complex will raise the river temperature approximately 7°F after complete mixing. Both the higher volume of river water withdrawal and the increase in river temperature due to the effluent discharge would be seasonally of environmental concern. The assumed cooling modes for these cases are acceptable only during periods of high river flow and low ambient river temperature.

In cases VIII, IX, X, XVII, XVIII, and XIX (once-through, wet towers, helper towers), 70 to 150 percent of the minimum river flow and 40 to 100

percent of the 15-year, seven-day minimum flow will be withdrawn. Effluent discharges will increase river temperatures from 7°F to 25°F. Both the high volume of water withdrawn and the large increase in river temperatures make these cases ecologically unacceptable.

Terrestrial Ecological Impacts

Construction of power plants results in occupancy of land by structures, construction of barriers such as fences and canals, and construction of transmission lines. This alteration of habitat interferes with wildlife movement and causes other ecological impacts.

Impacts of Structures Upon Wildlife. Aerial obstructions can be hazardous to birds, particularly if towers and wires are located on prominent points along major bird migration routes. Wires and towers are especially hazardous during weather conditions that impair visibility. Mortality is caused by collision with the obstruction. Sometimes, raptorial birds that habitually prefer to perch on the tallest structures are electrocuted by short circuiting electrical transmission lines.

Ground obstructions that interfere with the normal movement of animals are fences, canals, and ditches. Chain-link fences six or more feet tall provide effective barriers to mule deer but do not affect small mammals. Medium sized mammals often cross fences by burrowing.

Canals with concrete walls are efficient barriers to almost all land animals. Canals could seriously affect the local movement of mule deer by confining the population between the canal and the Columbia River. Mule deer are good swimmers and they often swim the Columbia River; however, they would not be able to climb steeply-sloped walls of a concrete-lined canal.

Open ditches with steep walls a foot or more in depth and a foot or more wide can obstruct the movement of Great Basin pocket mice and cause mortality. Such ditches are destructive to other animals, such as lizards, snakes, and shrews.

Habitat Changes Associated with the Development of Cooling Lakes.

Pronounced changes in plant communities occur when arid land is inundated with water to form lakes and ponds. Waste ponds on the Hanford Reservation had well-developed shoreline plant communities after 20 years. Vegetation zones consist of aquatic emergent species: cattail and reeds. Permanently moist soils support rank growths of grasses, especially reed canary grass, barnyard grass, rabbitfoot grass, and forbes, especially Russian knapweed, goldenrod, and cudweed. The most aggressive tree species is the peach leaf willow.

Aquatic emergent vegetation provides nesting sites and cover for the red-winged and yellow-headed blackbird, pied-billed grebe, American coot, and ruddy duck. Seeds of aquatic emergent plants provide food for many species of migratory waterfowl and shorebirds. Willow trees provide nest sites for the black-billed magpie, Swainson's hawk, red-tailed hawk, sparrow hawk, great horned owl, northern oriole, and common flicker. Many species of songbirds forage upon insects and seeds associated with shoreline vegetation (Fitzner and Rickard, 1974).

It is clear that the development of ponds and associated vegetational changes would be beneficial to avifauna and also for certain populations of mammals, especially muskrat, mink, meadow mouse, raccoon, skunk, and mule deer.

The animals that would be most deleteriously affected are the species that are adapted to the dry soils and shrub-steppe plant communities. The ancestral range of the Great Basin pocket mouse, grasshopper mouse, black-tailed hare, side-blotched lizard, gopher snake, burrowing owl, and long-billed curlew would be usurped. These kinds of animals would not find the ponds and adjacent habitats acceptable and would have to compete for space with established populations in the adjacent unmodified shrub-steppe habitats or perish.

Maximal populations of Great Basin pocket mice in shrub-steppe vegetation were estimated at about 120 per hectare (2.2 acres) (O'Farrell, et

al., 1975). It can be estimated that usurpation of 40,000 acres of steppe vegetation could result in the demise of habitat supporting two million pocket mice. However, there would still be much habitat available to sustain a large population of mice.

Other animals that would need to find nesting habitat elsewhere are the long-billed curlew and the burrowing owl. The problems of animals adapted to shrub-steppe habitats are not limited to the construction of a nuclear energy center at Hanford, but are compounded by changing land use patterns, especially conversion of steppe vegetation to farm land. New farms destroy vast acreages of suitable steppe habitat each year.

The total loss of ancestral shrub-steppe habitat acreage is recognized as a distinct possibility unless measures are taken to preserve representative acres. To protect and provide a place to study the ecological structure and function of representative shrub-steppe ecosystems, a 75,000 acre tract of land representative of several different kinds of shrub-steppe ecosystems has been established along the western boundary of the Hanford Reservation and is known as the Arid Lands Ecology (ALE) Reserve. The reserve is managed for ERDA by Battelle-Northwest. All vegetation types expected to be affected by the construction of HNEC facilities are represented on the reserve, except for Columbia River riparian communities and certain special biological habitats, such as sand dunes and riverine bluffs.

Habitat Changes Expected from Fenced Exclusion Areas. Tall chain-link fences are expected to interfere with the normal movement patterns of mule deer. Other mammals can cope with chain-link fences as barriers by burrowing beneath the bottom wire. Chain-link fences would not provide a barrier to reptiles or birds.

Site Occupation by Buildings, Parking Lots, Etc. The land occupied by buildings, parking lots, etc. is not available as wildlife habitat and will be lost to biological productivity for an indefinite time period.

Summarized Effects of Terrestrial Changes. A summary of the effects of HNEC facilities on the terrestrial ecology is as follows as given in Table 17.

TABLE 17: Summary of Costs and Benefits Related to Terrestrial Ecology

<u>BENEFITS</u>	<u>COSTS</u>
<u>Ponds and Lakes</u>	
Improved habitat for waterfowl and avifauna adapted to tree communities. Improved habitat for beaver, muskrat, mink, raccoon, and skunk.	Reduction of habitat acreage for typical shrub-steppe plants and animals.
<u>Chain-Link Fences</u>	
None	Disrupt normal travels of mule deer.
<u>Open Ditches</u>	
None	Disrupt normal travels of small mammals and reptiles.
<u>Aerial Obstructions (Wires & Towers)</u>	
None	Interference with migrating birds.
<u>Earth Excavation and Construction</u>	
None	Temporary noise and dust, reduction of habitat acreage for typical shrub-steppe plants and animals.

Meteorological Impacts

The major heat releases and atmospheric effects of energy centers are associated directly with power generation. Atmospheric effects of heat rejection from nuclear energy centers (NRC, 1976) have been postulated on the basis of theory, models, analogy and speculation. Unfortunately some of the more spectacular effects are primarily the result of the last two processes. Typical effects include: increases in humidity, cloudiness and fog, ground shadowing, enhancement of precipitation and modification of precipitation patterns, triggering of more severe weather types such as thunderstorms, and the concentration of vorticity resulting in the formulation of large dust devils.

The specific atmospheric effects which might be associated with a particular energy center are generally related to the form of heat rejection, the flux density and area of heat rejection, and the climate of the energy center site. For example, fog and humidity increases are associated with low-level wet cooling systems, and the more specular effects are postulated for closely spaced cooling systems with a high energy flux.

Rational evaluation of the significance of any effect of heat rejection requires that the extent and timing of the effect can be estimated quantitatively, and that significance be defined in meaningful terms. Each of the effects postulated in the Nuclear Energy Center Site Survey (NRC, 1976) report has been considered in a cursory manner to screen out improbable impacts and those which cannot be adequately evaluated at this time.

Concentration of vorticity has been related to high density of the rejected heat and relatively large areas. This was a major concern for the energy centers considered in the Nuclear Energy Center Site Survey where the flux density was about 0.5 kW/m^2 . The flux density for the HNEC would be between 0.1 and 0.3 kW/m^2 . In addition, there are no simple methods for quantifying the frequency, magnitude or effect of vortices which might be generated. As a result, detailed consideration of vorticity concentration has been postponed until better tools are developed.

Theory and numerical models exist which can provide insight into modification of precipitation patterns and the triggering of storms. As further research is completed, results will be applied to the HNEC. However, recently publicized problems in the National Hail Research Experiment (Science, 1976) raise questions about the reliability of quantitative estimates in this area.

The only atmospheric effects amenable to evaluation at this time are associated with the addition of moisture to atmosphere. In this case the evaluation is only semi-quantitative. Thus, the effect of cooling systems on fog and humidity are the atmospheric impacts used in selection of an overall HNEC heat sink management plan.

Specific criteria have been identified to determine the significance of changes in the meteorological conditions. These include: a statistically significant change in a meteorological variable, substantial adverse economic impact of a postulated change, initiation of an adverse ecological change, and adverse public reaction. These general criteria provide guidance on the detail required in specification of a postulated impact.

In most cooling system evaluations fog is considered either qualitatively or in terms of additional hours of fog. The impact of an additional hour of fog is indeterminate. If the visibility during that hour is six miles, the impact may be negligible or, at most, psychological. If, on the other hand, the visibility is one-eighth mile or less, the impact can be evaluated in economic terms by considering its effect on transportation and other activities which require greater visibility. In terms of the impact on the public, the use of hours of a given visibility rather than hours of fog is much more meaningful.

Since the impact of fogging had to be estimated in terms of hours of specified visibility, a multiple-source diffusion model was developed in which moisture releases from a variety of cooling systems could be simulated. The large numbers of possible cooling systems and reactor cluster locations were also considered in the model development; i.e., the model had to be economical as well as flexible. The model and its use are described in detail (Ramsdell, 1976). The model is currently equipped to treat moisture releases from the following cooling systems in a rudimentary fashion:

- once-through
- once-through with helper ponds
- once-through with helper towers
- cooling ponds
- mechanical draft cooling towers
- natural draft cooling towers
- wet-dry cooling towers

Comparison of the results with the results of other less sophisticated models and actual fog observations indicates that the model is conservative. That is, it tends to predict a greater impact than would be realistically expected if a more detailed treatment had been undertaken.

More than 50 different cases, ranging from a single four reactor cluster near the south side of the reservation to a full 40 reactor energy center, have been examined to evaluate the effects of energy center size, cluster locations and cooling system mix on fog and humidity. As expected, the initial test cases indicated that the most frequently impacted areas outside the energy center would be the Tri-City area of Richland, Kennewick, and Pasco and the region east of the Columbia River and north of Pasco.

A partial compilation of the results of the tests conducted to evaluate the impact of various heat sink management options on fog is presented in Tables 18 and 19. The range of hours of impact in Table 18 for both the 20 and 40 reactor energy centers reflects differences primarily caused by changes in cooling system mixes; differences due to cluster location are secondary. The greatest impact was predicted for those cases with extensive use of cooling ponds and once-through cooling with helper ponds. Lesser impact was predicted for mechanical draft cooling towers and once-through cooling with mechanical draft helper cooling towers, and the least impact was predicted for tall cooling towers and unassisted once-through cooling. It should be noted that where the predicted increase of total hours of fog is less than 40 hours, the predicted increase of hours of visibility less than one-half mile exceeds the increase of total hours of fog.

Three cases with wet-dry mechanical draft cooling towers were examined for both the 20 and 40 reactor energy centers. All but four reactors were assumed to use the wet-dry cooling systems. In these cases the fraction of wet cooling varied from 75% to 25%. The results are given in Table 19 along with the single four-unit cluster (0% wet) and full mechanical draft cooling tower (100% wet) results. These results indicate the fogging impact of wet-dry cooling system heat rejection at Hanford increases approximately linearly with the wet fraction for both the 20 and 40 reactor centers.

TABLE 18: Increased Hours of Fog and Visibility Less than One-Half Mile in the Tri-Cities due to an HNEC Using Evaporative Cooling

<u>Case</u>	<u>Increase in Fog</u>	<u>Increase in Visibility <1/2 mi.</u>
4 Reactor Cluster with Mechanical Draft Cooling Towers	15	28
20 Reactor Energy Center	34-250	39-162
40 Reactor Energy Center	90-288	71-184

TABLE 19: Additional Hours of Fog in the Tri-Cities for Energy Centers Using Wet-Dry Mechanical Draft Cooling Towers*

<u>Wet Cooling Fraction</u>	<u>20 Reactor Center</u>		<u>40 Reactor Center</u>	
	<u>All Fog</u>	<u>Visibility <1/2 mi.</u>	<u>All Fog</u>	<u>Visibility <1/2 mi.</u>
0%	15	28	15	28
25%	37	40	63	55
50%	57	52	117	86
75%	74	61	164	113
100%	98	75	210	139

* One four reactor cluster is assumed to use conventional mechanical draft cooling towers in each case.

The statistical significance of the postulated increase in total hours of fog and hours of less than one-half mile visibility can be assessed relatively easily using techniques for comparison of mean values. The results of this computation are given in Table 20 as a function of the years of observation following completion of the energy center. An assumed log normal distribution and Hanford fog and visibility statistics were used. The minimum significant increases in the table decrease with increasing observation period, and approach limiting values which are a function of the pre-center climatological fog and visibility records.

TABLE 20: Minimum Statistically Significant Increase in Hours of Fog and Visibility Less than One-Half Mile at the 95% Significance Level for Hanford

<u>Years of Observation</u>	<u>Change in Hours of Fog</u>	<u>Change in Hours of Visibility (<1/2 mi.)</u>
2	101.5	58.2
4	82.9	39.8
6	68.3	32.6
16	45.9	21.7
36	36.4	17.1
--	26.8	12.6

Since the life of a reactor is generally assumed to be 30 to 40 years, minimum detectable increases will be assumed to be the values given for 36 years of observation. Comparison of these values with predicted impacts given in Tables 18 and 19 shows that the use of evaporative cooling systems may lead to statistically significant impacts on fog and visibility.

The frequency of occurrence of five visibility categories has been estimated for the various cooling system combinations as an initial step in evaluation of the economic impact of moisture releases. Table 21 gives these estimates for current conditions and three cases in which exclusive use of mechanical draft cooling towers was assumed. The visibility categories are directly related to activities which are important to public

TABLE 21: Predicted Impact of Development of Nuclear Energy Center Using Mechanical Draft Cooling Towers on Fog and Visibility in the Tri-Cities

<u>Number of Reactors</u>	<u>Total Hours of Fog</u>	<u>Hours of Visibility Less Than Stated Distances (miles)</u>				
		<u><3</u>	<u><1</u>	<u><1/2</u>	<u><1/8</u>	<u><1/16</u>
0	278	196	132	101	36	8
4	293	223	162	129	45	12
20	376	297	221	176	56	16
40	488	396	300	240	72	22

convenience as well as to changes which can be evaluated in economic terms. An example of the relationship between these categories and the transportation industry is given below.

Reduction of prevailing visibility to less than three miles changes the rules governing airplane flight from visual rules to instrument rules. This has the effect of closing airports to most private pilots, those who are not qualified to conduct instrument flight. In addition to being inconvenient to affected pilots this has a calculable economic effect on local airport and flight service operators. Further reduction of visibility in the Tri-Cities to less than one mile effectively closes the Richland airport to all traffic, including the local commuter airline, Execuair. When visibility becomes less than one-half mile, all air traffic to and from local airports is halted. Surface transportation is impacted as the visibility falls below one-eighth of a mile. Finally when the visibility falls below one-sixteenth mile, surface traffic may be seriously impeded. The impact of reduced visibility on surface traffic can range from delays to an increase in traffic accidents.

These results were obtained using simple atmospheric models in an attempt to optimize heat sink management in a conceptual HNEC. The models are conservative in that they are biased toward overprediction of the impact of cooling system effluents on humidity and fog. Thus the models

are screening tools to be used to identify subjects for further, more realistic examination. Within this context the following conclusions have been reached:

- 1) The evaluation of any atmospheric impact postulated for heat dissipation must be conducted in quantitative terms which can be used to determine the significance of the impact.
- 2) Of the potential atmospheric impacts of large heat releases from energy centers, the one most amenable to quantitative evaluation in meaningful terms at this time is the increase in fog.
- 3) A postulated increase in frequency of fog can be translated into terms of visibility and both can be evaluated statistically.
- 4) The translation of a increase in fog to visibility terms permits economic evaluation of the impact.
- 5) The predicted impact of the HNEC on fog and visibility is statistically significant whether the energy center consists of 20 or 40 units.

Those heat sink management options which cause predicted impacts near the low end of the ranges given in Table 18 are least likely to produce significant impact when examined in more detail. These systems are primarily tall cooling towers, whether natural or mechanical draft, and unassisted once-through systems. Comparison of the predictions in Table 19 with the results in Table 20 indicate that extensive use of wet-dry or dry, low mechanical draft cooling towers may reduce the probability of fogging impact to a level consistent with the lower ends of the impact ranges given in Table 18. It should be noted that the single four-reactor cluster is identified as having a potential for reduced visibility during fog, although the impact on total hours of fog is not significant.

Comparison of Alternatives

The environmental interaction parameters of interest to the comparison of the heat sink alternatives and the evaluation of those parameters are summarized in Table 22 for the 20 reactor HNEC and in Table 23 for the 40 reactor HNEC.

TABLE 22: Summary Comparison of 20 Reactor Heat Sink Alternatives

Case	I, II	III, IV	V	VI	VII	VIII	IX	X	XI
Case Description	Short Wet Towers	Tall Wet Towers	Wet Dry Towers	Six Once-through and Ponds	Ten Once-through and Ponds	Ten Once-through and Towers	Helper Towers	Sixteen Once-through	Dry Towers
Net Annual Generation (10^4 kWh)	1,533	1,533	1,533	1,533	1,533	1,533	1,533	1,533	1,533
Capital Cost (\$ x 10^6)	7,200	7,240	7,730	7,080	7,010	7,050	7,390	6,930	8,100
Annual Fuel Cost (\$ x 10^6)	632	632	650	624	620	624	618	618	670
Annual O&M Cost (\$ x 10^6)	322	322	337	317	314	314	322	310	347
Electricity Cost (mills/kWh)	13.3	13.3	14.0	13.1	13.0	13.0	13.4	12.8	14.6
Resource Utilization									
Land (Acres)	3,200	3,200	3,200	21,700	21,700	3,200	3,200	3,200	3,200
Material									
Concrete (yards)	720,000	800,000	730,000	432,000	361,000	490,000	880,000	352,000	737,000
Steel (tons)	80,000	80,000	136,000	74,000	71,000	73,000	120,000	69,000	182,000
Water									
Withdrawals (cfs)	800	800	400	9,700	15,520	15,400	24,200	24,200	120
Evaporation (cfs)	600	600	300	500*	400*	300*	500*	120*	90
Discharge to River (cfs)	200	200	100	9,200	15,130	15,100	23,700	24,080	30
Chemical Releases (tons/yr)									
To Air (and then to land)	100	100	50	35	20	50	20	20	15
To Water									
TDS	14,000	14,000	7,000	49,000	41,000	7,000	3,000	3,000	0
Total Cu	140	140	70	120	110	70	30	30	0
Cl ₂	70	70	40	60	50	40	20	20	0
P	140	140	70	120	110	70	30	30	0

*Does not include evaporation from river.

TABLE 22: (Continued)

Case	I, II	III, IV	V	VI	VII	VIII	IX	X	XI
Aquatic Biology Effects	Insignificant Effects	Insignificant Effects	Insignificant Effects	Potential for damage to spawning salmon when river temperatures are high. Increased river temperatures in the winter may be beneficial to embryos and early larval stages of fish development.			Major damage to aquatic life because of large portion of river pumped through condensers and large increase in average river temperature during high river temperature conditions.		No Effects
Terrestrial Biology Effects	Insignificant Effects								
Meteorology Effects									
Cooling System Plumes	Five large low level plume systems	Four large high level plume systems. One low level system.	Five low level plume systems	Massive low-level fog system near White Bluffs		Three large plume systems (one low, two high)	Five large plume systems (one low, four high).	One large low level plume system. More fog near the Columbia River.	One large low level plume system.
Increased Ground fog in the Tri-Cities (Hours & percent increase with 1/2 mile visibility)	47 hrs. (42%)	23 hrs. (21%)	23 hrs. (21%)	54 hrs. (48%)	42 hrs. (38%)	9 hrs. (8%)	17 hrs. (15%)	Negligible Increase	No Increase
Increased Humidity in the Tri-Cities	Probably an insignificant effect. At high temperatures (85°F) the relative humidity will be increased up to 3% for less than 50 hours per year.						Negligible Increase		No Increase
Precipitation near the Hanford Project	May be a small increase in the fall, winter and spring. Probably insignificant increase in the summer months.						Negligible Increase		No Change
Agricultural Effects	Probably a negligible effect. There may be a decrease in solar radiation in the spring.							Unmeasurable Change	No Change
Societal Effects	Aesthetic effects of fog plumes. Increase in inconvenience and accidents because of foggy driving conditions and increased shutdown of airports.								

TABLE 23: Summary Comparison of 40 Reactor Heat Sink Alternatives

Case	XII, XIII	XIV, XV	XVI	XVII	XVIII	XIX	XX
Case Description	Short, Wet Towers	Tall, Wet Towers	Wet-Dry Towers	Partial Once-through	Helper	Full Once-through	Dry Tower
Net Annual Generation (10^4 kWh)	3.066	3.066	3.066	3.066	3.066	3.066	3.066
Capital Cost (\$ x 10^6)	14,400	14,500	15,500	13,900	14,800	13,800	16,400
Annual Fuel Cost (\$ x 10^6)	1,264	1,264	1,304	1,238	1,232	1,232	1,344
Annual O&M Cost (\$ x 10^6)	644	644	674	622	644	616	699
Electricity Cost (mills/kWh)	13.3	13.3	14.0	12.9	13.4	12.8	14.7
Resource Utilization							
Land (Acres)	6,400	6,400	6,400	6,400	6,400	6,400	6,400
Material							
Concrete (yards)	1,440,000	1,600,000	1,460,000	888,000	1,760,000	612,000	1,480,000
Steel (tons)	160,000	160,000	271,000	143,200	240,000	134,800	382,000
Water							
Withdrawals (cfs)	1,600	1,600	900	36,600	54,200	54,200	120
Evaporation (cfs)	1,200	1,200	600	500*	1,000*	120*	90
Discharge to River (cfs)	400	400	300	36,100	53,200	54,080	30
Chemical Releases (tons/yr)							
To Air (and then to land)	200	200	100	80	200	20	15
To Water							
TDS	28,000	28,000	14,000	11,000	3,000	3,000	0
Total Cu	300	300	150	110	30	30	0
Cl ₂	140	140	70	50	20	20	0
P	300	300	150	110	30	30	0

*Does not include evaporation from the river.

TABLE 23: (Continued)

Case	XII, XIII	XIV, XV	XVI	XVII	XVIII	XIX	XX	
Aquatic Biology Effects	← Insignificant Effects →			Major damage to aquatic life because of large portion of river pumped through condensors and large increase in average river temperature during high river temperature conditions.			No Effects	
Terrestrial Biology Effects	← Insignificant Effects →							
Meteorology Effects								
Cooling System Plumes	Ten large low-level plume systems	Nine large high-level & one large low-level plume systems	Ten low-level plume systems	Four large plume systems. More fog on Columbia River.	Six large plume systems.	One large low-level plume system. More fog on Columbia River.	One large low-level plume system.	
Increased Ground Fog in the Tri-Cities (Hours & percent increase with 1/2 mile visibility)	111 hrs. (99%)	55 hrs (49%)	55 hrs (49%)	18 hrs. (16%)	42 hrs. (36%)	Negligible Increase	No Change	
Increased Humidity in the Tri-Cities	Probably an insignificant effect. At high temperatures (>85°F) the relative humidity will be increased up to 6% for less than 50 hours per year.			Probably an insignificant effect. At high temperature (>85°F) the relative humidity will be increased up to 3% for less than 50 hours per year.		Same as for Case XII.	Negligible Change	No Change
Precipitation near Hanford Project	May be a small increase in the fall, winter and spring. Probably insignificant increase in the summer months.					Negligible Change	No Change	
Agricultural Effects	Probably a negligible effect. There may be a decrease in solar radiation in the spring.					Negligible Change	No Change	
Societal Effects	Aesthetic effects of fog plumes. Increase in inconvenience and accidents because of foggy driving conditions and increased shutdown of airports.						None	

Several simplifying assumptions were used during the preparation of these tables. The primary ones are as follows:

1. All economic costs are for 1975 dollars or completion of the construction in 1975.
2. The economic costs for a specific type of heat sink are independent of the plant location (with the restriction that once-through and helper systems must be located on the banks of the Columbia River).
3. The Hanford Reservation will continue under U.S. Government or industrial control and there can be no displacement of persons with homesites on those lands.
4. The rate of return on capital is 15%.
5. Helper cooling towers would be the same size as closed-cycle cooling towers and would transfer 72% of the waste heat to the atmosphere.
6. The intake and discharge structures on the Columbia River are located and designed to produce minimum impact on the aquatic life.

Analysis of the information developed concerning the alternatives leads to several important conclusions concerning the economic and environmental effects:

1. The differences in economic costs for systems using once-through, pond or wet tower cooling are relatively small (less than 5%). However, these cost differences are real because of inherent differences in design. Dry cooling towers cause 10 to 15% higher power costs than for wet cooling systems.
2. The differences in material usage generally are insignificant for cooling tower systems except for the increase in steel consumption for dry cooling systems.
3. Closed cycle cooling systems have an insignificant aquatic ecology effect.
4. Once-through cooling systems probably will have a major effect on the aquatic life if over 10 reactors have such cooling systems and the average river flow rate is below 54,000 cfs.
5. Because of the previous land disturbance and large amount of desert land available, the environmental effects of land use are insignificant except that creation of ponds could improve aquatic habitat. Project ALE will continue to provide an undisturbed large desert research area.

6. Cooling ponds and short wet cooling towers could cause a noticeable increase in ground fog formation at nearby cities and highways and on the Hanford Reservation.
7. Tall wet cooling towers (500 feet tall) probably would not cause a noticeable change in ground fog formation at nearby cities and highways for construction of up to 20 reactors.

Based on the above information, it is concluded that the best heat sink management system for an HNEC is a mixture of once-through and tall wet tower systems containing up to 10 once-through systems. Tall cooling towers appear more desirable than cooling ponds or short cooling towers because of equal economic costs and a much smaller impact due to ground fog formation. Selection of the number of once-through systems will depend on future decisions concerning the minimum flow rates in the Columbia River during the fall and winter periods. The suggested construction of up to 10 once-through systems is based on the assumption that the minimum flow rate will not decrease below the recent fifteen-year minimum, seven-day running average of 54,000 cfs and that enough reactors will be built in the Pacific Northwest so that most, if not all, of the reactors with once-through cooling can be shut down for their annual refueling outage during the high river temperature months of August, September, and October. With proper construction and operation of the once-through cooling systems to insure there is minimal effect on spawning salmon, addition of heat to the river during the colder winter months may be beneficial to the salmon population by increasing the growth rate of the young salmon.

Because of uncertainties in both the meteorological and aquatic biology analyses, a cautious approach should be used in scheduling the construction of the HNEC reactors. One strategy might be to defer construction of the once-through cooled reactors until after enough reactors with cooling towers are constructed so that the once-through reactors could be shut down during August to October without causing an electricity or outage personnel shortage. Similarly, the wet cooling towers could be designed such that dry cooling heat exchangers could be added if excessive fog formation occurs.

In the meantime, two important research studies should be made. Additional aquatic ecology studies should determine the benefits and costs that would result from heating the Columbia River during the various seasons of the year. It is possible that by proper heat additions, the total aquatic ecology could be improved. These studies should include a more accurate determination of the hydro-thermal regions near the intakes and discharges for once-through cooling.

Meteorological research should develop improved methods for estimating the effect of cooling tower operation on fog formation and other meteorological events near an HNEC. Until better analytical methods are available, it may be difficult to select the best cooling systems and convince the surrounding populations that the HNEC is not causing significant adverse effects.

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APPENDIX A

TERRESTRIAL ECOLOGY SPECIES

TERRESTRIAL ECOLOGY SPECIES

IMPORTANT VASCULAR PLANTS OF THE SAGEBRUSH-BITTERBRUSH/CHEATGRASS COMMUNITY

Common Name

Scientific Name

SHRUBS

Big sagebrush	<u>Artemisia tridentata</u>
†† Antelope bitterbrush	<u>Purshia tridentata</u>
Nauseosus rabbitbrush	<u>Chrysothamnus nauseosus</u>
Yellow rabbitbrush	<u>Chrysothamnus viscidiflorus</u>
Spiny hopsage	<u>Grayia spinosa</u>
Snow eriogonum	<u>Eriogonum niveum</u>
Prickly pear cactus	<u>Opuntia polyacantha</u>

PERENNIAL GRASSES

Sandberg bluegrass	<u>Poa sandbergii</u>
† Needle-and-thread grass	<u>Stipa comata</u>
Thickspike wheatgrass	<u>Agropyron dasystachyum</u>
Indian ricegrass	<u>Oryzopsis hymenoides</u>

PERENNIAL FORBS

Pale evening primrose	<u>Oenothera pallida</u>
Carey balsamroot	<u>Balsamorhiza careyana</u>
Longleaf phlox	<u>Phlox longifolia</u>
Scurf pea	<u>Psoralea lanceolata</u>
Yarrow	<u>Achillea millefolium</u>
Sego lily	<u>Calochortus macrocarpus</u>
Cluster lily	<u>Brodiaea douglasii</u>
Turpentine parsley	<u>Cymopterus terebinthinus</u>
Sand dock	<u>Rumex venosus</u>

ANNUALS

*Spring draba	<u>Draba verna</u>
*Jagged chickweed	<u>Holosteum umbellatum</u>
Tansy mustard	<u>Descurainia pinnata</u>
*Tumbleweed	<u>Salsola kali</u>
*Tumble mustard	<u>Sisymbrium altissimum</u>
†*Cheatgrass	<u>Bromus tectorum</u>
Sixweek's fescue	<u>Festuca octoflora</u>
Microsteris	<u>Microsteris gracilis</u>
Phacelia	<u>Phacelia linearis</u>
Polemonium	<u>Polemonium micrantha</u>
Plectritis	<u>Plectritis macrocera</u>
Bursage	<u>Franseria acanthicarpa</u>

*Alien species

† Important livestock forage

†† Important wildlife forage

BIRDS UTILIZING POND HABITATS

(Modified from Fitzner and Rickard, 1975)

ORDER PODICIPEDIFORMES

Family Podicipedidae

Horned Grebe
Eared Grebe
Western Grebe
Pied-billed Grebe

Podiceps auritus
Podiceps caspicus
Aechmophorus occidentalis
Podilymbus podiceps

ORDER CICONIIFORMES

Family Ardeidae

Great Blue Heron
Black-crowned Night Heron
American Bittern

Ardea herodias
Nycticorax nycticorax
Botaurus lentiginosus

ORDER ANSERIFORMES

Family Anatidae

Whistling Swan
Canada Goose
Mallard
Gadwall
Pintail
Green-winged Teal
Blue-winged Teal
Cinnamon Teal
American Wigeon
Shoveler
Redhead
Ring-necked Duck
Canvasback
Greater Scaup
Lesser Scaup
Common Goldeneye
Barrows Goldeneye
Bufflehead
Old Squaw
Ruddy Duck
Hooded Merganser
Common Merganser

Olor columbianus
Branta canadensis
Anas platyrhynchos
Anas strepera
Anas acuta
Anas crecca carolinensis
Anas discors
Anas cyanoptera
Anas americana
Anas clypeata
Aythya americana
Aythya collaris
Aythya valisineria
Aythya marila
Aythya affinis
Bucephala clangula
Bucephala islandica
Bucephala albeola
Clangula hyemalis
Oxyura jamaicensis
Lophodytes cucullatus
Mergus merganser

ORDER GRUIFORMES

Family Gruidae

Sandhill Crane

Grus canadensis

Family Rallidae

Sora

Porzana carolina

American Coot

Fulica americana

ORDER CHARADRIIFORMES

Family Charadriidae

Killdeer

Charadrius vociferus

Family Scolopacidae

Common Snipe

Capella gallinago

Long-billed Curlew

Numenius americanus

Spotted Sandpiper

Actitis macularia

Greater Yellowlegs

Tringa flavipes

Lesser Yellowlegs

Totanus flavipes

Pectoral Sandpiper

Calidris melanotos

Least Sandpiper

Calidris minutilla

Dunlin

Erolia alpina

Long-billed Dowitcher

Limnodromus scolopaceus

Western Sandpiper

Ercunetes mauri

Sanderling

Crocethia alba

Family Recurvirostridae

American Avocet

Recurvirostra americana

Family Phalaropodidae

Wilson's Phalarope

Steganopus tricolor

Northern Phalarope

Lobipes lobatus

Family Laridae

California Gull

Larus californicus

Ring-billed Gull

Larus delawarensis

Bonaparte's Gull

Larus philadelphia

ORDER CORACIIFORMES

Family Alcedinidae

Belted Kingfisher

Megaceryle alcyon

BIRDS OF PREY

ORDER FALCONIFORMES

Family Accipitridae

Sharp-shinned Hawk
Red-tailed Hawk
Swainson's Hawk
Golden Eagle
Marsh Hawk

Accipiter striatus
Buteo jamaicensis
Buteo swainsoni
Aquila chrysaetos
Circus cyaneus

Family Falconidae

Sparrow Hawk

Falco sparverius

ORDER STRIGIFORMES

Family Strigidae

Great Horned Owl
Burrowing Owl

Bubo virginianus
Speotyto cunicularia

UPLAND GAME BIRDS

ORDER GALLIFORMES

Family Phasianidae

California Quail
Ring-necked Pheasant
Chukar

Lophortyx californicus
Phasianus colchicus
Alectoris chukar

ORDER COLUMBIFORMES

Family Columbidae

Rock Dove
Mourning Dove

Columba livia
Zenaida macroura

BIRDS ASSOCIATED WITH TREES AND OTHER RIPARIAN
VEGETATION AROUND WASTE PONDS

ORDER PIDIFORMES

Family Picidae

Red-shafted Flicker	<u>Colaptes auratus</u>
Lewis' Woodpecker	<u>Asyndesmus lewis</u>
Hairy Woodpecker	<u>Dendrocopos villosus</u>
Downy Woodpecker	<u>Dendrocopos pubescens</u>

ORDER PASSERIFORMES

Family Tyrannidae

Eastern Kingbird	<u>Tyrannus tyrannus</u>
Western Kingbird	<u>Tyrannus verticalis</u>
Ash-throated Flycatcher	<u>Myiarchus cinerascens</u>
Say's Phoebe	<u>Sayornis saya</u>
Western Wood Peewee	<u>Gontopus sordidulus</u>

Family Alaudidae

Horned Lark	<u>Eremophila alpestris</u>
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Family Corvidae

Black-billed Magpie	<u>Pica pica</u>
Common Raven	<u>Corvus corax</u>
Common Crow	<u>Corvus brachyrhynchos</u>

Family Sittidae

Red-breasted Nuthatch	<u>Sitta canadensis</u>
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Family Troglodytidae

Winter Wren	<u>Troglodytes troglodytes</u>
Long-billed Marsh Wren	<u>Telmatodytes palustris</u>
Canon Wren	<u>Catherpes mexicanus</u>

Family Mimidae

Mockingbird	<u>Mimus polyglottos</u>
Sage Thrasher	<u>Oreoscoptes montanus</u>

ORDER PASSERIFORMES (Cont.)

Family Turdidae

Robin	<u>Turdus migratorius</u>
Varied Thrush	<u>Ixoreus naevius</u>
Hermit Thrush	<u>Hylocichla guttata</u>
Western Bluebird	<u>Sialia mexicana</u>
Townsend's Solitaire	<u>Myadestes townsendi</u>

Family Sylviidae

Golden-crowned Kinglet	<u>Regulus satrapa</u>
Ruby-crowned Kinglet	<u>Regulus calendula</u>

Family Motacillidae

Water Pipit	<u>Anthus spinoletta</u>
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Family Laniidae

Loggerhead Shrike	<u>Lanius ludovicianus</u>
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Family Sturnidae

Starling	<u>Sturnus vulgaris</u>
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Family Vireonidae

Hutton's Vireo	<u>Vireo huttoni</u>
Red-eyed Vireo	<u>Vireo olivaceus</u>
Warbling Vireo	<u>Vireo gilvus</u>

Family Parulidae

Orange-crowned Warbler	<u>Vermivora celata</u>
Nashville Warbler	<u>Vermivora ruficapilla</u>
Yellow Warbler	<u>Dendroica petechia</u>
Yellow-rumped Warbler	<u>Dendroica coronata</u>
Townsend's Warbler	<u>Dendroica townsendi</u>
MacGillivray's Warbler	<u>Oporornis tolmiei</u>
Wilson's Warbler	<u>Wilsonia pusilla</u>

Family Ploceidae

House Sparrow	<u>Passer domesticus</u>
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ORDER PASSERIFORMES (Cont.)

Family Icteridae

Western Meadowlark
Yellow-headed Blackbird
Red-winged Blackbird
Northern Oriole
Brewer's Blackbird
Brown-headed Cowbird

Sturnella neglecta
Xanthocephalus xanthocephalus
Agelaius phoeniceus
Icterus galbula
Euphagus cyanocephalus
Molothrus ater

Family Thraupidae

Western Tanager

Piranga ludoviciana

Family Fringillidae

House Finch
American Goldfinch
Rufous-sided Towhee
Savannah Sparrow
Lark Sparrow
Sage Sparrow
Dark-eyed Junco
Tree Sparrow
White-crowned Sparrow
Golden-crowned Sparrow
Swamp Sparrow
Song Sparrow

Carpodacus mexicanus
Spinus tristis
Pipilo erythrophthalmus
Passerculus sandwichensis
Chondestes grammacus
Amphispiza belli
Junco hyemalis
Spizella arborea
Zonotrichia leucophrys
Zonotrichia atricapilla
Melospiza georgiana
Melospiza melodia

BIRDS THAT FEED ON FLYING INSECTS

ORDER CAPRIMULGIFORMES

Family Caprimulgidae

Common Nighthawk

Chordeiles minor

ORDER PASSERIFORMES

Family Hirundinidae

Barn Swallow
Cliff Swallow

Hirundo rustica
Petrochelidon pyrrhonota

MAMMALS

Great Basin Pocket Mouse
Deer Mouse
Harvest Mouse
House Mouse
Grasshopper Mouse
Sagebrush Vole
Cottontail
Blacktailed Hare
Mule Deer

Townsend Ground Squirrel
Pocket Gopher

Cyote
Bobcat
Badger
Raccoon

Beaver
Muskrat
Mink
Weasel
Skunk

Perognathus parvus
Peromyscus maniculatus
Reithrodontomys megalotis
Mus musculus
Onychomys leucogaster
Lagurus curtatus
Sylvilagus nuttalli
Lepus californicus
Odocoileus hemionus

Spermophilis townsendii
Thomomys talpoides

Canis latrans
Lynx rufus
Taxidea taxus
Procyon lotor

Castor canadensis
Ondatra zibethica
Mustela vison
Mustela frenata
Mephitis mephitis

SNAKES AND LIZARDS

Pacific Rattlesnake
Gopher Snake
Side-blotched Lizard
Fence Lizard
Horned Lizard

Crotalus viridis
Pituophis melanoleucus
Uta stansburiana
Sceloporus graciosus
Phrynosoma douglasii

VASCULAR PLANTS OF MOIST HABITATS

Cattail
Reed Canary Grass
Rabbitfoot Grass
Cudweed
Bulrush
Wiregrass
Peachleaf Willow
Barnyard Grass
Russian Knapweed
Wild Onion

Typha latifolia
Phalaris arundinacea
Polypogon monspeliensis
Onopeltium margaritacea
Scirpus
Eleocharis
Salix amygdaloides
Echinochloa crus-galli
Centurea repens
Allium sibericum

STATION SERVICE POWER SUPPLY FOR A
HANFORD NUCLEAR ENERGY CENTER (HNEC)

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SUMMARY AND CONCLUSIONS

The main task of this study was to select an "alternate" station service supply system for multiple plants in the HNEC situation. A nuclear energy center at Hanford (HNEC) in the year 2000 is envisaged as five groups of generating units with three to five units in each group, served by three main 500 kV switching stations. The bulk power system for the Northwest Power Pool is at 500 kV; in addition, a 230 kV system that traverses the area will be interconnected with the 500 kV system at Vantage and Grand Coulee to the north and at McNary to the south of the Hanford Reservation. The power source for the station service circuits can be either the 500 or 230 kV systems or the 24 kV generator bus to the stepup transformer to the 500 kV system as shown in Figure 1. The latter alternative, with a switch to isolate the generator, has both functional and economic merit, and was adopted in this study for the "normal" power source in all cases examined. It is equally attractive for dispersed plants or centralized plants.

The assumed grouping of plants is such that the problems of selecting an "alternate" offsite station service supply are similar to those of three and four-unit stations now being designed, nine of which were reviewed for this study. The novel problem at a center of 20 stations is to estimate coincidental peak loads on a system supplying all alternate station service circuits in common under normal and abnormal conditions. NRC's restraints on the operation of a generating station when either of its normal or alternate station service circuits is not available, and the low historical failure rates of equipment in the normal supply circuits act to minimize transferring the load to an alternate circuit. The study indicated that with a possible connected station load of 1200 to 1500 MW, the probability of the maximum load exceeding 360 MW would be negligible. An analysis of loads under abnormal as well as normal conditions found the peak to be less than 360 MW. Load

EXAMPLE OF 500 kV - 230 kV
SYSTEM INTERCONNECTION
THROUGH AUTOTRANSFORMER

FIGURE 1. HNEC Transmission Systems and Typical Points of
Power Supply for "Offsite" Station Service Circuit

flow and economic data presented in the report are based on this finding. The data apply only if the station service for all plants is taken from the 230 kV system, designated Concept A in our study. In Concept B alternate circuit power is drawn from the 500 kV station bus, and the question of supply system capacity does not arise.

Load flow studies of the local transmission system indicated that 230 kV system reinforcements necessitated by HNEC station loads would comprise 55 to 60 miles of line in sections from Vantage to Hanford, and from Hanford to Gable Mountain switching stations at a cost of about \$8 million.

In order to demonstrate the engineering solutions to alternative methods of providing station service, certain assumptions were made with respect to the grouping, spacing, and orientation of the generating plant units, as well as their positions relative to the existing and anticipated main transmission line routes. In the southern part of the reservation, where development is already taking place, the pattern already established was followed to a total of five generating units. In the central and northern groupings, it was assumed that two-, three- and four-unit stations would resemble those of the Catawba, Palo Verde and Alan Barton designs. The relative positions of the 500 kV and 230 kV switching stations involved assumptions which affect not only the number of underground crossings but also other design features necessary to separate the offsite station service circuits. These assumptions of course influence the comparative cost estimates of Concept A and Concept B. Finally, the study assumed that the regulatory position now held on this topic by NRC would remain substantially as set forth in guides and standards now in effect or proposed.

Once the study had established those assumptions and base conditions with respect to the development of the HNEC and the development of transmission facilities in the vicinity of the Hanford Reservation, we then considered various means of providing alternate circuits to serve the station loads of 20 units. The two most attractive concepts were:

- A. Loop circuits from switching stations on the 230 kV system, serving three to five plants each, with 230/6.9 kV or 13.8 kV (6.9 kV is used

herein as typical of intermediate voltage) transformation at the station buses of each generating unit.

- B. Radial circuits from a 500/69 kV transformer, fed from a 1-1/2 breaker position on the same 500 kV bus carrying the main generator output, and having circuits to 69/6.9 kV transformers at each generating station unit (69 kV allows for extensive distance between switchyard and load).

The technical and operational merits of Concepts A and B were compared. No major differences were found with respect to the potential effects of the circuit characteristics on generating plant availability or on continuity of service to safety related plant loads. Significant differences were found in environmental effects, in the degree of uncertainty regarding regulatory position, and in flexibility for sporadic growth; these differences are discussed in the conclusions.

The estimated capital investment cost for the normal and alternate circuit lines and equipment, and grid reinforcements, for 17 additional generating plants at HNEC is \$78 million for Concept A and \$79 million for Concept B. A greater portion of the investment of Concept B comes early in the HNEC development period; the discounted present worth of the required capital investment is from 10 to 15% greater than that of Concept A.

In addition to the specific combinations of Concepts A and B, other possible methods or combinations were considered, some involving three off-site circuits instead of two, and one having a separate generating source to provide an alternate supply for all plants. A plant design with a bifurcated main generator bus would provide a good opportunity for having both offsite station service supply circuits on the generator bus. This combination appears to be both functionally and economically superior to most other designs; however, this design can only be used when the design of the major power circuits is already a bifurcated system and very few plants have such systems. The other alternatives were not attractive, and any advantage they may have would not warrant the added cost.

In conclusion, our study indicated that there are acceptable methods of providing station service to a 20-unit HNEC. The choice of method would depend on the economic, environmental and technical situation at the time the design of a new plant is committed, and on the preference of the responsible utility. Briefly, our study yielded the following conclusions:

- Extraordinary engineering difficulties in designing an HNEC's station service systems that will meet all utility and regulatory requirements are not anticipated.
- The choice of the 230 kV system (Concept A) involves the uncertainty of whether the NRC would require full capacity in the BPA system for all possible connected load. The capacity estimates herein are based on expectation of peak loads of only 24-30% of possible connected load; this expectation is based on a study of the probabilities of the number of operating plants simultaneously transferred to the alternate system.
- Either of the two alternate circuit concepts, Concept A or B, studied in detail would be acceptable based on safety and operability.
- The estimated costs of the two alternatives are roughly equal for the set of conditions assumed in this study, but Concept A has a 10 to 15% advantage in discounted present worth of required investment. Different geographical arrangements of plants and switching stations would affect the estimates, but not to the extent that one concept would have a marked economic advantage over the other.
- The principal advantage of Concept A, in which station service (alternate circuit) is taken from the 230 kV system, is that the method is flexible enough to accommodate sporadic growth of the number of generating stations planned at Hanford--that is, in the absence of a firm program for completion of a three- or four-unit group or for a full-scale HNEC development. This concept is already in use for plants planned in the vicinity of the Ashe switching station.

- The principal advantages of Concept B, in which the station service (alternate circuit) is taken from the 500 kV system, are: (1) it does not require any added offsite transmission line construction, thus involving no added environmental impact; and (2) the inherent capacity in the network is ample for any load combination, thus avoiding any uncertainty as to the regulatory agencies' position on required capacity in network transmission lines.
- Other station service supply methods or combinations which would meet operational and safety requirements are possible but at higher cost and without substantial added benefits.

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STATION SERVICE POWER SUPPLY FOR A HANFORD NUCLEAR ENERGY CENTER (HNEC)

INTRODUCTION

A transmission system to provide station service to plants at an energy center is the subject of this report, which follows from a study of transmission of electric power from an energy center at Hanford conducted by Battelle Pacific Northwest Laboratories with the assistance of the Bonneville Power Administration and reported in BNWL-B-426 Electric Power Transmission for a Nuclear Energy Center,⁽¹⁾ September 1975. Both studies were conducted for the Energy Research and Development Administration (ERDA).

The study's main task was to evaluate and select an "alternate" station service supply system for multiple plants in an HNEC situation. Designs have been developed in the U.S. for station service power supply systems for four-unit plants. Some of these designs have already been approved by NRC as complying with safety regulations, and have been accepted by utilities as providing for an adequate level of operating reliability and flexibility. Plans for three units have been approved at Hanford, and a system has been developed for a total of five units in one general locality. The study reported herein concerns the requirements for station service to a nuclear energy center of 20 units with a net capacity of 24 gigawatts (24,000 MW).

The specific case studied is that of station service supply for the 150% Case (i.e., a transmission system to accommodate growth of generating capacity to 23,000 MW by 1998) in the reference transmission study.⁽¹⁾ The anticipated rate of load growth is such that an energy center could have a total generating capacity of 24 GW by the year 2000. The scope of the study includes the station service transmission system from its offsite origin in the bulk power network to the station service buses in the plant. The internal redundant systems extending from those buses to the station loads would not be expected to differ because of the number of generating units in one complex.

STATION SERVICE REQUIREMENTS

The discussion of station service requirements relies on the following terms and definitions:

- Offsite Power System: The offsite external commercial power system from which station service power can be supplied.
- Standby Power System: The onsite power sources, usually diesel generators, and their distribution equipment provided to energize devices essential to safety and capable of operating independently of the offsite power system.⁽²⁾
- Normal Offsite Circuit: The circuit or circuits from the offsite power system that are normally used.
- Alternate Offsite Circuit: The circuit or circuits from the offsite power system that are used only when the normal circuit or circuits are out of service.

A station service supply system is designed to not only meet the station loads and the plant safety requirements set by the NRC, but also to comply with the utilities' requirements for satisfactory overall performance of the plant. Specific requirements vary with the character of the network to which the plant is to be connected.

STATION DEMAND

Station demand for typical light-water reactor plants has been estimated from compilations of connected loads and analysis of the operating sequences of plant equipment in various operating modes. These estimates were then checked with loads experienced in operating plants. The resulting range of station service electrical demands of one 1200-MW nuclear generating unit is shown in Figure 2. Station loads for 1200-MW units are usually less than 75 MW. In later discussion of load diversity, 75 MW is taken as a conservative average load of operating reactors, 40 MW as load under hot standby, and 13 MW under cold shutdown.

FIGURE 2. Range of Typical Station Service Loads for a 1200 MW Generating Plant

SAFETY REQUIREMENTS OF STATION SERVICE SUPPLY SYSTEM

Safety requirements specifically demand that two independent offsite sources of power be available to each reactor. This offsite power system is normally referred to as the "preferred power system." The preferred power system is acceptable when two separate paths from the transmission network to the standby power distribution system are provided; adequate physical and electrical separation between the two paths exists; and the system has the capacity and reliability to supply power to all equipment essential to the safety of the plant. The two separate paths are designated as the "normal" and "alternate" offsite circuits throughout this report.

It is instructive to realize what equipment will be reviewed for safety in the preferred power system. It includes the two (or more) identified power sources that can be operated independently of the onsite (station generator)

or standby power sources (diesel generators). It encompasses the grid, transmission lines (overhead or underground), transmission line towers, transformers, switchyard components and control systems, switchyard battery systems, the main generator, and disconnect switches, all provided to supply electric power to safety-related and other equipment. These components and associated systems will be subjected to a safety review. Special integrity checks for components will be made and the systems using these components will be subjected to a single failure analysis which checks that no single failure such as a tower falling, or a line failure, or a single failure in a switchyard can simultaneously affect both circuits such that neither can be returned to service "within a few seconds."⁽³⁾

One of the above safety considerations--that of providing adequate physical and electrical separation--may affect the design of preferred power sources and is especially true where many sites are involved. NRC proposes, for instance, that no other line cross these circuits, which would thus force underground crossing in addition to other measures not normally included in providing offsite station service to non-nuclear generating plants.

Insofar as the preferred power system is a part of a station service supply system, the capacity required merely for its operating flexibility would normally be far greater than the demands for safety. That is, overall plant demand for normal operation would be expected to exceed the demands of station loads essential to safety. However, the whole preferred power system will be examined specifically for all of the safety criteria. Those safety criteria for offsite electrical power are set by NRC and IEEE and are listed in Appendix A.

In spite of their number, the guides, standards and criteria provide only general guidance. The Nuclear Regulatory Commission bases its approval on an individual case review. Several examples of designs for preferred power sources, in Appendix B, illustrate the variety of schematic design that has been proposed. These designs of preferred power sources completed for multiple station power units have been ruled acceptable for existing projects.

Such criteria as physical and electrical independence, capacity to satisfy several conditions, the grid stability of the preferred (offsite) power source, the demand that the system function under single failure criteria--all may require design features not normally considered for operating flexibility and operating stability. However, none of these criteria appear to be limiting in any way to the concept of multiple station sites.

Thus, in answer to questions regarding the comparative safety of distributed or concentrated concepts of power generation, concentration of generation at a center would create no unresolvable safety problems relative to offsite power. Further, the existence of the large number of units at an energy center will no doubt result in greater usable backup capability and increased reliability of the preferred power sources.

HNEC BASE CONDITIONS

Tentative sites selected for nuclear plants are shown in circles on the map of Figure 3, and general areas suitable for the construction of, or expansion of, transmission switching stations are shown as squares. Corridors considered suitable for transmission lines are also shown.

Three WPPSS nuclear plants are in various stages of design and construction in area No. 1, with some switching station equipment now installed at the Hanford Station and some planned for the Ashe Station. A transmission line right-of-way is being established between the Hanford and Ashe Stations. The bulk power transmission plant to accommodate up to 24,000 MW at HNEC would be expanded from that already in place or planned.

This report assumes that circled areas 1 through 5 will be developed, with three to five generating units per area. The manner in which station service transmission lines are brought into the generating plants would depend on plant layout. To illustrate the possible methods of providing for station service, it is assumed that

- (1) The plants in or around area No. 1 would develop consistent with the pattern already established by the three plants now planned, with a considerable distance separating each unit.
- (2) The plants in areas No. 2 through 5 would be two-, three-, or four-unit aggregations similar to those planned for the Catawba, Palo Verde or Alan Barton plants, respectively. However, the switching stations for the Hanford plants would not be as close (around 1500 feet) to the station transformer bays as are the Catawba, Palo Verde and Alan Barton plants, but would be greater distances as determined by the location of the Ashe and Hanford switching stations and the proposed location of the Gable Mountain station shown in Figure 3.

These assumptions potentially affect the choice of station service method in that:

FIGURE 3. HNEC Tentative Sites

- (1) If one of the offsite circuits originates at the 500 kV switching station bus, a greater distance between the bus and the generating plant must be traversed by the station service circuit than with a closer orientation,
- (2) If an effort is made to keep a 230 kV switching station in the same general area as the 500 kV switching stations, more crossover situations may be encountered, and
- (3) With closely spaced units, more underground cable may have to be used in station service circuits between units than if the units are spaced at greater distances.

The feasibility of the 230 kV system as an offsite source will depend on the location of 230 kV lines in place in 1985. BPA already plans to extend them or increase their capacity for reasons other than the HNEC station service load. The general route of the 230 kV system to be in place in 1985 is shown in Figure 4 relative to the possible location of generating plants. Note that 230 kV lines pass close to all of the sites 1 through 5; thus that system is a definite candidate for HNEC station service. The way in which the system would have to be strengthened to serve that purpose is discussed later (see "Additions for 230 kV Supply").

FIGURE 4. General Route of 1985 Hanford 230 kV System

ALTERNATE CONCEPTS FOR A 20-UNIT CENTER

Station service designs for existing or planned three- and four-unit plants are outlined in Appendix B. The major scenarios considered for HNEC are:

- (1) A concept in which the normal circuit originates at the generator terminal bus but is capable of being disconnected from the generator by a load-break circuit breaker, and in which the alternate circuit originates in the 230 kV portion of the network. The concept follows the general pattern established for two of the three planned commercial plants at Hanford and is shown schematically in Figure 5 as Concept A.

FIGURE 5. Schematic Diagram of Station Service Circuits, Concept A

- (2) A concept in which the normal circuit is as above, but with the alternate circuit originating in the 500 kV switchyard on a breaker-and-a-half position as shown in Figure 6 as Concept B. This concept would eliminate the necessity for routing additional 230 kV lines through the HNEC. Such an arrangement is similar to, but not identical to, that used at the Palo Verde, Alan Barton, and Shearon Harris plants.

Other concepts were explored but were found to be less attractive. They are discussed briefly in a later section of the report.

FIGURE 6. Schematic Diagram of Station Service Circuits, Concept B

THE 230 kV SYSTEM

Utilities differ in their practices regarding normal distribution of station loads on the two offsite circuits. Some divide the loads on the two sources and automatically switch half the loads in the event of an outage on one circuit, while others keep all the load on one circuit and automatically switch all the load in the event of an outage on that circuit. This discussion assumes that the latter practice is followed (consistent with WPPSS plans to date) and that all station loads will be on the "normal" circuit at all times, except when it is in trouble or the generator bus to which it is attached is taken out of service for inspection, maintenance, or repair.

Most, if not all, of the nuclear plants now in operation do not have load-break switches between the generator terminals and the station service tap. If the tap circuit is used normally, the operator has no option but to transfer station loads to the alternate offsite circuit (sometimes called the startup circuit) when the plant is shut down or starting up. Therefore, there is no record of experienced use of the alternate circuit under conditions identical to those of Concepts A and B among operating plants. However, certain station operators report that:

- (1) Alternate circuits are used only when the plant is shut down or starting up.
- (2) Trouble in a normal circuit with its tie-in point in the network seldom occurs, and with its tie-in point on the generator bus, seldom if ever occurs.
- (3) There has been no occasion to exercise an option to manually transfer to the alternate circuit during plant operation.

Such experience indicates that with a load-break switch there would be few occasions to transfer station loads to the alternate circuit; such occasions would probably be limited to: (1) switching over in order to inspect or maintain equipment in the bus tap zone, and (2) testing of the

transfer switchgear and circuits. These operations would normally be expected to occur when the generator was shut down, at which time the station loads transferred would be only about 13 MW per generating unit.

In plants of only one to four units both the normal and the alternate offsite circuits have usually been designed to accommodate the sum of the maximum demands from connected loads on all generating units; however, where 20 units conceivably could be served from a single alternate source, lesser capacity based on load diversity must be considered.

According to NRC safety regulations, the conditions under which the alternate circuit may be used are:

- (1) With the generator operating at full or reduced load or at hot standby, but still connected to the system:
 - (a) When the normal circuit is out of service, the alternate circuit could be used for up to 72 hours on only one source of offsite power. The load would be that corresponding to normal plant operation, possibly followed by the sequence for shutdown.
 - (b) When the normal circuit is available but an operating option has chosen to use the alternate circuit, the latter could be used indefinitely at a load corresponding to normal plant operation.
- (2) With the generator in cold shutdown, at which time operating options could place station loads on the alternate circuit indefinitely.

Under the regulations that limit the use of the alternate circuit to those conditions, the probability of the operating loads of multiple plants being transferred to the alternate circuit is less than if the plant operators were free to use either source on a continuing basis regardless of the state of the other. We estimated that over the average year an operating plant would be on the alternate source because of (1) failure of the normal

supply or (2) suspected weakness in the normal supply causing the operator to switch over manually, not more than a total of 7 days. A crude way of reducing this experience to probabilities is to say that for 7/365 of the year, exactly one of the 20 plants is operating on the alternate supply while 19 of the 20 plants are operating on the normal supply. This condition evaluates the corresponding term of the binomial series for the probability of that event:⁽⁴⁾

$$20 p^{19} (1 - p) = 7/365 \approx 0.02.$$

Solving for p^{20} yields $p^{20} = 0.979805$. Six figure accuracy was chosen to demonstrate that 0.000001 is the same as an outage of about 32 seconds per year. Here, six figure accuracy assumes that loadings of less than 0.000001 are negligible. Using this data as a basis for further evaluation, the term for any three of the 20 plants simultaneously on the alternate circuit and the remaining 17 units operating on the normal circuit is:

$$(20)(19)(18)p^{17} (1 - p)^3 / (1)(2)(3) = 0.000001.$$

Similar computation yields the following probabilities.

One unit switched to the alternate circuit	0.020000
Two units switched to the alternate circuit	0.000194
Three units switched to the alternate circuit	0.000001
Four units switched to the alternate circuit	negligible

These probabilities demand that operating continuity of the normal system supply circuit, aside from planned outages, be greater than 0.99898 for each unit. This figure ranges from 0.999495 to 0.997372 when the probability for a single unit of the 20 units switched to the alternate supply ranges from 3.65 to 18.25 days per year, thus indicating that the above probabilities of three or four units being simultaneously transferred to the alternate circuit are not sensitive to the basic assumption (probability of 0.02) within the 3.65 to 18.25 day range. When time for scheduled maintenance has been considered, the remaining operation should be characterized by high reliability, and unanticipated outages for each normal circuit unit should be negligibly small.

If four operating units are used as a design basis ($4 \times 75 = 300$ MW), and 20% is added for units in cold shutdown that may be on the alternate circuit, then the design basis for power capacity in a common supply system would be 360 MW. Here, we have adopted the maximum power requirement for station loads as discussed in the section on "Station Demand." The adequacy of a 360 MW base is examined in the following paragraphs.

The probabilities shown above are for calculations based on a worst-case condition in which all 20 units were on line. On the average only about 16 units will be on line, although maintenance and refueling schedules may be such that for limited periods most of the plants in a center would be operating. When the units are shut down, internal loads are sufficiently low that station service loads of all units could be transferred without exceeding 360 MW.

The interim requirements for reinforcement of the 230 kV supply system, calculated on the same basis as the fully developed center and including the three units now planned, are:

1983	2 units	150 MW
1984	3 units	225 MW
1996	16 units	360 MW

A later section presents means by which the 230 kV system would be reinforced to provide for (1) the growing loads in the area and (2) the super-imposed capacity requirement of an HNEC.

Station Service Loads Under Abnormal Conditions

This section presents some of the possible abnormal conditions and the responses to them. The discussion assumes that all new generating units would be capable of continued operation carrying only local auxiliary loads after full-load rejection.

One could visualize a system instability that would separate all 500 kV incoming lines from one entire switching station and which would either leave the generators running on hot standby feeding their own station loads, or cause hot standby loads to be transferred to the 230 kV system.

In this situation, since all units would be expected to handle the load rejection and remain on their normal sources, it is assumed that the station loads of not more than half of the operating units would be instantaneously transferred to the 230 kV system, i.e., a total load of $4 \times 75 = 300$ MW, and that if effects of the system disturbance were prolonged, all seven units that may be affected could be reduced to a hot standby condition before all were placed on the 230 kV system (if such transfer were deemed advisable). In that case the total load would be $7 \times 40 = 280$ MW. Upon restoration of the system to normal and if hot standby station service loads have been transferred to the 230 kV system, the loads are restored to the normal circuits as each generator is brought from hot standby back on line. Under these conditions, loads never exceed 280 MW. If the units are allowed to go into cold shutdown, the load on the alternate circuit would be: $7 \times 13 = 91$ MW. With preheat of the first unit to be restarted, the load could be $100 + (6 \times 13) = 178$ MW. After the first unit is back on line, the 500 kV bus is re-energized (if not already done so by reconnection of lines to the network) and the units can be restarted from their normal circuits. In such a case, load never exceeds 178 MW.

If a wide-ranging tornado should affect all the 500 and 230 kV lines to a plant, the generators (or at least two) could be kept at hot standby for up to 72 hours to feed all station loads through their normal circuits; or its station loads would have to be connected to the standby diesel generator source until the offsite system is restored.

Under NRC regulations the alternate station service circuit would need sufficient capacity for all 20 units under cold shutdown: $20 \times 13 = 260$ MW.

All of these contingencies are believed to be of very low probability in the Hanford environment, and are judged to have the same probability of occurring as that determined for the cases of three to four simultaneously operating plant transfers developed above ("Estimate of Potential Station Service Load").

Based on our analyses of normal and abnormal operating conditions, we decided to use overall maximum demand of 360 MW for purposes of system design,

corresponding to a diversity factor between 3.33 and 4.17. It would allow for the most severe conditions visualized for one group of six or seven units plus one unit in another group, running, or four to five units on cold shutdown in other groups.

Since the diversity factor of smaller groups of units, for example the four or five units in one loop, would be less than 3.75 and since a diversity factor of 1.00 could be accommodated at 230 kV without significant added investment in conductors, full capacity has been assumed to be provided in conductors and switches in such loops.

The above discussion assumes no central control. Control cannot be exercised over the failures causing automatic transfers of loads to the 230 kV circuit. However, it can be exercised over (1) operation within the 72-hour period after one source is lost, (2) optional operation on the alternate circuit when the normal one is also available, and, (3) startup operations from the hot standby or cold shutdown condition. Dispatching control could assure that in the highly improbable event that load limits on the 230 kV line are approached, the timing of operational moves could prevent overloading. However, at times of widespread emergency, a dispatching office should probably not be burdened with such controls, and it is believed that the proposed design basis capacity would eliminate any need for control.

230 kV System Description

The expected 230 kV system in the 1990s is shown in Figure 7. It will consist of:

1. Substations at Midway, Gable Mountain, Hanford, Ashe, and White Bluffs
2. Three lines between Midway and Gable Mountain. These are the current ERDA Hanford Loop lines and the Midway Scootney line.
3. Two lines between Gable Mountain and Ashe
4. Two lines between Ashe and White Bluffs

The principal source to the Hanford Area 230 kV system is the Midway Substation. Midway is connected to the Priest Rapids powerhouse, Big Eddy,

FIGURE 7. HNEC Switching Stations for (230 kV System) 20 Generating Units.
Source of Station Service Power for Alternate Circuits, Concept A

Grand Coulee, Vantage and North Bonneville. Power can also be supplied through the White Bluffs and Scootney connections from McNary and Ice Harbor dams even if the lines to Vantage are out of service.

The 230 kV system will be connected to the 500 kV system by autotransformers at Vantage, Grand Coulee and McNary.

Additions for 230 kV Supply

The additional requirement of a 360-MW station service capacity for the HNEC will require reinforcement of the 230 kV system, which could either be transformer additions or 230 kV line Additions. Construction of two 230 kV lines between Vantage and Hanford and a second 230 kV line between Hanford and Gable Mountain provide the best system reinforcement.

Operation

In Concept A a number of 230 kV plant station service transformers would be connected to a loop from a 230 kV station. The normal operating condition would be with the loop opened in the middle with about half the plants served from each end of the loop. With this connection, service to only half of the plants on the loop would be lost during a line outage. A faulted section could be quickly isolated with disconnect switches, and plants could be transferred from one section of the loop to the other.

Analysis of the Projected 1990 System

A power flow study has been made which assumes 18 thermal generators installed in the Hanford area, with 15 peaking during a summer peak load condition. Although the study is shown as August 1989, loads and generation represent a more future condition (mid-1990s).

Initially, it was assumed that there could be 540 MW of station service load on the 230 kV system, split equally to three stations (Hanford, Gable Mountain and Ashe). Following a meeting with ERDA and PNL, the 230 kV load was reduced to 360 MW, with this load occurring at any of the three stations, but not simultaneously.

Results of our analysis of the projected 1990 system are shown in the diagrams of Appendix C, and discussed below.

1. This much generation in the Hanford area results in excessively heavy line loadings from White Bluffs to McNary. Even the addition of a 230 kV line between these stations does not unload the 115 kV lines. Support now planned in the McNary and Franklin area makes it possible to open the Badger-Richland and Benton-Franklin lines to separate these two areas when overloads occur. Compare load flow diagrams A8929 and A8931 (Appendix C).
2. The Midway bus is not a strong enough source for the amount of load supplied even with the lines between White Bluffs and McNary open. (See Diagram A8930, Appendix C).

3. The Midway source may be strengthened in either of two ways. One proposal is to add a 500/230 kV bank at Ashe (Diagram A8929). A second proposal is to add additional 230 kV lines from Vantage to the loop having the station service load (Diagram A8944). In case A8944, two 230 kV Vantage lines were terminated at Hanford and a second 230 kV line was added between Hanford, Gable Mountain and Ashe. This provides sufficient strength for a line outage with 360 MW of station service load supplied on the 230 kV system. The support from Vantage is favored since it used existing 500/230 kV bank capacity at Vantage. It also has better reliability. Figure 8 shows an example of peak power flow in the Hanford vicinity for this method of system reinforcement.

FIGURE 8. Hanford Area 230 kV System with 360 MW Load at Ashe

4. The Midway-Scootney 230 kV line was also terminated at Gable Mountain in this study. This provides additional support not only for the station service load but also for the two 230 kV lines to White Bluffs. This addition probably will be required before the extensive thermal plant development in the Ashe area. It is needed when the second 230 kV line to White Bluffs is added.

The schedule of construction of the added lines necessitated by HNEC loads is such that one line from Vantage to Hanford would be in service in 1994 and one in 1997, and the additional line from Hanford to Fable Mountain would be in service in 1997. These plans are based on present planning assumptions; transmission requirements, of course, could change in the future.

THE 500 kV SYSTEM

The 500 kV system projected for the 1990s is shown in the map of Figure 3 and the diagram of Figure 9. The 500 kV circuit arrangement proposed for an HNEC shown in Figure 4 is taken from the referenced transmission study BNWL-B-426. This diagram shows six or seven units feeding into each of the three switching stations, and such an arrangement may be considered typical of an HNEC development, although it is still uncertain how many units should feed into one switching station. The required circuit breaker interrupting capacities may become too great, or, in the final analysis, concentrating that much capacity at one station may be unacceptable. A switching station adjacent to each three- or four-unit station may be attractive from an economic standpoint. However, this question need not be resolved for purposes of exploring station service alternatives.

The system will evolve to fill the export power needs of the mounting generating capacity at HNEC, as well as the growing loads in the eastern part of the region. The capacity of the 500 kV system will not be affected by HNEC station service requirements under either Concept A or B. In Concept B, station service power drawn from the system over the alternate circuit merely subtracts from the overall power exported through a switching station. In Concept A, power drawn by the alternate circuit would come from

FIGURE 9. Switching Stations HNEC-24,000 MW (500 kV)

the 230 kV system, which is interconnected with the 500 kV system, but which would have little effect on 500 kV system capacity insofar as HNEC loads are concerned. Therefore no incremental costs would be incurred on the 500 kV offsite system by use of Concept B.

Although emphasis in the load-flow studies discussed under "Analysis of the Projected 1990 System" is on the 230 kV system, the case studies cover the 500 kV system as well. Incremental costs in the 500 kV system due to export power transmission from HNEC were evaluated in the reference study.⁽¹⁾ Those results would not be altered by the use of either method of providing station service power.

COMPARATIVE ANALYSIS OF CONCEPTS A AND B

The technical and functional characteristics of the alternate circuits of the two concepts are compared in Table 1. The normal circuits are the same in both concepts.

TABLE 1. Comparison of Technical and Functional Characteristics of Concept A and Concept B

Topic	Concept A	Concept B	Relative Merit
Line and equipment exposure to failure	Has longer lines at higher voltage (230 kV vs 69 kV), and more underground cable at crossings with 500 kV lines	Has more apparatus (transformers and circuit breakers) than A	Historical failure rate on these types of lines and apparatus is low in both concepts (Ref. 5,6). With a 72-hour grace period before forced shutdown, generator availability would be affected only if (a) the circuit cannot be restored within 72 hours, or (b) a plant is operating on the alternate circuit, its normal circuit having become unavailable less than 72 hours previously. The exposure difference between concepts, per se, would make little difference in generating plant availability.
Time to restore service after a failure	Overhead line failures are quickly repaired. Underground 230 kV cable repair would require cable stock on hand for quick repair, but schedules can go beyond 72 hours because of the loop arrangement	A failure of the 500/69 kV transformer could seriously affect the availability of two to four generating units if rapid repairs or replacement are not provided. Even though the failure rate for such transformers is low, the loss of 4800 MW of capacity on the system in the rare event of such failure could be serious. Thus, cost estimate for Concept B allows for a rail-mounted spare transformer, with capacity for four units, to be kept at HNEC for rapid transfer to an affected station. Spare 69 kV cable is also necessary, since a failure in the radial circuit would require a 72-hour repair.	If provisions for restoring service within 72 hours are made as indicated, the two concepts would be approximately equal in their potential effect on generating plant availability.
With shared circuits, probability of one or more plants being served from the alternate circuit at time of fault.	4-7 generating units are on a loop, but the loop is normally operated open in the middle so that only half would be affected by an outage.	3-4 generating units are on a 500/69 kV transformer. Transformer failure would affect all. Line failure would affect only one.	Any failure on A could affect 2-4 units. Only a transformer failure on B would affect more than one unit. Slight advantage for B.
System stability	See Relative Merit.	See Relative Merit.	The concepts seem equal with respect to the stability of its source on the bulk power system.

Table 1 (continued 1)

Topic	Concept A	Concept B	Relative Merit
Generating sources on the network	Hydro plants to the northeast and southwest will feed directly into the 230 kV system and tie into the 500 kV system at Vantage and McNary.	Adjacent plants at HNEC, growing in number and at different locations as the center develops, will feed directly into the 500 kV system and to the 230 kV system via system autotransformer.	No difference is detected in the reliability of the network as affected by number and location of generating feed points.
Exposure to tornado or earthquake	The 230 kV lines follow same general route as 500 kV lines in and around HNEC. The 230 kV switching stations in most cases would be in the same general areas as the 500 kV station.	See Concept A.	Both systems can be served from the north or the south. If line sections are lost, the switching stations could be served from the opposite direction. If structures of both systems are equally resistant to the forces, the effects of tornado or earthquake on generator availability or continuity of service to plant equipment would be equal. If entire switching stations are lost, safety loads would be transferred to internal generators in each case. Concept A may have slight advantage in that if only a 500 kV or a 230 kV station is lost, but not both, offsite service would still be available for safety (not operating) purposes.
Electrical separation of the normal and alternate circuits	Since one circuit is served from the 500 kV system and one from the 230 kV system, and since the closest points of interconnection of the two systems are at Vantage and McNary, A has a greater degree of electrical separation.	The two circuits' points of connection with the network are separated by 3 circuit breakers, all are in the same switching structure.	A has greater degree of electrical separation than B, and one circuit would remain in service even if three relaying zones were involved in a cascading failure. Both concepts meet NRC requirements.
Physical separation of the normal and alternate circuits	Required physical separation of offsite lines can be maintained. On-site lines would have separation at the closest points comparable to B. Underground cable would be used as required.	Separation is of concern only from the 500 kV switching station into the plant.	Necessary physical separation can be maintained in either concept - with some economic penalty to A for underground crossings.
Line capacity in the network	See <u>The 230 kV System</u> . Planned capacity is judged adequate but regulatory position is unknown.	Ample capacity for any combination of plant loads is inherent in the network.	Capacity of both concepts is believed to be ample as proposed, but there is uncertainty as to regulatory requirements for Concept A. If capacity in lines of Concept A has to be sufficient for all possible connected load, there would be a severe economic penalty.
Human error (inadvertent switch trip; wrong relay setting)	Error could affect more than one plant (see shared circuits, etc.)	Error could affect only one plant.	Susceptibility to error is about the same for both concepts. Possible consequences are slightly greater for Concept A.
Flexibility and quality of service during HNEC growth	Overhead loop lines can be changed or extended with relative ease, and with a constantly reliable service. The 230 kV line capacity would have to be increased at an appropriate time to accommodate the combined HNEC loads and flowthrough power. Lines are more exposed to construction interference than in Concept B.	Once 500/69 kV transformer and switchgear are located, Concept B is less flexible than A to major siting changes. Reliability of service during growth stages is comparable to that of Concept A.	All interim requirements can be met with either concept. The initial installations in both cases must be designed to accommodate growth.

Table 1 (continued 2)

<u>Topic</u>	<u>Concept A</u>	<u>Concept B</u>	<u>Relative Merit</u>
Adaptability for sporadic growth rather than firm scheduled growth of an HNEC.	Isolated plants and plant built from time to time in the absence of an overall program can be served under Concept A without large front-end investment. A few plants can be accommodated by the 230 kV grid with reserve capacity so that any re-inforcement chargeable to such plants would be many years in the future.	The economy of Concept B depends to a considerable extent on the sharing of 500 kV breaker and transformer costs by 3 to 4 plants. If authorization and timing are uncertain, the concept is at a disadvantage.	Under the conditions postulated here, we would consider it prudent to continue the use of Concept A.
Environmental impact.	Grid reinforcements of 55 to 60 miles of 230 kV transmission line in and north of the Reservation, with added visual land-use and other impacts from such lines.	No changes to the off-site grid. Lines at the site would be relatively unobtrusive at 69 kV voltage level.	Concept A would have greater environmental impact.

ACCESS TO THE GENERATING PLANTS

The comparative difficulties of transmission line access to the generating plants under each concept are illustrated in Appendix D. The major questions to be resolved are: How much underground 230 or 69 kV cable would be necessary at crossings with 500 kV lines, and how might the overhead and underground lines be affected by the configuration of plants in a group? The rough maps in Appendix D indicate the comparative requirements, and were used as a basis for comparative cost estimates.

Note that the open arrangement of the Ashe group involves less crossings, but more overhead line, in the 230 kV loop of Concept A than do the more compact arrangements of the two-, three-, and four-unit groups of Gable Mountain and Hanford.

It is assumed that line crossings of the 500 and 230 kV circuits would be made with the 230 kV circuit underground if the loss of both lines, together with a crucial circuit breaker malfunction were to cut off both the normal and the alternate station service supplies to a generating plant.

In the future there will be numerous crossings of 500 kV and 230 kV lines on the Hanford reservation or near it. By the year 2000 there could be from 25 to 30 such crossings whether or not Concept A were used for HNEC station

service. However, most of these crossings are not included in the above assumption; that is, loss of the two lines and malfunction of the most crucial breaker would not cut off all offsite station service to any generating unit. Therefore, the cost estimates to follow later in the report do not include the cost of placing these remote crossings underground.

COMPARATIVE COST ESTIMATES

Cost estimates are limited to the equipment and lines used solely for station service and the cost of 230 kV transmission additions allocated to HNEC station service loads (Concept A). The costs are incremental to those of the main generator power circuits to which they are attached, and they are in 1975 dollars.

The construction schedule of plants at the various sites throughout the HNEC could affect the relative economic merit of one form of station service supply over another. Best economy in the construction of generating plants at a center is achieved when the startup of successive plants at one general site is spaced about one year apart,⁽⁷⁾ although some overlap in startups might occur in different groups. For purposes of this economic comparison the following construction schedule is assumed (Table 2).

This cost comparison includes (1) capital investment cost at the site, (2) costs of reinforcing the BPA system to support the HNEC incremental load and (3) consideration of differential operating costs.

Capital Investment at the Site

Since cash outlay must precede in-service dates for both transmission lines and plant facilities by about 3 years on the average, the series of payments would begin in 1984 and continue through 1997. A breakdown of the total investment in station service facilities for 17 units (excluding the three now committed) is shown in Table 3.

Costs of BPA System Reinforcement

Concept B has no costs in this category since any power flow from the network to station service loads is over lines and transformers required for outward flow of generated power.

TABLE 2. Plants Beginning Commercial Operation

<u>Year</u>	<u>Ashe</u>	<u>Gable Mountain</u>		<u>Hanford</u>	
		<u>Group 1</u>	<u>Group 2</u>	<u>Group 1</u>	<u>Group 2</u>
1987	1				
1988	1				
1989	1				
1990	1				
1991		1			
1992		1	1		
1993			1		
1994			1		
1995			1	1	
1996				1	
1997				1	1
1998					1
1999					1
2000					1

TABLE 3. Investment in Station Service
Facilities (millions of dollars)

	<u>Concept A</u>	<u>Concept B</u>
<u>Normal Circuit</u>		
Ashe group, 4 added units	6.2	6.2
Gable Mt group, 6 units	9.4	9.4
Hanford group, 7 units	<u>10.9</u>	<u>10.9</u>
	26.5	26.5
<u>Alternate Circuit</u>		
Ashe group	9.9	12.2
Gable Mt group	16.3	16.8
Hanford group	17.4	19.7
Spare transformer	<u>--</u>	<u>4.0</u>
TOTAL	43.6	52.7

To determine reinforcement costs for Concept A that should be attributed to HNEC loads is complicated by growth of power transfer over the 230 kV lines through the area; by temporary excess capacity in portions of the system even under the best overall solution to the problem of accommodating growth; and by the imposition of an estimated demand of 225 MW on the 230 kV system by the three plants already committed. This demand is imposed regardless of whether any additional plants are built or whether Concept A or B is used for the 17 plants to follow.

As noted in "Additions for 230 kV Supply," the system reinforcements made necessary by a 20-unit HNEC would consist of 55 to 60 miles of 230 kV line in three sections. The cost of these lines and their terminal apparatus has been estimated at \$8.0 million. Part of the line construction would be in service in 1994 and part in 1997.

These system additions would not be needed earlier, even though the three plants already committed with a possible demand of 225 MW would be in operation as early as 1984. Capacity is expected to be available in the system during that interim period without any reinforcement specifically required for an HNEC.

The full costs of the system reinforcements are charged to Concept A rather than allocated between the three plants already committed and the 17 plants that would follow in an HNEC program; the rationale is that the reinforcements are not needed during the 1985-2000 period for committed plants but would be needed for the full-scale HNEC. Since the investment requirement comes rather late in the period, it has a relatively minor effect in a comparison of discounted present worth of investment costs of the two concepts.

In an overall economic sense, the allocated costs would be added to the other capital costs of Concept A; however, in actuality the costs would be incurred by BPA rather than by HNEC owners and would be recovered by BPA through wheeling or other service charges billed to the owners. The degree to which the incremental reinforcement costs are reflected in the charges would depend on contractual or rate-making policy and practice.

Timing of the Investment Requirements

Figure 10 illustrates the effect of timing of investment requirements. In Concept B the spare transformer must be available at the beginning of the period of HNEC expansion. In Concept A the allocated investment in offsite transmission system comes late in the period for reasons discussed in the preceding section.

The discounted present worth (at the beginning of the development period) of investments in the alternate circuits over the period is given in Table 4 for discount rates of 0, 5% and 10%. The "front-end cost" effect is greater for Concept B, thus increasing Concept B's disadvantage as the discount rate increases.

FIGURE 10. Estimated Cumulative Investment in Alternate Circuit Station Service Lines and Equipment

TABLE 4. Discounted Present Worth of Alternate Circuit Investments (million dollars)

	<u>Discount Rate</u>		
	<u>0</u>	<u>5%</u>	<u>10%</u>
Concept A	51.6	37.3	28.2
Concept B	52.7	41.0	33.3
Ratio A/B	0.98	0.91	0.85

The capital investment estimates show that:

1. The total investment requirement for 17 new generating units would be approximately equal for the two concepts, but the discounted present worth of the required investment would be for 10 to 15% less for Concept A.
2. Underground cable sections at crossover points comprise about 16% of the onsite investment of Concept A, but only about 8% of that of Concept B, which tends to penalize Concept A. The routing of 230 kV lines and the placement of 230 kV switching stations so as to reduce the underground requirements would narrow the difference, but not equalize the undergrounding requirements of the two concepts.
3. The costs of Concept A at Ashe are favorable because (a) part of the system would already be in place, and (b) the assumed placement of plants is more dispersed and open, thus requiring no additional underground transmission cable.
4. The normal station service supply circuit, which is the same for both concepts, involves about half the investment required for the alternate circuits.

Operating Cost

The only significant difference in operating cost between the comparative concepts is in no-load transformer losses. In Concept A the voltage is transformed from 230 to 6.9 kV in one step; in Concept B from 500 to 69 kV,

then from 69 to 6.9 kV. The 500 kV transformer of Concept B would usually carry little or no load but would be energized. A comparison of no-load losses shows a balance of about 900 kilowatts chargeable to Concept B in a fully developed center. When the demand and energy losses are valued on the basis of cost to generate in new facilities, the penalty to Concept B would rise to \$120,000 per year in 1996. This is only about one percent of the fixed charges on capital investment in the circuits at that time and may be ignored.

OTHER CONCEPTS

In addition to Concepts A and B, other combinations of normal and alternate circuits from the offsite system were considered. After an exploratory examination they were found to be unattractive in the HNEC situation, but merit brief discussion.

1. A system whose normal and alternate circuits originate at the 500 kV bus. The economics of this concept were disadvantageous; \$25 million in additional investment would be required without compensating benefits in reliability for 17 future units.
2. A system whose normal circuit originates at the 500 kV bus, as in Concept B and alternate on the 230 kV system as in Concept A. This concept also proved economically unattractive, averaging \$25 million in additional investment without compensating benefits.
3. A concept with a separate generating station to serve as an alternate offsite source for multiple plants.⁽⁸⁾ This concept would provide maximum independence between the two offsite sources. A gas turbine was considered for the generating source since it would be carrying no load for most of the time, although it would have to be prepared to supply load within a few seconds under certain contingency conditions.

If the separate system were designed to provide the capacity being considered for the 230 kV system at Hanford, i.e., 360 MW, it could be ruled out for the following reasons.

- Transmission from the generating station would probably have to be at 230 kV, and the investment in lines, circuit breakers and transformers would be approximately the same as for the alternate BPA 230 kV system with no benefits to offset added costs.
- The fixed charges on the generating plant investment and on the standby operating costs would add about \$1 million per year per reactor plant (in 1975 dollars), with no substantial compensating benefits. In effect, the generating capacity would be a duplication. Not being tied in with the BPA system, it could not be considered for peaking service (although a tie-in would not be ruled out on the basis of safety).

If such a system were designed to provide for only the critical station loads, transmission and distribution at a lower voltage may be feasible and the concept might be more attractive in a comparison with other schemes. However, providing only such minimum coverage and flexibility would run contrary to current practice by most utilities.

4. Use of three offsite circuits instead of two. Some utilities choose to use three circuits qualifying as "offsite circuits," even though the third is not required by NRC. This concept has the advantage of providing for unrestricted plant operation in the event of a prolonged outage on one of the station service supply circuits, such as an outage involving transformer replacement. One architect engineer has a standard design using three offsite circuits, two of which are tied to the station buses served alternately by two diesel generators of the onsite system, and one tied to the third bus for

non-critical station loads. The flexibility provided by such a system may justify the cost, especially if the offsite circuits are tied to a relatively low-voltage system (69 kV).

Should the utility want a third offsite source for the HNEC situation, combinations of the concepts described above or duplications of Concepts A or B would be possible. The 230 kV system would have two parallel lines from the principal source (Midway) to the vicinity of the site areas, which possibly could be connected so as to give added security to dual 230 kV station supply circuits. However, in the HNEC situation the added value of such redundancy did not justify the added cost in the opinion of the authors.

5. One of the two offsite circuits with capacity for only safety loads. Such a system would comply with prior NRC requirements but would lack operating flexibility, and raise the question of whether an immediate forced shutdown (rather than a shutdown after 72 hours) would cost the utility enough to pay for added capacity in the alternate circuit? The scope of this study does not include investigation of this question, but modern practice runs contrary to load shedding for loss of either offsite station service circuit, and the concept was rejected for that reason.
6. The following alternative applies only where the main generator bus is bifurcated, i.e., connected to two half-capacity transformers through two circuit breakers, such as in the plant designs of the McGuire, Perkins and Cherokee Stations of the Duke Power Company. A schematic drawing of such an arrangement is shown in Appendix B. Each of the two station service (offsite) circuits is taken from one side of the forked bus. The cost of such a system would be substantially less than those of the stations studied herein having conventional bus arrangements, and its lack of exposure is excellent.

The bifurcation designs provide a sufficient degree of electrical separation between the two circuits and presumably meet NRC

requirements in that they provide for continuity of service in one circuit in the event of failure in one of the three zones and failure of one breaker to open. The number of intermediate zones is not as great as in Concept A and B for conventional bus arrangements, but since very few plant designs incorporate the bifurcated bus, further analysis of the station service possibilities was not undertaken.

RESULTS OF ANALYSIS

The principal findings of our analysis are:

- The "normal" offsite circuit chosen for both comparative concepts, i.e., a circuit tapped from the generator bus at a point that can be isolated from the generator by a load-break switch, is confirmed as a preferred source of station power from functional, safety, and economic points of view. This applies to either dispersed plants or plants concentrated at a center. Alternative methods need be considered only for the "alternate" offsite circuit.
- The problems of providing an adequate alternate station service supply to an HNEC are similar to those of supplying service to three- and four-unit aggregations at other sites, several of which are in the planning stage; the difference is in the estimation of load diversity on a common transmission system (not directly connected with the bulk power system for the stations) serving several groups of plants, as would the 230 kV transmission system of Concept A.
- The restraints on operation of the generating plant when one of the station service circuits is unavailable, plus a policy of always using the "normal" circuit when it is available, limit the use of the alternate circuit to the extent that a design diversity factor of 3.75 could apply to a group of 20 operating plants. A 360 MW capacity in the system serving the group is estimated to be sufficient for any normal or abnormal combination of station service loads.
- With Concept A the BPA 230 kV system would be reinforced to provide sufficient additional capacity for possible station service loads at HNEC. Load-flow studies indicate that the best way of reinforcing the system is to add two lines between Vantage and Hanford, and one line from Hanford to Gable Mountain. These lines would add to the visual impact on the environment. With Concept B no changes would be required in either the 500 kV or 230 kV offsite transmission system.

- Assuming they are properly designed, either of the two concepts studied in detail, Concept A drawing from the reinforced 230 kV system and B drawing from the 500 kV system at the three major switching stations at the center, could meet NRC safety requirements and the ordinary requirements of operating utilities for reliability and flexibility.
- A comparison of the two concepts revealed no significant difference between them with respect to equipment failure rates, exposure to natural hazards, effect of human error, and degree of physical and electrical separation from the circuits of the normal supply system.
- Estimated costs of the two concepts were roughly comparable. The "front-end" cost effect was more pronounced for Concept B; thus the discounted present worth of Concept A's costs was somewhat lower than that of Concept B. In both cases the differences were within the margin of accuracy of the estimates. The estimates depend to some extent on the geographical arrangement of generating units and switching stations, but are not extremely sensitive to those conditions.
- Other methods and combinations of methods of supplying station service power to a nuclear center were considered. Although most of them were acceptable from a safeguards standpoint, their value to a plant operator did not appear to justify added costs. Where a plant design has a bifurcated generator bus, station service could be drawn from each of the two buses reliably and economically.

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APPENDIX A

List of Acceptance Criteria for Electric Power

Applying to Offsite Circuits for Station Service Power

Extracted from NUREG-75/087
Standard Review Plan
USNRC, Office of Nuclear Reactor Regulation
November 24, 1976

TABLE A-1. Acceptance Criteria for Electric Power

Criteria	Title
1. 10 CFR Part to	
a. 10 CFR §50.34	Contents of Applications: Technical Information
b. 10 CFR §50.36	Technical Specifications
c. 10 CFR §50.55a	Codes and Standards
2. General Design Criteria (GDC), Appendix A to 10 CFR Part 50	
a. GDC-1	Quality Standards and Records
b. GDC-2	Design Bases for Protection Against Natural Phenomena
c. GDC-3	Fire Protection
d. GDC-4	Environmental and Missile Design Bases
e. GDC-5	Sharing of Structures, Systems, and Components
f. GDC-13	Instrumentation and Control
g. GDC-17	Electric Power Systems
h. GDC-18	Inspection and Testing of Electrical Power Systems
i. GDC-21	Protection System Reliability and Testability
j. GDC-22	Protection System Independence
3. Institute of Electrical and Electronics Engineers (IEEE) Standards:	
a. IEEE Std 279-1971 (ANSI N42.7-1972)	Criteria for Protection Systems for Nuclear Power Generating Stations
b. IEEE Std 308-1971	Criteria for Class IE Electric Systems for Nuclear Power Generating Stations

TABLE A-1. (Continued)

Criteria	Title
c. IEEE Std 352-1972 (ANSI N41.4)	General Principles for Reliability Analyses of Nuclear Power Generating Station Protection Systems
d. IEEE Std 379-1972 (ANSI N41.2)	Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems
e. IEEE Std 450-1972	Recommended Practice for Maintenance, Testing and Replacement of Large Stationary Type Power Plant and Sub- station Lead Storage Batteries
4. Regulatory Guides (RG)	
a. RG 1.6	Independence between Redundant Standby (Onsite) Power Sources and between Their Distribution Systems
b. RG 1.32	Use of IEEE Std 308-1971, "Criteria for Class IE Electric Systems for Nuclear Power Generating Stations"
c. RG 1.53	Application of the Single-Failure Criterion to Nuclear Power Plant Protection Systems
d. RG 1.75	Physical Independence of Electric Systems
e. RG 1.93	Availability of Electric Power Sources
5. Branch Technical Positions (BTP) EICSB	
a. BTP EICSB 11	Stability of Offsite Power Systems

APPENDIX B

Schematic Arrangements for Offsite Station Service Circuits of Three- and Four-Unit Nuclear Plants, from Preliminary Safety Analysis Reports for the Respective Projects.

The safety and operational requirements for station service have been met in various ways in multi-unit plants or plant groups. Nine examples of schematic arrangements currently in use or proposed are given herein.

The example schematic arrangements (Figures B.1 through B.9) indicate two basic differences in design of offsite station service systems:

- (1) The point at which the circuits from the offsite power system tie in with the network, and
- (2) The number of generating units sharing the same buses, lines, or transformers serving station loads.

Options for point of connection with the network (tie-in point) include:

- (1) The generator output circuit (24 kV) with a generator load break switch as for the Hanford 1 and 4 and Hartsville designs.
- (2) The same 230 or 500 kV bus to which the generator is connected (e.g., designs for North Anna, Palo Verde, generator No. 1 at Alan Barton, and generator No. 1 at Shearon Harris).
- (3) A separate station generator bus in the same switchyard, but at lower voltage (e.g., three generators at Alan Barton and two at Shearon Harris).
- (4) Switching stations or lines in the vicinity, usually at voltage less than that of the bulk transmission system into which the generator feeds. The switching stations may either not be interconnected at the generator switching station or may be interconnected through an autotransformer (e.g., Hanford 1, 2, and 4, Hartsville, Alvin Vogtle, three generators at Alan Barton, and two at Shearon Harris).

The degree to which the various components of the circuits from the offsite power system are shared by other generating units is indicated in Table B-1. In this respect the most conservative design is that of Hartsville; that is, it has three circuits to the network. Otherwise, the

only conclusion to be drawn from the table is that it is common to have four generator units share station service supply circuits. The switching arrangements of current designs have differing degrees of flexibility. The amount of capital that a utility can afford to invest in added station service flexibility depends on the flexibility and reserve capacity already in the system to which the new generating unit is being attached.

We assumed that capacity in all alternate offsite circuits in these examples, except for the 115 kV circuit of Hanford 2, is sufficient for all possible connected loads.

The schematic drawings do not show the differing geographical distances between points at which the normal and alternate sources join the bulk power network. Some circuits tie in at the station switchyard, others at points up to 50 miles from the site.

FIGURE B.1. Hanford No. 2

FIGURE B.2. Hanford No. 1 and 4.

FIGURE B.3. Hartzville - 4 Units

FIGURE B.4. Alvin Vogtle - 4 Units

FIGURE B.5. North Anna - 4 Units

FIGURE B.6. Palo Verde - 3 Units

FIGURE B.7. Alan Barton

FIGURE B.8. Shearon Harris

FIGURE B.9. McGuire (a 2-unit plant)

TABLE B.1. Number of Generating Units Sharing Station Service Circuits and Equipment

Current Designs	Units	Entry to Network through Common High Voltage Switchyard	Entry to Network through Common Low Voltage Switchyard	One Circuit from Tie Point	Two Circuits from Tie Point	Three Circuits from Tie Point	Two Intermediate Transformers	Station Service Transformers
Hanford	5	4	5	1	5 on loop	--	--	1
Hartsville	4	2	2	--	2	--	--	1
Alvin Vogtle	4	--	4	--	4	--	--	1
North Anna	4	4	--	--	4	--	4	1
Palo Verde	3	3	--	--	--	3	--	3
Alan Barton	4	--	4	--	4	--	--	1
Shearon Harris	4	--	4	--	4	--	--	1

APPENDIX C

The load-flow diagrams of Appendix C contain the results of studies of methods of reinforcing the BPA 230 kV system in the vicinity of the Hanford reservation in order to provide sufficient capacity for the station service loads of 20 nuclear generating units.

FIGURE C.3. Hanford Area 230 kV System with 180 MW Load at Hanford, Gable Mt., and Ashe. McNary-John Day 500 kV Connection.

FIGURE C.4. Hanford Area 230 kV System with 180 MW Load at Hanford, Gable Mt., and Ashe.

FIGURE C.5. Hanford Area 230 kV System with 360 MW Load at Gable Mt.

FIGURE C.6. Hanford Area 230 kV System with 360 MW Load at Hanford. Scootenay reinforced, 115-kV system sectionalized.

APPENDIX D

Typical Configurations of Groups of Generating Plants

Assuming the base conditions stated in the "HNEC Base Conditions" section, the general layout of plants and lines in the southern (Ashe), central (Gable Mountain), and northern (Hanford) groups of units would be as illustrated in Figures D.1 through D.3. These figures show only the reactor-generator plant buildings, lines and switching stations, and exclude cooling towers and other plant ancillary structures and facilities. The 230 kV line taps and extensions would be added only if the 230 kV system were selected for station service.

Figures D.4 through D.6 show, to a larger scale than Figures D.1 through D.3, the orientation and spacing of the generators, transformer bays, and the switchyard for the multiple-unit groups of: (1) WPPSS plants near the Ashe switching station, (2) Alan Barton four-unit stations used as an example for one group near the Gable Mountain switching station and one near the Hanford switching station, and (3) Palo Verde three-unit stations used as an example for one group near the Hanford switching station. The orientation and spacing illustrate the relative problem of getting station service circuits into the transformer bays, the amount of underground cable that may be required, and the line spacing. Examination of these different designs reveals the measures that must be taken to provide station service.

FIGURE D.1. Map of Facilities in Vicinity of Ashe Switching Station

FIGURE D.2. Map of Facilities in Vicinity of Gable Mountain Switching Station

FIGURE D.3. Map of Facilities in Vicinity of Hanford Switching Station

FIGURE D.4. Orientation of Principal Structures
Planned for Hanford Plants

FIGURE D.5. Orientation of Principal Structures for Alan Barton Design

FIGURE D.6. Orientation of Principal Structures
for the Palo Verde Plant

IMPACT OF A HANFORD NUCLEAR ENERGY CENTER
ON GROUND LEVEL FOG AND HUMIDITY

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IMPACT OF A HANFORD NUCLEAR ENERGY CENTER ON GROUND LEVEL FOG AND HUMIDITY

INTRODUCTION

Battelle, Pacific Northwest Laboratory is currently involved in the evaluation of the nuclear energy center concept as it might be applied to development of the Energy Research and Development Administration's Hanford Reservation. In that study a number of subjects have been examined in detail and the results presented in technical reports⁽¹⁻⁴⁾; the over-all results have been summarized in an interim report⁽⁵⁾. During the past year the examination of various heat sink management options has continued in greater depth. The results of this work are contained in Selection of Heat Disposal Methods for a Hanford Nuclear Energy Center⁽⁶⁾. This document presents the details of a study of the atmospheric impacts of an Hanford Nuclear Energy Center (HNEC) that might result from the use of evaporative cooling alternatives. Specific cooling systems considered include once-through river cooling, cooling ponds, cooling towers, helper cooling ponds and towers and hybrid wet/dry cooling towers. The specific impacts evaluated are increases in fog and relative humidity.

The energy center concept generally involves the grouping of 10 to 40 power plants on a common site. The center may contain supporting fuel cycle facilities, however the major heat releases and atmospheric effects are expected to be associated directly with power generation. A summary of the postulated atmospheric effects of heat rejection from nuclear energy centers is presented in Reference 7. These effects have been postulated on the basis of theory, models, analogy and speculation. Unfortunately some of the more spectacular

effects are primarily the result of the last two processes. While a complete listing is not particularly important here, typical effects include: increases in humidity, cloudiness and fog, enhancement of precipitation and modification of precipitation patterns, triggering of severe weather such as thunderstorms, and the concentration of vorticity resulting in the formation of large dust devils.

The specific atmospheric effects which might be associated with a particular energy center are generally related to the form of heat rejection, the flux density and area of heat rejection, and the climate of the energy center site. For example fog and humidity increases are associated with low level wet cooling systems, while more spectacular effects such as concentration of vorticity are postulated for closely spaced cooling systems with a high energy flux.

The conceptual center being evaluated for Hanford (HNEC), which is located in South-central Washington State is shown in Figure 1, consists of 20 to 40 power plants with associated switching and transmission facilities, a fuel fabrication plant, two fuel reprocessing plants and a waste storage facility⁽⁵⁾. Each of the reactors is assumed to be rated at 1250 MW_e, so that total heat rejection from a 40 reactor energy center is approximately 10⁵ MW. Specific locations for the individual power plants have not been established, however it has been assumed that they will be grouped in clusters of 4 with each cluster covering approximately 1 sq. mi. Preliminary site evaluation indicates that the total area covered by the energy center will be between 100 and 300 sq. mi. with the larger value representing the full 40 reactor case. These values are in contrast to the 75 sq. mi. assumed for 40 reactor nuclear energy centers in the NECSS study.

FIGURE 1. The Hanford Reservation Location

A preliminary study of heat sink management for the HNEC⁽⁴⁾ has indicated that, from an engineering standpoint, a variety of cooling systems are potentially suitable for handling the heat dissipation. These systems range from once through cooling to dry cooling towers and include several hybrid systems. The selection of the cooling system mix to be assumed in evaluation of the HNEC concept has been a matter of some concern along with selection of specific locations for the clusters. An attempt has been made to resolve both issues through the development of a comprehensive heat sink management plan that would result in the most favorable balance between resource utilization, economics and environmental impact. In this effort it has been necessary to evaluate the effects of heat dissipation so that their significance could be rationally assessed.

Rational evaluation of the significance of any effect of heat rejection requires that the extent and timing of the effect be estimated quantitatively, and that significance be defined in meaningful terms. Each of the effects postulated in the NECSS report⁽⁷⁾ has been considered in a cursory manner to screen out improbable impacts and those which can not be adequately evaluated at this time.

Concentration of vorticity has been related to high density of the rejected heat and relatively large areas. This was a major concern for the energy centers considered in the NECSS where the flux density was about $.5 \text{ KW/M}^2$. The flux density for the HNEC would be between $.1$ and $.3 \text{ KW/M}^2$. There are no simple methods for quantifying the frequency, magnitude or effect of vortices which might be generated. As a result, detailed consideration of vorticity concentration has been postponed until better tools are developed.

The status with respect to modification of precipitation patterns and the triggering of storms is somewhat better. Theory and numerical models exist which can provide insight into these postulated effects. Several investigators are currently pursuing this avenue of research. When suitable results are achieved they will be applied to HNEC, although recently publicized problems in the National Hail Research Experiment⁽⁸⁾ raise questions about the reliability of quantitative estimates in this area.

The only atmospheric effects that are most amenable to treatment at this time are those associated with the addition of moisture to atmosphere. Even in this case the treatment is semi-quantitative at best. The effects of cooling systems on fog and humidity are the atmospheric impacts of heat rejection that have been used in selection of a overall HNEC heat sink management plan.

At the outset of the evaluation it was assumed that the addition of heat and moisture were not, in themselves, significant. Similarly it was assumed that a postulated small change in any naturally occurring atmospheric phenomenon would not be significant. Rather, significance must be achieved by meeting some specific criteria. Four possible areas for criteria have been identified. These include: a statistically significant change in a meteorological variable, substantial adverse economic impact of a postulated change, initiation of an ecological change, and adverse public reaction. The criteria other than that of statistical significance are still not satisfactorily defined, but the general areas provide guidance on the detail required in specification of a postulated impact.

ATMOSPHERIC MODEL

The introductory remarks above contain the seeds of the atmospheric modeling requirements for input to selection of an optimum heat sink management scheme. The number of combinations of reactor locations and cooling systems, plus the need to evaluate each combination under a variety of meteorological conditions indicate that a flexible, inexpensive model be used in the evaluation. Further the need to differentiate between the atmospheric impacts of various cooling system mixes indicates that the model should be as realistic and as sensitive to differences between cooling systems as possible.

With these requirements as a background, BATMAN a Battelle Atmospheric Management computer code was developed. Specifically the code was designed to assist in the selection of viable heat sink management options for the HNEC by providing estimates of the impact of evaporative cooling systems. To accomplish this objective, the code is capable of computing the diffusion of moisture released in the cooling of 1 to 20 arbitrarily placed reactor clusters. The number of reactors in each cluster is limited only in the sense that all reactors in the cluster must utilize the same type cooling system. A mixture of cooling systems within a cluster can be simulated by superpositioning 2 or more clusters with different systems. In reality, BATMAN is a computer code that provides "back of the envelope", computations for up to 20 simultaneous energy releases and 144 receptor locations.

The economy and flexibility needed to examine the many possible HNEC scenarios are incorporated in BATMAN through the use of climatological data input and a modified sector-averaged Gaussian plume diffusion model. Reactor cluster locations and cooling system emission characteristics are input at the time of program execution. The cluster locations

are identified with respect to a receptor grid; it is not necessary that they be on the grid. The receptor grid is a 12x12 matrix of surface points for which increases in water vapor density are computed. This increase may be computed at several levels above the surface for each grid point, if desired. The spacing between grid points may be adjusted with the north-south spacing independent of the east-west spacing.

Currently BATMAN can be run in two modes. In the first mode a specific scenario is examined (i.e., a fixed set of reactor clusters, a specified wind direction and speed, and a single atmospheric stability). BATMAN then provides estimates of increased density of atmospheric water vapor. An estimate of the frequency of occurrence of the scenario can be made if sufficient climatological information is available. The second mode uses climatological input in the form of a joint frequency distribution of occurrence of wind speed, wind direction and atmospheric stability. The number of hours per year that increases in vapor density can be expected to fall within selected ranges is estimated. If additional climatological data on the frequency of occurrence of saturation deficits (in terms of vapor density) are available, BATMAN can produce direct estimates of the increase in hours of fog at each receptor location.

Economy of operation of BATMAN is enhanced by computing diffusion estimates only if a receptor is in the plume from a given cluster. After all receptor locations are considered for one cluster the process is repeated for successive clusters until all have been treated. The change in water vapor density at each receptor location is the sum of the contributions from all clusters.

In the following sections the details and features of BATMAN are described. The computer code and a short users guide are presented in Appendix A at the end of this document.

Main Program BATMAN

BATMAN performs the typical function of a main program. It controls the flow of information by handling input and output, and by calling subroutines which perform most of the actual computations. In addition to these functions BATMAN computes the source term for each reactor cluster, determines the appropriate virtual source as a function of wind direction, and combines the results of the individual cluster impacts to estimate the impact of the energy center.

The moisture source term is determined from input data on number of reactors in a cluster, rates electrical power output and cooling system type. Additional inputs required in the source term evaluation are overall thermal efficiency of the power plant and the fraction of the waste heat which is rejected in the latent form. The remaining waste heat is assumed to be sensible (increased temperature). Radiative heat transfer is neglected. The total latent heat release is then used to compute a rate of evaporation. The thermal efficiencies and latent heat fraction are functions of cooling system type and atmospheric conditions. The relationships between efficiency and atmospheric conditions are summarily treated by use of seasonal or annual values. More detailed treatment of these relationships is not warranted because of the nature of the basic model.

The fundamental climatological data input to BATMAN consists of information on wind direction, wind speed, atmospheric stability, temperature, plume width and mixing depths. With these data and a moisture source term the model can compute

increases in water vapor density and the frequency of occurrence of increases within specified ranges. If the model is to convert the water vapor increase to frequency of occurrence of fog, additional climatological input is required. This information includes the number of hours being considered and the distribution of water vapor saturation deficits.

Wind direction must be specified in terms of sectors starting with sector 1 as the first sector east of north and increasing in a clockwise direction. The number of sectors is limited only by dimensions of the program. Currently the program is set for 16 sectors. Calm and variable winds should be distributed among the sectors. The distribution of these winds in proportion to the frequency of occurrence of directions during the remainder of the time should be conservative.

As with wind direction, the number of wind speed categories is limited by the program dimensions. The limitation is on the product of wind speed and direction classes and is currently set at 96. Thus, with 16 wind direction sectors, the number of wind speed classes is limited to 6.

The limitation on the product can easily be increased to accommodate more wind direction and/or speed classes. However, an increase in the number of classes rapidly increases computer storage requirements. For instance, increasing the number of direction classes to 36 and speed classes to 10 would increase storage requirements by almost 3200 words.

BATMAN will accept atmospheric stability data in the 4 category Hanford stability classification scheme or in either the 6 or 7 category Pasquill-Gifford scheme⁽⁹⁾. The stability classification scheme is specified by indicating the number of categories, with categories numbered in order of increasing stability.

A temperature input is required for plume rise computations if cooling towers are specified in the source description. The model is not particularly sensitive to the temperature input, therefore, a seasonal or annual average is adequate.

The diffusion model is used in a sector-averaged model, thus it is necessary to define the width of the sector occupied by the plume. There are no mathematical restrictions on the width of this sector, however, common sense would indicate that it should be at least as wide as the wind direction sectors.

The final climatological input required in all modes of operation for BATMAN is the specification of a mixing depth. The mixing depth is the upper limit to the vertical spread of the moisture plumes. As moisture reaches this level, it is reflected. If the mixing level is specified as zero, vertical diffusion of the plumes is unbounded.

Additional climatological data on the water vapor saturation deficit must be provided if the frequency of occurrence of fog is to be computed. This information is the expected number of hours of saturation deficit within ranges which may be specified. The model is currently limited to 10 ranges, but again that limit can be increased if necessary.

Finally, it is necessary to specify several physical parameters in addition to the source term, and climatology. These parameters include the grid spacing; the number of levels of interest and their heights; the type cooling systems, their dimensions and release heights, and a critical wind speed if cooling towers are specified. The critical wind speed is used in conjunction with ambient wind speed to determine when plume rise should be limited by downwash and when building wake effects should be considered.

The number of levels which can be considered is limited to a maximum of 10, but is also limited by the number of saturation deficit classes. The product of saturation deficit classes and levels must be less than 20. The grid spacing is restricted only by the cooling system dimensions. The model is not meant for a fine scale examination of effects near the sources. Thus the grid spacing should be larger than the characteristic horizontal dimensions of the cooling system. North-south and east-west grid spacings need not be the same.

Subroutine PRISE

Subroutine PRISE computes the plume rise for cooling tower releases. Prior to calling PRISE, BATMAN checks the wind speed. If the wind speed is equal to or greater than the critical speed, the plume rise is assumed to be zero and the effective release height is set equal to the actual release height. Otherwise, PRISE is called and the plume rise is computed. Following the plume rise computation the effective release height is determined. If it is above the mixing layer and the actual release height is below the lid, plume rise is reduced to make the effective release height equal to the top of the mixing layer.

Computation of plume rise is based on Briggs' formulae for final plume rise⁽¹⁰⁾. In these formulae, plume rise is a function of the sensible heat flux, the wind speed, atmospheric stability, atmospheric temperature and actual release height. The formulae do not account for latent heat flux, which in cooling towers may be several times the sensible heat flux. As a cooling tower plume condenses this latent heat contributes to additional plume rise. Therefore, provision has been made for inclusion of a latent heat correction factor.

In these formulae it is not appropriate to allow the wind speed to approach zero too closely. Thus, for wind speeds less than 1 m/s, the following assumptions were made: for stable atmospheric conditions the calm formulation was used, and for neutral and unstable conditions the wind speed was assumed to be 0.5 m/s.

The use of final plume rise formulae reduced the number of required plume use computations and is generally justifiable because of coarse grid spacing. Had plume rise been treated as a function of distance from the source the number of plume rise computations would have been several times as large.

Subroutine RCPTOR

The function of subroutine RCPTOR is to determine whether a receptor is within the plume from a cluster or not, and if it is to determine the distance from the virtual point source to the receptor.

The problem solved by RCPTOR is shown schematically in Figure 2. Position A is the location of the cooling system which is specified in the cooling system description along with a typical horizontal dimension for the system. Position B is the virtual point source. It is computed from the cooling system width, the angular width of the plume and the wind direction. The distance between A and B is constant once the source and plume widths are specified. Position C is a known point in the grid. Thus the positions of three vertices of a triangle are known.

From this information the remaining sides of the triangle, the distances between the actual and virtual sources and the receptor, can be computed. If the distance between the virtual source and the receptor is less than either of the other sides of the triangle, the receptor is not in the plume

FIGURE 2. Plume Source and Receptor Geometry

and RCPTOR returns to the main program to start consideration of the next receptor. If this virtual distance is the longest side of the triangle, the angle at B, labeled ϕ_1 is compared with $1/2$ the plume angular width, ϕ_0 . When ϕ_1 is less than or equal to ϕ_0 , RCPTOR initiates the diffusion computation. Otherwise the return from RCPTOR initiates consideration of the next receptor.

Subroutine SIGMAZ

The first step in the diffusion computation is the computation of the vertical dispersion parameter σ_z . Under normal conditions σ_z is a function of atmospheric stability and distance from the source. In BATMAN the distance between the receptor and virtual point source is used. When wind speeds are above the critical wind speed and low-level mechanical draft cooling towers are used, the value of σ_z is corrected for wake effects.

The basic formulations used for the relationships between stability, distance and σ_z are those suggested by Briggs⁽¹¹⁾. A seventh relationship has been added to treat the Pasquill-Gifford G stability class. The relationships are given in Table 1 and shown in Figure 3. Table 1 also serves to show the relationship between the Pasquill-Gifford and Hanford stability classes. The existence of the G stability class is in doubt and is currently an issue receiving attention.

Plumes from low-level, mechanical draft cooling towers are assumed to downwash and enter the wake behind the tower when the wind speed exceeds the critical speed. In these cases, the plume undergoes a rapid initial vertical dispersion due to the cooling tower wake. This effect is accounted for in subroutine SIGMAZ.

FIGURE 3. Sigma Z Curves

TABLE 1. Relationships Between σ_z , Atmospheric Stability and Distance Between the Receptor and Virtual Point Source

	<u>Stability Class</u>		<u>σ_z</u>
	<u>Pasquill-Gifford</u>	<u>Hanford</u>	
A			.20x
B		Unstable	.12x
C			.08x/(1+.0002x) ^{1/2}
D		Neutral	.06x/(1+.0015x) ^{1/2}
E		Slightly stable	.03x/(1+.0003x)
F		Moderately stable	.02x/(1+.0003x)
G			.012x/(1+.0003x)

A corrected estimate of σ_z is computed using the relationship

$$\sigma_{zc}^2 = \sigma_{zi}^2 + H^2/2\pi \quad (1)$$

where σ_{zc} is the corrected value, σ_{zi} is the initial uncorrected value and H is the height of the cooling tower. In cases where the source is a cluster of cooling towers with a large width, the net effect of this correction is generally small.

Subroutine DIFFUSE

The last subroutine used by BATMAN is DIFFUSE. It calls SIGMAZ and then uses the result to compute the water vapor density increase at the receptor. DIFFUSE is by far the longest and most complex subroutine.

The diffusion computations in DIFFUSE use a sector-averaged Gaussian plume model with complete reflection at the ground and an optional reflecting lid. The basic sector-

averaged model is described in Section 3.3 of Meteorology and Atomic Energy - 1968⁽⁹⁾ while the treatment of the reflecting lid is based upon Section 6.6 of Csanady's Turbulent Diffusion in the Environment⁽¹²⁾.

The model that was derived from these sources is:

$$(\Delta\rho_v)_{ki} = \frac{Q_i \hat{n}}{(2\pi)^{3/2} \sigma_z \bar{u} x} \sum_{j=-\infty}^{\infty} \left\{ \exp\left[\frac{(z-h_i+2jH)^2}{-2\sigma_z^2}\right] + \exp\left[\frac{(z+h_i+2jH)^2}{-2\sigma_z^2}\right] \right\} \quad (2)$$

where: $(\Delta\rho_v)_{ki}$ is the increase in water vapor density at receptor k due to source i,

Q_i is the water vapor release rate of source i,

$\hat{n}$ is related to the assumed plume width, ϕ_0 , by $\hat{n} = \pi/\phi_0$ when ϕ_0 is in radius,

ϕ_z is the vertical dispersion parameter,

$\bar{u}$ is the wind speed,

x is the distance between the receptor and virtual point source,

z is the height above the ground,

h_i is the effective release height for source i, and

H is the height of the reflecting lid.

Equation 2 can be simplified if any or all of z , h_i and H are zero. The greatest simplification occurs if H is zero. In that case the infinite sum is eliminated. If either h_i is zero the two exponential terms can be combined. If $z=0$ the infinite sum is twice the sum from 0 to ∞ . Finally, if all three are zero, the infinite sum and the exponential terms are eliminated.

DIFFUSE computes the relative water vapor increase $(\Delta\rho_v)_{ki}/Q_i$ by first calculating

$$\frac{\hat{n}}{(2\pi)^{3/2} \sigma_z \bar{u}_x}$$

and the denominator in the exponential terms. It then determines what simplifications can be made in the infinite sum. If there is no lid, the infinite sum reduces to the sum of the two exponential terms with $j=0$ and a check is made to see if the exponential terms may be combined or eliminated. In all cases where $H=0$ the computations are straight forward.

If the model cannot be simplified because $H=0$, DIFFUSE checks the ratio of H/σ_z . In the limit of σ_z becomes large, the vertical profile of the water vapor increase becomes a uniform distribution, and (2) reduces to

$$\frac{(\Delta\rho_v)_{ki}}{Q_i} = \frac{\hat{n}}{2\pi H \bar{u}_x} \quad . \quad (3)$$

A uniform distribution can be assumed with an error of less than 0.25% if the ratio H/σ_z is less than 1.5.

When a uniform concentration cannot be assumed with this accuracy, the summation is carried out between $j=-2$ and $j=+2$. In this process, all reflection terms that are less than 0.25% of the value of the term when $j=0$ are neglected. The terms to be neglected can be identified by examination of ratios between z , h_i , H and σ_z .

Finally DIFFUSE computes $(\Delta\rho_v)_{ki}$ according to

$$(\Delta\rho_v)_{ki} = Q_i \left[\frac{(\Delta\rho_v)_{ki}}{Q_i} \right] \quad (4)$$

The combination of the increases in water vapor density from all of the sources to estimate the total increase is accomplished in BATMAN. The next section describes this process and the treatment of the computational results.

Model Output

BATMAN has the flexibility to examine increases in water vapor content for both special cases and on a climatological basis. This section describes the output for both operational modes and discusses the interpretation of the output.

In both modes BATMAN computes the total increase in water vapor density at each grid point assuming that the contributions of the individual plumes are additive. Thus, the total increase is given by

$$(\Delta\rho_v)_k = \sum_{i=1}^N (\Delta\rho_v)_{ki} \quad (5)$$

where N is the number of sources (clusters).

If the effects of a single set of atmospheric conditions (wind speed, direction, stability and mixing depth) are being examined, this information can be obtained. Figure 4 shows a sample of the output of $\Delta\rho_v$ for the case of WNW winds at 6.93 m/s during moderately stable atmospheric conditions for a single 4 reactor cluster with mechanical draft cooling towers located at grid position 6.1, 7.5. These atmospheric conditions occur approximately 3.45% of the time. Figure 5 shows the impact of 20 reactors divided among 5 clusters under the

INCREASE IN MOISTURE (G/HOUR) AT Z				Z, METERS								
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
 
0.00	0.00											

FIGURE 4. Sample Computer Output of Increased Water Vapor Density
(1 Cluster)

INCREASE IN MOISTURE (G/M ³) AT Z = 0. METERS											
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	2.11	.63	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	2.17	1.44	.54	.44	.37	.17
0.00	0.00	0.00	0.00	0.00	0.00	0.00	.92	1.45	1.10	.60	.51
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	.59	1.20	1.13	.34
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	.52	.38
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	.71
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

THIS CONDITION OCCURS AN AVERAGE OF 302.6 HOURS PER YEAR

FIGURE 5. Sample Computer Output of Increased Water Vapor Density (5 Clusters)

the same climatic conditions. The grid locations for the 4 additional clusters in Figure 5 were at 5.5, 7.2; 4.7, 6.7; 3.7, 5.4 and 3.7, 4.9. Mechanical draft cooling systems were assumed for all clusters.

If a climatological output is desired, BATMAN can compute the number of hours of water vapor density increase within each specified range. In this case the number of hours of increase is computed as

$$H_o(\Delta\rho_v \geq a)_k = \sum_n \sum_u \sum_s \left[8766 P(n,u,s|\Delta\rho_v \geq a)_k \right] \quad (6)$$

where $H_o(\Delta\rho_v \geq a)_k$ is the number of hours that the water vapor density increase is greater than a at receptor k ; the summations are over wind direction, speed and atmospheric stability; 8766 is the average number of hours per year; and $P(n,u,s|\Delta\rho_v \geq a)_k$ is the joint frequency of occurrence of wind direction, speed and atmospheric stability that result in a water vapor density increase greater than a at receptor k . As many as 10 values for a can be used in any single simulation. A sample of the output is given in Figure 6 using the same 5 clusters used for Figure 5. This output is of value in determining the effects of moisture releases on relative humidity and wet-bulb temperature, but further computations are required to estimate the effect on fog.

If the impact of moisture releases on fog is to be estimated additional climatological information is required. That information describes the probability distribution of atmospheric water vapor saturation deficits, (i.e., the difference between the density of water vapor when air would be saturated and the actual vapor density). The increased number of hours of atmospheric saturation is given by

NUMBER OF HOURS THAT THE INCREASE IN MOISTURE AT Z =											0. METERS EQUALED OR EXCEEDED	1.00 g/m ³
140.3	92.9	92.9	118.3	75.4	96.4	44.7	8.8	41.2	33.3	40.3	40.3	
88.4	129.4	94.7	98.2	110.5	98.2	85.0	105.2	12.3	20.2	46.5	46.5	
68.4	70.1	127.1	127.1	250.7	323.5	221.8	93.8	63.1	4.4	43.8	75.4	
115.7	119.7	130.6	94.7	1297.4	1830.3	434.8	305.1	63.1	296.3	62.2	51.7	
90.0	106.9	7.0	28.1	64.9	159.5	2126.6	1050.2	221.8	270.9	241.9	210.4	
180.8	50.0	13.1	15.8	34.2	120.1	600.5	1782.1	923.1	823.1	84.2	84.8	
180.8	92.9	50.8	.9	48.5	35.0	110.5	848.8	909.0	965.1	641.7	335.7	
180.8	180.8	.9	.9	14.9	17.5	43.8	171.8	760.0	638.2	424.3	935.7	
180.8	145.5	102.6	107.8	.9	150.8	149.9	170.1	220.9	638.2	394.5	394.5	
57.9	102.6	102.6	102.6	129.6	65.7	149.9	150.8	149.0	181.5	394.5	394.5	
102.6	102.6	102.6	108.7	109.7	109.6	126.2	143.8	149.0	142.9	394.5	323.9	
57.9	102.6	45.6	108.7	108.7	109.6	64.9	64.9	149.0	149.0	78.9	102.6	

FIGURE 6. Sample Computer Output of Increased Hours of Water Vapor Density Exceeding a Fixed Value (1 g/m³)

$$(H_f)_k = \sum_{m=1}^M \left\{ H_o(\Delta\rho_v \geq a_m)_k P(a_{m-1} \leq d < a_m) \right\} \quad (7)$$

where $(H_f)_k$ is the increase in hours of saturation at k , M is the number of density increase categories and $P(a_{m-1} \leq d < a_m)$ is the probability that the saturation deficit is between a_{m-1} and a_m . Figure 7 shows a sample of the computer output of this information for the same 5 clusters used for previous figures. In this case the increased number of hours of saturation have been interpreted as an increased number of hours of fog.

Output Interpretation

Prior to closing the discussion of the atmospheric model and the model output, some discussion of interpretation of the model output is appropriate. The first two forms of model output describe the increase in moisture content in terms of grams of water vapor per cubic meter of air. This can be related to other measures of humidity such as relative humidity and wet bulb temperature.

The relationship between increase in water vapor density and increase in relative humidity is a function of the temperature of the air. This relationship is shown in Figure 8, where the increase in relative humidity for a 1 g/m^3 increase in water vapor density is given as a function of temperature. Two striking features are evident in the Figure. The first is that at low temperatures a small increase in vapor density will cause a large increase in relative humidity, and the second is that at high temperatures small increases in water vapor have little effect on relative humidity. These features indicate that the greatest direct impacts of moisture releases should occur in the winter and in cool or cold climates.

INCREASE IN NUMBER OF HOURS OF FOG AT 0. METERS											
35.4	30.5	29.1	34.6	21.1	26.2	15.6	20.8	19.1	20.4	31.9	22.7
19.3	34.3	34.8	41.1	39.0	32.9	29.9	36.7	28.7	25.7	32.0	34.0
24.7	25.9	30.3	30.5	50.8	84.3	56.4	55.4	52.2	35.0	45.9	53.3
27.0	27.2	23.2	19.0	355.2	454.4	155.1	78.8	61.8	72.9	54.3	46.8
20.5	27.1	14.6	21.0	29.9	88.1	609.1	262.3	128.0	103.4	92.7	67.3
21.6	22.5	13.8	14.7	28.2	33.8	171.2	504.2	214.5	179.6	96.9	88.9
27.6	23.9	11.7	12.3	29.7	33.9	62.6	209.7	258.6	227.7	137.1	111.0
29.3	33.7	11.5	15.2	17.9	22.6	28.7	53.4	191.6	150.0	165.5	117.1
25.3	34.1	35.2	27.9	19.7	39.1	45.6	53.7	89.5	150.4	117.9	120.6
21.8	26.1	30.0	40.7	31.9	28.9	35.1	53.0	62.3	90.5	119.8	111.2
20.9	20.9	26.6	31.4	26.6	31.1	35.5	49.7	44.1	49.8	118.3	93.4
14.8	17.8	21.5	23.9	26.0	34.2	31.5	31.5	42.0	36.7	44.9	76.1

FIGURE 7. Sample Computer Output for Predicted Increase in Hours of Saturation (Fog)

FIGURE 8. Relationship Between Relative Humidity Increase and Temperature for an Increase in Water Vapor Density of $1 g/m^3$

Wet-bulb temperature is of interest in the evaluation of the performance of evaporative cooling systems. The performance of these systems decreased as the wet-bulb temperature increases. Addition of moisture raises the atmospheric wet-bulb temperature. The rate of increase is a slowly varying function of temperature, however, in the normal range of atmospheric temperatures it is approximately 1 C° for each gram per cubic meter of moisture increase.

The interpretation of increased hours of saturation was briefly discussed earlier. This interpretation requires some clarification. If the probability in (7) is the probability of saturation deficit during periods without fog then the result is properly interpreted as an increase in the number of hours of fog. But, if the probability covers all hours including those with fog, the output should be interpreted as total hours of fog.

It should also be noted that this interpretation assumes that saturation of the atmosphere is synonymous with fog, when in fact it is not. Fog is defined as a restriction to visibility which is associated with high humidities and water droplets. Fog frequently forms and persists at humidities slightly below saturation and the atmosphere may be very near or at saturation without the formation of fog. Thus, the modeling definition of fog as saturation of the atmosphere is only approximately correct.

THE HNEC MODEL

The evaluation of impacts of moisture releases for an HNEC required that release characteristics be assumed for a variety of potential HNEC configurations. An initial configuration was suggested in Reference 5. However other configurations were considered to estimate effects of changes in the configuration

on the total impact of the moisture release. This section describes the spatial and cooling system configurations evaluated.

In all cases, the HNEC was assumed to consist of discrete clusters with 4 reactors rated at 1250 MW_e in each cluster. In addition, all reactors within a cluster were assumed to use the same type cooling system.

Cluster Locations

During the course of the modeling program, reactor clusters were located at 14 different sites within the Hanford Reservation. Figure 9 depicts the Hanford Reservation (enclosed by dashed lines) and cluster locations within the BATMAN grid system. Exact locations of the clusters are given in Table 2. The Figure also shows the major roads and population centers in the area. The climatological data used for the model simulations were obtained at the Hanford Meteorology Station. The grid system, itself, is oriented North-South with 8 km (5 mi) spacing.

Major topographic features not shown in Figure 9 include Rattlesnake Mountain, the Saddle Mountains and the Horse Heaven Hills. Rattlesnake Mountain runs along the southwest boundary of the Hanford Reservation and effectively blocks the movement of air from Hanford toward the area of Sunnyside, Grandview and Prosser. The Horse Heaven Hills lie to the south of Highway 12 and tend to force air to the southeast to follow the Columbia River. Finally, to the north of the Reservation the Saddle Mountains tend to force airflow from the south through the Columbia River gap near Beverly or deflect it toward the east. These airflow perturbations are not fully reflected in the climatology and cannot be treated by BATMAN.

FIGURE 9. The HNEC Cluster Locations in the BATMAN Grid System

Table 2. Positions of the 4 Reactor Clusters
for the HNEC Simulations

<u>Cluster</u>	<u>North-South Coordinate</u>	<u>East-West Coordinate</u>
1	6.10	7.50
2	5.50	7.20
3	4.70	6.70
4	3.70	5.40
5	3.70	4.90
6	4.20	4.20
7	3.30	4.00
8	2.90	4.80
9	2.60	4.40
10	3.10	4.50
11	6.10	5.90
12	2.60	6.30
13	2.70	5.80
14	2.50	7.00

Cooling System Models

The original problem which led to this modeling effort was one of heat sink management. Evaluation of cooling system types and locations are included within that problem. As a result a set of rudimentary cooling system models has been included in BATMAN. The cooling system models are not detailed and do not consider many of the physical processes that take place within cooling systems. Rather, the cooling system models provide a means to vary moisture release rates, release heights and horizontal scales. Seven different cooling systems have been simulated, however, there are only three different models. The basic models and their variation are described in this section.

The primary cooling system model in BATMAN is the low-level, mechanical draft cooling tower. This model assumes that the overall efficiency of the energy conversion is 33% and that 80% of the energy rejected will be released as latent heat of vaporization. With these assumptions a moisture source term is computed. The release height of mechanical draft cooling towers is assumed to be 25 m, further a characteristic horizontal dimension for the combined cooling systems in a cluster is assumed to be 1609 m (1 mi). In essence, the plumes from the individual cooling systems within a cluster are assumed to merge immediately.

The mechanical draft cooling tower model is altered to simulate a helper cooling tower on a once through cooling system by reducing the latent heat fraction from .80 to .60. Similarly, to simulate a hybrid, wet/dry cooling tower, the final moisture source term is multiplied by the wet cooling fraction. A tall natural draft cooling tower cluster is simulated by increasing the release height and decreasing the horizontal scale length to 154 and 400 m, respectively. Natural draft cooling towers may not be viable at Hanford, but mechanically assisted cooling towers of the same size may be.

The basic cooling model is simply a ground level, area source model. The pond for a 4 reactor cluster is assumed to be circular with a diameter of 9260 m. The total system efficiency is assumed to be 32%. Unlike the cooling tower model, in which the latent heat fraction was constant, the latent heat fraction in the cooling pond model is highly seasonal. It varies from a low of 56% in the winter to a high of over 200% in the summer. The latent heat release considers evaporation increases caused by construction of a pond on previously dry land. This is the cause of the high summer release rates. The modification of the basic cooling pond model to simulate helper ponds is accomplished by reducing the latent

heat release fraction. Background information on which the latent heat release fraction were based was supplied by the PNL Land Water Resources Department.

Although spray cooling ponds were not simulated, the basic cooling pond model with reduction of the horizontal scale length is the approach that would be taken.

The final cooling system simulated, and in many ways the least satisfactory, was once through cooling using the Columbia River. The approach taken was to assume that the river could be simulated by 5 circular areas that increased in size with distance from the source. The temperature increase in each area was computed assuming that the reactor effluent was thoroughly mixed with the river. The evaporation rate was then computed using the evaporation relationship in the COLHEAT river model⁽¹³⁾, the average river temperature, the Clausius-Clapeyron equation, and wind speed. In short, the whole process is both cumbersome and tedious. The results using this approach were not encouraging although they were intuitively reasonable.

The basic parameters of the cooling system models (cooling tower and pond) are given in Tables 3 and 4. Table 3 summarizes the horizontal scales and release heights for these systems, while Table 4 summarizes the overall efficiency and latent heat fractions. The annual average water consumption per reactor for each cooling system is also given in Table 4. It is interesting to note that a lower consumptive use of water is achieved with cooling towers than with cooling ponds.

Heat Sink Management Simulations

The various cooling system models and cluster locations were combined to give 27 cases for evaluation. Initial evaluations indicated that approximately the same results were

Table 3. Characteristic Cooling System Dimensions

<u>Cooling System</u>	<u>Horizontal Scale (m)</u>	<u>Release Height (m)</u>
Mechanical Draft Cooling Towers (also helper)	1609	25
Tall Cooling Towers (assisted Natural Draft)	400	154
Cooling Ponds (also helper ponds)	9260	0

Table 4. Cooling System Thermal Characteristics

<u>Cooling System</u>	<u>Efficiency</u>	<u>Latent Heat Fraction</u>					<u>Annual average water consumption (kg/sec)</u>
		<u>Annual</u>	<u>Winter</u>	<u>Spring</u>	<u>Summer</u>	<u>Fall</u>	
Cooling towers (short or tall)	.333	.800	.800	.800	.800	.800	801
Cooling Ponds	.320	1.260	.560	1.232	2.098	1.133	1340
Helper Cooling Towers	.333	.600	.600	.600	.600	.600	601
Helper Cooling Ponds	.320	.963	.559	.989	1.383	.910	1020

achieved when annual climatological data were used as when the results of simulations using seasonal data were combined. As a result most simulations were made using annual data. In two cases summer climatological data were used to examine the increases in humidity more closely.

The test cases that were used to evaluate the impact of the potential HNEC moisture releases are described in Table 5. The cooling systems and locations simulated in each case are denoted by the small letters in the Table. In Case 1 a single cluster of 4 reactors using mechanical draft cooling towers was examined. This is generally considered to represent the future conditions at Hanford because Site 1 is located near the area in which the Washington Public Power Supply System is constructing 3 reactors. However this was not an attempt to model the WPPSS cooling systems or evaluate their effects. Each of the remaining cases includes a cluster with mechanical draft towers at Site 1.

Cases 2 through 6 were used to examine the effect of cluster location on the population centers and roads in the area. These cases include grouping the clusters near both the north and south sides of the Hanford Reservation, aligning the clusters both perpendicular and parallel to the prevailing wind direction, and spreading them as widely as possible. These cases were selected without regard to other probable siting considerations.

Cases 7 through 11 examine the effects of a 5 cluster HNEC with clusters sited using criteria such as water availability, potential pond sites and distance from population centers. They also provide information on the relative effects of the various cooling systems. The simulations in cases 12 through 14 extended this evaluation to the full 10 cluster (40 reactor) HNEC.

Table 5. Site and Cooling System Combinations Simulated

Case	Site														Climatology
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	
1	a														annual
2	a	a	a	a	a										annual
3	a			a		a							a	a	annual
4	a					a			a		a			a	annual
5	a			a		a	a		a						annual
6	a	a	a	a							a				annual
7	a			b		b	b		b						annual
8	a			e		e	e		e						annual
9	a			d		d	d		d						annual
10	a	c	c	c	c										annual
11	a	c	c				e		e						annual
12	a	a	a	a	a	a	a		a	a	a				annual
13	a	c	c	c	c	c	c		c	c	c				annual
14	a	c	c	e	c	e	e		e	e	c				annual
15	a	a*	a*	a*	a*										annual
16	a	a ⁺	a ⁺	a ⁺	a ⁺										annual
17	a	a ^o	a ^o	a ^o	a ^o										annual
18	a	a*	a*	a*	a*	a*	a*		a*	a*	a*				annual
19	a	a ⁺	a ⁺	a ⁺	a ⁺	a ⁺	a ⁺		a ⁺	a ⁺	a ⁺				annual
20	a	a ^o	a ^o	a ^o	a ^o	a ^o	a ^o		a ^o	a ^o	a ^o				annual
21	a	a	a	a	a										annual
22	a	a	a	a	a	a	a		a	a	a				annual
23	a	c	c				d		d						annual
24	a	c	c	d	c	d	d		d	d	c				annual
25	a	c	c	c				f							annual
26	a	c	c					f					f		annual
27	a	c	c	c	c	c		f	c		c		f		annual
Cooling system types										low tower					a
										cooling pond					b
										tall tower					c
										helper tower					d
										helper pond					e
										river					f

* 75% wet, + 50% wet, ° 25° wet

The remaining simulations, except for cases 21 and 22, were done to identify those heat sink management options which minimize the potential impact of the HNEC moisture releases. Test cases 15 through 20 were directed toward the evaluation of hybrid wet/dry cooling systems, while those from 23 through 27 examined combinations of more conventional cooling systems.

The detailed results of the HNEC simulations will be discussed following a description of the Hanford climate.

THE HANFORD CLIMATE

Any evaluation of the impact of heat sink management alternatives on the environment must consider the climate of the region under consideration. Thus it is appropriate to describe the climate of the Hanford area in some detail. The basic reference on Hanford Climate is the Climatography of the Hanford Area prepared in 1972 by Stone, Jenne and Thorp⁽¹⁴⁾. The temperature and precipitation data in this work indicate that the Hanford area borders between a Steppe (BS) and desert (BW) climate using the Koppen classification scheme⁽¹⁵⁾. This classification is confirmed by the vegetation types that occupy most of the Hanford Reservation.

General Climatology

Meteorological observations have been made at numerous locations in the Hanford vicinity, but the only extensive records for a single location are those for the Hanford Meteorological Station (HMS). The HMS is located on a plateau at about 750 ft MSL and is about 300 ft above the Columbia River which flows through the reservation to the north and east. There are several significant topographic features within 20 miles of the HMS that affect some aspects of the Hanford climatology including wind.

Prior to the establishment of the HMS in December 1944, meteorological measurements were made by U. S. Weather Bureau cooperative observers between 1912 and 1943 and by the U. S. Weather Bureau in Richland for a short period at the end of 1943 and beginning of 1944.

The climatological data from these sources are summarized in Table 6. This summary gives both monthly and annual statistics for a large number of climatological variables and includes extreme values as well as means. Since 1975, the last year for which data are included in the table, several new records have been set, but there has been little variation in the climatological averages.

In addition to the month to month variation of climatological statistics presented in Table 6, there are distinct daily cycles which are superimposed on the seasonal variation. These daily cycles are most evident in temperature, humidity, and wind speed. The daily temperature cycle is familiar to all. The amplitude of this cycle at Hanford ranges from about 13 F° in December to about 30 F° in July and August. The daily cycle of relative humidity should also be familiar. It is related to the temperature cycle but out of phase, that is when the temperature decreases the humidity increases and conversely when the temperature increases the relative humidity decreases. The magnitude of the daily relative humidity variation at Hanford is about 25% throughout most of the year. However it decreases to about 10% in December and January. The daily wind speed cycle has a minimum during the morning hours and increases during the afternoon hours until it reached a maximum near sunset. It is most pronounced during the summer and almost imperceptible during the months of December and January. Figures 10 and 11 show these daily cycles for the months of January and July respectively.

TABLE 6. AVERAGES AND EXTREMES OF CLIMATIC ELEMENTS AT HANFORD
(BASED ON ALL AVAILABLE RECORDS TO AND INCLUDING THE YEAR 1975)

PAGE 1 OF 2

	TEMPERATURE (°F)												DEGREE DAYS (BASE 45°F)												PRECIPITATION (INCHES)																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																											
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EXTREME AVERAGES OR TOTALS
AND YEAR OR SEASON OF OCCURRENCE
1912-1975 TEMPERATURE AVERAGES (°F)

HIGHEST ANNUAL 56.2 1950
LOWEST ANNUAL 50.2 1920
HIGHEST WINTER 10-1-11 41.1 1933-34
LOWEST WINTER 24.2 1948-49
HIGHEST SPRING 10-1-11 58.2 1947
LOWEST SPRING 48.0 1955
HIGHEST SUMMER 11-1-11 78.2 1954
LOWEST SUMMER 70.3 1954
HIGHEST FALL 15-0-11 54.4 1963
LOWEST FALL 49.6 1946

1912-1975 PRECIPITATION TOTALS (IN.)

GREATEST ANNUAL 11.45 1950
LEAST ANNUAL 3.26 1967
SNOW, ICE, PELLETS (ISLEET)
GREATEST SEASONAL 43.6 1915-16
LEAST SEASONAL 0.3 1927-28

1945-1975 WIND SPEED AVERAGE (mph)

HIGHEST ANNUAL 8.9 1968
LOWEST ANNUAL 6.3 1957

1946-1975 RELATIVE HUMIDITY AVERAGE (%)

HIGHEST ANNUAL 57.9 1950
LOWEST ANNUAL 49.4 1967

1946-1975 SKY COVER AVERAGES
(SUNRISE TO SUNSET, SCALE 0-10)

HIGHEST ANNUAL 6.4 1966
LOWEST ANNUAL 5.1 1949

1953-1975 SOLAR RADIATION
AVERAGE DAILY TOTAL (HANGLEYS)

HIGHEST ANNUAL 330 1973
LOWEST ANNUAL 357 1947

TABLE 6. (cont) AVERAGES AND EXTREMES OF CLIMATIC ELEMENTS AT HANFORD CON'T.

(BASED ON ALL AVAILABLE RECORDS TO AND INCLUDING THE YEAR 1976)

2 4 2 1344

YEAR		1945		1946		1947		1948		1949		1950		1951		1952		1953		1954		1955		1956		1957		1958		1959		1960		1961		1962		1963		1964		1965		1966		1967		1968		1969		1970		1971		1972		1973		1974		1975		1976		1977		1978		1979		1980		1981		1982		1983		1984		1985		1986		1987		1988		1989		1990		1991		1992		1993		1994		1995		1996		1997		1998		1999		2000		2001		2002		2003		2004		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014		2015		2016		2017		2018		2019		2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032		2033		2034		2035		2036		2037		2038		2039		2040		2041		2042		2043		2044		2045		2046		2047		2048		2049		2050		2051		2052		2053		2054		2055		2056		2057		2058		2059		2060		2061		2062		2063		2064		2065		2066		2067		2068		2069		2070		2071		2072		2073		2074		2075		2076		2077		2078		2079		2080		2081		2082		2083		2084		2085		2086		2087		2088		2089		2090		2091		2092		2093		2094		2095		2096		2097		2098		2099		2100																																																																																																																																																																																																																																																																																																																																																																																																																																										
MEAN MONTHLY	112	3	4	10	15	20	26	30	34	38	42	46	50	54	58	62	66	70	74	78	82	86	90	94	98	102	106	110	114	118	122	126	130	134	138	142	146	150	154	158	162	166	170	174	178	182	186	190	194	198	202	206	210	214	218	222	226	230	234	238	242	246	250	254	258	262	266	270	274	278	282	286	290	294	298	302	306	310	314	318	322	326	330	334	338	342	346	350	354	358	362	366	370	374	378	382	386	390	394	398	402	406	410	414	418	422	426	430	434	438	442	446	450	454	458	462	466	470	474	478	482	486	490	494	498	502	506	510	514	518	522	526	530	534	538	542	546	550	554	558	562	566	570	574	578	582	586	590	594	598	602	606	610	614	618	622	626	630	634	638	642	646	650	654	658	662	666	670	674	678	682	686	690	694	698	702	706	710	714	718	722	726	730	734	738	742	746	750	754	758	762	766	770	774	778	782	786	790	794	798	802	806	810	814	818	822	826	830	834	838	842	846	850	854	858	862	866	870	874	878	882	886	890	894	898	902	906	910	914	918	922	926	930	934	938	942	946	950	954	958	962	966	970	974	978	982	986	990	994	998	1000																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																							
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[illegible]

* CATERPILLAR 2
 * SKY COVER AND PRECIPITATION OBSERVATIONS
 * NOT BEGIN UNTIL 1946
 * 1955 TO 1961
 * ALSO ON LARKLIN PLAYS

1. The first step in the process is to identify the problem. This involves gathering information about the situation and the people involved.

[illegible]

FIGURE 10. The Diurnal Cycles of Temperature, Relative Humidity and Wind Speed for January at Hanford

FIGURE 11. The Diurnal Cycles of Temperature, Relative Humidity and Wind Speed for July at Hanford

The observations of temperature and humidity at Hanford during the period from 1960 through 1970 were used to establish the saturation deficit climatology. The seasonal and diurnal variations of both temperature and humidity shown in Table 6 and Figures 10 and 11 would indicate that the average saturation deficit should show pronounced seasonal and daily variation. This is very much the case as is shown in Figure 12. This Figure shows a minimum deficit at about the time of sunrise and a maximum in mid-afternoon. December and January nights have particularly low deficits and are therefore the most probable times for induced saturation from moisture releases. During the summer, the average deficits are relatively large at all times even though they show a very large daily oscillation.

The distribution of the hourly saturation deficit values was determined. The particular portion of the distribution that is of interest is that describing the probability of small deficits. Figure 13 shows the probability that the saturation deficit will be less than a given value (the cumulative distribution function). Distributions are shown for both total hours and hours without fog. It should be noted that these distributions functions approach a single value for large deficits, and that they differ noticeably for low saturation deficits.

The most frequent restriction to visibility in the Hanford area is fog that occurs on an average of 38 days per year. On 24 of these days the visibility is restricted to less than 1/2 mile. Fog is highly seasonal, although it has occurred in every month. On a monthly basis, relative humidities range from a low of 30.5% in July to a high of 80.8% in December. High humidities (>90%) occur less than 1% of the time in the summer, about 9% of the time in the fall, almost 31% of the time in the winter and slightly more than 3% of the time in

FIGURE 12. The Diurnal and Annual Variation of Average Saturation Deficit (g/m^3) at Hanford

FIGURE 13. Cumulative Frequency Distributions for Saturation Deficits at Hanford

the spring. These statistics are reflected in the occurrence of fog. Of the annual average of 278 hours of fog, 95% occurs from November through February. This percentage increases to 99.7% when the months of October and March are included.

Hanford fogs are generally associated with low wind speed conditions. More than 70% of the hours of fog occur when the wind speed is less than 3.5 mph, and the average wind speed during fog is 2.5 mph. Table 7 gives detailed statistics on the duration and maximum persistence of both total and dense fog by months. January 1976 set a record for most hours of fog in a single month, 257. During that month fog was observed on a total of 20 days, including the last 16 days of the month.

Fog statistics indicate large natural variations in the occurrence of fog. The annual number of hours of fog at Hanford approximately follows a log-normal distribution as shown in Figure 14. Using observed values, a standard geometric deviation has been estimated for both hours of fog (0.285) and hours of visibility less than 1/2 mi. (0.362). Examination of more recent records does not indicate a change following deactivation of the reactors at Hanford.

Hours of fog is a rather nebulous figure for use in evaluation of impacts of large moisture releases. A better measure is related to visibility during fog. Cumulative frequency distributions of visibility during fog at Hanford (1960-1970) are shown in Figure 15 as cumulative distribution functions (cdf). The curve on the right in the figure represents the cdf for all cases of fog. The curve on the left represents those cases when the atmosphere was at or near saturation, (i.e., the saturation deficit in terms of water vapor density $\leq 0.05 \text{ g/m}^3$). It is obvious, that an increase in atmospheric moisture increases the density fog (reduce visibility) as well as increase the frequency.

Table 7. Total Duration and Maximum Persistence of Fog Tabulated in Hours for Hanford for the Period 1945-1970

ALL FOG (VIZ 0-6 MILLS)	AVG TOTAL DURATION	MAX TOTAL DURATION	YEAR	MIN TOTAL DURATION	YEAR	AVG DURATION PER DAY OF OCCURRENCE	MAX. PERSISTENCE ⁽¹⁾	YEAR
JAN	68.3	193.4	1965	0	1949	7.2	58.1	1955
FEB	36.4	206.2	1963	0	1967	6.2	58.0	1963
MAR	4.4	20.6	1951	0	1968+	3.1	12.2	1949
APR	0.3	2.8	1950	0	1970+	1.4	2.8	1950
MAY	0.3	2.7	1958	0	1970+	1.2	2.7	1958
JUNE	#	0.5	1948	0	1970+	0.5	0.5	1918
JULY	#	0.7	1966	0	1970+	0.7	0.7	1966
AUG	#	1.0	1959	0	1970+	1.0	0.7	1959
SEPT	0.3	5.5	1957	0	1970+	2.0	2.6	1957
OCT	7.6	61.6	1962	0	1970+	3.9	39.0	1962
NOV	55.4	148.0	1952	1.0	1960	6.8	65.4	1963
DEC	105.4	193.8	1947	6.5	1968	8.7	72.3	1947
Y	278.4	462.5 ⁽¹⁾	1964-65	147.7 ⁽²⁾	1918-49	7.0	72.3	1947-48
DENSE FOG (VIZ 1/4 MI OR LESS)								
JAN	20.4	52.4	1955	0	1949	3.4	15.0	1953
FEB	12.7	36.7	1963	0	1967+	3.8	16.7	1963
MAR	1.8	7.8	1949	0	1968+	2.2	5.0	1961
APR	0.1	1.8	1955	0	1970+	1.8	0	----
MAY	0.1	1.6	1958	0	1970+	1.6	1.6	1958
JUN	0	0	----	0	----	0	0	----
JULY	0	0	----	0	----	0	0	----
AUG	#	1.0	1959	0	1970+	1.0	0.7	1959
SEPT	0.1	3.2	1957	0	1970+	3.2	1.4	1957
OCT	3.1	35.2	1962	0	1970+	3.1	15.8	1962
NOV	21.1	71.4	1952	0	1960	4.1	20.6	1963
DEC	42.0	119.8	1947	1.3	1968	5.4	47.0	1957
Y	101.4	201.5 ⁽¹⁾	1962-63	47.3 ⁽²⁾	1948-49	4.2	47.0	1957-58

* TOTAL DURATION DENOTES TOTAL NUMBER OF HOURS AND TENTHS OF HOURS IN WHICH FOG IS OBSERVED.

DENOTES LESS THAN 0.05 HOUR

(1) DENOTES THE GREATEST NUMBER OF HOURS IN A SEASON

(2) DENOTES THE LEAST NUMBER OF HOURS IN A SEASON

(3) MAXIMUM PERSISTENCE OF DENSE FOG IS BASED ON THE PERIOD 1953-70

FIGURE 14. Percent Probability of Exceeding a Given Number of Hours of Fog at Hanford

FIGURE 15. Cumulative Frequency Distributions for Visibility During Fog at Hanford

The climatological data for the HMS are generally assumed to be representative of the entire region, although local variations in the climate are known to exist. Variations of importance are those associated with the Columbia River and the major topographic features which form the sides of the basin. There are differences between the northern and southern portions of the Hanford reservation. These are primarily small differences in temperature, humidity and wind.

Diffusion Climatology

The major impact of a Hanford Nuclear Energy Center on the atmosphere will result from the release of waste heat. The extent of the impact will be further related to the ability of the atmosphere to disperse the heat. The primary factors which govern dispersion or diffusion are atmospheric stability and the wind. The stronger the wind or less stable the atmosphere the more rapid the dispersion.

Results of numerous atmospheric diffusion experiments at Hanford indicate that 4 categories adequately describe atmospheric stability variations for the purposes of diffusion modeling. Figure 16 shows wind roses for Hanford for each of these stability categories and for all categories combined. The data are presented in tabular form in Table 8. The wind roses clearly show the prevailing wind direction at Hanford is from the west northwest and northwest.

If this area were void of significant topographic features, the major impact of an HNEC would be expected to occur to the east-southeast and southeast. However, the influence of the existing topographic features makes this a very tenuous assumption. Air flow measurements made over the reservation in the past few years indicate there are frequent local circulation patterns in which the HMS wind direction does not adequately

FIGURE 16. Wind Roses by Atmospheric Stability for Hanford

Table 8. Joint Probability of Wind Direction, Wind Speed and Atmospheric Stability at 200' for Hanford

		NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	N	VAR.	CALM	TOTAL
0 - 3	VS	0.06	0.06	0.04	0.06	0.06	0.12	0.07	0.07	0.06	0.05	0.06	0.10	0.08	0.10	0.11	0.09	0.08	0.09	1.37
	MS	0.29	0.30	0.24	0.29	0.40	0.55	0.32	0.29	0.23	0.26	0.25	0.44	0.41	0.56	0.48	0.49	0.25	0.66	8.71
	N	0.44	0.57	0.42	0.49	0.56	0.56	0.26	0.26	0.18	0.20	0.16	0.28	0.31	0.50	0.61	0.63	0.31	0.69	7.43
	U	0.37	0.44	0.25	0.30	0.25	0.26	0.13	0.11	0.08	0.10	0.08	0.10	0.09	0.19	0.22	0.38	0.30	0.06	3.71
4 - 7	VS	0.04	0.04	0.03	0.03	0.04	0.09	0.09	0.09	0.07	0.10	0.15	0.24	0.23	0.22	0.17	0.09	0.01	0.	1.75
	MS	0.28	0.21	0.18	0.21	0.30	0.50	0.34	0.32	0.29	0.39	0.52	1.02	1.21	1.35	0.94	0.54	0.03	0.	8.62
	N	0.35	0.38	0.27	0.32	0.36	0.47	0.27	0.26	0.22	0.31	0.29	0.39	0.56	1.04	0.72	0.56	0.08	0.	6.86
	U	0.77	0.71	0.44	0.46	0.44	0.52	0.29	0.33	0.33	0.36	0.26	0.28	0.33	0.75	0.78	0.86	0.23	0.	8.13
8 -12	VS	0.01	0.00	0.00	0.00	0.00	0.03	0.06	0.03	0.02	0.05	0.12	0.26	0.34	0.59	0.20	0.02	0.	0.	1.74
	MS	0.17	0.15	0.09	0.10	0.13	0.27	0.29	0.17	0.20	0.40	0.86	1.71	2.85	2.52	0.73	0.27	0.00	0.	10.94
	N	0.21	0.12	0.07	0.07	0.09	0.13	0.13	0.13	0.23	0.40	0.44	0.48	0.86	1.36	0.33	0.21	0.	0.	5.24
	U	0.40	0.29	0.11	0.08	0.07	0.14	0.10	0.11	0.25	0.41	0.38	0.22	0.43	1.01	0.39	0.36	0.00	0.	4.75
13-18	VS	0.00	0.00	0.	0.00	0.	0.01	0.02	0.01	0.01	0.01	0.04	0.10	0.28	0.81	0.07	0.00	0.	0.	1.38
	MS	0.10	0.06	0.03	0.04	0.02	0.10	0.18	0.12	0.17	0.42	0.86	1.25	3.45	2.66	0.24	0.11	0.	0.	9.80
	N	0.15	0.06	0.02	0.01	0.01	0.04	0.07	0.11	0.23	0.49	0.63	0.55	1.13	1.06	0.11	0.10	0.	0.	4.78
	U	0.21	0.11	0.03	0.01	0.00	0.02	0.03	0.04	0.13	0.40	0.49	0.19	0.51	0.79	0.07	0.12	0.	0.	3.16
19-24	VS	0.	0.	0.	0.	0.	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.04	0.12	0.00	0.	0.	0.	0.20
	MS	0.02	0.02	0.01	0.01	0.00	0.02	0.05	0.08	0.13	0.32	0.35	0.20	1.02	1.08	0.02	0.01	0.	0.	3.33
	N	0.05	0.04	0.01	0.00	0.00	0.02	0.03	0.07	0.20	0.46	0.45	0.22	0.84	0.81	0.02	0.04	0.	0.	3.26
	U	0.05	0.04	0.01	0.00	0.	0.00	0.01	0.02	0.08	0.26	0.31	0.09	0.29	0.59	0.01	0.02	0.	0.	1.79
OVER 24	VS	0.	0.	0.	0.	0.	0.00	0.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.	0.	0.	0.	0.01
	MS	0.00	0.00	0.	0.	0.	0.00	0.02	0.05	0.15	0.21	0.12	0.03	0.22	0.31	0.00	0.00	0.	0.	1.13
	N	0.02	0.01	0.00	0.00	0.	0.00	0.01	0.06	0.25	0.50	0.26	0.07	0.54	0.75	0.01	0.01	0.	0.	2.49
	U	0.01	0.02	0.01	0.	0.	0.	0.00	0.01	0.08	0.34	0.25	0.07	0.17	0.46	0.00	0.00	0.	0.	1.42
TOTALS	VS	0.11	0.11	0.07	0.10	0.11	0.25	0.24	0.20	0.16	0.22	0.39	0.71	0.96	1.85	0.56	0.20	0.09	0.09	6.44
	MS	0.87	0.75	0.55	0.65	0.85	1.44	1.20	1.02	1.17	2.01	2.96	4.65	9.16	8.49	2.41	1.42	0.28	0.66	40.53
	N	1.22	1.19	0.78	0.89	1.02	1.22	0.78	0.89	1.31	2.35	2.23	2.00	4.24	5.52	1.78	1.56	0.39	0.69	30.07
	U	1.82	1.62	0.84	0.86	0.76	0.95	0.56	0.63	0.95	1.87	1.77	0.93	1.82	3.77	1.48	1.74	0.53	0.06	22.96

represent air flow over the entire reservation. Evidence of these local circulations is seen in Figure 17, which shows wind roses for several locations on and surrounding the Hanford Reservation. In some cases these circulations will act to increase the rate at which the waste heat is dispersed, and in other cases they will have the opposite affect. Figure 18 further demonstrates differences in wind that can be observed at two places in relatively close proximity. The physical separation between the FFTF and the WNP-2 sites is about 2 miles, with FFTF to the west of WNP-2. The large frequency of winds from south-southwest through west at FFTF can be attributed to local circulations related to Rattlesnake Mountain that do not affect WNP-2.

A detailed evaluation of the transport and diffusion of thermal effluents from an HNEC would be a complex and relatively expensive process as a result of the local circulations. Therefore, a relatively simple dispersion model that uses HMS wind and stability data and assumes straight line transport has been used to examine the impact of various HNEC heat sink management alternatives on fog and humidity. The results of this evaluation are discussed in the next Section.

HNEC SIMULATION RESULTS

More than 50 different numerical simulations using BATMAN have been made to examine the potential impacts of moisture releases from a Hanford Nuclear Energy Center on fog and ground level humidity. Presentation of a complete set of the numerical results is beyond the scope of the present work. Rather, a summary of the pertinent results is presented. In the following sections, the predicted impact on the total number of hours of fog, the effect of site location and cooling system choice on the fog impact, and the effect of the HNEC

FIGURE 17. Surface Wind Roses for Various Locations on and Surrounding the Hanford Site. (The points of the rose represent the directions from which the winds come)

FFTF

WNP-2

FIGURE 18. Wind Roses for the FFTF and WNP-2 Sites

on visibility are discussed. In addition, the statistical significance of the predicted increases in fog is evaluated. Finally, the effects of an HNEC on summer humidity are examined.

The Predicted Increase in Hours of Fog

For each case BATMAN computed the predicted increase in fog at all grid points. Rather than summarize the predictions at specific locations, a number of general areas have been selected. These areas are: the Tri-Cities (Richland, Kennewick and Pasco), Eltopia, Othello, Beverly, the Hanford Meteorological Station, and Benton City. Table 9 gives the predicted increase in hours of fog at each of these locations for the 27 cases under consideration.

The numbers given in the Table are representative of the general region; they should not be taken as absolute. It is more realistic to compare the predictions for various cases at a site and to make evaluations on that basis than it is to assume each number is accurate.

The Tri-Cities is the most populous area near Hanford. Thus increases in fog in that area would have the maximum impact on individuals. Predicted increases in fog range from 15 hours for a single, 4 reactor cluster to 288 hours for a 40 reactor energy center. The larger predicted increases in fog could have a significant socio-economic effect.

Eltopia was selected to represent the agricultural region east of the Columbia River and north of Pasco. It also represents the conditions on Highway 395 north of Pasco. Increases in fog in this area might have some impact on agriculture, but the probable timing of fog would tend to mitigate this impact. A potentially more significant impact is the reduction of visibility along the highway. There are already frequent accidents above this section of road. In general the predicted

Table 9, Predicted Increases in Hours of Fog
in Selected Areas

<u>Case</u>	<u>Tri-Cities Average</u>	<u>Eltopia</u>	<u>Othello</u>	<u>Beverly</u>	<u>Hanford Met Station</u>	<u>Benton City</u>
1	15	6	1	6	2	2
2	98	97	19	30	30	39
3	88	84	36	21	112	28
4	106	57	30	33	116	33
5	102	74	32	31	129	35
6	100	81	16	29	29	21
7	250	208	118	187	578	152
8	207	154	94	161	480	135
9	78	52	26	25	84	25
10	55	41	11	26	14	14
11	122	83	41	118	197	74
12	210	197	75	53	168	88
13	112	84	28	44	50	50
14	288	211	118	191	524	175
15	74	68	18	23	19	26
16	57	37	11	18	15	21
17	37	32	8	11	4	10
18	164	147	51	46	110	69
19	117	97	34	34	71	48
20	63	37	13	22	24	24
23	60	36	12	30	30	20
24	144	127	50	47	103	49
25	44	34	9	21	10	12
26	34	29	6	18	8	7
27	90	54	25	40	37	30

increases in fog for Eltopia are smaller than for the Tri-Cities, but they are larger than for other areas off the Hanford Reservation.

The impact of an HNEC on the area north of the Hanford Reservation is represented by the predictions for Othello and Beverly. The population in the area is small, however Highways 24 and 243 are reasonably well traveled. In general the predicted increases here are relatively small. This is a reflection of atmospheric conditions favorable to diffusion and a low frequency of occurrence of southerly winds.

Advantages of Hanford as a potential site for a nuclear energy center are the large area available and the distance to populated locations. These factors tend to diminish the effect of any impact that moisture releases might have on fog. The predictions for Hanford Meteorological Station were selected to represent the conditions in the vicinity of and within the NEC. As such it is to be expected that the largest increases in fog should occur there. Under some conditions the impact there is twice that for the Tri-Cities. However, there are other cases where the reverse is true.

Finally Benton City was selected to represent the region to the west of Richland and south of Rattlesnake Mountain. Increases in fog in this area could significantly affect traffic along Highway 12. They could also affect agriculture by preventing or reducing the severity of late spring freezes that damage fruit crops in the area. In most cases the predicted fog increases for Benton City are relatively small.

The Influence of Site Location on Fog Increases

If the predicted increases in fog in Table 9 for cases 2 through 6 are examined, the influence of general siting strategies on the impact of fog increases can be evaluated. In cases 2 and 3 the clusters are located on lines approximately

perpendicular and parallel, respectively, to the prevailing wind direction. In case 4 they are spread over the entire reservation, and in cases 5 and 6 they are clustered on the north and south sides of the reservation, respectively. In each case all clusters were assumed to use low-level, mechanical draft cooling towers.

The effect of varying cluster locations on the predicted increase of fog in the Tri-Cities is rather small. The single largest factor in the changes in the predictions is the use of sites 6 and 7 or site 11. In general the variations in the other areas of interest off the Hanford Reservation are also small, and can be tied to the use of particular sites rather than a particular siting strategy.

The Hanford Meteorology Station represents the area where the predicted fogging impact is most affected by the choice of cluster locations. Because of the prevailing Northwest winds, the HMS is very susceptible to increases in fog when clusters are located at sites 6 and 7.

On the basis of foregoing evaluation, it was concluded that, except for local effects, the formation of fog was a secondary factor in determining the location of the clusters. As a corollary, it was concluded that the fogging impact of an HNEC would be only secondarily related to the ultimate location of reactor clusters.

The Influence of Cooling System Type on Fog Increases

The influence of cooling system type on the increase in fog was examined for a 20 reactor HNEC using the results of cases 2, 7 through 10, and 15 through 17. In these cases the clusters were positioned to take advantage of river water for helper cooling systems, natural basins for ponds, and proximity of the Tri-Cities for cooling towers.

The results given in Table 9 indicate that for conventional cooling systems the greatest fogging impact is caused by ponds. Tall cooling towers (natural draft or mechanically-assisted, natural draft) have the least impact. The Columbia River is too small to accommodate a 20 reactor HNEC on once through cooling, however substitution of the river for a portion of load should reduce the total impact off the Reservation. This is confirmed by the results of cases 25 and 26.

The impacts predicted for the use of either cooling ponds or helper cooling ponds were enough larger than those for cooling towers and helper towers to eliminate consideration of these two systems as the primary systems in a 40 reactor center. Case 14 did consider the combination of tall cooling towers and helper ponds, and it will be noted that this combination has the greatest impact on the Tri-Cities. It is improbable that adequate sites exist for cooling more than 2 or 3 clusters with ponds at Hanford.

The use of hybrid wet/dry cooling towers can significantly reduce the predicted increases in hours of fog. The results of cases 1, 2, 15, 16 and 17 have been combined to indicate the potential reduction as shown in Figure 19. By the use of a sufficiently large dry cooling fraction, hybrid wet/dry systems can reduce the fogging impact to essentially zero. The 15 hours of fog shown for 0% wet cooling result from 4 low-level, wet towers assumed for site 1 in all simulations.

Examination of the results of the mixed cooling system simulations shows that the use of once-through cooling for 1 or 2 clusters has essentially the same effect as using a relatively large fraction (~50%) of dry cooling.

On this basis, it is concluded that the use of tall cooling towers supplemented with once-through cooling is the optimum combination of conventional cooling systems. Almost

FIGURE 19. Relationship Between Increased Hours of Fog for an HNEC Using Hybrid Wet/Dry Cooling Systems and the Percent Wet Cooling

as acceptable is the sole use of tall towers. If a lesser impact on fog is required the only alternative, short of not constructing an HNEC, is the use of hybrid wet/dry towers with a very high percentage of dry cooling. It is also concluded that ponds are not acceptable for HNEC cooling for other than as emergency systems.

The Reduction of Visibility in the Tri-Cities

As indicated earlier, hours of fog is a somewhat nebulous impact. Fog may be relatively light and have little impact, or it may be dense and have a very significant economic impact. Thus, to establish the socio-economic impact of an HNEC through increased fog, it is necessary to describe the increase in frequency of fog in terms of visibility. This is also important as an aid in reducing the subjectiveness of the definition of fog when dealing with the public.

In order to convert hours of fog to visibility, it was necessary to develop a relationship between the two. The moisture releases from an NEC can contribute to fog by causing fog to form or by making naturally occurring fog more dense. Both contributions must be considered when making the conversion from hours of fog to visibility.

The relationship between increases in fog and increases in the occurrence reduced visibility assumed in this study is:

$$\Delta H v_k = [\Delta H f_k + (H f - H v) P_k(\theta)] P(V < V_r | d \leq .05 \text{ g/m}^3) \quad (8)$$

where $\Delta H v_k$ is the increase in hours of $V < V_r$ at receptor k; $\Delta H f_k$ is the increase in the total hours of fog (Table 9); $H f$ is the average number of hours of natural fog; $H v$ is the average number of hours with $V < V_r$ under current conditions; $P_k(\theta)$ is the probability the wind direction will carry moisture from the

HNEC to the receptor, $P(V < V_r | d \leq .05 \text{ g/m}^3)$ is the probability that the visibility will be less than V_r given the occurrence of fog and a saturation deficit of $.05 \text{ g/m}^3$ or less (Figure 15); and V and V_r are the visibility and reference visibility respectively. For an HNEC and a receptor in the Tri-Cities, $P_k(\theta)$ is .2205. Further, assuming that HMS fog statistics are representative for the Tri-Cities, H_f is 278 hours. For visibilities of 3, 1, 1/2, 1/8 and 1/16 miles the values of H_v are 195, 132, 97, 39 and 8 hours, respectively.

The increased visibility reductions that are predicted for the Tri-Cities are given in Table 10. It will be noted that for the single cluster case, and for other cases where the predicted increase in total hours of fog is small, the increase in the number of hours with visibility restriction to less than 3 miles exceeds the increased hours of fog. It will also be noted that the maximum increase in hours of visibility less than 1/16 mile is less than a factor of 5 larger than the increase predicted for a single 4 reactor cluster.

The increases given in Table 10 are combined with climatological information on visibility in Table 11 to show the predicted conditions in the Tri-Cities for various HNEC configurations. The various visibility categories were chosen with transportation in mind. When visibility drops below 3 mi, flight rules change from visual to instrument and many private pilots are effectively grounded. At 1 mile all flight operations at the Richland Airport stop, and at 1/2 mile the Pasco Airport closes. When the visibility falls to 1/8 mile or less, ground transportation is affected.

The Statistical Significance of the Predicted Increases

The mention of the impact of visibility reduction on transportation indicates a potential measure of significance

Table 10. Predicted Increases in Hours of Reduced Visibility in the Tri-Cities

	All Fog	Hours of Visibility				
		<u><3</u>	<u><1</u>	<u><1/2</u>	<u><1/8</u>	<u><1/16</u>
<u>4 Reactor Cluster</u>						
1	15	29	33	31	16	4
<u>20 Reactor Center</u>						
2	98	103	91	79	36	9
7	250	237	198	165	73	17
8	207	199	167	141	62	15
9	78	85	77	67	31	8
10	55	65	61	54	26	6
11	122	124	108	92	42	10
15	74	82	74	65	30	7
16	57	65	62	55	26	6
17	37	49	48	44	22	5
23	60	69	65	57	27	7
25	44	55	53	48	23	6
26	34	46	46	42	21	5
<u>40 Reactor Center</u>						
12	210	202	170	142	63	15
13	112	115	101	87	40	9
14	288	271	224	187	82	19
18	164	161	137	116	52	12
19	117	120	104	89	41	10
20	63	72	67	59	28	7
24	144	144	123	105	47	11
27	90	96	86	74	34	8

Table 11. Predicted Fog Conditions in the Tri-Cities with an HNEC (current conditions and predicted increases)

	Total Hours of Fog	Hours with Visibility				
		<3	<1	<1/2	<1/8	<1/16
<u>Current Conditions</u>	278	195	132	97	39	8
<u>4 Reactor Cluster</u>						
1	293	224	165	128	55	12
<u>20 Reactor Center</u>						
2	376	298	223	176	75	17
7	528	432	330	262	112	25
8	485	394	299	238	101	23
9	356	280	209	164	70	16
10	333	260	193	151	65	14
11	400	319	240	189	81	18
15	352	277	206	162	69	15
16	333	260	194	152	65	14
17	315	244	180	141	61	13
23	338	264	197	154	66	15
25	322	250	185	145	62	14
26	312	241	178	139	60	13
<u>40 Reactor Center</u>						
12	488	397	302	239	102	23
13	390	310	233	184	79	17
14	566	466	356	284	121	27
18	442	356	269	213	91	20
19	395	315	236	186	80	18
20	341	267	199	156	67	15
24	422	339	255	202	86	19
27	368	291	218	171	73	16

of the predicted increases. Other socio-economic tests of significance can be envisioned; they are difficult to evaluate. It is possible, however, to evaluate the statistical significance of the predicted increases by using the Hanford fog data and making several assumptions.

If natural climatic change is neglected, pre and post operational climatological data are assumed to exist, and the HNEC is completed at a single time, the hypothesis that an increase in fog has occurred can be tested. The t-statistic for examining the change of geometric mean in a log-normal distribution is

$$t_{\alpha, f} = \frac{\ln \left(\frac{H_f + \Delta H}{H_f} \right)}{\sigma_{\ln H_f} \left[\frac{1}{n_0} + \frac{1}{n_1} \right]^{1/2}} \quad (9)$$

where α is the level of significance, f is the number of degrees of freedom ($n_0 + n_1 - 2$), H_f is geometric mean number of hours of fog, and ΔH is the increase, $\sigma_{\ln H}$ is the standard geometric deviation of the distribution of H , and n_0 and n_1 are the number of years of fog of climatology before and after the HNEC started operation. For 26 years of Hanford data H_f is 278 hours and $\sigma_{\ln H}$ is .285.

Rather than compute a t-statistic, it is more informative to use tabled values of t and use (9) to compute the minimum statistically significant increases at a 5% level assuming values for n_1 . This has been done and the results are given in Table 12 for both total increase in hours of fog and increase in hours of fog with visibility less than 1/2 mile ($H_r = 101$ and $\sigma_{\ln H} = .362$).

Table 12. Minimum Statistically Significant
Increases in Fog in the Tri-Cities

<u>Years of HNEC Operation</u>	<u>Increased Hours of Fog</u>	<u>Increased Hours with Visibility <1/2 mi</u>
2	102	58
4	83	40
6	68	33
16	46	22
36	36	17
∞	27	13

The minimum statistically significant increases in Table 12 should be compared with the appropriate predictions in Tables 9 and 10. It is immediately obvious that many of the predicted increases are statistically significant. It is also evident that the predicted increases in dense fog (visibility less than 1/2 mile) may be significant when the increase in total hours of fog is not.

The Impact on Summer Humidity

Summer simulations were run to determine the impact of an HNEC on humidity to provide information for use in estimating the potential moisture release on human comfort. Figures 20, 21 and 22 show the number of hours that water vapor increases resulting from low-level, mechanical draft cooling towers would exceed 1 g/m^3 for a single cluster, a 20 reactor center and a 40 reactor center at Hanford, respectively. An increase of 1 g/m^3 in water vapor is equivalent to an increase in relative humidity of about 2% at 95 °F (see Figure 8). At a lower temperature more typical of morning and evening hours the increase in relative humidity would be between 5 and 10%.

FIGURE 20. Hours of Water Vapor Density Increase Exceeding 1 g/m^3 During Summer Months for a Single Cluster at Hanford

FIGURE 21. Hours of Water Vapor Density Increase Exceeding 1 g/m^3 During Summer Months for a 20 Reactor Energy Center at Hanford

FIGURE 22. Hours of Water Vapor Density Increase Exceeding 1 g/m^3 During Summer Months for a 40 Reactor Energy Center at Hanford

In examining these figures it is interesting to note the increase in both the frequency and areal extent of the HNEC impact as the number of reactors grows. Figure 20 shows the impact of a single cluster to be negligible and almost totally confined to the Hanford Reservation. As the number of clusters increases to 5, the effect becomes more prevalent to the east of the Reservation, but still affects relative humidity in the Tri-Cities less than 100 hours. The full 40 reactor HNEC increases the atmospheric humidity by 1 g/m^3 in the Tri-Cities about 150 hours each summer.

While the predicted humidity increases are small at the normal summer time temperatures they may cause some discomfort. No attempt has been made to evaluate changes in a temperature humidity or comfort index due to the increased humidity.

CONCLUSIONS

The major conclusions of this study are:

- 1) The cooling systems used in an HNEC will be a primary factor in determining the fogging impact. For a given HNEC size the impact can be minimized by using a combination of tall (natural or mechanically assisted natural draft) cooling towers and once-through cooling. Hybrid wet/dry cooling towers can achieve a relatively low impact if a large fraction of the cooling ($\geq 50\%$) is accomplished by dry heat exchange. The maximum fogging impact would be associated with cooling ponds.
- 2) The positions of the 4 reactor clusters of the HNEC within the Reservation would only have a secondary effect on the fogging impact. Increase in fog should not be an important factor in selection of cluster locations.

- 3) The number of hours of fog in the Tri-Cities could be increased by almost 300 for a 40 reactor HNEC and 250 for a 20 reactor center if conventional, low-level evaporative cooling systems are used. Other areas surrounding the Hanford Reservation would be affected less frequently. On the Reservation the number of hours of fog at the Hanford Meteorology Station could increase by almost 600.
- 4) The moisture releases from an HNEC would increase the density of naturally occurring fog. The changes in number of hours with low visibility are percentagewise greater than those in the total number of hours of fog.
- 5) Both the predicted increases in number of hours of fog and numbers of hours of low visibility are greater than the minimum statistically significant increases. Thus, they would be apparent in climatological data.
- 6) The statistical significance of the predicted increases does not indicate the extent of their socio-economic impact. It is necessary to evaluate these increases in socio-economic terms to identify the extent of the problems which might occur from increased fogging.
- 7) BATMAN is a relatively simple model which glosses over many physically important considerations in estimating the increased frequency of fog. If the predicted increases in fog are determined to present a serious problem, a detailed study should be made using more realistic models.

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APPENDIX A

BATMAN USER'S GUIDE AND COMPUTER CODE

BATMAN USER'S GUIDE AND COMPUTER CODE

Although no attempt has been made to optimize the programming in BATMAN, it is a relatively compact code. The maximum core required in compilation on a CDC 6600 is less than 20,000 words, and the maximum in program execution is less than 12,000 words. Program run time is about 20 sec for a 5 complex NEC with 320 possible combinations of wind direction, wind speed and atmospheric stability. Computations for a 10 complex reactor require about 35 sec. This appendix describes the input deck required to run BATMAN, gives 2 examples of input decks, and gives a listing of the program.

The input deck for BATMAN consists of 16 different types of cards. The read and associated format statements for these cards are shown in Figure A1. Not all of these cards are required for a given simulation.

The first card, NCASES, indicates the number of different simulations to be run in a single submission. It is followed by a cards, IOPT, which controls input and output options. If IOPT(1)=0 the code computes the increases in water vapor density for a single set of atmospheric conditions and prints them (see Figures 4 and 5). If IOPT(1)=1, increases in vapor density are computed for several sets of atmospheric conditions and the results are converted to hours of increase within selected ranges (see Figure 6). IOPT(2) controls the number of climatic data cards. If IOPT(2)=1, the program reads in the number of climate cards, otherwise it computes the number of cards from the number of wind direction and speed categories. Setting IOPT(3)=1 causes BATMAN to convert the hours of increased water vapor density into increased hours of saturation (fog) (see Figure 7).

```

READ (5,10020) NPLAT
READ (5,10020) TOPT
READ (5,10023) NXLIM,(XLIM(I),I=1,10)
READ (5,10001) FFF(1),FQ(1),FFF(2),FQ(2),FFF(3),FQ(3),FFF(4),FQ(4),
+ FFF(5),FQ(5)
READ (5,10011) NS,NU,KSTAR,I
IF (ICP(2).EQ.1) READ (5,10023) NDC
READ (5,10023) IDIR(1),ODIR(1),(FRQ(I,J),J=1,KSTAR)
READ (5,10023) NJOURS
IF (TOPT(3).EQ.1) READ (5,10012) (AHOURS(IH),IH=1,NXLIM)
READ (5,10026) NZ,(Z(I),I=1,10)
READ (5,10012) ANG,ZLID,UBC
READ (5,10012) XSPACE,YSPACE
READ (5,10012) LI
READ (5,10000) IFADJ
READ (5,10002) NSITES
READ (5,10004) NUNITS(I),KTYPE(I),POS(I,1),POS(I,2),QE(I),HO(I),W(I)

```

```

10000 FORMAT(10A8)
10001 FORMAT(10X,14F5.3)
10002 FORMAT(10X,14I5)
10004 FORMAT(10X,2I5,6F10.2)
10011 FORMAT(10X,3I5,5F10.0)
10012 FORMAT(10X,10F7.2)
10020 FORMAT(10X,10I1)
10023 FORMAT(10X,15,13F5.2)
10026 FORMAT(10X,15,13F5.0)

```

FIGURE A1. Input Statements and Formats for BATMAN

The third card in the deck defines ranges for summarization of the frequency of vapor density increases. It is an optional card required only if IOPT(1)=1. The first entry on the card is the number of categories; it is followed by the lower limit for each category (g/m^3), in increasing order. The upper limit of all categories is assumed to be infinite. The fourth control card contains information on the overall efficiencies and latent heat release fractions associated with the various cooling system types.

The climatological data input starts with the fifth card. NS, NU, and KSTAB are the number of wind direction sectors, wind speed and atmospheric stability categories, respectively. The final entry on this card is an average temperature ($^{\circ}\text{K}$) for use in plume rise computations. This parameter is not necessary unless cooling towers are simulated.

If a limited set of atmospheric conditions is being examined and IOPT(2)=1, a card is required which specifies the number of climatological data cards to follow. If IOPT(2)=0, BATMAN computes $\text{NDC} = \text{NS} \times \text{NU}$.

Next, the climatological data cards are read in. Each card consists of a wind direction sector, wind speed (m/s), and the frequency of occurrence (%) for each stability category with the given direction and speed. These cards are followed by a card containing the number of hours in the period being considered (8766 if annual averages are desired).

The final climatological card contains information on the climatology of saturation deficits and is needed only if IOPT(3)=1. The data on this card are the hours available for the formation of fog in each of the saturation deficit classes defined by the limits on card 3. The lower limit of the first class is assumed to be zero and the divisions between successive

classes are defined by the values of XLIM(I). If this card is used, there must be available hours for a total of NXLIM classes.

The four cards that follow define the computational grid and the individual cluster plume characteristics. The first card of the group determines the number of computational levels in the vertical (NZ) and establishes the height of each level Z(I). It is not necessary to define more than 1 level for computations. The second card sets the angular width of the plume (in degrees), establishes the height of the limit on vertical dispersion, ZLID(m), and sets a critical wind speed UBC, (m/s) which limits the rise of cooling tower plumes. If ZLID is zero, the plume is permitted to rise to the full height estimated in Subroutine PRISE and vertical dispersion is unlimited. If the wind speed exceeds UBC in any case, the plume rise for that case is set to zero and downwash and wake corrections are made. The following card establishes the grid spacing. XSPACE is the north-south spacing and YSPACE is the east-west spacing. It is not necessary that XSPACE and YSPACE be the same, however the computer output has approximately equal spacing in the two directions. The values of XSPACE and YSPACE should be large compared to the characteristic horizontal dimensions of the cooling systems simulated. The final card in this group is a plume rise correction factor to account for additional plume rise resulting from the release of latent heat. A value of 3 has been used for this factor.

The last group of 3 card types defines the case being simulated. This group must be repeated NCASES times. The first card in the group is a heading card which describes the case being simulated, and the second card gives the number of sources (clusters) in the case. The final card type is the source description. The information on this card includes the number of reactors in the cluster, the type cooling system and

its position in grid coordinates, the rated output of the reactor in MW_e , the moisture release height (m), and a characteristic horizontal dimension for the cluster. One card of this type is required for each cluster in the case. If a cluster uses two cooling system types, each must be described on a separate card. In this case the positions may be superimposed on one another.

Figures A2 and A3 give sample data decks for use with BATMAN. These Figures are followed by a complete listing of the BATMAN Code.

```

NCASES      2
LOPT        1
LEF/EQ  AM  .333 .800 .320 1.260 .333 .800 .333 .600 .320 .963
CLIMATE P    16    5    4    285.
NDC         1
DATA WNW/7   13 6.93          3.45
NHOURS      3766
LEVELS      7    .    50. 100. 200. 300. 400. 500.
ANG/LID/UC  22.5  500.    3.0
SPACING     8000. 8000.
CF          3.
CASE A      4 REACTORS      SITE 1      LOW TOWERS      WNW/7  MOD STABLE
NSITES     1
SITE 1      4    1          6.1        7.5      1250.        25.      1609.
CASE B     20 REACTORS     SITES 1-5    LOW TOWERS      WNW/7  MOD STABLE
NSITES     5
SITE 1      4    1          6.1        7.5      1250.        25.      1609.
SITE 2      4    1          5.5        7.2      1250.        25.      1609.
SITE 3      4    1          4.7        6.7      1250.        25.      1609.
SITE 4      4    1          3.7        5.4      1250.        25.      1609.
SITE 5      4    1          3.7        4.9      1250.        25.      1609.

```

FIGURE A2. A Sample Input Data Deck for Computation of Increases in Water Vapor Density

NCASES		1										
IOPT	1	1										
XLIM		8	.05	.50	1.00	1.50	2.00	3.00	4.00	5.00		
EFF/FQ	AN	.333	.800	.320	1.260	.333	.800	.333	.600	.320	.963	
CLIMATE	P	16	5	4		285.						
ANNUAL	1	1	.67	.42	.51	.34	.07					
ANNUAL	2	1	2.46	.79	.35	.28	.04					
ANNUAL	3	1	4.47	.40	.21	.17	.01					
ANNUAL	4	1	6.93	.21	.15	.10	.00					
ANNUAL	5	1	9.61	.05	.05	.02	.00					
ANNUAL	6	2	.67	.49	.66	.35	.07					
ANNUAL	7	2	2.46	.73	.39	.21	.04					
ANNUAL	8	2	4.47	.29	.12	.15	.00					
ANNUAL	9	2	6.93	.11	.06	.06	.00					
ANNUAL	10	2	9.61	.04	.04	.02	.00					
ANNUAL	11	3	.67	.27	.49	.27	.04					
ANNUAL	12	3	2.46	.45	.27	.18	.03					
ANNUAL	13	3	4.47	.11	.07	.09	.00					
ANNUAL	14	3	6.93	.03	.02	.03	.00					
ANNUAL	15	3	9.61	.01	.01	.01	.00					
ANNUAL	16	4	.67	.33	.57	.34	.07					
ANNUAL	17	4	2.46	.47	.32	.21	.03					
ANNUAL	18	4	4.47	.08	.07	.10	.00					
ANNUAL	19	4	6.93	.01	.01	.04	.00					
ANNUAL	20	4	9.61	.00	.00	.01	.00					
ANNUAL	21	5	.67	.27	.65	.46	.07					
ANNUAL	22	5	2.46	.45	.36	.30	.04					
ANNUAL	23	5	4.47	.07	.09	.13	.00					
ANNUAL	24	5	6.93	.00	.01	.02	.00					
ANNUAL	25	5	9.61	.00	.00	.00	.00					

FIGURE A3. A Sample Input Data Deck for
Computation of Increases in Fog

Figure A3 (continued)

ANNUAL	26	6	.67	.29	.65	.63	.13
ANNUAL	27	6	2.46	.53	.47	.50	.09
ANNUAL	28	6	4.47	.14	.13	.27	.03
ANNUAL	29	6	6.93	.02	.04	.10	.01
ANNUAL	30	6	9.61	.00	.02	.02	.00
ANNUAL	31	7	.67	.14	.30	.36	.08
ANNUAL	32	7	2.46	.30	.27	.34	.09
ANNUAL	33	7	4.47	.10	.13	.29	.06
ANNUAL	34	7	6.93	.03	.07	.18	.02
ANNUAL	35	7	9.61	.01	.04	.07	.01
ANNUAL	36	8	.67	.12	.30	.34	.08
ANNUAL	37	8	2.46	.34	.26	.33	.09
ANNUAL	38	8	4.47	.11	.13	.17	.03
ANNUAL	39	8	6.93	.04	.11	.12	.01
ANNUAL	40	8	9.61	.03	.13	.13	.00
ANNUAL	41	9	.67	.09	.20	.26	.07
ANNUAL	42	9	2.46	.34	.22	.29	.07
ANNUAL	43	9	4.47	.25	.23	.20	.02
ANNUAL	44	9	6.93	.13	.23	.17	.01
ANNUAL	45	9	9.61	.16	.45	.28	.00
ANNUAL	46	10	.67	.11	.23	.30	.06
ANNUAL	47	10	2.46	.37	.31	.39	.10
ANNUAL	48	10	4.47	.41	.40	.40	.05
ANNUAL	49	10	6.93	.40	.49	.42	.01
ANNUAL	50	10	9.61	.60	.96	.53	.00
ANNUAL	51	11	.67	.09	.18	.28	.07
ANNUAL	52	11	2.46	.27	.29	.52	.15
ANNUAL	53	11	4.47	.38	.44	.86	.12
ANNUAL	54	11	6.93	.49	.63	.86	.04
ANNUAL	55	11	9.61	.56	.71	.47	.00

Figure A3 (continued)

ANNUAL	56	12	.67	.11	.33	.51	.12
ANNUAL	57	12	2.46	.29	.40	1.03	.25
ANNUAL	58	12	4.47	.22	.48	1.71	.26
ANNUAL	59	12	6.93	.19	.55	1.25	.10
ANNUAL	60	12	9.61	.16	.29	.23	.01
ANNUAL	61	13	.67	.10	.36	.48	.09
ANNUAL	62	13	2.46	.34	.57	1.22	.23
ANNUAL	63	13	4.47	.43	.86	2.85	.34
ANNUAL	64	13	6.93	.51	1.13	3.45	.28
ANNUAL	65	13	9.61	.46	1.38	1.24	.04
ANNUAL	66	14	.67	.21	.58	.65	.12
ANNUAL	67	14	2.46	.77	1.05	1.36	.22
ANNUAL	68	14	4.47	1.01	1.36	2.52	.59
ANNUAL	69	14	6.93	.79	1.06	2.66	.81
ANNUAL	70	14	9.61	1.05	1.56	1.39	.12
ANNUAL	71	15	.67	.24	.70	.56	.13
ANNUAL	72	15	2.46	.80	.73	.94	.17
ANNUAL	73	15	4.47	.39	.33	.73	.20
ANNUAL	74	15	6.93	.07	.11	.24	.07
ANNUAL	75	15	9.61	.01	.02	.02	.00
ANNUAL	76	16	.67	.43	.72	.57	.10
ANNUAL	77	16	2.46	.89	.57	.54	.09
ANNUAL	78	16	4.47	.36	.21	.27	.02
ANNUAL	79	16	6.93	.12	.10	.11	.00
ANNUAL	80	16	9.61	.02	.04	.01	.00
NHOURS		8766					
AHOURS	AN	84.27	630.87	575.15	483.43	419.25	756.5 666.14 563.51
LEVELS		1	0.				
ANG/LID/UC		22.5	500.00	3.			
SPACING		8000.	8000.				
CF		3.					
CASE	12	40	REACTORS	SITES	1-7,9-11	ANNUAL CLIMATOLOGY	SHORT TOWERS

Figure A3 (continued)

NSITES	10						
SITE 1	4	1	6.1	7.5	1250.	25.	1609.
SITE 2	1	1	5.5	7.2	1250.	25.	1609.
SITE 3	1	1	4.7	6.7	1250.	25.	1609.
SITE 4	1	1	3.7	5.4	1250.	25.	1609.
SITE 5	1	1	3.7	4.9	1250.	25.	1609.
SITE 6	1	1	4.2	4.2	1250.	25.	1609.
SITE 7	1	1	3.3	4.0	1250.	25.	1609.
SITE 9	1	1	2.6	4.4	1250.	25.	1609.
SITE 10	1	1	3.1	4.5	1250.	25.	1609.
SITE 11	1	1	6.1	5.9	1250.	25.	1609.

```

      PROGRAM BATMAN(INPUT,OUTPUT,TAPE5=INPUT,TAPE6=OUTPUT)
      DIMENSION NUNITS(20),KTYPE(20),POS(20,2),QE(20),H0(20),W(20),
+      QT(20),QR(20),QL(20),QS(20),DV(20,2),VPOS(20,16,2),
+      IDIR(96),UBAR(96),FREQ(96,7),
+      Z(10),CHI(10),XLIM(10),IOPT(10),TYPE(7),
+      HEAD(10),AHOURS(10),
+      QWR(20),QW(20),EFF(7),FQ(7),
+      XTOTAL(12,12,20)
      KASE = 0
      READ (5,10023) NCASES
      PRINT 10050,NCASES
10050 FORMAT(1H1,10X,*NCASES CONSIDERED*,I8)
      PRINT 10007
      READ(5,10020) IOPT
10020 FORMAT(10X,10I1)
      GO TO (10,20) IOPT(1)+1
      10 PRINT 10021
10021 FORMAT(1H0,10X,*OUTPUT CONCENTRATION INCREASES*)
      GO TO 30
      20 PRINT 10022
10022 FORMAT(1H0,10X,*OUTPUT HOURS OF CONCENTRATION INCREASE*)
      READ(5,10023) NXLIM,(XLIM(I),I=1,10)
10023 FORMAT(10X,I5,13F5.2)
      PRINT 10024,NXLIM,(XLIM(I),I=1,NXLIM)
10024 FORMAT(1H ,10X,I5,' CONCENTRATION INCREASE LOWER LIMITS (G/M**3)
+ARF',10F6.2)
      30 CONTINUE
      TYPE(1)=10H LOW TOWER
      TYPE(2)=10H POND
      TYPE(3)=10HTALL TOWER
      TYPE(4)=10H H TOWER
      TYPE(5)=10H H POND
      TYPE(6)=10H RIVER

```

FIGURE A4. BATMAN Computer Code

Figure A4 (continued)

```

      READ(5,10001) EFF(1),FQ(1),EFF(2),FQ(2),EFF(3),FQ(3),EFF(4),FQ(4),
+      EFF(5),FQ(5),EFF(6),FQ(6),EFF(7),FQ(7)
10001 FORMAT(10X,14F5.3)
      PRINT 10009
10009 FORMAT(1H0,10X,*COOLING TYPE    EFFICIENCY    LATENT FRACTION*)
      DO 115 I=1,7
      PRINT 10010, TYPE(I),EFF(I),FQ(I)
10010 FORMAT(1H ,10X,A10,8X,F5.3,11X,F5.3)
      115 CONTINUE
C      INPUT CLIMATOLOGICAL DATA
      READ(5,10011) NS,NU,KSTAB,T
10011 FORMAT(10X,3I5,5F10.0)
      PRINT 10044,NS,NU,KSTAB,T
10044 FORMAT(1H ,10X,*CLIMATOLOGICAL PARAMETERS *,I5,2I5,F10.0)
      C1=6.2832/NS
      NDC=NS*NU
      IF(IOPT(2).EQ.1) READ (5,10023) NDC
      DO 120 I=1,NDC
      READ(5,10023)IDIR(I),UBAR(I),(FREQ(I,J),J=1,KSTAB)
10012 FORMAT(10X,10F7.2)
      DO 119 J=1,KSTAB
      119 FREQ(I,J)=FREQ(I,J)/100
      PRINT 10045,IDIR(I),UBAR(I),(FREQ(I,J),J=1,KSTAB)
10045 FORMAT(11X,*CLIMATOLOGICAL DATA *,I5,F7.2,7F8.4)
      120 CONTINUE
      READ(5,10023) NHOURS
      PRINT 10025,NHOURS
10025 FORMAT(1H ,10X,*TOTAL NUMBER OF HOURS =*,I6)
      IF(IOPT(3).EQ.1) READ(5,10012) (AHOURS(IH),IH=1,NXLIM)
      READ(5,10026) NZ,(Z(I),I=1,10)
10026 FORMAT(10X,I5,13F5.0)
      PRINT 10027,NZ,(Z(I),I=1,NZ)

```

Figure A4 (continued)

```

10027 FORMAT(1H ,10X,*CONCENTRATION COMPUTED AT*,15,* LEVELS, (IN METERS
+),*,10F6.0)
      IF(NXLIM*NZ-19) 50,50,40
40 PRINT 10028
10028 FORMAT(1H1,10X,*TOO MANY CONCENTRATION GROUPS AND LEVELS*)
      GO TO 20000
50 CONTINUE
      C2=.017453
C      INPUT LIMITS ON PLUME SPREAD, VERTICAL DISPERSION AND WAKE EFFECTS
      READ(5,10012)ANG,ZLID,UBC
      ANGR=ANG*C2
      CANG=COS(ANGR/2)
      TANG=TAN(ANGR/2)
      SANG=CANG*TANG
      PRINT 10013,ANG,ANGR
10013 FORMAT(1H ,10X,*ANGULAR WIDTH OF PLUMES IS*,F7.2* DEGREES/*,F7.4,
+      * RADIANS*)
      IF(ZLID.GT.0) PRINT 10014,ZLID
10014 FORMAT(11X,*VERTICAL DISPERSION IS LIMITED BY A LID AT *,F7.0,
+      * METERS*)
      IF(ZLID.LE.0) PRINT 10015
10015 FORMAT(11X,*VERTICAL DISPERSION IS NOT LIMITED BY A LID*)
      PRINT 10016,UBC
10016 FORMAT(11X,*DOWNWASH AND WAKE EFFECTS ARE ASSUMED FOR WIND SPEEDS
+ABOVE *,F5.1,* M/S*)
C      INPUT GRID SPACING
      READ(5,10012) XSPACE,YSPACE
      PRINT 10017,XSPACE,YSPACE
10017 FORMAT(1H ,10X,*NORTH-SOUTH GRID SPACING *,F7.0,METERS, EAST-WEST
+ GRID SPACING*,F7.0,* METERS*)
C      INPUT PLUME RISE CORRECTION FACTOR
      READ(5,10012) CF
      PRINT 10018,CF

```

Figure A4 (continued)

```

10018 FORMAT(1H ,10X,*PLUME RISE CORRECTION FACTOR FROM CLOUD MODEL IS*,
+      F10.3)
C      INPUT OF REACTOR COMPLEX DATA
5      CONTINUE
      KASE=KASE+1
      READ(5,10000) HEAD
10000 FORMAT(10A8)
      PRINT 10019,HEAD
10019 FORMAT(1H1,10X,10A8)
      PRINT 10007
      PRINT 10007
      READ(5,10002) NSITES
10002 FORMAT(10X,14I5)
      IF(NSITES.LE.20) GO TO 100
      PRINT 10003
10003 FORMAT(1H0,10X,*TOO MANY SITES*)
      GO TO 20000
100      CONTINUE
      DO 105 I=1,NSITES
      READ(5,10004)NUNITS(I),KTYPE(I),POS(I,1),POS(I,2),QE(I),HO(I),W(I)
10004 FORMAT(10X,2I5,6F10.2)
      K=KTYPE(I)
      IF(K.EQ.6) GO TO 101
      QT(I)=QE(I)/EFF(K)
      QR(I)=QT(I)-QE(I)
      QL(I)=QR(I)*FQ(K)
      QS(I)=QR(I)-QL(I)
      QW(I)=NUNITS(I)*QL(I)*400
      GO TO 105
101      CONTINUE
      QWR(I)=0.
      QL(I)=(NUNITS(I)/4)*QE(I)*W(I)*W(I)*.0007854
      QWR(I)=QL(I)/2.5

```

Figure A4 (continued)

```

      QE(I)=0.
      QS(I)=0.
      QR(I)=0.
105  CONTINUE
      PRINT 10005,NSITES
10005 FORMAT(1H0,10X,*THIS RUN CONSIDERS *,I5,* REACTOR COMPLEXES*)
      PRINT 10006
10006 FORMAT(1H0,10X,*SITE  UNITS   XPOS   YPOS       TYPE       HEIGHT  WID
+TH   QT      QE      QR      QL      QS      QW *)
      PRINT 10007
10007 FORMAT(1H )
      DO 110 I=1,NSITES
      K=KTYPE(I)
      QW1=QW(I)/1000
      IF(K.EQ.6) QW1=QWR(I)
      PRINT 10008,I,NUNITS(I),POS(I,1),POS(I,2),TYPE(K),HO(I),W(I),QT(I)
+      ,QE(I),QR(I),QL(I),QS(I),QW1
10008 FORMAT(11X,14,I7,2F7.2,2X,A10,F8.1,7F7.0)
110  CONTINUE
C      COMPUTE DISTANCE TO VIRTUAL SOURCE FOR EACH COMPLEX AND DETERMINE
C      VIRTUAL SOURCE POSITION AS A FUNCTION OF WIND DIRECTION
      DO 130 I=1,NSITES
      DV(I,1)=W(I)/(2*TANG)
      DV(I,2)=DV(I,1)*DV(I,1)
      POS(I,1)=XSPACE*(POS(I,1)-1)
      POS(I,2)=YSPACE*(POS(I,2)-1)
      DO 125 J=1,NS
      D=J*C1
      VPOS(I,J,1)=POS(I,1)-DV(I,1)*COS(D)
      VPOS(I,J,2)=POS(I,2)+DV(I,1)*SIN(D)
10040 FORMAT(1H ,10X,*DISTANCE TO VIRTUAL SOURCE, REAL AND VIRTUAL SOURC
+E COORDINATES*,5F10.0)
125  CONTINUE

```

Figure A4 (continued)

```

130 CONTINUE
C   COMPUTE INCREASE IN CONCENTRATION
    I3=0
    DO 5000 ID=1,NS
    DO 4000 IU=1,NU
    I3=I3+1
    DO 3000 IS=1,KSTAB
    IF(FREQ(I3,IS).LE.0) GO TO 3000
    DO 2000 IC=1,NSITES
    PR=0.0
    IF(H0(IC).LE.0.) GO TO 135
    IF(UBAR(IU).LE.UBC)
    +   CALL PRISE(KSTAB,IS,UBAR(IU),T,H0(IC),QS(IC),CF,PR),RETURNS(90
    +00)
    IF(PR.GE.ZLID) PR=ZLID-H0(IC)
135 CONTINUE
    HE=H0(IC)+PR
10029 FORMAT(1H,10X,*PLUME RISE AND EFFECTIVE RELEASE HEIGHT ARE (METER
    +S)*,2F10.0)
    IF(ZLID.GT.0.AND.HE.GT.ZLID) GO TO 2000
    DO 1000 IX=1,12
    XR=(IX-1)*XSPACE
    DO 999 IY=1,12
    YR=(IY-1)*YSPACE
    I2=IDIR(I3)
    CALL RCPTOR(POS(IC,1),POS(IC,2),VPOS(IC,I2,1),VPOS(IC,I2,2),XR,YR,
    +   CANG,DV(IC,1),DV(IC,2),DR),RETURNS(999)
10030 FORMAT(1H,10X,*SITE NUMBER, RECEPTOR POSITION AND VIRTUAL DISTANC
    +E ARE *,3I6,F10.0)
    IF(KSTAB.GE.6) ICT=KTYPE(IC)
    IF(KSTAB.EQ.4) ICT=KTYPE(IC)+7
    ISW= 5.2832/ANGR+.5
    IF(KTYPE(IC).EQ.6) QW(IC)=QWR(IC)*UBAR(IU)

```


Figure A4 (continued)

```

        CALL DIFFUSE(ISW,IS,UBAR(IU),                UBC,DR,ZLID,HE,QW(IC),
+       ICT,NZ,Z,CHI)
        DO 200 IZ=1,NZ
          XTOTAL(IX,IY,IZ)=CHI(IZ)+XTOTAL(IX,IY,IZ)
          CHI(IZ)=0
200    CONTINUE
999    CONTINUE
1000   CONTINUE
2000   CONTINUE
        HOURS=FREQ( I3 ,IS)*NHOURS
        GO TO (5000,2100),IOPT(1)+1
2100   CONTINUE
        DO 2230 IX=1,12
          DO 2220 IY=1,12
            DO 2210 IZ=1,NZ
              DO 2200 IL=1,NXLIM
                IIZ=IL*NZ+IZ
                IF(XTOTAL(IX,IY,IZ).GE.XLIM(IL)) XTOTAL(IX,IY,IIZ)=
+                XTOTAL(IX,IY,IIZ) + HOURS
2200   CONTINUE
2210   XTOTAL(IX,IY,IZ)=0.0
2220   CONTINUE
2230   CONTINUE
3000   CONTINUE
4000   CONTINUE
5000   CONTINUE
        GO TO (5100,6000) IOPT(1)+1
5100   CONTINUE
        DO 5120 IZ=1,NZ
          PRINT 11000,Z(IZ)
11000  FORMAT(1H1,10X,'INCREASE IN MOISTURE (G/M**3) AT Z  = ',F7.0,
+          ' METERS')
        DO 5110 IX=1,12

```

Figure A4 (continued)

```

        PRINT 11001,(XTOTAL(IX,IY,IZ),IY=1,12)
11001 FORMAT(1H0,10X,12F10.2)
        DO 5105 IY=1,12
          5105 XTOTAL(IX,IY,IZ)=0.
          PRINT 11003
11003 FORMAT(1H0)
          5110 CONTINUE
          PRINT 11002,HOURS
11002 FORMAT(1H0, 10X,*THIS CONDITION OCCURS AN AVERAGE OF *,F7.0,* HOUR
          +S PER YEAR*)
          5120 CONTINUE
          GO TO 20000
        6000 CONTINUE
          DO 6030 IZ=1,NZ
            DO 6020 IL=1,NXLIM
11010 FORMAT(1H1,10X,'NUMBER OF HOURS THAT THE INCREASE IN MOISTURE AT Z
          + = ',F7.0,' METERS EQUALED OR EXCEEDED ', F7.2,' G/M**3')
            PRINT 11010,Z(IZ),XLIM(IL)
            IIZ=IL*NZ+IZ
            DO 6010 IX=1,12
              PRINT 11004,(XTOTAL(IX,IY,IIZ),IY=1,12)
11004 FORMAT(1H0,10X,12F7.1)
              PRINT 11003
              IF(IOPT(3).EQ.1) GO TO 6010
              DO 6025 IY=1,12
                6025 XTOTAL(IX,IY,IIZ)=0.
              6010 CONTINUE
              IF(IOPT(3).NE.1) GO TO 6020
              DO 6012 IX=1,12
                DO 6011 IY=1,12
                  XTOTAL(IX,IY,IZ)=XTOTAL(IX,IY,IZ)+AHOURS(IL)*XTOTAL(IX,IY,IIZ)
                  + /NHOURS
                  XTOTAL(IX,IY,IIZ)=0.

```

Figure A4 (continued)

```
6011 CONTINUE
6012 CONTINUE
6020 CONTINUE
      IF(IOPT(3).NE.1) GO TO 6030
      PRINT 11005,Z(IZ)
11005 FORMAT(1H1,10X,*INCREASE IN NUMBER OF HOURS OF FOG AT*,F6.0,
+      * METERS*)
      DO 6015 IX=1,12
      PRINT 11004,(XTOTAL(IX,IY,IZ),IY=1,12)
      PRINT 11003
      DO 6014 IY=1,12
      XTOTAL(IX,IY,IZ)=0.
6014 CONTINUE
6015 CONTINUE
6030 CONTINUE
      GO TO 20000
9000 PRINT 12000
12000 FORMAT(1H ,10X,*TOO FEW STABILITY CLASSES IN SUBROUTINE PRISE*)
20000 CONTINUE
      IF(KASE.LT.NCASES) GO TO 5
      END
```

Figure A4 (continued)

```

SUBROUTINE PRISE(KSTAB,KSTB,UBAR,T,H0,QS,CF,PR),RETURNS(A1)
C  SUBROUTINE PRISE COMPUTES FINAL PLUME RISE USING BRIGGS 1969
C  FORMULAE.  IF UBAR IS LESS THAN 1 M/S THE CALM EQN IS USED FOR
C  STABLE CONDITIONS OR UBAR IS SET EQUAL TO .5 M/S IN UNSTABLE AND
C  NEUTRAL CONDITIONS.  INPUT IN METRIC UNITS, QS IN MW. PLUME RISE IS
C  CORRECTED FOR LATENT HEAT USING RESULTS OF COMPARISON WITH A 1-D
C  CUMULUS CLOUD MODEL.
      FB=8.9*QS
      GO TO (100,100,100,10,100,11,12), KSTAB
10  GO TO (21,21,31,32),KSTB
11  GO TO (21,21,21,21,31,32),KSTB
12  GO TO (21,21,21,21,31,32,33),KSTB
21  IF(UBAR-.5) 22,23,23
22  U=.5
      GO TO 24
23  U=UBAR
24  PR=(1.6/U)*((100*H0*H0*FB)**(1./3.))*CF
      GO TO 200
31  S=.049/T
      GO TO 40
32  S=.27/T
      GO TO 40
33  S=.49/T
40  CONTINUE
      IF(UBAR-1) 50,60,60
50  PR=5.0*(FB*FB/(S*S*S))**((1./8.))*CF
      GO TO 200
60  PR=2.7*(FB/(UBAR*S))**((1./3.))*CF
      GO TO 200
100 RETURN A1
200 RETURN
      END

```

Figure A4 (continued)

```

      SUBROUTINE RCPTOR(X0,Y0,XV,YV,XR,YR,CANG,DV,DV2,DR),
+RETURNS(A)
C      SUBROUTINE RCPTOR DETERMINES IF A RECEPTOR IS IN A PLUME AND
C      COMPUTES THE DISTANCE FROM A VIRTUAL SOURCE POINT IF IT IS. INPUTS
C      INCLUDE POSITIONS OF THE REAL AND VIRTUAL SOURCE AND RECEPTOR, THE
C      COSINE OF 1/2 THE ANGULAR WIDTH OF THE PLUME, AND THE DISTANCE
C      FROM THE REAL TO VIRTUAL SOURCE. IF THE RECEPTOR IS NOT IN THE
C      PLUME, THE SUBROUTINE RETURN SKIPS FURTHER CONSIDERATION OF THE
C      RECEPTOR.
10000 FORMAT(11X,*RCPTOR*,6F10.0,F10.5,2F10.0)
      D2=(XR-X0)*(XR-X0)+(YR-Y0)*(YR-Y0)
      IF(DV) 20,20,5
      5 CONTINUE
      DR2=(XR-XV)*(XR-XV)+(YR-YV)*(YR-YV)
      IF(DR2-D2) 20,20,10
      10 IF(DR2-DV2) 20,20,15
      15 DR=SQRT(DR2)
      RANG=(D2-DR2-DV2)/(-2*DV*DR)
10001 FORMAT(11X,*RCPTOR COMPUTATIONS *,F10.0,F10.5)
      IF(RANG-CANG) 20,30,30
      20 RETURN A
      30 CONTINUE
      RETURN
      END

```

Figure A4 (continued)

```

SUBROUTINE DIFFUSE(NS,KSTB,UBAR,      UBC,DR,ZLID,H,Q,ICT,NZ,Z,CHI)
C  SUBROUTINE DIFFUSE PERFORMS DIFFUSION COMPUTATIONS USING A SECTOR
C  AVERAGED GAUSSIAN PLUME MODEL WITH COMPLETE REFLECTION AT GROUND
C  LEVEL.  A REFLECTING LID IS OPTIONAL.  THE SOURCE MAY BE ELEVATED
C  OR AT GROUND LEVEL.  THE RELEASE HEIGHT IS ASSUMED TO BE BELOW THE
C  LID.  ALL REFLECTION TERMS CONTRIBUTING LESS THAN .25 PERCENT OF
C  THE DOMINANT TERM TO CHI/Q ARE NEGLECTED.  WHEN ZLID/SIGMAZ IS LESS
C  THAN 1.5, A UNIFORM VERTICAL CONCENTRATION IS ASSUMED.  TEN LEVELS
C  CAN BE TREATED, IF A LEVEL IS ABOVE THE LID THE CONCENTRATION IS
C  ZERO.  THE BASIC SECTOR AVERAGE MODEL IS DESCRIBE IN SECTION 3-3 OF
C  M+AE-1968.  TREATMENT OF REFLECTION IS BASED ON SECTION 6.6 OF TEXT
C  BY CSANADY, 1973
C  DIMENSION Z(10),CHI(10)
C  OBTAIN SIGMAZ ESTIMATE
C  CALL SIGMAZ(KSTB,UBAR,UBC,H,ICT,DR,SZ,SZ2)
10000 FORMAT(11X,*STAB,CLASS,WIND SPEED,RELEASE HEIGHT,ICT,DISTANCE,AND
+ SIGMAZ ARE*,15,F6.2,F5.0,15,F7.0,F6.2)
C  DNM= -2*SZ2
C  COEF=(.0635*NS)/(DR*SZ*UBAR)
C  IS THERE A LID, IF SO GO TO 30
C  IF(ZLID) 10,10,30
C  NO LID
C  ELEVATED RELEASE, IF SO GO TO 20
10 IF(H) 11,11,20
C  COMPUTE CHI/Q FOR GROUND LEVEL SOURCE WITHOUT LID
11 DO 15 I=1,NZ
C  IF(Z(I)) 12,12,13
12 CHI(I)=2*COEF
C  GO TO 15
13 CHI(I)=2*COEF*EXP(Z(I)*Z(I)/DNM)
15 CONTINUE
C  GO TO 300 TO COMPUTE CHI
C  GO TO 300

```

Figure A4 (continued)

```

C      COMPUTE CHI/Q FOR ELEVATED SOURCE WITHOUT LID
20 DO 25 I=1,NZ
    IF(Z(I)) 21,21,22
21 CHI(I)=2*COEF*EXP(H*H/DNM)
    GO TO 25
22 E1=EXP((Z(I)-H)**2/DNM)
    IF(Z(I)*H/SZ2-2.9957) 24,23,23
23 CHI(I)=COEF*E1
    GO TO 25
24 CHI(I)=COEF*(E1+EXP((Z(I)+H)**2/DNM))
25 CONTINUE
    GO TO 300
C      THERE IS A LID
30 R0=ZLID/SZ
    R02=R0*R0
C      IS THERE UNIFORM CONCENTRATION IN THE VERTICAL IF NOT GO TO 50
    IF(R0-1.5) 40,40,50
40 DO 45 I=1,NZ
    IF(Z(I)-ZLID) 42,42,41
41 CHI(I)=0
    GO TO 45
42 CHI(I)=2.507*COEF*R0
45 CONTINUE
    GO TO 300
C      IS THE SOURCE ELEVATED, IF SO GO TO 110
50 IF(H) 55,55,110
C      COMPUTE CHI/Q FOR GROUND LEVEL SOURCE WITH LID
55 DO 100 I=1,NZ
    IF(Z(I)-ZLID) 59,59,56
56 CHI(I)=0
    GO TO 100
59 IF(Z(I)) 60,60,80
60 IF(1.73-R0) 65,65,70

```

Figure A4 (continued)

```

65 CHI(I)=2*COFF
   GO TO 100
70 CHI(I)=2*COFF*(1+EXP(-2*R02))
   GO TO 100
80 R1=Z(I)/SZ
   R1R0=R1*R0
   E1=EXP(-R1*R1/2)
   IF(R02-R1R0-2.9957) 81,90,90
81 E1=E1+EXP((Z(I)-2*ZLID)**2/DNM)
   IF(R2+R1R0-2.9957) 85,90,90
85 E1=E1+EXP((Z(I)+2*ZLID)**2/DNM)
90 CHI(I)=COFF*E1
100 CONTINUE
   GO TO 300
C   COMPUTE CHI/Q FOR ELEVATED SOURCE WITH LID
110 R2=H/SZ
   R2R0=R2*R0
   DO 180 I=1,NZ
   IF(Z(I)-ZLID) 119,119,115
115 CHI(I)=0
   GO TO 180
119 IF(Z(I)) 120,120,140
120 F1=EXP(-R2*R2/2)
   IF(R02-R2R0-2.9957) 121,130,130
121 F1=F1+EXP((H-2*ZLID)**2/DNM)
   IF(R02+R2R0-2.9957) 125,130,130
125 F1=F1+EXP((H+2*ZLID)**2/DNM)
130 CHI(I)=2*COFF*E1
   GO TO 180
140 R1=Z(I)/SZ
   R1R0=R1*R0
   R1R2=R1*R2
   F1=EXP((Z(I)-H)**2/DNM)

```


Figure A4 (continued)

```
      IF(R1R2-2.9957) 141,145,145
141  F1=E1+EXP((Z(I)+H)**2/DNM)
145  IF(R02+R1R2-R1R0-R2R0-2.9957) 146,170,170
146  ZL2=2*ZLID
      E1=E1+EXP((Z(I)+H-ZL2)**2/DNM)
      IF(R02+R2R0-R1R0-2.9957) 150,151,151
150  F1=E1+EXP((Z(I)-H+ZL2)**2/DNM)
151  IF(R02+R1R0-R2R0-2.9957) 155,156,156
155  E1=E1+EXP((Z(I)-H-ZL2)**2/DNM)
156  IF(R02+R1R0+R2R0+R1R2-2.9957) 160,161,161
160  F1=E1+EXP((Z(I)+H+ZL2)**2/DNM)
161  IF(2*R02+R1R2/2-R1R0-R2R0-2.9957) 165,170,170
165  F1=E1+EXP((Z(I)+H-4*ZLID)**2/DNM)
170  CHI(I)=COEF*E1
180  CONTINUE
C    COMPUTE CHI(Z) FROM CHI(Z)/Q AND Q
300  DO 310 I=1,NZ
      CHI(I)=CHI(I)*Q
310  CONTINUE
      RETURN
      END
```

Figure A4 (continued)

```

SUBROUTINE SIGMAZ(KSTB,UBAR,URC,H,ICT,DR,SZ,SZ2)
C  SUBROUTINE SIGMAZ COMPUTES AN ESTIMATE OF SIGMA Z USING BRIGGS
C  RELATIONSHIPS. SIGMA Z IS A FUNCTION OF DISTANCE AND STABILITY.
C  FOR HIGH WIND SPEEDS AND COOLING TOWER PLUMES A CORRECTION FACTOR
C  IS ADDED TO SIGMA Z TO ACCOUNT FOR WAKE EFFECTS.
GO TO (10,11,10,10,11,11,10,12,12,12,12,12,12,12),ICT
10 GO TO (21,22,23,24,25,26,27),KSTB
11 GO TO (21,22,23,24,25,26,26),KSTB
12 GO TO (22,24,25,26),KSTB
C  COMPUTE INTIAL SIGMA Z ESTIMATE
21 SZ=.2*DR
GO TO 30
22 SZ=.12*DR
GO TO 30
23 SZ=.08*DR/(SQRT(1+.0002*DR))
GO TO 30
24 SZ=.06*DR/(SQRT(1+.0015*DR))
GO TO 30
25 SZ=.03*DR/(1+.0003*DR)
GO TO 30
26 SZ=.02*DR/(1+.0003*DR)
GO TO 30
27 SZ=.012*DR/(1+.0003*DR)
30 GO TO (35,50,50,35,50,50,50,35,50,50,35,50,50,50),ICT
35 IF(UBAR-URC) 50,40,40
C  CORRECT SIGMA Z FOR COOLING TOWER WAKE
40 SZ2=(SZ*SZ+H*H/6.28)
SZ = SQRT(SZ2)
GO TO 100
50 SZ2=SZ*SZ
100 CONTINUE
RETURN
END

```

A REVIEW OF POTENTIAL TECHNOLOGY
FOR THE SEISMIC CHARACTERIZATION
OF NUCLEAR ENERGY CENTERS

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1.0 INTRODUCTION

This study is part of the ERDA-funded Hanford Nuclear Energy Center (HNEC) Program and is one of a series of technical investigations in support of that study. The primary objectives of the study were: 1) to review, analyze, and summarize the existing seismic evaluation technique and criteria for the siting and design of individual nuclear facilities, 2) to speculate as to how the criteria may change in the immediate future, 3) to convey the concept that new seismic criteria may have to evolve in the future to accommodate the magnitude of capital, generating capacity, and nuclide inventory associated with the centralized NEC concept, and 4) to identify techniques and tools that may be available to guide in the drafting of and the compliance with any new seismic criteria.

Risk is often defined as the mathematical product of the occurrence probability of a specific event and the associated consequence. The consequences may be categorized as 1) primary, i.e., impact of a radioactive release to the biosphere, and 2) secondary, i.e., loss of electrical generating capacity. Assuming that all of the facilities within a NEC respond as a unit to an initiating (seismic) event, it would appear that the centralization concept would be at a disadvantage. The consequences of an event in excess of the Safe Shutdown Earthquake (SSE) or the Design Basis Earthquake (DBE) would be greater than for the dispersed siting concept. However, if all of the funds expended on the siting and seismic design for the dispersed concept were channeled into a single enhanced evaluation of the centralized site, then possibly the error band associated with the SSE and DBE events might be reduced. Furthermore, improved facility design might be implemented due to the more dramatic consequences associated with centralization. In other words, if all of the eggs are placed in a single basket, one would like to have the basket of strength commensurate with the consequences of losing the contents. The fundamental point is: the NEC concept may motivate technological advancements in seismically related design and siting of nuclear facilities and may prompt the evaluation of new criteria specifically designed to reduce the risk associated with the centralization concept.

2.0 PRESENT SEISMIC CRITERIA

The Nuclear Regulatory Commission (NRC) is charged with the responsibility for regulating all uses of nuclear energy. To fulfill this function, the NRC has established design requirements for nuclear power plants, and reviews each license application for construction of such a facility to ensure that these requirements are met.

Many factors are evaluated when designing nuclear plants in order to provide sufficient safety for operation, control, and containment. Of these factors, the resistance of a nuclear power plant to strong motion earthquakes is one of the most significant design constraints considered in a license application.

Earthquakes present a unique hazard because their potential effects on nuclear plants are among the most significant that can result from natural causes. They are also unique in that they simultaneously threaten every structure, system, and component, even redundant systems, and thus lead to the possibility of a common mode failure. In addition, the ground motion induced may result in associated phenomena, such as landslides, subsidence, or liquefaction of the soil in and around the plant site.

The design requirements are established via laws, regulations, and established policy. To provide an overview for site selection and design requirements arising from seismic and geologic considerations, an appendix to the NRC criteria, 10 CFR 100, title "Appendix A - Seismic and Geologic Siting Criteria for Nuclear Power Plants," has been formulated (AEC, 1975). This appendix is to be followed by all applicants for nuclear power plant construction and operating licenses. It contains seismological and geotechnical requirements and general procedures for determining seismic input criteria at a site. This includes consideration of potential earthquake-induced effects such as vibratory ground motions, soil and slope instabilities, floods, and water waves. These criteria must be incorporated in preliminary and final safety analysis reports, prepared according to standard NRC format and content requirements (AEC, 1972). In addition, the criteria must be

used in conjunction with NRC regulations which are issued as NRC Regulatory Guides. These guides establish those methods, techniques, and parameters that are acceptable for use in a license application. The NRC has also issued their Standard Review Plan (SRP) in an attempt to speed licensing time. This document describes in detail specifically how the NRC reviews a license application and the material the application is expected to contain. These various documents, many of which are summarized in Appendix A, provide the basis for this section.

The remainder of this section is organized into four subsections, each of which describe in more detail the present seismic design criteria for nuclear power plants. Seismic Input describes the methodology used to obtain site ground motion for design. As this is one of the most controversial elements of the design chain, considerable detail is presented. Soil-Structure Interaction describes methods used to quantify the effects of ground motion on site structures. Structural Analysis describes the methods used to analyze and design structures for the effects of earthquake ground motion. Seismic Operating Criteria describes various criteria affecting plant operation.

SEISMIC INPUT

The principal investigations and procedures required to license a nuclear plant are outlined in the NRC criteria document denoted as Appendix A, 10 CRF 100, "Seismic and Geologic Siting Criteria for Nuclear Power Plants," (AEC, 1974). This section reviews the geologic, seismologic, and site soils investigations and testing required for use in deriving ground motion criteria in accordance with the above document.

In order to comply with Appendix A, 10 CRF 100, the coordinated efforts of the geology, seismology, and engineering disciplines are required (Figure 1).

The planning phase comprises the preliminary work required to develop and coordinate subsequent field and office studies. This includes literature reviews, site inspections, and scheduling of future work.

FIGURE 1. Geotechnical Investigations for Evaluating Ground-Motion Characteristics

The investigation phase includes detailed regional and site investigations, laboratory testing, and preliminary estimates of vibratory ground motions at the site. The work in each of these categories is closely related.

The regional geologic and seismologic studies involve investigation and evaluation of the physiography, stratigraphy, tectonics, and geologic and seismic history of the area. These studies identify the seismic events and associated geologic features that together define the most significant earthquakes used to evaluate the site response.

The site geology and soils investigations determine the local geologic conditions, including the soil profile and the rock and soil properties required for static and dynamic design. The soil dynamic properties required include the shear modulus, damping ratio, Poisson's ratio, mass density, and shear strength. Of these, the shear modulus and damping are most significant in seismic response calculations. These soil properties are obtained from a field exploration and laboratory testing program consisting of borings, geophysical surveys and other field measurements, subsurface soil sampling, and laboratory tests.

The engineering phase involves evaluations and engineering studies necessary to determine the ground motion criteria for the site and procedures for evaluation of potential site failure conditions such as liquefaction.

There are several definitions in 10 CFR 100 that warrant elaboration. First, the NRC criteria define two levels of earthquake ground motions for which a nuclear plant must be designed: the Safe Shutdown Earthquake (SSE) and the Operating Basis Earthquake (OBE). Typically, these earthquakes are obtained by correlating past earthquakes with known geologic structures or - in the absence of such features - with tectonic provinces.

The SSE represents the maximum possible earthquake event at the site. This hypothetical event may not have occurred at the site

in historic times, and therefore, it is primarily based on a detailed investigation of the regional and local geology, regional seismology, and characteristics of the underlying soil materials. The nuclear plant should be designed for this earthquake so that all systems necessary to protect the health and safety of the public will remain functional both during and after the event. Structures and components may suffer severe damage from the SSE, but the design must allow a safe and orderly shutdown subsequent to the seismic event. The allowable lower bound for the peak horizontal ground acceleration at the site for an SSE is 0.1 g.

The OBE represents the earthquake event that can be expected to occur at the site during the operating life of the plant. This earthquake, like the SSE, is based on a detailed investigation of the regional and local geology, regional seismology, and characteristics of the underlying soil materials. The nuclear plant should be designed for this earthquake so that those systems of the plant necessary for continued operation without undue risk will remain functional both during and after the event. If the OBE is exceeded at the site, the plant must shut down until it is demonstrated that critical features of the plant have not been damaged. Currently, the allowable lower bound for the peak horizontal ground acceleration at the site for an OBE is 0.05 g or one-half the SSE, whichever is greater.

Second, a fault is a tectonic structure along which differential movement of adjacent earth materials has occurred parallel to the fracture plane. Surface faulting is differential ground movement at or near the surface caused by fault movement. The NRC criteria for a fault to be considered capable of surface movement during plant lifetime requires one or more of the following:

1. Movement at or near the surface at least once in the last 35,000 years and more than once in the last 500,000 years.
2. Fault-related instrumentally determined microseismicity.
3. A relationship to an active fault such that movement on one fault could reasonably be expected to be accompanied by movement on the other.

Third, tectonic province is a region with relatively consistent geologic features. The province boundaries are determined through a regional analysis of the geologic and tectonic environments and the seismic history of the area (Coulter et al, 1973). The tectonic province concept is particularly important where earthquake epicenters cannot be related to known faults or other specific major tectonic structures. An understanding of these definitions, which are unique to the ERDA and the NRC, is crucial to an appreciation of the current methodology for design of dispersed nuclear power plants.

Regional Geology

The geologic characteristics of the site region should be investigated in sufficient detail to provide a clear understanding of the physical processes involved in the geologic history of the area while emphasizing the potential for future seismic activity. The size of the region to be investigated is both area- and site-dependent and may be limited to 200 miles around the site or may include an entire tectonic province depending on the regional tectonics.

The geologic investigations begin with an evaluation of available literature. This is correlated with existing published and unpublished geologic maps. The preliminary stratigraphic relationships, tectonic framework, and geologic history are then determined, resulting in a preliminary geologic map. Aerial photographs and standard geologic field mapping techniques are used with subsurface studies to prepare the final geologic map and establish the physiography, stratigraphy, and structural geologic conditions of the area.

Physiography

Detailed site and aerial reconnaissance is performed to identify important geologic surface features (land forms, drainage patterns, areas of surface water collection, etc.), and to evaluate the relationship between such features and probable subsurface conditions. The relationship between the regional and site physiography should be considered. The final product is a regional physiographic map.

Stratigraphy

The stratigraphic investigations include an analysis and description of the lithology, composition, mode of occurrence and age of the various geologic units underlying and surrounding the site. Regional geologic maps are prepared. Stratigraphic column and geologic cross sections relating regional and local geologic conditions to the site are prepared. This information is developed from the literature, field mapping of outcrops, well logs, and special borings.

Tectonics

Investigations of the tectonics include identification and evaluation of all tectonic structures in the region, whether buried or at the surface. These structures include folds, basins, domes, and faults. The possible effects of man-related activities near the site should be considered, such as the earthquakes produced by the loading effects of dams or reservoirs, the pumping or extraction of subsurface water, or the extraction of minerals.

Identification of all capable faults within 200 miles of the site is of particular importance. They may be observed directly from exposures in the field or detected during well drilling or boring. Usually, their identification is based on more indirect evidence such as gravity or aeromagnetic surveys, acoustical or seismic profiles, black-and-white, color, or infrared aerial photography, multispectral satellite imagery, and side-looking radar imagery. In particularly difficult situations, final assessment is often based on angled borings, trenching, and tunneling.

As defined above, a capable fault is one along which movement has occurred in geologically recent times. Various dating techniques are used to evaluate these potential fault movements:

1. The limiting age of 35,000 years is established indirectly by using geologic methods or absolutely by using radioactive carbon techniques.
2. The limiting age of 500,000 years is established indirectly by using:
 - Geologic methods, which include paleontologic and stratigraphic relations, weathering profiles, and geomorphic features.

- Paleomagnetic methods based on remnant magnetism.
- Radiometric methods measuring radioactive decay.
- Geochemical methods which measure the concentration of specific trace elements or oxides.

Once capable faults are identified, their potential for producing a major earthquake must be evaluated. Thus, the following features of those faults longer than those lengths indicated in Table 1 should be determined:

1. Fault length.
2. Magnitude and nature of past displacement.
3. Geologic history of movement, particularly the age of the latest.
4. Relationship of fault to regional tectonic structures.

TABLE 1. Minimum Fault Length Versus Distance from Site (AEC, 1972)

<u>Minimum Distance from Site, (miles)</u>	<u>Minimum Fault Length to be Considered (miles)</u>
0 - 20	1
20 - 50	5
50 - 100	10
100 - 150	20
150 - 200	40

A tectonic map should be prepared showing the location of major faults, folds, warps, and other structural features, defining them in terms of dimensions, attitude, and age. This map should also show areas of actual or potential surface or subsurface subsidence, uplift, or collapse from tectonic or human activities.

Geologic History

The final step in the regional geology investigations is the reconstruction of the geologic history of the area, emphasizing late Tertiary and younger tectonic history. This history is of prime importance as it provides the regional framework for establishing the pattern and age of major deformations including recent faulting.

Site Geology and Soil Engineering Properties

As depicted in Figure 1, site geology and soil engineering investigations are required at nuclear power plant sites. It is convenient to include them in this section since many of the studies required are natural follow-ons to the work performed in the regional and site geology investigations.

The overall purpose of these investigations is to define all aspects of the site geology, including the soil and rock profiles and the material properties required for foundation design, stability evaluations, and seismic response calculations. These investigations result in the determination of the soil and rock classifications, the thickness and lateral distribution of the soil strata, groundwater levels, and the engineering properties of the bedrock and of each soil layer down to bedrock or to relatively firm materials. Both field and laboratory investigations are carried out.

Field Data

Field investigations are carried out using borings, trenches, and geophysical techniques such as seismic refraction surveys, inhole surveys and electrical resistivity surveys.

Laboratory Data

Laboratory testing is carried out to classify the soil and rock, determine the unit weight, relative density, shear modulus, damping, Poisson's ratio, bulk modulus (rarely), and static and dynamic strength.

A summary of the field and laboratory testing is shown in Table 2.

Seismology

A summary of the seismology and ground motion requirements is presented in Figure 2.

The potential for earthquake activity near a nuclear power plant site is determined from the seismic history and characteristics of the site and the surrounding region, and their relationship to the geologic conditions. This requires a thorough research, review, and evaluation of all historic earthquakes that have affected, or could reasonably be expected to have affected the site. Listings of these earthquakes should be prepared and should include:

1. Date of Occurrence.
2. Epicentral Intensity and Magnitude.
3. Epicenter Location.

This information is used to compile:

1. Epicentral Maps. Two maps are required, each showing tectonic structural features and earthquake epicenters in the site vicinity. One shows the epicenters of all earthquakes within 50 miles of the site and the other epicenters of all earthquakes equal to or larger than intensity IV (MM) within 200 miles of the site.
2. Correlation of Epicenter Locations and Tectonic Structures. The epicenters, or locations of highest intensity, of historic earthquakes should be correlated with tectonic structures having any part within 200 miles of the site.

TABLE 2. Determination of Soil Material Properties Required
for Vibratory Ground Motion Investigations

<u>Property</u>	<u>Type of Test</u>	<u>Soil Materials</u>	<u>Most Commonly Used</u>
Classification	Field	All Types	Visual inspection
		Granular	Visual inspection; grain-size; natural water content
	Laboratory	Cohesive	Visual inspection; Atterberg limits; natural water content
Unit Weight	Field	All types	In-place density
	Laboratory	All types	Undisturbed specimen
Relative Density	Field	Granular	Standard penetration
	Laboratory	Granular	Undisturbed specimen, if obtainable
Shear Modulus*	Field	All types	Geophysical
	Laboratory	All types	Triaxial; simple shear; resonant column
Damping*	Laboratory	All types	Triaxial; resonant column
Poisson's Ratio	Field	All types	Geophysical
	Laboratory	All types	Triaxial, usually estimated
Bulk Modulus	Laboratory	All types	Triaxial; not commonly measured
Static Strength	Laboratory	Cohesive	Unconfined compression
Dynamic Strength	Laboratory	All types*	Triaxial

3. Rates of Attenuation with Distance. If possible, isoseismal maps should be compiled.
4. Recurrence Intervals. If sufficient data are available, the frequency of occurrence of earthquakes of a given size should be determined. These recurrence intervals provide useful supporting data for defining the design earthquake.
5. Identification of Appropriate Empirical Data. Typically, earthquakes are reported in terms of magnitude, intensity, and epicentral distance. Empirical charts relating these parameters to peak acceleration, duration of strong shaking, etc., are available in the literature and must often be used to estimate ground motion at nuclear plant sites.
6. Other Data. When available, other data are reported, such as the duration of strong shaking, the area within which the earthquake was felt, important damage effects (such as landslides, liquefaction, or subsidence), tsunami, etc.

The purpose of the geologic and seismologic studies of the region and site is to establish the SSE and OBE. These studies provide the information necessary to identify the seismic events and geologic features that define the most significant earthquakes to consider in evaluating vibratory ground motion effects at the site.

The most significant earthquakes are determined from an evaluation of the seismology, geology, and seismic and geologic histories of the site and surrounding region. The most severe earthquakes associated with tectonic structures or tectonic provinces in the region surrounding the site are identified by considering the historic earthquakes and other factors such as duration and felt areas, damage effects, recurrence intervals, earthquake magnitude vs. fault length, and displacement on the fault. If capable faults exist in the region, the most severe associated earthquake should be determined by also considering their geologic history. The general procedures for defining the most significant potential earthquakes are as follows:

1. Where the historic earthquakes of greatest intensity can be correlated with a fault or tectonic structure near the site, the epicenters of these events are assumed to be located at the point on the fault or structure closest to the site.
2. Where the epicenter of a large earthquake cannot be related to a fault or tectonic structure it must be identified with a tectonic province. If the site is also within that province, the earthquake is assumed to occur at the site. Otherwise, the earthquake is assumed to occur at the point along the boundary of the tectonic province that is closest to the site.

Once potential significant earthquake events are located, the basic design parameters required for the seismic response studies can be determined. These parameters include the peak ground acceleration, the duration of strong shaking, and peak rock acceleration. They are obtained from both the intensity-duration data for the region and from the empirical data that relate these parameters to the magnitude, intensity, and epicentral distance of the earthquake event.

SOIL STRUCTURE INTERACTION

The previous section described the present methodology for determining the seismic design bases for dispersed nuclear power plants. This section reviews the next step in the overall seismic methodology chain and the effect of the seismic input on the site features, and evaluates the modifications made on the seismic input through interaction with the site structures and other construction works.

The dynamic interaction of structures and their supporting soil media has been the subject of investigations spanning at least the past 40 years. While much of the initial work focused upon machine foundation vibration problems and development of suitable analytic models for prediction of structure response to dynamic loads, it has long been recognized that soil effects can be significant in the seismic response of large-scale structural systems. The general observation has been made that, in the case of the

light flexible structures comprising the bulk of conventional construction, soil influence in modifying the dynamic response of the structures is usually small. The exception to this observation is the case of conventional structures founded upon very flexible soil media (typical shear wave velocities less than 1000 ft/sec). At the other extreme is the case of massive rigid structures, such as nuclear power containment structures and concrete dams. For these structures, interactive effects will generally be significant if not dominant in structural seismic response, with interaction modifying both the base response and structural and equipment response at higher elevations in the structure. The importance of interaction effects depends, in a specific case, upon the relative mass, stiffness, and damping characteristics of the structure and surrounding soil. For massive, stiff structures, the dominant interaction contribution comes from rocking; rocking can produce significantly higher structural response at locations away from the center of mass, with peak accelerations increasing by an order of magnitude over the input free-field accelerations. While nuclear containment structures are typically sited at locations possessing "good" soils from the point of view of stability and other dynamic characteristics and the structures are partially embedded in the soil media, interaction is typically of major importance in determining the structure and equipment loads induced by potential earthquake excitation.

The significance of soil-structure interaction for nuclear power plants and analytical techniques for dealing with the associated phenomena have been the subject of intensive investigation and publications since the late 1960's. However, experimental investigation of interaction effects and validation of analytical procedures has lagged far behind theoretical developments, due in part to the paucity of strong-motion earthquake records taken in any structures, let alone nuclear containment structures.

Rock Site

When the nuclear power plant structures are founded on rock, the soil structure interaction (SSI) requirements are usually very simple. Because interaction effects on rock are negligible, the seismic input is applied directly to the structures.

Soil Site

When the nuclear power plant structures are founded on soil, specific SSI calculations are required. The methods acceptable to the NRC are depicted in Figure 3, which will serve as the basis for the review:

1. Deconvolution Model

This is a one-dimensional model based on the assumption that horizontal earthquake motions are transmitted by vertically propagating shear waves and vertical earthquake motions by vertically propagating compressive waves. Although the model requires viscoelastic soil layers, the method takes account of soil nonlinearities by an equivalent solution for the response in which the nonlinear soil properties (shear modulus and damping factor) are consistent with the strains experienced. The approach has been termed a deconvolution because the calculations are made with Fourier Transforms of the input. The output from the calculations is simply the transform of the input times the transfer function of the site. If the output is a bedrock spectrum, the process is termed a deconvolution. A convolution, on the other hand, yields a surface spectrum, given a bedrock spectrum.

2. Synthetic Regulatory Guide 1.60 Time History

The major output of the section, Seismic Input, is the peak acceleration for the SSE and OBE. This parameter with Regulatory Guide (R.G.) 1.60 spectra determines the spectral shape and value for the site seismic input. However, time history analyses are performed as a time history is required. The procedure by which such a time history is generated is as follows. First, it is assumed that the response spectrum amplitudes are the same as the Fourier spectrum amplitudes. This is a conservative assumption for the zero or lightly damped response spectrum. Then, a Fourier phase spectrum is calculated using a random number generator and the inverse transform of the two spectra is calculated. This, of course, consists of an infinitely long wave train and thus must

FIGURE 3. Site Response Soil-Structure Interaction Design Procedures

be shaped. The shaping is usually in accordance with the analysts' judgment constraining total duration and duration of strong shaking. A check is then made to examine the agreement between the response spectrum of the time history and the design response spectrum. If the agreement is unacceptable, iterative techniques are employed to force agreement.

3. Vary Soil Properties

The soil shear and bulk moduli, mass, and damping are varied about the mean properties according to the scatter obtained in the laboratory test results. The intent here is to incorporate anticipated uncertainties into the design chain. The soil shear modulus is usually derived from in situ or laboratory measurements on the shear wave velocity and these measurements are rarely repeatable within $\pm 25\%$. This means that the derived values of the shear modulus usually scatter $\pm 50\%$. The NRC, therefore, requires that applicants vary the shear modulus $\pm 50\%$ or as the scatter in the data indicates, to account for this variability. Deconvoluted results are obtained for the mean, maximum, and minimum properties.

4. Envelope 60% Spectra

The results of the three deconvolutions in the preceding step are three time histories are used as the input to three response analyses using the deconvolution model and the respective soil properties, and three spectra at the structure foundation level obtained. These analyses and the three base time histories are used to obtain a single time history which when input to the deconvolution model with mean soil properties in a response analysis will result in a response spectra at the foundation level of the structure that is equal to or greater than 60% of the starting R.G. 1.60 spectra. This is the time history used for the SSI response analyses.

This process is admittedly conservative and an alternative acceptable to the NRC is to use the three base time histories and perform

three SSI response analyses. This is less conservative but more expensive. This modification is generally desirable in high seismic areas.

5. Develop Simple Structural Model

This structural model is used in the SSI model of the site. Typical models are represented by several tens of nodes and are thus not as detailed as the ones used in the detailed structural analyses which consist of hundreds of nodes.

6. Select Soil-Structure Interaction (SSI) Approach

Two approaches are presently acceptable. One models the soil indirectly by using equivalent springs and dashpots and the other models the soil directly by using the finite element model. Until recent ACRS meetings, the latter method was preferred but the situation is unclear at this time. The probable result will be that the soil spring method will become more acceptable.

7. Soil Spring Approach

The soil parameters to be selected include equivalent soil "springs" and "dashpots" (possibly frequency dependent). As noted above this method may see a resurgence in popularity. This is because the former differences between the soil spring and finite element approaches are being reconciled, the NRC appears more receptive, and the soil spring method is simpler and less expensive than the finite element method. Details of methods acceptable to the NRC will have to await continuing licensing activity.

8. Finite Element Approach

Heretofore the finite element approach has been preferred in most applications. The model is two- or quasi-three-dimensional. A number of decisions must be made including the lateral (and possibly vertical) extent of the model, the mesh refinement (this determines the highest frequency transmitted faithfully), the soil layering (horizontal layers are assumed), and methods for approximating

radiation damping (transmitting boundaries, lateral refinement) being some of the most important. Sometimes two soil layerings are selected corresponding to the plant "North-South" and "East-West" soil profiles, and two sets of SSI analyses performed. Occasionally SSI analyses are not performed for the vertical earthquake component (less interaction occurs) or for the OBE (the SSE results are scaled).

9. SSI Calculations

The major objective of the soil-structure interaction calculations is to obtain basemat response for subsequent detailed structural analyses. A second objective can be to obtain floor response spectra but these are also obtained in the detailed structural analyses. For certain sites the SSI calculations will also be used for foundation stability evaluations such as liquefaction analyses. In this latter case for problem sites the SSI calculations are sometimes performed also using scaled real earthquake records rather than R.G. 1.60 time histories.

STRUCTURAL ANALYSIS

The previous two sections both focus on the third major element in the seismic design chain, Structural Analysis. Seismic input and soil structure interaction result in the basic definition of the loads to be used in structural analysis.

As an introductory comment, it is noted that the greatest changes in seismic design will be due to: 1) the improved seismic strong motion data base that will accrue with time, 2) improved earthquake source and transmission characterization, and 3) improved knowledge of soil and soil-structure behavior during strong excitation, rather than to changes incorporated in the structural area. This is because a great deal of analytical and experimental effort has already been performed in the structural design area. This is not to say that new knowledge will not develop in the structures area. The point is that changes in the structural design area will result more from decisions, for example, to take credit for reserve structural strength using inelastic methods that are currently available, than

being forced by the development of new knowledge. Relative to seismic input and soil-structure interaction, a great deal of readily available structural technology already exists.

The basic NRC guide is the Standard Review Plan, Sections 3.7 and 3.8. The present structural response methodology is described in Figure 4. No attempt will be made to describe this chain in detail, or to develop a similar chain for design, because the discussion would become mired in details. Rather, a few significant aspects will be discussed.

1. Mathematical Modeling

A great deal of variability exists in the detail of the mathematical models used. For example, even at the same design level a complex three-dimensional structure can be found to be represented by models ranging from a simple two-dimensional "stick" one, to a complete three-dimensional finite element representation of the entire building, to complete three-dimensional models of all the structures of an entire floating nuclear plant. In a number of cases involving even more detailed levels of analysis and design, more refined models of local regions of the larger models are made, and there is also a great deal of variability in how this is accomplished. It is not an easy task to rationally decide the requirements of models and clear guidelines do not yet exist.

2. Analysis Methods

In the SSI step only the time history (time or frequency domain) type of analysis method was used. This lack of variability does not exist in the structural analysis and design area. The methods used include:

Nonlinear (implicit, explicit, degrading, cracking,
 gaps, contact, impact, etc.)

Time History (modal, direct integration, implicit, ex-
 plicity, frequency domain)

Response Spectra

FIGURE 4. Structural Analysis (Design Procedures)

Quasi-Static (statically applied loads obtained from a
dynamic response analysis)

Static (non-transient loads)

Thermal, thermal/structural

3. Combination of Three Earthquake Components

The requirement to design for three earthquake components introduces a significant complexity into the design-analysis process. Much of this is in the nature of "bookkeeping," that is, keeping track of results and combining them according to an established method.

There are two basic methods which can be used: 1) combine results from three separate seismic analyses, and 2) obtain results from one seismic analysis using three stochastically independent seismic inputs applied simultaneously. An allied complex problem is the combination of seismic and other loads in the required load combination design formulas.

4. Equipment and Safety System Design

Just as in the case of the effects of seismic input and soil structure interaction on structures, one of the most significant effects of the structural analysis and design methods used is on equipment loads and the design of safety systems.

SEISMIC OPERATING CRITERIA

The final topic to be considered in the review of the present seismic methodology is seismic operating criteria. The major question in this area is whether it is advisable to require a seismic trip, automatically, upon detection of a seismic event.

Existing Seismic Instrumentation and Regulations

There are presently no requirements for a seismic trip on commercial power reactors but certain seismic instrumentation must be provided for sensing and recording purposes.

Seismic instrumentation at nuclear power plants consists mainly of triaxial time-history accelerographs, peak accelerographs, seismic switches, and response spectrum recorders. The purpose of this instrumentation is to record an earthquake and monitor the plant's response. Information from the instrumentation can then be used to help establish whether the OBE has been exceeded and if it has to shut the plant down.

Seismic Standards

The regulations and standards that determine the present seismic instrumentation requirements are Regulatory Guide 1.12 and ANSI standard N18.5 (ANSI, 1974). A proposed standard, ANS 2.10/N643, is under review and specifies the response the plant operator should make based on the instrument readings following a seismic event. Basically, this standard relies on a controlled, manual shutdown in a two-step approach.

Whether the OBE has been exceeded is determined in the first step. This is indicated if a minimum number of points of the recorded response spectrum have exceeded the OBE design response spectrum or if there is an equipment malfunction. In either case, the plant is shut down in a controlled manner which may take 5 to 10 hr. Restarting the plant may require the approval of both the NRC and the plant owner. There is no clear criterion to assess the advisability of restarting the plant, so once a plant is shut down it may be down for some time. There is really only one data point of this type, the June 7, 1975, event at the Humboldt plant, and in this case the plant was not operating. In this case the owner inspected the plant, reported the results to the NRC, and the event does not appear to have delayed startup significantly, if at all.

If, in Step 1, it is determined that the OBE was not exceeded, then the operator continues operation and proceeds to Step 2. In Step 2 the recorded data are analyzed to determine if the design floor response spectrum has been exceeded. If the floor-response spectrum for the OBE has been exceeded, the plant is shut down. The analysis may take up to 1 week.

Note that the intent of the ANSI standard is to enable the operator to determine whether the plant should be shut down and to shut down if the

OBE has been exceeded. In judging this, the operator is to take into account only the condition of the plant and not the need for the electric generating capacity of the plant.

In some cases, detailed structural analyses of the plant may be required.

Current Changes in Operating Criteria

The current requirements, regulations and guidelines are due to be enlarged very soon. Perhaps the most significant revision in licensing requirements for operating plants will be embodied in the program for reevaluation of operating plants now being formulated by NRC. This program introduces the concept that all existing plants must be formally reviewed to ensure that they exhibit a "level of safety" consistent with the current state-of-the-art, and provides a mechanism for reviewing future regulations to ensure that any significant developments are back-fitted.

Thus, the formal review procedure will be open ended over the life of the plant. This philosophy has developed as a result of congressional pressure, criticisms by the ACRS, and a growing awareness by the NRC staff that for older plants the basis for regulatory compliance is not well documented.

In principle, this program is consistent with 10 CFR 50.109, which allows the NRC to impose backfits that provide "substantial additional protection" to public health and safety, but its implementation could escalate the application of backfits. NRC has informally announced that the general approach would be to compile a list of all potential safety issues (possibly as many as 300), identify the specific items that apply to each plant, and make a finding for each issue as to why corrective action should or should not be implemented.

3.0 POTENTIAL FUTURE SEISMIC CRITERIA

In Section 2, the present seismic criteria used for dispersed nuclear facilities were reviewed. It was noted that the criteria are somewhat dynamic in nature and therefore some attempt at time extrapolation is warranted. Furthermore, nuclear energy centers, if subjected to the existing criteria used for dispersed plants, may be subjected to a greater magnitude of risk because of the centralization of facilities and the associated vulnerability to large-scale seismicity. Therefore, this section is designed to delineate anticipated near-term changes in the present criteria and to recommend areas where additional renovations may be considered by the regulatory agency in the long term. These recommendations will be made in reference to the unique aspects of Nuclear Energy Centers as previously discussed and accordingly, should be reviewed in such a context.

POTENTIAL NEAR-TERM CHANGES

To set the stage, it is useful to summarize changes in the licensing process which may be anticipated in the very near future. This summary is based on:

- Informal discussions with NRC licensing personnel
- Review of recent ACRS meetings
- Discussions with other consultants engaged in the seismic design of nuclear power plants.

Possible changes in the licensing process may not be implemented as regulatory guides for some time, but could be introduced into the review policy over the next 6 to 12 months. Based on present trends, the policy changes will be gradual and will necessarily be accompanied by confirmatory research. It is important to stress at this point that confirmatory research is required for each of these items; the research required for validation, however, is relatively modest compared to that which may be required for many of the items discussed later in this section.

Seismic Input

With regard to the near-term changes in the seismic input, it is likely that the minimum SSE peak acceleration will be increased to 0.2 g and that of the OBE to 0.1 g. This is based on a more careful analysis of seismic records which indicate that the East Coast, where the minimum levels are usually applied, has lower attenuation characteristics than previously thought.

Another gradually emerging policy change concerns R.G. 1.60. As described previously, the ground motion at a site is currently represented by a response spectrum that is site-independent. The NRC is already relaxing the site independency of ground motion on a case-by-case basis. Formal guidelines will probably emerge outlining acceptable site-dependent and earthquake magnitude spectra.

Soil-Structure Interaction

With regard to near-term changes in soil-structure interaction, much greater emphasis will be placed on site effects. Guidelines will probably emerge, establishing such site modeling criteria as:

- How to model the soil properties (equivalent linear or nonlinear).
- How to incorporate soil hysteretic damping.
- The circumstances under which a deconvolution calculation is inappropriate (such as a shallow soil layer over bedrock).

Another important shift in policy that may emerge is the requirement to determine the site and structure response to several synthetic accelerograms. Each of these seismograms would envelop a specified response spectrum (which might be magnitude-dependent), but would differ in their duration and phase.

Further, a great deal of effort will be devoted to improving and specifying techniques to obtain soil properties in situ. There is a great deal of concern regarding the validity of laboratory soil properties and

the corresponding models of large earthquake strains. The hope is that sufficiently large strains can be generated by a down-hole or cross-hole device to circumvent this uncertainty.

In the soil-structure interaction design component attention will be formally directed at modeling other modes of seismic energy (besides vertically propagating shear waves). Most effort will center on the traveling wave effect on a large foundation. Several analytical techniques have been proposed and some have actually been employed to address specific licensing problems. Informal policies regarding the use of these models will probably first evolve from the ASLB and the ACRS hearing process and formal policies will follow verification.

Also in the soil-structure interaction design component, the structural plane strain two-dimensional modeling will come under increased scrutiny with the result that simpler three-dimensional models will become acceptable provided they accurately model all the degrees of freedom of the structure. The use of lumped mass methods in particular, despite other modeling uncertainties, will be permitted in a wider variety of applications.

Policy will also be changing with regard to the two-dimensional modeling of the soil, but for a different reason. The present two-dimensional modeling requires that the analyst develop a two-dimensional model of a three-dimensional site and this is usually accomplished by selecting a cross section through the site and assuming that every other cross section parallel to that selected is identical. Even though the site response might be derived from the examination of the response of several different cross sections, this does not explicitly take account of the effects of "out of plane" structures. For complex sites, this could be very significant. Guidelines will emerge which will set forth the limitations of the two-dimensional modeling and indicate how two-dimensional cross sections should be selected in those circumstances where a two-dimensional response is acceptable.

Structural Analysis

In terms of the structural analysis component, one can expect a near-term change to reflect the increasing concern with the torsional response of the structure. As with all these near-term changes in regulatory policy, awareness of the significance of the torsional response has evolved from issues raised on specific licenses. The changes with regard to the structural response will consist of guidelines indicating the circumstances under which the torsional response is important, both geologically and structurally, and indicating acceptable modeling techniques.

Operating Criteria

Finally, with regard to operating criteria, it is worthy of note that within the last year the NRC formally organized, and heavily staffed, a Division of Operating Reactors (DOR). This new organization is certain to issue many new guidelines and regulations, but it is presently difficult to anticipate them with any detail. There is, however, one item that DOR will almost certainly take a stand on, the advisability of seismic scram systems. This is a very controversial point because spurious scrams and scrams during small nonhazardous earthquakes could cause significant disruption of electric systems through the sudden loss of electric power and potential damage to plants as a result of thermal shock. Nevertheless, the scram system may provide an additional margin of safety and thus warrants careful consideration.

LONG-TERM CHANGES

Based on the best information available, the above paragraphs have summarized potential short-term changes in seismic design criteria. These changes are relatively easy to identify since they all represent a natural evolution of the current procedures. It is anticipated that most of these changes will be incorporated in one form or another in the next few years.

No attempt will be made to predict long-term criteria development for NECs. However, three subject areas will be presented from which

criteria may be derived in the future. The unique nature of Nuclear Energy Centers may motivate the development of criteria in the following areas:

- The breadth and depth of seismic input analysis
- The use of site-specific earthquakes and front end oriented analytical and numerical models.
- The use of continuous, real-time seismic prediction techniques.

The following section is devoted to a relatively detailed discussion of the available tools and techniques that may function to meet potential criteria in the aforementioned areas.

4.0 FUTURE SEISMIC CRITERIA--TOOLS TO MEET THE CHALLENGE

One of the central points of this study is that NECs will be sensitive to anything that can affect any significant percentage of the facilities in a single event. Seismic events are clearly in this category and therefore seismic criteria for NECs may be somewhat different from those now in existence for single plants. The evolution of this criteria will necessarily parallel increased understanding of seismic processes and effects, the development of tools to generate necessary data, and the implementation of effective methods for evaluating the generated data. Therefore, some of these new or relatively unexploited tools and methods will be discussed in this section. Given the centralization of capital and generating capacity, NEC sponsors will undoubtedly take great interest in protecting against the potential disabling effects of a large earthquake. This will probably occur on a voluntary basis; however, to ensure compliance and uniformity new criteria will be drafted and enforced by the regulatory agencies.

SEISMIC INPUT AND RESPONSE ANALYSIS^(a)

Geologic requirements for siting energy centers will obviously require an extensive regional seismic analysis of greater breadth and depth than is currently exercised. The technology presently available to conduct the desired full spectrum of studies is not totally available and as such, advancement of present technology and development of new technology are required. The following list illustrates tools and techniques that are generally available but are not utilized to their full potential or could be greatly enhanced by additional research and development. The list is designed to complement the classical techniques that were delineated in Section 2.

^(a) A portion of this section has been derived from the efforts of the United States Geological Survey and specifically, the Earthquake Hazard Reduction Program Staff (G.S.C. 701).

Remote Sensing

Remote sensing systems operating from aircraft and spacecraft platforms can collect much of the data needed for regional (hundreds of miles) tectonic studies. This is a unique source of data for identification and analyses of regional fault patterns and geologic structures. More sophisticated and flexible techniques are needed to rapidly analyze these data and produce the desired enhanced and filtered output formats. Advanced airborne remote sensing systems should be developed to collect specific data types on a local scale to complement the regional satellite data.

Electromagnetic Exploration

A variety of electromagnetic methods utilizing a wide range of wavelengths are available for shallow to deep crustal investigations. The depth of penetration and resolution of the mapping depends on the selection of wavelengths, but the effective range extends from fractions of meters to tens of kilometers. Natural signals due to lightning (VLF-LF) and disturbances in the geomagnetic field (ULF) as well as a broad range of man-made signals (pulse and continuous) from high power transmitters are feasible electromagnetic sources. Various methods are available for data reduction and enhancement; however, research in data interpretation is necessary especially in developing analytical, numerical, and experimental techniques applicable to the detection of major crustal dislocations.

Geomagnetic and Gravity Surveys

Special techniques using high density aeromagnetic and gravity data for fault detection are available, but there is much room for improvement in data reduction techniques. Methods utilizing directly measured gradients of the magnetic field can potentially yield additional geologic detail. Techniques based on the Poisson relationship between magnetic and gravity anomalies and utilizing simultaneously collected magnetic and gravity data could remove some of the ambiguity inherent in present methods of analyzing both magnetic and gravity data.

Acoustical Methods

Standard land-based reflective and refractive seismic surveys are in common practice. However, new techniques such as cross-borehole tomography, holography, and surface (Rayleigh) wave analysis are proving feasible for subsurface evaluation. Furthermore, because of their linear character and long extent, faults often intersect marine and inland water bodies. Thus, water-based sub-bottom reflection profiling techniques appear to have merit.

Deep Stratigraphic Correlation

Subsurface stratigraphic information and sequence correlation are required from near surface to great depths for construction and verification of a geological model.

The information could be obtained through limited deep drilling and logging of test boreholes. Both in-situ geophysical logging and drill core analysis can be used for acquisition of the data. Some work is needed to improve resolution for in hole determination of density, porosity, permeability magnetization, magnetic and electrical susceptibility, fractures, radioactivity, sonic velocity and pore fluid and petrological identification.

Tectonic Measurements

Telemetered tiltmeters could be used to monitor strain changes continuously at many locations in order to document slow and rapid crustal deformations. In addition, surveying techniques such as the laser interferometer for leveling and trilateration could be implemented to monitor local or gross regional deformations. Finally, creepmeters and short alignment arrays should be placed within fault zones to measure small displacements.

Heat Flow Measurements

Geothermal logging equipment and interpretive techniques could be implemented to develop information on temperature as a function of depth in the crust and upper mantle. Any detected anomalies could indicate weaknesses in the local crust that may be associated with faulting.

Regional Tectonic and Structural Modeling

Seismic risk evaluations are usually based on meager geological and historical earthquake data. More details and depth of knowledge about local and regional tectonic processes are needed, particularly for siting major nuclear power centers.

Methods should be implemented to manipulate, superimpose, and graphically display large quantities of diverse geological, geophysical, and hydrological data. In addition, this should include multiparameter correlation of recorded microquakes, strain patterns, strain events, and other features to search for evidence of propagation of strain or slip events. Numerical and physical models could be developed to study and describe large-scale crustal plate movements as well as regional and local faulting and folding.

Adequate Staff and Hardware Facilities

Prior to, during, and subsequent to construction, adequate staff and computer facilities should be available for maintaining and updating a dynamic computer-based model of the crust and upper-mantle earthquake-generating system, for evaluating the significance of monitored field data in terms of the state of the model and for formulating subsequent uses of the model.

Passive Seismic Techniques and Site-Specific Earthquake Simulations

These two methods appear to show considerable potential for advancing the capabilities of earthquake hazard reduction and seismic input characterization. Therefore, they will be discussed in much more detail in subsequent parts of this report.

Seismic Engineering

- Develop a basis for estimating the principal characteristics of strong ground motion such as spectral characteristics, attenuation rates, influence of the source, the travel path, and local site conditions.

- Install two-dimensional arrays of strong motions instruments in the structures and in the free field to monitor spectral characteristics and attenuation of earthquakes and the influence of local geology, soils conditions, and topography.

Advanced Techniques

Some instruments and methods require further testing or development or are too costly for extensive use at present. Nuclear Energy Centers may provide the incentive for accelerated research in many of these areas;

- In-situ stress measurements by hydraulic fracturing or borehole strain-relaxation measurements
- Quartz-tube strain meters or other short base shallow-burial strain meters
- Multibeam laser-ranging instruments to increase the precision of free-air-path distance measurements
- Long-period, broad-band, large-dynamic-range seismographs to record a broader spectrum of ground motion for improved studies of earthquake sources
- Water-level recorders and volumetric-strain meters of high stability and sensitivity
- Stable high-sensitivity recording magnetometers to search for magnetic precursors to seismic events
- Widespread systematic monitoring of water composition at flowing springs or wells to search for geochemical precursors to earthquakes
- Extensive drilling and direct examination and instrumentation of fault zones at depth.

MICROSEISMIC NETWORKS

The use of microseismic networks both during the site selection process and after plant startup could be very desirable.

First, as an aid in the site selection process, such a network would provide valuable information that would supplement the historical seismic record at the site. Generally, seismic zones are defined by a historical record of damaging shocks supplemented in recent years by instrumentally recorded and located earthquakes. One of the most significant problems is the short period of recorded history with which seismologists have to deal. In areas where the mean time between damaging earthquakes may be a thousand years, an historic record of several hundred years can be totally inadequate. For a number of years seismologists have considered the problem of using the much higher rate of micro-earthquakes, which are very small earthquakes with magnitudes less than about 2.0 on the Richter scale, as a statistical measure of activity from which to extrapolate to large but less frequent damaging earthquakes.

As a result of extensive instrumentation in the western United States by the U.S. Geological Survey, it is now clear that micro-earthquakes have a much greater significance for determining fault "capability" and potential earthquake hazards than was previously thought to be the case. Some questions remain, of course, but it is clear that micro-earthquakes are not as diffusely distributed as was previously thought. Whenever they have been studied in detail, they are found to be closely related to geologic structures capable of generating significant earthquakes. This is not to say that every micro-earthquake indicates an active fault, but rather, when a distribution of small events defines a planar region in the earth, this is virtually uncontrovertible evidence of the existence of an active fault.

If an adequate statistical sample is available, there appears to be in many cases a reasonable relationship between the rate of small earthquake activity and that of larger shocks, thus making possible a useful estimate of recurrence times for damaging shocks. The length of time necessary to collect significant data varies widely from one region to another. In general, areas of low seismicity should be sampled over a larger period of time in order to provide dependable statistics. The time intervals thus range from several months to several years.

In addition to the definition of seismic zones, micro-earthquake data can provide important information on the stresses operative by using the first-motion pattern for a number of micro-earthquakes to form a composite focal mechanism characteristic of the region. This can be used to determine whether the type of faulting is likely to be thrust, strike-slip or normal faulting (which has an important bearing on engineering estimates of strong ground motion).

Micro-earthquake data seem most useful when other geological data are ambiguous or difficult to obtain. For example, consider the case of an apparently inactive fault which lacks suitable exposures or materials to provide a date of most recent movement. Under current ground rules, if the date of most recent movement cannot be clearly established as previous to several hundred thousand years, the fault must be assumed to be capable of generating an earthquake. Extensive field efforts at great cost can be put into such an investigation, whereas micro-earthquake information obtained at a relatively small expense may have the capability of providing an unambiguous answer in the event the fault is active. Because this tool is most effective in providing information about active structures rather than inactive ones, it is important that it be used as early as possible in the site selection process. Ideally, a seismic network should be established when the general region has been established and several sites are under consideration. Under these conditions the micro-earthquake technique has the capability to save considerable expense in detailed field investigations at several sites by early identification of potentially active faults.

The operation of a network installed during the site selection procedure could be continued at a very small cost after construction and startup of a plant. The network would serve two important purposes. First, such a network could conveniently be coordinated with a seismic scram system to eliminate spurious scrams and scrams due to non-damaging earthquakes. Second, if run at several gains, the network would also provide valuable information in the event a large earthquake occurred. This information

would assist in verifying site response models, soil-structure interaction models and structure-structure interaction models. Such data have never been recorded. The absence of data and therefore lack of verification of design procedures has been a major factor for concern in the safety of nuclear power plants.

SITE-SPECIFIC EARTHQUAKES

As described earlier, the current methodology for selecting the design ground motion at a site is based largely on Regulatory Guide 1.60 which, in essence, specifies the frequency content of the ground motion. R.G. 1.60 is site-independent in that the same frequency content is considered appropriate for every site. Although the amplitude of the ground motion, which is determined by an estimate of peak acceleration, is very site dependent, analysts are becoming increasingly aware of the physical inconsistencies of requiring identical spectral shapes. It now seems implausible that the ground motion from a nearby small earthquake would have the same frequency content as a large, distant earthquake. Observations such as these have prompted both technical and political speculation that the conservatism in seismic design might be less than once thought. This uncertainty has caused the NRC to regulate the seismic input almost completely on a case by case basis, a system that lacks the uniformity of review for which they strive.

The development of a new site-specific approach to characterize the design ground motion for a facility was therefore greeted with relative enthusiasm by the utilities, the intervenors, and the NRC. This new approach examines the problems from a calculational physics point of view; if the earthquake rupture process can be quantified, then the site-specific ground motions results from the propagation of the stress waves through the earth to the site of interest.

General Methodology

The general methodology is to first obtain a quantitative feeling for the rupture process in the tectonic province containing the site. This is

accomplished by selecting one or more nearby earthquakes whose ground motion has been recorded, and to develop detailed rupture processes for the earthquakes by trial-and-error until the recorded and calculated ground motions are within 10 to 20%. This exercise lends credibility to the calculations and expands one's knowledge of the earthquake processes by providing such detailed physical parameters associated with earthquakes as:

- Rupture orientation and extent
- Rupture velocity
- Fracture sequences
- Dynamic stress drop over the fault surface
- Fault offset.

Having calculated these parameters, one might expect roughly the same parameters on other faults of the same dimensions and mechanisms and in the same tectonic province. Thus, it would seem reasonable to use these parameters in a predictive calculation. If the verification earthquakes are not exactly like the postulated earthquakes then the processes would become elements in a parametric survey and the predicted ground motion would envelop the parametric results. In any case, the credibility and accuracy of such an approach appears to be many times greater than the credibility of any site-independent ground motion spectra.

Finite Element Calculations

The calculational approach to this problem is unique in that it links a very powerful nonlinear finite element code (which calculates the response in the rupture zone) with a newly developed semi-analytical procedure for synthesizing seismic waves in a horizontally stratified visco-elastic earth. This two-stage approach optimizes the use of computer resources and still can provide a high frequency response (20 Hz) out many tens of miles.

The finite element computer code, SWIS, is very versatile and considers either static or dynamic problems in one-, two-, and three-dimensional geometries with equal efficiency. In addition, both nonlinear and linear behavior may be analyzed. The dynamic calculations may be performed using either the explicit or implicit time interaction schemes. Also, for explicit dynamic calculations, SWIS has the capability of varying the time step within the computational mesh. This capability has been quite useful for structure-medium calculations (Sweet, 1976). SWIS has been verified against known theoretical solutions for both continuum and structural analysis problems (Frazier and Petersen, 1974; Sweet et al., 1976; Sweet, 1976).

The SWIS code employs a time-centered explicit method for integrating the equilibrium equations in time. The calculation scheme proceeds as follows:

1. The various global arrays are initialized. These include nodal positions, nodal displacements, nodal velocities, applied nodal forces, and nodal masses.
2. Element calculations are performed to obtain the nodal restoring forces. The steps in this calculation are to:
 - (a) Compute strain
 - (b) Compute stress^(a)
 - (c) Compute restoring forces
 - (d) Repeat operations (a), (b) and (c) for each element in the grid to produce the complete listing of the nodal restoring force.

(a) The nonlinear material models presently available in SWIS are as follows: (Sweet et al., 1976):

- Von Mises/Drucker-Prager model
- Soil and rock cap models
- Variable moduli model
- Tensile failure model
- $P-\alpha$ crush-up model.

3. Integrate the equation of motion to advance the solution by one time step Δt :
 - (a) Compute nodal accelerations
 - (b) Compute advanced nodal velocities
 - (c) Compute advanced nodal displacements.
4. Set $t = t + \Delta t$ and return to Step (2).

This procedure is illustrated in Figure 5.

The sequence of steps outlined above can result in as few as 180 floating-point multiply-and-add operations per three-dimensional element for the special case of rectilinear zoning. This is fewer calculations than are required for multiplying the nodal displacements by the stiffness matrix. Actual calculations generally require about 700 floating point multiply-and-add operations per three-dimensional element and about one third this value for two-dimensional calculations. The use of SWIS for numerically simulating earthquake rupture is described and illustrated in Appendix B. The data for such a calculation includes:

- Numerical Grid
- Geologic Layering (density, wave velocities, and attenuation coefficients for each geologic material)
- Initial State of Stress
- Point of First Rupture
- Coefficients for Sliding Friction
- Rupture Extent

The rather massive three-dimensional simulation provides particle motions and material stresses in the regions close to the rupture surface. The major function of SWIS in the SISPEQ analysis, however, is to produce detailed information on fault slip as a function of position and time. The suitability of the finite element for matching abrupt changes in slip which occur near the crack tip is illustrated in Appendix B. It is these abrupt changes in slip that gives rise to high frequency components in the ground shaking.

FIGURE 5. Schematic of the Computational Sequence for Solving the Equations of Equilibrium Using Conventional Finite Element and SWIS Methods

Synthetic Seismograms

Fault slip, which is computed by SWIS, provides input to PROSE, a newly developed procedure for propagating waves in horizontally layered, visco-elastic earth. Thus, PROSE serves to propagate seismic energy from the earthquake source to points on the earth's surface where synthetic seismograms are produced. Mathematically, this is accomplished by spatially and temporally convolving the fault slip from SWIS with the medium response from PROSE, which is characterized in the form of surface motions due to instantaneous slip at a single point on the rupture surface. The convolutions serve to sum the time-dependent production of seismic energy over the entire rupture surface thereby providing the desired ground motions.

The PROSE algorithm is the only method currently available for analytically synthesizing all of the multiply reflected and refracted P and S waves as well as Rayleigh and Love surface waves in a horizontally stratified medium. The method is based on well-known procedures in seismology (Haskell, 1953, 1963, 1964). As illustrated in Figure 6, the equations of motion, expressed in cylindrical coordinates, are transformed: time (t) is converted to frequency (ω) using a Fourier transform; azimuth (θ) is converted to harmonic wave order (n) using a Fourier series; and radial distance (r) is converted to horizontal wave number (k) using a Bessel transform. No transform is performed on the vertical coordinate (z). The result of these transforms is to produce ordinary differential equations in (z) which are solved analytically for each layer. Continuity conditions are enforced at the layer interfaces and transformed surface tractions are set to zero on the free surface to produce solutions for transformed particle displacements as a function of the independent variables (ω, n, k, z) and the forcing term which results from slip on an infinitesimally small segment of the fault. Except for computer roundoff, solutions are exact and complete. Excessive roundoff errors have been avoided at this point using a procedure similar to that advanced by Gilbert and Backus (1966).

FIGURE 6. Flow Chart for Site Specific Earthquake Analysis

The complete seismic synthesis is obtained by performing inverse transformations on ω , n and k to get the solutions in terms of t , θ , and r , respectively. It is here that PROSE is unique in that the inverse transformations are performed to frequencies in excess of 20 Hz without neglecting any wave types. The details of how this has been accomplished are beyond the scope of this report.

The accuracy of the PROSE wave synthesis has been tested in several ways including comparisons of particular wave types with other seismic methods, e.g., first arrival body waves and later arriving surface waves. Figure 7 shows a comparison of the analytical method with finite element results for a surface load on a homogeneous earth. Figure 8 illustrates the uniqueness of PROSE for producing complete seismograms in a horizontally layered earth. Beside the prominent P-, S-, and surface wave arrivals, there are many reflected and refracted arrivals from seismic energy trapped within the layers. The complexity of the seismogram dramatically illustrates how layering in the earth influences the propagation of seismic waves.

Additional technical details of this promising approach are presented in the appendix.

EARTHQUAKE PREDICTION AND CONTROL

The ability to accurately predict and/or control large earthquakes would obviously have considerable impact on the implementation of the NEC concept at least from the seismic hazard perspective. Therefore, a brief discussion of this research area merits inclusion in this report. For specific technical details the reader should refer to the indicated references. The main point to keep in mind is that it is within reason to anticipate a regulatory guide requiring adequate earthquake prediction capability at a NEC site.

Prediction Methods

Currently two independent methods are being explored: 1) statistical techniques, and 2) geophysical methods. The first uses the catalogued

FIGURE 7. Time Histories of Surface Displacement Resulting from Point Force on a Homogeneous Half-Space Finite Element Simulation Utilized 0.7 km Grid Spacing

POINT FORCE ON LAYERED MEDIA
OVER A HALF-SPACE

FORCE = $\delta(t)$

LAYER PARAMETER VALUES

LAYER NO.	THICKNESS (km)	DENSITY (gm/cm ³)	P-WAVE VELOCITY (km/sec)	S-WAVE VELOCITY (km/sec)
1	0.3	2.0	5.2	3.0
2	0.3	2.1	5.8	3.3
3	0.3	2.2	6.5	3.8
4	0.3	2.4	7.4	4.3
HALF-SPACE		2.7	10.4	6.0

FIGURE 8. Prose Solution for the Surface Displacement at Radius

history of earthquakes in a region as a key to estimating when and where such future events may occur. The second involves the observation and interpretation of certain changes in the physical environment in earthquake-prone regions as indicators of an impending event.

The desired prediction must include the expected magnitude range, the geographical location, the time interval, and the degree of uncertainty. The statistical approach tends to yield information concerning the gross geographical aspects, longer time intervals, and general magnitude ranges. Data base correlations of frequent events, seismically quiescent gaps along plate margins, and epicenter migrations or pattern trends are chiefly used. To improve the resolution and prediction lag time, geophysical precursors show the best potential.

Geophysical methods involve searching for, identifying, and monitoring changes in the physical state of the earth that are precursory to earthquakes. In general the list includes: perturbation in the compressional wave-shear wave velocity ratio, ground dilation, anomalous changes in ground tilt, variations in radon concentrations in ground water, anomalous magnetic fields, anomalous electrical resistivity, the relative abundance of large and small earthquakes, perturbation in water wells, lakes and streams, anomalous animal behavior, and gaseous emissions especially hydroxides have been investigated as potential precursors for prediction. It would appear that any successful prediction method utilizing geophysical parameters will have to incorporate and couple many of the aforementioned observations.

To lend perspective to this potentially fruitful area of research, several of the conclusions from the Panel on Earthquake Prediction of the National Research Council are stated.

1. A scientific prediction will probably be made within the next 5 years for an earthquake of magnitude 5 or greater in California. With appropriate commitment, the routine announcement of reliable predictions may be possible within 10 years in well instrumented areas although large earthquakes may present a particularly difficult problem.

2. In a realistic attack on the earthquake-hazard problem, the development of an earthquake - prediction program and the upgrading of earthquake - engineering design and construction are complementary and equally necessary, and should be carried on at the same time.
3. Predictions of earthquakes should specify time, magnitude, place, and uncertainty, but any reasonable bracketing of these parameters would be useful.
4. At present, the ability to detect and locate an impending earthquake requires a dense distribution of instruments in the quake area. Improved observational networks in areas of high earthquake probability are mandatory if we are to gain the fundamental knowledge on which to build an effective earthquake-predictive program.
5. The physical nature of precursory phenomena is complex, and current models to explain them are crude; improvement of these models will require considerable effort in the field and laboratory, as well as in theoretical studies.

It is important to note that the apparent consensus is: given adequate effort, predictions may be feasible in a time span on the order of 10 to 20 years. This may well be coupled to the critical time frame for NEC siting and construction programs.

Earthquake control, although extremely promising in terms of its impact or consequences, is not currently within the bounds of our technology. Proposed methods such as manipulating pore fluid pressure in a fault zone deserve research support, but should not be seriously considered in siting criteria studies at this point in time.

5.0 SUMMARY AND CONCLUSIONS

The primary objective of this report can be subdivided as follows: 1) to review, analyze and summarize in compact form the existing procedures as encompassed in seismic criteria for the siting and design of individual nuclear facilities, 2) to speculate as to how the criteria may change in the immediate future, 3) to convey the point that seismic criteria for NECs may have to evolve due to the magnitude of capital, generating capacity, and the safety problems involved, and 4) to identify techniques and tools that may be available to guide the drafting of and the compliance with the future seismic criteria with special emphasis on Nuclear Energy Centers.

No attempt has been made to speculate on specific siting or operating criteria or to prioritize the identified list of methods and hardware that could potentially be implemented to meet such criteria. Some form of screening based on cost/benefit analyses, availability, proprietary nature, and overall verification and credibility would be a logical extension of this study.

This section is devoted to: 1) summarizing changes in seismic input, soil structure interaction, and structural analysis that in the opinion of the authors will be evaluated for incorporation into seismic criteria guidelines, 2) delineating some additional areas that might be reviewed, and 3) recommending logical extensions of this study.

ANTICIPATED CRITERIA CHANGES

Criteria changes are anticipated in seismic input, soil structure interactions, and structural analysis.

Seismic Input

Increasing the SSE and OBE will have an obvious impact on construction cost in some parts of the country, especially in the East. The need to increase the levels has not been absolutely demonstrated, and is based primarily on intuition. Ideally, such an increase should be based on

careful risk analysis such as those developed by using the techniques of Cornell (Cornell, 1968) or Nair (Nair, 1976).

Site-dependent spectra and site specific earthquake approaches will require confirmatory research to provide a sufficient technical basis to justify a Regulation Guide. The best known researcher in this area is M. Trifunac (1974), who has strongly and repeatedly advocated the use of an input design spectrum that was more dependent on the source mechanism and travel path history. The basic problem is an inadequate data base of strong motion records for many parts of the country, particularly for large earthquakes. The costs of implementation of site-specific earthquake techniques will probably not be a major factor since it replaces many elements in the conventional design chain (site response, alternative studies, statistical and probabilistic analyses). The method has undergone a reasonable degree of verification and is being extended for specific NRC review. These changes relate to singular plants as well as NECs; however, the unique aspects of NECs may accelerate their evaluation and implementation.

Soil-Structure Interaction

There should be a substantial effort to develop improved site response methods especially for NECs, considering the relatively large areas involved. Here, however, there are real interface problems. The entire regulatory process is built around the concept of deconvolution. Because deconvolution requires Fourier superposition, the soil mechanical properties must be linear. The method that Professor Seed has developed (Schnabel, Lysmer, and Seed, 1972) iterates elastic solutions to achieve an equivalent-linear solution to the non-linear response. All this is to say that, technical merits aside, we may be designing with deconvolution techniques for quite awhile. It would be prudent, therefore, to elevate the equivalent linear method to the most sophisticated position possible. One improvement that would significantly add to the credibility of the method would be the inclusion of a better hysteretic damping model. Such a model is not being worked on, but if it were available, it would improve the site response calculations with no cost or interface difficulties.

With regard to synthetic accelerograms, the concept is straightforward and the tools are available (Trifunac, 1971; Donovan, 1973). Once the need for several accelerograms is demonstrated, the policy will follow shortly. The costs and interface difficulties are negligible, but some of the codes for generating the accelerograms are proprietary. A sufficient number of these codes are in the public sector, however, so that this is a minor problem.

Shannon and Wilson, Inc. (Shannon and Wilson, 1976) has devoted a great deal of effort to developing reliable in-situ measuring devices. Such devices could result in slightly higher exploration costs, but savings would probably result elsewhere (for example, laboratory testing). A logging or measuring device could very likely be developed in this area.

The traveling wave problem may result in the development of appropriate techniques, and the problem is sufficiently simple that several alternatives should be provided. Lawrence Livermore Laboratory is currently interested in the problem and has recently summarized their perspective of the issues (Bernreuter, 1977). Possible traveling wave criteria could impact other seismic criteria, i.e., the deconvolution. Also difficulties would arise in regulating a partitioning of energy between traveling and vertically incident. Despite these difficulties, traveling waves will be considered, at least informally, in licensing applications. There would probably be some small additional costs associated with implementation of such criteria.

The two-dimensional/three-dimensional modeling difficulties are presently being researched by Professor Lysmer and his colleagues. Their efforts or variations thereof will almost certainly be incorporated into licensing policy. Their methods are non-proprietary and the only cost is the additional computer time required for solution.

Structural Analysis

There would be negligible impact on the licensing process if modeling constraints were laid out with regard to torsion. Most computer codes

readily accommodate that degree of freedom, the additional costs are negligible and the only extra effort is in modeling.

ADDITIONAL AREAS FOR REVIEW

A great deal of emphasis has been placed on the unique nature of nuclear energy centers; i.e., centralization of large capital expenditures, generating capacity, and nuclide and waste inventory. It is the opinion of the authors that sponsors of an NEC will welcome any improvements in seismic risk analysis. Many individuals, not the least of which the NRC staff, have identified areas in the criteria that could be improved if the appropriate technology were available and adequately verified. It may well be that the unique nature of NEC coupled with the long lead time associated with NEC acceptance and implementation may enable criterial development to encompass potential improvements in our technology. This has already been intimated in the discussion on site-specific earthquakes and earthquake prediction. The intent of this summary is not to criticize existing procedures but merely to illuminate areas that given technological advancement might be amended or appended to future criteria for Nuclear Energy Centers. These discussions will necessarily be brief.

Seismic Input

Some concern has been voiced as to the definition of a capable fault. Geology is evolving from an art into a science and as this progresses, our understanding of tectonics and associated seismicity improves. It is hoped that additional research efforts will result in a better understanding of faulting and its impact on surface facilities. Similarly as our understanding of intermediate to deep earthquake mechanisms and their relationships to fault motion improves this may be reflected in the criteria for NECs. Unfortunately this is a difficult and time-consuming effort.

A second area of concern is with the lack of correlation between seismological parameters such as intensity-acceleration data. There are

numerous reasons for this lack of correlation: 1) the quality of building construction varies widely; 2) the frequency content of the ground motion relative to the natural periods of the structures affected causes considerably different structural amplification factors over the peak ground acceleration; 3) large and small earthquakes are intermixed; and 4) a wide range of epicentral distances are used in the correlations. Obviously the paucity of data is the culprit in this case. As the data base grows so will the empirical correlations. It is anticipated that given adequate research support, the relationships required by regulatory agencies to draft criteria will be improved by the time an NEC is licensed.

Site Response/Soil-Structure Interaction

Five major areas will be addressed in this section. Once again it must be stated that these problem areas are not the result of lack of objectivity on anyone's part but merely from a lack of reasonable alternatives that have been adequately verified. It is hoped that additional effort in these areas will be productive and that NEC criteria will parallel any results.

The first concern relates to the soil measurements and modeling. The input required from an analyst is shear modulus (G) and damping factor (Δ) as a function of average strain, density, and Poisson's ratio for each significant layer above bedrock. Currently, the lack of in-situ measuring devices dictates that the information be generated in laboratory tests on cores. This results in uncertain estimates of average shear strain throughout the core, potentially large errors due to core sample disturbance and sample size effects, and tensional and compressional symmetry in strain-dependent soil properties. Thus the mathematical formulation allows the soil to not only push the structures, but to pull them as well. To circumvent this problem the regulations have had the insight to stipulate that the foundational level spectrum be derived from three separate soil response calculations to encompass possible minimum and maximum variations. It is interesting to note that this results in effectively increasing the surface design spectrum. It is anticipated that improvements in in-situ measuring

capabilities may preclude this procedure and the conclusion is that this is one very important applied research area.

Another problem relates to site modeling based on borehole logs which delineate the stratigraphy. Some flexibility exists in the choice of a model and the characteristics of bedrock which can have a profound effect on final design parameters. It is hoped that criteria for an NEC would circumvent any non-uniqueness presented here.

Another concern is the conversion of seismic response spectra into acceleration time histories. There are two major assumptions involved. First, there is a 0.1% damped response spectrum associated with the Fourier spectrum. This relation is tenuous, and the effects of a non-zero damped spectrum are not well understood. A second, and more important, assumption is that the spectral amplitudes control the soil structure interaction response and the phasing of the individual frequencies is random in nature. Thus, there is an infinite set of time histories that could represent a target spectrum. If phases were deemed an important parameter, it would be necessary to know the sensitivity of the system response. Additional work should be performed concerning the sensitivity to the particular phase spectrum prior to drafting NEC criteria.

Finally, the equivalent linear method (ELM) is a major concern because of a lack of verification with real data, the basis of damping formulation and its extrapolation to strong motion earthquakes, and the statistical smoothing associated with superposition of multiple records. Obviously the NRC recognizes these concerns as they have required that the foundation level spectrum be not less than 60% of the surface spectrum. However, for NEC criteria, additional work would be advisable.

Structural Analysis

Because the technology of structural analysis is extremely advanced relative to seismic risk analysis and soil-structure interaction, it is difficult to define areas where the advent of an NEC would change criteria.

However, one area that may deserve some additional effort is in the combination of loads. This occurs at two levels. First, the net earthquake load must be characterized, and this involves either combining individual structural loads from each of the three earthquake components or combining the three components vectorally and performing a more complex three-dimensional structural analysis. Whichever approach is taken requires a decision as to the orientation of the incoming seismic energy relative to the structure. This may force criteria as to facility spacing. Second, the NRC requires that the seismic loads be combined with operating loads, transient loads, and abnormal loads. The manner in which all these loads are combined determines the final design loads on the structure and equipment and thus can be considered the bottom line criteria.

RECOMMENDED STUDY EXTENSIONS

This study is designed to be preliminary and educational in nature. Such a composite description of existing procedure is not currently in print to our knowledge. However, recommendations as to an extension of this study appear appropriate. Therefore, the following areas are presented for evaluation:

- 1) Development of hypothetical criteria for an NEC and a program to meet such criteria using Hanford as a test case.
- 2) Prioritization, cost/benefit analysis, and availability screening of the identified tools and procedures
- 3) Implementation of one or more of the most dramatic techniques such as site-specific earthquakes using Hanford as the test case.

The site-specific element should be noted since we are of the opinion that any additional meaningful work under Items 2 and 3 must necessarily be site specific.

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APPENDIX A
BACKGROUND, REGULATORY GUIDES AND STANDARDS

APPENDIX A

BACKGROUND, REGULATORY GUIDES AND STANDARDS

(Adapted from ASCE Manual, Ref. A-7)

A.1 BACKGROUND INFORMATION

The requirements governing nuclear power plant design generally paralleled conventional design requirements until the early 1960's. Beginning about 1965 the Regulatory Division of the Atomic Energy Commission (now NRC), in their review and approval of the Preliminary Safety Analysis Reports (PSAR) required considerably more detail. The Commission also began to require evaluation of extreme loads. In addition, the efforts on the ASME Boiler and Pressure Vessel Code Section III and the Joint ACI-ASME Committee on concrete containments and pressure retaining components and the standards development efforts of the American Nuclear Society (ANS), and the American National Standards Institute (ANSI) as a coordinating agency, all combined to develop over the past 12 years a large quantity of new design criteria applicable to nuclear design. This development has proceeded to the point where there are over 75 different documents prepared by a variety of industrial and regulatory groups in the U.S. which have a direct bearing on safety related structural design and analysis.

A.2 PHILOSOPHY OF PROTECTION AGAINST NORMAL AND EXTREME LOADS

Nuclear structural design requirements are to a considerable degree unique. In no other structural system are extreme loads such as tornadoes, earthquakes effects, etc., typically in excess of any recorded historical data at a site, and postulated accidents down to the 10^{-7} probability range explicitly considered in design. The consideration of extreme loads of such low probability is warranted by the potential consequences of accidents associated with nuclear facilities (Ref. A-3). As a result, a much broader spectrum of extreme loads are considered in design of nuclear facilities compared to conventional ones.

It also should be understood that the overall reliability of a structural system is not only a function of the applied loads but also the reliability of the structural response of the structure to that load. The quality assurance programs for the design and construction of conventional building structures typically have been based on informal or "in house" procedures which rely heavily on the integrity and competence of first line supervision. In such structures quality control has for the most part been based on visual inspection. Such procedures are in contrast to pressure vessel quality assurance and control procedures which require extensive audits, approval of quality assurance procedure, and third party inspection of quality control tests which include radiography, ultrasonic testing, dye penetrant and magnetic particle testing of as-built components. To a large extent many of the quality assurance and quality control measures traditionally used in pressure vessel design are now applied to concrete and steel safety class structures.

The risk associated with the occurrence of a particular event in its most simplistic form is the product of the probability of occurrence of the event and the consequences of the event. For a desired risk level, as the probability of occurrence of an event decreases, the consequences may be allowed to increase. Thus increase in consequences in structural design may be associated with reduced safety margins in design of structures for low probability events.

Central to this extreme load design philosophy is the reduction of structural safety factors as the probability of load occurrence is reduced. This requires that the response of structures to extreme loads must be predicted with a higher degree of confidence than is typically the case with conventional structures. As a result, quality control and quality assurance requirements are considerably more stringent than for conventional structures, and nonconventional analytical qualification may be required.

A.3 GENERAL CONSIDERATION IN DESIGN AND SAFETY CATEGORIZATION OF STRUCTURES

The specialized requirement of structural design and analysis presented in this Manual are applicable to "Safety Class Structures." This section presents various safety classifications typically used to describe the safety classifications of structures, mechanical and electrical components (Ref. A-4).

The use of Safety Classes established by ASME and ANS standards should not be confused with the Seismic Category I classification established by Federal Regulation 10CFR100 Appendix A and further defined by the NRC in R.G. 1.29. In general the NRC Seismic Category I applies to all structure systems and components "important to safety" which must remain functional in the event of an SSE. "Important to safety" is further defined by the NRC as those structures, systems, and components whose function is to assure: (1) the integrity of the reactor coolant pressure boundary, (2) the capability to shut down the reactor and maintain it in a safe shut-down condition, or (3) the capability to prevent or mitigate the consequences of accidents which could result in offsite exposures comparable to the guideline exposures of 10CFR100. Because the safety classification of structures, systems and components defined by the NRC is restricted to earthquakes, there is a tendency to use the industry safety classifications.

For structures, systems and components important to safety, five safety classifications are defined; two general classifications without gradation, one for structures and one for electrical systems and components, and three graded safety classes for mechanical systems and components.

Structures, systems and components that are categorized in the five safety classes are designed to remain functional during all design basis events, unless it can be demonstrated that the structures, systems and components will not be required to perform their safety function during such events or that such events are precluded from interacting on the structure, system or component by an isolation or barrier system. Safety class structures, systems and components are subject to the Quality

Assurance requirements of Federal Regulations (Ref. A-5). Structures, systems and components not considered important to safety are designed Non-Nuclear Safety (NNS) and in general are designed to meet conventional requirements.

The failure of any NNS structure, system or component may not lead to loss of function of any safety class structure, system or component.

A.4 SUMMARY OF EXISTING CODES, STANDARDS AND REGULATIONS

This section is presented to assist determining the sources of design criteria required for nuclear power plants. The role and purpose of various agencies, codes and standards groups are briefly discussed and references to source material presented.

A.4.1 Summary of Current AEC, ASME, ACI, ANS, ACI-ASME and IEEE Seismic Standards

Figure A-1 is a summary of the current codes, standards, and criteria generally applicable to the seismic design and analysis of nuclear facilities. Not included but playing an important role is the American National Standards Institute (ANSI). Through its technical society representation of the Nuclear Technical Management Board, ANSI determines the needs for, assigns, and schedules the development of standards. Many standards developed by sponsoring organizations also carry ANSI designations. Where such designations are identified the corresponding ANSI designation is shown parenthetically. Reference A-6 contains a list of nuclear standards under the auspices of ANSI.

A.4.2 Federal Regulations

The most important of the NRC documents in the structural area are Federal Regulations 10CFR100 Appendix A and 10CFR50 Appendices A and B. These documents have the weight of Federal law to require compliance.

A.4.2.1 10 CFR 100 Appendix A

This document defines the OBE SEE and the way their intensities are determined. It also locates where the earthquake motion is defined and sets the width of fault zones as a function of fault length and defines capable and noncapable faults.

NRC	ANS-ANSI	ASCE-AISC	ASME-ACI	IEEE
10 CFR 100 Appendix A	ANS 2.1 Guidelines for Determining the Vibratory Ground Design Earthquake	IG3-Land and Behavior Criteria	N-166-Seismic Qualifications for Nuclear Power Plant Structures Equipment	344-Guide for Seismic Qualification of Class I Electrical Equipment for Nuclear Power
10 CFR 50 Regulatory Guides		IG5-Seismic Design IG6-Impact and Impulse Design		
Regulatory Guide 1.12 Instrumentation For Earthquakes (Revision 1, 4/74)	ANS 2.2 Earthquake Instru- mentation Criteria for Nuclear Power Plants	IG7-Foundation Design	N-167-Seismic Analysis of Category I Structures, Systems and Components	
Regulatory Guide 1.29 Seismic Design Classification (Revi- sion 1, 8/73)	ANS 2.7 Earthquake Fault Criteria for Loca- tion of Power Reactor Sites	IG9-Structural Aspects of Nuclear Plant Siting -Surface Plants -Floating Plant -Underground Plants	N-249-Combination of Loadings for the Design of Component Supports Under Upset, Emergency and Faulted Plant Conditions	
Regulatory Guide 1.60 Design Response Spectra for Seismic Design of Nuclear Power Plants (Revi- sion 1, 12/73)	ANS 2.10 Guidelines for Use of Data Obtained from Earthquake Instrumentation	N175-Geological Design Criteria	N-250-Combination of Loadings for the Design of Category I Mechanical Components Under Upset, Emergency and Faulted Plant Conditions	
Regulatory Guide 1.61 Damping Values for Seismic Design of Nuclear Power Plants (10/73)	ANS 2.11 Guidelines for Deter- mining Geological Information at Power Reactor Sites		N-252-Combination of Loadings for the Design of Fluid System Compo- nents and Steel Contain- ments Under Upset, Emer- gency and Faulted Plant Conditions	
Regulatory Guide 1.70.9 Additional Information Design of Seismic Category I Structures (11/74)	ANS 2.12 Combined Natural and Manmade Hazards			
Regulatory Guide 1.70.23 Information for Safety Analysis Reports - Seismic Qualification of Instrumentation and Electrical Equip- ment (2/75)				
Regulatory Guide 1.92 Combination of Modes and Spatial Components in Seismic Response Analysis (12/74)				
Standard Review Plan SRP 2.5 Geology and Seismology				
SRP 3.6 Seismic Design				

FIGURE A-1. Index of Current Codes, Standards and Criteria Applicable to Seismic Design

A.4.2.2 10 CFR 50 Appendix A

This document defines General Design Criteria to be used in the design of safety class nuclear plant facilities. It contains the following criteria of particular interest:

- Criterion 1 - Quality Standards and Records
- Criterion 2 - Design Bases for Protection Against Natural Phenomena
- Criterion 4 - Environmental and Missile Design Bases
- Criterion 16 - Containment Design
- Criterion 50 - Containment Design Bases
- Criterion 53 - Provisions for Containment Testing

A.4.2.3 10 CFR 50 Appendix B

This document describes the quality assurance criteria for nuclear power and fuel reprocessing plants. It is divided into the following areas:

1. Organization
2. Quality Assurance Program
3. Design Control
4. Procurement Document Control
5. Instructions, Procedures and Drawings
6. Document Control
7. Control of Purchased Material, Equipment and Services
8. Identification and Control of Materials Parts and Components
9. Control of Special Processes
10. Inspection
11. Test Control
12. Control of Measuring and Test Equipment
13. Handling, Storage and Shipping
14. Inspection, Test and Operating Status
15. Nonconforming Materials, Parts or Components
16. Corrective Action

17. Quality Assurance Records
18. Audits

A.4.3 NRC Regulatory Guides

Regulatory Guides are prepared by the NRC Division of Regulatory Standards and are issued to describe methods acceptable to the NRC Regulatory staff, delineate techniques used by the staff in evaluating specific problems or postulated accidents, or provide guidance to applicants. Regulatory Guides are not regulations and compliance with them is not required. Methods different from those in the guides are acceptable if they provide a basis for the findings requisite to the issuance or continuance of a permit or license.

Guides are issued in the following divisions:

1. Power Reactors
2. Research and Test Reactors
3. Fuels and Materials Facilities
4. Environmental and Siting
5. Materials and Plant Protection
6. Products
7. Transportation
8. Occupational Health
9. Antitrust Review
10. General

In the following paragraphs a brief description of those Regulatory Guides of particular interest to the Civil-Structural Engineer is presented.

A.4.3.1 R.G. 1.12 - Instrumentation for Earthquakes

This guide defines the instrumentation required to record the effects of earthquakes.

A.4.3.2 R.G. 1.29 - Seismic Design Classification

This guide defines those systems and components which require verification of seismic design adequacy. Such seismic design adequacy is required to assure (1) the integrity of the reactor coolant pressure boundary,

(2) the capacity to shut down the reactor and maintain it in a safe shut-down condition, (3) prevent or mitigate consequences of accidents which could result in radiation release in excess of 10 CFR Part 100 guideline exposures.

A.4.3.3 R.G. 1.60 Design Response Spectra for Seismic Design of Nuclear Power Plants

This guide establishes the ground response spectra which will be used to seismically qualify structures located at ground and to qualify time history input motion which are used to develop amplified spectra for use in design of components located within building structure. Horizontal as well as vertical spectra are specified.

A.4.3.3 R.G. 1.61 - Damping Values for Seismic Design of Nuclear Power Plants

This guide presents interim modal damping values which are currently acceptable to the NRC. Values are tabulated for both the OBE and SSE and different structures, systems, and components.

A.4.3.5 R.G. 1.70 - Standard Format and Content of Safety Analysis Report for Nuclear Power Plants - LWR Edition

This document identifies the principal information that should be provided by applicants in safety analysis reports for light-water-cooled reactors and defines a uniform format for the information. The Standard Format was developed in parallel with and is keyed to the Standard Review Plans prepared by the NRC Office of Nuclear Reactor Regulation.

A.4.3.6 R.G. 1.91 - Evaluation of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plant Sites

This guide describes a method acceptable to the NRC Regulatory staff for determining safe distances from a nuclear power plant to a transportation route over which explosive material may be carried. It also provides data for the development of peak positive overpressure associated with accidental explosions as a function of distance and equivalent TNT charge.

A.4.3.7 R.G. 1.92 - Combination of Modes and Spatial Components in Seismic Response Analysis

This guide provides a suggested method for combining seismic response effects between modes including closely spaced modes as well as spatial combinations considering independence of directional components of the earthquake.

A.4.4 NRC STANDARD REVIEW PLANS, SRP

Regulatory Standard Review Plans are prepared for the guidance of the NRC Directorate of Licensing staff responsible for the review of applications to construct and operate nuclear power plants. These documents are made available as part of the Commission's policy to inform the nuclear industry and the general public of staff scope and policies on Safety Analysis Reports. Standard Review Plans are not substitutes for Regulatory Guides or Federal Regulations and compliance with them is not required. Standard Review Plan sections are keyed to the Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, R.G. 1.70. Not all sections of the Standard Format have a corresponding review plan.

The Standard Review Plans in general incorporate requirements of "Branch Position Papers" which in the past were informally issued for guidance in the preparation of Safety Analysis Reports.

A.4.5 AMERICAN NUCLEAR SOCIETY, ANS

The American Nuclear Society (ANS) typically prepares systems or functionality standards on nuclear plant design while ASME, ACI, etc., typically prepare hardware standards on the detailed design and stress or behavior analysis of specific components.

A.4.5.1 ANS-2 - Site Criteria

The ANS-2 committee covers the criteria which affect the plant and have their basis in natural phenomena. A list of guidelines prepared by this group is shown in Figure A-1.

A.4.5.2 ANS-50 - Reactor System Safety Criteria

The second major ANS committee activity develops the safety criteria for the design of the four major nuclear reactor types used in the U.S., i.e., Pressurized Water Reactors, Boiling Water Reactors, Gas Cooled Reactors, and Sodium Cooled Fast Breeder Reactors. In addition to the four major subgroups on each reactor type this committee is concerned with the plant process conditions of design and their load combinations including interaction with natural phenomena and the associated operating or design condition criteria and the safety classification of components. This committee also has two subcommittees developing missile and pipe whip and high energy fluid jet effects design criteria.

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(A revision is due soon.)

APPENDIX B
THREE-DIMENSIONAL FAULT MODEL

APPENDIX B

THREE-DIMENSIONAL FAULT MODEL

B.1 TECHNIQUE VERIFICATION

The value of numerical computer methods for modeling earthquakes hinges on demonstrated credibility. Consequently, considerable effort has been devoted to testing and verifying the various methods that are used.

On the most elementary level, the accuracy of the numerical scheme has been examined for propagating waves in a homogeneous medium. The conclusion is that, in the absence of material viscosity, waves travel slower in the finite element grid than in the continuous medium. This numerical dispersion is dependent on the number of element dimensions per wave length. For wavelengths longer than six grid dimensions, the reduction in the propagation velocity of numerical waves is very insignificant and does not exceed 4%.

The method for numerically simulating fault slip has been tested and verified in several ways: The first test was to numerically reproduce analytical results for a growing surface of dislocation in a full space. Excellent results have been reported by Geller and Frazier (1974) and more recently by Geller and Frazier (1976) using the SWIS code to model a propagating dislocation acting in a 2-D plane strain. The slip model has also been verified in 3-D by comparing with analytical results.

Numerical simulations for propagating dislocations serve to verify the computer methods that are used for modeling slip. However, additional tests are needed to substantiate the computer models for simulating stress drop on a growing crack. This process is verified by numerically reproducing analytical results for the problem of a growing circular crack in a pre-stressed medium (Kostrov, 1964; Burridge and Willis, 1969; Richards, 1973). The particle displacement that results from an instantaneous drop in shear stress is presented in Figure B-1 at various points along the path of rupture, which is expanding at 0.9β . Whereas the analytic solution applies for a self-similar crack that expands at a constant rupture velocity forever, the 3-D finite element code was used to simulate a circular crack that starts at a point, grows to a radius of ten element dimensions at a constant

rupture velocity, and then stops. The material was healed in a finite element model when the slip attempted to reverse directions.

The accuracy that is achieved using 3-D brick elements is remarkable. Particle velocity is infinite immediately following rupture in this idealized model. Yet, the finite element model produces particle displacements that jump, with no apparent oscillation, to the analytical values in a single time step (the symbols +, in Figure B-1 designate the individual time steps of the SWIS code).

Several other calculations have been performed to demonstrate the capabilities of the SWIS code for propagation P-waves, S-waves, and surface waves. More important, at this point, is the suitability of the computer methods for simulating physical rupture.

B.2 STRIKE-SLIP CALCULATIONS

Having verified the finite element code as a positive approach to simulating propagating ruptures, we have also compared finite element results with the laboratory results obtained by Archuleta and Brune (1975). First though, a finite element solution to a bilaterally propagating stress drop over a semicircular plane embedded in a homogeneous, isotropic, elastic, half-space will be described. A cross section of that medium is shown in Figure B-2. The rupture originates at the free surface at the center of the semicircular arc and then propagates as a semicircular wavefront which has a speed of 0.9 of the shear wave speed. The fault plane is limited to a radius of 10 elements. Because of the symmetry of the displacement field and because the rupture is bilateral, only one quadrant of the half-space V is needed to grid. Thus, Figure B-2 shows twice as much grid as actually used. (As a matter of notation, the direction of the shear has been specified as the Y_1 direction; the direction normal to the free surface and towards increasing depth as Y_2 , and the direction perpendicular to the plane of the fault Y_3 which form a right-handed system.) Figures B-3 and B-4 show the development of the horizontal particle velocity field on the free surface as the free surface as the rupture propagates and stops. The vector sum of the $\dot{u}_1$ and $\dot{u}_3$ for all four quadrants is plotted where the dot denotes a time

FIGURE B-1. Displacements on a Circular Fault Growing at 0.98. Dashes are three-dimensional finite element results for fault which stops growing at radius r . Solid lines are Kostrov's analytic solution for circular fault which doesn't stop.

FIGURE B-2. Cross-section of a Half-Space Illustrating Finite Element Grid Used for Three-dimensional Run in Which Semicircular Fault had 10 Elements on a Radius

FIGURE B-3. Horizontal Particle Velocity Field on the Free Surface at Four Instants in Time During a Three-dimensional Simulated Earthquake

5 sec

6 sec

FIGURE B-4. Same as B-3 (except only two instants in time are shown)

derivative. The heavy dark line extends around the border of the rupture. One can see the compressional and shear lobes of the classical double couple radiation field; the propagation of waves from the ends of the fault. On a larger scale, one can discern the propagation of the near-field transverse motion propagating at the P-wave speed. Figure B-5 shows in greater detail the time histories of displacement and velocity of nodes 1-11. The nodes lie right on the fault trace at the free surface. Node 1 is at the origin (0, 0, 0), node 2 is at (1, 0, 0), node 3 is at (2, 0, 0), etc. The particle velocities illustrate more clearly the dynamics occurring as the rupture propagates and stops. First, all components of particle velocity exhibit an amplification as the rupture propagates. Secondly, the vertical ($\dot{u}_2$) component is comparable to the transverse component ($\dot{u}_3$). An interesting phenomenon can be seen most easily in $\dot{u}_3$. (This phase is the emerging long-period signal clearly seen at nodes 2-6.) The second part of the stopping phase propagates from node 1 out through the other nodes. This occurs because now the node at the origin has locked which generates this wave. (This wave is seen as the trough of the long-period wave most clearly visualized in $\dot{u}_3$ around nodes 2-6.) In addition to saving time histories of selected positions plus the time history of every point on the fault, we also calculate and save the maximum horizontal and vertical particle velocity and displacements everywhere on the free surface. A contour plot of the distribution of maximum horizontal particle velocity is displayed in Figure B-6. The fault region is magnified and have plotted all four quadrants. The contours are labeled A-1. The number in parenthesis is the value of the particle velocity in cm/sec if the fault radius were equal to 10 km and had a stress drop of 100 bars, e.g., B(200) means that contour is for 200 cm/sec. For the most part, the area within one fault radius has peak particle velocities greater than or equal to 15 cm/sec. Quite striking are the high values of particle velocities in the two-lobed triangular region near the fault trace.

Figure B-7 shows results obtained from a finite element run in an attempt to match displacement time histories measured by Archuleta and Brune (1975). Because this rupture was not bilateral, two quadrants of a half-space were used in this run. The fault plane is semicircular, but

PARTICLE DISPLACEMENTS

PARTICLE VELOCITIES

FIGURE B-5. Particle Displacements and Velocities for Points on the Fault Trace at the Free Surface

FIGURE B-6. Contour Map of Maximum Horizontal Particle Velocity on the Free Surface of a Three-Dimensional Element Simulation of a Bilaterally Propagating Rupture

COMPARISON OF DISPLACEMENTS
FROM FOAM EXPERIMENT (Δ) AND FINITE ELEMENT CODE (-)

FIGURE B-7. Comparison of Three-dimensional Finite Element Displacements Generated by a Unilaterally Propagating Rupture Against Foam Rubber Displacement Data

only four elements on a radius were used instead of 10 used in the run discussed above. Rupture velocity was set at 0.74 of the shear wave speed. The match between static amplitudes is close. The rise time of the foam rubber displacements are initially comparable to the finite element result, but the overall rise time in the foam rubber model is slower. This difference which may stem from several causes, e.g., lack of uniform, prestress in the foam rubber or time-dependent friction is not completely resolved.

B.3 RUPTURE MODELING

Rupture modeling in the finite element work is based on the widely accepted "stick-slip" concept of frictional instability (Brace and Byerlee, 1966; Byerlee, 1970; Byerlee and Brace, 1968; Scholz, et al., 1972). Basically, the concept of the stick-slip model is that rupture initiates at a point when the shear stress exceeds a critical value τ_k which is a function of the material strength and the stress component acting normal to the fault plane. When this critical state of stress is reached, the material rapidly loses some of its capacity for supporting shear, and consequently, the shear stress drops from τ_k to a lower value τ_f which is rather insensitive of the rate at which local processes (material alterations) occur. Material on the opposing faces of the fault begins to slide in the direction of the stress drop $\tau_k - \tau_f$ as a result of the imbalance that is created. The readjustment of material on a macroscopic scale accentuates the state of stress in any adjacent material that has not yet ruptured, and in this way the zone of rupture spreads. As the sliding and the locally stored strain energy is relieved, sliding decelerates due to opposing friction stress. At the instant the slip velocity reverses direction, shear stress drops below the shear carrying capacity of the material during sliding, τ_f . At this point, microscopic failure processes are no longer exceeded, and the fault material appears to heal. Additional stick-slip failure can occur only if the shear stress exceeds the initial value τ_k or some modified value slightly less than τ_k .

The failure process currently operating in the finite element code differs from the stick-slip model in one important respect: The onset of rupture is not determined from a failure criterion but rather from a

prescribed velocity. That is, the rate at which the rupture spreads into competent material is prescribed. This procedure has been adopted in the initial work to insure that the grid size does not have an undesirable influence on the rupture model. A new method based on fracture energy for spontaneously initiating new crack surface also has developed. It appears that the use of fracture energy as a criterion for creating new crack surface is far superior to stress criteria which depend rather strongly on grid size. However, it is intended to continue to prescribe rupture velocity until a spontaneous rupture model is developed which is insensitive to grid size.

The three-dimensional computer model has considerable flexibility for including complexities, such as rate-dependent effects that may arise during actual earthquakes.

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RELIABILITY OF GENERATION AT A HANFORD
NUCLEAR ENERGY CENTER (HNEC)

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I. SUMMARY AND CONCLUSIONS

A nuclear energy center characteristically would have large amounts of electric generating capacity in a relatively small geographical area. For an HNEC (20 plants) in year 2005 this could amount to 30% of system capacity; typically utilities limit concentration of thermal plant generation to about 15% of system requirements. For this reason it is appropriate to examine the reliability of generation at a nuclear energy center to determine if it could be less than at dispersed sites because of local conditions and the close proximity of many generating units. In this report, reliability of generation at a Hanford Nuclear Energy Center (HNEC)^(a) is assessed by comparing it with that at Dispersed Sites (DS)^(b) throughout the Pacific Northwest.

Reliability as considered here is measured in terms of two sets of risks:

Risk of forced outage, which is the probability of the occurrence of events that could cause plant outages, with the loss of generating capacity and energy that would otherwise be available to the system as the consequence.

Risk of user power shortage, which is similar to the probability of forced outage as defined above, but considers in addition the probable state of system reserves at the time of a forced outage. A surplus or a deficit of capacity and energy to serve system loads is the consequence in this case.

Risk of Forced Outage

Events that could cause greater and, or, more frequent outages in the HNEC case than in the DS case include earthquake, volcanic ashfall, release of radioactive contaminants, flood, switching station failure from aircraft crash and sabotage, and tornado. Other types of external forces or internal failures (of which 12 were analyzed) would affect HNEC and DS equally, and were excluded from the risk comparisons.

(a) HNEC, a conceptual nuclear energy center containing 20 generating units of 1200 MW capacity each, located at Hanford, Washington.

(b) DS, an alternative concept; namely, 20 generating units of similar capacity in six clusters at sites along the Columbia and Willamette rivers in Washington and Oregon.

The combined risk from these causes, is estimated in Table 1. The scenario considers a mature HNEC in the year 2005 with 20 units assumed in place.^(a)

TABLE 1. RISK OF FORCED OUTAGE

Probability, Events per Year		<u>Consequent Generating Capability Loss</u>	
		<u>Capacity, GW</u>	<u>Probable Duration, Days</u>
<u>HNEC</u>	<u>DS</u>		
1.1×10^{-2}	1.1×10^{-2}	5	7
6.0×10^{-3}	1.1×10^{-5}	12	8
1.6×10^{-3}	0	24	40

From the above comparison, the risk of a 5 GW outage at single clusters is approximately the same for HNEC and DS, but the risk of simultaneous outages at two or more clusters (12 to 24 GW) is substantially greater for HNEC. Although the risk of forced outage is greater for HNEC it may nevertheless be acceptable from the standpoint of the power user because of the effectiveness of reserves in the PNW system as reflected in the risk of power shortage.

Risk of User Power Shortage

The greatest possible forced outage is one involving 100 percent of the HNEC capacity on line, or 30 percent of the operating capacity on the system in the year 2005. If such an outage occurred instantaneously, it could be partially offset by spinning reserves and inflow of power over tie lines to the south; but system loads would have to be reduced by shedding some industrial load and about 20 percent of the system commercial and residential load. Additional reserves would be brought on line immediately following the onset of the outage, and a few hours later the system could enter a regime of management of an energy shortage of about 16 percent of normal usage, for a period of about four months.

(a) No analyses of interim periods were considered.

The risk of user power shortage would be:

Probability: 1×10^{-4} per year; once in 10,000 years.

Consequence: Shedding of 20 percent of mixed loads for up to six hours, followed by a 16 percent energy shortage for four months.

Instantaneous interruption of 30 percent of the system power flow would severely shock the system. If sufficient load were not shed, there would be substantial risk of system breakup, resulting in black-out pockets in the region for up to 12 hours duration. If black-outs did occur, they would threaten the health and safety of the public to some extent but probably not seriously if reasonable emergency procedures were in place and followed. Black-outs would not be a threat with instantaneous loss of 20 percent of the system capacity or less, or with a 30 percent loss in stages over an hour or more.

The impact of energy curtailment would be controlled by emergency measures now being put in place. With priority use of energy, the adverse economic effects of 16 percent curtailment are not expected to be severe. Lifestyles would be affected and real hardships can be expected for some whose employment would be curtailed.

The risk described above is for the greatest possible outage. Lesser outages would occur more frequently but have diminished consequences. For example, the risk of interruption of half of the HNEC operating capacity, would be:

Probability: 9×10^{-4} events per year; once in 1100 years.

Consequences: Shedding of about 10 percent of mixed loads in PNW for tens of minutes until added reserves are placed on line, with no following load curtailment. (A 5% reduction in energy consumption resulted largely through conservation efforts as a result of the drought of 1976-77.)

Danger of blackouts under such conditions is virtually eliminated, and societal effects would be considerably reduced. Societal risks from substantial generating loss at an HNEC are more meaningful when compared with those from natural disasters (rather than with DS risks).

As a general rule society seems to be willing to accept accident probabilities of 10^{-7} events per year or less where the consequences could be considerable loss of life, or probability in the range 10^{-6} to 10^{-4} where some loss of life may occur along with extensive property loss. Somewhat greater risks are acceptable where the property or economic loss would be moderate with little or no loss of life such as from a maximum HNEC outage.

Under these criteria the HNEC reliability risks described above may be acceptable. However, if they are not, the risk may be reducible by a factor of 10 or more. Earthquake is the predominant contributor to HNEC risk. Reduction of that contribution by a factor of 10 would result in an overall reduction of the risk by approximately the same factor. Modifications to the NRC inspection requirements, along with designing essential power handling structures and equipment outside the reactor facility to an earthquake resistance level somewhat above that of the Operating Basis Earthquake (OBE), have reasonable prospects of being effective and feasible.

CONCLUSIONS

Conclusions reached as a result of this study are:

1. The risks of forced outage of generating capacity arising from the kinds of events analyzed herein are greater for HNEC than for the DS case site configuration.
2. With HNEC the probability of occurrence of the greatest capacity and energy shortages as felt by the power users is once in 10,000 years. The consequences would not be expected to include loss of life or great economic loss.
3. If this risk is deemed unacceptable, it can be significantly reduced in ways now considered feasible.
4. The reliability of energy centers relative to the risk of loss of power to users is definitely site-dependent. The HNEC has space available for relatively wide separation of clusters within the Center to increase their reliability by increasing the independence of each from activities at another cluster. More importantly, the HNEC has the advantage of being tied to a hydroelectric system with a large amount of energy storage capacity which lessens the consequences of large outages of thermal plants in the Pacific Northwest System.

5. The major uncertainties in this assessment are the risks from ashfall, due to sparcity of data; and the duration of outages from all catastrophic events, due to lack of statistics because of the rarity of such occurrence at major thermal power plants.

6. The potentially most productive areas for additional study are:

1) finding ways in which the safety of nuclear plants following an OBE (Operating Basis Earthquake) but less than an SSE (Safe Shutdown Earthquake) could be assured without requiring immediate shutdown of operating plants for inspection. Permission to stagger the inspections following an earthquake less than an SSE would reduce the probability of the greatest HNEC power shortage from once in 10,000 years to once in 40,000 years (perhaps information from seismic instrumentation in the facility will become sufficiently acceptable to relieve the current regulation to shut down immediately to inspect), and 2) estimating the monetary costs of designing the non-Category I portions of the plant essential to continuous generation, to earthquake resistance criteria somewhat above Code levels.

II. INTRODUCTION

A nuclear energy center (NEC) would have a large number of generating units that could be affected simultaneously by natural disasters or that could experience cascading failures triggered by a serious accident at one of the units. In the nuclear energy center concept, a number of generating units are relatively closely spaced, and the reliability of the generation as a result of their proximity could have an important bearing on the feasibility of the concept. The risk of forced outage^(a) of a large amount of capacity must be carefully assessed. Risk is a combination of the probability of occurrence of a causative event, and the consequences of that event. The consequences of a forced outage are its impact on the Pacific Northwest generating and transmission system, and on the power consumer if lost generation exceeds reserve capacity and loads must be dropped.

These risks have been discussed briefly in prior studies on NECs.^(1,2,3) In this report comparative risks between an energy center at HNEC and at dispersed sites in the PNW have been analyzed in more detail.

The reliability of a nuclear energy center at Hanford (HNEC) was compared to that of a dispersed case (DS) consisting of sites at generalized locations in Washington and Oregon. HNEC is assumed to contain up to 20 generating units of 1200 MW net capacity each. The dispersed case is assumed to contain an equal number of units in six clusters of three or four units each.

The base assumptions are similar to those adopted in prior studies of transmission for an HNEC.^{(b)(4,5)} The analysis is not intended to apply generally to nuclear energy centers since its results are strongly influenced by regional characteristics and the unique configuration of the HNEC case. However, certain inferences regarding a general case can perhaps be made as a result of the analysis.

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- (a) The assumption that load growth in the region to the year 2005 could be balanced by 24 GW of capacity at HNEC in addition to existing generating facilities at other sites. Thus future thermal plants, not now committed to other sites are assumed for this study to be located at HNEC.
 - (b) A forced outage is defined as an unplanned loss of generating capacity which must be immediately replaced by reserve generating capacity.

Three generating units are under construction by the Washington Public Power Supply System (WPPSS) at Hanford. The characteristics of these plants are used as examples in the analysis.

Under the assumptions adopted for the study, the generating capacity in the HNEC case would be in five clusters with distances between adjacent clusters of 3 mi to 8 mi.

In the DS case the capacity would be in six clusters, within a triangular area defined by Hanford, WA, Portland and Eugene, OR.

Causes of forced outages in both cases may be categorized as internal or external, and man-made or natural. Exposure to failure from internal causes would be approximately equal for the two cases. With the exception of certain types of failure in a common switching station, a failure would affect only one plant at a time. If one unit fails within a cluster and transmits failure to an adjacent unit in that cluster, however, an internal failure could affect more than one unit. Whenever a failure transmits no farther than the confines of one cluster, exposure is the same for the HNEC and DS cases. If the event could affect adjacent clusters at HNEC, a potential difference in risk between the HNEC and DS cases would result. Only one type of communicable failure for either case has been hypothesized, namely, a class 9 accident with consequent release of radioactive gases and particulates that are airborne to plants in adjacent clusters causing them to be shut down for evacuation of personnel.

If disturbances due to external causes are sufficiently widespread and if the conditions generated by them are beyond design levels, these obviously can affect more than one cluster in the HNEC case. For such causes to affect more than one such cluster in the DS case they would have to be extremely widespread. Severe earthquake, volcanic ashfall, and widespread floods are examples and these possibilities are examined in the report.

A forced outage can occur through failure of either the nuclear or non-nuclear portions of the plant. For safety reasons, the nuclear portions are built to more rigid standards than are the non-nuclear portions, and can be expected to withstand greater stresses from external causes without failure than can the non-nuclear portions. However, after an earthquake exceeding the

OBE level, but less than the SSE, shutdown for inspection is required whether the plant is damaged or not. This would constitute a forced outage and loss of generation as serious as any shutdown forced by damage to essential facilities.

The concern here is the risk of losing more than one cluster at one time, thereby stressing the capacity reserves on the system, plus the risk of losing this capacity for long periods of time thereby depleting the energy reserves of the system. The loss of one cluster of four units is considered an acceptable (if undesirable) risk since it may have approximately equal probabilities of occurrence in either the HNEC or DS cases. Therefore, the difference in probabilities of concurrent outages of more than four units in either the HNEC or DS is the key element in the study. Note that the average forced outage rate of all the units studied over a period of years may be essentially equal between the HNEC and DS cases.^(a) Further, if no single outage were greater than, for example, 5 GW from either case, the impact on the system would be manageable. If one single outage were to involve 15 to 24 GW, however, the impact would be serious. (In view of the consequences, the probability of the latter occurrence must be low for the risk to be acceptable).

The consequences must be understood in the acceptance of even a very low level of probability of occurrence. The consequences of a forced outage of 15 to 24 GW on the PNW system are examined as of the year 2005, when total system generating capacity is expected to total more than 80 GW. Assumptions that are made regarding the state of the system at that time and the measures that might have to be taken to manage such an outage are discussed later in the report. Societal impact following the power curtailment is discussed. Finally, consideration is given to possible modifications to the HNEC case that might result in reduction of probability of major outage or in reduction of the impact.

(a) Any failures due to generic weaknesses in nuclear plant design or construction would involve equal capacities in the HNEC and DS cases.

III. DESCRIPTION OF HNEC AND DS CASES

The HNEC case in its full development in the period 2000-2005 consists of twenty 1200 MW (net) units located at site areas 1 through 5 shown in the map of the Hanford reservation, Figure 1. This assumes that essentially all new thermal plants on the system, other than those now committed elsewhere will be sited at HNEC. Output from the generating units is assumed to be fed into three switching stations which are connected to the 500 kV transmission network. The switching arrangement is shown in Figure 2. A preliminary analysis indicates that the critical time with respect to the reliability of the HNEC would be at or near its full development. The HNEC generation in terms of percentage of total generation in the system would be greatest. For this reason the risk comparisons between HNEC and DS cases are made with 20 units in place.

The Dispersed Case deals with generalized rather than specific sites, since specific sites have not been designated or, to our knowledge, studied in detail. They are intended to be representative of sites that might be selected in view of growth at load centers, availability of cooling water, seismicity, and other general siting criteria. The generalized site areas, taken from Reference 4⁽⁶⁾ are shown in Table 2. These general site areas are shown on the map, Figure 3. One switching station would serve each cluster.

For purposes of this study the arrangement of generating units within each cluster is assumed to resemble that of the Palo Verde or Alan Barton plot plans for three or four units, or the Hanford arrangement of three to five units.

TABLE 2. Number and Location of Dispersed Sites

<u>Site Areas</u>	<u>Generating Units</u>
Hanford	3 (in addition to the 3 units presently committed)
Pebble Springs or W. Roosevelt	4
N.E. of Portland	4
Willamette Valley, A	3
Willamette Valley, B	<u>3</u>
	17 + 3 = 20

○ REACTOR CLUSTER

□ SWITCHING STATION

SCALE: 1" = ~ 7 MILES

FIGURE 1. HNEC Tentative Sites

FIGURE 2. HNEC Switching Stations - 24 GW (500 kV)

FIGURE 3. General Locations of Dispersed Sites

REFERENCES - I, II AND III

1. USNRC, Nuclear Energy Center Site Survey--1975, NUREG-0001, January 1976.
2. USAEC, Evaluation of Nuclear Energy Centers, WASH-1288, January 1974.
3. Battelle PNL Staff, Harold Harty, Project Manager, Hanford Nuclear Energy Center, An Interim Conceptual Study, BNWL-B-458, VC-80, November 1976.
4. Battelle Northwest Laboratories, Electric Power Transmission for a Hanford Nuclear Energy Center, BNWL-B-426, UC-80, September 1975.
5. R. L. Richardson and W. J. Dowis, Station Service Power Supply for a Hanford Nuclear Energy Center (HNEC), BNWL-2076, UC-80, December 1976.
6. Oregon Nuclear and Thermal Energy Council, State-Wide Siting Task Force Report, July 1974.

IV. INITIATING EVENTS

Events that conceivably could cause forced outages at more than one cluster concurrently were screened. Those considered are listed below. The reasons for excluding the events listed under that caption are developed in Appendix A. Briefly, either the probability of the event was too low to have any significance, or the risks associated with the event were approximately equal between the DS and HNEC cases.

TABLE 3. Events Considered for Analysis

<u>Natural</u>	
<u>Included</u>	<u>Excluded</u>
Earthquake	New volcano
Tornado	Meteorite
Ash fall	River channel blockage
Flood	Extremely low river runoff
<u>Man-induced</u>	
Release of airborne contaminants	Aircraft crash at generating plant
Aircraft crash (switching station only)	Explosions: Industrial Sabotage Military action
Sabotage (switching station only)	Toxic gases Fires, including sodium fire Failure of offsite station service High-current faults

V. COMPARISON OF RISKS

RELIABILITY STANDARDS

Reliability in the larger sense includes the effects of both scheduled and forced unplanned outages. Any difference in reliability between plants at these sites would be in the number and length of forced outages. Scheduled outages would be expected to be equal for a plant of the same design whether it was at a center or a dispersed site. Scheduled inspections and repairs might be accomplished in less time at a center because of the greater work forces that may be concentrated there, but in this report no differences were assumed to exist.

A nuclear generating plant of 1200 MW capacity has an expected forced outage rate of 5.5%, or 482 hr/yr.⁽¹⁾ (System reserve needs are determined in part by this rate.) Of that total, less than two hours, on the average, are due to external events of the type of concern in this study.⁽²⁾ The major cause of forced outage are equipment failures and malfunctions, and operator error. If HNEC outages from external events were to double or triple, it would make little difference in the 5.5% outage rate above, since the doubling or tripling would apply to just the 2 hr. On the other hand, if on rare occasions 20 large generating units were to be affected by a single event, the temporary demand on system reserves could be enormous. The types of outages of concern here have very low probability but serious consequences. Adequate reserves for such contingencies cannot be maintained economically. The outcome of this study is to ascertain the extent to which normal reserves, based on conventional forced outages of lesser magnitude, would provide for system service and stability in the event of the rare HNEC outage involving more than one cluster.

It is apparent that there is no norm for forced outages of generating capacity of the magnitude of those to be discussed. The risks necessarily have to be evaluated on the basis of other risks assumed by society. The risks examined here pertain to power outages and energy shortages that could result in economic loss. Some loss of life could result, but such risk is expected to be minimal and was not studied in detail.

The major focus here is the loss of generation with its effect on the production of goods and services and the lifestyle of the power consumer.

As a general rule society seems to be willing to accept accident probabilities of 10^{-7} or less per year where the consequences could be considerable loss of life, or probability in the 10^{-4} to 10^{-6} range when some loss of life may occur along with extensive property loss. Somewhat greater risks are acceptable when the property loss would be moderate with little or no loss of life. For events of major magnitude, each case has to be examined separately in relation to the benefits of the endeavor versus its risks.⁽³⁾

TECHNIQUE OF RISK ASSESSMENT

A basic assumption in the assessment of difference in risk between HNEC and DS cases is that the risk of an outage of all units in one cluster is approximately the same in both cases. Any difference in risk arises from the effects of a single event on additional clusters at HNEC, effects which are avoided in most DS cases because of the greater distances between sites. The risk of forced outage of all units at a single cluster at different sites may be somewhat different, because of the site characteristics. However, these differences are compensated sufficiently in the plant design, and are not included in this analysis.

The causes of outages examined include those such as earthquake and ash-fall in which the effects may be felt over wide areas, and those such as tornado and accidental radioactive release in which the effects are more localized. In all cases, however, the techniques employed are similar. Two sets of probabilities are developed 1) that of the occurrence of the event, and 2) that of multiple clusters being exposed to the event. These probabilities are combined to arrive at a cumulative probability distribution for the number of generating units at which design levels would be exceeded. A third set of probabilities is applied for earthquakes of various severity levels resulting in failure of essential equipment other than Category I for the purpose of examining the effect of NRC post-earthquake inspection requirements. Estimates are then made of the time required to inspect and or repair the plants.

The probability of occurrence of the initiating event is taken from authoritative sources to the extent that such information is available for the PNW and specifically for the HNEC site in Eastern Washington. When such source information is too general or data are too sparse, the probabilities are modified through the use of records on local incidence, or through simulations based on available data.

Probabilities of exposure of multiple clusters to events are obtained by compiling all possible ways in which 1 to 20 generating units can be affected by a single cause, and compiling a probability distribution of numbers of units forced out of service per event. The number of units exposed is a function of configuration of clusters, tendency of the disturbing force to move in certain directions, and the distance over which threshold intensity is exceeded at exposed sites. In all cases, the probability of exposure of multiple units (sites) to an event is independent of the occurrence of that event.

Certain assumptions were required to develop probabilities of exposure. For example, it was assumed that attenuation of earthquake ground motion be uniform in different directions from the epicenter, that tornadoes move in a straight line, and that wind direction during an accidental release of airborne contaminants will not change during the release so that deposition will be within a 22.5° sector.

The results of developing the above probabilities are elements of histograms of $P(E)$, where E is relative exposure in terms of units exposed per event, and $P(F)$, where F is frequency of occurrence in terms of events per year. Combining these two elements gives $P(N)$ where N is number of units forced down in terms of units per year:

$$P(N) = P(E) \times P(F)$$

$P(N)$ values are generated for each kind of event affecting more than one cluster. For example, consider exactly 7 units affected by tornadoes, $[P(N)]_7$. This is all cases of tornadoes of various wind speeds, direction, path widths acting on the HNEC and DS configurations of clusters to result in a forced outage of 7 units at either. All probabilities of $P(N)_7$ are added similarly, probabilities of tornadoes forcing 2, 3, 4, 5, and 6 units out of service are discretely summed.

The above sums form histograms of numbers of units affected by an event, with which cumulative probability curves are constructed as it is detailed in later sections.

The probability that a generating unit would be forced out of service when the design threshold conditions are encountered is taken as 1.0 for all types of events. For example, if an earthquake is at or beyond the OBE level, if flood waters reach a given level, or two inches of ashes have been deposited, it is assumed that there is a probability of 1.0 that the plant would have to shut down. However, in one case, that of earthquake, data are available on the probability of failure versus the degree to which the threshold has been exceeded. These data were used in supplementary calculations to illustrate the probabilities of given amounts of generating capacity being forced out of service by earthquakes in the absence of current NRC inspection requirements applying in such cases.

Information on extent of damage versus intensity of the event was obtained partially from literature and discussions with operators of facilities who had experienced such incidents, and partially from engineers, plant operators, and maintenance people with knowledge based on the vulnerability of plant structures and equipment. The estimate of repair time was approached by setting upper and lower bounds.

The above procedures are carried out for each of the events considered, and the results added to arrive at the overall risk difference.

REFERENCES V, Reliability, Standards, and Technique

1. Pacific Northwest Coordination Agreement, Contract No. 14-02-48221, September 1964.
2. EI Equipment Availability Task Force, Equipment Availability Fossil Component Cause Code Summary Report - 1973.
3. Chauncey Starr, Benefit-Cost Studies in Sociotechnical Systems, Perspectives on Benefit-Risk Decision Making, Natl. Academy of Engineering, April 26-27, 1971.

EARTHQUAKE

Introduction

Under certain circumstances, an earthquake could shut down all generating units at an HNEC. An estimate of the probability and consequences of such an event is made in this section, and the results are compared with those of a parallel study of effects of earthquake on dispersed plants.

Earthquakes that would cause horizontal acceleration, at a site, at the OBE level (0.125 g at Hanford) would necessitate shutdown of a plant at that site for inspection. If the ground shaking were above OBE horizontal acceleration there would be some potential for damage to code-design equipment and structures. After inspection, and repair of any damage to essential facilities, the plants could be returned to service. Safety-related facilities would have an extremely low probability of damage for accelerations below the SSE level (0.250 g at Hanford); i.e., too low to be of interest in this study.

Definitions

Appendix A to 10 CFR Part 100 defines the Safe Shutdown Earthquake (SSE) as "based on an evaluation of the maximum earthquake potential...", and the Operating Basis Earthquake (OBE) as one that "...could reasonably be expected to affect the plant site during the operating life of the plant...".

The nuclear reactor and its appurtenances essential to plant safety are designed for ground accelerations corresponding to the SSE intensity level, and the remainder of the plant to building codes in which the design ground accelerations usually lie close to those of the OBE.⁽¹¹⁾

Criteria for HNEC Plants

The following statements taken from Reference 3 present the basis for selection of the OBE and SSE design levels for existing Hanford plants^(a) and presumably for all units at HNEC.

(a) These are units 1, 2, and 4 under construction for the Washington Public Power Supply System (WPPSS).

"The maximum vibration level at the site from historic earthquakes has been 0.015 g associated with the site intensity IV(MM) from the Milton-Freewater earthquake. The greatest vibration level expected at the site from the 'maximum earthquake' is 0.125 g."

"An 0.25 g vibration level is assigned as a value at ground surface in the site area. This value is consistent with the conservatism previously adopted for design criteria at the Hanford reservation and is consistent with the vibratory accelerations associated with an intensity VIII(MM) earthquake.... . This earthquake is assigned to the Rattlesnake-Wallula alignment, the closest tectonic structure of significance to the site. Since no attenuation was taken in the selection of the SSE, this is a conservative approach. 0.25 g acceleration value is adopted for the SSE."

"An OBE equivalent to 0.125 g (1/2 SSE) will be used in the design of all Seismic Category I structures. The chosen value for the OBE is based on the greatest vibration level expected at the site," during the normal lifetime of the facility.

Criteria for Dispersed Sites

Local seismic conditions at the DS sites may be such that the design accelerations could differ from those in effect at Hanford. The OBE design points for plants planned for western Washington are 0.16 g and 0.12 g. However, to simplify the analyses of this report it can be assumed that the OBE and SSE levels would be approximately the same as at Hanford. Small differences in the OBE and SSE levels from those in effect at HNEC would not affect the validity of the analysis to follow.

Analytical Techniques

The objective of this part of the study was to estimate the probability of outage of (x) megawatts of capacity as a function of the probability of a) occurrence of earthquakes of different magnitudes, and b) two or more clusters being at a distance from the epicenter at which they would be subjected to horizontal ground acceleration of 0.125 g or greater.

As a minimum, the outage time will be that required by NRC for inspection. As a maximum, the outage must include time for the above and necessary repairs from actual damage from an earthquake of probable intensity (above 0.125 g).

A simplistic approach is the only one possible within the scope of this study. In this approach, computed free field ground movement at the study sites due to earthquakes centered in sensitive zones common to two or more clusters determines the probable number of generating units affected by a given earthquake. It is assumed that transmission of vibratory movement through rock is uniform in all directions, giving a circular isoseismic pattern. It is not expected that perfect circular isoseismic patterns would actually develop but, as discussed under Attenuation, such patterns would be true enough to give meaningful comparisons between the HNEC and DS case outage probabilities.

Also, no cognizance was taken of known faults in the immediate vicinity of sites. Those at Hanford were, of course, taken into consideration in the setting of the SSE for WPPSS plants, but the effects of any faults near or between DS sites of this study were ignored. The possible effects of any vibratory feedback of plant structures to the soil was not examined, but it is assumed that these would not extend beyond the area containing a cluster.

Those areas in which earthquakes are expected to occur most frequently were identified.⁽⁶⁾

"Significant potential epicentral areas were defined based upon the seismic history of the region and a general consideration of known tectonic structures. The maximum earthquake magnitude that can reasonably be expected to occur in each significant potential epicentral area was predicted by a statistical consideration of historical earthquakes of different magnitudes and a consideration of known fault conditions."

The location of sites relative to these seismically active areas as shown in Figure 4 was considered in the adoption of earthquake frequencies to be described later.

Earthquake Characteristics

This study is concerned with single earthquake events. It is recognized that earthquakes can occur at different epicenters in the same region within

FIGURE 4. Earthquake Zones Near Site Boundaries

a short time interval, but such combinations of events are too improbable to consider. Also ignored are aftershocks of lesser magnitude, which may cause added damage to structures weakened by the first shock.

It is recognized that earthquake resistant designs must take into consideration a number of phenomena other than ground horizontal acceleration. Among them are frequencies, velocities, displacements, vertical accelerations, and effect of different types of underlying material. Structural design in response to the ground shaking must take into account the damping, elastic limits, and other factors. It is assumed here that all of these aspects would have been adequately accommodated in the design, so that structures that respond to maximum ground horizontal acceleration, responds similarly in all other respects.

Earthquakes are classified by magnitude of energy release on the Richter scale, and by ground shaking intensity (at any distance from the epicenter) on the Modified Mercalli Intensity (MMI) scale.

"Earthquakes of MMI greater than VI are of principal interest, because only these are strong enough to cause damage to structures."⁽¹⁾

Intensities above X (MMI) are considered to be greater than the earthquake potential at any of the study sites.

Ground Characteristics-Attenuation

"Seismic energy is not uniformly radiated from the source; in addition, variations in attenuation characteristics along the ray paths of the propagating waves cause nonuniform attenuation, hence the surface excitation pattern is not symmetric and in fact is very complex and difficult to predict."⁽⁶⁾

Figure 5 from the same reference shows the patterns of attenuation of certain earthquakes in the region of interest. The earthquake epicentered near Walla Walla has an approximately circular pattern, lending some assurance that the assumption discussed previously is acceptable for that area including HNEC. Some isoseismic plots, such as that of Figure 6 are very irregular, and in many cases are elongated on the east-west axis. This may be due to inconsistent reporting, to local faults, or to geological features that may have influenced the analysis. If elongation in the east-west direction is present, it would not reduce the conservatism of the analysis in that propagation in the north-south and northwest-southeast directions are of most importance in HNEC studies.

The use of circular patterns from DS sites around Portland where historical patterns are irregular is questionable. However, the study findings are less sensitive in Portland cases as only one cluster would be affected by irregular attenuation rates.

Attenuation curves used in this study are from Schnabel and Seed.⁽⁵⁾ Average values of attenuation in rock from this reference are shown in Figure 7.

Probability of Earthquake Occurrence

The probability of occurrence of earthquakes encompassing the HNEC and DS sites was derived in the following way. The probable occurrence data for the calculations were based on the seismicity of the western U.S.⁽²⁾ Several curves are presented in this reference. The one chosen for use in this report

FIGURE 5. Intensity IV, Isoseismal for Major Earthquakes in Pacific Northwest

FIGURE 6. Isoseismal Map - 1936 Milton-Freewater Earthquake

appeared to match data points well in the Richter 5.5 to 7.0 range of principle interest here. The correlation is:

$$\text{Log } N = -0.662 - 0.881 M$$

where N is the number of earthquakes equal to or greater than the magnitude point, and M is the magnitude on the Richter scale.

This expectation, based on earthquakes over a wide area, was compared with a record of earthquake frequency experienced in the Puget Sound area.⁽⁷⁾ Figure 8 contains plots of the two curves. The Puget Sound area has had more seismic events than areas east of the Cascades, and it would be expected that the frequency per unit area computed for 42,000 mi² of the Puget Sound area would be greater than for the western U.S. as a whole. Since the 121,000 mi² of interest in the Pacific Northwest for this reliability study have large areas to the east and south of Puget Sound having a low level of seismic activity, it was concluded that the use of the western U.S. curve would be appropriate as an overall indication of seismicity in this region. As discussed below, this average value is adjusted on the basis of the history of earthquakes in the site areas.

A record was obtained of known earthquakes in longitude range -125° to -115°, and latitude range 43° to 51°, an area considered representative of the western U.S. It covered maximum intensities equal to or greater than VI (MMI) or having a magnitude equal to or greater than M5.5.⁽¹⁰⁾ Earthquake occurrence in the 1° rectangles containing the study sites were noted, and the western U.S. frequency curve data were adjusted by the ratio of the earthquake occurrence in that rectangle to the average occurrence over the entire region. For example, the HNEC site lies in a rectangle that had three earthquakes of the 77 listed, and the rectangle occupied approximately 1/80 of the region. The adjustment factor for that site was $3/77 \div 1/80 = \sim 3$ for intensities of VI to VII corresponding to magnitudes of 5.2 to 5.6. Factors for magnitudes 6.6 and 7.6 were set according to general seismic information concerning the site areas. The resulting factors are listed in Table 4.

These factors are intended to be conservatively high, and also consistent with seismic data presented for sites that are being developed.

FIGURE 7. Average Values of Maximum Accelerations in Rock

FIGURE 8. Probability of Earthquake Occurrence

TABLE 4. Factors to Adjust Western U.S.
Earthquake Data to Site Areas

	Magnitude, Richter Scale			
	5.2	5.6	6.6	7.6
HNEC	3.0	3.0	0.75	0
Pebble Springs	1.0	1.0	0.33	0
Portland	3.0	3.0	3.0	3.0
Willamette Valley	1.0	1.0	0.33	0

Probability of Forced Outage

The overlap areas in which earthquakes occur to affect multiple clusters are presented in the maps of Figures B1, B2, B3 and B4 of Appendix B. Calculations of probability of outage of generating units by earthquake are also in Appendix B. The results of analysis are presented in Figure 9, Zone A.

The immediate effect of an earthquake above the OBE intensity is a programmed shutdown of the plant for inspection of all Category I systems.

NRC regulations state:

"If vibratory ground motion exceeding that of the Operating Basis Earthquake occurs, shutdown of the nuclear power plant will be required. Prior to resuming operations the licensee will be required to demonstrate to the Commission that no functional damage has occurred to those features required for continued operation without undue risk to the health and safety of the public."

Forced outages to fulfill the inspection requirement have the probabilities shown in curve A, Figure 9. Curve B shows probable forced outages due to actual failure of structures or equipment from the effects of earthquakes.

Probability of Forced Outage Through Failure of Essential Facilities

If a structure built to Code standards is subjected to its design acceleration, (0.125 g at HNEC, the OBE) the probability of failure has been estimated at 0.03.⁽⁴⁾ For the same structure subjected to twice this acceleration, namely 0.25 g, the probability of failure has been estimated to increase to about 0.25. The latter results from projections based on estimates of increased probability of damage to Category I structures at twice their design acceleration level.⁽¹¹⁾ For non-Category I structures the estimate is not based on a rigorous development but is assumed to be a reasonable approximation.

FIGURE 9. Probability of Forced Outage of Generating Units at HNEC and DS by Earthquake

This probability of failure reflects the effect of factors of safety normally used in designs, and the observed response of structures to earthquake forces. The intensities of earthquakes of interest here range from the OBE level (0.125 g) to about 90% of the SSE level (0.22 g). Values of 0.10 to 0.25 have been used as the probability of forced shutdown because of damage suffered to Code structures from accelerations in the range 0.015 to 0.022 g. The probabilities of forced outage due to failure from an earthquake causing accelerations in this range are shown in Zone B of Figure 9.

The comparative data shown in Figure 9 reveal that:

- The probability that one cluster would experience ground acceleration exceeding 0.125 g is greater for the DS case because of the greater number of exposed locations. The probability levels for single clusters are reasonably consistent with the definition of the OBE--an earthquake that could "reasonably be expected to affect the plant site during the operating life of the plant".
- In this study six generating units is the maximum number that could be affected by one earthquake in the DS case, and 20 in the HNEC case. The probability of multiple clusters being affected in the DS case drops off rapidly to 5.5×10^{-4} events per year for six units; for HNEC it drops off more slowly to 1.6×10^{-3} events per year for 20 units.
- Outages following earthquakes of increasing intensities in the OBE-SSE range are from 10 to 4 times more likely to occur in fulfilling the inspection requirement, than to occur from the effects of damage to essential facilities. The inspection requirements significantly increase the risk of loss of large amounts of generating capacity.

Probable Site Intensity

Where one or more clusters (both HNEC and DS) are affected by one earthquake, the most probable horizontal acceleration has been estimated as shown in Table 5. The estimates are made from computations of intensity at the site from earthquakes having epicenters spaced throughout the overlap areas, or, for single clusters, spaced throughout the annulus around the site.

TABLE 5. Probable Horizontal Accelerations at Sites,
Within the Range of 0.125 to 0.250 g

Number of Clusters	Horizontal Acceleration, g	
	HNEC	DS
1	0.142	0.167
2	0.151	0.175
3	0.150	0.180
4	0.153	--
5	0.220	--

Estimate of Outage Period

If the outage is solely for inspection, i.e., if there is no obvious damage and if no indications of damage are found in the course of the inspection, the time requirement estimate would be governed by the scope of the inspection. That could range from a walk-through visual inspection to a thorough-going test of system functions.

The scope of inspection required to satisfy both the plant operator and the NRC has not yet been defined, nor have criteria for acceptance of test results been issued. NRC is currently preparing proposed criteria.

Regulatory Guide 1.12, Instrumentation for Earthquakes Revision 1, was issued in April 1974. This guide sets forth the instrumentation considered desirable to detect and record the effects of seismic motion, from which floor response spectra as well as other effects can be calculated.

"This information will be needed to determine 1) the conservatism in the modeling and design assumptions made for the structure and design input motion to the supported systems and components, and 2) the advisability of continuing the operation of the plant without a safety analysis following an earthquake."⁽²¹⁾

It would appear that as a minimum, the inspection will include an analysis of all pertinent instrumentation readings and records; identification of the structures and facilities that are most likely to have been affected by vibratory motion at frequencies having high amplitude; a thorough inspection of any vulnerable structures, equipment, vessels and piping; and perhaps tests on safety systems.

The extent of the inspection will depend on the intensity of the earthquake, unusual phenomena observed in plant operation following the earthquake, the extent of readily observable damage, and the preparation of the analysis.

The work necessary to accomplish an inspection on the above general grounds, following a quake with a ground intensity in the range indicated was estimated for purposes of this report, at from 3 to 60 days. The inspection time associated with the most probable acceleration, 0.15 g, was estimated to be 7 days on the average. That period is used in the computations on energy production loss to follow.

Estimates of damage caused by earthquakes, and time required to restore service, are based on certain assumptions:

- That knowledge gained from analysis of well-instrumented and thoroughly analyzed earthquakes such as the San Fernando earthquake of February 1971 would be applied in the designs of generating plants and switching stations. (The San Fernando earthquake caused peak ground accelerations in certain areas of 0.30 to 0.50 g, considerably greater than the 0.125 g to 0.25 g range discussed here).⁽⁸⁾
- That HNEC operation and maintenance forces would be prepared to cope with earthquake effects in a manner similar to that of California utilities.⁽⁹⁾
- That temporary measures to restore service would be taken wherever possible, with permanent repair to follow, as technical specifications permit.

If significant damage is suffered to non-Category I facilities, repair times will depend on the nature and extent, the availability and competence of repair crews, and the management of materials and spare equipment.

Failure can take place either through malfunction of certain instruments or equipment causing automatic or manual shutdown of the plant, or through physical damage to structures, lines or equipment, causing automatic or manual shutdown. In a malfunction there may be little or no damage, and the principal work during the shutdown will be for inspection and analysis. In the event of physical damage, repair of obvious damage can proceed concurrently with inspection of other portions of the plant.

Malfunction may be due to sensing instrument contacts closing or opening in error, the effects of sloshing liquid levels on instrumentation, leaks in air pressure or hydraulic lines, vibration instrumentation on rotating equipment, or others.

Damage to non-Category I facilities could result from:

- Shifting of massive equipment on foundations, or failure of foundations with damage to interconnecting piping or conduits systems, and possible damage to the equipment itself.
- Shaft bending in rotating equipment with consequent rubbing or bearing misalignment.
- Toppling of panelboards or tall slender structures not properly braced.
- Secondary effects of broken pressure piping.
- Structural failure.
- Failure due to faulty materials or design (even though presumably designed to respond properly to the spectra of earthquake motion.)

Non-Category I facilities of a typical LWR plant most vulnerable to earthquakes in the OBE-SSE range were considered in relation to the probable intensity range given previously. The estimates of time required to repair damage to these facilities at an LWR, subjected to horizontal accelerations are:

	<u>0.150 g</u>	<u>0.22 g</u>
Maximum	20 days	100 days
Minimum	3 days	15 days
Probable	7 days	40 days

These estimates are used in the calculation of loss of energy production due to earthquake.

For example, an earthquake in the OBE-SSE range would result in:

- a programmed shutdown for an inspection expected to require 7 days, even if no malfunction takes place or no damage is suffered,
- a damage repair requirement of 7 to 40 days which could run concurrently during much of the inspection time.

To arrive at a probability of loss of available energy, the capacity shown as the abscissa of Figure 9 was multiplied by the time to inspect, as a minimum, and possibly the time to both inspect and repair. For example, the loss of 12 generating units (14.4 GW), shown on curve A of Figure 8 as having a probability of 5.3×10^{-3} events per year, is multiplied by the probable outage period, 7 days, and by the assumed plant capacity factor, 87%, to give loss of available energy, 2105 GWh. This energy loss has the same probability as the capacity loss since it derives from the latter.

Earthquake Risk

Both the capacity and energy loss curves are shown in Figure 10, in terms of GW and GWh.

From these curves, risk to earthquakes for several specific losses of capacity or energy are:

<u>Capacity Loss, GW</u>	<u>Loss of Available Probable Energy, GWh</u>	<u>Probability of Occurrence/year</u>
8	500 (min)	0.0086
8	3300	0.0086
18	2600	0.0034
24	20,000	0.0016
24	50,000 (max)	0.0016

FIGURE 10. Risk of Both Capacity and Energy Generation loss from Earthquake at HNEC

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TORNADO

Introduction

This section contains an assessment of the risk of forced outage of generating units at multiple clusters because of tornadoes. The probability of a tornado striking the first cluster is a function of the number of tornadoes experienced, and their path areas in the region. The probability of the same tornado striking a second cluster is a function of expected path length, the configuration of the clusters relative to each other, and to the prevailing direction of movement of tornadoes in the region. The number of units affected within a cluster is a function of path direction. It could also be a function of path width but the plant layout and probable path width are not sufficiently definitive to distinguish path width effects.

The only tornadoes considered here are those that would move in such directions that they could affect more than one cluster at Hanford. As discussed later, about 68% of the tornadoes in this area may be expected to move in a northeasterly direction, but the configuration of cluster sites is such that a single tornado moving in that direction could not strike more than one cluster. Therefore, the probabilities of tornado strikes that are developed herein do not include all strikes that could affect individual clusters in either the HNEC or DS cases. The only group of tornadoes considered (those other than the 68%) are the same for both the HNEC and DS cases to permit valid comparisons. These are tornadoes with movement along northwest-southeast, and east-west axis, comprising only about 32% of all tornadoes.

Nuclear Regulatory Commission Criteria

Facilities essential to reactor safety must meet NRC requirements set forth in Regulatory Guide 1.76 with respect to resistance to tornado damage.⁽²⁾ They must be designed and constructed to withstand a Design Basis Tornado (DBT). DBT characteristics are given in the following table from Guide 1.76.

The Hanford reservation lies in Region III of the table. The peak tornado velocity estimated for the HNEC site is 214 mph, somewhat below the 240 mph criterion of Region III.⁽³⁾ The portions of plants authorized to date are designed to comply with the 240 mph criteria of the above table, and all

TABLE 6. Design Basis Tornado Characteristics

Region	Maximum Wind Speed (mph) (a)	Rotational Speed (mph)	Translational Speed (mph)		Radius of Maximum Rotational Speed (ft)	Pressure Drop (psi)	Rate of Pressure Drop (psi/sec)
			Maximum	Minimum (b)			
I	360	290	70	5	150	3.0	2.0
II	300	240	60	5	150	2.25	1.2
III	240	190	50	5	150	1.5	0.6

- (a) The maximum wind speed is the sum of the rotational speed component and the maximum translational speed component.
- (b) The minimum translational speed, which allows maximum transit time of the tornado across exposed plant features, is to be used whenever low travel speeds (maximum transit time) are a limiting factor in design of the ultimate heat sink. The ultimate heat sink is that complex of water sources, including associated retaining structures, and any canals or conduits connecting the sources with, but not including, the intake structures of nuclear reactor units. Regulatory Guide 1.27 (Safety Guide 27), "Ultimate Heat Sink," describes a basis that may be used to implement General Design Criterion 44 of Appendix A to 10 CFR Part 50 with regard to the ultimate heat sink.

future plants in HNEC would similarly comply. DS plants at the more westerly sites may lie in Region II. Reactor facilities wherever located would be designed to meet tornado conditions. The probability of exceeding the DBT therefore would be the same (about 10^{-7} events per year) for all sites.

Non-Category I facilities are designed to withstand tornado windspeeds of up to about 100 mph and remain in service. Many of these may be essential to continued plant operation. This study is therefore concerned with the probability of occurrence of tornadoes having a windspeed of 100 mph and above. It is assumed that design for pressure change and for impact of tornado-propelled missiles would be consistent with that for windspeed. Windspeed alone is a suitable measure of tornado intensity.

A general correlation between windspeed and path area is given in Reference 4,

"If one knows the tornado area is z , then the best estimate of windspeed is $w = 2400 \cdot (15 + e^{-0.41 \ln z - 1})$, and the windspeed will have a standard deviation of 25 mph around this best estimate".

Thus windspeed can be related to path area, z . Path area can then be related to probable width and length of path. Those windspeeds in excess of 100 mph determine the extent of damage and consequently the estimated repair time.

Direction of Tornado Movement

Pathways followed by tornadoes striking more than one cluster are shown in Figure 11.

The direction in which tornadoes tend to move in the Hanford area is shown in Figure 12. An analysis of tornadoes experienced in the area gives the following percentages for tornado movement in different compass directions:

FIGURE 11. Pathways for Tornadoes at HNEC

FIGURE 12. Direction of Movement of Characterized Tornadoes in 20-Year Period, 1950-69

<u>Direction Toward</u>	<u>Percent of Total No. of Tornadoes</u>
NW	13.6
NNW	4.5
N	4.5
NNE	0
NE	68.4
ENE	0
E	4.5
ESE	0
SE	4.5
SSE	0

Sites lying along axes parallel to the axis of the "alleys" shown in Figure 12 have a greater probability of being affected in common by a tornado than sites, such as HNEC, lying along an axis at right angles to the axis of the alley.

Tornado Start Points

A tornado may start at any point inside or outside of a cluster of generating plants. The probability of one tornado striking a second cluster will depend on the starting point as well as the path length. To deal with this aspect, the percentage of path length remaining after the tornado has struck the first cluster was taken as a random percentage of the path length.

Regional Tornado Experience

The data on which the following estimates are based consists of:

- 1) records of tornadoes in the states of Washington, Oregon and Idaho over the period 1950-69. The size distribution of 46 tornadoes is given in Table 7 from Reference 4.

TABLE 7. Size Distribution of Tornadoes (Mc^{-2})

<u>No. of Events</u>	<u>Area Mi^2</u>
34	<0.1
2	0.1
2	0.15
2	0.16
1	0.30
1	0.50
1	0.72
1	1.15
1	2.7
1	6.0

- 2) a simulation of 200 yr of tornado incidence at a Hanford site, based on the above data.⁽⁴⁾ The simulated tornadoes of interest in this study, i.e., those having a probable path length as great as or greater than the distances between clusters, are used for risk computation.
- 3) records over the period 1965-74 in the states of Washington, Oregon and Idaho, including length and width of path, and direction of movement. These data were used for path length and width correlation with the 200 yr simulation.

These records and simulations indicated that:

- 1) The additional data on path areas of the 1965-74 record was consistent with the 1950-69 data with regard to the distribution of path size, except for the 0.001 mi^2 group which is not pertinent to this study.
- 2) In the 1965-74 list, five tornadoes have a path length of 4 mi or greater. Consequently 13 tornadoes having a path length of 4 mi or greater are predicted when projecting the above record to a 200 yr period. In the 1965-74 period, a path length to path width ratio of 50 occurred in more than 74% of the tornadoes. These 13 simulated tornadoes which were used in the study are given in Table 8.

TABLE 8. Tornadoes with Path Length over 4 Miles

<u>Area Mi²</u>	<u>Path Width, Yards</u>	<u>Path Length, Miles</u>
0.90	236	6.70
0.48	172	4.90
0.44	165	4.69
1.70	325	9.22
7.80	695	19.74
2.70	409	11.62
0.82	225	6.40
0.45	167	4.74
2.60	401	11.40
0.30	136	3.87
4.50	528	15.00
0.29	134	3.81
3.80	485	13.78

Probability of Exposure to a Tornado

The points most vulnerable to tornadoes are cooling towers, overhead lines and switching stations. Typical locations of those plant components are noted in connection with width and direction, to determine the probable number of units affected.

Cooling towers of the forced draft type are reported to be costly to build to withstand windspeeds above 110 mph. At sites in western Washington and Oregon towers may be of the natural draft type which reportedly can be economically designed for higher windspeeds. Or at sites such as Pebble Springs, ponds may be used instead of towers. These features might make marginal differences in tornado risks at DS sites but not in the analysis of effects of strikes at HNEC, where cooling towers presumably would be of the forced draft type but would have tall enclosures to reduce fog. They may have construction features similar to natural draft towers, and may be more resistant to tornadoes than conventional forced draft towers.

Probability of Occurrence

The tornado event probability was obtained by applying to the list of 13 tornadoes having a path length sufficient to reach a second cluster, a random number designating the path length remaining after the tornado has struck the first cluster. This reduced the number of tornadoes likely to reach a second cluster to seven in 200 yr. Since each tornado occurred once in a 100-mi radius area in 200 yr, the probable annual frequency of its touching any point would be:

$$\text{Probable Annual Frequency of Tornadoes} = \frac{\text{Path Area (mi}^2\text{)}}{100^2\pi \text{ (mi}^2\text{)} \times 200 \text{ yr}}$$

This probable annual frequency was multiplied by the exposure probabilities associated with tornado paths. These products were summed over all combinations of tornadoes associated with one, two and four generating units. Since a single tornado would occur only at any one of five possible clusters, the sum of the combinations developed above was divided by five.

The two clusters at Hanford which make up part of the DS case were treated in the same way. The other clusters in the DS case were too far apart to be affected by one tornado.

It was assumed that the first cluster struck by a tornado would suffer the same effect in both the HNEC and DS cases. It was estimated that, on the average, two units of the first cluster may be affected in both DS and HNEC cases, by tornadoes strong enough to reach two clusters at HNEC. In figures to follow, two units (from the first cluster) were added to the number of units forced out of service in the second cluster to give total capacity affected.

Probability of Forced Outage

The results of the analysis are presented in tables in Appendix B and in Figure 13.

It will be noted that:

- 1) In the HNEC case, four units are the probable maximum number forced out of service in clusters beyond the first, for a total of six. In

FIGURE 13. Probability of Forced Outage of Generating Units from Tornadoes

the DS case, two units are the probable maximum number forced out of service beyond the first cluster for a total of four, maximum.

- 2) The probability of a second cluster in an HNEC being struck is very low, 7.5×10^{-8} in the DS case, and 2.5×10^{-7} in the HNEC case.
- 3) The results are somewhat sensitive to assumptions as to plant layout. If all clusters were as spread out as cluster No. 1, the southernmost cluster, the total number of units to be struck would be less.
- 4) There is only one combination involving three clusters at HNEC.
- 5) A perspective on tornadoes as a cause of forced outage of multiple units may be gained from the following:

	<u>Probability/yr</u>
• Tornado strike probability from map of 5° squares in the contiguous U.S. from Wash-1300 ⁽¹⁾ containing all tornadoes above 73 mph.	3.7×10^{-5}
• Windspeeds 100 mph or over, from simulation of Reference 4.	4.4×10^{-6}
• Probability of second cluster at HNEC being struck by tornadoes in excess of 100 mph.	2.4×10^{-7}
• Probability of a Design Basis Tornado	1×10^{-7}

Windspeeds

As noted previously the damage inflicted on a plant by a tornado is a function of windspeed. Windspeeds associated with the 13 tornadoes of interest are given below in Table 9. Six of these have path lengths too short to affect units beyond those in one cluster. Then, the effects of only seven tornadoes are analyzed.

These are all well below the Design Bases Tornado, 240 mph, however, all except for one have windspeeds above the threshold of possible damage to facilities.

TABLE 9. Tornado Windspeeds Associated with Path Area

<u>Path Area</u> <u>Mi²</u>	<u>Windspeed</u> <u>mph</u>
0.9	163
0.48	137
0.44	163
1.70	172
7.80	149
2.70	141
0.82	154
0.45	116
2.60	153
0.30	154
4.50	117
0.29	98
3.80	179

Tornado Risk

Mandatory inspections following a tornado are not required by regulation. A plant struck by a tornado would shut down only if damaged to the extent that shutdown is actually forced or is considered prudent in view of the circumstances.

Damage can occur because of wind forces, pressure differentials or wind driven missiles. Only missiles associated with normal plant operation are assumed available such as wood poles, timbers, small vehicles that could damage outside transformers, switchgear or similar equipment. No nearby construction is assumed in progress.

Code design structures and equipment can expect to be affected, such as cooling towers of the forced draft type, overhead electric lines, switching stations, high tanks, stacks and buildings with sheet metal sidings. (5)

It is assumed that temporary repairs to restore service would be made wherever they are feasible.

Under these conditions the estimated average forced outage times following tornadoes of the windspeeds listed are:

	<u>Days</u>
Maximum	80
Minimum	10
Probable	40

The "probable" estimate is used in the computation of loss of energy production capability.

Risk of forced outage at HNEC is shown in Figure 14. The risk at selected points is:

<u>Capacity GW</u>	<u>Probable Energy Loss, GWh</u>	<u>Probability of Occurrence/yr</u>
4.8	1000	1.4×10^{-7}
4.8	4000	1.4×10^{-7}
7.2	6100	4.0×10^{-8}
7.2	11,500	4.0×10^{-8}

The analysis shows that the HNEC risk from tornadoes is very low relative to risk from other causes evaluated in the study.

FIGURE 14. Risk of Capacity and Energy Generation Loss from Tornado at HNEC

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RADIOACTIVE RELEASE

Introduction

The risk to be assessed in this section is that of forced shutdown of generating plants due to accidental release of radioactivity from a class 9 accident; i.e., a fuel melt and breach of containment at one of the nuclear generating plants. Such a release would occur only after failure of multiple safety systems. The chain of events would consist of 1) failure of containment at one plant, 2) rapid shutdown of other plants at that cluster and immediate evacuation of personnel at that cluster, 3) orderly shutdown of plants at other clusters where the potential for radiation exposure will force evacuation of operating personnel, and 4) decontamination of these plants and their immediate environs, with resumption of operation when radiation levels are acceptable. The unit releasing the radioactivity is assumed to be no longer available.

Before the full development of the 20-unit HNEC could be completed, it is possible that LMFBRs would replace some of the planned LWR generating units. In Reference 5, Proposed Final Environmental Statement, Liquid Metal Fast Breeder Reactor Program, the authors note that, "detailed probabilistic risk assessments have not yet been performed, although some preliminary studies have begun." The report refers to the Reactor Safety Study regarding LWR plants. It implies that some of the same phenomena tending to limit releases, and the very low probability of occurrence of large releases, may apply at LMFBRs also.

Since, presumably, the LMFBRs would occupy the same sites (within the clusters) as the LWRs, be subject to the same wind conditions, and have the same order of probability of occurrence, the only significant change in the event of a class 9 accident at an LMFBR would be the somewhat different radioactive releases. If it can be assumed that the affected plants could still be shut down safely and be decontaminated with comparable applied effort, then the risks to adjacent clusters from a class 9 accident at an LMFBR would be comparable to those from an LWR.

In this report, therefore, it is assumed that no difference in risk of forced outage from radioactive releases would exist by reason of a few of the LWR positions being filled by LMFBRS.

One or two fuels reprocessing plants can be assumed to be in operation at or near the HNEC. The unit in existence currently, however, and associated with the weapons program is assumed to have been decommissioned by the year 2000. Risks of loss of generation and of power shortages at an HNEC due to release of radioactivity following an accident exceeding the design bases at a fuels reprocessing plant are not included in this report. They are not included for two reasons. First, a source term, i.e., the amount of radioactivity that can be expected to be released following a major accident at a fuels reprocessing plant is not available. Preliminary reviews indicate that this source term would not exceed and probably be less than the source term from a fuel melt accident and release at a reactor.⁽¹⁾ The second reason is that probable sites for fuels reprocessing plants were not identified. Hence, these were not included in the meteorological model developed for the HNEC conditions (3). When these two factors become available, the contribution of a fuels reprocessing plant at an HNEC to the risk of loss of generation at an HNEC can be readily estimated.

WASH-1400, Reactor Safety Study, a report of the NRC published in October 1975⁽²⁾ contains the results of a comprehensive study on the subject of accidental radioactive releases from light water reactors and their probable effect on populations and property. While the safety of the general public following a reactor accident is always of paramount importance, such concerns are not a part of the current review. This reliability study on radioactive releases considers only two scenarios. The first is the potential for exposure to generating plant operating personnel during the passage of the radioactive cloud forcing their evacuation, thus causing plant shutdowns. Second, the number of plants forced out of service temporarily because of ground contamination following the accident may deny access or occupancy to control rooms or other parts of the facility and force a loss of generating capability. Decontamination

(1) K. J. Schneider - Private Communication, 1978.

of the facilities and grounds sufficient to return them to operation in the shortest possible time is assumed and only activities addressed to maintaining or restoring generating capacity are considered.

FIGURE 15. Schematic Outline of Consequence Model Radioactivity Release

As indicated by Figure 15, the source term was taken from the Reactor Safety Study. Any of the accident source terms identified in that study could be used to indicate the potential dose rates in reactor control rooms, (a) from the passing cloud following the accident; and (b) from ground level contamination during the period following deposition. Specifically, as an example, the class 9 accident identified as release category PWR-2 was selected (Table 5-1, Ref. 2). This was judged to be as probable as any other event. It also postulates great or greater quantities of radioactive material released as any other accident. It can be considered as worst case. The tabulation of radionuclides released in this event is given in Appendix B.

The HNEC model assumed that the containment breach resulted in a source 100 meters wide which spread downwind over a 22 1/2° as it moved out from the point of release. Figure 16 illustrates one such release at Cluster No. 2 with

clusters 3 and 4 shown within a $22\frac{1}{2}^\circ$ sector downwind. The model integrates Hanford meteorological history and has provided a tabulation of the probabilities of one or more reactor sites having specific values of air concentrations normalized to release rate $\bar{x}/Q'$ with units of sec/m^3 . (3)

FIGURE 16. Sites and Areas Involved in Radioactive Release at HNEC
(Example: Release at cluster 2)

As above, the dispersion of the radioactive cloud results in radiation exposure to those inside the facility during the assumed half hour passage of the cloud (referred to as the air submersion dose), and exposure to these same personnel from ground contamination following passage of the cloud. Inhalation of cloud debris or radioactive material resuspended from contaminated surfaces, are not primary factors. It was assumed that adequate filtering would be in place to isolate work areas and personnel from all airborne radioactivity. Similarly, short- and long-term health effects from drinking potentially contaminated water or eating contaminated food are assumed not to be significant for these scenarios. Only potential external exposures to occupational workers, i.e., staff members at the generating facilities, are assumed. These potential exposures are assumed to become a part of the routine administrative responsibilities that limit occupational exposures. Relaxation of administrative controls to facilitate a more rapid recovery of generating capacity is not assumed.

The release of radioactive material during the accident is assumed to occur over a half-hour period (Ref. 2) and the subsequent radiation levels from the air immersion dose are assumed to persist for a one-half hour period regardless of the distance of each area from the source or the time it took for the cloud to arrive.

PROBABLE CONSEQUENCES - AIR SUBMERSION

The potential radiation dose to personnel who remain inside a facility such as a control room have been developed as a probability function of at least M reactors at an HNEC receiving a stated dose, given that a class 9 accident of the PWR-2 type has occurred in one unit. The probability for the class 9 accident at any one of twenty units is given as 1.6×10^{-4} /year (Ref. 2, Table 5-1) or once every 6000 years.

The conversions to potential dose as indicated in Figure 17 are made by using the following:

$$\begin{aligned} \text{Dose (rem)} &= \left(\frac{\text{Rem.}}{\text{sec/m}^3} \right) \times \left(\frac{X}{Q} \text{ sec/m}^3 \right) \\ &= \text{Rem, as a function of time after release, and, of Hanford meteorology} \end{aligned}$$

FIGURE 17. Risk of Loss of Capacity and Energy Generation from Radioactive Release at HNEC

The Shielding reduces the calculated exposure received by those inside the building by a factor of 10 (Ref. 2, Appendix VI, Table 11-8).

Table 10 below gives different probabilities of various radiation levels occurring at more than one facility given the condition that a PWR-2 accident has occurred in one and that 1000 seconds have elapsed since the release began. Time since release is a factor because of the distance the cloud can travel, assuming the average wind speed of 3 meters per second.⁽³⁾ For example, at HNEC after one thousand seconds, reactors only in the cluster containing the affected unit could be exposed to the cloud.

TABLE 10. Dose to Personnel Remaining Inside M Reactors
As a Function of Probability of M Reactors
Being Involved

Dose, Rem	Probability of 3, 4, 5 Units Receiving Stated Dose		
	3	4	5
280	1.0	0.85	0.25
130	↑	0.85	0.26
60		0.85	0.27
28		0.85	0.29
13		0.86	0.31
6		0.88	0.37
2.8		0.88	0.40
1.3		0.88	0.41
0.6		0.88	0.42
0.3	1.0	0.88	0.42

The tabulation indicates that the conditional probability of people in up to 3 units in the cluster receiving exposure varying from 280 rem to 0.3 rem is 1.00. The difference would be caused by varying meteorology. Similarly, the probability of up to 5 units at a cluster receiving similar exposures varies from 0.25 to 0.42. The amount of exposure at nearby reactors and sites depends on the wind speed and wind direction at the time of the accident. It is entirely possible for no reactors except the affected unit to be involved.

The following, Table 11, tabulates similarly derived probabilities at 10,000 seconds following the initiation of the release. During this interval the cloud would have had time to travel to the most distant reactor assuming the event occurred at cluster 1 or cluster 5. See Figure 16.

TABLE 11. Probability of Personnel Inside of M Reactors
Receiving Stated Radiation Doses

<u>Dose, Rem</u>	<u>Dose Rate (Rem/Min)</u>	<u>3,4,5 At 1st Cluster</u>	<u>7,8,9 At 2nd Cluster</u>	<u>11,12,13 At 3rd Cluster</u>	<u>16 - 20 At 4th Cluster</u>
2.0	0.070	1.00-0.8-0.4	0.16-0.13-0.08	0.01-0.01-0.01	0.02
0.93	0.030				0.02
0.43	0.010				0.02
0.2	0.007	1.00-0.8-0.4	0.19-0.15-0.11	0.90-0.09-0.08	<u>0.03</u>
Probability of 0.2 thru 2.					≤0.1

The above indicates that the probability of the people located at the four reactors in the most distant cluster (4th) receiving doses from 2 to 0.2 rem is either 0.02 or 0.03. This can be interpreted as saying that the probability of receiving at least 2 rem exposure in the control room after 10,000 seconds is at least 0.02, given that the PWR-2 accident occurred in the most distant cluster. The overall probability of the distant reactors being affected is $1.6 \text{ to } 10^{-4} \times >0.02$, or, $>2 \times 10^{-6}$ or at least about once per 5×10^7 years.

Similarly, personnel in control rooms in the nearest 3 reactors can expect any dose up to 280 rem if they remain in the control room, given that a class 9 accident has occurred. All units in this cluster would immediately shut down and all crews would rapidly evacuate (only if doses were significant). Further, emergency evacuation procedures will be followed by the operating staff in all units at an HNEC if a class 9 accident has occurred in any. Depending on the time for the accidental release to develop from the containment vessel following the accident and possible obvious meteorological conditions, it may not be necessary to shut down many of the more distant reactors and evacuate personnel. Further it may be more prudent to stay put to utilize the building for shielding rather than evacuate and risk exposure to the passing cloud with the shielding of only an auto. However, in this review all reactors are assumed to shut down to at least a hot stand-by condition with an average electrical energy loss of 57.6 GWh (2 days) per unit.

Hence, the instantaneous loss of 1.2 GW from the affected reactor plus up to an additional 4.8 GW from units in the same cluster can be expected and probably without warning to the electrical grid system operators. Time would be available to notify the electrical grid system operators of pending emergency shutdowns at most of the remaining units. This has been assumed in the analyses.

For the dispersed option the consequences from potential air submersion doses following a class 9 accident at any one of the reactors is significantly less. Two of the five clusters assumed to be located at the Hanford site in the dispersed concept are close enough to be affected if a class 9 accident does occur in a reactor in one of these two. The other three clusters, however, are separated such that an accident in any one of these will not affect the operation of any reactors in any of the other four.

Fallout Contamination

The immediate consequences from the passing cloud are relatively short lived. Potential radiation levels within generating facilities (control rooms) from outside ground contamination from fallout from the cloud, however, may deny access to these facilities until decontamination efforts or radioactive decay have reduced the levels to acceptable amounts. To quantify this analysis, the following table compares the probabilities of having measurable control room radiation levels on the day of the accident prior to decontamination and before significant radioactive decay.

For the assumptions made, note that the probability is about 1 in 8 (0.12) that at least 9 reactors will have a radiation level of 0.2 rem/hr in their control room from ground contamination.

In the model shown in Figure 17, the concentrations of activity per square meter have been estimated (3) using the Hanford meteorological data as before including the appropriate deposition factors. The buildup of radioactivity deposited is assumed to have come to equilibrium during the passage of the cloud. The radiation levels within the facility were reduced by a factor of 0.7 to account for normal ground terrain (non-smooth surfaces). It is assumed that immediate efforts will be undertaken to reduce the dose rates due to contamination around the facilities. Thus an additional factor of 1/7 was

TABLE 12. Comparison of Probability That a Certain Dose Rate Would be Received in the Control Room From Deposited Material During the First Day Following An Accident

<u>At Units</u>	<u>Dose Rate to Persons In The Control Room</u>	<u>Probability</u>	
		<u>Partial, (i.e., Given That An Accident Occurs)</u>	<u>Total (including The Probability Of The Event)</u>
2 through 3 (same cluster)	(2 rem/hr)	1.0	1.6×10^{-4}
2 through 4 (same cluster)	(2 rem/hr)	0.88	1.4
2 through 5 (same cluster)	(0.02 rem/hr)	0.40	0.64
7 or 8 or 9 (next cluster downwind)	0.2 rem/hr	0.12	0.19
11 or 12 or 13 (second cluster downwind)	0.02 rem/hr	0.06	0.09
16 through 20 (third cluster downwind)	0.002 rem/hr	0.02	0.03×10^{-4}

chosen (Ref. 2, Table VI 11-8) as a result of preliminary decontamination efforts at each affected facility. The potential exposures are thus reduced by a factor of ten. In addition, the shielding afforded by the building to those inside further reduces their doses by a factor of 0.1 (Ref. 2, Table VI 11-8).

For those isotopes of interest (see Appendix B), the effects of radioactive decay over 7, 14, 30, and 60 day intervals are shown in Table 13.

The following tabulation shows that the third cluster (the first cluster includes the affected unit) and an average 15-18 km away, that the probabilities of units in this cluster having at least 1 mrem/hr in their control rooms 14 days after the accident is only about 12 times less (0.08) probable than the accident itself. Stated in other words, after 14 days the probability of a dose rate of at least 1 mrem/hr in the control of reactors up to 15-18 km away is at least 1 in 12 (0.08).

TABLE 13. Probabilities of Persons in Control Rooms
Receiving Dose Rates of ≥ 1 mrem/hr at
Varing Intervals Following the Accident

<u>No. of Units</u>		<u>Number of Days Following Accident</u>				
		<u>0</u>	<u>7</u>	<u>14</u>	<u>30</u>	<u>60</u>
	3	1.00	1.00	1.00	1.00	1.00
1st cluster	4	0.88	0.88	0.88	0.88	0.88
	5	0.42	0.42	0.42	0.42	0.42
7 or 8 or 9 2nd cluster		0.160	0.136	0.136	0.122	0.12
11 or 12 or 13 3rd cluster		0.100	0.08	0.08	0.06	0.06
15 or 16 4th cluster		0.030	0.023	0.023	0.018	0.018

Decontamination efforts greater than those reducing the levels by a factor of 1/7 may have to be undertaken in many facilities. This appears entirely feasible.

For this unit close to the affected reactor, extensive decontamination procedures of the environs around each facility will be required to reduce radiation levels inside the facility to acceptable amounts (≤ 1 mrem/hr) so that these generating units can be restored to service. Table 14 shows these estimates.

TABLE 14. Reduction of Expected Radiation Dose Rates
To People Within a Control Room From Ground
Contamination With Time After Accident^(a)

	Day				
	<u>0</u>	<u>7</u>	<u>14</u>	<u>30</u>	<u>60</u>
Control Rooms of Any of the Other 3 Units (within same cluster as accident)	2	0.220	0.176	0.122	0.097

(a) Assuring a decontamination factor of 1/7

The data in the above table indicates that after an accident occurs, the radiation dose rate in the control rooms of adjacent reactors will not be acceptable for routine occupancy for at least 60 days. Thus, a loss of 4.8 gigawatts (entire site) for probably up to 2 months has the same probability of occurrence as the accident itself, unless additional decontamination efforts are applied to these facilities and their common site.

SUMMARY

The results are summarized in Figure 17. The three lower curves estimate the loss of energy in Gw-hr for various losses of generating capacity. The curves differ by the estimates of times to decontaminate and recover operating capability. For example, the maximum curve estimates 60 days to recover any capacity at the cluster in which the event occurred, that 5 units were located at the cluster, and that 45, 30 and 15 days were required at the other clusters. The minimum estimate was for 2 days for those units not affected at the site of the accident plus 7, 3, and 2 days for the other clusters. The probable estimate is that maximum estimated by several utilities operating nuclear facilities.

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FLOOD

Introduction

One hundred percent of the HNEC capacity and 70% of the DS case capacity would be on a single river, the Columbia. Of the 70% of DS capacity, the 20% at Pebble Springs is isolated from effects of floods on the Columbia because of its elevation and an independent water supply at that site. Other DS sites are not identified specifically and consequently site elevations or plans for cooling facilities are not available. A comparison of flood risk, therefore, can be drawn only by making the broad assumption that if 100% of HNEC capacity is affected by flood, 50% of the DS capacity would likewise be affected.

Flooding of river pump houses is the only way operation of any of the plants would be affected. As will be seen, most of the critical HNEC facilities, with the exception of their river pump houses, are at elevations above the level of the Limiting Case Flood, as for example, the elevations set for WPPSS plants No. 1, 2 and 4.

The cooling pond at Pebble Springs, 60,000 acre-ft, provides cooling water for routine operation for extended periods.⁽¹⁾ Loss of river pump facilities due to flooding on the Columbia would not affect electrical generation at this site. Even with some use of water from the pond for irrigation, the plant could be expected to remain in operation for many weeks before the pond level, without makeup, would be too low for continued operation at full power. Consumptive use for two generating units would average 6000 acre-ft per month, or 12,000 acre-ft per month for four units.

At the Oregon DS sites, where makeup water for 30% of the DS capacity is assumed to come from the Willamette River or its tributaries, the possible effects of flooding is assumed to be noncoincidental with a Columbia River flood.

The "probable maximum" unregulated flood on the Columbia is 1,600,000 cfs, which as now regulated by flood control by existing dams is 1,400,000 cfs.⁽²⁾ The largest known historical flood on the Columbia at river mile 352, (position of initial HNEC plants) had a peak discharge estimated at 800,000 cfs. These peak flows are considerably below the peak flow associated with Artificial Flood No. 1, namely a breach of the Grand Coulee Dam.

Limiting Case Flood

A Grand Coulee Dam failure has been established as the Limiting Case Flood (also, Artificial Flood #1) for the Hanford reach of the Columbia. It is based on a breach in which 25% of the face of the dam would be removed with a consequent outfall peak of 8,800,000 cfs at Grand Coulee Dam, and a peak discharge at Richland of 4,800,000 cfs.⁽³⁾ The flow computation took into consideration an evaluation of the effects of the flood on downstream dams, with failure of earthfilled portions and subsequent release of storage pools.

Elevations of the flood peaks for the floods described above are:⁽²⁾

	<u>Elevation, MSL at River Mile 352 (HNEC)</u>
Probable Maximum Flood - 1,400,000 cfs	389
Limiting Case Flood - 4,800,000 cfs	424.5
Plant Elevations (level for water entry into plants)	479
River Pump House Floor	389

Category I structures of plants currently being built are designed to withstand the static and dynamic forces of the Limiting Case Flood, the breach of Grand Coulee Dam.

Although future HNEC plants may have different elevations, it can be expected that they will maintain a comparable relationship with the Limiting Case Flood level at corresponding points on the river. The plant elevations cited above are for the reactor facility. It may be assumed that all code designed facilities essential to power generation will be built at or near this same elevation, except the river pump house.

Probability of Exceeding the Probable Maximum Flood

An estimate of the probability of exceeding the Probable Maximum Flood is given in Reference 4. That report refers to river mile 340, which is 12 mi downstream from the point at which the WPPSS plants are being built. The reference report uses a Probable Maximum Flood of 1,320,000 cfs. The conditions and assumptions are sufficiently typical of those of HNEC that the findings are pertinent. Figure 18 from Reference 4 is a discharge frequency curve for the Columbia River, applicable to the Richland reach.

FIGURE 18. Discharge Frequency Curve
Columbia River Near Richland

Extrapolation of curve B, Figure 1, to 1.32 million cfs indicates a probability on the order of 10^{-7} events per year. (Willamette River flooding conditions were not reviewed. It was assumed that frequency would be the same as for the Columbia. This is believed to be a conservative assumption with regard to comparative risk between the HNEC and DS. Flooding at the Willamette River involves the loss of only six generating units in comparing HNEC with DS. This loss has a relatively moderate impact.)

Probability of Occurrence of Artificial Flood No. 1

There are insufficient data for an estimate of the probability of Artificial Flood No. 1. Reference 5 contains an estimate of the probability of failure of concrete arch dams, worldwide, of 10^{-4} events per year. Grand Coulee Dam is a massive gravity-type concrete dam for which the only conceivable cause of failure, other than military attack, is earthquake. It is located in an area of relatively low seismicity.⁽⁶⁾ In the opinion of a Bureau of Reclamation spokesman, "we can state that worldwide there is no record of any type of concrete dam

ever having failed due to an earthquake ("Catalog of Dam Disaster, Failures and Accidents", by A. O. Babb and T. W. Mermel). The probabilities of an earthquake-induced failure is therefore much less than 10^{-4} for Grand Coulee."⁽⁷⁾

For purposes of this report it is assumed that the probability of such a failure is less than for the Probable Maximum Flood, and that it may be disregarded in the risk comparison.

Probability of Forced Outage from Flood

To sum up the findings on flood risk:

- 1) A Columbia River flood that would effect 100% of HNEC capacity would be likely to affect 50% of the DS capacity. Possible floods at other DS sites would probably not be coincidental with Columbia River floods. A flood on the Willamette River could affect 30% of the DS capacity, but Willamette flood conditions were not reviewed since the sites themselves are not specific.
- 2) The HNEC facilities with the exception of the river pump houses are sited at elevations at or near the Limiting Case (Grand Coulee Dam failure) Flood level. The probability of this flood is believed to be less than 10^{-7} , and hence possible effects from this flood are disregarded. The risk lies in river pump houses being flooded at flow elevations that are greater than those of the Probable Maximum Flood, but less than the Maximum Case Flood. An extrapolation of discharge-frequency curves indicates that the probability of a Probable Maximum Flood is of the order of 10^{-7} /yr.

It is assumed that each group of plants would be affected as a block, i.e., all units in the 20, 10 and 6-unit groups would be affected if a flood greater than the Probable Maximum Flood were to occur. A marginal flood might affect only part of the generating units in each of these blocks, but the available information does not justify making a distinction. The cumulative probabilities are constant since all clusters have equal probability of river pump house flooding in the event of the Probable Maximum Flood (10^{-7} /yr), with 10 units being the maximum number that could be affected at once in the DS case, and 20 units in the HNEC case.

Risk from Floods

A flood that substantially exceeds the Probable Maximum Flood possibly would incapacitate the river pump house through:

- water soaking of electrical equipment,
- silt deposits in equipment,
- damage to structures caused by impact of water or debris,
- washout of foundations or embankments, and/or
- stress on connecting piping.

The rapidity with which the facilities can be repaired may be governed by other flood effects, i.e., effect on transportation facilities, availability of spare equipment, availability of crews, and the like. The assumptions as to these possible effects and the extent of the damage enters into the estimates of upper and lower bounds, and probable time to return the units to service are given below:

	<u>Average Days of Forced Outage per Generating Unit</u>
Maximum	45
Minimum	7
Probable	20

Figure 19 indicates risk of HNEC forced outage from generating capacity loss (curve A) and energy production loss (curve B). For capacity loss in the range of 0-12 GW there is no difference in risk between the HNEC and DS cases.

FIGURE 19. Risk of Loss of Capacity and Energy Generation from Flood at HNEC

REFERENCES - FLOOD

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ASHFALL FROM CASCADE VOLCANOES

Introduction

This section develops the risks of HNEC and DS plants being forced out of service by ashfall. Difficulties are encountered in attempting to quantify such a risk in that information on the magnitude of ash discharges in the past is spotty, and the threshold condition for a forced outage from this cause has not been defined. A threshold would be determined by the characteristics of the ash, and by any added measures taken in the design of the plant to tolerate this event. No record has been found of large thermal power plants having been subjected to such conditions. The only record obtained on the effects of ashfall on electric power generation, transmission, and distribution is that of the eruption of Mount Usu in northern Japan starting on August 7, 1977. The affected generating plants are hydroelectric, and the maximum transmission voltage in the affected area is 100 KV.⁽³⁾

The frequency and severity of volcanic explosions of the type that could affect plants at the distances involved here can be estimated on the basis of the history of eruptions in the Cascades, although imperfectly so, because of the sparsity of data on the magnitude of ash discharges. The threshold conditions and the time that may be required to return the plant to service after an incident in which design conditions were exceeded are necessarily conjectural.

Properties of Ashfalls

In volcanoes, "the magma is formed far below the earth's surface, where pressures are very high. The high pressure forces gases to dissolve in the molten rock, the most important being water, carbon dioxide, and sulfurous compounds. As the magma reaches the surface through volcanic vents, the pressure is reduced and the dissolved gases are released."⁽¹⁾ Ashes can be propelled to elevations of 30,000 to 49,000 feet, or more. Sulfur dioxide "injected into the atmosphere by a volcanic explosion... is converted through photochemical processes into small droplets of sulphuric acid,"⁽¹⁾ These droplets and small ash particles remain in the stratosphere for long periods and are transported many hundreds of miles. Other products remain below the stratosphere and settle of their own weight or are washed from the sky by clouds and rain.

The possible effects of both volcanic ash and droplets of sulphuric acid are to be considered.

The ash from Glacier Peak, which is typical of that from the Cascade volcanoes, had an average glass content of 85% and an average crystal content of 15%. Listed in order of abundance the crystals consist of andesine, hypersthene, hornblende, magnetite, and a trace of augite.⁽²⁾ The median diameter of the particles decreased from 500 μ at Glacier Peak to only 22 μ at a point 173 mi to the east, and to 24 μ at a point 116 mi to the southwest (particles in the stratosphere are about 2 μ). The size of the particles deposited in the Hanford area (from St. Helens and Mazama) is such that 58% are greater, and 42% less, than 74 μ .⁽⁵⁾

After an eruption of the explosive type the ash carried by winds is deposited over wide areas. The distances over which Glacier Peak ashes were deposited are indicated above. Ash from the Mount Mazama eruption of about 7000 years ago (Crater Lake Oregon) deposited in the Pasco Basin to a depth of about six inches, demonstrating that with a major eruption, under the right weather conditions, great amounts of ash can be carried over 300 miles.

Over the last 15,000 yr, in addition to the ashfall at Hanford from Mount Mazama noted above, there have been other substantial ashfalls, from Mount St. Helens eruptions of 13,000 and 1500 years ago.

The ashfall from each event ranges from a fraction of an inch to 6 in. (or greater in spot locations) in depth in this area. Local winds and rainfall, and deposits carried in surface runoff, probably account for variation in thickness of ash deposits. Deposits in various localities could be much less or much greater than the average over a wider area.

The pattern of deposits from the events discussed above suggests that the winds at the time of the eruptions were mainly from the southwest, but at times from the west-northwest and the east. Reference 2 contains a hypothesis of atmospheric conditions to give the observed deposition, in which a "low pressure area moving from the Pacific eastward over Glacier Peak during the eruption is the most likely situation that would account for the observed distribution...".

FIGURE 20. Volcanic Peaks and Plant Site Locations

As to the duration of the eruptions, "From sedimentary and petrographic evidence, it is abundantly clear that the eruption of Glacier Peak was single and short. It may have endured for only a few days or possibly for a few weeks. ... Of these two possibilities the latter appears more plausible..."⁽²⁾ The probable duration of such eruptions is important in that the effect of an ash-fall on plant operations may be manageable if deposition is gradual.

Probability of Occurrence

Reference 4 contains a graph of the relative amounts of volcanic products discharged by "every Cascade eruption over the last 15,000 years so far dated by radiocarbon methods". The ash products shown on this chart were scaled (although "the intensity scale is not an arithmetic progression, it represents the approximate order of ranking of the estimated volume of volcanic products of known Cascade eruptive episodes") and a probability distribution of indexed amounts of ash release was prepared. The result is shown in Figure 21.

Unfortunately, the 19 eruptions that are charted in Reference 4 do not include all that are known to have occurred from the Cascades. It is reported that within the last 12,000 yr there have been more than 30 eruptions at Mount St. Helens, three at Lassen Peak, 11 at Mount Rainier, and seven mudflows associated with volcanic activity at Mount Baker. It is assumed, however, that most of the major ash eruptions are included in the chart. Also, the indexing of ash volumes as described above is imperfect. "The volume of the Mazama eruption, intensity X, was between three and five times greater than intensity IX."⁽⁴⁾ These are the only two for which volume has been calculated. (The Mazama ash eruption is represented by the point of maximum intensity in Figure 27. It is the only point that has a large deviation from the straight line defined by other points). Even with these defects the data on the 19 events were used since no other was found upon which to base probabilities of volcanic ash discharges.

Probability of Exposure

Whether a cluster would be exposed to ashes from a given volcanic eruption would depend on the amount of ashes expelled (as indicated by the above index),

FIGURE 21. Probability of Ash Discharge from Cascade Volcanoes

the wind direction and velocity during the eruption, and the distance of the cluster from the volcano. The variability of high altitude winds and of rainstorms in the path of the plume sometimes cause the deposition to decrease nonuniformly with distance. In the 50-200 mi range, the deposition may be greater at a more distant point than at a point closer to the volcano. However, "Many deposits of this type (coarser debris in deposits, ten to hundreds of miles long) are almost linear, and their configurations reflect the direction of the reactor resultant wind above the volumes at the time of eruption."⁽⁶⁾

The procedure used to derive approximate probabilities based on available information is described in Appendix B, along with calculations of exposure and occurrence probabilities. The product, i.e., the probability of forced outage versus number of generating units affected, is given in Figure 22.

Effects of the Mount Usu Eruption⁽³⁾

The initial eruption of Mount Usu expelled ash to a height of 39,000 feet, and following eruptions to lesser heights. Six major eruptions, each lasting from two to three hours, occurred over a period of seven days. Minor eruptions followed some of the major ones. Weather conditions were changeable during the period, windy, rainy, cloudy and fair. The wind direction at the time of the eruptions ranged over 180 degrees centered in the southwest. Wind velocity was up to 55 mph out of the northwest in dry weather, and up to 45 mph out of the south in rainy weather. Ash was deposited to a depth of about two inches or more over a 20 to 25 mile radius in the windward direction. Ashfall near the volcano measured up to 40 inches in thickness.

Most damage to the electric power system occurred where the ashfall was two inches or greater in thickness. Two hydroelectric plants at which operation was affected were each about three miles from the volcano. Generation outages were caused by the intakes and penstocks being choked with pumice, and the outages were prolonged by delays in permission to clear the system by washing the pumice to streams that fed irrigation systems or that flowed into fishing grounds. A major thermal power plant 19 miles east of the volcano was not affected (the weather was dry when ash was blown in that direction).

Transmission and distribution systems were damaged to the extent that service to some 500 homes in the region was interrupted for a total of two to three days, and to some 3000 homes for about 18 hours. These outages were caused largely by volcanic ash and rain, which after deposition would stick to surfaces and "become like solid concrete." It would cause insulators to fail electrically, poles and line conductors to fail structurally, and trees to fall into lines. The greatest damage occurred during periods of simultaneous eruption and rain. The bad effects of the ash-rain mixture on thermal generating plant insulators and lines of HNEC could be similar to that of the reported effects on the distribution systems in the vicinity of Mount Usu. The low probability of rain in eastern Washington, unless rain were caused by ash in the atmosphere, would lessen the risk of extensive damage from ashfall.

Risk from Ashfall

The consequences of a given ashfall would, of course, be equal for HNEC and DS plants receiving equal ashfall.

Corrective operations may involve:

- Replacement of water inventories in open reservoirs that have been made too acid by the ashfall,
- Replacement of clogged filters,
- Removal of ash from heat radiating surfaces,
- Washing of acid and ash residues from insulator surfaces or insulator replacement if the deposits have hardened,
- Check of instruments that may have been affected by infiltration of ash particles where air is not effectively filtered,
- Clearing of drifts from transportation routes,
- Inspection of oil reservoirs and oil filters for admittance of abrasive particles,
- Clearing of ash mud from cooling towers.

An estimate of the cleanup time, and if necessary, time for repairs, follows:

	<u>Days of Forced Outage</u> <u>2 to 8 in. of Ash</u>
Maximum	7
Minimum	2
Probable	3

It is assumed that crews can be obtained to work on all of the shutdown plants at the same time.

Risk of Outage from Ashfall

The estimate of risk of forced capacity and energy outage from ashfall is shown in Figure 23. Probability of occurrence is shown in curve A, and corresponding energy production loss in curve B.

From Figure 23, note that the probabilities of capacity loss from ashfalls are constant.

FIGURE 22. Probability of Forced Outage of Generating Units from Ashfall from Cascade Volcanoes

FIGURE 23. Risk of Loss of Capacity and Energy Generation from Ashfall at HNEC

REFERENCES - ASHFALL

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5. Ward Carithers, Pumice and Pumicite Occurrences of Washington, State of Washington, Division of Mines and Geology, 1948.
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SWITCHING STATIONS

Introduction

The reason for examining switching stations separately is to assess the risk of routing power from six or seven units through one switching point, as at HNEC, relative to that of routing of power from three or four units through a single switching station as at a DS, and to determine whether the vulnerability of the switching station is greater than that of the generating plants.

The same disruptive event could interrupt more power flow when occurring at a switching station than when occurring at the generating stations. For example, an aircraft crash into a switching station could interrupt the power from six or seven units in the HNEC case, or power from three or four units in the DS case. If it crashed at any one of the generating clusters, the shutdown would probably be limited to one or possibly two units at either an HNEC or DS.

This section is confined, therefore, to an assessment of risk at a single switching station. If two switching stations were affected by an initiating event, the magnitude of the event is assumed to be great enough to simultaneously affect all generating units feeding power to these stations.

Station Vulnerability

A typical layout of a 500 kV switching station using the breaker-and-a-half arrangement now favored by BPA and many other utilities is shown in schematic form in Figure 4 of Section III.

One vulnerable point is the bus structure which runs throughout the station length. If the two buses in this structure are incapacitated at the same time, the "pooling" function of the station is lost, but power flow can be maintained from those generators that are in positions mutually occupied by lines interconnecting with other points in the network. Continuity of operation would be sustained if the stricken buses were cleared by the two outer circuit breakers while the third (middle) breaker remains closed. If one end of the station were damaged, power flow at the other end may continue in this way. Power flow in the system would have to readjust to an incident of that severity. With readjusted flow the output of the station could still be the equivalent of several generating units even though power from some units was reduced.

All other localized damage would have less impact, cutting off one or more generators or lines while the buses, or at least one bus, remained in service. It may be concluded that to interrupt all power flow through the station, the event would have to disrupt functions throughout the entire station area. For example, a severe earthquake could disrupt all operations.

The station service transformer used in common by three or four generating units^(a) for the alternate supply is another vulnerable item. Although damage to this transformer would not shut the generating units down, a regulatory requirement would force shutdown if service is not restored within 72 hr.

Another vulnerable item are the battery DC supplies for relaying functions at the station. Damage to this power supply along with damage to the main buses or lines could prevent breakers from opening to isolate trouble. Consequently, one trouble point could involve the entire station if the DC supply were out. Stations as important as these would have redundant battery supplies, both of which would have to be lost.

The area occupied by a 500 kV switching station for seven generating units at an HNEC would be approximately 1500 by 500 ft, transmitting 8.4 GW. The following analysis concerns the risk of an event that would interrupt 50 to 100% of the power flow at the station. Events evaluated include those already considered for the generating plants, namely earthquake, flood, tornado, releases of airborne contaminants and ashfall, plus aircraft crash and sabotage.

Earthquake Effects

Switching station structures and equipment are being designed by BPA for a horizontal ground acceleration of 0.24 g in the Puget Sound area and 0.12 g in the Portland area. In eastern Washington, with the exception of areas of greater than average seismic activity, the design of the stations is governed by wind resistance criteria rather than ground shaking criteria. The effective resistance to ground shaking is reported to be somewhat less than 0.12 g. For purposes of this study, it is assumed that the switching station's resistance to ground shaking is equivalent to that of a 0.10 g, essentially code design.⁽²⁾

(a) This applies to configurations typified by Concept B, Reference 1.

The probability of ground shaking of this intensity is:

$$3(7.93 \times 10^{-3}) = 2.4 \times 10^{-2}^{(3)}$$

With a probability of 0.1 for significant damage to a code design facility, the probability of an earthquake disabling 50% or more of the switching station is less than 3×10^{-3} events per year ($0.1 \times 2.37 \times 10^{-2} = 2.37 \times 10^{-3}$). Three such stations are assumed at HNEC and the probability of losing any one of the three is $3 \times 2.37 \times 10^{-3} = \sim 7 \times 10^{-3}$.

The design of manufactured equipment affects the resistance of switching stations to earthquakes. The most vulnerable items are the heavy pieces mounted on post insulators, such as a live circuit breaker, lightning arrestors, and potential transformers.⁽²⁾

Power transformers are located at the generating plants at HNEC and are not considered switching station equipment. Damage to one transformer would affect only one generating unit.

During the San Fernando earthquake of February 9, 1971, the Sylmar switching station,^(a) which appeared to be close to the epicenter, experienced accelerations between 0.35 and 0.50 g. The damage was severe.⁽⁴⁾ As a result of that incident, possible ways of increasing the resistance of equipment to ground shaking were studied with the expectation that stations built in subsequent years would suffer less damage if subjected to identical conditions. Although Hanford is never expected to experience ground shaking over 0.25 g, its station design should nevertheless benefit from that experience.

Tornado Effects

The switching stations footings are designed to 80 mph constant windspeeds, for use at any location, and equipment is designed with gust factors equivalent to 100 to 120 mph.⁽²⁾

The probability of tornado windspeeds exceeding that level is 4.4×10^{-6} strikes per year at points within the HNEC region. The median path width of tornadoes in this region is around 300 yd. Moving along the long axis of the

(a) Refers to the switching station only, not the rectifier station which was even more seriously damaged.

station a tornado with windspeeds in excess of the above levels could possibly disrupt station operation completely. Moving along the short axis it could disrupt some fraction of the power flow, perhaps 50 to 60%. The orientation of the existing Ashe and Hanford stations is such that there would be an approximately 90% possibility that 50% or more of the positions would be affected by a tornado strike. The resulting probability of 50% or more of the power flow being interrupted is 4.0×10^{-6} per year.

Radioactive Release Effects

The assumption used in the preceding section on effect of releases on adjacent clusters of generating plants is that significant deposition would take place around the point of release regardless of wind direction. In the HNEC, any one of the three switching stations each serving two clusters would be within a two mile radius or less of adjacent clusters it serves.

Since the switching stations are not normally attended and since the functioning of the station would not be directly affected by the deposits, the station would not be forced out of service immediately following the passage of the plume or from deposition. Decontamination of the station could proceed, part of it while the station remains in operation, and part of it while sections of the station are de-energized. Forced shutdown of parts of the station would take place only in the event of some equipment failure that would entail the use of work forces in a station bay before it had been decontaminated.

In view of the above no significant contribution to the risk of forced outage of generators at the second cluster results from switching station exposure to radioactive releases. Outages necessary for cleanup could be scheduled.

Ashfall Effects

Ashfall could possibly cause some forced outage of a switching station, while the connected generating units remain fit for service, by 1) forming conducting paths around insulators in high voltage circuits, 2) placing a blanket of heat insulating material over heat radiating surfaces, and 3) clogging filters in equipment that required ventilation.

The probability of forced outage from this cause is estimated to be the same as that of the generating plants, 3×10^{-5} events per year.

Aircraft Crash

From information presented in Appendix A, the possibility of a large aircraft striking a nuclear power plant having a shadow area of 0.137 mi^2 is 4.6×10^{-7} . For the switching station alone having a shadow area of about 0.05 mi^2 the probability would be 1.68×10^{-7} .

$$\frac{0.05}{0.137} \times 4.6 \times 10^{-7} = 1.7 \times 10^{-7}$$

The risk is additive to that of the other causes acting upon generating plants.

Sabotage

Sabotage at the switching station could be more effective in forcing a number of generating plants out of service than if it were applied at the generating plants themselves. For example, two explosives strategically placed and set to detonate at the same time could incapacitate a station, and interrupt the flow of power from up to seven generating units. There is no rational basis upon which to arrive at the probability of such an event. The probability can, of course, be reduced by maintaining adequate security under the provisions of 10 CFR-70.

If sabotage were to be successful in interrupting power flow, the damage to equipment would not be expected to extend throughout the entire station, although it could be severe. Part of the station could probably be put back in operation relatively soon, and the remainder restored on a temporary or permanent construction basis.

Flood

The possible effects of flooding on switching stations is considered for the HNEC model in that some of the stations may be located at somewhat lower elevations than the generating plants.

The Ashe station site near Cluster 1 has an elevation of about 437 ft above sea level, 48 ft above the Probable Maximum Flood level for WPPSS plants, and 12 ft above the level of Artificial Flood No. 1 at that point on the river. Since no underground portions are at risk, the danger of flood interfering with station operation can be ruled out at Ashe. Further checking on relative flood vulnerability would be necessary at the Hanford stations and the proposed Gable Mountain site.

Total Risk

The risks discussed above are in two categories:

- A: Additive to the risk of loss of generation from the second cluster, in that either the generators in the second clusters or the switching station could be the cause of the forced outage, and
- B: Occurring at the same time and from the same cause as the generating plant outage in the second cluster, and, of significance only if the risk is greater at the switching station.

The probability of a loss of more than 50% of the power through a switching station and the associated outage periods are given in Table 15.

The probabilities in Category A are additive to the generating plants, and assuming that sabotage risk is controlled, their sum is about 4.3×10^{-6} events per year. The repair time would range from 15 to 40 days, with a probable time of 25 days. This probability and their consequence are factors in the added risk of loss of power from a second cluster being affected by a single event at the switching station.

In Category B, all the risks are less than or approximately equal to their counterparts in the generating plant assessment, add nothing to overall risk, and can be ignored.

The resulting switching station risk is shown in Figure 24.

TABLE 15. Summary of Risk of Interruption of Power Flow at Switching Station

<u>Event</u>	<u>Probability of Interrupting 50% or More of Power Flow/yr</u>	<u>Probable Re- pair Time/Days</u>
Category A		
Tornado	4.0×10^{-6}	25
Aircraft crash	1.7×10^{-7}	40
Sabotage	Indeterminate	--
Flood	10^{-7}	15
Category B		
Earthquake	7×10^{-3}	15
Release of Radioactivity	$<10^{-7}$	
Ashfall	3×10^{-5}	4

FIGURE 24. Risk of Capacity and Energy Generation Loss Caused by Switching Station Outage at HNEC

REFERENCES - SWITCHING STATIONS

1. Battelle Pacific Northwest Laboratories, Station Service Power Supply for a Hanford Nuclear Energy Center (HNEC), BNWL-2076/UC-80, December 1975.
2. Paul White, BPA Substation Design, Personal Communication, June 3, 1977.
3. T. Hsieh, D. Okrent, and G. E. Apostolakis, On the Average Probability Distribution of Peak Ground Accelerations in the U.S. Continent Due to Strong Earthquakes, UCLA-ENG-7516, March 1975.
4. Refer to No. 8 in Earthquake Section.

Risk of Forced Outage, HNEC versus DS

This section combines the data on probabilities of forced outage for an HNEC and DS, and compares the estimated lost energy production during outages, between the two concepts.

Figures 25 and 26 summarize the results developed in prior sections. Here, gigawatts of capacity lost for HNEC and DS are plotted against the respective probabilities of these losses. The dotted line at the top of the figures is the total probability of 4 to 24 GW of capacity being lost through any one of the causes shown separately in curves under the dotted line. The dotted curves for earthquake and ashfall are alternates related to administrative matters. These total probabilities for HNEC and DS are compared in Figure 27.

The principal findings in this comparison are 1) the probability of loss of capacity in the DS case drops off rapidly after 6 GW; 2) although up to 12 GW can be lost, the increment greater than 6 GW has a low probability and for practical purposes can be ignored, and 3) in HNEC, the probability of forced outage from earthquake is dominant, about 25 times the probability of all other causes combined. (If outages due to earthquake were forced by plant failure rather than an inspection requirement, the probability would be reduced tenfold for accelerations up to 0.175 g and fourfold for accelerations up to 0.25 g, as shown by the dashed curve of Figure 25.

Other findings are:

- Earthquake, ashfall, and flood could affect up to 100% of HNEC capacity; radioactive release up to 80%; and tornadoes and switching station failure up to 35%. Flood could affect up to 50% of total capacity, tornadoes 30%, and others 15 to 20% at much lower probabilities of occurrence.
- After earthquake, ashfall appears to be the major contributor to probability of outage. However, the basis of assessment of this cause is tenuous.
- Radioactive release occupies an intermediate position on the scale of probability; but if an administrative requirement would shut down all HNEC plants if one were to have a release then this would become the major contributor after earthquake.

- Flood and tornado are unimportant risk contributors.
- The probability of single clusters being forced out of service is somewhat greater for DS than for HNEC because of greater exposure to earthquake and ashfall.

FIGURE 25. Probability of Forced Outage - All Causes at HNEC

FIGURE 26. Probability of Forced Outage - All Causes at DS

Figure 27. Probability of Forced Outage, HNEC vs DS

FIGURE 28. Risk of Forced Outage at HNEC

The probable duration of forced outages under the stated assumptions are tabulated below:

	Average Days		
	Maximum	Minimum	Probable
Earthquake (0.125 to 0.175 g)	20	3	7
(0.22 g)	100	15	40
Tornado	80	10	40
Flood	45	7	20
Radioactive release	60	7	15
Volcanic ashfall	7	2	3
Substation	40	15	25

These time periods are used to establish potential loss of generation as shown in Figure 28 for HNEC (a similar figure for DS is not given because of low probability). Curve A of this figure is the composite capacity loss probability curve of Figure 25. Curve B and the shaded zone around it show possible generation losses associated with different causative events. For example, an 14 GW outage due to flood may have a probable outage time of 40 days while an 14 GW outage due to volcanic ashfall may have an outage time of only three days. That range is represented in the vertical dimension of the shaded zone. The "probable" line within the zone represents an estimate based on weighting of the probable repair times of each component cause according to its probable frequency of occurrence.

Representative points marked in the diagram are tabulated below to indicate the range of size of the blocks of generation that could be involved versus probability of occurrence.

Capacity MW	Energy GWh	Probability Events/Year
6	250	0.011
24	1,000	0.0016
8	1,100	0.0087
16	2,400	0.0043
24	20,000	0.0016
24	50,000	0.0016

VI. SIMULTANEOUS LOSS OF THERMAL AND HYDROELECTRIC CAPACITY

INTRODUCTION

In an investigation of risk of loss of generation at an HNEC vs that at dispersed sites, the question arises, would an HNEC entail risk of greater loss of regional generation in the event of catastrophic conditions on the Columbia River than the loss that would be experienced with dispersed sites? This question is discussed below.

Simultaneous loss of thermal and hydroelectric capacity could occur 1) if a flood were great enough to incapacitate downstream hydroelectric dams and at the same time, immerse the river pump houses supplying coolant makeup to thermal plants, or 2) if a drought were sufficiently severe and prolonged to reduce the capacity of hydrogeneration and also starve the thermal plants of coolant makeup.

If either a severe flood or drought were to occur, the amount of hydro capacity that would be affected would, of course, be the same for the HNEC and DS cases. The amount of thermal capacity that would be affected in addition would depend on the flood or drought. For example, if the Columbia at HNEC were affected but not all tributaries, only a portion of the DS case capacity may be flooded or starved, while the remaining portion stays in service.

Drought

After consideration of the risk of a widespread and prolonged drought affecting both hydro and thermal generation coincidentally, it was concluded that there would be no substantial difference in the magnitude of the resulting outage between the HNEC and DS cases. The reason is contained in the discussion on extremely low river flow in Appendix A. Briefly, in a prolonged drought, time would be available to take emergency measures to provide coolant makeup to thermal plants in low-flow portions of the river system, whether they be at HNEC or at DS sites.

River Blockage or Diversion

Other events such as river blockage or diversion occurring in the middle or lower reaches of the Columbia conceivably could affect some thermal and

hydroelectric capacity, and the effects of such events on thermal plants of the HNEC and DS cases are reviewed in Appendix A. Effects on hydroelectric plants could include possible flooding of hydro plants upstream from the point of blockage, and temporary interruption of generation at plants downstream. In event of a blockage, the downstream hydro plants would not be damaged immediately but could be damaged later by flood waters resulting from overtopping and disintegration of the blockage.

The probabilities of occurrence of such blockages are discussed in Appendix A. Although there are no accurate bases available to evaluate this probability, one may suppose that it could be of the same general order as that of an Artificial Flood No. 1.

The consequences of blockage, again with the exception of a major change of channel that could bypass some of the downstream dams, would be less than those of an Artificial Flood No. 1. Fewer plants would be affected and with less damage occurring. For these reasons, this section considers floods from dam failure rather than river blockage as the events that could have the greatest effect on simultaneous loss of thermal and hydro generation.

Floods

Artificial Flood No. 1 would incapacitate many plants, both thermal and hydro, and inflict much damage, causing long generator outages. The natural river floods discussed in the section on Floods, that affect river pump houses of thermal plants primarily, are not considered, as the hydroelectric generation would not be seriously affected. The hydroelectric generating resources that would be affected by a Artificial Flood No. 1 in 1977, and estimated for 1987, are given in Table 16.

From an Artificial Flood No. 1 in the year 2005, 1) all hydro capacity on the Columbia below Grand Coulee would be forced out of service, and 2) 100% of the thermal capacity at HNEC or 50% of the DS case capacity would be shut down for lack of coolant makeup.

The severity of damage at the dams downstream of Grand Coulee Dam would probably be such that comparatively long periods would be required for rebuilding. Since the major facilities of the thermal plants are above this flood level, their operation could be restored much more rapidly.

TABLE 16. Hydroelectric Capacity on the Columbia River
from Grand Coulee to the River Mouth, GW

	<u>1977</u>	<u>1987⁽¹⁾</u>
January Peaking Capability, ^(a) GW	16	20.5
Critical Period ^(b) Energy Production Capacity, Average GW	8.3	8.4

- a. Peaking capability, the maximum ability of firm resources of the system to carry a peak load.
- b. Critical period, that multimonth period, determined for the Coordinated System under adverse stream flows of historical record, during which the least amount of estimated firm energy load can be served from firm resources.

Risk of Forced Outage

Regional generation that would be affected by an Artificial Flood No. 1 in 1977, and by the same flood in 2005 with HNEC or DS in place, are given in Tables 17 and 18 respectively. Assumptions used in the preparation of these tables are 1) new hydro power developed after 1987 will be insignificant, 2) data on resources include all peaking and reserve generating facilities in the region, 3) by 2005 the regional capacity reserves will be 20% of January peak load, 4) peak generating capacity will total about 84 GW in 2005, 5) a 75% average plant factor of thermal units, for computation of energy production capability, and 6) average system load factor will remain at about 63%.

TABLE 17. Generation Affected by an Artificial
Flood No. 1 in 1977

January Peaking Capacity, GW	
Hydroelectric plants on Columbia, Grand Coulee to the mouth	16
Thermal plants on the Columbia	1.2
Other hydro and thermal plants	<u>9.9</u>
	27.1
Critical Period Energy Production Capability, average GW	
Hydroelectric plants on Columbia	8.3
Thermal plants on Columbia	1.6
Other hydro and thermal plants	<u>5.5</u>
	15.4

TABLE 18. Generation Affected by an Artificial
Flood No. 1 in 2005

	<u>HNEC</u>	<u>DS</u>
<u>January Peaking Capacity, GW</u>		
Hydroelectric plants on the Columbia, Grand Coulee to the mouth	20.5	20.5
Thermal plants on the Colum- bia	24.0	12.0
Other hydro and thermal plants	<u>25.5</u>	<u>37.5</u>
	70.0	70.0
<u>Critical Period Energy Produc- tion Capability, Average GW</u>		
Hydroelectric plants on the Columbia	8.4	8.4
Thermal plants on the Colum- bia	18.0	9.0
Other hydro and thermal plants	<u>12.6</u>	<u>21.6</u>
	39.0	39.0

The percentage of total regional resources affected by the
flood would be:

	<u>Percent</u>	
	<u>HNEC</u>	<u>DS</u>
Capacity	64	46
Energy	68	45

From information in the preceding tables:

- 1) In the year 2005 with the DS case the hydroelectric and thermal energy resources that would be affected by Artificial Flood No. 1 would be 45% of the total resources in the region.
- 2) In the year 2005 with the HNEC case the hydroelectric and thermal resources affected would be 68% of the total resources in the region, as determined by energy production capability loss. The DS case, therefore, has a marked advantage in potential for retaining a greater percentage of both capacity and energy generating resources in service following such a flood.

- 3) From Table 17, in the year 1977 such a flood would affect 64% of system resources, as determined by energy production loss. This may be compared with the 68% that would be affected with HNEC in 2005. The risk corresponding to 64% loss of generating capacity has societal acceptance; acceptance of a risk corresponding to 68% loss of generating capacity with HNEC is only slightly greater and with a probability of occurrence estimated at less than 10^{-7} /yr.

In the comparison, the HNEC case has benefited by the assumption that capacity reserves would have increased to 20% of peak load by 2005. If they had not increased to that extent the 68% figure for HNEC would be somewhat greater.

In conclusion, an Artificial Flood No. 1 is the only event for which the dependence on energy in the Pacific Northwest from an HNEC would cause a substantially greater simultaneous loss of hydro and thermal energy resources than would the Flood with a DS case (68% vs 45%). The probability of occurrence of such a flood is extremely low. The loss of generation with HNEC would be 68% of regional generating resources, as compared with 64% if the flood were to occur at the present time. The thermal portion of lost resources could be restored to service in perhaps two to three weeks; but the hydro portions would require dam and station repairs over many months to restore them to service.

These cases of combined hydro and thermal capacity loss are not included in the following section on Impact of Forced Outages since the comparison is limited to the reliability of nuclear generation, not hydroelectric.

REFERENCES - SIMULTANEOUS LOSS OF THERMAL AND HYDROELECTRIC CAPACITY

1. Pacific Northwest Utilities Conference Committee, West Group Forecast of Power Loads and Resources, July 1976-June 1987, March 1, 1976.
(Reviewed with issue for July 1977-June 1988, February 15, 1977)

VII. IMPACT OF HNEC OUTAGES ON SYSTEM OPERATION

INTRODUCTION

The impact of possible loss of generation due to HNEC outages is discussed with respect to a) sudden capacity loss and its short-term effects, and b) loss of energy production capability with its longer-term effects. In extreme cases, the effects of capacity loss could resemble those of the northeastern blackout of 1965 and the New York City blackout of 1977 with their temporary disruption of normal activities in the blackout areas. The effects of energy shortage have not been experienced on a comparative scale, but plans are being made for coping with such shortages. For small shortages in which the reserves on the system are capable of meeting generation deficiencies, there would be no immediate impact on the power user, although if prolonged, there might be some impact on power costs. These possible impacts are considered in relation to probability of occurrence.

In this discussion capacity or capacity loss means the total capacity of all units affected by an event, independent of their operating status at the time of the event, for example, the capacity of 20 HNEC units is $1.2 \text{ GW/unit} \times 20 \text{ units} = 24 \text{ GW}$.

Generation loss means energy production capability that is not available to the system because of the loss of capacity over a period of time due to an event. It is assumed that the lost capacity would have operated at an average plant factor of 0.87 during the outage period. This is greater than the 0.75 assumed annual plant factor, but it is used to take a conservative position with respect to the possible impact of an outage that occurred in winter months when the loads on thermal plants may be greater than the annual average. For example, generation loss in the event of a loss of 24 GW of capacity for 60 days would be $24 \text{ GW} \times 60 \text{ days} \times 24 \text{ hr} \times 0.87 \text{ PF} = \sim 30,000 \text{ GWh}$.

Energy shortage means the amount of normal system loads curtailed (dropped) mandatorily because of insufficient energy resources. They are shown on Reserve Energy Planning Model runs as "negative energy surplus", i.e., as an

energy deficit. They bear a statistical relationship to the generation loss associated with the events being studied. System reserve energy would take the place of HNEC generation loss in varying degrees, as shown later.

Loads assumed to be on the system in 2004-2005 for purposes of this report are:

<u>Load</u>		
Average	January to April	45,600 MW
Average	Annual	42,125 MW
Peak		70,000 MW

Peak load estimated for 1986-87 in Reference 4 is 37,896 MW. The above 70 GW estimate represents an annual increase of about 3.5% between 1987 and 2005 as compared with the West Group Forecast increase at a 5.1%/yr rate from 1977 to 1987.

System resources assumed for 2005 including miscellaneous peaking facilities are:

Total peak resources (other than HNEC)	60,000 MW
HNEC	<u>24,000 MW</u>
Total	84,000 MW

Energy resources, with the addition of the thermal units, are assumed to be such as to provide an adequate margin over the 42,125 average MW load estimate. The relative energy resources in 2005 are reflected in the data from the Energy Reserve Planning Model to follow in this section.

The resource estimates affect the results of this study in that they determine how much system generating capacity remains in the system after the hypothetical HNEC outage has occurred, i.e., the percentage of system generating capacity that remains after up to 24 GW of capacity has been forced out of service. The foregoing estimates are considered to be middle-of-the-road, and therefore appropriate for the purpose of demonstrating the impact of the postulated generating outages.

In 2005, with the assumptions used in the HNEC case for purposes of this study, the status of generating resources would be:

	<u>2005 Generating Resources</u>	
	<u>Capacity, GW</u>	<u>Energy, Average GW</u>
Total	84	45
HNEC (percent of total)	24 (29%)	18 (40%)
DS 4-unit cluster (percent of total)	4.8 (5.7%)	3.6 (8%)

As noted previously, the outage cases of the HNEC study start with four units affected, and range up to the full 20 units. DS case outages range from 3 to 10 units.

Most of the causes of forced outages of interest were assumed to occur randomly throughout the year.

The number of generating plants that would be operating at the time of an event, and their loading, would depend on the season of the year, how much reserve is assigned to thermal units, refueling schedules, and conditions on other parts of the system. Operating policy as envisioned for 2005 governed the inputs to the simulations of the thermal generation portions of the system. The outage probabilities computed in prior sections of the report were inserted into the simulations of thermal plant operation as perturbations of normal operations.

A necessary assumption in describing the effects of reduced energy production capability is that system loads as influenced by the severity of winter weather be normal or near normal. In the winter of 1976-77 in the New York-New Jersey area, space heating requirements were 30% above normal, whereas the fuel suppliers (fossil fuels in that case) had made provisions for only an 8% margin. If a major outage of the type to be described were to occur during an extremely hard winter in the Pacific Northwest the electric energy shortage effects (where much of space heating is electrical) would be exacerbated.

There are numerous points on Figure 28 of the section on Composite Risk, the curve of capacity and energy loss versus probability of occurrence, that

could be used to illustrate the reliability risk of an HNEC. In discussion to follow, emphasis is placed on the maximum possible capacity loss, 24 GW, and a generation loss of 30,000 GWh (1.5 times the probable maximum). The impact of intermediate values of capacity and energy generation losses are also discussed.

IMMEDIATE IMPACT OF FORCED OUTAGE

Many factors would contribute to the impact of a catastrophic event at HNEC on the PNW system in the first hours following the event. The following analysis relates to system conditions anticipated for the year 2005.

Outage Magnitude

The number of generators operating at the time, and their loading, will vary with the seasons. In the winter months, at times of peak system loads, most of the HNEC units would be operating; in spring and summer months many units would be down for refueling and scheduled maintenance, with a greater percentage of the system load then being carried by hydro plants. An example of how such outages may be scheduled is:

<u>Season</u>	Number of units	Avg % of total HNEC
	<u>Shut down for 2 months</u>	<u>Capacity Available</u>
Aug - Nov.	4	90
Dec - Mar.	2	95
April - July	14	65

Assuming that available generators are loaded to 87 percent of capacity at the time of the event, the loss of generation would be:

<u>Number of Units Affected by an Event</u>	<u>Probable Interrupted Power Generation GW</u>		
	<u>Aug-Nov</u>	<u>Dec-Mar</u>	<u>Apr-July</u>
8	7.4	7.9	5.4
14	13.0	13.9	9.5
20	18.6	19.8	13.5

Onset of the Outage

The immediate impact of an HNEC outage on the system would depend to some extent on the amount of advance notice of shutdown, if any, and on the intervals between successive losses of power from affected generating units. Some of the outage causes would permit advance notice, for example, floods, ashfall, and radioactive release. Others would take place without notice, for example, earthquake, the first cluster hit by a tornado, and an aircraft crash into a switching station. Since earthquake is the most probable cause of outage, and since it would occur without notice, it is assumed in this discussion that no notice is given before the first generating units are forced out of service.

The shutdown of units subsequent to the first unit or group may span periods of one or two hours, for example:

- An earthquake may cause failure of essential equipment that would cause simultaneous shutdown of eight units, followed within an hour or several hours by manual shutdown of perhaps another eight units which had been subjected to OBE conditions as verified by analysis of instrument records.
- Ashfall accumulations rates would probably be such as to permit at least 30 minutes between the shutdown of successive clusters.
- A tornado may require tens of minutes to travel the distance between adjacent clusters.
- Flood crests may take minutes or tens of minutes to travel the distance between adjacent pump houses.
- Radioactive plumes may take tens of minutes to travel between clusters, the time depending on wind velocities.

In all probability the initial loss of generation would not exceed the equivalent of that from two clusters, 9 to 10 GW, possibly followed by additional amounts within tens of minutes, and with all units involved in the outage dropping off or being shut down normally within an hour or two.

The only incident visualized that could instantaneously affect more than 10 GW is an earthquake with a probability of 4×10^{-4} events per year.

The distinction between capacity dropped instantaneously and that dropped over following minutes or hours is important with respect to the ability of the system to respond without instability and consequent separation of parts of the system.

Capacity Reserves

Capacity reserves in the Pacific Northwest are presently calculated at 12% of the estimated system peak load. In the near future, this may be raised to 15%. Operating reserves normally are 7% of the peak thermal resources and 5% of the peak hydro resources. One-half of the reserves are spinning, available immediately, and one-half are available within 10 minutes.

For planning purposes, reserves for unforeseen load growth are set at one half of a year's load growth for utility type loads. Utility type loads are those in commercial and residential categories which cannot be estimated as accurately as heavy industrial loads. Reserves for new resources that may not come into service as scheduled are called planning reserves, and represent the amount left over after Federal, Public, and Private system reserves have been determined under present methods. If reserves planned for these purposes are not yet in service, or if they are installed but already loaded at the time of an event, the effective reserves would be:

<u>Reserves</u>	<u>% of Resources</u>	<u>GW</u>
"Spinning"	6	4.2
Available in 10 min	<u>6</u>	<u>4.2</u>
	12	8.4

If reserves planned for unforeseen load growth and possible delays in new generating capacity have not been absorbed, some reserves in addition to those listed above may be available. These would require substantial time periods to bring into service.

Role of the Hydro System in Providing Capacity Reserves

The hydro system can provide capacity reserves beyond those described above, for short periods, during certain times of the year, summer for example. Stored water can be released through surplus capacity in turbine generators

to provide power on short notice. The degree to which this emergency resource can be utilized is limited by available water, and by the effects of rapid water release on river elevations below the dams and the consequent effects of high elevations. The curve in Figure 29 prepared by BPA, indicates the allowable duration of such usage. The 100% point on the ordinate corresponds to a system peak capacity, in 2005, of from 31 to 37 GW depending on reservoir elevations. The upper end of the curve is of principal interest here, i.e., the capability over the first few hours.

Storage water withdrawals from the system for peaking in an emergency cannot exceed those defined by the curve; without significant spilling, nor extend beyond the 12-hour point. For example, with reservoir and river flow conditions corresponding to 32 GW at 100%, the normal use of the hydro system would be below 80%, or 26 GW. Ninety-two percent, or 29 GW, about 3 GW above normal maximum, could be taken for four hours.

Role of Pumped Storage in Providing Capacity Reserve

By 2005 there may be some 5 GW in pumped storage on the system. Water in these reservoirs would also be available on short notice for emergency generation, if not already in service at the time of the outage. The duration of such generation could be for a few hours up to 40 hours depending on reservoir fill at the time of the incident. Such capacity serves as part of the forced outage reserve in the hydro system.

Role of Thermal Plants in Providing Capacity Reserve

Gas turbine driven generators are beginning to appear on the system, and may add a few GW to the peaking capacity of pumped storage units in 2005. The advantage of the gas turbines in an emergency as compared with pumped storage is that they can supply power for relatively long periods, (although the power would be costly).

Some of the planned system capacity reserves, perhaps up to 55% of operating reserves, may be in nuclear plants at that time. All or part of the reserves allocated to HNEC would be negated with the HNEC outage. The distribution of thermal reserves would recognize such a possibility.

FIGURE 29. Percent of Seasonal Instantaneous Peak Sustainable Hydro MW vs Number of Hours Per Day of Peaking

Other thermal plants on the system partially loaded or in hot standby could provide energy capacity rather quickly, but in cold standby would require about 10 hours.

Emergency Power Inflow Over Tie Lines

In the event of a sudden major deficiency in generation in the PNW system, power may be available from tie lines, provided that the effect of power withdrawals from the other systems does not affect them to the extent that the operators would disconnect the ties.

The one DC and two AC lines to the southwest have a total capacity of about four GW.

The pattern of diversity capacity exchange, if contracted between the regions, would be power flowing south from May through September, and north from November through March. Any capacity available to the PNW over these lines in an emergency would be additive to the reserve capacity within the PNW system if covered under contracted agreements. If a catastrophic event were to take place in the summer months when power is normally flowing south, the reversal of that flow could make a net 4 to 8 GW available to the PNW. How long that flow could be sustained would depend on energy conditions in the California and Arizona systems.

If the event took place in the winter months when power is flowing north, no change would take place if the lines are already loaded to capacity and if the line connections remain intact. If the lines were inadvertently opened, the PNW capacity deficit would be increased by 4 GW or whatever the power flow was at the time. If the outage occurred at an off peak point in the daily or weekly transmission load curves, some relief may be available even in winter months.

A review of the month-by-month capacity exchange shows that these tie lines could make additional capacity contribution in an emergency as follows. For example, in the summer months of June, July or August, the 8 GW is obtained by a reversal of 4 GW flow out to 4 GW flow into the PNW system.

	<u>GW</u>
Jan and Feb	0*
March	2*
April	4
May	6
June, July, Aug	8 (if available)
Sept	6
Oct	4
Nov	2*
Dec	0*

*With additional capacity contribution if the event occurred in daily or weekly transmission light-load periods.

Generation outages of the magnitude discussed here would be very rare, and it is assumed that the inter-regional agreements would allow adjacent regions to make exceptional contributions to the stricken area in such an emergency, to the extent of their capability without undue hazard to their own operations.

Ties with Canadian generating resources may permit a power flow of some three GW by 2005. Without a pattern of normal power flow, no emergency relief from this tie line can be assumed.

Available generating capacity in Idaho and Utah would be relatively small; help in an emergency is expected to be insignificant.

Load Shedding

The immediate effect of a large loss of generating capacity may be a drop in system frequency below the level at which certain loads are shed to maintain system integrity. The first loads to be shed would be industrial loads totalling about four GW. An effort would be made to restore service to the non-interruptible portions of this load, three GW, within ten minutes or as soon as possible. If the frequency dropped further, additional loads would be dropped according to contingency plans.

Transmission System

System integration is maintained through the transmission system. That system must have sufficient capacity and stability to accommodate the shift to reserve generating capacity wherever it is on the system. The ability of the PNW transmission system to respond to changes of the magnitude discussed here has not been substantiated by studies, but is assumed for purposes of this report. The scope of this report is limited to generation at an HNEC, and power flow through adjacent switching stations. The effect of losing substantial amounts of transmission capacity generating from HNEC may be equivalent to loss of substantial portions of HNEC generation, but should be evaluated separately.⁽¹⁾

Communications and Planning

If an HNEC were to develop, there would be concomitant development of communications systems and planning procedures to appropriately handle major outages, however remote the probabilities of such outages. The costs associated with communications, monitoring, relaying, and load shedding systems would not be expected to be prohibitive. The objective would be to manage the system so that, with normal reserves, due operating reliability could be achieved, by judicious load shedding if necessary--not by providing additional costly reserves.

Summary of System Responses to Large Outages

In summary, immediate system relief in the event of large outage in the year 2005 would be provided by reserves, tie line transfers, and load shedding as in Table 19.

Restoration Period

The restoration of at least partial service to shed loads would follow the onset of the outage. It is estimated that steps taken to restore the system to a state of managed energy shortage could be accomplished within six hours in most situations, and within 12 hours in the worst situation, one in which some system breakup did occur in spite of load shedding and other measures to maintain stability and tie line connections.

TABLE 19. Summary of Generating Outage Relief Capabilities,
Without Shedding of Commercial and Residential Loads

	<u>GW</u>
<u>Immediate Response</u>	
Spinning reserves	4.2
Transfer over tie lines	
~75% of the time	4 to 8
~25% of the time	0 to 4
Shedding industrial loads	<u>4</u>
Subtotal	8.1 to 16.1
<u>Response after tens of minutes</u>	
Operating reserves	4.2
Additional temporary power from reservoir withdrawals, ~50% of the time	0 to 4
Pumped storage installations ⁽³⁾	0 to 5
Gas Turbines ⁽³⁾	<u>0 to 2</u>
	4.2 to 15.2
<u>Response after hours</u>	
Planned reserves for unforeseen loads and late new generating resources, not already absorbed	<u>0 to 5.6</u>
Total	12.3 to 36.9
% of Total system capacity (84 GW)	15% ⁽¹⁾ to 44% ⁽²⁾

(1) Consistent with 12% operating reserves, and some additional relief from tie lines and load shedding.

(2) Compare with ratio of excess capacity at average load, to total capacity - 48%

(3) Part of this capacity may be in Operating Reserves.

The amounts in Table 19 would be reduced by the amount of operating reserves that may have been assigned to the HNEC thermal units affected by the outage.

From the table:

- Instantaneous loss of 8 GW could be accommodated, with 75 percent probability that 12 GW could also be accommodated without commercial and residential load shedding.
- Instantaneous loss of 8 GW, followed in tens of minutes by additional loss of 4 GW, for a total of 12 GW, could be accommodated.
- Instantaneous loss of 12 GW, followed in tens of minutes by additional loss of 8 GW (the maximum probable HNEC outage) would have a 50 to 75 percent probability of accommodation without additional load shedding.
- Instantaneous loss of 12 to 20 GW (the maximum possible HNEC outage) would require automatic or emergency manual shedding of substantial amounts of mixed loads beyond the 4 GW industrial block. There would be a risk of system breakup, i.e., segregation of portions of the system. The segregated portions would have disproportionate loads and generation--some would continue in service and some would black out. The aim of the system operations would be to prevent such a breakup by widespread load shedding, either automatically or manually, since it is easier and quicker to restore shed load than to resynchronize a system from separate pieces. The duration of outages on the shed load portions of the system would depend on the ensuing events, i.e., the additional generation that may be lost in minutes or hours after the original instantaneous loss, and progress in bringing up operating and energy resources.

To sum up this section concerning the immediate effects of HNEC forced outages:

- Capacity losses could range up to 20 GW in period of high load on the PNW system (70 GW load) or to 14 GW in low load periods (<44 GW load), i.e., to about 30 percent of generating capacity then on line.

- Instantaneous capacity losses of 12 GW and staged losses totalling up to 20 GW could be accommodated without impact on the public at most times of the year. At the most adverse times (25 percent of total time) these losses would entail temporary shedding of perhaps 10 percent of commercial and residential loads. The probability of such loss is about 9×10^{-4} events per year, or once in 1100 years.
- Instantaneous capacity losses of more than 12 GW would entail greater amounts of load shedding, to keep the system intact, perhaps 20 percent of the commercial and residential load on the system. The probability of such loss is about 1×10^{-4} events per year, or once in 10,000 years.
- It is believed that adequate communications, control systems, and operating procedures can be developed to cope with the largest outage without system breakup or collapse, even though it might require load shedding of the proportions indicated above. Restoration to normal or to a managed energy shortage could be accomplished within six hours. However, if system breakup should occur, reintegration could be accomplished within 12 hours.
- Following the first few hours, the management of the system would follow contingency plan for allocation of energy in a period of energy shortage.

The impact on the system in the days and weeks following such an impact incident are discussed in the following section.

FOLLOW-ON IMPACT OF FORCED OUTAGE

A loss of energy production capability caused by events such as those discussed previously resulting in capacity loss would affect the capability of the system to meet its firm and interruptible loads.

This capability projected to the year 2005 has been estimated by the Northwest Power Pool Coordinating Group's Energy Reserve Planning Model described in Reference 2. This model, with minor changes to accommodate this study, was used to simulate the system when the HNEC is assumed to reach maturity.

Normally, the model is used for examining the capability of the Northwest Power Pool to meet growing loads as projected in and beyond the West Group forecast. For this study the model was used to estimate the effects of loss

of large blocks of generation. No load growth was assumed by this model for the years of interest: namely, those typical of the period following HNEC maturity. System resources were essentially those projected by the same forecast with 24 GW of this resource at either dispersed sites or at an HNEC. The program examined the system's ability to meet firm load over a 16-yr period using randomly selected parameters such as reservoir storage, snowpack, rainfall, expected runoff, state of other thermal reserves, etc.

Each year was divided into three 4-month periods; namely, hydro system early drawdown, August through November; late drawdown season, December through March; and system refill-hold, April through July. Five hundred trials (games) per case were run with data points summarized at each 4-month period. The period of interest contained 6000 data points; namely, 4 yr x 3 periods/yr x 500 trials/yr. It was estimated that any simulation by this model using different combinations of the randomly selected parameters would be within 2% of others. For insights useful in the analyses here, a single run accumulating 6000 data points was judged sufficient.

The simulation of forced outages resulted from assuming that 30,000 gigawatt hours (GW-hr) of energy was not available from an HNEC during the 4-month periods, assuming the HNEC had a capacity to generate 24 GW. An annual plant availability factor of 0.75 was assumed with availability factors in each 4-month interval varying over a rather wide range, depending upon the chance combinations of the variable parameters. Outage cases less than 30,000 GW-hr were not separately analyzed in this model since their effects could not be clearly distinguished from the effects of other perhaps unexpected variations in the system operation not assessed here. Also, a review of the individual games indicated that on a number of occasions, an outage of 30,000 GW-hr could be absorbed with no system energy deficit (user energy shortage) while lesser outages sometimes resulted in deficits.

Five Dispersed Sites were assumed, each with 4.8 GW capacity. The outages simulated for these clusters were for the full capacity of the cluster being down for 2 months out of any 4-month period; i.e., 6000 GW-hr. In most cases, the initiating events of concern would affect only one cluster of four generating units at a time. In a few trials, an event being widespread could affect more

than one Dispersed Site. These did not occur frequently enough to justify added simulation to identify their effect.

The comparative numbers of periods in which deficits of different magnitudes occurred are listed in Table 20.

From the model, energy deficits from HNEC occurred in 696 four-month periods (out of a 6000 four-month period population sample). Detailed examination indicated that 624 of the 696 were due to the 30,000 GW-hr loss at the HNEC.

From a detailed analysis of the computer runs, the numbers of periods in which deficits among the 6000 game periods appear are:

	Number of 4-month Periods Having Energy Deficits in 4 yr and 500 games	
	HNEC	DS
1. September through December	379	345
2. January through April	151	56
3. May through August	<u>166</u>	<u>121</u>
	696	522

TABLE 20. Number of Load-Loss Events
Due to Generation Outages

Load Loss, Average MW Over a 4-month Period	Number of Energy Deficit Periods			
	HNEC	DS	DS Adjusted (a)	Difference (HNEC-DS)
0 - 1,000	201	244	244	-42
1,000 - 2,000	132	185	185	-53
2,000 - 3,000	70	63	54	16
3,000 - 4,000	51	19	0	51
4,000 - 5,000	53	8	0	53
5,000 - 6,000	39	3	0	39
6,000 - 7,000	41			41
7,000 - 8,000	74			74
8,000 - 9,000	29			29
9,000 - 10,000	<u>6</u>			6
	696	522		

(a) Explained in Appendix C.

Most of the deficits occur in the early winter months when loads are fairly high and when information on snowpack to replenish stored water in the hydro system is not yet available. Since the forced outages occur at random, it would be expected that their occurrence would be almost equally shared by the three periods. The inequities in the number of deficit periods are due, therefore, to system conditions and response rather than to incidence of the outages. These observations apply to both the HNEC and DS cases. The greater numbers of HNEC deficit periods relative to DS in the second and third periods are to be expected. Even though conditions are more favorable in those periods with respect to response to outages (in spite of the fact that many refueling outages for thermal plants are in the third period), the greater magnitude of the HNEC outages will result in more load-loss situations.

An analysis of the information shown in part in the foregoing tables reveals that for a 30,000 GW-hr HNEC outage:

- 1) Of the 624 incidents of HNEC outages out of the 6000 trials in the sampling by the model, in 315 of these, the system effects in terms of system energy deficits were no worse than those of the DS case, i.e., the probability that a load loss would be no greater than in the DS case is 50%.
- 2) In 120 trials the additional deficits caused by outages at HNEC were in the 2000 to 5000 MW range, i.e., a probability of 19% of causing a load loss of 5760 to 14,400 GW-hr.
- 3) In 154 trials HNEC caused deficits in the 5000 to 8000 MW range, i.e., the outage would have a probability of 25% of causing a load loss of 14,400 to 23,230 GW-hr.
- 4) In 35 trials HNEC caused deficit periods in the 8000 to 10,000 MW range, i.e., an outage would have a 5.6% probability of causing a load loss of 23,230 to 29,000 GW-hr.

In effect, system reserves offset generation losses to the extent that curtailment of service to power users approximating the HNEC generation loss seldom occurred among the many trial situations of this study.

Load loss effects between the 6000 GW-hr and 30,000 GW-hr energy loss points are not identified by the available data from the simulation but are estimated by interpolation.

Figure 30 is a plot of the cumulative annual probability of load loss in GW-hr, for the greatest probable generation losses of HNEC and DS. The curves were obtained by multiplying the probabilities of occurrence of the generation loss, as developed in prior sections, by the probabilities of system response as developed in this section, as explained in Appendix C.

The area between the maximum probable DS and HNEC curves represents the added risk of HNEC. Curves for lesser amounts of capacity loss, and for lesser outage periods, at an HNEC would lie within this area. An earthquake outage of all 20 units for which the repair time is the maximum rather than the probable repair time would be represented by points outside of the shaded area of Figure 30.

It will be noted that a major energy shortage, 20,000 GW-hr, would have a maximum probability of 10^{-4} events per year. On the low end, an energy shortage of 6000 GW-hr would have a maximum probability of 3×10^{-3} events per year, depending on the character of the generation outage. Intermediate load loss levels would have probability ranges as shown in Figure 30. For example, a 15,000 GW-hr load loss would have a maximum probability of 3×10^{-4} events per year.

The shaded area of Figure 30 showing the difference in risk is the overall measure of added user risk from HNEC, as compared to DS.

The results of the study emphasize the fact that the Pacific Northwest power pool is able to supply reserve energy in large amounts if the outage occurs at a time of favorable circumstances in the hydro system. Further, there are more years in which circumstances are favorable than when they are unfavorable. By simulating a large number of events, occurring at times when changing circumstances in the hydro system are encountered, the system capability can be illustrated as in the foregoing tables and figures. In considering the effects of large numbers of trials or games, the reader must remember that the use of such numbers is for statistical purposes only. As noted in

FIGURE 30. A Comparison of Risk of Energy Shortages Resulting from HNEC and DS Outages

previous sections, the probabilities of occurrence of major energy shortages are of the order of 0.0001 events per year. It is unlikely that one such event would occur in an HNEC lifetime.

The results of several individual games, in which varying amounts of negative and positive surplus energy occur, are given in Appendix C. The simulated performance of the system can be better understood from a review of these game results and the accompanying discussion in Appendix C.

REFERENCES - IMPACT OF HNEC OUTAGES ON SYSTEM OPERATION

1. Electric Power Transmission from a Hanford Nuclear Energy Center, BNWL-B-426, Battelle, Pacific Northwest Laboratories, Richland, WA 99352, September 1975.
2. Technical Coordinating Group Energy Reserve Planning Model Progress Report, Northwest Power Pool Coordinating Group, January 21, 1975.

VIII. SOCIETAL IMPACT

Power outages of the type described herein could have adverse societal effects in the categories of health and safety, economics, and disturbance of lifestyle.

HEALTH AND SAFETY

The health and safety of the public are more likely to be affected by complete loss of service than by the longer term periods of managed reduction of energy consumption. Building elevators, water and sewage systems, rail transportation, traffic signals, lighting of public streets and many other necessities are dependent on electric power supply. The 1965 power blackout in the Northeast and the 1977 blackout in New York City are examples of power outages that have affected the health and safety of the public to some degree. The adverse health and safety effects of the 1965 event were minimal, while the 1977 were considerably worse because of looting and deliberate setting of fires in ghetto areas. Those incidents serve to warn of some consequences that could follow sudden power interruptions, but also to demonstrate that the reaction of the public can be salutary and that great hazards to health and safety do not necessarily accompany such an incident.

The 1965 event affected some 25 million people, and the 1977 event 10 million. A 2005 forced outage involving more than 12 GW or 15,000 GWh could affect perhaps 15 million people over a much wider geographical area in the Pacific Northwest.

In the 1965 blackout, power was restored to most of the affected urban areas in about 12 hr, and in the 1977 event in about 25 hr. Had complete loss of service persisted, more serious health and safety consequences may have followed. Assurance of ability to restore service within a reasonable period is important to the acceptance of such risk.

The short term effects of major HNEC outages could resemble those of the 1965 and 1977 events, if the instantaneous loss of HNEC power exceeded 12 GW.

As noted previously, an intense earthquake is the only event that could cause such a loss. Its frequency of occurrence is estimated at once per 10,000 years. All other events would entail some time delay between the dropping of generating units at different clusters, with good prospects for avoiding any prolonged area blackouts, although mixed residential and commercial loads as well as industrial loads might be shed in certain areas until other reserves could be brought on line. Such shed loads would not exceed 25 percent of the total; and outages would not last more than six hours.

In view of the rarity of all events involving more than one cluster at HNEC, and expectations for early return of electrical services to near normal, the risk to public health and safety is considered low.

Economic Effects

In the Pacific Northwest there is a strong linkage between the region's economy and the region's usage of electricity. Energy shortages for any reason for an extended period of time possibly would create considerable economic loss. Specific allocation of energy shortages has not been investigated as part of this analysis. Additional study is required to quantify the resulting economic consequences. Fortunately, there is only an estimated 0.0001 probability that severe energy shortages will result from HNEC shortages.

The shortage of energy in an incident of the type being discussed is temporary and would be felt mainly in then-existing industries. The situation should not be seen as one of chronic power shortage that would discourage new industry from locating in the area. Prospective owners and investors would identify a shortage resulting from a rare incident as a freak occurrence, one that would not deter them from choosing what might otherwise be an attractive location.

Economic losses would be suffered by 1) the industries and communities directly affected, 2) secondary support activities, and 3) indirectly by the general public. The public may be affected in a general way by suspended activity in industry, and the corresponding reduction in taxes paid into state and local governments; but also in any power rate increases or surcharges that may come as a result of the use of high-cost emergency generating resources or

through the effects of continuing fixed charges on plants that are not in use temporarily.

Under regional conditions where water reserves and alternative fuel supplies are at normal levels the economic impact of a 20,000 GW-hr loss from HNEC could be considerably moderated through voluntary conservation and voluntary implementation of contingency plans. In addition, arrangements may be made for the import of electricity from outside the region, arrangements not included in the system simulations of this study.

In addition to voluntary exchange of electrical energy between regions, some of which has been assumed in the system simulation, the Federal Power Commission has asserted that it:

"...enjoys very broad emergency power to deal with an electric energy shortage. These powers extend to all generation of electricity throughout the United States, including federal agencies generating electricity. The FPC claims it has power to compel any generator of electricity to transfer power to a utility experiencing a deficiency of electric energy. It can control the terms of compensation to be paid for such transfer. It has served notice by Orders 520 and 520A that it will compel such transfers wherever excess power exists anywhere in the United States which can be practicably used to cure a deficiency. It has also indicated by implication, but refrained from stating outright, that it may order a transfer of power from one utility to another even if to do so will render the first utility unable to satisfy the requirements of its consumers."(1)

The primary economic impact of increasing the region's electrical supply by fuel switching, extending fossil unit operation, and by purchasing electricity from outside the region will most likely be an increase in cost of electricity for that period.

Measures such as these for increasing supply, and conservation, may serve to satisfy individual and commercial requirements with little reduction in employment and production when energy deficits are of the order of 10%. Greater deficits, for example the 15% deficit (for four months) of the maximum probable outage may result in some economic loss other than increased electricity cost. The amount of possible loss has not been estimated.

Life Style

This discussion on life style, as for economic effects, refers to the effects of an energy shortage over weeks or months rather than the short term disturbance of a 6- to 12-hr complete outage.

The use of electricity pervades the home and working environment of most Americans, such as refrigeration, cooking ranges, water heaters, television, clothes washers and dryers, lighting, and for many, space heating and cooling. In office and commercial establishments are typewriters, copy machines, computers, lighting, ventilation, and communications. In terms of life style a shortage of energy for any length of time means curtailment of these uses, or a periodic interruption of use.

This type of societal impact is of less importance than that of health and safety and economics, but it could have political repercussions, especially if prolonged more than a few weeks. Much of the public would not comprehend the logic of a very-low-probability event that had actually taken place. They would tend to criticize the utility and the local government.

The excellent reliability records of the U.S. utilities has conditioned the populace to near-perfect service. However, "questions are being raised about the cost of very high reliability. Regulatory bodies essentially have left reliability standards to the judgment of utilities. Customers have little or no input. An important factor is that the cost of outages to consumers and the economy in general is very difficult to determine. Another problem is that the actual and planned levels of reliability are hard to determine for any given utility or to compare among utilities because of inconsistent data. What is needed is a much more complex and dynamic examination of optional reliability than has been done."⁽²⁾ This includes the costs associated with the levels of reliability.

By the year 2005, in an era of higher energy cost the public may better understand the tradeoff between cost and reliability, and better accept temporary inconvenience if they are convinced that merits of energy centers can compensate for a very small degree of added reliability risk. If there are

benefits, they will accrue to the public throughout the life of the project, whereas incidents of the type described herein would have only a small chance of occurring during the project's lifetime.

The degree to which the economic and life style effects noted above may be felt in the event of an HNEC outage would depend on the size of the energy deficit. The maximum probable deficit arrived at in Section VII is 20,000 GWh, about 5.3% of the prospective total annual energy production in 2005, or about 16% of the average production over a 4-month period. In the Energy Reserve Planning Program simulations very few cases occurred in which system energy deficits due to an HNEC outage of 30,000 GWh are carried over into a following 4-month period. It can be assumed therefore that the effects of an outage would be felt over a 4-month period, and that an approximate 20% shortage is the maximum that might be expected.

When impacts of such outages were sustained over weeks or months, the necessary load reductions would be accomplished by managed curtailment of various uses as discussed previously. Plans for mandatory curtailment are taking form in northwestern states.^(3,4) For example, in Washington the Emergency Power Bill was signed into law in June 1977. The law provides for two phases of effort to meet energy shortages, 1) an energy supply "alert", and 2) an energy supply "emergency". An alert, which can be declared by the governor for 90 days, and extended with certain approvals, would affect mainly the public sector. An energy supply emergency can be declared for 30 days and extended with the concurrence of the state legislature, and can affect both the public and private sectors.

Examples of the kinds of action that can be taken are:

- Alert
 - Appeal for voluntary reduction
 - Suspend environmental standards
 - Reduce consumption by state or civic entities
 - Curtail school hours
- Emergency
 - Implement mandatory curtailment plans of utilities

Impose surcharges and fines
 Curtail outdoor lighting
 Allow only part time operation of certain commercial establishments
 Impose restrictions on comfort cooling
 Apply percentage cuts for all consumers
 Impose severe restrictions on all operations
 Authorize service interruptions or voltage reductions

Some of these measures would reduce both peak and average loads. Rotating blackouts would reduce peaks, and perhaps to a lesser extent the average loads. Some steps would be more effective in different seasons.

Summary

The societal effects of shortages are estimated in Table 21 along with probabilities of being experienced as taken from Figure 30 page 113.

TABLE 21. Societal Impact of Energy Deficits

<u>Energy Deficit</u> <u>GWh (1000)</u>	<u>Societal Impact</u>	<u>Probabilities,</u> <u>Events/Year</u>
2.5	Alert declared, generation loss probably offset by voluntary conservation at behest of government and utilities	0.0045
5	Conservation, plus cutoff or interruptible loads. Some economic loss entailed	0.0035
10	Emergency declared. Above steps taken, plus governmental restrictions on public, commercial and industrial use. Appreciable economic loss	0.001
15	Further governmental restrictions on nonessential uses as per emergency plan. Substantial economic loss	0.00035
15 to 20	Implementation of full powers of the emergency legislation, including some or all of the measures listed under "Emergency" on page 133, economic loss, and appreciable effect on lifestyle.	0.0001

The table indicates that the maximum probability of substantial economic loss is no greater than 0.00035 events/yr once in 2850 years, and for substantial curtailment of power to residential users no greater than 0.0001 events/yr (once in 10,000 years).

In searching for an historical event that had a comparable effect on the public as power consumers, the authors considered the drought of 1976-77. The actual consumption of energy with relation to the forecast, or to the norm, is influenced by both supply and demand. The supply of energy was affected by the drought, but also by water conditions in periods preceding and following the drought. The demand could be affected by temperatures, by voluntary conservation effects related or not related directly to the drought, and by keeping interruptible loads off line.

These combined effects resulted in the firm power energy consumption in that year being 4.6% below the forecast; and total consumption, including interruptible industrial load, being 6.8% below forecast. The 4.6% energy use reduction for one year, may be compared with the 16% reduction risk, from the maximum HNEC outage, for four months. Although no mandatory reductions were imposed on the public consumer during the drought, a 16% reduction may require mandatory reductions for a four month period.

REFERENCES - SOCIETAL ASPECTS

1. Emergency Contingency Planning, Northwest Energy Policy Projects, page II-24, Portland, Oregon 1977.
2. Electrical Week, p. 5, February 7, 1977.
3. Plans for Mandatory Curtailment Taking Final Form in States, Northwest Public Power Bulletin, No. 5, 1977.
4. Proposed Regional Guidelines for Curtailment Planning, July 20, 1977, Pacific Northwest Regional Commission.

IX. CONSIDERATION OF REDUCTIONS IN THE RISK OF HNEC FORCED OUTAGES

The probability of forced outage of HNEC has been indicated to be very low from all events except earthquakes. Because the subsequent consequences of large outages to the region can be substantial however, the potentials for some reduction of the risk (lower probability of occurrence and/or lesser consequences) are briefly considered.

Figures 25 and 26 show the ranking of HNEC and DS risks, i.e., the ranking indicates for example that earthquakes result in higher risks of loss of loads than all others combined. The following gives the ranking:

1. Earthquake (inspection requirement)
2. Earthquake (repair requirement)
3. Ashfall
4. Radiation release
5. Switching station (all causes)
6. Flood
7. Tornado

EARTHQUAKE

Administrative Considerations

The NRC regulation requires shutdown for inspection of nuclear-safety-related portions of the plant following any earthquake at or above the OBE intensity and less than the SSE. This is a mandatory requirement even if the plant continues in operation during the quake and has received no apparent damage.

If essential facilities have not been damaged, shutdown of the plants can be reasonably orderly under emergency shutdown and load-shedding procedures.

The time required for the subsequent mandatory inspection in this study was estimated to be a week. The HNEC concept would be adversely affected. Note that the risk from an earthquake on HNEC or a DS could be reduced by a factor of 10 in most cases and 4 for this instance of the SSE if the inspection

requirements were eased. Shutdowns with subsequent long delays for inspection could be avoided wherever earthquakes less than an SSE occurred.

Design Consideration

Seismic instrumentation properly located may be or become adequate to give reliable assurances that the earthquake was less than the SSE and that the design has been adequate. Such instrumentation may supplement or even replace the extended mandatory inspection. A substantial reduction in the risks of HNEC and DS outages from earthquakes would result.

Risk of earthquake damage to the Code-design portions^(a) of the plant would be reduced, of course, if those portions were designed to a horizontal acceleration greater than 0.125 g, closer to the associated criteria of the Category I portions of the plant. Whether the added cost would be justified would depend on the added values attached to the use of such a Center, along with the assessment of the risk that can reasonably be taken with respect to earthquake effects.

A somewhat greater spacing between clusters, or three units per cluster instead of four or five, would reduce the risk of earthquake effects somewhat, but the beneficial effect would be small and probably would not justify added costs.

ASHFALL

Knowledge of the possible effects of ashfall on plant operations is so meager that the quality of the assessment is highly uncertain. Further study analysis and experimentation on the effects could move the zone shown in Figure 30 in either direction. The dust storms occasionally experienced in the Hanford area are good indicators of where trouble might be experienced with the much more voluminous mass of a two- to six-in. ashfall. Such studies would be recommended before any design changes to reduce risk be considered.

(a) Code-design portions refers to facilities other than Category I features essential to power generation.

Following that, measures might be considered that would:

- permit quick filter changes,
- cover exposed water pools,
- control possible ash drifts,
- seal instruments and machines that could be damaged by ash infiltration, and
- make provisions for insulator washing if the anticipated effects of acid deposits are adverse.

If it can be shown that with certain economical preventative measures a nuclear plant would have a better probability of remaining operational under a 6-in. average ashfall deposited over a 3 to 7 day period, the perceived risk would decrease in importance.

FLOOD

The vulnerable point of the HNEC plants to flood is their river pumping plants. The vulnerability of a Pebble Springs plant would be greatly reduced by the availability of stored water in the planned reservoir. An obvious way to reduce the effect of flood on HNEC plant operability is to provide a backup source of coolant makeup in the form of a pond, reservoir or well system that could serve a cluster of plants. This backup source need have only sufficient capacity to serve the plants until the river pump houses be restored, or temporary pumping facilities be provided to deliver makeup water from the river after the flood had subsided.

The above pertains to natural floods that could incapacitate river pump houses. It could pertain also to Artificial Flood No. 1, but first, one would have to make a more careful study to ascertain that in the event of such a flood, other impediments to continued delivery of power are not likely to appear, such as washed-out transmission line towers and consequent cutting of vital system connections.

OTHER CAUSES

Of the remaining causes, only two opportunities for risk reduction are worthy of mention:

- 1) Switching stations could be designed to handle the output of only one cluster, and
- 2) Structures vulnerable to tornadoes, particularly vital overhead cluster lines, and cooling towers, could be designed to reduce the risks, i.e., by placing critical lines underground and by orienting lines of towers at right angles to prevailing tornado travel directions.

An option that must be addressed is that of providing additional reserve capacity to the added reliability risk at a center. This alternative does not appear to be feasible because such a large amount of reserve capacity would be needed to make any appreciable reduction in the risk that it would be uneconomical. The preferred course would be to improve reliability at the Center via reduction of effects of earthquake.

In enumerating the possibilities for reliability improvement over that of the model used for this study, no inference is made regarding justification, or regarding the need for improvement. If improvement is needed, efforts should be directed to the effects of earthquake, since a substantial improvement in the effect from other causes would make little change in the overall risk.

APPENDIX A

TYPES OF DISRUPTIVE EVENTS EXCLUDED
FROM COMPARATIVE ANALYSIS OF RELIABILITY

TYPES OF DISRUPTIVE EVENTS EXCLUDED FROM COMPARATIVE ANALYSIS OF RELIABILITY

TYPES OF EVENTS EXCLUDED

NEW VOLCANOES

Eleven new volcanoes have formed on the earth since 1750 A.D. The probability of occurrence of a new volcano that would affect a generating plant cluster would be of the order of 10^{-9} to 10^{-11} events per year. Its estimated value within this range would depend on whether new volcanoes would appear at random over the entire face of the earth, or would tend to appear in locations which are presently active or contain recently extinct volcanoes. While the latter is the more reasonable, the probability of occurrence under either assumption is too low to be of interest in this comparison. Activity from existing volcanoes has been covered in the section on Ashfall Effects.

METEORITES

Data have been gathered on meteorite impact frequency.⁽¹⁾ Meteorites of iron and stone of a size of interest here range from 10 to 10^{13} tons in weight. The combined probability of meteorites striking a site would be of the order of 10^{-9} to 10^{-10} events per year. The chance of a meteorite having a destructive area of impact large enough to involve more than one cluster would be even less. (The probability of occurrence of 10 to 10^4 fatalities from a meteorite would be in the 10^{-4} to 10^{-7} range.⁽⁶⁾ The probability of striking inhabited areas is greater than the probability of striking the much smaller land area occupied by power plants).

A meteorite estimated to have had a weight of about 2.7 metric tons fell in Kirin province, China, on March 8, 1976. The meteorite broke into three major fragments weighing 1.7, 0.4 and 0.12 metric tons.⁽³⁾ The largest fragment left a pit in frozen ground measuring about 2 m wide and 6.5 m deep. Smaller fragments were scattered over an area of 500 km^2 . This example has a meteorite weight below the range indicated above, but serves to indicate that for stony meteorite types:

- 1) The area over which fragments can be strewn may be quite large and could involve more than one cluster, but
- 2) The area of severe damage by each major fragment would probably be relatively small. Within each cluster, a major fragment striking critical plant facilities would probably involve only one unit rather than all units. A very large meteorite conceivably could affect other clusters through ground shaking.

Iron type meteorites would be expected to have less fragmentation and less probability of involving more than one cluster.

Although HNEC may have slightly greater exposure than DS for the reasons given above, the probabilities are so low, and the possible number of units involved so small, that meteorite strikes were eliminated from the comparison.

FLOODS OR LOW WATER LEVELS FROM RIVER CHANNEL DIVERSION OR BLOCKAGE

A blockage of the Columbia or its tributaries in the past has occurred in these ways:

- 1) Following an earthquake on December 14, 1872, "The most important slide reportedly occurred just north of Entiat where a section of Old Broken Mountain fell into the Columbia River and completely blocked the flow of water for about 12 hr. The slide area is just above Entiat Rapids at what is now referred to as Earthquake Point. The section of mountain exposed by this slide is now called Ribbon Cliffs because of prominent basalt dikes in the crystalline rock face."⁽¹³⁾
- 2) "In historic times, no more than a few hundred years ago, a large landslide occurred on the southeast face of Table Mountain near the site of Bonneville Dam. The river was completely blocked for a short period of time, raising the water about 200 ft above normal stream level, before overtopping the natural dam."⁽¹⁴⁾
- 3) "During the last glacial period, about 15,000 yr ago, Clark Fork was blocked by ice in northern Idaho forming Lake Missoula extending into Montana. At about the same period, ancient Lake Lewis

was formed by a blockage of the Columbia River near the present community of Hood River, downstream from the site (Pebble Springs). The cause of this blockage is not established, but may have been either ice, landslide or lava flow."⁽¹³⁾

- 4) "The Clark Fork was blocked at least twice in the last 20,000 yr, resulting in floods between 18,000 and 20,000 yr ago, and 13,000 yr ago."⁽⁷⁾
- 5) "Ancient Lake Lewis formed most likely as a result of hydraulic damming of the Columbia at three restrictions. Those are: 1) the Columbia Gorge downstream from Portland, 2) the gorge at Hood River, and 3) Wallula Gap. If landslides, lava flows or ice jams were significant there should be some scars left. None have been reported. Instead, calculations show that the gorge could not pass water through those restrictions at the rate it was moving downstream. Hence, water was backed up at the three sites. Significantly the last flood (13,000 yr ago) appears to have been of the same magnitude as the earlier one, based on the nature of the deposits, but rose to only about 900 ft in the Pasco Basin versus 1150 for the earlier one. The reason is probably that the constrictions were reamed out by the earlier flood."⁽¹⁰⁾

The following opinions regarding the danger of diversion or blockage of the Columbia in the vicinity of Hanford and Pebble Springs are found in safety analysis reports.

"--The Columbia River is deeply incised and does not meander so that cutoffs above the site are not possible. Ice formation is not of sufficient thickness to cause ice jams. There are no topographic conditions upstream of the site that would provide complete blockage of the river by landslide."⁽¹³⁾

"In the vicinity of the site the river bed is well defined, and it is very unlikely that the river would be diverted from the present location by natural causes. Any possible effect on water supply to the makeup water pump house from river bed changes should come from extremely slow changes which can be corrected as they occur. The river has not

frozen over in the Hanford reach during the past twenty-five (25) yr, and icing on the river has not been a problem at pump houses or out-fall structures associated with the Hanford plutonium production plants." (14)

The historical and prehistorical river blockages have been attributed to ice, lava flow, and landslides or, for Lake Lewis, hydraulic damming at river flow restrictions. No evidence was found to indicate a significant risk of ice blockage in the river either in reaches of interest here or in upstream areas. Similar risks would result from lava flow. Lava flow conceivably could occur near the river in the vicinity of Mount Hood. Blockage at this point, however, would affect only the Portland site of the DS case, and would have no effect insofar as multiple-cluster outages are concerned.

Landslides can occur 1) from earthquakes in either rock or soil formations near the river, 2) from undercutting soil bluffs by river flow, and 3) from possible effects of irrigation water on soil shear strength, weight, and stability.

North of the HNEC site as far as Grand Coulee the river bank formations are mostly rocky. Earthquake-induced slides from these rock formations could occur in this portion of the river. The slide at Ribbon Cliffs noted above is an example of an earthquake-induced rock slide. Complete blockages in this portion of the river could reduce river water elevations at all of the HNEC sites and some of the DS sites in this study. Partial river blockage above any of the storage dams upstream of the sites would not seriously affect either HNEC or DS.

White Bluffs on the eastern side of the Columbia River opposite HNEC are Ringold Formation sediments that are subject to some undercutting, and, more importantly, to the effects of irrigation. In recent years perched water in the bluffs along the river edge has developed from irrigation and is appreciably above the river level. The loss of shear strength in the clay-rich sediments, and added weight of the water, and their effect on the stability of the soil, are factors in studies of possible soil movement. If portions of these bluffs should slump into the river, blockage may occur.

In documentation in support of safety studies for the Fast Flux Test Facility (FFTF) near HNEC the conclusion is reached that "Geologic evidence indicates that the FFTF site has not been inundated for perhaps several thousand to many thousands of years (by large earth avalanches or landslides). No evidence indicates that even the largest slides that have occurred in the White Bluffs area have had more than relatively local impact on the area."⁽⁸⁾

After a brief investigation of the White Bluff condition a soil mechanics firm noted that "There are two possible modes for landslides, i.e., 1) a series of shallow steep slides which would cascade into the river with the material pulverized and rapidly eroded by the river, or 2) a few very large, massive and slow moving slides which would move into the river diverting it away from its east bank and which because of the mass would require some time for erosion by the river to restore its original channel. With the advent of irrigation we believe the second mode of landslides is the more critical and based on limited information the more likely."⁽⁹⁾

Although the historical evidence indicates that any slides that have occurred have not been large enough to have had widespread effects, the new factor--irrigation on the Bluffs--may increase the probability of large slides. The tendency to slides in the White Bluffs area can be monitored.⁽⁹⁾ Possibly, irrigation practices could be modified to limit excess drainage, or be curtailed if the potential risks were great enough.

In the event of a major slide, the extent of blockage would depend on the amount of material dislodged, how quickly the temporary dam breaks after overtopping, and the river flow at the time. During concurrent high-river flows, large amounts of soil could be washed downstream with no effective blockage of river flow. During concurrent low flows, the river run may be completely blocked. The blockage may occur below some HNEC sites and above others. River bed contours in the White Bluffs area indicate that slides from the bluffs would be more likely to block and be overtopped than to divert the river flow to a permanent channel west of the slide.

The possible effects of a White Bluffs landslide of approximately one million cu yd on river flow and elevations were considered, with given assumptions

as to the time for the earthdam to fail after it was overtopped, and the river flow rates. (The effects of wave action from downstream backwater flow were ignored.) For example, if flooding occurred simultaneously with a bluff slumping into the river, the approximate elevation of the flood wave crest in the vicinity of the southern HNEC cluster would be about 400 ft above Mean Sea Level (MSL), for a river flow of 600,000 cfs, (1 in 200-yr flood) and about 410 ft for a river flow of 1,400,000 cfs [the Probable Maximum Flood (PMF)]. These elevations of flood waters would be above the Probable Maximum Flood elevation, 389 ft, and below the Limiting Case Flood elevation, 424 ft. They would flood the river pump houses but not the major plant facilities. Water elevations upstream from the blockage would rise gradually until the dam is overtopped. At the 1,440,000 cfs flow these levels would already be close to the maximum tolerated at the river pump houses. At this extreme flow the river pump house at both upstream and downstream plants would be affected by the slide.

For these assumptions and flood conditions to occur, the drainage area for the Columbia would have to produce a river flow close to or exceeding the historical maximum, and, in addition, the conditions at White Bluffs would have to be such as to induce the slide.

The probabilities of occurrence of such a combination of conditions have not been estimated. The combination would include the probability of high river flow with recently completed or projected large flood control projects on the river, that of conditions at White Bluffs to induce a slide, and that of the slide being of sufficient volume to completely block the channel. The probability of the occurrence of a 600,000 cfs flow has been estimated at once/700 yr, and that of a Probable Maximum Flood has been estimated at once per 10^7 yr. Since other factors in the probability equation would also have low values, it would appear that the combination may be below the area of interest. This assumption is necessarily conjectural lacking further information on the likelihood of collapse under the conditions at White Bluffs.

The probabilities of a slide occurring at low flow may be much higher but for equal dam height the elevation of the flood crest above and below the blockage would be less than for high flow, with less chance of flooding the river pump houses.

Returning to the earthquake-induced rock or earth slide, historical events indicate that three changes of major features on the Columbia River may have been from landslides, which may have been induced by earthquake (one is known to have been earthquake-induced) during the last 15,000 yr. These occurred at different points and would not have affected the entire river. For example, the Ribbon Cliffs slide was above the confluence of the Snake and would not have seriously affected the lower Columbia; and the Table Mountain event would not have affected upper portions of the mid Columbia.

The probability of three such events occurring where the same portion of the river would be affected, based on these data, would therefore be much less than $3/15,000$, i.e., much less than 2×10^{-4} events per year.

Although this analysis of river blockage probabilities and consequences is very rough and preliminary, it indicates that the risk may be less than others analyzed in the report, and need not be included in the quantitative evaluation.

EXTREMELY LOW RIVER FLOW

Lack of available makeup cooling water at the river pump suction intake point could occur in the event of very low flow in the river because of freak weather conditions in the drainage area, or in the event of blockage or diversion of the channel as discussed above. Extremely low precipitation would affect these river systems supplying cooling water for these sites:

<u>Site</u>	<u>River</u>
HNEC Hanford	Columbia River
DS Hanford	Columbia River
Pebble Springs	Columbia River
Portland area	Columbia River (or possibly Cowlitz or Kalama)
Oregon	Willamette River or tributaries

Some 70% of the DS Case generating capacity and 100% of the HNEC Case capacity would depend on Columbia River water.

The HNEC points of withdrawal of river water are above the confluence of the Columbia and Snake Rivers, while Pebble Springs is below it. The Portland area site is near the mouth of the Columbia and the Oregon sites are on a Columbia River tributary, the Willamette. Even though HNEC is upstream of some of the major tributaries flowing into the lower river, it is on a reach of the river carrying drainage from large areas in the northwestern U.S. and Canada and furthermore, it is downstream of the major storage dams.

River surface elevation necessary for reliable pumping opposite the WPPSS plants under construction is 343 ft MSL (river mile 352). The flow here corresponding to that level is 36,000 cfs. If river flow dropped much below that amount, the HNEC plants would be incapable of sustained operation.

Flow is now regulated by Grant County PUD at their Priest Rapids Dam so that "it will not result in flows of less than 36,000 cfs of water at the Hanford Works of the Atomic Energy Commission except when conditions are beyond the licensee's control".⁽¹⁵⁾

Historical records of the USGS gauging station (R.M. 394.5) located 2.6 mi downstream from Priest Rapids Dam show low daily average flows of 20,000 cfs in January 1937. At that time there were only 1.19 million acre-ft of upstream storage on the river as compared with 38.2 million acre-ft at present, and 51 million potential.⁽¹⁶⁾ The 20,000 cfs flow in 1937 may be considered as a historical low in natural river flow in the Hanford reach prior to the building of the major upstream storage dams. This flow may be considered as having a probability of 1/75 or 0.013 events per yr. A 14,800 cfs natural flow would have a probability of 0.001 events per yr, again without use of stored water as indicated in Reference 13.

The total usable storage of dams from Grand Coulee Dam to the Columbia River headwaters now totals about 38.2 million usable acre-ft. Some additional storage below Grand Coulee would bring the total to around 40 million acre-ft. Disregarding withdrawals above Hanford this amount of storage would sustain a flow of 36,000 cfs for 559 days. From full reservoirs the release of stored water could supplement the 1000-yr low flow of 14,800 cfs, to achieve a level of 36,000 cfs at Hanford, for 947 days if used for that purpose alone.

The above statistics are presented only to place the amount of storage in perspective. There would be competing uses for stored water that may or may not be compatible with maintaining a 36,000 cfs minimum flow at HNEC. These uses include irrigation, power at hydroelectric dams, navigation and fisheries accommodations. The water consumption for 20 operating plants with wet cooling towers would be about 1100 cfs. If an HNEC were in place its importance to the region would justify a high priority in the scheduling of use of the water. It is evident that the upstream reservoirs provide the means of sustaining adequate flow during a substantial drought period. Starting full, and with no other withdrawals, they can sustain a 36,000 cfs flow for 947 days. Starting partially full, and with other withdrawals, they could probably sustain minimum flows through at least a one-yr drought.

Plants with reservoirs of their own, such as the cooling pond and irrigation reservoir proposed for Pebble Springs, could tolerate low water periods of many weeks duration in which makeup water from the river were cut off. The length of the period would depend on irrigation withdrawals.

Finally, if a prolonged drought should empty the upstream reservoirs and drop the natural flow below the point at which suction can be maintained on the river pump intakes, the time taken to reach that stage would be sufficient for other emergency measures to be taken. These could take the form of extensions to intake pipes, temporary booster pumping stations, or drilling of wells to provide makeup water.

In summary,

- 1) The Columbia River could supply makeup coolant to 100% of the HNEC capacity and 70% of the DS capacity; 30% of the DS Case capacity takes makeup from the Willamette River which may or may not be affected by drought at the same time,
- 2) In view of the nature of the river system, and the stored water at upstream dams, the probabilities of flows dropping to critical levels are extremely low. However, if flows were to drop to that degree, the progression to that stage would take enough time that contingency plans to provide makeup water could be implemented at either the HNEC or the DS sites.

For these reasons the difference in risk from this cause is considered too low to be included in these comparisons.

AIRCRAFT CRASH

The annual probability of an aircraft striking a nuclear power plant is estimated to be:⁽²⁾

<u>Aircraft Size</u>	<u>Location of Plant</u>	
	<u>Beyond 5 mi of Airport</u>	<u>Within 5 mi of Airport</u>
Small, <12,500 lb	1.4×10^{-5}	3.3×10^{-5}
Large, >12,500 lb	4.6×10^{-7}	1.1×10^{-6}

These probabilities would apply whether the plant were part of a cluster or sited alone.

Since HNEC sites would be more than 5 mi from an airport, and presumably the DS sites would also, the 4.6×10^{-7} probability would apply. Furthermore, in view of the limited impact area, no mechanism can be visualized whereby more than one cluster could be affected by an aircraft crash other than by a crash into a switching station carrying the output of multiple generating units (previously discussed).

The extremely low probability of affecting more than one cluster is the reason for exclusion of aircraft crash at the generation plant from the study.

EXPLOSIONS

Explosions can occur at tanks at industrial complexes, tank cars or trucks on rail or highway, on tanker ships on waterways, or bombs from military or saboteur operations. Tanker ships can be excluded since explosive cargo is not carried on the Columbia River at the plant sites and, if it were, the distances would provide adequate protection except for river bank pumping or outfall facilities. Military explosives are excluded as a matter of policy.

Conceivably, industrial complexes could be attracted to a nuclear center. Since there are none now, and since any that may be placed in the Center in the future would be sited so as to be compatible with the generating plants,

exposure of multiple clusters to possible explosions can be avoided. NRC criteria would ensure that the safety of the nuclear plants is maintained.

A nuclear plant is considered safe at a distance of 8 to 10 km from an explosion.⁽⁴⁾ It would be feasible to maintain such distance from possible explosive sources in the Hanford reservation. The chance of more than one cluster being affected under the controls which are both necessary and feasible would be extremely remote.

The same precautions could and would be taken with respect to potentially explosive materials transported in the plant vicinity by rail or over highways.

As for DS sites, it is assumed that whether industrial plants existed in the vicinity of the site before its development, or were planned after the generating plant came into service, adequate controls would be exercised there also. There may or may not be the flexibility of siting that exists at Hanford. In any case, it was concluded that no discernible difference in risk from industrial explosions existed between the HNEC and DS cases.

With respect to bombs placed by saboteurs, certain conclusions were reached by the authors of References 5 and 6 which are significant:

"Protection of nuclear power reactors against sabotage is provided both by the nature of the nuclear process and by explicit protective actions of licensees in accordance with AEC regulations."⁽⁵⁾

The massive shielding, radioactivity of the process, sealed containment vessel, and redundant safety systems are noted, along with deterrents to unauthorized entry.

"Successful sabotage of a reactor at an NEC or Dispersed quad would require a sequence of several events, each of them quite improbable, and even then the severity of the results would depend on the state of the reactor core and cooling systems as well as the weather at the time."⁽⁵⁾

"With the implementation of current security measures it appears that the probability of successful sabotage is low, and further reductions in probability can be anticipated in the future."⁽⁶⁾

Our study is concerned with the probabilities of success of sabotage of all generating units at one cluster plus one or more units at another cluster, at the same time. A sabotage plan conceivably could include two clusters at an HNEC or two at distant DS sites. Tactics for carrying out such a plan might differ for the two cases, but there is no fundamental reason why the prospects of success should be much different. The prospects of success would be extremely low, given that the successful sabotage of even one generating unit would be as difficult as indicated above. These statements were oriented primarily to the reactor and its safety systems, and perhaps less so to the non-nuclear facilities. However, the security measures apply to both.

If sabotage of a single generating unit were successful to the point that radioactive contaminants were released, the effects on other units would be the same as though the release were caused by equipment failure. Those effects are included in the comparative analysis.

For those reasons, bomb blast sabotage has been excluded from detailed comparison, except for the possibilities at switching stations, which are discussed in another section.

TOXIC GASES

The danger from toxic gases from nearby industrial plants cannot be evaluated without knowledge of the industrial process. However, since power generation would be the principal activity at a nuclear energy center, it can be assumed that controls would be exercised to limit this risk to very low levels.

At LWR and LMFBF generating plants, the only source of toxic gases other than radioactive releases and sodium fires discussed elsewhere is stored chlorine for water treatment. The amounts of chlorine stored and the separation of clusters at HNEC is such that a chlorine release at one cluster would be greatly diluted if carried by wind to an adjacent cluster.

FIRES

For multiple clusters to be affected, a fire would have to be widespread and difficult to control, such as a major forest fire. HNEC has minimum

exposure in this sense. No industrial fire within the plants can be visualized that would extend to other clusters.

A sodium fire at an LMFBR is a special case in which the fire itself would not involve other clusters, but the airborne products from the fire might affect them.

SODIUM FIRES

Since LMFBRs may supplement LWRs in the 1990s, at the HNEC or DS sites, the possible effect of sodium fires on generating units in an adjacent HNEC cluster was considered. This discussion is limited to the burning of sodium that would come from the primary or secondary coolant circuits in its normal operating condition, i.e., not following a fuel melt accident. The latter type of accident is discussed in another section of the report.

Some radioactivity will be present in the sodium. "The principal source of activity in the primary sodium is from neutron activation in the primary sodium itself. Neutron capture in ^{23}Na forms ^{24}Na (15 hr half-life). Smaller concentrations of ^{22}Na (2.6 yr half-life) are formed by $(n, ^2n)$ reactions with ^{23}Na . Depending on the number of fuel failures that may have occurred during prior plant operations and on the amount of corrosion of irradiated cores structural members, other radioactive species may also be present." "The sodium in the secondary coolant circuit is not normally radioactive except for tritium that has diffused through the intermediate heat exchanger tubing."⁽¹¹⁾

Reference 12 contains the results of analyses of a) releases of sodium from the primary system, into an inert atmosphere, and b) releases of sodium from the secondary system into air-filled spaces. With reference to the latter, "release of sodium and of its oxides to the environment is a relatively minor consideration due to its low chemical toxicity." In the section describing tests, "0.5% of the spill mass was released from the cell as aerosol particles", and when a coverplate was used, "Smoke release from the cell was 0.03% of the spill mass...."

These references describe the measures that can be taken to limit the rate of combustion, confine the combustion products, and extinguish fires that may

occur. The possibility of a sodium fire in the waste heat exchangers of FFTF, which was assessed in connection with the licensing of WPPSS plants at Hanford, would not exist in a commercial LMFBR since the sodium coolant circuit would all be within the confinement vessel.

The response of such containment systems is expected to limit releases to the extent that radiation levels beyond the site boundary for a 1000 MW LMFBR would be a 2-hr, whole-body dose of 12 mrem at a distance of 2000 ft, and a 30-day whole-body dose of 4.5 mrem at 2 mi.⁽¹¹⁾

The releases of radioactivity would be greater in the event that primary sodium burns and the containment systems fail. No estimate is available presently as to the plume characteristics for a commercial LMFBR. A calculation has been made for FFTF.⁽¹²⁾ Although the primary sodium inventory at a 1000 MW LMFBR would be greater than at FFTF, the amount of the release would not be proportionately greater because of plant design features to limit the size of possible pools.

To summarize, in the rare event of accidental release of the combustion products of a large sodium fire:

- If the burning sodium were from the primary circuit, and if all fire control and containment features failed, there could be a radioactive plume which, if the wind conditions were right, could be carried to adjacent clusters. A quantitative assessment has not been made. The effects can be judged by studies of FFTF potential releases. The radioactive sodium deposition in the 1000 MW plant case is estimated to be no greater than that computed for FFTF, and is of course, much less than the total radioactive deposits that would result from LWR releases following a fuel melt. In the unlikely event that some radioactivity were deposited, continued operation of adjacent clusters is believed to be possible if operating personnel have available air packs for outside operations if needed until the plant could be decontaminated.
- No problems would be created at adjacent clusters if the sodium were from the secondary circuit since little or no radioactivity would be present in the combustion products.

For these reasons sodium fires were excluded for consideration as an added risk at HNEC.

LOSS OF OFFSITE STATION SERVICE POWER

Loss of offsite station service power would force shutdown of a plant within 72 hr for safety reasons. The probability of occurrence of such loss was assessed for the HNEC and DS cases.

Several possible ways in which HNEC could receive offsite station service power from the network in the vicinity were explored in Reference 17. These included the 220 kV system as a source, as for the WPPSS plants under construction, and the 500 kV system over which the output of the center would be fed into the bulk power network. Similar alternatives would exist at most of the dispersed sites.

The reliability of offsite power supply would depend on that of 1) the network from which the power is drawn, and 2) the circuits carrying power from the network to the station service transformers. The reliability of the network is a function of the number of independent sources of power on the network that would have a good chance of remaining connected to the HNEC switchyards in the event of system faults or disturbances. The greater the number of generating stations in the vicinity of each cluster, and the shorter the interconnecting transmission lines, the greater will be the reliability of the network as far as that one particular cluster is concerned (assuming that relaying on all lines and in all situations is equally dependable, and that the lines and terminals are constructed to the same standards). From this standpoint, the reliability of the network source to HNEC should be greater than that to isolated clusters if the 500 kV system is used as the source of power. If the 220 kV system is used as the source, the reliability of service to HNEC should be equal to or better than that to the typical isolated cluster.

Turning to the second element, the circuits connecting the network with the station service transformers, the most significant fact is that failure of a circuit or piece of equipment could not involve more than three or four generating units. Any event, such as a severe earthquake, that could affect more than one circuit or one transformer would also act to shut down plants in

other ways--ways that are discussed in the sections of the report concerned with switching stations and overhead lines from the switching stations to the station service transformers at the operating plants.

It was concluded that:

- 1) with offsite power supply from the 500 kV system there is no way in which more than one cluster could be affected at HNEC other than collapse of the network in eastern Washington. If that should occur, the operation of the plants would be interrupted anyway. The effect of loss of offsite power is additive to the risk of loss of generation at a Center only if the cause of the trouble is apart from causes that can force shutdown in other ways,
- 2) with offsite power supply from the 220 kV system, the reliability of service would be equal to or better than that to the typical isolated cluster,
- 3) the prospects of having offsite power available for restarting from the hot or cold state are approximately equal for the HNEC and DS cases,
- 4) failure in a circuit from the network to a station service system could in no case affect more than four generating units.

For these reasons loss of offsite power was not quantitatively assessed as a source of differences in risk between the HNEC and DS cases. HNEC is considered to be in an advantageous position with respect to reliability of station service power.

FAULT CLEARING

One of the characteristics of an energy center is that currents would be greater for faults on the transmission system near a center than for faults near a dispersed site, requiring power circuit breakers of greater interrupting capacity than are now available. The problem of reliable clearing of faults has been considered in prior studies of transmission from energy centers.^(5,6) Although the problem may be properly categorized as one of transmission rather than generation, it concerns generator protection and access of

generation to the transmission system as well as its impact on system stability and reliability; and it should be included in an investigation of generation reliability differences between DS and an HNEC.

The state-of-the-art with respect to such devices is summed up as follows:

Certain cases examined in regional studies (of energy centers) would have an available fault current of up to 86 kVA which is in excess of interrupting capacity of available circuit breakers. Within the last two decades the interrupting time of circuit breakers has been reduced from eight cycles of the power frequency to two cycles, and at 500 kV the standard rating is 40 kVA and two cycles. Breakers capable of interrupting up to 63 kVA in two cycles at voltages up to 800 kV are being developed and should be available within the next few years. Development of a synchronous interrupting device capable of interrupting faults at the first current zero is proceeding. Further research is expected to extend interrupting capacities and shorten fault clearing times. However, when designing for interruption of extremely large fault currents, additional strengthening of many associated equipment components to withstand very large mechanical stresses may also be required. Other approaches may be less costly.

Another ac circuit breaker development which could benefit NECs is the current limiting breaker. It or an extremely fast (one cycle) relay and circuit breaker system could provide a way to mitigate many of the extremely high fault current difficulties. More generators could thus be tied together normally at an NEC switchyard. This could reduce the number of transmission lines required for reliability purposes.⁽¹⁷⁾

Among the alternatives open to the designer in the 1990s will be 1) to apply adequate interrupting capacity breakers if these have been developed by that time, 2) to use current limiting breakers, 3) to install extremely fast sectionalizing breakers to reduce fault levels, or 4) to design generating stations and their interconnecting transmission lines so as to limit fault currents to the interrupting capacity of equipment then available. The choices will take into account economics, reliability, and environmental impact.

The question is--would the higher fault currents, with the equipment and system design that would be used to interrupt the current and isolate the fault, be likely to cause greater generating outages than the lesser fault currents with the conventional equipment of the DS case? In the HNEC case the designer would aim for the same level of reliability as in the DS case, and only if equal protection became economically prohibitive would the aim be lowered and the reliability consequences accepted. With the alternatives expected to be then available it is considered likely that an equal level of reliability could be achieved economically.

However, if there were some doubt as to the level of reliability that could be achieved, the consequences of breaker failure should be evaluated.

A fault on a transmission line near a HNEC switching station would be cleared at the switching station end by two circuit breakers in a breaker-and-a-half bus arrangement. If one of them failed it would be backed by a breaker or by a group of breakers in parallel. In this sequence not more than one generator would be dropped. If a failure occurs in the backup, a third line of breaker protection is available, but by that time the stability of the system could be threatened, with possible outage of all generating capacity at the station. The difference in probability of such an outage at HNEC versus that at DS is a function of the product of the probabilities of successive failure of two circuit breakers in each case, or of one circuit breaker and one in a group of six parallel breakers.

Modern 500 kV heavy duty circuit breakers have a failure rate of about one failure in 200 attempts, a probability of failure of 0.005. The probability of successive failure of two breakers would be $(0.005)^2$, or 2.5×10^{-5} , and that of one breaker and six in parallel, 1.5×10^{-4} . The probability of an outage of up to 20 generating units because of such a sequence of failures would be the product of a) the annual occurrence rate for transmission system faults near the station, b) the factor 2.5×10^{-5} or 1.5×10^{-4} , and c) the probability that the system would become unstable under the circumstances, and that x generators would separate from the system. Good estimates of factors a) and c) are not available, but the presence of the 2.5×10^{-5} or 1.5×10^{-4}

factor ensures that the probability of occurrence of such events per year would be low enough that overall reliability of generation would not be affected significantly. If the probability of failure of a higher capacity breaker were greater than 0.005 its square would be greater than 2.5×10^{-5} , but the increase in probability of failure would have to be substantial to change the general conclusion.

The additional question can be asked--if the fault occurred on a tie line between two HNEC switching stations, and if the system did not become unstable, could outage of generators occur at both stations? In that event both stations would be affected in the same way at the same time, the probability of double circuit breaker failures occurring at both ends is the square of that of occurrence at one end, placing this risk below the area of interest.

For the reasons given above the high-fault-current characteristic of the Center is deemed a reliability risk that would not significantly alter the risk level set by other contingent events.

SUMMARY

A summation of all of the exclusions discussed above follows in Table A-1.

Finally, although an effort was made to anticipate all the sorts of risks that may enter into a comparison of Centers and Dispersed Sites, some generic problem not now foreseen could arise in future years to affect the risks of plant outages in any one area. This is an intangible risk difference, which diminishes as more experience is gained with nuclear plants, and as the seismic, hydrological, meteorological and other characteristics of the area become better understood. There has been 34 yr of operation of noncommercial nuclear facilities at Hanford, and considerable experience has been gained elsewhere in the operation of light-water reactor commercial plants, so the intangible risk of unforeseen generic problems in the HNEC model is believed to be acceptably low.

TABLE A-1. Summary of Effects of Miscellaneous Outage Causes

Cause	Probability of Occurrence, Events per Year	Probability That an Event That Occurred Would Affect More Than One HNEC Cluster	Comment
New volcano	10^{-9} to 10^{-11}	high	Highly improbable
Meteorite	10^{-9} to 10^{-10}	intermediate	Even if one more than one cluster were affected, probably not all units in each cluster
River channel blockage	low	high	Insufficient data to quantify
Extremely low river runoff	low	high	Large upstream storage protects minimum flow, and there would be time to take emergency measures
Aircraft crash	10^{-6} to 10^{-10}	zero	Applies equally to HNEC and DS
Explosions	control to low level	low	Risk can be controlled at Center
Toxic gases	control to low level	low	Risk can be controlled at Center
Fires-general	high at one cluster	zero	Absence of combustibles between clusters
Fire-sodium	intermediate	low	Reduce hazard by control of pool size
Offsite station service failure	intermediate	low	If it occurred, could affect only a few units immediately; 72 hr wait for repair. Risk difference small but in favor of HNEC
Fault clearing	low	high (if incident triggers instability)	Depends partially on improved equipment development, or greater expenditures to gain reliability

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APPENDIX B

COMPUTATION OF PROBABILITIES OF HNEC AND DS OUTAGES

APPENDIX B

COMPUTATION OF PROBABILITIES OF HNEC AND DS OUTAGES

This appendix contains computations of probabilities of x generating units being affected by one event. Computations for earthquake, tornado, release of radioactive contaminants, and volcanic ashfall are included.

EARTHQUAKE

Earthquake effects were analyzed as follows:

- 1) Circles were drawn around each cluster site on a map, the radius being the computed distance at which an earthquake of magnitude M would produce a free field horizontal acceleration of 0.125 g. Quakes of magnitude M with epicenters lying within the circle would cause a shutdown of the plant, while those outside the circle may be felt but would not affect plant operations.
- 2) In areas where circles overlap, an earthquake of magnitude M would affect two or more clusters (Overlap Areas).
- 3) When this area is multiplied by the probability of occurrence of quakes of magnitude M per unit area (including an adjustment for proximity to active earthquake areas), it represents the probability of forced shutdown of x generating units.
- 4) The above procedure, carried out for the full range of magnitudes applicable to this region, accumulated and plotted, generates a curve of annual probability of x generating units being subjected to accelerations in excess of the OBE.
- 5) The probable horizontal acceleration resulting from earthquakes in the overlap areas was calculated, using distances from the site center.
- 6) Another factor was applied to account for the probability of failure of essential facilities if the structure were subjected to accelerations at and above their code design.

- 7) The time required to inspect the plant and, if necessary, to repair damage following the incident (caused by the probable acceleration) was estimated.
- 8) A curve of probable generation loss as a result of the forced outage was prepared from the information obtained.

Figures B-1 through B-4 are maps of the critical (overlap) areas for magnitudes Richter 7.6, 6.6, 5.5, and 5.2, respectively. These maps also indicate the boundaries of the most active earthquake areas in the Pacific Northwest as reported in Reference 14 in the Earthquake section.

Table B-1 contains data for calculation of probabilities of x generating units being affected by an earthquake of given magnitude occurring in the overlap areas. In Table B-2 the probabilities of n , $n + 1$, etc. units are grouped and added, and cumulative probabilities derived. These are probabilities of outages as required by current inspection requirements.

Table B-3 contains calculations for probability of outages as forced by failure of essential plant equipment.

FIGURE B-1. Circular Areas Within Which an Occurrence of an Earthquake of Richter 7.6 Cause Horizontal Acceleration ≥ 0.125 g at the Center

FIGURE B-2. Circular Areas Within Which an Occurrence of Earthquakes of Richter 6.6 Cause Horizontal Acceleration ≥ 0.125 g at the Center

FIGURE B-3. Circular Areas Within Which an Occurrence of Earthquakes of Richter 5.6 Cause Horizontal Acceleration ≥ 0.125 g at the Center

FIGURE B-4. Circular Areas Within Which an Occurrence of Earthquakes of Richter 5.2 Cause Horizontal Acceleration ≥ 0.125 g at the Center

TABLE B-1. Calculation - Outage Probabilities,
Earthquake, HNEC

		Sites	Number of Units	Magnitude Richter	Area mi ²	Frequency 10 ⁻⁶ /yr	Adj. Factor	Probable Frequency 10 ⁻⁶ /yr
			a	b	c	d	e	c x d x e
DS Case	WV-A	3	7.6	4469	0.044	0		
	WV-B	3		4469	↓	0		
	WV-A&B	6		1892	↓	0		
	P	4		6361	↓	3.0	840	
	PS	4		5133	↓	0		
	PS-H1	7		1316	↓	0		
	PS-H2	7		820	↓	0		
	PS-H1-H2	10		1020	↓	0		
	H1	3		208	↓	0		
	H2	3		416	↓	0		
	H1-H2	6		4925	↓	0		
	WV-A	3	6.6	1946	0.301	1.0	584	
	WV-B	3		1946	↓	1.0	584	
	P	4		1946	↓	3.0	1757	
	PS	4		1946	↓	0.33	193	
	H1	3		226	↓	0.75	51	
	H2	3		226	↓	0.75	51	
	H1-H2	6		1663	↓	0.75	375	
	WV-A	3	5.6	804	2.35	1.0	1889	
	WV-B	3		804	↓	1.0	1889	
	P	4		804	↓	3.0	5668	
	PS	4		804	↓	1.0	1889	
	H1	3		123	↓	3.0	867	
	H2	3		123	↓	3.0	867	
	H1-H2	6		682	↓	3.0	4808	
	W1	3	5.2	64	3.30	1.0	211	
	W2	3		64	↓	1.0	211	
	P	4		64	↓	3.0	633	
	PS	4		64	↓	1.0	211	
	H1	3		33	↓	3.0	326	
	H2	3		33	↓	3.0	326	
	H1-H2	6		31	↓	3.0	307	
HNEC Case	H1	5	7.6	359	0.044	0	0	
	H5	4		359	↓			
	H1-H2	9			↓			
	H4-H5	7			↓			
	H1,2,3	13			↓			
	H3,4,5	11			↓			
	H1,2,3,4	16			↓			
	H2,3,4,5	15			↓			
	H1,2,3,4,5	20		4925				

TABLE B-1. (contd)

		Sites	Number of Units	Magnitude Richter	Area mi ²	Frequency 10 ⁻⁶ /yr	Adj. Factor	Probable Frequency 10 ⁻⁶ /yr
			a	b	c	d	e	c x d x e
HNEC Case (contd)	H1		5	6.6	208	0.301	0.75	47
	H5		4		208			47
	H1-2		9					
	H4-5		7					
	H1-2-3		13					
	H3,4,5		11					
	H1,2,3,4		16					
	H2-3,4,5		15					
	H1,2,3,4,5		20		1114			251
	H1		5	5.6	124	2.35	3.0	874
	H5		4		124			
	H1-2		9		124			
	H4-5		7		124			
	H1-2-3		13		151			1064
	H3-4-5		11		151			1064
	H1-2-3-4		16		124			874
	H2-3-4-5		15		124			874
	H1-2-3-4-5		20		198			1395
	H1		5	5.2	33	3.30	3.0	326
	H1-2		9		26			257
	H1-2-3		13		6			59
	H2-3		8		25			247
	H2		4		32			317
	H3-4		7		3			30
	H4		3		27			267
	H4-5		7		36			356
	H5		4		27			267

TABLE B-2. Probabilities of OBE Accelerations Being Exceeded at n, n + 1, etc. Generating Units

DS Case			HNEC Case		
Number of Units	P 10 ⁻⁶	P Cgm 10 ⁻⁶	Number of Units	P 10 ⁻⁶	P Cgm 10 ⁻⁶
3	584		4	47	
	584			874	
	51			317	
	51			267	
	1889			1505	11,253
	1889		5	47	
	867			874	
	867			326	
	211			1247	9,748
	211		7	47	
	326			874	
	326			30	
	7856	24,537		356	
4	840			1307	8,501
	1757		8	247	7,194
	193			47	
	5668			874	
	1889		9	257	
	633			1178	6,947
	211		11	47	
	11,191	16,681		1064	
6	375			1111	5,769
	4808		13	47	
	307			1064	
	5490	5,490		59	
			15	1170	4,658
				47	
				874	
			16	921	3,488
				47	
			20	874	
				921	2,567
				251	
				1395	
				1646	1,646

TABLE B-3. Probabilities of Outages Forced
by Failure of Essential Facilities

<u>No. of Units</u>	<u>Total P 10⁻⁶</u>	<u>Factor</u>	<u>P 10⁻⁶</u>	<u>P Cum. 10⁻⁶</u>
<u>DS</u>				
3	7856	0.1	786	2454
4	11,191	0.1	1119	1668
6	5490	0.1	<u>549</u>	549
<u>HNEC</u>				
4	1505	0.1	151	1372
5	1247	↓	125	1221
7	1307		131	1096
8	247		25	965
9	1178		118	940
11	1111		111	823
13	1170		117	712
15	921		92	595
16	921		92	503
20	1646	0.25	411	411

TORNADO

Exposure probability was computed in the following way:

- 1) On an HNEC map, slots were drawn enclosing vulnerable facilities for each pair of clusters as in Figure 2 of the Tornado section. A tornado that would affect two or more clusters would be confined in the slot.
- 2) The angles that tornado paths would take within the slot boundaries were measured, and the percentage of tornadoes traveling in those directions were noted.
- 3) The number of generating units that would be forced out of service by tornadoes moving through a cluster having one of the standard plot plans was estimated. The estimate was based on typical plot plans

for 3, 4 and 5 unit clusters. The orientations chosen for clusters other than No. 1 in Figure 11 were with the long axis of the cluster lying generally northwest-southeast. Cluster No. 1 has no predominant axis.

- 4) The distances that a tornado would have to travel to strike a second or third cluster after it had struck any one of the five clusters were measured. The percentage of tornadoes moving in given directions, and numbers of units affected in all possible combinations of direction, length and cluster configuration were arranged in descending order of distance. This provided the combination of generating units that would be affected by a tornado having a given effective path length. The probabilities of occurrence of tornadoes of given path length were then applied to the generating unit combinations to obtain the probabilities of a given number of units being forced out of service by tornadoes.

TABLE B-4. Possible Paths in which a Tornado Could Affect Two or More Clusters

<u>Cluster Number</u> <u>To From</u>		<u>Distance,</u> <u>Miles</u>	<u>Direction</u> <u>Tornadoes</u> <u>Head Toward</u>	<u>Percent of</u> <u>Tornadoes in</u> <u>This Direction</u>	<u>Reverse</u> <u>Direction</u>	<u>Percent of</u> <u>Tornadoes in</u> <u>the Reverse</u> <u>Direction</u>
1	5	17.54	SE	4.5	NW	13.6
1	4	15.72	SE	4.5	NW	13.6
1	3	7.86	SSE	0	NNW	4.5
1	2	4.83	SSE	0	NNW	4.5
2	3	4.23	SE	4.5	NW	13.6
2	4	12.34	SE	4.5	NW	13.6
2	5	14.88	ESE	4.5	WNW	0
3	4	8.83	SE	4.5	NW	13.6
3	5	11.49	ESE	4.5	WNW	0
4	5	3.75	E	4.5	W	0

TABLE B-5. Arrangement of Numbers of Units Affected,
in Descending Order of Distance(a)

<u>From</u>	<u>To</u>	<u>Distance, Miles</u>	<u>Number of Units(b)</u>	<u>Percent of Tornadoes Involved in This Length and Direction</u>
1	5	17.54	4	13.6
5	1	17.54	2	4.5
1	4	15.72	2	13.6
4	1	15.72	1	4.5
2	5	14.88	2	0
5	2	14.88	2	4.5
2	4	12.74	2	13.6
4	2	12.74	4	4.5
3	5	11.49	2	0
5	3	11.49	2	4.5
3	4	8.83	2	13.6
4	3	8.83	2	4.5
1	3	7.86	4	4.5
3	1	7.86	2	0
1	2	4.83	4	4.5
2	1	4.83	2	0
2	3	4.23	2	13.6
3	2	4.23	2	4.5
4	5	3.75	2	0
5	4	3.75	1	4.5

-
- (a) Tornado of effective length x will have a probability of reaching all combinations below x in the table.
(b) Beyond first cluster.

TABLE B-6. Event Probability^(a)

Path Area Miles ²	Path Width Yards	Path Length Miles	Random Percent	Effective Path Length Miles ^(b)	Probability of Occurrence 10 ⁻⁷ /yr ^(c)
0.44	165	4.69	0.90	4.22	0.7
1.70	325	9.22	0.90	8.30	2.71
7.80	695	19.74	0.20	3.95	12.41
0.82	225	6.40	1.00	6.40	1.31
2.60	401	11.40	0.40	4.56	4.13
4.50	528	15.00	0.90	13.50	7.16
3.80	485	13.78	1.00	13.78	6.05

(a) For tornadoes from Jaech 200-yr simulation having sufficient path area for a path length of 3.75 mi or more, using a length/width ratio of 50, compute effective path length and event probability.

(b) Remaining length after striking first cluster, path length multiplied by random number.

(c) $\frac{\text{Path Area (mi}^2\text{)}}{100 \text{ mi}^2 \pi \times 200 \text{ yr}}$

TABLE B-7. Combined Probabilities

Tornado		Exposure Probability		Event Probability	Outage Probability
Path Area mi ²	Effectuated Length Miles	Units	P _E	PN 10 ⁻⁸	10 ⁻⁸
0.44	4.22	2	0.136	7.0 ↓	0.952
		2	0.045		0.315
		1	0.045		0.315
1.70	8.30	4	0.045	27.1 ↓	1.220
		4	0.045		1.220
		2	0.136		3.685
		2	0.045		1.220
		1	0.045		1.220
7.80	3.95	1	0.045	124.1	5.584
0.82	6.40	4	0.045	13.1 ↓	0.589
		2	0.136		1.782
		2	0.045		0.589
		1	0.045		0.589
2.60	4.56	2	0.136	41.3 ↓	5.617
		2	0.045		1.858
		1	0.045		1.858
4.50	13.5	2	0.136	71.6 ↓	9.737
		4	0.045		3.222
		2	0.045		3.222
		2	0.136		9.737
		2	0.045		3.222
		4	0.045		3.222
		4	0.045		3.222
		2	0.136		9.737
		2	0.045		3.222
		1	0.045		3.222
3.8	13.78	2	0.136	60.46 ↓	8.222
		4	0.045		2.721
		2	0.045		2.721
		2	0.136		8.222
		2	0.045		2.721
		4	0.045		2.721
		4	0.045		2.721
		2	0.136		8.222
		2	0.045		2.721
		1	0.045		2.721

TABLE B-8. Collection of Like Numbers of Units Affected, HNEC

$\times 10^{-8}$			
<u>1 Unit</u>	<u>2 Units</u>	<u>3 Units</u>	<u>4 Units</u>
0.315	0.952	0	1.220
1.220	0.315		1.220
5.584	3.685		0.589
0.589	1.220		3.222
1.850	1.782		3.222
3.222	0.589		3.222
<u>2.721</u>	5.617		2.721
15.509	1.858		2.721
	9.737		<u>2.721</u>
	3.222		20.858
	9.737		
	3.222		
	9.737		
	3.222		
	8.222		
	2.721		
	8.222		
	2.721		
	8.222		
	<u>2.721</u>		
	87.724		
(*5) Cumulative Probability:			
3.101	17.54		4.17
24.811	21.71		4.17

RADIOACTIVE RELEASE

1) Air Submersion Case - (Passing Cloud)

- a) Selection of Radionuclides - The radionuclides used were those selected for the reference report, Reference 2 of the text and Table VI 3-1 of that report. The tabulation is repeated below as Table B-9. The model used to convert these radioactive species into external body dose was SUBDOSA.^(4, Text) The results are given in the following table, Table B-10, where body dose is given as a function of time after release. Note that for the times shown, to 20,000 sec, the external body dose does not vary significantly.
- b) Dose Calculation - The external total-body dose for this accident in $\text{rem}/(\text{s}/\text{m}^3)$ was converted to a radiation dose in rem as a function of a probability by using data in Table 4, Reference 3 of the text. For example, for the first 1000 seconds following a release, the radiation dose factor is a constant; namely, $1.4 \times 10^{-8} \text{ rem}/(\text{s}/\text{m}^3)$. The associated normalized concentrations (χ/Q) that range from $1 \times 10^{-5} (\text{s}/\text{m}^3)$ to $1 \times 10^{-8} \text{ s}/\text{m}^3$ have varying conditional probabilities of involving three or more reactions as shown in Table 4, Reference 3. The radiation level inside a facility associated with a χ/Q of $1 \times 10^{-5} \text{ s}/\text{m}^3$ during the first 1000 seconds for example, is $1.4 \times 10^{-8} \text{ rem}/(\text{s}/\text{m}^3) \times 1 \times 10^{-5} \text{ sec}/\text{m}^3$ and including a shielding factor of 0.2 yields 280 rem. These conversions for several values of χ/Q for the first 1000 seconds are given in Table B-12, following. During the first 1000 seconds, units in only the same cluster as the accident would likely be affected. Thus, from Table B-12, the probability of personnel at three or more reactors receiving a radiation dose of at least 280 rem say in their control room is 1.00. From the same data, the probability of five or more having this radiation level is at least 0.25. Five or more assumes that the single cluster with five units was involved. Similar calculations can be for other concentrations in the air as a function of meteorology and distances, and are summarized in Table B-11.⁽⁵⁾

TABLE B-9. Initial Activity of Radionuclides in the Nuclear Reactor Core at the Time of the Hypothetical Accident (Reference 2)

No.	Radionuclide	Radioactive Inventory Source (curies x 10 ⁻⁸)	Half-Life (days)
1	Cobalt-58	0.0078	71.0
2	Cobalt-60	0.0029	1,920
3	Krypton-85	0.0056	3,950
4	Krypton-85m	0.24	0.183
5	Krypton-87	0.47	0.0528
6	Krypton-88	0.68	0.117
7	Rubidium-86	0.00026	18.7
8	Strontium-89	0.94	52.1
9	Strontium-90	0.037	11,030
10	Strontium-91	1.1	0.403
11	Yttrium-90	0.039	2.67
12	Yttrium-91	1.2	59.0
13	Zirconium-95	1.5	65.2
14	Zirconium-97	1.5	0.71
15	Niobium-95	1.5	35.0
16	Molybdenum-99	1.6	2.8
17	Technetium-99m	1.4	0.25
18	Ruthenium-103	1.1	39.5
19	Ruthenium-105	0.72	0.185
20	Ruthenium-106	0.25	366
21	Rhodium-105	0.49	1.50
22	Tellurium-127	0.059	0.391
23	Tellurium-127m	0.011	109
24	Tellurium-129	0.31	0.048
25	Tellurium-129m	0.053	0.340
26	Tellurium-131m	0.13	1.25
27	Tellurium-132	1.2	3.25
28	Antimony-127	0.061	3.88
29	Antimony-129	0.33	0.179
30	Iodine-131	0.85	8.05
31	Iodine-132	1.2	0.0958
32	Iodine-133	1.7	0.875
33	Iodine-134	1.9	0.0366
34	Iodine-135	1.5	0.280
35	Xenon-133	1.7	5.28
36	Xenon-135	0.34	0.384
37	Cesium-134	0.075	750
38	Cesium-136	0.030	13.0
39	Cesium-137	0.047	11,000
40	Barium-140	1.6	12.8
41	Lanthanum-140	1.6	1.67
42	Cerium-141	1.5	32.3
43	Cerium-143	1.3	1.38
44	Cerium-144	0.85	284
45	Praseodymium-143	1.3	13.7
46	Neodymium-147	0.60	11.1
47	Neptunium-239	16.4	2.35
48	Plutonium-238	0.00057	32,500
49	Plutonium-239	0.00021	8.9 x 10 ⁶
50	Plutonium-240	0.00021	2.4 x 10 ⁶
51	Plutonium-241	0.034	5,350
52	Americium-241	0.000017	1.5 x 10 ⁵
53	Curium-242	0.0050	163
54	Curium-244	0.00023	6,630

EXTERNAL TOTAL-BODY DOSE FROM RSS ACCIDENT PWR-2

The external total-body dose has been calculated for the release inventory of the Reactor Safety Study (WASH-1400) accident PWR-2. The calculated dose is normalized to a time-integrated air concentration of 1.0 sec/m^3 . The dose is presented as a function of time after release in the table below.

TABLE B-10. External Total-Body Dose for Accident PWR-2

<u>Time, Seconds</u>	<u>Total-Body Dose rem/(sec/m³)</u>
0	1.4×10^8
100	1.4×10^8
200	1.4×10^8
500	1.4×10^8
1,000	1.4×10^8
2,000	1.3×10^8
5,000	1.2×10^8
10,000	1.0×10^8
20,000	8.0×10^7

TABLE B-11. Conditional Probability that Personnel in at Least 3 or 4 or 5 Reactors Would Experience the Stated Radiation Doses from the Passing Cloud Following a Release from a Reactor Accident at an HNEC

Radiation Dose Assuming Shielding Factor of 0.2	Conditional Probabilities for Numbers of Reactors		
	3	4	5
280	1.000	.850	.250
130	1.000	.852	.256
60	1.000	.853	.268
28	1.000	.853	.290
13	1.000	.865	.313
6	1.000	.876	.369
2.8	1.000	.878	.397
1.3	1.000	.881	.409
0.6	1.000	.884	.417
0.28	1.000	.884	.421
0.13	1.000	.884	.427

2) Ground Contamination

- a) Selection of Radionuclides - The radionuclides used were also those selected in the reference study.⁽⁴⁾ This selection, important to external exposure from ground deposition, was based on the radioactive half-life and the type and the energy of the emitted radiation. For purposes of this study, the selected nuclides were divided into two groups according to half-life as shown in the following table, Table B-12. Section of the table lists the relatively long-lived species whose contribution to the radiation level is essentially constant over the time period of interest here; namely, 60 days. Section II contains the short-lived species whose contribution will decrease over the times of interest, some very rapidly.

TABLE B-12. Ground Level Summation

Section I

Long Term Isotopes Used for the Study Where $e^{-\lambda t} \approx 1$

<u>Species</u>	<u>Half-Life</u> <u>Days</u>	<u>Conversion Factor</u> $\times 10^9 \frac{\text{m rem}}{\text{hr}} / 1/\text{m}^2$	$\Sigma \times 10^9$ $\frac{\text{m rem}}{\text{hr}} / 1/\text{m}^2$
Cs ¹³⁷	1100	9.87	
Cs ¹³⁴	750	67.5	77.35
Ru ¹⁰⁶	366	0.75	78.10 x 10
Co ⁶⁰	1920	0.1	78.2
Co ⁵⁸	71	0.1	78.3

Section II

Shorter Term Isotopes at Time Zero

<u>Species</u>	<u>Half-Life</u> <u>Days</u>	<u>Conversion Factor</u> $\times 10^9 \frac{\text{m rem}}{\text{hr}} / 1/\text{m}^2$	$\Sigma \times 10^9$ $\frac{\text{m rem}}{\text{hr}} / 1/\text{m}^2$
Cs ¹³⁶	13	22.5	
I ¹³¹	8.05	166.6	189.1
Ru ¹⁰³	39.5	39.5	228.6
Zr ⁹⁷	0.71	3	231.6
Zr ⁹⁵	65	3	234.6
Hb ⁹⁵	35	3.1	237.7

- b) Dose Calculations - The External Dose Conversion Factor as shown in Column 3 was developed for each isotope used in this analysis as follows. DR is derived from the Conversion Factor as follows.

$$DR = DF \times D/Q \times S \times e^{-\lambda t}$$

where

DR = Dose Rate, m rem/hr

DF = Dose Factor, a value in m rem/hr/p Ci/m²

see

D/Q = Normalized surface concentration (1/m²) as a function of Hanford meteorology--Reference 3, Table 5

S = Source Term, given in p Ci for each isotope--Reference Table VI, 3-1 as modified by Table I, 5-1

$e^{-\lambda t}$ = Correction for radioactive decay.

The DR as a function of D/Q are given in Column 3 for time equal to zero, and summed in Column 4. The long-lived component is essentially constant and can be summed with the short-lived component at the times of interest. For these studies, the times are shown in the following table with the corresponding conversion dose. For example, at 120 days, the total conversion dose of 84 m rem/hr/m² consists of the long-lived component 78.3 m rem/hr/m² plus the short-lived component 5.91 m rem/hr/m².⁽⁵⁾

TABLE B-13. External Dose Conversion Factor vs. Time

	Days After Event						
	<u>0</u>	<u>7</u>	<u>14</u>	<u>30</u>	<u>45</u>	<u>60</u>	<u>120</u>
Conversion Dose $\frac{\text{m rem}}{\text{hr}}/\text{m}^2$	316	226	176	143	123	105	84

At the times shown, these Dose Conversion Factors, when related to the normalized concentrations, Table 5 (Reference 3 of the text) yield the radiation doses from ground contamination and the associated probability that a given number of reactors will be affected. These values modified by shielding factors resulting from the deposition is on uneven surfaces (Reference 2, Vol. VI, Tables 11-7, -8) and afforded by the building are given in the left column of Table B-14. This table depicts radiation levels inside a facility and the probability that three or four or five, etc. facilities may be involved. From this table, it can be seen that the probability that nine or more reactors have a radiation level of at least 2 m rem/hr(.002)/hr is 0.08. Similar tables were developed for 0, 7, 30, 45 and 60 days following a radionuclide release.⁽⁵⁾ These in turn were the basis for the development of the probability of loss of electrical energy in GWh from a release of radioactive material.⁽⁵⁾

TABLE B-14. Probabilities of 11 or More Reactors Having Different Radiation Levels
14 Days Following an Accident Assuming Preliminary Decontamination
Efforts Have Reduced Radiation Levels by a Factor of 10

Radiation Level rem/hr	Cluster 1			Cluster 2			Cluster 3			Cluster 4
	3	4	5	7	8	9	11	12	13	16-20
0.176	1.000	0.850	0.250							
0.08	1.000	0.852	0.257	0.001						
0.038	1.000	0.853	0.268	0.021	0.008	0.008				
0.018	1.000	0.853	0.290	0.046	0.028	0.016				
0.008	1.000	0.865	0.313	0.069	0.035	0.024	0.011	0.011	0.011	
0.004	1.000	0.876	0.369	0.126	0.088	0.044	0.030	0.016	0.016	
0.002	1.000	0.878	0.397	0.158	0.127	0.081	0.066	0.059	0.056	0.018
0.0008	1.000	0.881	0.409	0.172	0.138	0.098	0.085	0.079	0.073	0.023
0.0004	1.000	0.884	0.417	0.182	0.148	0.102	0.090	0.082	0.075	0.024
0.0002	1.000	0.884	0.421	0.188	0.155	0.108	0.095	0.086	0.078	0.025
	1.000	0.884	0.427	0.194	0.165	0.121	0.108	0.100	0.090	0.030

ASHFALL

The estimation of probabilities of ashfall at the plant sites was made without explicit information on the volume of ash discharged from volcanoes in historic events. A relative index of volume was used in the following way. A family of curves was prepared that conformed as closely as possible with observed deposition of ash in the Hanford vicinity from the three eruptions noted in the body of the report. It is assumed that an average deposition of less than about 2 in. in one event would not force shutdown or would be compatible with staggered outages one at a time for corrective action. Since the historical data are very sparse, the curves are based mainly on hypothetical relationships between the volume of ash expelled, the mean wind velocity off the coast and the distance of the nuclear plant site from the volcano.

The curves of Figure B-5 indicate that for a cluster having a distance from a volcano equal to or greater than that shown on one of the family of curves, a combination of x wind velocity and y relative volume of ash discharged would cause a shutdown if the corresponding point lies to the right of the curve, but would not do so if it lies to the left of the curve.

To assess the probability of forced outage:

- 1) A 30° sector centered at a volcanic peak was drawn on a map of the area with the centerline of the angle on one site (HNEC or DS). If more than one DS site is within the sector all are included in the effects of one eruption. (It is assumed that an ashfall at HNEC would have the same effect on all clusters).
- 2) The compass directions enclosed by the sector were noted, and from Figure B-6 the enclosed wind vectors and their corresponding mean wind speeds were recorded.
- 3) The distances between the volcano and the enclosed sites were measured.
- 4) From Figure B-5, the index of magnitude of ash released to the atmosphere required to force shutdown at the site under the wind and distance conditions was found, together with its probable occurrence frequency (from Figure 27 in the Ashfall section).

FOOTNOTES:

- (1) POINTS TO RIGHT OF CURVE PROBABLY CAUSE SHUTDOWN; POINTS TO LEFT OF CURVE INDICATE CONTINUOUS OPERATION OR STAGGERED SHUTDOWN IN WHICH NO MORE THAN ONE CLUSTER IS DOWN AT ANY ONE TIME.
- (2) ABOVE APPLIES TO DISTANCES EAST OF PEAKS; TO THE WEST, WITHIN 25 MILES, SHUTDOWN IS ASSUMED AT A RELEASE INDEX OF 3.0 AND GREATER.

FIGURE B-5. Threshold Conditions for Forced Outage from Ashfall

- 5) This procedure was carried out for each volcanic peak in succession. The probabilities of occurrence and exposure and the number of units affected were listed for each possible source and wind direction.
- 6) Probabilities for each set of x units were summed up, and cumulative probability curves constructed.

Tables B-15, B-16 and B-17 contain probability computations for Figure 28 in the section on Ashfall.

FIGURE B-6. Seasonal Migration of the Mean Wind Direction Off the Coasts of Washington and Oregon

TABLE B-15. Probability of Outage from Ashfall, HNEC

Source	Site	Distance, Miles	Angle/Degrees		Month	Wind Velocity, Knots	Index of Ash Volume	Position Probability	Occurrence Probability x 10 ⁻⁴	Outage Probability x 10 ⁻⁴	Number of Generating Units
Baker	Hanford	194	138	168	July	11	3.25	1		2.0	20
					June	4	-	-		-	-
Rainier	Hanford	112	98	128	March	7	3.5	1		1.7	20
					September	6	4.0	1		1.3	20
					April	8	3.1	1		2.1	20
St. Helens	Hanford	132	76	106	April	7	3.0	1		2.2	20
Adams	Hanford	94	69	99	April	7	2.8	1		2.5	20
Hood	Hanford	129	48	78	March	14	1.95	1		3.9	20
					April	7	3.80	1		1.45	20
Mazama	Hanford	272	27	57	February	18	2.40	1		3.1	20
					November	19	2.2	1		3.4	20
Shasta	Hanford	370	11	41	December	20	2.95	1		2.3	20
					February	18	3.3	1		1.9	20
Lassen	Hanford	419	11	41	December	12	-				
					February	17	3.6	1		1.6	20
					November	13	-				
										29.45	20
Divide by (8 peaks x 12 months = 96) =										0.307	20

TABLE B-16. Probability of Outage from Ashfall, DS Case

Source	Site	Distance, Miles	Angle/Degrees		Month	Wind Velocity, Knots	Index of Ash Volume	ϕ Position (a) Probability	Occurrence Probability $\times 10^{-4}$	Outage Probability $\times 10^{-4}$	Number of Generating Units
			To	From							
Baker	Hanford	194	138	168	July	11	2.5	1	2.9	2.9	6
		228	138	168	-						
		194	138	168	June	4	-				
		228	138	168	June	4	-				
	Pebble Springs	228	151	181	-						
	Portland	177	188	218	-						
	WV-1	282	188	218	-						
	WV-2	337	188	218	-						
Rainier	Hanford	112	98	128	March	7	3.5	0.5	1.7	0.85	6
	Pebble Springs	116	128	158	March	7	3.5	0.5	1.7	0.85	4
	Pebble Springs				September	6	4.0	1		1.3	4
	Portland	61	220	250	-						
	WV-1	163	200	230	-						
	WV-2	214	200	230	-						
St. Helens	Hanford	136	76	106	April	7	3.9	1		1.4	6
	Pebble Springs	112	100	130	March	7	3.5	1		1.7	4
	Portland	24	180	210	-						
	WV-1	109	200	230	-						
	WV-2	160	200	230	-						
Adams	Hanford	94	69	99	April	7	3.0	1		2.2	6
	Pebble Springs	75	108	138	March	7	3.3	1		1.9	4
	Pebble Springs	75	108	138	September	6	3.8	1		1.5	4
	Portland	61	272	302	-						
	WV-1	129	213	243	-						
	WV-2	180	213	243	-						
Hood	Hanford	129	48	78	March	14	1.95	1		3.9	4
	Hanford		48	78	April	7	3.8	0.33	1.45	0.48	4
	Pebble Springs	81	73	103	April	7	3.0	0.33	2.2	0.73	4
	PS + H	129	63	93	April	7	3.8	0.33	1.45	0.48	10
Mazama	H + PS	272	27	57	February	18	2.4	1.0	3.1	3.1	10
	Pebble Springs	215	27	57	November	19	1.8	1.0	4.2	4.2	4
	Portland	228	350	20	January	9	-	0.33	-	-	
	Portland				December	20	1.8	1.0	1.8	1.8	4
	WV-1	133	333	3	January	9	3.3	0.33	1.9	0.63	3
	WV-2	94	310	340	-		-				
	WV-1 + WV-2	133	320	350	January	9	3.3	0.33	1.9	0.63	6

TABLE B-16. (contd)

Source	Site	Distance, Miles	Angle/Degrees		Month	Wind Velocity, Knots	Index of Ash Volume	ϕ Position(a) Probability	Occurrence Probability $\times 10^{-4}$	Outage Probability $\times 10^{-4}$	Number of Generating Units
			To	From							
Shasta	Pebble Springs	313	18	48	February	18	2.7	1		2.65	4
	H + DS	370	18	48	February	18	3.3	1		1.9	10
	Pebble Springs	313	18	48	November	19	2.5	1		2.7	4
	H + DS	370	18	48	November		3.1	1		2.1	10
	WV-1	230	355	25	December	20	1.7	0.5	4.5	2.25	3
	Po. + WV-1	328	355	25	December		2.4	0.5	3.1	1.55	7
	WV-1	230	355	25	February	18	2.3	1		3.25	3
	Po. + WV-1	328	355	25	February		2.75	1		2.5	7
Shasta	WV-2	182	337	7	January	9	4.0	0.5	1.3	0.65	3
	WV-1 + WV-2	230	337	7	January		-				
	WV-2	182	345	15	January		3.8	0.5	1.45	0.73	3
	WV-1 + 2	230	345	15	January		-				
	Po. WV 1 & 2	328	345	15	January		-				
	WV-2	182	345	15	December	20	1.5	0.5	5.0	2.5	3
	WV-1 + 2	230	345	15	December		1.8	0.5	4.2	2.1	6
	Po. + WV-1 & 2	328	345	15	December		2.5	0.5	2.7	1.35	10
Lassen	Pebble Springs	360	11	41	February	17	3.2	1	2.0	2.0	4
	H + PS	419	11	41	February	17	3.7	1	1.55	1.55	10
	WV-2	251	15	45	December	12	3.8	1	1.45	1.45	3
	WV-1 + 2	345	15	45	December	12	4.0	1	1.3	1.3	6

(all others too distant)

(a) Probability of angular orientation occurring within one month.

TABLE B-17. Sum of Probabilities for n Units Affected,
DS Case, Probabilities, 10^{-4}

Generating Units	<u>3</u>	<u>4</u>	<u>6</u>	<u>7</u>	<u>10</u>
	0.63	0.85	2.90	2.55	0.48
	2.25	1.30	0.85	2.50	3.10
	3.25	1.70	1.40		1.90
	0.65	1.90	2.20		2.10
	0.73	1.50	0.63		1.55
	2.50	3.90	2.10		1.35
	1.45	0.48	1.30		
		4.20			
		1.80			
		2.65			
		2.70			
		2.00			
		<u>0.73</u>			
	<u>11.46</u>	<u>25.71</u>	<u>11.38</u>	<u>4.05</u>	<u>10.48</u>
Divide by $8 \times 12 = 96$	0.119	0.268	0.118	0.042	0.109
Cumulative	0.656	0.537	0.269	0.151	0.109

APPENDIX C

EXAMPLES OF PACIFIC NORTHWEST SYSTEM RESPONSE
TO HNEC AND DS OUTAGES

APPENDIX C

EXAMPLES OF PACIFIC NORTHWEST SYSTEM RESPONSE TO HNEC AND DS OUTAGES

This appendix contains descriptions of example "games" taken from computer runs of the Energy Reserve Planning Model. The "games" are intended to explain why the system visualized for the period of interest could sometimes provide reserve energy for the maximum postulated HNEC outage without any load being dropped, while at other times with a DS outage of much lesser magnitude would be unable to supply all loads.

Examples 1 and 2 are for 30,000 GWh outages at HNEC that result in large energy deficits (load dropping); examples 3 and 4 are for 30,000 GWh outages at HNEC that are absorbed without any effect on loads; and examples 5 and 6 are for 6,000 GWh outages at DS that result in dropping of some load.

EXAMPLE 1 - HNEC, 7161 AVERAGE MW DEFICIT PER (OVER FOUR MONTHS)

Period 1, September to December:

	<u>Generation (Deficits) MW, Average</u>
Run of river	5,638
Draft	<u>5,393</u>
Hydro total	11,031
Thermal	<u>24,433</u>
Total generation	35,464
Load	<u>42,625</u>
Deficit	(7,161)

Comment

This event took place during the early drawdown period, September through December. The natural river flow during that period was low, providing only 5638 average MW over the 4-month period. Storage was drafted to provide 5393 average MW, including 313 average MW of provisional energy (energy borrowed

from the following period reserves with agreement of participants). This is the maximum allowable. The thermal energy production with the HNEC out for two months was 24,433 average MW, whereas without the outage it would have been about 33,000 MW. The total thermal and hydro energy production fell 7161 MW below the load. The combination of the low natural river flow in this particular year, and the HNEC outage, resulted in the energy deficit.

EXAMPLE 2 - HNEC, 7518 AVERAGE MW DEFICIT

Period 3, May to August:

	Generation (Deficits) MW, Average
Run of river	17,134
Draft	(5,140) (Refill Reservoirs)
Hydro total	11,994
Thermal	18,638
Total generation	30,632
Load	38,150
Deficit	(7,518)

Comment

This event took place in May through August, the refill and hold period. The natural river flow was moderately high, but the draft of stored water in the previous period had been large and it was necessary to refill reservoir in this period to fulfill Coordination Agreement requirements. The maximum provisional energy (313 MW) was taken, however, to support the loads to the maximum allowable extent. The thermal generation in this period was reduced even below the amount caused by the HNEC outage, indicating that some of the other thermal capacity on the system was also down during the period on planned or unplanned outages. The load loss was due, therefore, to a combination of low stored water at the start of the period, and other thermal generation having outages in the same period, possibly for refueling since this activity is concentrated in this period.

EXAMPLE 3 - HNEC, 6533 AVERAGE MW SURPLUS

Period 3, May to August:

	<u>Generation (Refill Reservoirs) MW, Average</u>
Run of river	33,314
Draft	<u>(8,000)</u>
Hydro total	25,314
Thermal	<u>19,369</u>
Total generation	44,683
Load	<u>38,150</u>
Surplus	6,533

Comment

This event took place in May to August, the refill and hold period. The natural flow was very large during this period in this year. No drafting was required, reservoirs could be refilled to replace a substantial draft in the preceding period. The thermal generation was somewhat lower than would be due to HNEC alone, indicating some other thermal plant outages. The loads in this period were less than in winter months, the generation requirements (load) being only 38,150 MW as compared to 42,625 and 45,600 in other periods. The combination of low load and high river flow placed a very low requirement on the thermal system in this case. Even with the HNEC outage there is a surplus of 6533 average MW.

EXAMPLE 4 - HNEC, 1300 AVERAGE MW SURPLUS

Period 2, January to April

	<u>Generation MW, Average</u>
Run of river	12,981
Draft	<u>10,874</u>
Hydro total	23,855
Thermal	<u>23,045</u>
Total generation	46,900
Load	<u>45,600</u>
Surplus	1,300

Comment

This event occurred in January to April, the late drawdown period. The natural river flow was average, providing 12,891 MW over the period. A relatively large draft of reservoirs could be made, generating 10,874 average MW. Thermal generation with the HNEC outage was 23,045 MW. Loads were relatively high in this period 45,600. The result was a surplus of 1300 average MW. The relatively high loads of the early winter season were met in this case, even with the HNEC outage, through a combination of heavy use of available stored water, a moderate river flow, and most other thermal capacity being on line.

EXAMPLE 5 - DS CASE, 1842 MW DEFICIT

Period 1, September to December:

	Generation (Deficit) MW, Average
Run of river	8,188
Draft	<u>3,875</u>
Hydro total	12,063
Thermal	<u>28,720</u>
Total generation	40,783
Load	<u>42,625</u>
Deficit	(1,842)

Comment

The thermal generation in the period indicates that at least one DS cluster was down, and possibly other system thermal units with planned or unplanned outages. The run of river flow was relatively low. With provisional energy the total draft was only 3875 average MW. The combination of low thermal generation, moderately low run of river hydro capability, and limited draft in a period of substantial load resulted in a deficit of 1843 average MW in the period.

EXAMPLE 6 - DS CASE, 1098 MW DEFICIT

Period 1, September to December:

	Generation (Deficit) MW, Average
Run of river flow	7,327
Draft	<u>2,120</u>
Hydro total	9,447
Thermal	<u>32,078</u>
Total generation	41,527
Load	<u>42,625</u>
Deficit	(1,098)

Comment

In the period previous to this one in the simulation, the maximum provisional draft had been taken, and in this period the equivalent to 872 average MW was returned to storage (not shown above). The run of river flow was relatively low. With the negative provisional energy restriction, the draft could be only 2120 MW. Not more than one DS cluster could have been down, but the relatively low run of river flow, together with the low net draft energy, could not meet the early winter loads. This period had followed a period in which thermal generation had been very low and the reservoirs had been drafted to the limit.

RATIONALE FOR ADJUSTMENT OF NUMBERS OF DEFICIT PERIODS IN DS CASE, TABLE 15

In the simulation of the DS case, each of the five clusters had approximately 2500 situations in which extended outages caused by the rare events analyzed in this report occurred. These 12,500 situations (5 x 2500) took place in a total of 24,000 four-month periods covering the entire span of the study. With 12,500 situations occurring at random in 24,000 periods more than one precipitating rare event occurred in a number of periods. A sampling of games indicated that two events occurred in the same four-month period on 6.6% of the periods; and three events in a four-month period occurred in 0.33% of the periods.

Although the DS case does have potential outages that involve more than one cluster, the actual probability of such occurrences is less than the 6.6 and 0.83 percentages that were experienced in the computer run through random distribution of the events. If analyses of the contributions from the DS case is to be limited to 6000 GWh outages, the effects of the multiple cluster outages (>6000 GWh) should be removed.

This was accomplished by removing about 7% of the greatest DS deficits from the DS column of number of deficits in Table 14. Perhaps not all of the greatest deficits were caused by these multiple-cluster outages, but it is judged that most of them were. The adjustment described above gives an adequate approximation to a DS case, limited to single-cluster events, as a reference base for HNEC comparisons.

Calculations from Table 15

In Table 15, some of the items in the Load Loss column were not caused by simulated HNEC outages. A count of the HNEC outage events from the computer runs gave 2497 events in 24,000 periods, or 10.4 percent. Applied to the 6000 trials, the number of events is shown to be 624. The following amounts are added:

- 1) 35 events in which the deficits were in the 8000 to 10,000 MW range,
- 2) 154 events in which the deficits were in the 5000 to 8000 MW range, and
- 3) 120 events, by which the number of HNEC deficits exceeded that of DS, in the 2000 to 5000 MW range,

for a total of 309 events, and subtracted from the 624 total number. The result is 315 events in which the effect of HNEC on user energy shortage was no greater than that of DS.

Calculation of User Energy Shortage Probabilities

The data for construction of Figure 30 were computed in the following manner:

- From the computer runs for a 30,000 GWh loss at HNEC, and a 6000 GWh loss at DS, curves were drawn with the abscissa being the ratio of energy shortage to generation loss, and the ordinate being incremental probability

of occurrence. Thus two bounding curves were available, with interpolations between them being possible for intermediate values of generation loss between 30,000 and 6000 GWh.

- A 20,000 GWh curve was developed from the above data, and from that curve incremental probabilities were obtained for steps from 0.2 to 1.0 in the ratio of energy shortage to generation loss. From Figure 28 a point was selected on the 20,000 GWh curve, for example, at 0.8 on the abscissa, having a probability of 0.14. This point would correspond to a $0.8 \times 20,000 = 16,000$ GWh user energy shortage. From the curve of Figure 28 the incremental probability of an energy shortage of the 20,000 GWh is 1.68×10^{-3} . The probability of a 16,000 GWh user shortage on the 20,000 GWh curve is $0.14 \times 1.68 \times 10^{-3} = 2.4 \times 10^{-4}$. Other points on the 20,000 GWh can be obtained in the same manner. The corresponding cumulative probability value for this point is 3.07×10^{-4} .
- A similar procedure is followed for curves of 15,000, 10,000 etc. GWh and plotted on the curve of energy shortage versus cumulative probability.
- The several curves form an envelope that defines the area of probable risk difference of Figure 30.

TABLE C-1. Data for Figure 30, Comparison
of Risk of Energy Shortage

HNEC							
Gen. Loss, GWh	Cum. (P ₁) (a) Figure 28	Increment P ₁	Ratio Gen. Loss Shortage	Shtg., GWh	Inc. (P ₂) (b)	Increment (P ₃) (c)	Cum. (P ₃)
a	b	c	d	e	f	(c x f)	g
20,000	1.68×10^{-3}	1.68×10^{-3}	0.1	2,000	0.35	5.88×10^{-4}	17.78×10^{-4}
			0.3	6,000	0.23	3.86	11.90
			0.5	10,000	0.20	3.36	8.04
			0.7	14,000	0.18	3.00	4.68
			0.9	18,000	0.10	1.68	1.68
			1.0	20,000	0.04	0.67	0.67
13,000	1.68×10^{-3}	1.68×10^{-3}	0.1	1,300	0.44	7.39	25.70
			0.3	3,900	0.36	6.04	18.31
			0.5	6,500	0.31	5.21	12.21
			0.7	9,100	0.27	4.54	7.06
			0.9	11,700	0.15	2.52	2.52
			1.0	13,000	0.08	1.34	1.34
6,000	2.1×10^{-3}	1.68×10^{-3}	0.1	600	0.53	8.90	35.60
			0.3	1,800	0.48	8.06	24.70
			0.5	3,000	0.42	7.06	16.64
			0.7	4,200	0.35	5.88	9.58
			0.9	5,400	0.22	3.70	3.70
			1.0	6,000	0.12	2.02	2.02
700		DS 11.23×10^{-3}	0.5	350	0.62	6.96×10^{-3}	9.65
			1.0	700	0.24	2.69	2.69
1,051		5.50	0.5	525	0.61	3.35	4.50
			1.0	1,051	0.21	1.15	1.15
1,752		0.011	0.5	876	0.57	0.0063	0.0082
			1.0	1,752	0.17	0.0019	0.0019

(a) P₁ - Probability of generation outage.

(b) P₂ - Probability of ratio, energy shortage to generation outage.

(c) P₃ - Probability of energy shortage.

METEOROLOGICAL EVALUATION OF MULTIPLE
REACTOR CONTAMINATION PROBABILITIES
FOR A HANFORD NUCLEAR ENERGY CENTER

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METEOROLOGICAL EVALUATION
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INTRODUCTION

One alternative in the siting of power plants is the energy center, where 10 to 40 power plants are located at a common site. Within the energy center the individual generating units are generally grouped in clusters of about 4. The Pacific Northwest Laboratory has been studying the application of this concept to the Department of Energy's Hanford area for several years⁽¹⁻³⁾. The conceptual Hanford energy center is composed of nuclear power plants, hence the name Hanford Nuclear Energy Center (HNEC). Previous topical reports have covered a variety of subjects related to the HNEC including: electric power transmission⁽⁴⁾, fuel cycle⁽⁵⁾, and heat disposal⁽⁶⁻⁸⁾. This report discusses the probability that a radiation release from a single reactor in the HNEC would contaminate other facilities in the center. The risks, in terms of reliability of generation, of this potential contamination are examined by Clark and Dowis⁽⁹⁾.

The grouping of power generating facilities increases the possibility that several, or all, of the facilities might be disabled by a single event. If the energy center contains a nuclear power plant, a reactor accident could lead to the shutdown of other units. Significant reactor accidents are highly improbable, but could result from the successive failure of reactor safety features. These are discussed in References (10) and (11)*. Significant releases of radioactivity could also occur from a nuclear fuels reprocessing plant, however releases from reprocessing plants have not been considered in this analysis.

*Appendix A contains a description of the various classes of reactor accidents, and Appendix B describes reactor accidents involving reactor cores.

To evaluate the risks associated with multiple reactor contamination following a release of radioactivity, it is necessary to estimate the probability that more than 1 reactor or cluster will be contaminated at some level as well as estimate the probability of an accident at a single reactor. Reference (11) and Appendix B provide information needed to estimate the probability of an accident in a single reactor. This report concentrates on the estimation of the probability of multiple reactor contamination assuming that a release will occur.

The following section presents an outline of the theoretical problem and its solution. It is followed by a description of the Hanford Nuclear Energy Center and its climatology. The results of the study are then presented and sensitivity of the results to changes in variables is explored. Finally conclusions drawn from the work are summarized.

THEORETICAL DEVELOPMENT

In case of a reactor accident involving a significant release of activity in an energy center, the multiple reactor contamination problem resolves into two types of questions. The first deals with determination of the number of reactors directly downwind of the accident, and the second deals with the concentration of material in the plume or deposited on exposed surfaces in the vicinity of each reactor downwind of the accident. Once the locations of reactors in an energy center are specified, the number of reactors directly downwind of an accident is determined by the location of the accident, the wind direction, and the plume width. The contamination at each reactor in the plume is determined by its distance from the accident, the amount of material released and variables that control the diffusion and deposition of atmospheric contaminants, such as wind speed, stability and mixing depth. Thus, the probability

needed in risk assessment must be specified in terms of number of power plants and level of contamination. In this section, a general method will be developed for making estimates of this bivariate probability.

Basic Assumptions

As estimating the required probability depends on numerous assumptions, the validity of the estimates are no better than the underlying assumptions. Therefore, basic assumptions made in the development of the general method of solution are stated explicitly here.

It is postulated that significant accidents are equally probable in all nuclear power plants in an energy center, and further that the probability of two accidents occurring simultaneously is negligible. This leads directly to the assumption that the probability of a significant accident in a nuclear energy center is:

$$P_A = N_t P(1) \quad (1)$$

where P_A is the probability of an accident in the center, $P(1)$ is the probability of an accident in any given reactor and N_t is the total number of reactors. Determination of $P(1)$ is the province of reactor design and safety engineers, therefore $P(1)$ will be assumed to be known. The probability $P(M,I)$ of M power plants being contaminated at a level I is given by

$$P(M,I) = P(M,I|A)P_A \quad (2)$$

where $P(M,I|A)$ is a conditional probability assuming that an accident will occur. This conditional probability is a function of energy center geometry and climate.

Theoretically, the conditional probability can be determined by considering all permutations and combinations of individual reactors, discarding those which cannot occur for geometric reasons, and weighting the possible combinations by the frequency of occurrence of wind direction, wind speed and atmospheric stability. However, as the N_t increases, this procedure rapidly becomes impractical because the number of permutations which must be evaluated is proportional to $N_t!$. To reduce the number of combinations, it has been assumed that the power plants in a cluster may be treated together; if one reactor in a cluster is contaminated following an accident, all are. The conditional probability that an accident will occur in a given cluster, $P_{S|A}$, is

$$P_{S|A} = \frac{n_s}{N_t} \quad (3)$$

where n_s is the number of reactors in the cluster, again assuming that an accident will occur in the energy center.

Development

If an accident occurs in a given reactor in an energy center under known atmospheric conditions, standard diffusion models can be used to determine the number of downwind clusters, and to estimate the concentration of radioactive materials in the air and deposited on the surface at each cluster. As the distance from the release point increases the number of clusters potentially involved will increase, but the concentration in the plume and on the surface will decrease. Thus, to define the number of reactors significantly affected following an accidental release it is necessary to first define a minimum significant contamination level.

The atmospheric diffusion of non-depositing materials has been studied extensively, and currently accepted models are described in standard reference works^(12,13). A general sector-average model has been developed for diffusion computations with respect to the HNEC⁽⁸⁾. This model is:

$$\begin{aligned}
 (\bar{X}/\dot{Q}) = & \frac{\hat{n}}{(2\pi)^{3/2} \sigma_z \bar{u} x} \sum_{j=-\infty}^{\infty} \left\{ \exp \left[\frac{(z-h+2jH)^2}{-2\sigma_z^2} \right] \right. \\
 & \left. + \exp \left[\frac{(z+h+2jH)^2}{-2\sigma_z^2} \right] \right\} \quad (4)
 \end{aligned}$$

where:

$(\bar{X}/\dot{Q})$ is the average air concentration at a distance x from the source and a height z above ground divided by the release rate $\dot{Q}$.

$\hat{n}$ is related to the assumed plume width, ϕ_0 , by $\hat{n} = \pi/\phi_0$ when ϕ_0 is in radians.

σ_z is a vertical diffusion parameter related to atmospheric stability.

$\bar{u}$ is the wind speed.

h is the effective release height, and

H is the height of the mixed layer.

In the present context both z and h can be assumed to be zero, and Equation (4) simplifies to:

$$\left(\frac{\bar{X}}{\dot{Q}} \right) = \frac{2\hat{n}}{(2\pi)^{3/2} \sigma_z \bar{u} x} \left[1 + 2 \sum_{j=1}^{\infty} \exp \left(\frac{-2j^2 H^2}{\sigma_z^2} \right) \right] \quad (5)$$

And, as a practical matter the infinite sum can be truncated after $j=2$ without significant effect.

As the material released during an accident is carried downwind, it will deposit on surfaces. Since the deposited material is no longer in the plume, air concentrations should be reduced from the values computed using Equation (5). Van der Hoven⁽¹⁴⁾ describes the correction that is usually made. In that correction, the source term becomes a function of distance, and is reduced as distance increases,

$$\dot{Q}(x) = \dot{Q}_0 \exp \left\{ -\frac{2}{\sqrt{2\pi} \bar{u}} \int_0^x \frac{V_d}{\sigma_z} d\xi \right\} \quad (6)$$

$\dot{Q}(x)$ is the depleted source term, $\dot{Q}_0$ is the initial source term, and V_d is the ratio between the flux of material to the surface and the air concentration near the surface. This correction, in effect, depletes material from the whole plume. A more realistic correction model⁽¹⁵⁾ depletes the material at the surface and diffuses a concentration deficit vertically. The two corrections have been compared by Horst⁽¹⁵⁾. On the basis of this comparison, the source depletion model was determined to be adequate for the current study.

Incorporating the deposition correction, the air concentration at the surface for a depositing material is given by:

$$(\bar{x}/\dot{Q}_0) = \left(\frac{\bar{x}}{\dot{Q}(x)} \right) \exp \left\{ \frac{-2}{\sqrt{2\pi} \bar{u}} \int_{x_1}^{x_2} \frac{V_d}{\sigma_z} d\xi \right\} \quad (7)$$

where x_1 is the distance from the virtual to real source and x_2 is the distance from the virtual source to the receptor. By definition the amount of material deposited is:

$$\left(\frac{\omega}{Q_0}\right) = v_d \left(\frac{\bar{x}}{\dot{Q}_0}\right) \quad (8)$$

where ω is the surface concentration in gm^{-2} and $Q_0 = \dot{Q}_0 T$. T is the duration of plume passage (assumed to be equal to the release duration).

Contamination following an accident is now defined by Equations (7) and (8). Clearly there are two conditional probabilities of interest, one with contamination defined in terms of $(\bar{x}/\dot{Q}_0)$ and the other defined in terms of (ω/Q_0) . The first will be denoted by $P_1(M, I|A)$ and the second by $P_2(M, J|A)$.

Since $(\bar{x}/\dot{Q}_0)$ and (ω/Q_0) are continuous variables it is necessary to establish ranges of involvement before the conditional probabilities are defined. If, for $(\bar{x}/\dot{Q}_0)$ the range limits are denoted by a_i , $i \geq 1$, and for (ω/Q_0) they are denoted by b_j , $j \geq 1$, then we let

$$I=i \text{ for } a_i \leq \left(\frac{\bar{x}}{\dot{Q}_0}\right) < a_{i+1} \quad (9a)$$

and

$$J=j \text{ for } b_j \leq \left(\frac{\omega}{Q_0}\right) < b_{j+1} \quad (9b)$$

The number of power plants involved is equal to the total number of power plants in the source cluster and in downwind receptor clusters with I and/or J greater than some predetermined value.

If there are several clusters downwind of a release there will be several pairs of M and I or J for which probabilities can be estimated. The first pairs will be $M=M_0=n_s$, where n_s is again the number of reactors in the source cluster, and $I, J = \text{maximum values}$. In the second, $M=M_1=n_s+n_1$ where n_1 is

number of power plants in the closest receptor cluster. This value of M will be paired with values of I and J determined for the receptor cluster. If there is a second receptor cluster, a third set of pairs will have $M=n_s+n_1+n_2$, and I and J determined for the second receptor cluster. The existence of m_2 implies the existence of m_1 and m_0 where $m_2 > m_1 > m_0$. It also implies the existence of higher degrees of contamination for m_1 and m_0 .

Given a source cluster, wind direction, wind speed, atmospheric stability and receptor cluster locations, values for M , I and J can now be computed. Computation of conditional probabilities associated with the given conditions requires the frequency of occurrence of the given meteorological conditions. Denoting that frequency by $f(\theta, u, st)$, where θ represents wind direction, u represents wind speed and st represents atmospheric stability, the conditional probability for each pair of values is given by the product

$$P_{s|A} f(\theta, u, st)$$

For the energy center the conditional probabilities are estimated by summing over all sources and atmospheric conditions. Thus,

$$P_1(M, I|A) = \sum_s \sum_{\theta} \sum_u \sum_{st} P_{s|A} f(\theta, u, st) \quad (10a)$$

and

$$P_2(M, J|A) = \sum_s \sum_{\theta} \sum_u \sum_{st} P_{s|A} f(\theta, u, st) \quad (10b)$$

where M , I and J are determined as before. Equations (10a) and (10b) are not the final forms on which the HNEC analysis was based. Rather the analysis was based on the cumulative

probabilities that at least k power plants would be contaminated at level ℓ or greater. These cumulative probabilities result from the summations

$$P_1^* (M, I | A) = \sum_{M=k}^{N_t} \sum_{I=\ell}^{\ell_{\max}} P_1 (M, I | A) \quad (11a)$$

$$P_2^* (M, J | A) = \sum_{M=k}^{N_t} \sum_{J=\ell}^{\ell_{\max}} P_2 (M, J | A) \quad (11b)$$

The astrisks are used to indicate the double summation where these conditional probabilities are discussed in the remainder of the report.

THE HANFORD NUCLEAR ENERGY CENTER

During the HNEC conceptual studies numerous sites have been considered as potential cluster locations. Figure 1 shows the boundaries of the Hanford area and 14 of the locations considered. Analysis of the HNEC concept is currently concentrating on a 20 power plant center with clusters located at sites 1 through 5. In this report, HNEC specifically refers to power plant clusters at these locations. Table 1 gives the make-up of each cluster and its position in the computational grid.

In the computational scheme, the reactors within a cluster are treated as a single entity; no effort has been made to examine intra-cluster variations. When a cluster is assumed to contain the reactor that is the release source, the cluster is represented by a structure located at the cluster position which has dimensions typical of power reactors. The horizontal dimension assumed is 100 m, and the vertical is 61 m. When a cluster is considered as a potential receptor following release in another cluster, it is represented simply by a point.

FIGURE 1. Potential HNEC Cluster Locations.

TABLE 1. Make-Up and Position of the HNEC Reactor Clusters

Cluster	Number of Reactors	Grid Position	
		N-S	E-W
1	5	6.10	7.50
2	4	5.50	7.20
3	4	4.70	6.70
4	3	3.70	5.40
5	4	3.70	4.90

The source-receptor geometry is shown in Figure 2. The source cluster is located at point A with its horizontal dimension perpendicular to the wind direction. The sensitivity of results to variations in model parameters, including source width, will be examined in a later section. The receptor cluster is located at point C. Because the diffusion model used (Equation 5) is for point sources and the actual source is assumed to have a finite width, it is necessary to determine a virtual point source, B. Points A and C are determined when the physical configuration of the energy center is established, but point B must be determined relative to A from the source width, the wind direction and the angular width of the plume. Determination of whether or not a particular receptor is in a particular plume is described in Reference 8.

In addition to characterizing the HNEC by its physical dimensions, it is necessary to characterize it climatologically. The basic reference on Hanford Climatology is Climatography of the Hanford Area⁽¹⁶⁾. Additional information relative to the conceptual HNEC is given in Reference 8. In general, the climate is typical of a mid-latitude desert-steppe. The prevailing wind directions are northwest and southwest, with

FIGURE 2. Plume Source and Receptor Geometry.

speeds averaging between 2 and 3 ms^{-1} . However, despite the relatively low averages, there are occasional periods with high speeds.

Atmospheric diffusion is related to wind and atmospheric stability as shown in Equations (4) and (5). A joint frequency distribution of wind direction, wind speed and atmospheric stability is required for diffusion computations involving specific sources and receptors. Table 2 gives this distribution for Hanford. The relationship between Hanford atmospheric stability classes and the more familiar Pasquill-Gifford classes is given in Table 3. This table also gives the specific relationships used to compute σ_z as a function of stability and distance from the source. These relationships were developed by Briggs⁽¹⁷⁾.

Examination of the models described in the previous section shows that several additional meteorological parameters must be specified. These are: the plume width, the height of the mixing layer, and the deposition velocity for depositing material.

Selection of the angular width for the sector-average plume model is governed by the form of available wind direction information and the assumed duration of releases of interest. The compilation of the joint frequency wind data in Table 2, strongly suggests that a minimum sector width of 22.5 be used. This choice is further recommended when the requirements of various Regulatory Guides issued by the Nuclear Regulatory Commission are considered^(18,19).

The mixing height tends to vary both daily and seasonally. The greatest mixing heights are generally found on the summer afternoons and the lowest on winter nights. However, for computational purposes a constant value of 1500 m has been assumed for this study. This value is probably low for summer and high for winter.

TABLE 2. Joint Probability of Wind Direction, Wind Speed and Atmospheric Stability at 200' for Hanford

		NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	N	VAR.	CALM	TOTAL
0 - 3	VS	0.06	0.06	0.04	0.06	0.06	0.12	0.07	0.07	0.06	0.05	0.06	0.10	0.08	0.10	0.11	0.09	0.08	0.09	1.37
	MS	0.29	0.30	0.24	0.29	0.40	0.55	0.32	0.29	0.23	0.26	0.25	0.44	0.41	0.56	0.48	0.49	0.25	0.66	6.71
	N	0.44	0.57	0.42	0.49	0.56	0.56	0.26	0.26	0.18	0.20	0.16	0.28	0.31	0.50	0.61	0.63	0.31	0.69	7.43
	U	0.37	0.44	0.25	0.30	0.25	0.26	0.13	0.11	0.08	0.10	0.08	0.10	0.09	0.19	0.22	0.38	0.30	0.06	3.71
4 - 7	VS	0.04	0.04	0.03	0.03	0.04	0.09	0.09	0.09	0.07	0.10	0.15	0.24	0.23	0.22	0.17	0.09	0.01	0.	1.75
	MS	0.28	0.21	0.18	0.21	0.30	0.50	0.34	0.32	0.29	0.39	0.52	1.02	1.21	1.35	0.94	0.54	0.03	0.	8.62
	N	0.35	0.38	0.27	0.32	0.36	0.47	0.27	0.26	0.22	0.31	0.29	0.39	0.56	1.04	0.72	0.56	0.08	0.	6.86
	U	0.77	0.71	0.44	0.46	0.44	0.52	0.29	0.33	0.33	0.36	0.26	0.28	0.33	0.75	0.78	0.86	0.23	0.	8.13
8 - 12	VS	0.01	0.00	0.00	0.00	0.00	0.03	0.06	0.03	0.02	0.05	0.12	0.26	0.34	0.59	0.20	0.02	0.	0.	1.74
	MS	0.17	0.15	0.09	0.10	0.13	0.27	0.29	0.17	0.20	0.40	0.86	1.71	2.85	2.52	0.73	0.27	0.00	0.	10.94
	N	0.21	0.12	0.07	0.07	0.09	0.13	0.13	0.13	0.23	0.40	0.44	0.48	0.86	1.36	0.33	0.21	0.	0.	5.24
	U	0.40	0.29	0.11	0.08	0.07	0.14	0.10	0.11	0.25	0.41	0.38	0.22	0.43	1.01	0.39	0.36	0.00	0.	4.75
13-18	VS	0.00	0.00	0.	0.00	0.	0.01	0.02	0.01	0.01	0.01	0.04	0.10	0.28	0.81	0.07	0.00	0.	0.	1.38
	MS	0.10	0.06	0.03	0.04	0.02	0.10	0.18	0.12	0.17	0.42	0.86	1.25	3.45	2.66	0.24	0.11	0.	0.	9.80
	N	0.15	0.06	0.02	0.01	0.01	0.04	0.07	0.11	0.23	0.49	0.63	0.55	1.13	1.06	0.11	0.10	0.	0.	4.78
	U	0.21	0.11	0.03	0.01	0.00	0.02	0.03	0.04	0.13	0.40	0.49	0.19	0.51	0.79	0.07	0.12	0.	0.	3.15
19-24	VS	0.	0.	0.	0.	0.	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.04	0.12	0.00	0.	0.	0.	0.20
	MS	0.02	0.02	0.01	0.01	0.00	0.02	0.05	0.08	0.13	0.32	0.35	0.20	1.02	1.08	0.02	0.01	0.	0.	3.33
	N	0.05	0.04	0.01	0.00	0.00	0.02	0.03	0.07	0.20	0.46	0.45	0.22	0.84	0.81	0.02	0.04	0.	0.	3.26
	U	0.05	0.04	0.01	0.00	0.	0.00	0.01	0.02	0.08	0.26	0.31	0.09	0.29	0.59	0.01	0.02	0.	0.	1.79
OVER 24	VS	0.	0.	0.	0.	0.	0.00	0.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.	0.	0.	0.	0.01
	MS	0.00	0.00	0.	0.	0.	0.00	0.02	0.05	0.15	0.21	0.12	0.03	0.22	0.31	0.00	0.00	0.	0.	1.13
	N	0.02	0.01	0.00	0.00	0.	0.00	0.01	0.06	0.25	0.50	0.26	0.07	0.54	0.75	0.01	0.01	0.	0.	2.49
	U	0.01	0.02	0.01	0.	0.	0.	0.00	0.01	0.08	0.34	0.25	0.07	0.17	0.46	0.00	0.00	0.	0.	1.42
TOTALS	VS	0.11	0.11	0.07	0.10	0.11	0.25	0.24	0.20	0.16	0.22	0.39	0.71	0.96	1.85	0.56	0.20	0.09	0.09	6.44
	MS	0.87	0.75	0.55	0.65	0.85	1.44	1.20	1.02	1.17	2.01	2.96	4.65	9.16	8.49	2.41	1.42	0.28	0.66	40.53
	N	1.22	1.19	0.78	0.89	1.02	1.22	0.78	0.89	1.31	2.35	2.23	2.00	4.24	5.52	1.75	1.56	0.39	0.69	30.07
	U	1.82	1.62	0.84	0.86	0.76	0.95	0.56	0.63	0.95	1.87	1.77	0.93	1.82	3.77	1.48	1.74	0.53	0.06	22.96

TABLE 3. Relationship Between Hanford and Pasquill-Gifford Stability Classes and Determination of Sigma z

<u>Hanford</u>	<u>Pasquill-Gifford</u>	<u>σ_z</u>
Unstable	B	.12x
Neutral	D	.06x/(1 + .0015x) ^{1/2}
Slightly Stable	E	.03x/(1 + .0003x)
Moderately Stable	F	.02x/(1 + .0003x)

The deposition velocity is a function of the density of material, the size of particles (if a particulate), atmospheric turbulence characteristics, and height of reference concentration⁽²⁰⁾. Many observed values of deposition velocity for materials of interest tend to be about 0.01 ms^{-1} (14-21). As a result, it is reasonable to assume a constant value of 0.01 ms^{-1} and accept the accompanying uncertainty in the computations. A more sophisticated treatment of deposition velocity would probably not yield significantly better results with respect to the basic problem under consideration.

Although constant values have been assumed for many of the geometric and meteorological parameters for the primary evaluation of the probability of multiple reactor involvement, the sensitivity of the results to variations in these parameters has been examined. The results of the sensitivity studies are presented in the next section following presentation of the primary study results. In general the primary results are relatively insensitive to small changes in any of the model parameters.

RESULTS

The results of this study are presented in two sections. The first section presents the primary results, i.e., the values of $P_1^*(M, J|A)$ and $P_2^*(M, J|A)$ computed with Equations (11a) and

(11b). The second section presents the results of the sensitivity studies.

Primary Results

The primary results of the probability computations are presented in Tables 4 and 5 for ground level air and surface contamination, respectively. It is immediately obvious that the tables are identical except for the definition of contamination and the order of magnitude of the concentration. The reason for this lies in the relationship expressed in Equation (8). However, it is important to remember that the deposition velocity affects the air concentration as well as the surface concentration (Equation (7)).

The probability that more than a single reactor cluster will be contaminated at some level following a release of radioactivity in the HNEC is .194. This is seen in Tables 4 and 5 for I or $J \geq 0$ and $M \geq 7$. Similarly the probability of involvement of 3 or more clusters is .108. These probabilities should be evaluated relative to the conditional probability that a given reactor will be the source of the release, which is .05.

If an air or surface concentration of significance is identified and a source term is estimated, Tables 4 and 5 can be used to estimate the probability that M or more reactors will be involved at the significant level or at a greater level. Assuming that the ratio between a significant air concentration and release rate is 10^{-7} sm^{-3} , Table 4 shows that the probability of 5 or more reactors being involved is .397. The probability of 7 or more being involved is .158, and the probability of 13 or more is .056. Table 5 can be used in a similar manner when a significant surface concentration is defined and the total release is estimated.

If, for some reason, the probability that exactly y clusters will be contaminated is of interest, it can be computed

TABLE 4. Conditional Probability That at Least M Reactors Would be Contaminated Following an Accident at an HNEC. Contamination Defined by Normalized Air Concentration Equal to or Greater than Tabled Value

Normalized Concentration (sm^{-3})	Number of Reactors									
	3	4	5	7	8	9	11	12	13	16
1.00×10^{-5}	1.000	.850	.250							
4.64×10^{-6}	1.000	.852	.256	.006						
2.15×10^{-6}	1.000	.853	.268	.021	.008	.008				
1.00×10^{-6}	1.000	.853	.290	.046	.028	.016				
4.64×10^{-7}	1.000	.865	.313	.069	.035	.024	.011	.011	.011	
2.15×10^{-7}	1.000	.876	.369	.126	.088	.044	.030	.016	.016	
1.00×10^{-7}	1.000	.878	.397	.158	.127	.081	.066	.059	.056	.018
4.64×10^{-8}	1.000	.881	.409	.172	.138	.098	.085	.079	.073	.023
2.15×10^{-8}	1.000	.884	.417	.182	.148	.102	.090	.082	.075	.024
1.00×10^{-8}	1.000	.884	.421	.188	.155	.108	.095	.086	.078	.025
>0	1.000	.884	.427	.194	.165	.121	.108	.100	.090	.030

TABLE 5. Conditional Probability That at Least M Reactors Would be Contaminated Following an Accident at an HNEC. Contamination Defined by Normalized Surface Concentration Equal to or Greater than Tabled Value

Normalized Concentration (m^{-2})	Number of Reactors									
	3	4	5	7	8	9	11	12	13	16
1.00×10^{-7}	1.000	.850	.250							
4.64×10^{-8}	1.000	.852	.256	.006						
2.15×10^{-8}	1.000	.853	.268	.021	.008	.008				
1.00×10^{-8}	1.000	.853	.290	.046	.028	.016				
4.64×10^{-9}	1.000	.865	.313	.069	.035	.024	.011	.011	.011	
2.15×10^{-9}	1.000	.876	.369	.126	.088	.044	.030	.016	.016	
1.00×10^{-9}	1.000	.878	.397	.158	.127	.081	.066	.059	.056	.018
4.64×10^{-10}	1.000	.881	.409	.172	.138	.098	.085	.079	.073	.023
2.15×10^{-10}	1.000	.884	.417	.182	.148	.102	.090	.082	.075	.024
1.00×10^{-10}	1.000	.884	.421	.188	.155	.108	.095	.086	.078	.025
> 0	1.000	.884	.427	.194	.165	.121	.108	.100	.090	.030

from the information in Tables 4 and 5. This probability is equal to the probability that y or more clusters will be contaminated minus the probability that $y+1$ or more clusters will be. For example, the probability that exactly 2 clusters in an HNEC would be contaminated following a radioactive release is $.194 - .108 = .086$.

Appendix B provides information for estimating source terms for each release category for several radio-nuclides. Significant air and surface concentrations can be determined in relation to dose rates.

Model Sensitivity

In the preceeding section the tables presented give the conditional probabilities that at least M reactors will be involved at or greater than a given level assuming that a release takes place. A number of assumptions with respect to model parameters were required in the computations that produced the estimates. In this section we examine the effects of varying the parameters. The HNEC case described earlier will serve as a basis for comparison.

The effects of variation of the parameters on air and surface concentrations can be identified by examining Equations (5) through (8). However, our primary interest is in probabilities, air and surface concentrations are only part of the problem. The summations indicated in Equations (10) and (11) tend to mask many of the changes that might be expected on the basis of considering concentrations. In other cases the effects are as expected but somewhat more diffused.

Mixing Height. When probability computations were made for assumed mixing heights of 500, 1500 and 2500 m, the resulting variations in probability estimates were judged to be insignificant. Decreasing the height to 500 m or increasing it to 2500 m caused changes in probability of less than .01 from the

values in Tables 4 and 5. In most cases the changes were .001 or .002.

Source and Plume Width. Intuitively, increasing either the plume or source width can be expected to decrease concentrations at any given distance from the source. Increasing the source width increases the distance from the virtual point source to the real source and the receptor. Equation (5) shows that this decreases the uncorrected air concentration. However when the correction for deposition is considered in Equation (7), the relative increase in the distance to the real source is more than that to the receptor. As a result the value of the integral in the exponential term is reduced and the exponential term approaches unity. This serves to counter the reduction of the uncorrected concentration when the actual air and surface concentrations are estimated. The net effect of increasing the source width may be either an increase or decrease in concentrations.

The effect on the conditional probabilities of increasing source and plume width are shown in Table 6. For both 22.5 and 45 degree plume widths, increasing the source width from 100 to 400 m has no apparent effect on the probability. Increasing the source width to 1600, with a 22.5 degree plume, increases the probability that two or more clusters will be contaminated by about 7% and probability of involvement of 3 or more clusters by about 37%. With a 45° plume, increasing the source width to 1600 m increases the probability of contamination of 2 or more clusters by less than 2%, and does not affect the probability that 3 or more clusters will be involved. An increase in plume width from 22.5° to 45° results in a significant increase in conditional contamination probabilities. For either a 100 or 400 m wide source the maximum increase in probability is just under 18% for $M \geq 9$. For an assumed source width of 1600 m, the maximum increase is about 12.5% for $M \geq 9$.

TABLE 6. Variation of the Conditional Probability That
at Least M Reactors Would be Contaminated Following
an Accident at an HNEC With Source and Plume Width.
Contamination Defined by Air or Surface Concentra-
tion Greater than Zero

Source Width (m)	Plume Width (°)	M												
		3	4	5	7	8	9	11	12	13	15	16	17	20
100	22-1/2	1.000	.884	.427	.194	.165	.121	.108	.100	.090	.030	.030		
400	22-1/2	1.000	.884	.427	.194	.165	.121	.108	.100	.090	.030	.030		
1600	22-1/2	1.000	.892	.529	.297	.245	.193	.141	.108	.108	.048	.040		
100	45	1.000	.926	.569	.344	.300	.300	.240	.190	.181	.128	.120	.083	.043
400	45	1.000	.926	.569	.344	.300	.300	.240	.190	.181	.128	.120	.083	.043
1600	45	1.000	.926	.580	.362	.318	.318	.240	.190	.181	.128	.120	.083	.043

Table 6 is concerned only with the probability that reactors will be in the plume following an accident. It is not concerned with the concentration of material in the plume or on the ground at the reactors. The effects of changes in source and plume width on both plume coverage and concentration are shown in Table 7 for a relatively high level of involvement. The concentration intervals in the computation used prevent a detailed evaluation of the effect on concentration, but trends are evident in the Table.

Assuming a basic plume width of 22.5° , an increase in the source width from 100 to 400 m slightly increases the probability of 7 or more reactor involvements as seen in Table 7. Since Table 6 does not show an increase in involvement, the increases in Table 7 must result from increases in concentration due to reduction in deposition near the source. Further increasing the source width to 1600 m continues to increase the probability of 2 or more clusters being involved, but the increases are less than those due to the increased plume coverage. As a result they cannot be attributed to increased concentrations. The only exception to this is for $M \geq 5$, where the increase is .093 greater than that due to increased plume coverage.

For a plume width of 45° , Table 7 indicates that increases in source width from 100 to 400 and 1600 m are accompanied by small changes in probability. When M is greater than 9 the increases must be attributed, in part, to increases in concentration. Changes in probability due to increases in source width are generally less than 1% for a 45° wide plume.

Increasing plume width from 22.5 to 45 degrees increases the area covered by the plume by a factor of 2. However, it also reduces the distance between the virtual and real source. The net effect is an increase in probability that is less than would occur if only the areal increase were considered.

TABLE 7. Variation of Conditional Probability That at Least M Reactors Would be Contaminated Following an Accident at an HNEC With Source and Plume Width. Contamination Defined by Normalized Air Concentration Greater Than 10^{-7} sm^{-3} or Normalized Surface Concentration Greater than 10^{-9} m^{-2} .

Source Width (M)	Plume Width (°)	Number of Reactors										
		3	4	5	7	8	9	11	12	13	15	16
100	22.5	1.000	.878	.397	.158	.127	.081	.066	.059	.056	.018	.018
400	22.5	1.000	.878	.397	.160	.129	.081	.067	.061	.057	.019	.019
1600	22.5	1.000	.886	.492	.259	.203	.153	.096	.066	.066	.027	.022
100	45	1.000	.908	.519	.286	.210	.180	.128	.073	.063	.009	
400	45	1.000	.908	.517	.284	.210	.181	.129	.081	.070	.020	.010
1600	45	1.000	.906	.522	.295	.228	.200	.136	.082	.071	.021	.011

Energy Center Configuration. The sensitivity of the results given in Tables 4 and 5 to the configuration chosen for the HNEC was examined by comparison with results of computations for 6 other configurations. In each case the average separation between adjacent clusters was set at 12.7 km, the same as for the HNEC. The configurations selected were a circle, (all 5 clusters on the perimeter), a cross in which the clusters were arranged on perpendicular lines with 3 clusters each, and lines with different orientations. The HNEC configuration is nearly a line oriented NW/SE.

Table 8 shows the variation of the conditional probability with configuration. The effect of configuration on the maximum number of reactors contaminated following a release is immediately obvious. If the risks associated with the contamination of 3 or more clusters are excessive, a circular configuration can eliminate that probability. However, Table 8 shows that the probability of 2 reactor involvement is relatively high for a circular configuration when compared with the other configurations. Similar results are seen for the cross configuration.

When a linear configuration is used, the probability that all reactors would be involved following an accident will always exist. But, in general, linear configurations have relatively low probabilities of 2 cluster contamination. Comparison of the probabilities for $M \geq 7$ shows that variation of line orientation has a significant effect. Rotating line orientation 45° from N/S to NW/SE increases the probability of 2 cluster involvement by a factor of 3 and 3 cluster involvement by almost a factor of 3.

While the variations just discussed appear to be real, the basic model used in the computations combined with the climatological resolution of wind direction can lead to unreal variations. A small ($<10^\circ$) reorientation of a configuration

TABLE 8. Variation of Conditional Probability That at Least M Reactors Would be Contaminated Following an Accident at an HNEC with NEC Geometric Configuration. Contamination Defined by Normalized Air or Surface Concentration Greater than Zero.

<u>Configuration</u>												
HNEC	1.000	.884	.427	.194	.165	.121	.108	.100	.090	.030	.030	
N/S Line	1.000	.862	.300	.063	.055	.055	.049	.039	.039	.033	.023	.019
NW/SE Line	1.000	.886	.390	.190	.160	.160	.152	.112	.112	.104	.064	.058
E/W Line	1.000	.867	.321	.111	.098	.098	.070	.053	.053	.048	.031	.027
NE/SW Line	1.000	.866	.319	.104	.095	.095	.064	.050	.050	.043	.030	.024
Cross	1.000	.891	.471	.265	.216	.178	.033	.033				
Circle	1.000	.881	.406	.236	.183	.091						

with respect to prevailing wind directions may significantly alter the probabilities computed. And in some cases can alter the maximum number of clusters that could be involved following an accident. Reorientation of the HNEC by a few degrees (or changing the orientation of the sectors in which wind directions are reported) would increase the maximum number of reactors involved to 20. These changes are artifacts that limit the utility of the results in a quantitative sense.

Cluster Spacing. The conceptual HNEC is not typical of many energy centers because it is relatively widely dispersed. Therefore each of the seven cases was reevaluated with spacing between clusters reduced by a factor of 4. Reducing spacing by a factor of 4 reduces the distance from the virtual point source to the receptor without changing the distance between the virtual and real sources. This increases both the corrected air and surface concentrations by more than a factor of 4. However, the resulting changes in probability are generally less than a factor of 2.

Table 9 shows the conditional probability for a relatively high level of contamination for both close and wide spacing. Relatively small increases in probability are shown for 2 cluster involvement when the spacing is reduced. The increases in probability are relatively large for 3 and 4 cluster involvement.

For a more detailed examination of the effects of spacing Table 10, which gives results for the HNEC configuration with close spacing, can be compared with Table 4. With close spacing the highest level of 2 cluster contamination occurs at $\bar{X}/\dot{Q}_0 \geq 4.64 \times 10^{-5} \text{ sm}^{-3}$, while for the standard HNEC it occurs at $\bar{X}/Q \geq 4.64 \times 10^{-6} \text{ sm}^{-3}$. In general, for a given M and a fixed probability, the level of contamination is about an order of magnitude greater for the closely spaced HNEC than it is for the widely spaced center.

TABLE 9. Variation of Conditional Probability That at Least M Reactors Would be Contaminated Following an Accident at an HNEC With Configuration and Spacing Between Clusters. Contamination Defined by Normalized Air Concentration Equal to or Greater than 10^{-7} sm^{-3} or Normalized Surface Concentration Equal to or Greater than 10^{-9} m^{-2} .

Configuration	Spacing	Number of Reactors											
		3	4	5	7	8	9	11	12	13	15	16	20
HNEC	C	1.000	.884	.427	.194	.165	.121	.108	.100	.090	.030	.030	
	W	1.000	.878	.397	.158	.127	.081	.066	.059	.056	.018	.018	
N/S Line	C	1.000	.862	.300	.063	.055	.055	.049	.038	.038	.032	.022	.017
	W	1.000	.860	.293	.055	.040	.032	.021	.011	.011	.002	.001	
NW/SE Line	C	1.000	.886	.390	.190	.158	.156	.145	.105	.105	.095	.059	.050
	W	1.000	.881	.370	.162	.121	.110	.090	.041	.041	.016	.009	
E/W Line	C	1.000	.870	.340	.130	.098	.097	.068	.052	.052	.046	.029	.025
	W	1.000	.865	.314	.102	.081	.075	.042	.018	.018	.005	.005	
NE/SW Line	C	1.000	.866	.319	.104	.093	.092	.059	.046	.046	.038	.026	.020
	W	1.000	.862	.304	.081	.062	.056	.024	.012	.012	.002	.001	
Cross	C	1.000	.891	.471	.265	.216	.178	.033	.033				
	W	1.000	.885	.433	.216	.173	.137	.019	.019				
Circle	C	1.000	.881	.428	.258	.205	.091						
	W	1.000	.877	.386	.206	.159	.082						

TABLE 10. Conditional Probability That at Least M Reactors Would be Contaminated Following an Accident at an HNEC, Assuming Close Spacing. Contamination Defined by Normalized Air Concentration Equal to or Greater than Tabled Value.

Normalized Concentration (sm^{-3})	<u>Number of Reactors</u>									
	3	4	5	7	8	9	11	12	13	16
1.00×10^{-4}	1.000	.850	.250							
4.64×10^{-5}	1.000	.852	.257	.009	.005	.005				
2.15×10^{-5}	1.000	.853	.268	.021	.012	.008				
1.00×10^{-5}	1.000	.853	.285	.040	.024	.014				
4.64×10^{-6}	1.000	.861	.313	.070	.038	.019	.004	.004	.004	
2.15×10^{-6}	1.000	.872	.353	.114	.070	.037	.022	.016	.016	
1.00×10^{-6}	1.000	.880	.398	.163	.129	.075	.061	.052	.052	.018
4.64×10^{-7}	1.000	.881	.414	.179	.148	.103	.090	.082	.074	.024
2.15×10^{-7}	1.000	.884	.420	.187	.155	.112	.099	.090	.080	.026
1.00×10^{-7}	1.000	.884	.427	.194	.165	.117	.104	.095	.084	.028
>0	1.000	.884	.427	.194	.165	.121	.108	.100	.090	.030

Deposition Velocity. The deposition velocity is the last of the model parameters evaluated in the model sensitivity studies. Equation (7) indicates that the corrected air concentration decreases as the deposition velocity increases. The variation of surface deposition is more complex as shown in Equation (8). Differentiation of Equation (8) with respect to deposition velocity indicates that surface concentration is maximized for some value of deposition velocity. The deposition velocity that maximizes surface concentration is a function of wind speed, atmospheric stability, and the distances of the real source and receptor from the virtual point source.

Figures 3 and 4 show the effect of deposition velocity on the conditional probability with contamination defined by air concentration. Figure 3 is for $M \geq 7$, while Figure 4 is for $M \geq 11$. Both figures show that small deposition velocities have little effect on air concentrations over the range of distances in the HNEC. They also show that increasing deposition velocity has more effect at high levels of contamination than at low levels. Both of these results are expected.

Comparison of the figures shows that the reduction of probability at large deposition velocities occurs more gradually for $M \geq 7$ than it does for $M \geq 11$. This can be explained as a result of the summation over all possible combinations of sources, receptors and atmospheric conditions. Since more source-receptor combinations lead to $M \geq 7$ than lead to $M \geq 11$, the variation of probability with V_d should be more gradual for $M \geq 7$ as shown.

As a practical matter, for $\bar{x}/Q \geq 10^{-7} \text{ sm}^{-3}$ or less, air concentrations computed with $V_d \geq .01 \text{ ms}^{-1}$ can be assumed to be equal to those for non-depositing material.

The variation of conditional probability with deposition velocity when contamination is defined by surface concentration is shown in Figures 5 and 6 for $M \geq 7$ and $M \geq 11$ respectively.

FIGURE 3. Variation of Conditional Probability That 7 or More Reactors Would be Contaminated Following an Accident in an HNEC With Deposition Velocity. Contamination Defined by Normalized Air Concentration.

FIGURE 4. Variation of Conditional Probability That 11 or More Reactors Would be Contaminated Following an Accident in the HNEC With Deposition Velocity. Contamination Defined by Normalized Air Concentration.

FIGURE 5. Variation of Conditional Probability That 7 or More Reactors Would be Contaminated Following an Accident in an HNEC With Deposition Velocity. Contamination Defined by Normalized Surface Concentration.

FIGURE 6. Variation of Conditional Probability That 11 or More Reactors Would be Contaminated Following an Accident in an HNEC With Deposition Velocity. Contamination Defined by Normalized Surface Concentration.

These figures show the general trend that would be expected on the basis of the discussion of Equation (8). Again the effects of V_d are most pronounced for the highest level of involvements, and they are more gradual for $M \geq 7$ than for $M \geq 11$.

The predicted maximum in surface concentration is reflected in the broad peaks in probability in Figures 5 and 6. These peaks occur at deposition velocities of about $.01 \text{ ms}^{-1}$.

CONCLUSIONS

As part of the conceptual evaluation of a Hanford Nuclear Energy Center, the reliability of generation is being assessed. The purpose of the work discussed in this report was to provide meteorological estimates of the probability of multiple reactor contamination following an accidental release of radioactivity. In this context the primary results of the study are contained in Tables 4 and 5. This section summarizes the results in these tables and in the section on model sensitivity.

The conditional probability that contamination would be confined to the reactors in a single cluster in the HNEC is .806 if it is assumed that an accident will occur. The probability that reactors in two or more clusters would be contaminated is .194, that for three or more is .108, and that for four or more is .030.

If contamination is further defined by normalized air or surface concentrations at downwind reactors, the probability that two or more clusters would be involved at a relatively high level (normalized air concentration $\geq 10^{-7} \text{ sm}^{-3}$ or surface concentration $\geq 10^{-9} \text{ m}^{-2}$) is .153. The probability that three or more clusters being contaminated at these levels is .066. Thus, the probability for two or more clusters being involved is about 3 times the probability that a given reactor will be the source of the release, and the probability of

three or more clusters being involved is somewhat larger than the probability of a given reactor having the accidental release.

Sensitivity studies indicate that the probability estimates presented in Tables 4 and 5 can be altered significantly by changing several of the model parameters. However, the model, as applied to the HNEC, is not sensitive to increases in the thickness of the atmosphere's mixing layer when the layer thickness is greater than 500 m.

Increasing the assumed width of the source from 100 to 400 m has no effect on the probability that M or more reactors would be downwind of the accident. But, it did increase the level of contamination slightly by decreasing the plume depletion due to deposition near the source. A further increase in source width to 1600 m increases probabilities close to the source (small M) by increasing the plume coverage and increases probabilities at a distance (large M) by decreasing deposition.

Increasing plume widths from 22.5 to 45 degrees decreases concentrations and increases plume coverage. The net result is increases in conditional probability of up to .128 and .047 for 100 and 1600 m source widths respectively when a relatively high level of contamination is considered.

Changing the energy center configuration can have a significant affect on the probability of multiple reactor contamination. Variations in the conditional probability of factors of 3 and more can be obtained by changing the configuration and its orientation with respect to the prevailing wind directions. In using configuration changes to alter the conditional probability, trade offs are required. Reduction in the probability of involvement of two or more clusters may increase the probability of involving 3 or 4 clusters.

Decreasing the spacing between clusters increases the level of contamination significantly, if the number of reactors and probability are predetermined. However, there are only small increases in the probability of contamination at a given level and number of reactors when spacing is decreased.

Finally, the model results are sensitive to the choice of deposition velocities. Deposition velocities above $.01 \text{ ms}^{-1}$ decrease air concentrations significantly, and this is reflected in a decrease in conditional probabilities. They also affect the amount of material deposited. The probability of involvement, where involvement is defined by surface concentration, is a maximum for the HNEC for deposition velocities of about $.01 \text{ ms}^{-1}$. As a result, the use of a deposition velocity of $.01 \text{ ms}^{-1}$, which is consistent with observed values for reactor effluents of interest, yields conservative predictions of contamination through both air and surface concentrations.

In the light of the results of the model sensitivity studies, the estimates of the conditional probability that M or more reactors would be contaminated following a release of radioactivity at an HNEC presented in Tables 4 and 5 are considered to be reasonable. Although the estimates can be altered by changing meteorological parameters in the models, there are no compelling reasons to change them, nor are there significant benefits to be gained if the parameters are changed. Energy center configuration and spacing are the only reasonable means for use in altering the conditional probability of multiple reactor contamination following a release of radioactive material.

Appendix A

Reactor Accident Classes

TABLE A1. Classification of Postulated
Accidents and Occurrences*

No. of Class	Description	Example(s)
1	Trivial incidents	Small spills Small leaks inside containment
2	Misc. small releases outside containment	Spills Leaks and pipe breaks
3	Radwaste system failures	Equipment failure Serious malfunction or human error
4	Events that release radioactivity into the primary system	Fuel defects during normal operation Transients outside expected range of variables
5	Events that release radioactivity into secondary system	Class 4 and Heat Exchanger Leak
6	Refueling accidents inside containment	Drop fuel element Drop heavy object onto fuel Mechanical malfunction of loss of cooling in transfer tube
7	Accidents to spent fuel outside contain- ment	Drop fuel element Drop heavy object onto fuel Drop shielding cask - loss of cooling to cask, transportation incident on site
8	Accident initiation considered in design- basis Evaluation in the safety analysis report	Reactivity transient Rupture of primary piping Flow decrease - steam- line break
9	Hypothetical sequences of failures More severe than Class 8	Successive failures of multiple barriers normally provided and maintained

*From Reference 10

Appendix B

Accidents Involving Reactor Cores

TABLE B1. Release Categories Following Reactor
Accidents Involving Core*

<u>Pressurized Water Reactors</u>	
PWR 1	Steam explosion due to molten UO_2 falling into water followed by missile rupturing containment.
PWR 2	Core melt and failure of radioactivity removal systems followed by rupture of containment.
PWR 3	Similar to PWR 1 and 2 but involves partial success of radioactivity removal systems.
PWR 4	Core melt with containment not fully isolated, containment radioactivity removal systems have failed.
PWR 5	Similar to PWR 4 except removal systems operative.
PWR 6	Core melt through bottom, above ground containment intact. Radioactivity removal systems inoperative.
PWR 7	Similar to PWR 6 except radioactivity removal system operating.
PWR 8	Core doesn't melt, release of activity in the gaps of fuel rods, containment fails to isolate properly.
PWR 9	Similar to PWR 8, except containment isolates correctly.
<u>Boiling Water Reactors</u>	
BWR 1	Similar to PWR 1.
BWR 2	Core melt after containment over pressure rupture caused by loss of decay heat removal systems, limited deposition of radioactive materials. Release directly to atmosphere.
BWR 3	Similar to BWR 2 except material released through the reactor building to the atmosphere.
BWR 4	Core melt, containment fails to operate properly and the leakage is enough to prevent containment over pressure rupture.
BWR 5	Core does not melt, but activity is released from the gap of the fuel rods. Activity passes through reactor building gas treatment system and is released to the atmosphere through a tall stack.

* From Reference 11

TABLE B2. Parameters of Releases Following Reactor Accidents Involving Core*

Release Category	Probability per Reactor Year	Release Duration (Hr)	Warning Time (Hr)	Fraction of Core Inventory Released			
				Xe-Kr	I	Cs-Rb	Ba-Sr
PWR 1	9×10^{-7}	0.5	1.0	0.9	0.7	0.4	0.05
PWR 2	8×10^{-6}	0.5	1.0	0.9	0.7	0.5	0.06
PWR 3	4×10^{-6}	1.5	2.0	0.8	0.2	0.2	0.02
PWR 4	5×10^{-7}	3.0	2.0	0.6	0.09	0.04	5×10^{-3}
PWR 5	7×10^{-7}	4.0	1.0	0.3	0.03	9×10^{-3}	1×10^{-3}
PWR 6	6×10^{-6}	10.0	1.0	0.3	8×10^{-4}	8×10^{-4}	9×10^{-5}
PWR 7	4×10^{-5}	10.0	1.0	6×10^{-3}	2×10^{-5}	1×10^{-5}	1×10^{-6}
PWR 8	4×10^{-5}	0.5	N/A	2×10^{-3}	1×10^{-4}	5×10^{-4}	1×10^{-3}
PWR 9	4×10^{-4}	0.5	N/A	3×10^{-6}	1×10^{-7}	6×10^{-7}	1×10^{-11}
BWR 1	1×10^{-6}	2.0	1.5	1.0	0.4	0.4	0.05
BWR 2	6×10^{-6}	3.0	2.0	1.0	0.9	0.5	0.1
BWR 3	2×10^{-5}	3.0	2.0	1.0	0.1	0.1	0.01
BWR 4	2×10^{-6}	2.0	2.0	0.6	8×10^{-4}	5×10^{-3}	6×10^{-4}
BWR 5	1×10^{-4}	5.0	N/A	5×10^{-4}	6×10^{-11}	4×10^{-9}	8×10^{-14}

* From Reference 11, Table 5.1

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

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

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 Battelle-Northwest, 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 focuses 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 is to further develop a concept of a system which will transmit power from HNEC to markets in the Pacific Northwest, and to compare it with a system to serve the same loads from dispersed generating capacity; the major portion of the dispersed capacity would be in the general vicinity of load centers. The latter alternative would follow conventional siting practice and is referred to as a distributed (DIST) 100% system or case for 1998, and (DIST) 150% case for 2002.

The planning of a power transmission system is an iterative process developed over a considerable time period. This report is an initial iteration, and substantial further studies will be required to firm up a transmission system from an HNEC, should such a generation expansion develop. Some of the required additional studies are presented in the last section of the report.

For purposes of formulating a concept, thermal generating capacity at HNEC is assumed to reach 15,000 MW by 1998 (100% case). A transmission system

to accommodate growth of generating capacity to 23,000 MW by 2002 (150% case) or earlier if the rate of load buildup is greater than forecast, is also studied. Lastly, general 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.

Since the original issuance of this report the Nuclear Regulatory Commission completed its study, NUREG-0001, "Nuclear Energy Center Site Survey-1975,"⁽¹⁾ which contains information from this and other transmission studies for nuclear energy centers.

In updating this HNEC study the authors have taken cognizance of information and opinions given by other contributors to the NRC study which are pertinent to the transmission situation in the Pacific Northwest. Direct comparison between the results of this report and those of referenced reports can seldom be made since many of the hypothetical energy centers of other studies are not benefitted by being in an existing high-capacity transmission network.

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, and peaking capacity by the hydro system. In 1975 it was estimated that in a currently projected development of new thermal generation on the system, some 65% of the capacity installed between 1988 and 1998 would be at sites to the west, and some 35% at sites to the east of the Range, part of the latter coal-fired. In 1978 it is estimated that substantially more than 35% of new capacity will be east of the Cascades, but the earlier estimate was allowed to stand to better illustrate the effects of distance of generating stations from load centers. Under this distributed (DIST) concept the total cross-mountain power flow in January 1999 from hydro and thermal plants is estimated to be 24,000 MW. Under the HNEC-100% concept the flow would be 31,000 MW, and under the HNEC-150% concept, 37,000 MW. The estimated West Group Area load used for the DIST and HNEC-100% alternates (January 1999 peak load conditions) is 56,500 MW. The comparable load assumed for the 150% cases (January 2003 peak load conditions) is 64,000 MW.

This study assumes that the resource schedule developed by the Pacific Northwest Utilities Conference Committee (PNUCC) will be implemented: that all thermal plants scheduled through 1988 will be completed on schedule and that generation reserve requirements will be satisfied. Only those plants scheduled after 1989 will be free to be located either in distributed sites or at the HNEC.

The major issues examined in the comparison of the DIST and HNEC transmission concepts 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, 500 kV double or single circuit,

a voltage currently used in the PNW system. This type of system can accommodate growth up to at least 23,000 MW of thermal capacity at an HNEC. Significant additional transmountain capacity needs would require 1100 kV transmission, which should be technologically proved by the mid-1980s.

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 500 kV Double-Circuit Transmission Lines</u>	<u>Miles of Line Added</u>
DIST-100%	2	365
DIST-150% } HNEC-100% }	3	545
HNEC-150%	4	725

In alternate cases one 1100 kV line could substitute for one or two lines of the HNEC-100% case, and two 1100 kV lines could substitute for three of the four lines in the HNEC-150% case. In the 1100 kV alternatives, lines of that voltage level would be constructed rather than 500 kV lines for those high-capacity circuits to be constructed after 1100 kV technology is sufficiently developed (energization by the latter 1980s). 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 23,000 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. 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 500 kV, and later with 1100 kV, the transfer capacity of the corridors could be increased up to about 87,000 MW. Assuming a 50,000 MW development at HNEC, the cross-mountain capacity required to transmit power to the west from eastern thermal and hydro generation would be about 60,000 MW.

The economics of the alternative concepts are summarized below. The costs are for transmission facilities added after 1988, estimated in constant 1978 dollars. Capital investment required for lines, switching stations, series capacitors, and reactive compensation, including interest during construction, is estimated to be:

	\$ Million		
	<u>Investment</u>	<u>Interest During Construction</u>	<u>Total</u>
DIST-100% Case	275	84	359
DIST-150% Case	458	140	598
HNEC-100% Case	446	137	583
HNEC-150% Case	655	200	855

The difference between the DIST and HNEC-100% case estimates--including fixed charges on the above investment, system energy losses, and costs of supplying reactive power to the system--is a measure of the added transmission cost burden of the HNEC case. The annual cost differences range up to \$74 million in 1998 as generating capacity at an HNEC increases from 3600 MW to 15,000 MW. Under peak load conditions system losses are 300 MW greater for the HNEC-100% case over the DIST-100% case and 550 MW greater for the HNEC-150% case over the DIST-150% case.

The effective added unit cost, i.e., the costs of the added transmission plant going into service after 1988 divided by the capacity of, or energy from, HNEC plants coming on line after 1988 is estimated at:

\$6.80 per year per kilowatt of capacity, or about
1.0 mill per kilowatt hour at 75% plant capacity factor.

The added cost burden estimated above is one measure of the penalties that must be offset by the benefits of an HNEC, if HNEC is to be attractive from an economic standpoint. This unit cost burden 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 added unit transmission cost.

The estimated costs of the HNEC-150% case were compared with preliminary estimates of the DIST-150% case to ascertain whether the added transmission cost for an HNEC would increase or decrease with expanded generating capacity and expanded transmission capacity. As generating capacity increased from 15,000 to 23,000 MW, the transmission cost per unit of energy transmitted decreased, thus indicating that the 500 kV transmission system described is an attractive economic choice.

Environmental factors can be summarized as follows:

- 4500 acres in new rights-of-way for DIST versus 4745 acres for HNEC-100% and 5405 acres for HNEC-150%. The HNEC cases require greater acreage in agricultural, range, and forest land than the DIST case, but somewhat less in residential/industrial land.
- More visual intrusion in cross-mountain corridors caused by (larger) 500 kV towers replacing 230 kV towers--one additional line for the HNEC-100% case and two additional lines for the HNEC-150% case, as compared with the DIST 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 DIST 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 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 for the DIST and HNEC cases 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 alternate 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 23,000 MW from HNEC markets is considered feasible from the standpoints of technology and access to rights-of-way. Technology for the 500 kV concepts is now at hand except for breakers of higher interrupting capacity, or solutions for limiting fault current. Technology for the alternative 1100 kV transmission should be proven by the mid-1980s.
- The HNEC transmission system concept may have an additional environmental impact over that of distributed generation.
- The estimate of added transmission cost burden of the HNEC case (1.0 mill per kilowatt hour) is of the order of 5% of cost of bulk power delivered to load centers.
- 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 DIST concept.
- 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.

As indicated by the conclusions, we recommend the following items for further study:

- A more detailed study of the electrical characteristics of the generating plants at HNEC to determine the limits of transient stability and economy of size

- A detailed study of transmission system requirements to provide station service for the plants at the energy center. (This study was conducted and is reported in Reference 2.)
- A more complete study of an HNEC development beyond the 23,000 MW level

GENERAL APPROACH

As the Pacific Northwest electric power system grows, concentrating new thermal generating capacity at Hanford would result in a different average transmission distance than would dispersing such capacity, i.e., placing nuclear or coal-fired plants at acceptable sites closer to load centers. Economic and environmental penalties due to added transmission requirements would be weighed against the advantages of the energy center.

To assess the differences in transmission investment, power and energy losses, and land requirements, between HNEC and distributed generation (DIST) alternates, assumptions must be made on rate of load growth, probable location of new thermal generating capacity under usual processes of site selection, and the availability of rights-of-way for new transmission lines.

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 internal transmission requirements. Transmission to loads outside the Northwest would involve a different alternative supply than that assumed for the regional loads. However, the study does include the effects of presently allowed exchanges over existing tie lines to the Southwest.

Tables 1 and 2 contain schedules of thermal capacity assumed to be installed at HNEC. The tables include all new thermal capacity for the region (other than that now committed to other sites) required to meet system load growth including allowance for adequate system reserves. It is assumed that all units would be of 1250 to 1300 MW gross capacity.

If the trend is toward more use of coal-fired plants at sites other than Hanford, the dates for reaching the designated generating capacities of the HNEC 100% and 150% cases would be delayed. This would not invalidate

TABLE 1. Assumed Plant Additions at HNEC in Megawatts

<u>Calendar Year</u>	<u>100% Case</u>		<u>150% Case</u>	
	<u>Incremental</u>	<u>Total</u>	<u>Incremental</u>	<u>Total</u>
Through 1988		3,600		3,600
1990	1,250	4,850		
1991	1,250	6,100		
1992	1,250	7,350		
1993	1,250	8,600		
1994	1,300	9,900		
1995	1,300	11,200		
1996	1,300	12,500		
1997	1,300	13,800		
1998	1,300	15,100		15,100
1999			1,300	16,400
2000			2,600	19,000
2001			1,300	20,300
2002			2,600	22,900

TABLE 2. Assumed Plant Additions at Hanford
for DIST Case in Megawatts

<u>Calendar Year</u>	<u>100% Case</u>		<u>150% Case</u>	
	<u>Incremental</u>	<u>Total</u>	<u>Incremental</u>	<u>Total</u>
Through 1988		3,600		3,600
1995	1,300	4,900		
1997	1,300	6,200		6,200
2000			1,300	7,500

the results of this analysis, however, since the coal-fired plants would be incorporated into both the HNEC and DIST cases and their transmission requirements met in both. The incremental transmission needs of the nuclear plants would still approximate those of the HNEC and DIST cases with generating additions timed as in Table 1.

DISTRIBUTED GENERATION (DIST)

In a conventional development of thermal generating resources, utilities would select sites that are licensable and that tend to be near load centers. Numerous alternatives exist, but from developing trends, it would appear that throughout the 1988-98 period about 65% of the new thermal capacity would be located west of the Cascade Range in Washington or in Oregon, and 35% would be east of the Range, probably in the Mid-Columbia area. These general trends have been used in the DIST cases.

In 1978, the expected trend in thermal plant siting is toward substantially more than 35% of new capacity being located east of the Cascades. However, for purposes of this report the DIST sites originally chosen for comparison with HNEC are allowed to stand. These original sites are probably optimistic or idealistic with respect to closeness to load centers. More DIST sites in eastern locations would entail more transmission than for western locations. The difference in transmission requirements between HNEC and DIST would then be reduced, i.e. become more favorable to HNEC. Use of the original DIST sites in the updating of the report results in the estimates of HNEC transmission penalties remaining conservatively high.

Generating capacity conceivably could develop in a variety of ways, one of which could be the installation of coal-fired plants in the Wyoming and Montana coal fields with their output transmitted to Pacific Northwest loads. This alternative would involve a choice on the part of the responsible utility of accepting the costs of transmission in preference to the costs of coal shipment. The transmission costs associated with transmission of electrical energy from Montana could be much greater than those of either the DIST or HNEC cases because of the greater distances. However, to have any economic significance the combined coal-fired plant and its transmission system would

have to be compared with the HNEC and its transmission system. This is beyond the scope of this study, which evaluates only the transmission differences between nuclear plants dispersed and nuclear plants concentrated at HNEC. A coal plant with its coal transported such as the coal-fired plant planned for Carty Reservoir near Boardman, Oregon, could be substituted, if competitive, for nuclear plants at any of the study sites.

AVAILABILITY OF NEW 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 a transmission system to accommodate HNEC power flow, an important goal has been to confine the new lines to existing rights-of-way wherever 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. Further, it has been assumed that in the DIST and HNEC cases, additional rights-of-way could be obtained as necessary to tie generating plants at new sites in with the existing network.

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 or at distributed sites, is that covered by the West Group Area utilities. The members of this group are Bonneville Power Administration, Pacific Power and Light Co., Portland General Electric Co., Puget Sound Power and Light, Washington Water Power Co., and 104 public agency customers of BPA. The areas served are shaded on the map of Figure 1. West Group Area loads include BPA and PP&L loads in western Montana and BPA loads in southern Idaho. Other loads in these areas are in the East Group.

FIGURE 1. West Group Area of Northwest Power Pool

Source: Power Outlook, BPA, U.S. Department of Interior, December 1970.

HNEC SITE

The Hanford reservation covers approximately 600 square miles, part of which is unavailable, it being used for government facilities, arid lands 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 transmission lines are also shown.

Construction of or planning for three nuclear plants by WPPSS in area No. 1 is in progress, with some switching station equipment now installed at the Hanford Station and some planned for the Ashe Station. A transmission line right-of-way is being established between the Hanford and Ashe Stations. The transmission plant to accommodate up to 23,000 MW at HNEC would be expanded from that already in place or planned.

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

It is assumed that only power plant group sites No. 1 through 5 would be involved through 2002 and that the higher-numbered sites, or other possible locations in the southern portion of the Hanford reservation, would be developed only if expansion beyond 23,000 MW in generating capacity were to take place. Each of these general site areas are assumed to accommodate at least four 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 systems for both the DIST and HNEC cases conform with the reliability criteria of the Western Systems Coordinating Council and the BPA Basic Planning Assumptions.

FIGURE 2. HNEC Tentative Sites

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.

DEVELOPMENT OF COMPARATIVE CONCEPTS

Growth of the existing transmission system as already planned to the year 1988 would precede any divergence in growth between the DIST and HNEC concepts. The initial divergence in the nature of the physical plant would begin to appear in 1989, to accommodate the first of the new nuclear plants (beyond the three units now planned for the Hanford location) that would begin the HNEC buildup in generating capacity. Differences in initial capital outlays between DIST and HNEC concepts would begin to occur about 1985 in the design and construction of transmission facilities that would go into service in 1990.

All major elements of the comparative system concepts have been considered, including lines, switching terminals at the sending and receiving points, voltage transformation, reactive supply, generating plant in-house service supply through transmission system branch lines, and subtransmission systems served from receiving points on the main transmission grid.

Subtransmission systems and system costs could be affected by the voltage levels and by the location of transmission stations at receiving points. Costs differences in these portions of the systems could become significant if the character of the main transmission system caused greater or lesser amounts of subtransmission equipment, including underground cable, to be required, or caused the voltages of these cables to be greater or lesser than those of the comparative concept.

However, in this study of the concepts to be described, no appreciable difference in the nature of, or costs of, subtransmission systems in the load areas was found. The principal reason is that with the main power transmission circuits of the HNEC concept remaining at 500 kV during the period studied, which is the same voltage visualized for the DIST concept, conditions at the receiving terminals would be similar, and subtransmission systems would also be similar. Any underground subtransmission that would be required would arise from local conditions and not from the character of the main transmission grid.

Before descriptions of the HNEC and DIST concepts are presented, it should be noted that:

- (1) all lines in both concepts are of overhead construction--in no case did application of the foregoing criteria require underground transmission in the Pacific Northwest system; and
- (2) although higher voltages were considered for the HNEC concept, and 1100 kV remains an alternate, the 500 kV double-circuit line was selected, in this study only, for economic comparisons through the year 1998; therefore, the voltage of main lines in both the HNEC and DIST concepts is 500 kV, which is presently used in the system.

DESCRIPTION OF TRANSMISSION SYSTEM CONCEPTS

The transmission system of the Pacific Northwest as planned to 1988 is shown in Figure 3, which includes major transmountain lines to be constructed between 1978 and 1988, listed in Table 3. Additions and modifications to this base system to accommodate a DIST-100% concept are listed in Table 4 and shown in Figure 4 over the background of the 1988 system. Additions to accommodate the HNEC concept are shown in Table 4 and Figure 5 and 6 for the 100% and 150% cases, respectively.

Figure 3 shows only one DC transmission line to the south. A second line is in the BPA budget but its construction is not committed. If it is built, the load flow diagrams to be presented herein would be modified somewhat, but the required east-west transmission lines for the respective HNEC

FIGURE 3. Pacific Northwest Transmission System as Planned Through 1988

TABLE 3. Major Cross-Mountain Line Additions^(a)
Between 1978 and 1988

<u>Year in Service</u>	<u>Miles</u>	<u>Description</u>
1980	71	Ashe-Slatt 500 kV High-Capacity Double-Circuit
1980	155	Slatt-Marion 500 kV High-Capacity Double-Circuit

(a) Several smaller system reinforcements are not included in this table.

Note: The above are common to all cases.

TABLE 4. Major Cross-Mountain Line Additions^(a) Between 1988 and 2002

<u>Year in Service</u>	<u>Miles</u> ^(b)	<u>Description</u>
<u>Distributed Case-100% (1988-1998)</u>		
Late 1980s to Early 1990s	180	Ashe-Portland Area, 500 kV High-Capacity Double-Circuit
Mid-1990s	185	Grand Coulee-Snoqualmie, 500 kV High-Capacity Double-Circuit
<u>HNEC - 100% (1988-1998)</u>		
Late 1980s to Early 1990s	180	Ashe-Portland Area, 500 kV High-Capacity, Double-Circuit
Early 1990s to Mid-1990s	185	Grand Coulee-Snoqualmie, 500 kV High-Capacity, Double-Circuit
Mid-1990s to Late 1990s	180	Gable Mt.-Portland Area (No. 1) 500 kV High-Capacity Double-Circuit
<u>HNEC - 150% (1988-2002)</u>		
Lines as in the HNEC-100% case plus the following:		
2000-2002	180	Gable Mt.-Portland Area (No. 2) 500 kV High-Capacity Double-Circuit

(a) Several smaller system reinforcements are not included in this table.

(b) Approximate distances.

FIGURE 4. Pacific Northwest Transmission System for Additions for DIST Case

FIGURE 5. Pacific Northwest Transmission System for Additions for 100% HNEC Case

FIGURE 6. Pacific Northwest Transmission System for Additions for 150% HNEC Case

and DIST cases would not change. Also, the differential transmission losses between the HNEC and DIST cases would be expected to remain approximately the same with or without an additional DC line. The primary use of the DC lines in the future will be for capacity exchange. The flow in the DC lines at the January PNW peak load as shown in the following load flow diagrams, would be into the PNW system rather than out of it, except in years in which there would be considerable excess hydro energy. This circumstance would not significantly change the cross-mountain transmission requirements of the comparative cases.

Power flows in corresponding corridors are shown (Figure 7 through 10) under January peak load conditions for the level of development of each case.

In addition to the major cross-mountain lines listed in Table 4, other sections of lines will be needed to connect the dispersed generating plants with the transmission system as well as to augment local system capacity. For the period beyond 1988, the following line additions are common to both the DIST and HNEC cases:

- A single-circuit 500-kV line from Grand Coulee to Bell Substation (Spokane), 85 miles.
- A second single-circuit 500-kV line between Raver and Monroe Substations in the Puget Sound area, 40 miles.
- A second single-circuit 500-kV line from Pebble Springs to John Day, 35 miles.
- Portland area reinforcement:

Harris-Rivergate 500-kV single-circuit line, 15 miles.

Troutdale-Harris 500-kV double-circuit line, 10 miles.

In addition to the lines described above, the following lines will also be needed for the DIST-100% case:

- A single-circuit 500-kV line of approximately 30 miles from a Western Washington plant site to the Allston Substation (south of Longview).
- A 50-mile single-circuit 500-kV line from a western Oregon plant site to the Lane Substation (near Eugene).

FIGURE 7. Peak Load Power Flows for 100% DIST Case (January 1999)

FIGURE 8. Peak Load Power Flows for 100% HNEC Case (January 1999)

FIGURE 9. Peak Load Power Flows for 150% HNEC Case (January 2003)

FIGURE 10. Peak Load Power Flows for 150% DIST Case (January 2003)

For the HNEC cases, an 80-mile line from Marion Substation (near Salem) to Lane Substation will be needed. The line construction requirements of the several cases are summarized in Table 5. (Some of the smaller line segments common to all cases are eliminated in the capital cost estimates to follow.)

Series compensation would be added to some of the new and existing lines as the line loading increased. Capital cost estimates, which follow later in the report, include the costs of such equipment.

Reactive supply equipment also is added as needed. The amount of reactive supply required in the various cases, and assumptions made with respect to the sources of supply, are discussed under the following section on losses.

The systems generally defined by the above maps (Figures 4-6) and descriptions from the bases for the following cost estimates. Peak load power flows in January 1999 (Figures 7, 8) and in 2003 (Figures 9, 10) may be compared with the total nominal capacities of corresponding parts of the system as augmented by the lines described above. For distances involved in this report, the approximate nominal maximum capacities of the lines are:

500 kV	double-circuit, high-capacity	5000 MW
500 kV	single-circuit, high-capacity	2500 MW
500 kV	single-circuit, std. capacity	1500 MW

These nominal ratings are for transmission lines of 150 to 200 miles in length within an established 500 kV network. The "standard capacity" line has 3-Bunting conductors per phase and no series compensation. The "high capacity" line has 3-Chukar conductors per phase and 50% series compensation. The ratings conform with the Revised Line loadability curve of Reference 3. Under normal system conditions the peak line loadings would approach the nominal capacity around the year 2000. Under outage conditions on parallel lines, or with outages in parts of the system such that power flow in an alternative path is increased, the flows temporarily could exceed the nominal capacity ratings given above, but would not exceed the thermal limits nor experience intolerable phase angle differences.

TABLE 5. Summary of 500 kV Line Construction (Beyond 1988)

	<u>DIST (100%)</u>	<u>HNEC (100%)</u>	<u>HNEC (150%)</u>
<u>Double-Circuit (Miles)</u>			
Ashe - Portland	180	180	180
Coulee - Snoqualmie	185	185	185
Harris - Troutdale	10	10	10
Gable Mountain - Portland No. 1	--	180	180
Gable Mountain - Portland No. 2	<u>--</u>	<u>--</u>	<u>180</u>
TOTAL	375	555	735
<u>Single-Circuit (Miles)</u>			
Nuclear (Western Oregon) - Lane	50	--	--
Harris - Rivergate	15	15	15
Raver - Snoqualmie - Monroe	40	40	40
Nuclear (Western Washington) - Allston	30	--	--
Coulee - Bell	85	85	85
Slatt - John Day	35	35	35
Marion - Lane	<u>--</u>	<u>80</u>	<u>80</u>
TOTAL	255	255	255
Total Line Miles	630	810	990
Total Circuit Miles	1005	1365	1725

LOSSES

Under peak load conditions the system losses in the respective cases, including the DIST 150% case, are tabulated in Table 6.

The peak losses are system-wide, for both the January 1999 and 2003 peak load conditions. For purposes of this study it is assumed that the loss difference will follow a smooth curve from zero in 1988 through the computed points. To convert the peak real power losses (Table 6) to average energy losses, the peak loss figure has been multiplied by a loss factor of 0.55 since the losses are mainly a function of the square of the current, and the current is related to the system load factor which ranges from 70% to 75%.

TABLE 6. System Peak Losses

	<u>MW</u>	<u>MVAR</u>
<u>100% Cases</u> <u>(56,500 MW Load Level,</u> <u>January 1999)</u>		
HNEC	1850	14,200
DIST	<u>1550</u>	<u>10,100</u>
Difference	300	4,100
<u>150% Cases</u> <u>(64,000 MW Load Level,</u> <u>January 2003)</u>		
HNEC	2380	21,000
DIST	<u>1860</u>	<u>14,000</u>
Difference	520	7,000

Certain assumptions regarding the sources of supply are necessary in order to evaluate the effect of differences in MVAR requirements. For instance, it is assumed that 25% of the reactive supply will come from the generators of the new thermal plants, and 75% from capacitors. Again, it is assumed that that buildup of the difference in MVAR requirements will follow a smooth curve from zero in 1988 to the designated values in the late 1990s.

TERMINAL SWITCHING ARRANGEMENTS

Conceptual bus arrangements at the HNEC line terminals are shown in Figures 11 and 12 for the 100% and 150% cases, respectively. Each station allows for one or two generating plants to supply possible local industrial load, and one or two positions for outgoing lines to local load centers. Generating units up to a total of eight (including one or two for local loads) could possibly be accommodated in each station, assuming that interrupting duty can be held within acceptable limits. Beyond that, more concentration

FIGURE 11. Switching Stations HNEC-100% (1998) Case (500 kV)

FIGURE 12. Switching Stations HNEC-150% (2002) Case (500 kV)

of power in the switchyard would aggravate problems regarding handling fault currents; it would also be inadvisable with respect to exposing too great a portion of the system generating capacity to complete failure of a switching station.

Growth of capacity at HNEC beyond 30,000 MW would require a fourth switching station at an appropriate location with respect to the remaining nuclear plant sites.

Safety requirements for nuclear plants specify that two independent off-site 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 system to the station 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 alternates 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." Satisfactory station service power could be obtained as economically at HNEC as at a DIST site, perhaps more so. (Although Figures 11 and 12 do not contain detailed information on station service arrangements, such detail can be obtained from Reference 2).

Bus arrangements for the one, two, or three-unit plants of the DIST concept would be of a conventional type.

CONSTRUCTION

The construction peak would occur in the period 1988 to 1992 when transmission expenditures in the HNEC 100% case would average \$17 million per year higher than in the DIST case. This increment of added demand on construction markets would be a relatively small fraction of the total regionwide generating and transmission plant construction work anticipated at that time.

The only added construction complications due to HNEC-100% would be the construction of one line, Gable Mountain to Portland, in addition to the other two cross-mountain lines to be built in the DIST case. Conditions in various

rights-of-way are different, but usually the construction of a 500 kV double-circuit line would entail removal of an existing 230 kV line. Since most of the rights-of-way are shared by two or more lines, the 230 kV line must be removed and the 500 kV line built without interference with an adjacent active line.

Similar line replacement has been accomplished between Grand Coulee and the Puget Sound area. While the degree of difficulty varies with the terrain and the line configurations in a given locality, there appear to be no insurmountable obstacles to the successful completion of such projects.

By the time this construction is scheduled, there should be ample alternative routes over which the power then being carried on the 230 kV line could be carried, while maintaining necessary spare capacity in the transmission system for emergencies. No extraordinary system operations management problems are anticipated.

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 23,000 MW in generating capacity. To this end, some consideration is given in the report to expansion or adaptation of the 2002 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 7 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

TABLE 7. Cascade Pass Right-of-Way Capacity

Pass	1970 MW	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	1,500	2,600	6,500	11,500
Snoqualmie	550	550	5,000	10,000
Stampede	3,700	3,700	17,700	22,700
Columbia River	950	2,250	11,500	16,500
Lolo	1,950	1,950	11,200	21,200
Mt. Wilson	1,500	1,500	11,500	16,500
Breitenbush	<u>500</u>	<u>500</u>	<u>5,000</u>	<u>10,000</u>
Total Capacity	10,650	13,050	68,400	108,400
System Transfer Capability(a)	8,000	10,500	55,000	87,000

(a) Includes margin for reliability.

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.

Handling that amount of power from one general area would involve many questions of system design, some of which are noted in the section on Proposed Additional Studies. 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 23,000 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 1988-98 period. The transmission system concept for either DIST or HNEC would serve both the new hydro capacity and the new thermal capacity at its designated location. Although the new transmission facilities will not serve the new thermal plants exclusively, the estimated transmission cost difference between the DIST and HNEC-100% cases is a result of site selection for the thermal plants only, and therefore represents a true cost burden chargeable to HNEC. For this reason, the emphasis in the discussion of unit cost burden is placed on differences between DIST and HNEC 100%. In the HNEC-150% case, costs are examined as an extension of HNEC-100% costs.

The capital cost estimates include transmission lines, switching stations and series compensation. They exclude (1) transmission lines, other than the high capacity lines, which are common to all alternates, (2) transformers, (3) subtransmission costs that would be the same for the comparative cases, and (4) some costs that may be different for the comparative cases but of relatively little economic significance, such as 230-kV or 115-kV transmission lines for in-house service of generating plants of the DIST or HNEC cases.

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 1988, and that would be incurred to accommodate the series of new thermal generating plants to be installed in the alternative concepts.

ECONOMIC GROUND RULES

1. Estimates are given in constant 1978 dollars.
2. Losses are to be charged on the basis of cost of new nuclear generating capacity to offset losses, plus estimated nuclear fuel cost over the 1988-98 period unescalated from 1978. The resulting estimated unit cost of power losses is \$112 per kilowatt of demand, plus 5.5 mills per kilowatt hour.

3. Present worth of transmission line cost is computed at an 8.25% discount rate representative of anticipated future cost of money to BPA.
4. The composite annual cost ratio applied to capital cost to obtain annual charges is 11.8%. It includes interest and amortization, capital replacement, charges for supporting general plant operation and maintenance, and general overhead.

ESTIMATES

Capital investment is estimated to be:

	\$ Million		
	<u>Investment</u>	<u>Interest During Construction</u>	<u>Total</u>
DIST-100% Case	275	84	359
DIST-150% Case	458	140	598
HNEC-100% Case	446	137	583
HNEC-150% Case	655	200	855

Figure 13 shows the timing of capital expenditures for HNEC-100% case versus the DIST case. The difference in capital investment is \$171 million. The shaded areas represent the added capital expenditures of HNEC over those of DIST. The shaded area would be reduced by the areas in 1987 and 1990 when DIST investment would exceed that of HNEC, to arrive at the net added investment of \$171 million for HNEC, without interest during construction. With interest during construction the estimated added investment of the HNEC-100% case is \$224 million.

Figure 14 is a plot of the differences in value of losses, and fixed charges on capital presented in Table 8, which contains estimates of total cost differences between the DIST and HNEC-100% cases.

Energy losses at the assumed unit value of energy increase until the added losses due to HNEC reach \$41.6 million in 1998 or 56% of the total difference in cost between the two cases. The costs of reactive supply are relatively low.

FIGURE 13. Schedule of Capital Expenditures, DIST and HNEC-100% Cases

FIGURE 14. Difference in Value of Annual Transmission Losses, HNEC Versus DIST-100% Cases

TABLE 8. Added Transmission Cost^(a) Burden for
HNEC-100% Case Versus DIST-100% Case^(b)

Year	Fixed Charges on Capital	Transmission Losses	Cost of Reactive Supply	Total	Total Discounted to 1989
1989	2.4	0	0.5	2.9	2.9
1990	2.4	2.8	1.1	6.3	5.8
1991	0.4	6.9	1.5	8.8	7.5
1992	21.5	11.1	2.1	34.7	27.4
1993	21.5	15.0	2.7	39.2	28.5
1994	1.8	19.4	3.3	24.5	16.5
1995	26.3	24.2	4.0	54.5	33.9
1996	26.3	29.8	4.6	60.7	34.8
1997	26.3	35.3	5.3	16.9	35.5
1998	26.3	41.6	6.4	<u>74.3</u>	<u>36.4</u>
				372.8	229.2

(a) millions of (1978) dollars

(b) difference between case estimates

Figure 15 shows year-by-year the unit cost difference derived by dividing the extra transmission costs for the HNEC case by the energy delivered to the system by HNEC generators added after 1988. The varying costs and line loadings at the beginning of the 10-year period result in fluctuating unit cost differences which stabilize at about one mill per kilowatt hour when all lines are in service and become well loaded. The levelized (at 8.25%) HNEC unit cost burden for the period would be about 1.0 mill per kilowatt hour as shown in Figure 16.

In a preliminary comparison of the 150% cases, the added annual transmission cost burden of the HNEC in 2002 was found to be approximately the same as for the 100% cases in 1998, and the added cost burden per unit of energy transmitted less than that of 1998. Prior to the end of this period some 1100 kV lines may come into service, which could modify the economics of transmission.

FIGURE 15. Difference in Annual Charges Related to Capital Investment HNEC Versus DIST, 100% Cases

FIGURE 16. Added Transmission Cost Burden: HNEC-100% Case Versus DIST Case, per Unit of Energy from Post-1988 HNEC Plants

A summation of the economic effects of the HNEC follows:

- Additional transmission capital investment with interest during construction in the HNEC-100% case over that of the DIST-100% case would be \$224 million over the 1985-95 period.
- Added cost burden on the HNEC-100% case including losses would be:
 - Annual costs ranging up to \$74 million in 1998.
 - Unit costs of \$6.80 per year per kilowatt of capacity in generating plants added after 1988, or about 1.0 mill per kilowatt hour generated.
- For the HNEC-150% case, estimated capital investment would increase from the \$446 million of the 100% case to \$655 million. The difference in annual costs between the HNEC and DIST 150% cases indicates that cost of transmission per unit of energy transmitted would decline as the HNEC capacity increased from 15,000 to 23,000 MW.

ANALYSIS OF SYSTEM CONCEPTS

This section of the report briefly examines the reliability, reserve, technological development and environmental aspects of the DIST and HNEC concepts.

RELIABILITY

The reliability of the DIST and HNEC transmission concepts can be compared by examining the probability and consequences of system disturbances in each case; 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. In general, the reliability criteria now in effect would apply to both concepts, but the method of interconnection to conform to the reliability criteria could result in greater expectation of load loss in the HNEC case because of the system configuration.

In addition to differences in configuration, differences in technology could affect reliability, at least temporarily, through the learning-curve effect taking place as equipment of the new design is placed in commercial service. However, consideration of such effects is not included here, first, because the 500-kV system involves a minimum of as-yet-unproven technology, and secondly, because the ongoing expansion through the use of 1100-kV (considered an alternate) is an extension of present overhead transmission technology rather than a new departure, and its use can be deferred until adequate testing programs are conducted.

Exposure

Exposure to transmission system outages, which may or may not involve load outages, would be greater in the HNEC case because of (a) more miles of transmission line, (b) more power carried over certain rights-of-way, and (c) a greater 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 in both DIST and HNEC concepts and may be eliminated as a source of potential difference in reliability between the two concepts.

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 condition 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.

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.

Both the HNEC and DIST system design concepts respond to the loss of any line without interruption of service to loads on any part of the system. In the HNEC-150% case the most heavily loaded line to the Portland area would have a peak load of about 4500 MW with 23,000 MW of capacity at HNEC. 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 in the HNEC than in the DIST case, more spare capacity is provided in other lines in the network, and the consequences (no load loss) would be the same for the DIST and HNEC cases.

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. In some situations this could cause loss of more load in the HNEC case than in the DIST case. 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 case, since more generating capacity is connected to a single switching station than in the DIST case, more 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 station 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 more serious reliability consequences with the HNEC concept, 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 more than in a DIST situation.

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 9 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.

The risk of interruption of power at a DIST switching station is somewhat higher, but the maximum power interruption would be 4.8 GW instead of 8.4 GW.

TABLE 9. 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.

One further point is to be noted: the Gable Mountain station is shown as having two major outgoing lines (HNEC-150% case). If a station incident opened both lines, the load drop consequences could be greater than for potential incidents of this type in the DIST case. These lines are to be kept in separate rights-of-way for obvious reasons.

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 as great as that of circuit breakers applied in the DIST alternative. 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 more vulnerable than DIST 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 a comparison of HNEC and DIST 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 and DIST with respect to these probabilities there is no clear difference in Items (1) and (2), but there is some disadvantage to 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 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 1988 with its "distributed" hydro and thermal generation will be a closely coupled system, with internal interconnecting 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.

System conditions consistent with internal stability will remain in the DIST case if interconnecting ties between the new distributed generating stations and existing stations are of sufficient capacity. In the HNEC case,

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 either the DIST or HNEC concepts.
- Stability between the PNW and adjacent systems will be affected in much the same way by both concepts, 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 would be exposed to a very-low-probability class of events that could affect reliability adversely relative to DIST, and that class of events could not be compensated reasonably by system design measures.
- In other exposure classifications the HNEC and DIST concepts have essentially equal reliability.

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 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 load 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. In either the DIST or HNEC case large amounts of peak power would flow from the Upper Columbia region. Therefore, the availability and cost of reserve power are estimated to be roughly equivalent for the comparative cases.

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 150% case allows an available fault current of 86 kA which is in line with the interrupting capacities for the most recent 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. In line with these advances, further research is expected to extend interrupting capacities and shorten fault clearing times to one half cycle.

ENVIRONMENTAL IMPACT

The HNEC transmission concept presented herein, i.e., one limited to 500 kV AC overhead lines, would have environmental effects similar to those of the DIST case, mainly in the categories of visual impact and the amount of land used for rights-of-way.

Differences in visual impact would occur wherever 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 17). In the HNEC-100% case there would be one additional cross-mountain line of approximately 180 miles replacing lower voltage lines over and above that of the DIST case; and in the HNEC-150% case, two lines, for a total of 360 additional miles of line. 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 10. The land use requirement for the HNEC-100% case is only 5.4% greater than the DIST case. It is somewhat greater than that of the DIST case in the agricultural, range-land and forest land categories, but somewhat less in the residential/industrial land category. The requirements of the HNEC-150% case, relative to those of the HNEC-100% case, are 14% greater, the major portions being in agricultural land.

STANDARD CAPACITY
500 KV SINGLE CIRCUIT
1500 MW
R.O.W. 125'

HIGH CAPACITY
500 KV DOUBLE CIRCUIT
5000 MW
R.O.W. 135'

HIGH CAPACITY
1100 KV SINGLE CIRCUIT
10,000 MW
R.O.W. 170'

STANDARD CAPACITY
230 KV SINGLE CIRCUIT
300 MW
R.O.W. 125'

FIGURE 17. EHV-UHV Tower Configuration, Capacity, and Right-of-Way Requirement

TABLE 10. Summary of Land Use for New
Rights-of-Way Beyond 1988(a)

<u>Land Use (Acres)</u>	<u>DIST</u>	<u>HNEC (100%)</u>	<u>HNEC (150%)</u>
Agricultural	2040	2190	2635
Rangeland	1695	1785	1985
Forest Land	490	555	570
Residential/ Industrial	<u>275</u>	<u>215</u>	<u>215</u>
TOTAL	4500	4745	5405

(a) Assumes utilization of existing right-of-way by replacing existing lower voltage lines with higher capacity lines.

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 affects on either species.

The potential exists for some environmental degradation associated with the removal of existing 230 kV circuits and construction of 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 re-established 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 under either the DIST or HNEC design. Greater potential exists for adverse impact with the HNEC configuration since greater transmission line mileages are involved for agricultural, rangeland and forestland habitats. There are no rare or endangered species that would be adversely affected by construction of either design.

ALTERNATIVES

1100 kV AC

In the Pacific Northwest situation the only real contenders at present for bulk power transmission, other than the 500-kV double-circuit lines of the preferred HNEC concept, are 1100 kV or combinations of 500 and 1100 kV overhead AC lines. With a 500-kV grid already existing, 1100 kV was selected at the next overlay voltage level to be considered since this would provide greater transfer capacity and more efficient use of existing rights-of-way than 800 kV. The 1100 kV line also reflects the criterion that the overlay voltage should be twice the existing system voltage level.

Preliminary review of the feasibility and economy of several alternate solutions indicated that 500 kV double-circuit overhead lines would provide the necessary capacity and reliability. With transmission additions confined within available rights-of-way, HNEC generation levels in excess of 23,000 MW can be transmitted with 500 kV lines. Since technology and rights-of-way for a 500 kV transmission development are available, it was decided to limit the basic alternatives under study to this level. However, since future load and resource patterns beyond the year 2000 may require greater transmountain transfer capacity than the 500 kV lines would provide, several 1100 kV alternatives were studied and compared with the 500 kV cases. This was done to anticipate longer-range needs and to compare on a preliminary basis the technical, economic, and environmental requirements and impacts in a combined 500 kV and 1100 kV development.

In the study of possible solutions, it was assumed that 1100 kV overhead lines and equipment would be available for operation by the middle 1980s. Development of technology of 1200 kV lines and equipment has been in progress in the U.S. since 1967. BPA has built and operated a 1.3 mile 1100 kV test section of line adjacent to the Santiam Substation since December 1976. An unenergized test section for mechanical tests was built near Moro, Oregon in the same period. It is expected that design parameters for an 1100 kV line will be established by the fall of 1980. After two to five years more for final development and planning, construction of lines could commence in the mid-1980s.

Among the problems of the 1100 kV line under study are radio and audible noise, other induction effects, biological effects on plants and wildlife, and mechanical stresses imposed upon multiple-conductor bundles of the configurations planned for 1100 kV. Designs are proposed for electrostatic gradients at ground level no greater than for existing 500 kV lines.

BPA studies thus far indicate that the 1100 kV development appears feasible. Assuming positive results from the BPA 1100 kV test program and others in progress, a program of 1100 kV system design and development may be implemented with the goal of an operating 1100 kV line by the latter 1980s or early 1990s.

For the above reasons, 1100 kV transmission was considered a viable alternate, although not the desired choice for widespread use in the 1989-99 period, primarily because of present economic and technological uncertainties.

Preliminary work on the merits of different alternatives produced Table 11 of comparative losses. Although the cost of losses would be reduced by use of 1100 kV, the amount of capital requirement and its timing are disadvantageous. However, preliminary BPA studies indicate that the 1100 kV system would compare favorably with 500 kV on an economic basis.

TABLE 11. HNEC Alternatives - Loss Comparison

<u>Description</u>	<u>Losses (a)</u>	
	<u>MW</u>	<u>MVAR</u>
<u>100% Cases</u>		
Three 500 kV double-circuit lines	1850	14,200
One 1100 kV line, One 500 kV double-circuit line	1810	13,300
One 1100 kV line, Two 500 kV double-circuit lines	1700	12,000
<u>150% Cases</u>		
Four 500 kV double-circuit lines	2380	21,000
Two 1100 kV lines, One 500 kV double-circuit line	2140	18,500

(a) Losses shown are for the total system. Not included in the table are two 500 kV high-capacity, double-circuit lines to be completed by 1985. These are of the same type as the 500 kV lines in the table but are deleted since they are (1) common to all alternatives, and (2) scheduled for completion before 1985.

UNDERGROUND TRANSMISSION

As indicated previously, in the Pacific Northwest region underground transmission is not competitive economically with overhead transmission in any portion of the comparative systems. However, its use may be required for environmental or other reasons in certain portions of the system on a limited basis for either the HNEC or DIST system. It is recognized that underground transmission that would be feasible in certain circumstance is under development in cryogenic and other forms, but it has no place as an alternative in this study.

HIGH VOLTAGE DIRECT CURRENT TRANSMISSION

An 800 kV DC overhead line is in service between the Pacific Northwest and California, but this type of line is economically feasible only over distances greater than those used for bulk transmission within the Pacific Northwest marketing area; therefore, it was not considered an alternative to overhead AC.

PROPOSED ADDITIONAL STUDIES

Topics for additional study are suggested implicitly in the foregoing discussion.

- (1) A detailed study of the electrical characteristics of thermal generating plants, particularly in the context of a nuclear energy center. Among the items to be studied would be transient and steady-state stability, short circuit requirements, and economy of size, as well as how machine characteristics would effect the design and operation of the transmission system.
- (2) A detailed study of transmission system requirements to provide station service for the plants at the energy center. Items to be studied should include the design of the system, reliability considerations including common mode failures, transformation required, and the number and type of lines required to augment the present system. (This study was conducted, and is reported in Reference 2).
- (3) A more complete longer-range study which will examine development of the HNEC beyond the 23,000 MW level and the transmission system necessary to accommodate such a development. The study may also help in determining a limit on the feasible capacity at the Center based on advanced technological and system-design considerations.

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THE IMPACT OF A HANFORD NUCLEAR
ENERGY CENTER ON CLOUDINESS AND
INSOLATION

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THE IMPACT OF A HANFORD NUCLEAR ENERGY CENTER ON CLOUDINESS AND INSOLATION

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INTRODUCTION

Reactor cooling system effluents could, under some conditions, contribute to an increase in cloudiness and a decrease in insolation (solar radiation received at the earth's surface). This report presents the results of an evaluation of the potential impact of a Hanford Nuclear Energy Center (HNEC) on cloudiness and insolation. It is one of a series of reports prepared by the Pacific Northwest Laboratory (PNL) in the course of an evaluation of the energy center concept as it might be applied to the Department of Energy's Hanford Area in Washington State⁽¹⁻³⁾. Previous topical reports in the series deal with a variety of subjects including electrical transmission⁽⁴⁾, fuel cycle⁽⁵⁾, heat disposal⁽⁶⁻⁸⁾, and reliability of generation⁽⁹⁻¹⁰⁾.

The energy center concept involves the grouping of a large number of power plants at a common site. An energy center may also include fuel production and waste disposal facilities. Typically the number of power plants considered ranges from 10 to 40. In the conceptual evaluation of a Hanford Nuclear Energy Center both 20 and 40 generating unit centers have been considered, with the 20 unit center receiving the most attention. Within an energy center the individual power plants are generally grouped in clusters of about 4.

Thermal power plants cooling systems ultimately release a significant amount of energy to the atmosphere. In current designs this energy is primarily released as latent heat of evaporation of water and sensible heat in the form of

increased air temperature. Both the addition of water and the increase in temperature can contribute to the formation of clouds by increasing the instability of the atmosphere and triggering natural cloud formation processes. The additional water vapor may also contribute to the formation of clouds by directly bringing the air to saturation.

Increasing the cloudiness will, in turn, alter the balance of short wave (solar) and long wave (terrestrial) radiation. An increased cloud layer will increase the fraction of incoming solar radiation reflected prior to reaching the surface. Some of the reflected solar radiation will reach the surface as diffuse radiation and some will be lost to space. The increased cloudiness will also absorb an increased fraction of the long wave terrestrial radiation. Much of this energy is reradiated toward earth and is thereby retained in the earth-atmosphere system.

Specifically this report estimates the change in sky cover and the resulting change in solar radiation. It does not attempt to distinguish between direct and diffuse solar radiation, and it does not deal with the impact of increased cloudiness on long wave radiation.

The report is divided into four sections. In the first section we will develop the approach followed in the study, starting from estimation of the distributions of cooling system effluents, proceeding through estimation of changes in sky cover, and ending with estimation in changes in insolation. In the second section we will briefly describe the HNEC and discuss the aspects of the climatology of the Hanford Area that relate to sky cover and solar radiation. We will then develop the specific relationships required to make actual estimates of the changes. In the final sections we will examine

the estimated changes, compare them with worst case estimates, discuss their statistical significance, and discuss the conclusions reached.

CONCEPTUAL DEVELOPMENT

Estimating changes in sky cover and solar radiation is a complex problem. If approached rigorously as a time varying, three dimensional problem in atmospheric diffusion and transport, thermodynamics and radiative transfer, it would require resources beyond those currently available. Therefore, we approach the problem in a series of steps, each of which is treated with simplified "back of the envelope" models. Frequently it is necessary to resort to use of probability arguments.

Sky cover is one of the variables included in standard weather observations. It is the fraction of the sky covered by clouds and is expressed in tenths. The amount of sky cover reported is a subjective estimate of the observer and not the result of a precise measurement. Sky cover observations include the estimated or measured height of each cloud layer. A ceiling is said to exist when the total sky cover is 6/10 or greater. Some weather observations also include cloud types. The cooling system effluents from an HNEC might alter any or all of these cloud characteristics. In this study we will concentrate on estimating the change in the total sky cover. However, in the process of estimating these changes we will postulate certain, limited changes in cloud height and type.

Changes in sky cover are potentially related to a number of factors including: wind direction and speed, atmospheric stability, air temperature and humidity profile, the magnitude and distribution of the cooling system effluent releases, the time of day and year, and the initial sky cover. To a large extent the sky cover change will be a function of the magnitude

of the perturbation in atmospheric humidity and stability caused by the combined effluents from the cooling systems. The form of the change will be affected by atmospheric stability, temperature and humidity, and the location of the change will be a function of wind direction and geometric configuration of the source. Finally the increase in total sky cover cannot exceed fraction of the sky that is clear.

Our basic approach is to first treat the problem of atmospheric diffusion and transport of cooling system effluents to identify the location where changes are most likely, and to estimate the magnitude of the atmospheric perturbation caused by the effluents. This is done using a multiple-source, sector-average, Gaussian diffusion model. We will then use the estimated magnitude of the perturbations at each location in the effluent plume to estimate the fractional increase in sky cover at the location. Finally we will use the probability of occurrence of the modeled atmospheric conditions (wind direction, wind speed and atmospheric stability), and the fractional increase in sky cover to modify the climatological sky cover probability distribution. The climatological distribution of sky cover is assumed to represent current conditions in the entire area and is therefore independent of position, but the revised sky cover probability distribution is a function of position. The revised sky cover distribution is then used to estimate the change in insolation at each location.

The undepleted insolation passing through a plane normal to the sun's rays at the top of the earth's atmosphere is about $1.95 \text{ ly min}^{-1} (\text{cal/cm}^2\text{-min})$. This is called the solar constant. The solar energy reaching the earth's surface is a function of latitude, time of year and day, cloudiness and air quality. Usually the energy flux is significantly less than the solar constant. However, occasionally the combination of direct radiation and radiation reflected from clouds can cause the energy flux at the surface to approach the solar constant

for short periods. The effect of cloudiness on solar radiation depends on a number of factors including, the amount of sky cover, cloud types, and cloud height. There are several types of solar radiation measurements, however the most common is measurement of total incoming short-wave radiation received on a horizontal surface at the earth's surface. This measurement does not distinguish between direct and diffuse radiation.

To estimate the changes in solar radiation resulting from increased sky cover, we will make use of the revised sky cover probability distribution and empirical relationships between sky cover and solar radiation. These relationships, developed using insolation data collected at Hanford, provide an estimate of the solar radiation that would be expected at each location based on the revised cloud distribution. The decrease in insolation can then be estimated by comparing current climatological average values with those estimated from the revised cloudiness distribution.

We will now develop each of these concepts in detail.

The Diffusion Model

The multiple-source diffusion model used in this study was developed for an earlier HNEC study and is described in detail in Reference (8). It is a sector-average, Gaussian model that incorporates reflection at the surface and at an optional upper boundary. Individual sources are treated as virtual-point sources, and the concentration at each receptor point is estimated by combination of the concentrations from all sources. The sector-average model is described in Section 3.3 of Meteorology and Atomic Energy - 1968⁽¹¹⁾, while the treatment of the reflecting lid is based upon Section 6.6 of Csanady's Turbulent Diffusion in the Environment⁽¹²⁾.

For purposes of this study we will use water as an indicator of the modification potential of the cooling system

effluents. A large increase in atmospheric water content is assumed to correspond to a high potential for increasing sky cover. However, we do not claim that the modification will be caused by any specific process, i.e., saturation or triggering an instability.

The model used to estimate increases in water content (assumed to be water vapor) is:

$$(\Delta c_v)_{ki} = \frac{Q_i \hat{n}}{(2\pi)^{3/2} \sigma_z \bar{u} x} \sum_{j=-\infty}^{\infty} \left\{ \exp \left[\frac{(z - h_i + 2jH)^2}{-2\sigma_z^2} \right] + \exp \left[\frac{(z + h_i + 2jH)^2}{-2\sigma_z^2} \right] \right\} \quad (1)$$

where:

- $(\Delta c_v)_{ki}$ is the increase in water vapor concentration at receptor k due to source i,
- Q_i is the water vapor release rate of source i,
- $\hat{n}$ is related to the assumed plume width, ϕ_0 , by $\hat{n} = \pi/\phi_0$ when ϕ_0 is the radians,
- σ_z is the vertical dispersion parameter,
- $\bar{u}$ is the wind speed,
- x is the distance between the receptor and virtual point source,
- z is the height above the ground,
- h_i is the effective height for source i, and
- H is the height of the reflecting lid.

Equation 1 can be simplified if any or all of z , h_i and H are zero. The greatest simplification occurs if H is zero. In that case the infinite sum is eliminated. If h_i is zero the two exponential terms can be combined. If $z=0$ the infinite sum is twice the sum from 0 to ∞ . Finally, if all three are zero, the infinite sum and the exponential terms are eliminated.

In the current application none of these simplifications is appropriate, but the infinite sum is truncated at $j=2$.

In the case of cooling tower effluents the effective height of release is the actual release height plus plume rise due to buoyancy. Briggs' formulae are used to estimate final plume rise⁽¹³⁾.

In model computations, the Briggs' formulations⁽¹⁴⁾ for σ_z are used. Table 1 gives the Hanford stability classes used, the corresponding Pasquill-Gifford stability classes, and the Briggs' σ_z formulations.

TABLE 1. Relationships Between σ_z , Atmospheric Stability and Distance from the Virtual Point Source to Receptor

<u>Stability Class</u>		<u>σ_z</u>
<u>Pasquill-Gifford</u>	<u>Hanford</u>	
A		.20x
B	Unstable	.12x
C		.08x/(1+.0002x) ^{1/2}
D	Neutral	.06x/(1+.0015x) ^{1/2}
E	Slightly stable	.03x/(1+.0003x)
F	Moderately stable	.02x/(1+.0003x)
G		.012x/(1+.0003x)

During high wind speed conditions, a standard wake correction is applied to the values of σ_z .

The Sky Cover Model

In the current application, the diffusion model is run for each combination of wind speed, direction and atmospheric stability. At the completion of each run the increase in water content is used to estimate the increase in cloudiness as a

function of position. The climatological change in sky cover is estimated by summing the results for each combination of wind speed, direction and stability weighted by frequency of occurrence of the combination. For this initial study we assume that sky cover is statistically independent of these factors. If a more detailed study is warranted, the statistical independence will be examined and taken into account as necessary.

The relationship between the cooling system effluents and increased cloudiness are not well established. A number of studies, e.g., References (15) through (17), have used numerical models to predict the extent clouds and plumes produced by cooling towers. In general these models require more input data than is readily available for an HNEC. In addition, the models' abilities to adequately handle the synergistic effects of multiple effluent sources are open to question. As a result, we will treat the relationship between effluent concentration and increased cloudiness in a highly parameterized fashion. We will assume that an increase in water content at a point is directly related to a fractional increase in cloudiness. The relationship will be entered in the sky cover model as a table. As better information becomes available, the table can be altered and more realistic relationships can be formulated.

If we let SC represent the sky cover, the amount of the sky available for increased cloudiness is (10-SC). The increase in sky cover is then the product of the sky available and the fractional increase, f_i , resulting from a given cooling system effluent concentration, i.e.,

$$\Delta SC^* = f_i (10-SC) \quad . \quad (2)$$

And, the estimate of the corresponding sky cover assuming an operating HNEC, SC^* is

$$SC^* = SC + f_i(10-SC) \quad . \quad (3)$$

We will assume that the sky cover observations at the Hanford Meteorology Station are representative of the whole Mid-Columbia Region so that SC is not a function of position. However, the fractional increase in sky cover is a function of position. Therefore, SC* is also a function of position.

We will treat the temporal variation of average sky cover by use of probability distributions for SC. These distributions will be changed on a monthly basis. Systematic diurnal variations in sky cover exist, but in the Mid-Columbia region they are small compared to the annual variation represented by the monthly probability distributions. As a result, they will be neglected.

It seems reasonable to assume that the relationship between cooling system effluent concentration and fractional increase in sky cover should have both annual and diurnal variability. Because of the limited information on which to base this relationship, we will neglect any diurnal variations and treat the annual variations by altering the conversion table seasonally. In the winter we will allow a relatively small increase in water content to make a relatively large fractional increase in sky cover; in the summer a relatively large increase in water content will make a relatively small fractional increase in sky cover, and the spring and fall will be treated in an intermediate manner. We will examine the sensitivity of the sky cover model to changes in the conversion table by modeling each season with a "worst case table" in which a small increase in water content results in an overcast sky condition.

After the change in sky cover is estimated at each position, the sky cover probability distribution at each position will be updated. If we let $P_o(SC)$ be the climatological probability of sky cover, SC, and P_w be the joint probability of the given wind speed and direction, and atmospheric stability, the change in

sky cover probability ΔP_{SC} is :

$$\Delta P_{SC} = P_o(SC) P_w \quad . \quad (4)$$

We then update the sky cover probability distributions at each position using SC and SC* as indices:

$$P_{ij}^*(SC^*) = P_{ij}^*(SC^*) + \Delta P_{SC} \quad (5)$$

and

$$P_{ij}^*(SC) = P_{ij}^*(SC) - \Delta P_{SC} \quad (6)$$

where $P_{ij}^*(SC^*)$ and $P_{ij}^*(SC)$ are updated parts of the sky cover probability distribution at position i,j . Prior to the first update, $P_{ij}^*(SC)$ are set equal to $P_o(SC)$; as the number of conditions modeled increases they take on their own characteristics.

When all atmospheric conditions have been modeled, we compute a new mean sky cover for each position using Equation (7):

$$\overline{SC}_{ij}^* = \sum_{SC^*} SC^* P_{ij}^*(SC^*) \quad . \quad (7)$$

The initial average sky cover is computed using SC and $P_o(SC)$. Finally we estimate the increase in sky cover as:

$$\Delta \overline{SC}_{ij} = \overline{SC}_{ij}^* - \overline{SC} \quad . \quad (8)$$

The outputs of the sky cover model are, then: an updated probability distribution of sky cover, an estimate of the average sky cover assuming an operating HNEC, and an estimate

of the increase in average sky cover over its current climatological value. Each of these items varies from month to month.

The Solar Radiation Model

The literature on the relationship between sky cover and solar radiation is relatively extensive and much of it is applicable to the current problem. Geiger⁽¹⁸⁾ indicates that the ratio of solar radiation on clear days to that on cloudy days is about .25 in the winter, .50 in the summer, and has an annual average about .40. More recent works⁽¹⁹⁻²³⁾ give quantitative relationships between sky cover and radiation. In general these relationships show a quadratic decrease in radiation with increasing sky cover. A wide range of numerical constants in the relationships indicates that the equations are rather specific to the particular data set used in their development. As a result we will use solar radiation and sky cover data from Hanford to develop our own relationship.

The literature (e.g., 20, 24-27) clearly shows that, in addition to total sky cover, cloud type is a significant factor in determining the reduction in solar radiation. In particular high, thin cirriform clouds are significantly less effective in reducing solar radiation than are lower, thicker clouds. The use of total sky cover, including cirriform clouds in estimating solar radiation tends to underestimate in solar radiation^(20,25). Lund⁽²⁴⁾, and Lund and Shanklin⁽²⁶⁾ indicate that the probability seeing the sun is 6 to 20% greater than the probability of a cloud-free line of sight. The difference is largely a result of cirriform clouds. Finally Angell and Korshover⁽²⁷⁾ indicate that high, thin cirrus clouds have no effect on sunshine. As a result, our treatment of the sky cover probability distribution will distinguish between sky and low ceilings. High ceilings will be treated as cirriform clouds.

We will estimate the solar radiation at any time during operation of an HNEC as the product of the solar radiation in the absence of the HNEC and a function that relates sky cover and solar radiation at Hanford. That is:

$$SR_{ij}^* = SR_0 F(SC^*, \overline{SC}) \quad (9)$$

where SR_{ij}^* is an estimate of the solar radiation at i, j given sky cover SC^* ; SR_0 is the average solar radiation and $F(SC^*, \overline{SC})$ relates solar radiation and sky cover.

The average solar radiation for a given period of time is found by weighting the estimates of the past HNEC solar radiation by the probability of SC^* . This is shown in Equation (10):

$$\overline{SR}_{ij}^* = \overline{SR}_0 \sum_{SC^*} F(SC^*, \overline{SC}) P_{ij}^*(SC^*) \quad (10)$$

where $\overline{SR}_0$ is the appropriate pre-HNEC average. The decrease in solar radiation is then simply the difference between $\overline{SR}_{ij}^*$ and $\overline{SR}_0$.

Prior to developing the table that specifically relates cooling system effluent concentration to increased sky cover and a mathematical expression for $F(SC^*, \overline{SC})$, we will discuss the HNEC configuration and the Hanford area climate.

THE HANFORD NUCLEAR ENERGY CENTER

The conceptual HNEC configuration and the climatology of the Hanford area are important because the results presented are specific to the HNEC, although the approach described is general.

HNEC Configuration

The Hanford area is situated in the southern portion of Eastern Washington near the Oregon border as shown in Figure 1. The Columbia River, which runs through the area, provides an adequate source of water for the operation of wet cooling systems in the center.

During the HNEC conceptual studies numerous sites have been considered as potential cluster locations. Analysis of the HNEC concept is currently concentrating on a 20 power plant center with clusters located at sites 1 through 5 in Figure 2. In this report, HNEC specifically refers to power plant clusters at these locations. Each cluster consists of four power plants that are assumed to use mechanical draft towers for cooling.

In the computations, the cooling systems for the power plants in each cluster are treated as a single entity; no effort has been made to examine small scale effects. When a cluster is to be the effluent source, a virtual point source is found using wind direction, stability and an actual source width of 1609 m (1 mi.). It is assumed that each cluster will occupy approximately 2.6 Km^2 (1 sq. mi.). The height of the cooling towers is assumed to be 25 m. Receptors are treated as points. A detailed discussion of the source-receptor geometry is contained in Reference 8.

Hanford Diffusion Climatology

The basic reference on Hanford Climatology is Climatography of the Hanford Area⁽²⁸⁾. Additional information relative to the conceptual HNEC is given in Reference 8. In general, the climate is typical of a mid-latitude desert-steppe. The prevailing wind directions are northwest and southwest, with speeds averaging between 2 and 3 m s⁻¹ and occasional periods of high speeds.

FIGURE 1. The Location of the Department of Energy's Hanford Area.

FIGURE 2. The Mid Columbia Area and Potential Cluster Locations for an HNEC. Grid Spacing is 8000 M.

Atmospheric diffusion is related to wind and atmospheric stability as shown in Equation (1). The joint frequency distributions of wind direction, wind speed and atmospheric stability required for diffusion computations involving specific sources and receptors are given in Tables 2-5 for Hanford by season.

TABLE 2. Spring Percentage Frequency Distribution of Wind Speed and Wind Direction at 200-Foot Level vs. Atmospheric Stability

		NNE	NE	ENE	E	ESE	SE	SSE	S	SSH	SW	WSW	W	WNW	NW	NNW	N	VAR.	CALM	TOTAL
0 - 3	VS	0.05	0.03	0.01	0.04	0.05	0.05	0.03	0.03	0.03	0.03	0.03	0.10	0.06	0.06	0.08	0.05	0.05	0.05	0.82
	MS	0.16	0.20	0.13	0.14	0.26	0.29	0.18	0.16	0.17	0.22	0.16	0.38	0.27	0.32	0.31	0.27	0.16	0.22	3.99
	N	0.28	0.42	0.29	0.34	0.32	0.32	0.09	0.18	0.13	0.17	0.10	0.22	0.16	0.28	0.34	0.46	0.39	0.11	4.59
	U	0.35	0.50	0.24	0.31	0.23	0.26	0.12	0.11	0.10	0.08	0.07	0.10	0.09	0.18	0.20	0.44	0.31	0.02	3.72
4 - 7	VS	0.01	0.01	0.01	0.	0.04	0.06	0.04	0.04	0.07	0.12	0.12	0.20	0.22	0.19	0.11	0.05	0.	0.	1.28
	MS	0.18	0.16	0.13	0.21	0.28	0.45	0.26	0.32	0.27	0.34	0.56	1.03	1.03	1.05	0.62	0.44	0.02	0.	7.35
	N	0.33	0.49	0.31	0.38	0.28	0.51	0.26	0.34	0.27	0.36	0.33	0.40	0.52	0.73	0.59	0.55	0.08	0.	6.63
	U	0.78	0.81	0.52	0.46	0.41	0.58	0.39	0.42	0.38	0.44	0.26	0.27	0.36	0.82	0.78	0.90	0.17	0.	8.74
8 -12	VS	0.01	0.01	0.00	0.	0.00	0.04	0.06	0.02	0.01	0.05	0.13	0.20	0.28	0.59	0.13	0.02	0.	0.	1.54
	MS	0.16	0.19	0.14	0.13	0.13	0.27	0.31	0.21	0.26	0.42	0.96	1.95	2.95	1.81	0.61	0.27	0.	0.	10.78
	N	0.24	0.16	0.10	0.11	0.10	0.15	0.18	0.21	0.39	0.52	0.54	0.61	0.84	0.97	0.27	0.27	0.	0.	5.66
	U	0.43	0.37	0.15	0.11	0.09	0.23	0.21	0.20	0.40	0.55	0.46	0.27	0.52	1.07	0.41	0.43	0.00	0.	5.91
13-18	VS	0.	0.	0.	0.00	0.	0.01	0.03	0.	0.01	0.00	0.05	0.11	0.26	0.70	0.07	0.01	0.	0.	1.25
	MS	0.10	0.07	0.05	0.07	0.02	0.12	0.26	0.09	0.14	0.46	1.15	1.66	3.68	2.23	0.21	0.18	0.	0.	10.49
	N	0.19	0.08	0.03	0.01	0.01	0.05	0.11	0.17	0.32	0.60	0.83	0.81	1.25	0.95	0.06	0.10	0.	0.	5.59
	U	0.35	0.18	0.04	0.02	0.00	0.03	0.06	0.09	0.29	0.62	0.70	0.28	0.70	0.91	0.11	0.20	0.	0.	4.59
19-24	VS	0.	0.	0.	0.	0.	0.00	0.01	0.01	0.	0.	0.	0.01	0.05	0.14	0.01	0.	0.	0.	0.22
	MS	0.02	0.01	0.01	0.02	0.	0.02	0.07	0.05	0.11	0.28	0.47	0.23	1.27	0.96	0.02	0.01	0.	0.	3.54
	N	0.08	0.04	0.01	0.	0.00	0.03	0.05	0.09	0.25	0.58	0.66	0.33	1.09	0.87	0.02	0.04	0.	0.	4.14
	U	0.09	0.05	0.01	0.01	0.	0.	0.01	0.04	0.19	0.48	0.55	0.18	0.47	0.69	0.02	0.03	0.	0.	2.81
OVER 24	VS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.01	0.00	0.	0.	0.00	0.	0.	0.	0.	0.01
	MS	0.01	0.01	0.	0.	0.	0.	0.	0.02	0.08	0.18	0.11	0.02	0.34	0.33	0.	0.01	0.	0.	1.11
	N	0.02	0.01	0.00	0.00	0.	0.	0.01	0.04	0.20	0.63	0.41	0.08	0.66	0.76	0.00	0.00	0.	0.	2.84
	U	0.01	0.03	0.02	0.	0.	0.	0.	0.01	0.14	0.71	0.47	0.13	0.33	0.57	0.00	0.00	0.	0.	2.42
TOTALS	VS	0.07	0.05	0.03	0.04	0.09	0.16	0.17	0.10	0.12	0.21	0.33	0.62	0.86	1.68	0.39	0.12	0.05	0.05	5.13
	MS	0.62	0.63	0.47	0.57	0.70	1.15	1.07	0.89	1.03	1.90	3.41	5.28	9.53	6.71	1.76	1.16	0.18	0.22	37.25
	N	1.15	1.10	0.75	0.84	0.71	1.06	0.69	1.03	1.57	2.86	2.88	2.49	4.53	4.55	1.31	1.42	0.43	0.11	29.43
	U	2.02	1.93	0.98	0.91	0.74	1.10	0.78	0.87	1.49	2.89	2.52	1.23	2.47	4.22	1.53	2.00	0.48	0.02	28.18

TABLE 3. Summer Percentage Frequency Distribution of Wind Speed and Wind Direction at 200-Foot Level vs. Atmospheric Stability

		NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	N	VAR.	CALM	TOTAL
0 - 3	VS	0.02	0.01	0.	0.01	0.00	0.02	0.01	0.02	0.01	0.03	0.03	0.03	0.04	0.03	0.01	0.02	0.01	0.01	0.31
	MS	0.10	0.09	0.07	0.09	0.10	0.15	0.07	0.10	0.08	0.12	0.16	0.25	0.20	0.24	0.12	0.16	0.10	0.10	2.28
	N	0.17	0.28	0.20	0.24	0.25	0.27	0.09	0.19	0.11	0.17	0.12	0.17	0.14	0.19	0.25	0.30	0.41	0.08	3.63
	U	0.36	0.47	0.20	0.24	0.26	0.30	0.18	0.21	0.12	0.20	0.16	0.17	0.12	0.27	0.22	0.43	0.61	0.03	4.55
4 - 7	VS	0.01	0.01	0.01	0.01	0.01	0.02	0.03	0.03	0.01	0.04	0.08	0.17	0.16	0.09	0.06	0.03	0.00	0.	0.76
	MS	0.17	0.15	0.12	0.15	0.20	0.30	0.18	0.17	0.17	0.31	0.43	0.93	0.86	0.63	0.44	0.21	0.04	0.	5.46
	N	0.38	0.40	0.25	0.34	0.41	0.54	0.29	0.36	0.30	0.41	0.40	0.44	0.46	0.67	0.55	0.55	0.20	0.	7.00
	U	1.32	1.28	0.74	0.89	0.72	0.91	0.56	0.73	0.72	0.80	0.59	0.64	0.61	1.21	1.08	1.38	0.67	0.	14.86
8 - 12	VS	0.	0.01	0.	0.	0.01	0.01	0.01	0.02	0.01	0.02	0.08	0.23	0.33	0.42	0.17	0.02	0.	0.	1.33
	MS	0.20	0.20	0.10	0.14	0.19	0.16	0.22	0.11	0.09	0.26	0.77	1.93	2.98	1.43	0.37	0.23	0.	0.	9.38
	N	0.21	0.14	0.07	0.08	0.11	0.11	0.09	0.07	0.17	0.46	0.57	0.65	0.78	0.84	0.22	0.19	0.	0.	4.77
	U	0.66	0.49	0.20	0.18	0.15	0.20	0.13	0.18	0.42	0.86	0.75	0.42	0.73	1.47	0.52	0.55	0.01	0.	7.91
13-18	VS	0.	0.	0.	0.	0.	0.00	0.01	0.	0.01	0.01	0.02	0.09	0.23	0.86	0.07	0.	0.	0.	1.26
	MS	0.07	0.07	0.05	0.06	0.01	0.05	0.11	0.03	0.05	0.14	0.56	1.27	4.92	2.28	0.19	0.07	0.	0.	9.91
	N	0.07	0.05	0.03	0.01	0.00	0.03	0.06	0.04	0.11	0.35	0.69	0.75	1.60	0.94	0.07	0.06	0.	0.	4.85
	U	0.23	0.15	0.05	0.04	0.02	0.03	0.03	0.04	0.12	0.68	0.80	0.30	0.81	1.44	0.08	0.10	0.	0.	4.92
19-24	VS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.00	0.	0.03	0.16	0.00	0.	0.	0.	0.	0.20
	MS	0.01	0.02	0.01	0.01	0.	0.00	0.01	0.01	0.02	0.05	0.10	0.12	1.61	1.85	0.02	0.01	0.	0.	3.84
	N	0.03	0.06	0.02	0.01	0.00	0.	0.00	0.01	0.05	0.15	0.35	0.26	1.69	1.54	0.01	0.01	0.	0.	4.18
	U	0.04	0.06	0.01	0.01	0.	0.	0.01	0.01	0.09	0.24	0.35	0.12	0.45	1.21	0.02	0.01	0.	0.	2.60
OVER 24	VS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.00	0.	0.	0.	0.	0.	0.00
	MS	0.	0.01	0.	0.	0.	0.00	0.	0.00	0.01	0.01	0.01	0.00	0.32	0.63	0.00	0.	0.	0.	0.99
	N	0.00	0.01	0.00	0.	0.	0.	0.01	0.01	0.01	0.06	0.15	0.05	1.19	1.79	0.01	0.	0.	0.	3.28
	U	0.00	0.03	0.01	0.	0.	0.	0.	0.	0.02	0.14	0.20	0.06	0.26	1.02	0.01	0.	0.	0.	1.73
TOTALS	VS	0.03	0.02	0.01	0.02	0.01	0.05	0.05	0.06	0.04	0.10	0.22	0.49	0.79	1.56	0.31	0.07	0.01	0.01	3.86
	MS	0.55	0.53	0.34	0.44	0.49	0.66	0.58	0.42	0.40	0.89	2.02	4.51	10.89	7.06	1.14	0.68	0.14	0.10	31.86
	N	0.87	0.93	0.57	0.68	0.77	0.95	0.54	0.68	0.74	1.60	2.27	2.36	5.86	5.98	1.11	1.10	0.61	0.08	27.71
	U	2.61	2.48	1.21	1.36	1.15	1.45	0.91	1.10	1.45	2.92	2.85	1.71	2.97	6.62	1.92	2.47	1.30	0.03	36.57

TABLE 4. Fall Percentage Frequency Distribution of Wind Speed and Wind Direction at 200-Foot Level vs. Atmospheric Stability

		NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	N	VAR	CALM	TOTAL
0 - 3	VS	0.08	0.08	0.06	0.09	0.11	0.19	0.13	0.11	0.08	0.06	0.09	0.14	0.12	0.15	0.17	0.17	0.09	0.20	2.13
	MS	0.42	0.39	0.35	0.40	0.54	0.78	0.36	0.39	0.31	0.35	0.33	0.51	0.57	0.75	0.67	0.65	0.36	1.00	9.13
	N	0.58	0.89	0.52	0.65	0.73	0.65	0.32	0.24	0.19	0.17	0.16	0.29	0.29	0.61	0.77	0.74	0.28	0.68	8.79
	U	0.52	0.56	0.39	0.48	0.31	0.34	0.12	0.09	0.06	0.09	0.07	0.05	0.09	0.19	0.30	0.41	0.23	0.06	4.37
4 - 7	VS	0.05	0.05	0.04	0.04	0.05	0.14	0.17	0.15	0.10	0.13	0.23	0.31	0.31	0.35	0.20	0.09	0.01	0.	2.44
	MS	0.36	0.24	0.20	0.21	0.36	0.67	0.50	0.40	0.42	0.50	0.55	1.11	1.58	1.71	1.11	0.64	0.03	0.	10.58
	N	0.38	0.36	0.25	0.31	0.50	0.51	0.27	0.19	0.20	0.22	0.23	0.27	0.46	1.05	0.81	0.58	0.03	0.	6.61
	U	0.69	0.56	0.36	0.37	0.50	0.46	0.18	0.14	0.18	0.17	0.14	0.13	0.26	0.56	0.85	0.86	0.06	0.	6.48
8 - 12	VS	0.01	0.00	0.	0.01	0.	0.04	0.10	0.03	0.02	0.06	0.17	0.40	0.48	0.73	0.20	0.01	0.	0.	2.27
	MS	0.21	0.12	0.07	0.07	0.12	0.34	0.42	0.20	0.24	0.50	0.88	1.66	3.02	2.98	0.93	0.34	0.	0.	12.11
	N	0.17	0.11	0.03	0.04	0.06	0.12	0.13	0.13	0.20	0.35	0.39	0.37	0.55	1.04	0.36	0.18	0.	0.	4.26
	U	0.38	0.21	0.04	0.03	0.04	0.11	0.04	0.05	0.12	0.18	0.22	0.13	0.25	0.79	0.43	0.36	0.00	0.	3.38
13-18	VS	0.00	0.	0.	0.	0.	0.01	0.03	0.00	0.01	0.01	0.05	0.12	0.39	1.02	0.08	0.	0.	0.	1.73
	MS	0.12	0.05	0.01	0.03	0.00	0.12	0.20	0.17	0.20	0.40	0.83	1.04	2.99	2.54	0.25	0.12	0.	0.	9.10
	N	0.13	0.07	0.01	0.01	0.01	0.06	0.07	0.11	0.26	0.58	0.58	0.39	0.70	0.75	0.15	0.11	0.	0.	3.99
	U	0.18	0.09	0.01	0.	0.	0.01	0.03	0.02	0.05	0.20	0.32	0.09	0.33	0.48	0.07	0.12	0.	0.	2.01
19-24	VS	0.	0.	0.	0.	0.	0.	0.00	0.00	0.00	0.00	0.01	0.00	0.05	0.14	0.	0.	0.	0.	0.21
	MS	0.03	0.02	0.02	0.	0.	0.01	0.05	0.13	0.14	0.31	0.39	0.18	0.77	0.79	0.02	0.01	0.	0.	2.86
	N	0.02	0.03	0.01	0.	0.00	0.02	0.03	0.09	0.24	0.56	0.50	0.13	0.43	0.58	0.02	0.02	0.	0.	2.71
	U	0.04	0.03	0.01	0.	0.	0.00	0.01	0.01	0.07	0.22	0.23	0.06	0.19	0.32	0.01	0.02	0.	0.	1.19
OVER 24	VS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.00	0.	0.	0.	0.	0.	0.	0.	0.	0.00
	MS	0.	0.01	0.	0.	0.	0.	0.02	0.05	0.13	0.14	0.10	0.04	0.13	0.18	0.	0.	0.	0.	0.80
	N	0.01	0.01	0.01	0.	0.	0.	0.01	0.06	0.27	0.58	0.24	0.08	0.26	0.36	0.01	0.00	0.	0.	1.90
	U	0.01	0.04	0.00	0.	0.	0.	0.	0.01	0.08	0.30	0.20	0.05	0.08	0.19	0.01	0.	0.	0.	0.98
TOTALS	VS	0.14	0.14	0.10	0.14	0.16	0.37	0.43	0.30	0.21	0.26	0.56	0.98	1.36	2.39	0.66	0.27	0.10	0.20	8.78
	MS	1.15	0.83	0.65	0.71	1.02	1.92	1.54	1.34	1.49	2.20	3.09	4.53	9.07	8.94	2.97	1.77	0.38	1.00	44.57
	N	1.29	1.48	0.90	1.01	1.29	1.36	0.83	0.85	1.36	2.46	2.10	1.50	2.69	4.38	2.12	1.63	0.31	0.68	28.25
	U	1.83	1.48	0.81	0.88	0.85	0.92	0.37	0.31	0.56	1.16	1.18	0.52	1.19	2.53	1.67	1.77	0.29	0.06	18.41

TABLE 5. Winter Percentage Frequency Distribution of Wind Speed and Wind Direction at 200-Foot Level vs. Atmospheric Stability

		NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	N	VAR.	CALM	TOTAL
0 - 3	VS	0.10	0.12	0.07	0.10	0.10	0.22	0.11	0.13	0.11	0.09	0.10	0.14	0.08	0.15	0.19	0.12	0.18	0.12	2.24
	MS	0.49	0.53	0.42	0.54	0.70	1.01	0.67	0.53	0.35	0.38	0.35	0.62	0.62	0.95	0.82	0.88	0.37	1.35	11.57
	N	0.75	0.70	0.61	0.74	0.94	1.00	0.56	0.42	0.28	0.30	0.25	0.50	0.63	0.94	1.08	1.04	0.18	1.92	12.84
	U	0.24	0.24	0.18	0.15	0.17	0.16	0.10	0.04	0.04	0.03	0.02	0.07	0.07	0.11	0.16	0.23	0.05	0.12	2.18
4 - 7	VS	0.10	0.10	0.06	0.08	0.07	0.14	0.12	0.14	0.09	0.12	0.18	0.28	0.22	0.26	0.32	0.19	0.04	0.	2.52
	MS	0.43	0.31	0.27	0.26	0.35	0.57	0.44	0.39	0.31	0.40	0.52	1.00	1.37	2.01	1.60	0.88	0.04	0.	11.15
	N	0.32	0.35	0.25	0.25	0.26	0.34	0.29	0.15	0.12	0.25	0.20	0.42	0.80	1.72	0.91	0.59	0.01	0.	7.22
	U	0.28	0.19	0.12	0.11	0.12	0.12	0.03	0.03	0.04	0.02	0.03	0.05	0.09	0.40	0.38	0.28	0.00	0.	2.31
8 - 12	VS	0.01	0.	0.01	0.01	0.01	0.05	0.06	0.05	0.05	0.06	0.11	0.20	0.26	0.61	0.29	0.03	0.	0.	1.82
	MS	0.13	0.09	0.03	0.06	0.10	0.33	0.22	0.15	0.23	0.43	0.81	1.28	2.44	3.92	1.03	0.25	0.00	0.	11.50
	N	0.20	0.09	0.05	0.04	0.08	0.13	0.11	0.08	0.17	0.25	0.23	0.28	1.30	2.61	0.48	0.18	0.	0.	6.28
	U	0.11	0.08	0.03	0.01	0.01	0.03	0.02	0.02	0.06	0.03	0.08	0.04	0.23	0.69	0.19	0.09	0.	0.	1.71
13-18	VS	0.01	0.00	0.	0.	0.	0.01	0.01	0.03	0.02	0.03	0.05	0.12	0.26	0.68	0.08	0.	0.	0.	1.30
	MS	0.10	0.05	0.00	0.01	0.04	0.09	0.16	0.17	0.28	0.48	0.91	1.02	2.16	3.62	0.33	0.08	0.	0.	9.70
	N	0.19	0.05	0.00	0.01	0.02	0.03	0.05	0.14	0.23	0.43	0.43	0.25	0.96	1.61	0.15	0.15	0.	0.	4.71
	U	0.10	0.02	0.01	0.	0.	0.01	0.00	0.01	0.07	0.09	0.14	0.06	0.17	0.31	0.04	0.05	0.	0.	1.09
19-24	VS	0.	0.	0.	0.	0.	0.00	0.01	0.01	0.01	0.01	0.01	0.02	0.03	0.05	0.00	0.	0.	0.	0.15
	MS	0.01	0.02	0.	0.	0.00	0.03	0.07	0.12	0.24	0.67	0.45	0.28	0.44	0.71	0.03	0.01	0.	0.	3.08
	N	0.05	0.03	0.	0.00	0.01	0.01	0.04	0.10	0.29	0.54	0.31	0.14	0.14	0.25	0.03	0.08	0.	0.	1.99
	U	0.04	0.03	0.01	0.	0.	0.00	0.00	0.02	0.03	0.09	0.10	0.01	0.05	0.12	0.00	0.03	0.	0.	0.54
OVER 24	VS	0.	0.	0.	0.	0.	0.00	0.	0.01	0.01	0.01	0.	0.00	0.	0.	0.	0.	0.	0.	0.02
	MS	0.01	0.00	0.	0.	0.	0.01	0.05	0.13	0.38	0.53	0.27	0.08	0.09	0.09	0.00	0.00	0.	0.	1.64
	N	0.05	0.02	0.	0.	0.	0.01	0.01	0.11	0.50	0.73	0.25	0.07	0.05	0.06	0.01	0.05	0.	0.	1.91
	U	0.03	0.01	0.	0.	0.	0.	0.00	0.01	0.06	0.19	0.13	0.02	0.01	0.04	0.00	0.01	0.	0.	0.51
TOTALS	VS	0.22	0.23	0.14	0.19	0.18	0.43	0.32	0.35	0.29	0.32	0.45	0.76	0.85	1.76	0.88	0.35	0.22	0.12	8.07
	MS	1.18	1.00	0.72	0.87	1.20	2.04	1.61	1.48	1.80	3.07	3.31	4.28	7.11	11.30	3.81	2.10	0.41	1.35	48.64
	N	1.58	1.25	0.91	1.04	1.30	1.51	1.06	1.00	1.56	2.48	1.67	1.66	3.87	7.19	2.66	2.09	0.19	1.92	34.95
	U	0.76	0.57	0.35	0.26	0.30	0.32	0.16	0.13	0.29	0.46	0.50	0.29	0.61	1.67	0.78	0.70	0.05	0.12	8.34

Selection of angular width for the sector-averaged plume is governed by the form of available wind direction data. Table 2 shows that Hanford wind data have been compiled in 16 direction sectors. As a result, the plume width has been set at 22.5° for this study. The mixing height tends to vary diurnally and seasonally with the greatest heights generally found on summer afternoons and the lowest on winter nights. We will ignore the known diurnal variation and assume a constant mixing height for each season, as shown in Table 6. A recent series of measurements at Hanford is expected to provide better information on mixing heights.

TABLE 6. Assumed Heights of the Mixed Layer by Season

<u>Season</u>	<u>Height</u>
Spring	1000 m
Summer	1500 m
Fall	1000 m
Winter	500 m

Hanford Sky Cover Climatology

Sky cover is observed and recorded each hour at the Hanford Meteorology Station. At the end of each month, the average sky cover for daylight hours is computed and published internally for use by the Hanford contractors. The sky cover data in Reference 28, in these monthly summaries, and in a random sample of data taken from the original records form the basis of the climatology presented here.

Annual and monthly sky cover averages for Hanford are presented in Table 7 for several different data sets. It should be noted that for every month the sky cover during daylight hours is equal to or greater than the 24 hour average.

This is an indication that convective activity, caused by solar heating, is a significant factor in the cloud formation processes at Hanford.

The last column in Table 7 gives the standard deviation of the monthly sky cover averages for the period 1967 through 1977. They are negatively correlated with the mean sky cover. That is, high average sky covers are associated with small standard deviations. This means that the year to year variability in sky cover in the winter is less than that for the summer. As a result a given change in the long term average sky cover would be easier to detect statistically in the winter than it would be in the summer.

TABLE 7. Monthly and Annual Sky Cover (in Tenths) for Hanford with Standard Deviation of Monthly Averages of Sky Cover for Daylight Hours about the Mean for the Period 1967-1977

	<u>All Hours 1967-1970</u>	<u>Daylight 1946-1975</u>	<u>Daylight 1967-1977</u>	<u>St. Dev. 1967-1977</u>
January	7.6	7.8	8.0	.58
February	6.9	7.4	7.4	.74
March	6.2	6.8	7.0	.67
April	6.1	6.4	6.6	.68
May	5.5	5.8	6.0	.72
June	4.9	5.3	5.4	.96
July	2.7	2.8	3.3	1.02
August	3.1	3.2	3.2	1.54
September	4.0	4.0	4.0	1.41
October	5.5	5.9	6.0	1.13
November	7.0	7.6	8.0	.77
December	7.8	8.1	8.0	.58
Annual Average	5.6	5.9	6.1	

Average sky cover is given in Table 8 for each hour for the mid-day period between 0800 and 1600 PST by months. During the months of November through February the sky cover is a maximum in the morning about sunrise. During the remainder of the year it is a maximum in the mid to late afternoon. The diurnal variation in sky cover is less than 2 tenths in all months and is greatest in the spring and fall. The diurnal variation is relatively small compared with the annual variation of monthly averages.

TABLE 8. Mid-Day Variation of Monthly Average Sky Cover (in tenths)

	<u>TIME (PST)</u>								
	8	9	10	11	12	13	14	15	16
January	8.3	8.2	8.2	8.1	8.1	8.1	8.0	8.0	8.1
February	7.6	7.6	7.5	7.3	7.4	7.4	7.4	7.4	7.4
March	6.3	6.7	6.6	6.8	6.9	7.0	7.0	6.9	6.9
April	6.3	6.3	6.4	6.5	6.7	7.0	7.0	6.9	7.0
May	5.4	5.5	5.6	5.8	6.0	6.2	6.1	6.3	6.4
June	4.7	4.8	5.0	5.3	5.2	5.3	5.3	5.4	5.6
July	2.5	2.4	2.5	2.6	2.8	2.9	3.0	3.1	3.2
August	3.2	3.0	3.2	3.2	3.3	3.4	3.5	3.6	3.7
September	4.3	4.2	4.3	4.3	4.3	4.4	4.4	4.4	4.4
October	5.8	5.8	5.8	5.8	6.0	6.2	6.3	6.4	6.4
November	7.7	7.6	7.4	7.4	7.6	7.7	7.6	7.5	7.3
December	8.4	8.3	8.5	8.4	8.3	8.2	8.1	8.1	8.0

Hanford Solar Radiation Climatology

Solar radiation is measured at the Hanford Meteorological Station using a calibrated Eppley Pyranometer. Signals from the device are continuously recorded on a strip chart and reduced manually to determine the solar radiation received each hour.

The average daily solar radiation at Hanford is given in Table 9 by month for the periods 1953 through 1975 and 1967 through 1977. The standard deviations of the individual monthly averages in the 1967-1977 period are given in the third column. The final two columns of the table involve the solar radiation received at the top of atmosphere above Hanford. The incident radiation estimates in column 4 are taken from Reference (29). The last columns shows that the fraction of the incident radiation received at the surface varies from about 40% in the winter to slightly over 70% in July. One of the major factors affecting this fraction is sky cover.

Diurnal variation of the monthly average solar radiation between 0800 and 1600 PST is shown in Table 10. The maximum insolation occurs in July for the hour beginning at 1100 PST, rather than in June. Again this can be attributed to the difference in cloudiness between July and July.

SPECIFIC HNEC SKY COVER AND SOLAR RADIATION MODELS

The final topic to be covered prior to the presentation of the study results is the development of HNEC specific models for the conversion of cooling system effluent concentrations to changes in sky cover and solar radiation. In this section we will deal with the change in sky cover first and then the change in solar radiation. We will end the section with a quick check on the consistency of our models with existing information.

TABLE 9. Average Daily Solar Radiation (ly day⁻¹)

	<u>Daily Total 1953-1975</u>	<u>Daily Total 1967-1977</u>	<u>Standard Deviation 1967-1977</u>	<u>Incident at Top of Atmosphere</u>	<u>Fraction Received at Sfc</u>
January	120	118	14	260	.46
February	202	203	11	400	.50
March	340	338	22	580	.59
April	475	472	43	780	.61
May	576	584	30	910	.63
June	628	630	31	950	.66
July	659	650	42	920	.72
August	558	556	49	830	.67
September	423	415	38	650	.65
October	262	268	24	450	.58
November	132	130	17	300	.44
December	92	93	18	220	.42
Annual	372	372		605	.61

TABLE 10. Mean Solar Radiation (ly hr^{-1})
by Month and Hour

	<u>TIME (PST)</u>								
	<u>08</u>	<u>09</u>	<u>10</u>	<u>11</u>	<u>12</u>	<u>13</u>	<u>14</u>	<u>15</u>	<u>16</u>
January	4.8	11.7	17.3	21.4	21.9	18.8	13.6	6.3	1.3
February	11.1	19.8	27.8	32.4	33.1	30.0	24.1	15.6	6.0
March	24.0	35.3	43.6	48.7	48.2	43.9	36.9	26.4	14.6
April	38.6	49.4	56.7	58.7	57.7	52.0	45.1	34.1	22.1
May	47.8	58.0	64.2	67.2	63.7	59.7	52.8	42.1	29.4
June	52.1	61.4	67.6	70.5	69.2	63.8	56.3	46.2	34.1
July	53.1	63.5	71.1	74.7	73.8	69.0	61.7	50.7	37.6
August	44.6	55.5	63.0	66.0	66.1	62.7	53.5	42.2	29.0
September	34.8	45.7	53.4	56.0	55.6	50.3	40.9	29.4	16.4
October	22.2	31.6	38.3	41.2	39.8	33.8	24.9	14.8	5.0
November	9.8	17.0	22.0	24.0	23.0	18.9	13.0	5.6	0.6
December	4.2	9.7	14.5	17.3	17.3	14.5	9.2	3.4	0.1

Sky Cover Increase

The conversion factor that relates changes in sky cover to cooling system effluent concentration will be assumed. However, prior to stating the assumption, we will examine additional information that should be related to the conversion.

Figure 3 shows the diurnal variations of sky cover and temperature and relative humidity near ground level for January, April, July and October. In the winter the diurnal sky cover variation is small, the temperatures are generally low and the relative humidity is high. Under these conditions we will assume that cooling system effluents might cause an increase in cloudiness due to triggering convective activity or they might simply saturate the air. In the former event only a portion of the available clear sky would be covered by an increase in

FIGURE 3. Diurnal Variation of Sky Cover, Relative Humidity and Temperature for January, April, July and October

cloudiness and in the latter all the clear sky would be covered.

In the remaining seasons the temperatures are sufficiently high that the probability of saturating a large volume of air is remote. As a result increases in cloudiness would be associated with increased convective activity. The large diurnal variation in sky cover shown for the spring and fall indicates that the atmosphere is generally ready for the formation of clouds if convective activity can be initiated. The diurnal variation in sky cover is relatively small in the summer, even though the temperature variation is high. This indicates that convective activity, although associated with the production of clouds, is not as efficient as it is in the spring and fall. As a result, in our conversion from effluent concentration to sky cover increase a given effluent concentration will be assumed to cause a larger fractional increase in sky cover in the spring and fall than it does in the summer. During these seasons, the maximum fractional increase in sky cover will be less than 100% of the available free sky.

Having established this background, we assume the conversion factors presented in Table 11. Earlier we assumed that water concentration would be a tracer for the cooling system effluents, thus Table 11 uses increased water content as the independent variable.

The actual conversion between effluent concentration and increased sky cover is unknown, therefore this table represents a significant weakness in the study. However, the conversions assumed probably will result in over estimation of the increase in sky cover. To ensure that a maximum increase in cloudiness is evaluated, we will run each of the mid season months with a worst case conversion table. In that table an increase of water content of 0.1 g m^{-3} will result in a 100% fractional increase in cloudiness, i.e., the sky cover will increase to 10/10.

TABLE 11. Conversion Table Relating an Increase in Water Content to an Increase in Sky Cover

<u>Winter</u>		<u>Spring</u>		<u>Summer</u>		<u>Fall</u>	
$\Delta\rho_v$ <u>(g m⁻³)</u>	<u>f_i</u>	$\Delta\rho_v$ <u>(g m⁻³)</u>	<u>f_i</u>	$\Delta\rho_v$ <u>(g m⁻³)</u>	<u>f_i</u>	$\Delta\rho_v$ <u>(g m⁻³)</u>	<u>f_i</u>
< 0.1	0	< .25	0	< .25	0	< .25	0
0.1 to 0.3	.2	.25 to .50	.2	.25 to .50	0.1	.25 to .50	.2
0.3 to 0.5	.5	.50 to 1.0	.4	.50 to 1.0	0.3	.50 to 1.0	.4
> 0.5	1.0	> 1.0	.8	> 1.0	0.5	> 1.0	.8

The Relationship Between Sky Cover and Solar Radiation

Intuition leads us to expect an inverse relationship between sky cover and solar radiation. This expectation is borne out by data as is shown in Figure 4, which shows the annual variation of monthly averages. It is particularly evident in the increase in insolation between June and July although Table 9 shows that the solar radiation received at the top of the atmosphere decreases.

For current purposes, it is necessary to relate hourly rather than monthly averages. Some guidance is provided in Reference (19) through (23) which treat this relationship on a month by month basis. To develop a single relationship that can be used for all months, we will normalize observed solar radiation to the long-term mean for the month and time of day of the observation and relate sky cover observations to an appropriate mean. Normalized solar radiation is simply $SR/\overline{SR}$, but the normalized sky cover expression is more complex. To obtain a nondimensional sky cover variable with a range of zero to two, and a value of one when the sky cover is equal to the mean value, we make the following transformation:

$$\xi = \begin{cases} \frac{SC}{\overline{SC}} & SC \leq \overline{SC} \\ 1 + \frac{SC - \overline{SC}}{10 - \overline{SC}} & SC \geq \overline{SC} \end{cases} \quad \begin{matrix} (11a) \\ (11b) \end{matrix}$$

where ξ is the nondimensional sky cover.

Initially we will treat the case of low level clouds (ceiling below 10,000'). Then we will treat the case of high level clouds.

FIGURE 4. Annual Variation of Average Sky Cover and Solar Radiation

Matveev⁽¹⁹⁾ cites a number of studies in this area and gives linear, quadratic and exponential models for the sky-cover insolation relationship. Other authors⁽²⁰⁻²³⁾ tend to favor a quadratic model, although the model forms are not completely comparable. As a result, for the low cloud case we will try three models and compare the results. The models are:

$$1. \quad F(SC^*, \overline{SC}) = G_1(\xi) = a_0 + a_1 \xi, \quad (12a)$$

$$2. \quad F(SC^*, \overline{SC}) = G_2(\xi) = b_0 + b_1 \xi + b_2 \xi^2, \quad (12b)$$

and $3. \quad F(SC^*, \overline{SC}) = G_3(\xi) = c_0 \exp(c_1 \xi^2) \quad (12c)$

The constants in these models can be evaluated using the random data sample taken from the period 1967 through 1977. Average values of normalized solar radiation were computed for $\xi = 0$ and $\xi = 2$ using the 0900, 1200 and 1500 observations. These averages are given in Table 12 along with the standard errors in the estimates of the averages. Constants in G_1 were evaluated using these values. The constants in G_2 and G_3 were evaluated using these values along with the assumption that $SR/SC = 1$ when $\xi = 1$. Model constants are given in Table 13, and the three models are compared with a small data sample in Figure 5.

The literature (e.g., References (24), (26) and (27)) indicates that high clouds, particularly cirriform clouds, have relatively little effect on insolation. Table 12 shows that for Hanford, when $\xi = 2$ and the ceiling is above 10,000 ft, the average normalized solar radiation is 1.10. As a result, we will assume that $F(SC, \overline{SC})$ is 1.10 for all values of ξ if there is a high ceiling. Figure 6 shows data for high clouds and the line representing $SR/\overline{SC} = 1.10$.

TABLE 12. Average and Standard Error
of Normalized Solar Radiation
During Clear and Overcast
Skies at Hanford

<u>$\bar{\xi}$</u>	<u>(SR/SR)</u>	<u>Standard Error</u>
0	1.25	.05
2 (low ceilings)	.56	.08
2 (high ceilings)	1.10	.07

TABLE 13. Coefficient Values for the Models
Relating Changes in Sky Cover and
Solar Radiation

<u>Model</u>		<u>i</u>		
		<u>0</u>	<u>1</u>	<u>2</u>
1	$a_i =$	1.25	-.345	
2	$b_i =$	1.25	-.155	- .095
3	$c_i =$	1.25	-.223	+1.85

FIGURE 5. The Relationship Between Normalized Solar Radiation and Transformed Sky Cover for Low Clouds.

FIGURE 6. The Relationship Between Normalized Solar Radiation and Transformed Sky Cover for High Clouds

Both Figures 5 and 6 show a significant amount of scatter in the data. This is to be expected because we have not accounted for position of the clouds relative to a direct line between the sun and the pyreheliometer. Other factors contributing to the scatter include cloud type and atmospheric turbidity.

Consistency of the HNEC Specific Models

In developing the sky cover and solar radiation models in the preceeding chapter we indicated a need for the sky cover frequency distributions for each month. The distributions assumed are presented in Table 14. Although the distributions are assumed, they are based on the information contained in Table 23 of Reference 28 and have been adjusted to give appropriate mean sky covers. The division of sky cover between high and low ceiling categories was adjusted using solar radiation data and the random data sample.

When we substitute these frequency distributions into Equation (10), we get:

$$\frac{\overline{SR}}{\overline{SR}_0} = \sum_{SC^*} F(SC, \overline{SC}) P(SC) \quad . \quad (13)$$

If the solar radiation model $F(SC, \overline{SC})$ and the frequency distribution $P(SC)$ are both correct then $\overline{SR}$ will be equal to $\overline{SR}_0$ and the summation will equal 1.

Table 15 presents a comparison of the average sky cover computed from the assumed frequency distributions with climatological values and the values of the summation in Equation (13). The summations were carried out for mid-season months for the linear and quadratic models for $F(SC, \overline{SC})$, and for all months for the exponential model. In each case, the

TABLE 14. Assumed Initial Sky Cover Frequency Distributions

Sky Cover (tenths)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	.04	.08	.10	.08	.12	.15	.40	.36	.34	.17	.06	.03
1	.02	.04	.05	.04	.05	.06	.10	.10	.08	.06	.04	.03
2	.02	.03	.04	.04	.05	.06	.08	.08	.05	.05	.03	.03
3	.02	.03	.04	.04	.05	.06	.07	.07	.04	.04	.03	.03
4	.03	.03	.04	.05	.07	.06	.06	.07	.04	.04	.03	.03
5	.03	.03	.04	.05	.08	.06	.04	.06	.04	.04	.03	.03
6	.03	.03	.04	.06	.04	.06	.04	.05	.04	.04	.03	.03
7	.04	.03	.04	.06	.06	.05	.04	.03	.04	.04	.03	.03
8	.07	.03	.03	.08	.07	.05	.01	.01	.03	.04	.04	.03
9	.10	.08	.03	.08	.07	.06	.01	.01	.04	.04	.04	.04
10	.15	.20	.15	.09	.07	.07	.11	.11	.10	.15	.20	.23
6*	.03	.03	.04	.05	.04	.05	.01	.01	.03	.03	.03	.02
7*	.03	.03	.04	.06	.05	.05	.01	.01	.03	.04	.03	.02
8*	.08	.03	.03	.07	.06	.05	.01	.01	.03	.03	.04	.03
9*	.12	.06	.04	.07	.06	.05	.01	.01	.03	.04	.05	.06
10*	.19	.24	.25	.08	.06	.06	.01	.01	.04	.15	.30	.33

*Ceiling above 10,000 ft

TABLE 15. Check on the Internal Consistency
of Assumed Monthly Sky Cover
Distributions and the Sky Cover
Insolation Models

	<u>Average Sky Cover</u>		<u>Normalized Solar Radiation</u>		
	<u>Actual Daylight Hours</u>	<u>Assumed PDF</u>	<u>Linear</u>	<u>Model Quadratic</u>	<u>Exponential</u>
January	7.8	7.8	.96	.99	.99
February	7.4	7.4			.93
March	6.8	6.8			1.02
April	6.4	6.4	.97	1.01	1.01
May	5.8	5.7			1.02
June	5.3	5.4			1.03
July	2.8	3.1	1.03	1.07	1.07
August	3.2	3.2			1.02
September	4.0	4.1			1.05
October	5.9	5.9	.99	1.02	1.02
November	7.6	7.7			1.00
December	8.1	8.1			.98

assumed distribution appears to be reasonable. However, the data in Table 15 are only an indication of reasonableness. They do not prove that the distributions are correct. At best the data show that sky cover distributions and solar radiation models are internally consistent with readily available climatological data.

RESULTS

The development of the analytical tools for estimating changes in sky cover and solar radiation for the current study has been completed. It is clear that they are rudimentary. They are, in fact, a collection of "back of the envelope models" that only provide an indication of the order of magnitude of the potential changes. As we examine the results presented here, we must continually remember that the precision in the numerical values is not an indication of the precision of the estimates.

Predicted increases in sky cover are given in Table 16 for 6 areas in and around the HNEC. Each estimate is a spatial average. The HNEC estimates are averages for the area in the immediate vicinity of the assumed cluster locations. The Tri-Cities estimates are averages for the entire Richland, Kennewick, Pasco area. The ALE estimates are for the Arid Land Ecology study area along the southwest border of the Hanford Area. Wahluke Slope borders the northern side of the Hanford, and the Mesa-Eltopia area lies directly east of Hanford. Finally the Yakima Valley estimates are for the area around Sunnyside, Grandview and Prosser.

Examining Table 16 we see the expected result that the maximum increases in sky cover occur in the immediate vicinity of the HNEC clusters. The predicted increases in average sky cover for the spring, fall and winter are statistically significant assuming an observation period of 11 years following completion of the HNEC and an unchanged sky cover variance. The predicted increases during the summer are not statistically significant.

Off the Hanford Area the greatest changes in sky cover are predicted for the Mesa-Eltopia and Tri-Cities areas. However, These increases are not statistically significant.

TABLE 16. Predicted Increase in Sky Cover
(in tenths)

	Existing SC Daylight Hours (tenths)	HNEC	Tri- Cities	ALE	Wahluke Slope	Mesa/Eltopia	Yakima Valley
January	7.8	1.0**	0.3	0.2	0.2	0.4	0.1
February	7.4	1.2**	0.4	0.2	0.2	0.4	0.2
March	6.8	0.7*	0.1	0.1	0.1	0.3	0.1
April	6.4	0.8**	0.1	0.1	0.1	0.3	0.1
May	5.8	0.9**	0.2	0.1	0.1	0.4	0.1
June	5.3	0.4	0.1	0.1	0.1	0.1	<
July	2.8	0.6	0.1	0.1	0.1	0.2	0.1
August	3.2	0.6	0.1	0.1	0.1	0.2	<
September	4.0	1.6**	0.4	0.3	0.3	0.6	0.2
October	5.9	1.1*	0.3	0.2	0.2	0.4	0.1
November	7.6	0.6*	0.2	0.2	0.1	0.2	0.1
December	8.1	0.9**	0.3	0.2	0.1	0.3	0.1

*Significant at the 95% confidence level

**Significant at the 99% confidence level

< less than .05

At this point we should briefly discuss statistical significance. In testing statistical significance we use Student's t test between means⁽³⁰⁾, and assume that we have no more information about either sky cover or solar radiation than provided by records of routine observations. We do not consider a predicted change significant unless we have at least 95% confidence that the difference between the current climatological mean and the predicted mean would not result from normal variation between data samples. The fact that a change is evaluated as not statistically significant does not mean it wouldn't occur, only that it would be difficult to detect within the time specified because of normal variability of the atmosphere.

During the course of the study complete sets of computations were made using different initial sky cover distributions. The computations indicate that the predicted changes in sky cover and solar radiation are not particularly sensitive to moderate changes in the assumed sky cover distributions if the mean sky cover remains relatively constant. However the results are rather sensitive to changes in the mean sky cover.

Increases in sky cover would be aesthetically displeasing, however that would be difficult to evaluate. They would also result in decreases in solar radiation. Tables 17 and 18 present the changes in solar radiation that are predicted to result from an operating HNEC.

Table 17 compares decreases in solar radiation predicted by the three models relating changes in sky cover to changes in insolation. Perusal of the table rapidly leads to the conclusion that the predicted decrease is not particularly sensitive to the model used within the limits of those tested. Throughout the remainder of this report, the estimated changes in insolation are results obtained using the exponential model.

TABLE 17. Comparison of the Results from Linear, Quadratic and Exponential Models for the Relationship Between Sky Cover and Solar Radiation. Tabled Values are Predicted Decreases in Insolation (ly/day)

	<u>Model</u>	<u>INEC</u>	<u>Tri-Cities</u>	<u>ALE</u>	<u>Wahluke Slope</u>	<u>Mesa/Eltopia</u>	<u>Lower Yakima Valley</u>
January	linear	23	8	5	4	10	3
	quadratic	24	8	5	4	10	3
	exponential	24	9	5	4	10	3
April	linear	53	10	7	7	18	4
	quadratic	49	9	6	6	20	4
	exponential	51	9	6	6	21	4
July	linear	39	6	5	5	13	3
	quadratic	31	4	4	4	11	2
	exponential	32	5	4	4	11	2
October	linear	35	9	6	6	14	4
	quadratic	33	8	6	5	12	4
	exponential	33	9	6	6	11	4

The greatest impact on solar radiation is seen in Table 18 to be in the immediate vicinity of the clusters. In general, the predicted reductions in solar radiation are about 20% in the winter, 10 to 15% in the spring and fall, and 5% in the summer. Except for August, the decreases are statistically significant. In most cases, we would have 99% confidence that the predicted decreases was not a normal variation.

The offsite impacts are greatest in the Mesa-Eltopia and Tri-Cities areas as expected from the changes in sky cover. But, we note that the decreases in solar radiation predicted for these areas for February and for the Mesa-Eltopia area for March and May are statistically significant even though the changes in sky cover were not significant. We further note that each significant change in sky cover is paired with a significant decrease in solar radiation. This leads to the conclusion that changes in solar radiation would be a more sensitive indicator of an atmospheric modification than changes in sky cover. This conclusion is reasonable and might have been expected since insolation measurements are much more precise than sky cover estimates. It might also have been expected because the coefficient of variance of the monthly average insolation is significantly smaller than that for monthly average sky cover.

The combined effects of the sky cover and solar radiation changes for the area in the vicinity of the HNEC clusters are summarized in Figure 7. The current relationship, shown in Figure 4, is shown in dashed lines for comparison. The obvious change to be noted is the shift of the enclosed area toward increased cloudiness and lower insolation. There is also a change in the shape of the area, which indicates a more rapid or earlier shift from summer to fall and more gradual but delayed shift from spring into summer. The ecological significance of these changes needs evaluation.

TABLE 18 . Predicted Decrease in Solar Radiation
(ly/day)

	Existing <u>SR</u> <u>(ly/day)</u>	<u>HNEC</u>	<u>Tri-</u> <u>Cities</u>	<u>ALE</u>	<u>Wahluke Slope</u>	<u>Mesa/Eltopia</u>	<u>Yakima</u> <u>Valley</u>
January	120	24 **	9	5	4	10	3
February	202	40 **	14 **	8	7	16 **	5
March	340	40 **	7	5	5	17 *	3
April	475	51 **	9	6	6	21	4
May	576	62 **	11	8	8	25 *	5
June	628	36 **	5	4	4	12	2
July	659	32 *	5	4	4	11	2
August	558	26	4	3	3	9	2
September	423	56 **	14	10	9	20	7
October	262	34 **	9	6	6	11	4
November	132	15 **	5	3	3	6	2
December	92	18 *	7	4	3	8	2

*Significant at the 95% confidence level

**Significant at the 99% confidence level

FIGURE 7. The Predicted Variation of Average Sky Cover and Solar Radiation in the Vicinity of an Operating HNEC

Earlier we discussed the uncertainty in the conversion from cooling system effluent concentration to increase in sky cover, and promised to compare the estimated changes with "worst case" estimates. Those comparisons are presented in Tables 19 and 20.

In general, the "worst case" changes in sky cover and solar radiation for January are only slightly larger than those estimated originally. In April and October the worst cases changes are about a factor of two larger than those originally estimates, and in July the "worst case" estimates are larger by a factor of 4 or more.

In the Mesa-Eltopia Area the "worst case" changes in both sky cover and solar radiation are statistically significant for each month for which they were evaluated. In the Tri-Cities, the worst case sky cover increases are statistically significant for January as are the solar radiation decreases for January and October. In the other areas even the "worst case" changes are not considered statistically significant.

TABLE 19. Comparison of Predicted Increases
in Sky Cover with Worst Case Values

		January	April	July	October
HNEC	P	1.0**	.8**	.6**	1.1**
	WC	1.0**	1.6**	3.4**	7.9**
Tri-Cities	P	.3	.1	.1	.3
	WC	.4	.4	.6	.6
ALE	P	.2	.1	.1	.2
	WC	.2	.2	.4	.4
Wahluke Slope	P	.2	.1	.1	.2
	WC	.2	.2	.3	.3
Mesa/Eltopia	P	.4	.3	.2	.4
	WC	.6*	1.0**	1.6**	1.0*
Yakima Valley	P	.1	.1	.1	.1
	WC	.1	.1	.2	.2
Existing Mean Sky Cover (daylight hours)		7.8	6.4	2.8	5.9

*Significant at the 95% confidence level

**Significant at the 99% confidence level

TABLE 20. Comparison of Predicted Decreases
in Solar Radiation with Worst Case
Values

		January	April	July	October
HNEC	P	24**	51**	32**	34**
	WC	25**	95**	151**	54**
Tri-Cities	P	9	9	5	9
	WC	11*	23	24	19*
ALE	P	5	6	4	6
	WC	5	13	15	10
Wahluke Slope	P	4	6	4	6
	WC	5	13	14	10
Mesa/Eltopia	P	10	21	11	11
	WC	13*	57**	72**	30**
Yakima Valley	P	3	4	2	4
	WC	3	8	10	7
Existing Mean Solar Radiation (ly/day)		120	475	659	262

*Significant at the 95% confidence level

**Significant at the 99% confidence level

CONCLUSIONS

Using a combination of "back of the envelope" models we have estimated the changes in sky cover and solar radiation that might result from the operation of a Hanford Nuclear Energy Center. We have assumed that the center is composed of 20 power reactors using mechanical draft cooling towers and that all reactors operate continuously. In addition, we have assumed that the climatological conditions of the Hanford Meteorological Station are representative of the current conditions for the entire area surrounding the HNEC. Again we must remember that the models used are rudimentary and that numerical precision does not indicate model accuracy.

Based on the models and these assumptions we have arrived at the following conclusions:

- 1) Increases in sky cover and decreases in solar radiation resulting from the operation of an HNEC would generally be small outside the immediate vicinity of the reactor clusters.
- 2) The changes in sky cover and solar radiation in the immediate vicinity of the clusters would be statistically significant during the fall, winter and spring. During the summer, the decreases in June and July solar radiation would also be significant.
- 3) The decreases in solar radiation predicted for the Mesa-Eltopia area for February, March and May are statistically significant, as is the decrease in the Tri-Cities for February.
- 4) When "worst case" assumptions are made for the conversion of cooling system effluent concentrations to increases in sky cover, the estimated changes in both

sky cover and solar radiation from the original estimates range from a few percent in January to a factor of 4 or more in July.

- 5) The predicted changes in sky cover and solar radiation are not particularly sensitive to changes in the initial sky cover distribution if the mean sky cover remains reasonably constant, and the changes in solar radiation are not sensitive to the model relating sky cover and insolation.
- 6) Changes in solar radiation are likely to be a more sensitive indicator of atmospheric modification than are changes in sky cover.

In addition, it is readily apparent that the wind direction distribution is one of the most important factors considered. The specific impacts predicted at a given receptor depend to a large extent on the position of the receptor relative to the HNEC and on the wind direction distribution.

The predicted changes in sky cover and solar radiation have been evaluated for statistical significance, which relates to our ability to detect the change. Further studies are needed to evaluate the social and ecological significance of the predicted changes.

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LICENSING AND ACCIDENT REVIEWS
FOR AN HNEC

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SUMMARY

An examination of the different criteria in the Code of Federal Regulation (CFR) particularly Chapter 10, the Regulatory Guides of the Nuclear Regulatory Commission (NRC), the Standard Work Plan Reviews, some specific standards and public correspondence of the Advisory Committee for Reactor Safety (ACRS), current proposed legislation, and reviews of several generic studies of nuclear energy centers did not reveal any areas where the concept of a nuclear energy center at Hanford would be limited by technical concerns. Rules or regulations or formal official guidance that address specifically Nuclear Energy Centers, however, do not exist. Such regulations and guidance will apparently be developed and promulgated following informal and preliminary petitions to the regulatory bodies requesting an energy center per se. Current practice does include siting up to several power plants at a single site, referred to as multiple-unit sites with up to four power reactors located at one site. Preliminary planning has included five units in two groups, one of two and the other of three, which are rather widely separated. The latter may be of interest to a nuclear energy center at Hanford, because of the distances at Hanford that are available to separate the sites. Regulations and guides that direct current practice in siting multiple-units at one location may be adequate to address most if not all of the considerations for siting required for the concept of twenty units at Hanford located at five sites, each of which would contain three to five power generating reactors. The technical studies completed in support of the concept of an HNEC have analyzed many of the key licensing issues that would normally be associated with the siting of several thermal nuclear power plants at one location. To contribute to these, an analysis of the effects of a class nine accident at one unit on the other power reactors at an HNEC was completed. Some perspective relative to other similarly improbable events was gained in this analysis. In part because of the distances available between sites at Hanford, the consequences of a class nine accident onsite can be assessed to be less probable than the consequences from ashfalls from volcanic activity in the Cascades and significantly less probable than the consequences from earthquakes for which designs and procedures have been developed. Consequences here are measured in losses of electrical generating capacity.

INTRODUCTION

The purpose of this review was to identify siting or other concerns that may indicate limitations on the ability to license a nuclear energy center at Hanford.

Several studies on nuclear energy centers have been completed and some have included licensing (regulatory) aspects of siting nuclear power centers.⁽¹⁻³⁾ This review however, was primarily to identify any limitations that may affect licensing specifically at an HNEC.

The scope included examining existing criteria for siting nuclear facilities, including single reactor and multireactor (multi-unit) sites. To fill a void in other analyses and to gain some perspective on another impact of an HNEC, the scope was extended to analyze the consequences within the HNEC, of a class nine accident at a unit at one site. A predictive model utilized in this analysis was developed from meteorological parameters based on thirty years of meteorological records⁽⁴⁾ at Hanford.

From this analysis, additional perspective was developed on the relative severity of the effects of rare events, both man made and from unstable conditions in nature, on the operation of (and the ability to license) an energy center at Hanford (HNEC).

Further insights on the unique siting characteristics of an HNEC have resulted from such perspectives.

LICENSING REVIEW

This evaluation consists of reviews of appropriate parts of Volume 10 (and others) of the Federal Code, the current Regulatory guides, the Standard Review Plans (NUREG 0075), the Proposed Standard Review Plans for EIS (NUREG 0098), appropriate published correspondence on multiple siting from the Advisory Committee on Reactor Safety, the prior reviews on nuclear energy centers and the related studies completed for the concept of a nuclear energy center at Hanford. Each was reviewed to identify possible areas of constraints or support for an HNEC.

The current status of regulations on nuclear energy centers is perhaps best summarized by a part of a recent revision to Regulatory Guide 4.11, Terrestrial Environmental Studies for Nuclear Power Stations, Rev 1, August 1977.

In the introduction of this guide the following appears:

- * This guide is intended to reflect current practice, i.e., the siting of up to several power plants at a single site. Prior consultation with the staff is recommended if larger-scale "Energy Centers" are contemplated.

*Lines indicate substantive changes from previous issue.

Groups in the regulatory body, the Nuclear Regulatory Commission, apparently are not now considering the preparation of codes and guides directed to larger scale Energy Centers.^(a) Codes and guides have increasingly noted however, siting several power plants at a single site (multi-unit sites) (see Appendix A.)

Although four units at a site have been the most for which approval has been sought of NRC and others such as the state agencies, the regulations

(a) The Tyronne Energy Park in Dunn County, Wisconsin, which was recently issued a construction permit by NRC, is not to be identified as an energy center. The park connotation results from the aesthetic features planned for this site which is to contain one (perhaps two eventually) power units.

and guides do not specifically limit the number of units at a site to four. Presumably, if all of the existing regulations and guides were satisfied, more than four units may be acceptable.

Present planning for which construction permits have been sought has included two stations of two units and three units each located about twenty-five miles apart.^(a) The siting issues here may be of interest to an HNEC because of the distances available between some sites at Hanford. Figure 2 (see page 14), indicates the general layout of these sites at Hanford and the table gives the approximate distances between the proposed sites.

A recent review examined the expansion potential for existing nuclear power station sites.⁽⁵⁾ An interesting concept of mini NECs was developed in this analysis. Thus the potential for developing essentially a small NEC might exist utilizing the criteria in existing codes and guides. Hanford was rated as having the potential to expand from the existing three to a large nuclear energy center. This backdoor approach to an energy center was not defended in another recent review largely because of the absence, in this approach, of long-range planning which was deemed essential.⁽⁶⁾ Parenthetically, the observation was made that presently organized utilities, institutions, and political entities are not capable of handling and evaluating the long-term planning and firm commitments of the large resources required for (twenty unit) NECs.

Whatever other reservations may exist concerning a large NEC (twenty units) at Hanford, siting criteria that would limit licensing the proposed units do not at this time appear to include limiting restraints.

(a) Duke Power Company, Perkins and Catawba sites in South Carolina

REVIEW OF THE FEDERAL CODES

No regulations in the Federal code currently address nuclear energy centers per se.

Limitations on annual dose equivalents from exposure to radiation and on quantities of radioactive material released from the entire fuel cycle have been imposed by EPA.^(a) These latter restrictions as they may affect an HNEC are addressed in a supporting document.^(b)

Regulations that bear on siting and safety where several thermal nuclear power plants may be located on one site are reviewed in Appendix A. As above, none appear to be limiting to the concept of an HNEC, but of course none are directed specifically to nuclear energy centers.

REVIEW OF THE REGULATORY GUIDES

By definition, "Regulatory Guides are issued to describe ... methods acceptable to the NRC staff implementing ... regulations ... to provide guidance to applicants." The Guides are not substitutes for regulations (as contained in the Federal Codes for example) and compliance with them is not required. However, they are generally closely followed. More recent guides provide input relating to multi-unit sites. None of these guides issued so far would appear to deny an HNEC. The results of this analysis are tabulated in Appendix B. Two other documents were included in this part of the review; namely, the Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, NUREG-75/087 and Draft, Environmental Standard Review Plans for the Environmental Review of Construction Permit Applications for Nuclear Power Plants, NUREG-0158 Parts 1, 2 and 3. Both were prepared as internal working documents for the NRC staff, prepared by this staff for the purpose of improving the quality and uniformity of the reviews undertaken by NRC. They make reference to the appropriate codes and

(a) Title 40 Code of Federal Regulations, Part 190, "Environmental Radiation Protection Standards for Nuclear Power Operations," Federal Register, Vol. 42 (No. 9), pp. 2858-2861, January 13, 1977.

(b) Radiological Studies, J. K. Soldat.

guides where sharing of services among units or where more than one unit may be located at a site. No additional insights or guidance on multi-unit siting is contained in these documents.

OTHER REVIEWS

In response to a request from the NRC staff, the Advisory Committee on Reactor Safeguards recommended in December of 1975 several criteria in current siting policies be considered.⁽⁷⁾ One of the recommendations noted that studies may be needed on the short- and long-term consequences of a major accident in a nuclear installation on other operations at a multi-unit site such as a nuclear power park. Included in the closure was another recommendation that attention should also be given to the development of additional criteria for sites containing more than one reactor or nuclear facility. Recent guides and regulations have noted criteria for multi-unit sites. As noted above--none so far have been restrictive to the concept of an HNEC.

THE RADIOLOGICAL CONSEQUENCES OF CLASS NINE ACCIDENT AT HNEC

The analysis is based on a meteorological model developed in one of the HNEC conceptual studies.⁽⁴⁾ This model uses 30 years or more of meteorological records at Hanford from which some expectations of the frequency of occurrence (probability) of different meteorological parameters have been developed. These parameters include for example, prevailing wind directions, average wind speeds, atmospheric stability, the height of the mixing layer and others.

To these parameters are added an expected plume width, a deposition velocity to account for depositing material released in the accident and the assumption that essentially all of the release occurs over 0.5 hours. This model, when superimposed on the layout of the five quads on the site of the HNEC, predicts in a probabilistic manner, the effects of accident releases from a unit in any one quad on the remaining reactors at the HNEC. The model thus yields the conditional probabilities of M quads being involved with different levels of air concentrations or surface depositions of radioactive material, given that a class nine accident has occurred at a reactor in one of them. The following two tables developed from that report show these results. Notice, for example, that for all normalized concentrations in both tables, the probability of the reactors in the same quad being involved is 1.0 (a certainty) according to this model. The probability, for example, of three or more quads being involved with a normalized air concentration of 1×10^{-7} is 0.07 (0.066) (Table 1).

Similarly for ground deposition as shown in Table 2. Note that the concentrations (left column) are given in terms of normalized surface concentrations. As an example, for concentrations equal to or greater than $1 \times 10^{-8} \text{ m}^{-2}$, the conditional probability that at least two quads are contaminated is 0.05 (0.046) given that an accident occurs.

The result of only four quads of the five proposed being involved is a limitation of the models, orientation of clusters and wind direction classes. The probability of the fifth quad (16-20 reactors) being involved, while extremely low, must be considered possible.

TABLE 1. Conditional Probability that at Least M Quads Would be Involved^(a) Following an Accident at an HNEC.

Normalized Air Concentration, s/m ³	Same Quad	Number of Quads		
		≥2	≥3	≥4
1.00 x 10 ⁻⁵	1.000			
4.64 x 10 ⁻⁶	1.000	0.046		
4.64 x 10 ⁻⁷	1.000	0.069	0.011	
2.15 x 10 ⁻⁷	1.000	0.126	0.030	
1.00 x 10 ⁻⁷	1.000	0.158	0.066	0.018
4.64 x 10 ⁻⁸	1.000	0.172	0.085	0.023
2.15 x 10 ⁻⁸	1.000	0.182	0.090	0.024
1.00 x 10 ⁻⁸	1.000	0.188	0.095	0.025
>0	1.000	0.194	0.108	0.030

(a) Involvement is defined by normalized air concentration equal to or greater than tabled value.

The full development of the consequences requires a description of a source term and a method to convert the involvement in normalized concentrations to corresponding levels of dose. Figure 1 illustrates the procedure used.

As indicated by Figure 1, the source term was taken from the Reactor Safety Study.⁽⁸⁾ Any of the accidents involving the core that were identified in that study could be used to develop subsequent potential doses at other reactor sites from a) the passing cloud immediately following the accident; and b) ground level contamination during the period following deposition. Table 3 summarizes these accidents and the release mechanisms involved. For this analysis, the class nine accident identified as release category PWR-2 was selected. This was judged to be about as probable as any other event. It also postulates as great or greater quantities of radioactive material released as in any other accident for a ground level release. It can be considered as worst case. The tabulation of radionuclides released in this event are given in Tables 4 and 5. From these tabulations, the appropriate nuclides were

TABLE 2. Conditional Probability that at Least M Quads Would be Involved(a) Following an Accident at an HNEC.

Normalized Surface Concentration, s/m ³	Same Quad	Number of Quads		
		≥ 2	≥ 3	≥ 4
1.00×10^{-7}	1.000			
4.64×10^{-8}	1.000	0.006		
2.15×10^{-8}	1.000	0.021		
1.00×10^{-8}	1.000	0.046		
4.64×10^{-9}	1.000	0.069	0.011	
2.15×10^{-9}	1.000	0.126	0.030	
1.00×10^{-9}	1.000	0.158	0.066	0.018
4.64×10^{-10}	1.000	0.172	0.085	0.023
2.15×10^{-10}	1.000	0.182	0.090	0.024
1.00×10^{-10}	1.000	0.188	0.095	0.025
>0	1.000	0.194	0.108	0.030

(a) Involvement is defined by normalized surface concentration equal to or greater than tabled value.

FIGURE 1. Schematic Outline of Consequence Model Radioactivity Release

TABLE 3. Release Categories Following Reactor Accidents Involving Core^(a)

<u>Pressurized Water Reactors</u>	
PWR 1	Steam explosion due to molten UO_2 falling into water followed by missile rupturing containment.
PWR 2	Core melt and failure of radioactivity removal systems followed by rupture of containment.
PWR 3	Similar to PWR 1 and 2 but involves partial success of radioactivity removal systems.
PWR 4	Core melt with containment not fully isolated, containment radioactivity removal systems have failed.
PWR 5	Similar to PWR 4 except removal systems operative.
PWR 6	Core melt through bottom, above ground containment intact. Radioactivity removal systems inoperative.
PWR 7	Similar to PWR 6 except radioactivity removal system operating.
PWR 8	Core doesn't melt, release of activity in the gaps of fuel rods, containment fails to isolate properly.
PWR 9	Similar to PWR 8, except containment isolates correctly.
<u>Boiling Water Reactors</u>	
BWR 1	Similar to PWR 1
BWR 2	Core melt after containment over pressure rupture caused by loss of decay heat removal systems, limited deposition of radioactive materials. Release directly to atmosphere.
BWR 3	Similar to BWR 2 except material released through the reactor building to the atmosphere.
BWR 4	Core melt, containment fails to operate properly and the leakage is enough to prevent containment over pressure rupture.
BWR 5	Core does not melt, but activity is released from the gap of the fuel rods. Activity passes through reactor building gas treatment system and is released to the atmosphere through a tall stack.

(a) From Reference 8

TABLE 4. Initial Activity of Radionuclides in the Nuclear Reactor Core at the Time of the Hypothetical Accident (Reference 8)

No.	Radionuclide	Radioactive Inventory Source (curies x 10 ⁻³)	Half-Life (days)
1	Cobalt-58	0.0078	71.0
2	Cobalt-60	0.0029	1,920
3	Krypton-85	0.0056	3,950
4	Krypton-85m	0.24	0.183
5	Krypton-87	0.47	0.0528
6	Krypton-88	0.68	0.117
7	Rubidium-86	0.00026	18.7
8	Strontium-89	0.94	52.1
9	Strontium-90	0.037	11,030
10	Strontium-91	1.1	0.403
11	Yttrium-90	0.039	2.67
12	Yttrium-91	1.2	59.0
13	Zirconium-95	1.5	65.2
14	Zirconium-97	1.5	0.71
15	Niobium-95	1.5	35.0
16	Molybdenum-99	1.6	2.3
17	Technetium-99m	1.4	0.25
18	Ruthenium-103	1.1	39.5
19	Ruthenium-105	0.72	0.185
20	Ruthenium-106	0.25	366
21	Rhodium-105	0.49	1.50
22	Tellurium-127	0.059	0.391
23	Tellurium-127m	0.011	109
24	Tellurium-129	0.31	0.048
25	Tellurium-129m	0.053	0.340
26	Tellurium-131m	0.13	1.25
27	Tellurium-132	1.2	3.25
28	Antimony-127	0.061	3.86
29	Antimony-129	0.33	0.179
30	Iodine-131	0.85	8.05
31	Iodine-132	1.2	0.0958
32	Iodine-133	1.7	0.875
33	Iodine-134	1.9	0.0366
34	Iodine-135	1.5	0.280
35	Xenon-133	1.7	5.28
36	Xenon-135	0.34	0.384
37	Cesium-134	0.075	750
38	Cesium-136	0.030	13.0
39	Cesium-137	0.047	11,000
40	Barium-140	1.6	12.3
41	Lanthanum-140	1.6	1.67
42	Cerium-141	1.5	32.3
43	Cerium-143	1.3	1.38
44	Cerium-144	0.85	284
45	Praseodymium-143	1.3	13.7
46	Neodymium-147	0.60	11.1
47	Neptunium-239	16.4	2.35
48	Plutonium-238	0.00057	32,500
49	Plutonium-239	0.00021	8.9 x 10 ⁶
50	Plutonium-240	0.00021	2.4 x 10 ⁶
51	Plutonium-241	0.034	5,350
52	Americium-241	0.000017	1.5 x 10 ⁵
53	Curium-242	0.0050	163
54	Curium-244	0.00023	6,630

TABLE 5. Parameters of Releases Following Reactor Accidents Involving Core^(a)

Release Category	Probability per Reactor Year	Release Duration (Hr)	Warning Time (Hr)	Fraction of Core Inventory Released			
				Xe-Kr	I	Cs-Rb	Ba-Sr
PWR 1	9×10^{-7}	0.5	1.0	0.9	0.7	0.4	0.05
PWR 2	8×10^{-6}	0.5	1.0	0.9	0.7	0.5	0.06
PWR 3	4×10^{-6}	1.5	2.0	0.8	0.2	0.2	0.02
PWR 4	5×10^{-7}	3.0	2.0	0.6	0.09	0.04	5×10^{-3}
PWR 5	7×10^{-7}	4.0	1.0	0.3	0.03	9×10^{-3}	1×10^{-3}
PWR 6	6×10^{-6}	10.0	1.0	0.3	8×10^{-4}	8×10^{-4}	9×10^{-5}
PWR 7	4×10^{-5}	10.0	1.0	6×10^{-3}	2×10^{-5}	1×10^{-5}	1×10^{-6}
PWR 8	4×10^{-5}	0.5	N/A	2×10^{-3}	1×10^{-4}	5×10^{-4}	1×10^{-3}
PWR 9	4×10^{-4}	0.5	N/A	3×10^{-6}	1×10^{-7}	6×10^{-7}	1×10^{-11}
BWR 1	1×10^{-6}	2.0	1.5	1.0	0.4	0.4	0.05
BWR 2	6×10^{-6}	3.0	2.0	1.0	0.9	0.5	0.1
BWR 3	2×10^{-5}	3.0	2.0	1.0	0.1	0.1	0.01
BWR 4	2×10^{-6}	2.0	2.0	0.6	8×10^{-4}	5×10^{-3}	6×10^{-4}
BWR 5	1×10^{-4}	5.0	N/A	5×10^{-4}	6×10^{-11}	4×10^{-9}	8×10^{-14}

(a) From Reference 8, Table 5.1

selected as principal contributors to a dose at other reactor sites from air submersion and from ground deposition.

The HNEC meteorological model assumed that the containment breach resulted in a source 100 meters wide which spread downwind over $22\frac{1}{2}^{\circ}$ as it moved out from the point of release. Figure 2 illustrates one such release at cluster 2 with clusters 3 and 4 shown within a $22\frac{1}{2}^{\circ}$ sector downwind.

Cluster No.	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>
1	5.4 (3.36)	12.9 (8.02)	25.5 (15.85)	28.3 (17.59)
2		7.5 (4.66)	20.4 (12.68)	23.4 (14.54)
3			13.1 (8.14)	16.5 (10.25)
4				4.0 (2.99)

FIGURE 2. Sites and Areas Involved in Radioactive Release at HNEC
Example: Release at cluster 2, with distances between
clusters tabulated in kilometers (miles).

DEVELOPMENT OF THE DOSE DUE TO AIR SUBMERSION (PASSING CLOUD)

Source Conversion

The radionuclides given in Table 4 were submitted to the model for dose estimates which converted these radioactive species into external total body dose,⁽⁹⁾ in units of rem/(sec/m³) as a function of time.

These calculated doses, normalized to a time integrated air concentration of 1.0 sec/m³ by the SUBDOSA model are given in Table 6. Note that for the first 1000 seconds following the release, the values are constant and that after 20,000 seconds, they have decreased only by about 57% to 8×10^7 rem/(sec/m³). The time becomes a factor in recognizing distances the cloud would travel. If an average wind speed of 2 to 3 m/sec during the incident was developed from historical records, then the above tabulation for the first 1000 seconds accounts for the same dose factor for up to 2 to 3 kilometers from the accident site. The meteorological model further reduces this source term with depletion of the cloud contents by fallout along the way.

As an example, for the first 2000 seconds, the probability of different doses involving two or more quads can be immediately determined.

$$D_{(0-2000 \text{ sec})} = X/Q \text{ (s/m}^3\text{)}^a \times \text{rem/(sec/m}^3\text{)}^b$$

a - from Table 1

b - from Table 6

Assume from Table 1, a normalized air concentration of 1×10^{-7} (s/m³). Using the dose in rem/(s/m³) up to the first 2000 seconds from Table 6, the result is:

$$\begin{aligned} D_{0-2000 \text{ sec}}(\text{in rem}) &= 1 \times 10^{-7} \text{ (s/m}^3\text{)} \times 1.3 \times 10^8 \text{ rem/(s/m}^3\text{)} \\ &= 13 \text{ rem} \end{aligned}$$

TABLE 6. External Total-Body Dose for Accident PWR-2

<u>Time, seconds</u>	<u>Total-Body Dose, (*) rem/(sec/m³)</u>
0	1.4×10^8
100	1.4×10^8
200	1.4×10^8
500	1.4×10^8
1,000	1.4×10^8
2,000	1.3×10^8
5,000	1.2×10^8
10,000	1.0×10^8
20,000	8.0×10^7

(*) SUBDOSA Model⁽⁹⁾

Assuming a shielding factor of $0.2^{(8)}$ for those inside (in a control room for instance), the resulting dose is 2.6 rem received from the overhead cloud during its half hour passing. The probabilities of two or more quads receiving this dose is the same as given in Table 2 for ≥ 2 quads involved with this level (1×10^{-7} sec/m³) of normalized air concentration. Table 1 then can be reconstructed in terms of dose, as shown in Table 7. Note that the left-hand column is now in terms of dose. If 2 to 3 m/s of wind speed is assumed, only these units close enough to be enveloped during the 2000 seconds or less of cloud travel are included in this table.

The model predicts that the dose accumulated in control rooms in the same quad as the affected reactor will vary from 280 rem to 0.130 rem. This range includes the heaviest concentrations considered plausible and are worst case conditions. Emergency procedures that are commensurate with risk will have to be in place to shut down the reactors and evacuate the personnel. The probability of the event, a loss of a full core, is once in about every 6000 years (1.4×10^{-6}).

TABLE 7. Conditional Probability that Personnel in at Least 2, 3, or 4 Quads Would Experience the Computed Radiation Doses from the Passing Cloud Following a Release from a Reactor Accident at an HNEC (The first 2000 seconds)

Radiation Dose in Rem, Assuming Shielding Factor of 0.2	Conditional Probabilities of at Least 2 Quads Being Exposed,	
	Same	≥ 2
280	1.000	-
130	1.000	0.01
60	1.000	0.02
28	1.000	0.05
13	1.000	0.07
6	1.000	0.13
2.8	1.000	0.16
1.3	1.000	0.17
0.6	1.000	0.18
0.28	1.000	0.19
0.13	1.000	0.19

The actual probabilities of M or more quads being involved in any release is obtained by factoring in the conditional probability of a reactor accident of this type occurring; namely,

$$P_a = P(\text{actual}) = N \times P(1) \text{ where}$$

N = Number of reactors at the site

P(1) = probability of this type of accident for
one reactor = 8×10^{-6} /reactor year (Table 5)

$$P(A) = 20 \times 1 \times 10^{-6}/\text{reactor year}$$

$$P(A) = 1.6 \times 10^{-4}/\text{reactor year}$$

Thus, if each of the conditional probabilities given in Table 7 were multiplied by 1.6×10^{-4} , the result would be a tabulation in actual probabilities for M or more quads having the associated doses from a passing cloud.

In this manner the actual probabilities of M or more quads being involved with different dose levels due to the passage of the cloud are developed from Table 1 and given in Tables C-1 through C-5 in Appendix C.

The actual probabilities of three or more reactors in the same quad as the accident with different dose levels due to the passage of the cloud are developed as a special case and are given in Table C-1.

The exposures vary with the times shown after the accident due to the rapid decay of some radionuclides and due to depletion of the cloud due to fallout. The probabilities of the nearest reactors (same quad) being involved with substantial doses is the same as the probability of the accident, 1×10^{-4} / reactor/yr. If an accident does occur, the probability is high that the reactors in the nearest quad will be heavily involved. The probability of at least ≥ 3 quads (thirteen reactors or more) being involved is significantly less and for all 5 quads (twenty reactors) the occurrence is possible but its probability vanishingly low.

DEVELOPMENT OF DOSE RATES DUE TO DEPOSITION

The exposure due to deposition (fallout) is calculated in terms of a dose rate where the exposure from the passing cloud (air submersion) was estimated in total dose in rem that resulted during the half hour passage of the cloud. The dose rates of interest are those within a reactor building, control room for example, from ground contamination outside. The radionuclides used to develop dose rates from ground contamination are taken from the reference study.⁽⁸⁾ This selection was based on the radioactive half-life and the type and the energy of the emitted radiation which are important to external exposure from ground deposition. These selected nuclides were divided into two groups according to half-life as shown in the following Table 9. Section I of the table lists the relatively long-lived species; the contribution from these to the radiation level is essentially constant over the time period of interest here; namely, approximately sixty days. Section II contains the short-lived species whose contribution will decrease over the times of interest, some very rapidly.

TABLE 8. Radionuclides Used for Ground Deposition
(WASH-1400, Appendix VI, 8.3.1.2)

Section I		Section II	
Long-Term Isotopes Used, Where $e^{-\lambda t} \approx 1$		Shorter-Term Isotopes	
Species	Half-Life Days	Species	Half-Life Days
^{137}Cs	1100	^{136}Cs	13
^{134}Cs	750	^{131}I	8.05
^{106}Ru	366	^{103}Ru	39.5
^{60}Co	1920	^{97}Zr	0.71
^{58}Co	71	^{95}Nb	35
^{95}Zr	65		

Source Conversion

Converting the radioactivity from the above species to dose rates was done as follows:

$$\text{DR} = \text{DF} \times \text{D/Q} \times \text{S} \times e^{-\lambda t}$$

DR = Dose Rate, mrem/hr

DR = Dose Factor, a value in mrem/hr/pCi/m² - (Reference, Nuclear Regulatory Guide 109, page 1.109-41, Table E-6
Whole body dose from surface contamination in pCi/m².)

D/Q = Normalized surface concentration (1/m²) as a function of Hanford meteorology--Reference 4, or see Table 2 of this report.

S = Source term, given in pCi for each isotope, Reference Tables 4 and 5.

$e^{-\lambda t}$ = Correction for radioactive decay.

For example, the contribution of the dose rate from ^{137}Cs on contaminated ground was determined by

$$\begin{aligned} \text{DR}_{137} &= \text{DF} \times \text{D/Q} \times \text{S} \times e^{-\lambda t} \\ &= 4.2 \times 10^{-9} \times \text{D/Q} \times 23.5 \times 10^{17} \times 1 \\ \text{DR}_{137} &= 98.7 \times 10^8 \times \text{D/Q} \text{ (mrem/hr-m}^2\text{)} \text{ (D/Q values as in Table 2)} \end{aligned}$$

Table 9 summarizes these results for all of the nuclides involved in a dose rate from ground contamination.

TABLE 9. Development of Dose Rate Factors for Both Long-Term and Short-Term Isotopes

<u>Nuclide</u>	<u>T^{1/2} > 60 days Dose mrem/hr-m² x 10⁹</u>	<u>Nuclide</u>	<u>Dose mrem/hr-m² x 10⁹</u>
			<u>T^{1/2} > 60 days (at T = 0)</u>
^{137}Cs	10.04	^{136}Cs	22.5
^{134}Cs	45.0	^{131}I	166.6
^{95}Z	3.0	^{103}Ru	7.92
^{106}Ru	0.75	^{97}Zr	3.3
^{60}Co	0.10	^{95}Nb	<u>3.06</u>
^{58}Co	<u>0.11</u>	TOTAL	203.4 x 10 ⁹ at T = 0
TOTAL	59 x 10 ⁹		

From the above, the nuclides with the shorter half lives contribute the major portion of the dose rate immediately after the passage of the cloud.

Shortly after twenty-one days, the contribution from the longer half-life nuclides becomes predominant. Table 10 illustrates this.

TABLE 10. Dose Rates in mrem/hr-m² as a Function of Time

Elapsed Time, Days	Contribution from Shorter Half-Life Nuclides, mrem/hr-m ² x 10 ⁹	Total Longer(a) plus Shorter Half-Life Material, mrem/hr-m ² x 10 ⁹
0	203.4	262.4
7	144.6	199.8
14	93.7	152.7
21	62.4	121.4
30	42.2	101.2
45	24.6	83.6
60	16.7	75.7
90	9.1	68.1
120	5.1	64.1

(a) Longer life nuclides contribute essentially a constant 59 mrem/hr-m² x 10⁹

The information from the Total column in the above summary, when multiplied by the appropriate normalized concentrations given in Table 2 will yield dose rates at the selected days after the accident.

Then, the conditional probabilities result that these dose rates would occur to those standing on the ground outside of the reactor buildings in at least M quads, assuming that an accident occurs at one unit.

Shielding factors from uneven ground (0.7) and a windowless building (0.2) would reduce the dose rates to those inside by a factor of 0.14. A conservative estimate of attenuation of the dose due to distance from the source to those inside is estimated to be another 0.7. A more realistic attenuation factor would be greater by at least a factor of 10. But, to be conservative, a total shielding factor of just 0.1 is thus assumed (0.7 x 0.2 x 0.7). A further significant reduction of the source level from the most preliminary decontamination efforts is also not included. It was assumed, however, that intake ventilation filtering systems functioned as designed with no radioactive material entering the facilities to contribute to dose levels inside.

As an example, the dose rate inside a building after fourteen days, assuming an involvement outside of $1 \times 10^{-8} \text{ (m}^{-2}\text{)}$ (Table 3) would be as follows:

$$DR_{14} = 1 \times 10^{-8} \text{ m}^{-2} \times 93.7 \times 10^9 \text{ mrem/hr-m}^2 \times 10^{-1} = 93.7 \text{ mrem/hr}$$

The probability of at least two quads having this dose rate would be obtained from Table 2 at the involvement level of $1 \times 10^{-8} \text{ m}^{-2}$.

A new set of tables developed from Table 2 but expressed in terms of dose rates at several finite times following the accident is given in Appendix C.

CONCLUSIONS - ACCIDENT REVIEW

The results are given in terms of the most probable involvements based on several assumptions in meteorology.⁽⁴⁾ For the dose within buildings due to a passing cloud, lethal doses are not predicted for any who remain inside during the passage; but these doses are, however, for the reactors in the same and next quads as the accident, substantial. If any are caught outside and remain submersed in the cloud for the time estimated for it to pass, a lethal dose is predicted. Emergency procedures for this low probability event, once about every 6000 years, can be expected to be in place to prevent this. These procedures would be essentially the same as required for other accidents involving a reactor core. Most of these would not result in accidental releases, but full-scale emergency procedures would be constantly available if needed. For the reactors more distant from the accident, the times available to take proper action prior to arrival of the cloud and the much lower doses that occur, result in no real threat to personnel assuming proper actions are taken. From contaminated ground from fallout at reactor sites near the accident, the dose rates are predicted to be significant for the greater releases. Substantial decontamination efforts are predicted to be required to restore nearby reactors to operating status. For example, surface dose rates of about 75 mrem/hr outside (7.5 mrem/hr inside) are estimated to be possible for at least fifteen reactors although 50 times less probable than the accident itself. Manageable dose rates however result even in the worst predicted case. Some reduction will occur as

the radionuclides decay with time, but the real reductions in dose rates in reasonable time periods will result only from decontaminating each affected site.

The risk of this event when the consequences are loss of generating capability, compare favorably with rare natural events. It was shown that a loss of generating capacity from a class nine accident at an HNEC is less likely than a loss of generating capacity from an ashfall from volcanic activity in the Cascades and significantly less likely than a loss of generating capacity from an Operating Basis Earthquake.⁽¹⁰⁾ See Appendix D.

In this review, numerically conservative values of dose and dose rates were developed and meteorology parameters specific to Hanford were used. This analysis while adequate to indicate probable exposures and consequences, is not a detailed safety analysis. Such an analysis would be a subject for further development of the HNEC concept.

Finally, the probability of occurrence of the accident selected as the example in this review from the reference report;⁽⁸⁾ namely, the PRW-2, is used throughout as single valued. At best, it is an estimate with some error bounds which if developed in the reference report were not given. Knowing the conservatism that was used in that report to develop the estimate, it seems plausible to accept it as a reasonable approximation. As such, it is utilized here to make comparisons with estimates of the frequency of occurrence of other rare events to provide perspective among them. This procedure was used knowing that estimating the frequency of occurrence of any rare event is an uncertain process.

ACKNOWLEDGMENT

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APPENDIX A

REVIEW OF THE FEDERAL CODES

APPENDIX A

REVIEW OF THE FEDERAL CODES

The Code of Federal Regulations 10 CFR, particularly Parts 50 and 100, contain sections that may affect but apparently not limit the concept of an HNEC. Appendix A of 10 CFR 50, General Design Criteria for Nuclear Power Plants, includes a few criteria that impact multi-unit stations more or less directly. These criteria are quite general however, and, as currently issued are not limiting for multi-unit sites at an HNEC. The following summarizes these specific criteria which impact multi-unit stations.

<u>No.</u>	<u>Title</u>	<u>Impact</u>
5	Sharing of Structures Systems and Components	For systems involving safety. designs for sharing must not impair ability to perform their safety functions including an accident in one and an orderly shutdown and cool down in remaining units.
17	Electric Power Systems	Perhaps the most detailed of these design criteria and including offsite power requirements for safety functions. Offsite power criteria will affect multi-unit siting.
18	Inspection and Testing of Electric Power Systems	Designs must allow testing and transfer of power including offsite power systems.
34	Residual Heat Removal	Criteria included for offsite power to provide necessary safety functions.
44	Cooling Water	Criteria included for offsite power to transfer heat load to ultimate heat sink.

Other examples of the need to satisfy these basic design criteria in 10 CFR 50 may develop if multi-unit sites come into being and a pooling among stations of equipment, manpower, or services may be proposed.

A recent addition to 10 CFR 50, paragraph 34,^(a) relative to maintaining integrity of structures, systems, and components important to safety during construction at multi-unit sites would not impact the HNEC concept. It is unlikely that construction underway on reactor operation at one multi-unit station is likely to affect construction or operation at another multi-unit station at an HNEC.

Part 100 of 10 CFR, Reactor Site Criteria, includes criteria for consideration for siting multiple reactor facilities. The criteria in this Code that relate most to an HNEC are those that limit radioactive effluents from all LWRs at a site. As above, as can be determined from just a concept of an HNEC, the impact of these criteria have been reviewed and not found limiting in other sections of the conceptual study including the radiological section.

The Environmental Protection Agency (EPA) issued new regulations consisting of the addition of a new Subchapter F and Part 190, in January 1977.^(b) These give environmental radiation protection standards for nuclear power operations.

In the discussion of major issues that had been raised during the comment period, some conclusions were made by EPA regarding the impact on the new standards of multi-unit sites.

The Agency inferred that multi-unit sites closer than ten miles may require special attention during licensing and that for sites containing up to five reactors, conformance to criteria in 10 CFR 50, Appendix I, by these multi-unit stations should provide reasonable assurance of compliance with these new EPA standards. Considering the long distance from any multi-unit site at Hanford to the nearest populated zone, the conclusion relating to the ten miles between sites does not appear to be limiting to the HNEC concept. The conclusion is not however a part of the Federal Code.

(a) Federal Register, Vol. 43, No. 135, Thursday, July 14, 1977.

(b) Federal Register, Vol. 42, No. 9, Thursday, January 13, 1977.

APPENDIX B

REVIEW OF REGULATORY GUIDES

APPENDIX B

REVIEW OF REGULATORY GUIDES

None of the current regulatory guides are directed to energy centers as indicated in the text. Moreover not much guidance for energy centers specifically can be inferred from those guides which mention siting multi-unit stations.

However, the concept of several multi-unit sites at an HNEC, developed sequentially as separate stations, is interesting largely because of the land areas available for siting, low population zones plus other technical and environmental features unique to an HNEC that are described elsewhere in these analyses. This concept was included during the following review of the Regulatory Guides.

<u>Regulatory Guide No.</u>	<u>Title</u>	<u>Synopsis</u>
1.6	Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems	Matter of nearby hydroelectric, nuclear or fossil units as standby power sources at multiple-unit sites to be evaluated on individual case basis.
1.27	Ultimate Heat Sink	In a multi-unit station, safety design precludes more than one reactor unit in accident condition at one time - "an ultimate heat sink complex serving multiple units should be capable...cooling all units it serves." This subject was addressed in this review. ^(a)
1.32	Criteria for Safety-Related Electric Power systems for Nuclear Power Systems	Some electrical systems are forbidden to be shared by multi-unit stations but is not limiting to HNEC in current designs.
1.75	Physical Independence of Electrical Systems	Not applicable to concerns for multi-unit installation.

(a) Heat Sink Management Studies, L. D. Kannberg.

Regulatory Guide No.	Title	Synopsis
1.81	Shared Emergency and Shutdown Systems for Multi-Unit Nuclear Power Plants	Provides guidance only to a multi-unit station and sharing of systems and components onsite of multi-unit stations.
1.91	Availability of Electric Power Sources	Relative to offsite power source, operating guidance is given when one is lost. Availability of adequate offsite backup power for an HNEC can be met but many more stations may depend on its reliability to always provide two operating sources, for each reactor in the several quads at an HNEC HNEC.
1.109	Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for Evaluating Compliance with 10 CFR 50, Appendix I.	These are guides to implement (in part) Appendix I, 10 CFR 50
1.111	Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors.	
1.112	Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light-Water-Cooled Power Reactors.	
1.113	Estimating Aquatic Dispersion of Effluents from Accidental and Routine Reactor Releases for the Purpose of Implementing Appendix I.	

There are other guides that will relate to the existence of multi-unit stations. Emergency Plans, Regulatory Guide 101, will have to be cognizant of the presence of multi-unit stations and include their presence.

Nearby multi-unit stations may be supportive of each other in emergency planning perhaps and certainly in the pooling of efforts to maintain industrial security Regulatory Guide 1.17, Protection of Nuclear Power Plants Against Sabotage. Some existing requirements can be reinforced by the presence of multi-unit stations at an HNEC.

APPENDIX C

AIR SUBMERSION AND GROUND DEPOSITION

APPENDIX C

AIR SUBMERSION AND GROUND DEPOSITION

TABLE C-1. Probability $\times 10^{-4}$ that at Least M Reactors in the Same Quad as the Accident Would be Involved. Involvement is defined as the dose received inside a reactor building, as indicated in Column 1, from the passage of the radioactive cloud 1000 seconds after a release.

<u>Rem</u>	<u>Number of Reactors</u>		
	<u>3</u>	<u>4</u>	<u>5</u>
280	1.6	1.4	0.5
130	1.6	1.4	0.4
60	1.6	1.4	0.4
28	1.6	1.4	0.5
13	1.6	1.4	0.5
6	1.6	1.4	0.6
2.8	1.6	1.4	0.6
1.3	1.6	1.4	0.6
0.6	1.6	1.4	0.7
0.3	1.6	1.4	0.7
>0	1.6	1.4	0.7

Example--The probability of at least five reactors (if the quad has five) receiving 6 rem within 1000 seconds (approximately 17 minutes) after a release at another reactor is 6×10^{-5} ($0.6 \times 1 \times 10^{-4}$) per reactor year, a frequency of once about every 16,000 years. This table is a special case in estimating doses within a quad. For up to 1000 seconds and more following an accident, the only quad involved is the one containing the reactor having the accident.

TABLE C-2. Probability $\times 10^{-4}$ that at Least 2 Quads Would be Involved Following an Accident at an HNEC. Involvement is defined as the dose received inside a reactor building, as indicated in Column 1, from the passage of the radioactive cloud 2000 seconds (33 minutes) after a release.

<u>Rem</u>	<u>Probability ≥ 2 Quads</u>
260	0.01
120	0.03
56	0.07
26	0.07
12	0.11
5.6	0.20
2.6	0.25
1.2	0.28
0.6	0.29
0.1	0.3
>0	0.31

Example--The useful probabilities here are those associated with ≥ 2 quads as the cloud moving at 2 to 3 m/sec could reach quads adjacent to the accident site. A dose of 5.6 rem would affect at least 2 quads with a probability of 2×10^{-5} or with a frequency of once about every 50,000 years. The error band in the probability estimate may be 2 or 5 or even 10 times lower. The corresponding frequency may be once every 5,000 years. The conclusions are not changed however. The range of dose expected would extend from 120 to 0.1 rem.

TABLE C-3. Probability $\times 10^{-4}$ that at Least M Quads Would be Involved Following an Accident at an HNEC. Involvement is defined as the dose received inside a reactor building, as indicated in Column 1, from the passage of the radioactive cloud 5000 seconds (1 hr, 23 min) after a release.

<u>Rem</u>	<u>Probability</u>		
	<u>≥ 2 Quads</u>	<u>≥ 3 Quads</u>	<u>≥ 4 Quads</u>
240			
111	0.1		
52	0.3		
24	0.07		
11	0.11	0.02	
5.2	0.20	0.05	
2.4	0.25	0.11	
1.1	0.28	0.14	
0.5	0.29	0.14	
0.2	0.3	0.15	
>0	0.31	0.17	

The elapsed time is sufficient to involve at least 13 reactors. (≥ 3 quads)

Example--The probability of at least 3 quads (≥ 13 reactors) receiving 5.2 rem is 5×10^{-6} ($1 \times 10^{-4} \times 0.05$) a frequency of once about every 200,000 years.

TABLE C-4. Probability $\times 10^{-4}$ that at Least M Quads Would be Involved Following an Accident at an HNEC. Involvement is defined as the dose received inside a reactor building, as indicated in Column 1, from the passage of the radioactive cloud 10,000 seconds (2 hr, 46 min) after a release

<u>Rem</u>	<u>Probability</u>		
	<u>≥ 2 Quads</u>	<u>≥ 3 Quads</u>	<u>≥ 4 Quads</u>
200			
93	0.01		
43	0.03		
20	0.07		
9.3	0.11	0.02	
4.3	0.20	0.05	
2.0	0.25	0.11	0.03
0.9	0.28	0.14	0.14
0.4	0.29	0.14	0.04
0.2	0.3	0.15	0.04
>0	0.31	0.17	0.05

The elapsed time is sufficient at wind speeds of 2 to 3 m/sec for the cloud to reach the quad containing a fifteenth reactor.

Example--The probability of a dose of 2 rem in at least 4 quads (15 reactors) is 3×10^{-6} ($3 \times 10^{-2} \times 10^{-4}$) or once about every 330,000 years. It is about 50 times less probable at HNEC for at least 15 reactors to have this dose as it is for reactors in the same quad as the accident to have the dose. ($1.6/0.03 = 50$).

TABLE C-5. Probability $\times 10^{-4}$ that at Least M Quads Would be Involved Following an Accident at an HNEC. Involvement is defined as the dose received inside a reactor building, as indicated in Column 1, from the passage of the radioactive cloud 20,000 seconds (5 hr, 33 min) after a release

<u>Rem</u>	<u>Probability</u>		
	<u>≥ 2 Quads</u>	<u>≥ 3 Quads</u>	<u>≥ 4 Quads</u>
160			
74	0.01		
34	0.03		
16	0.07		
7.4	0.11	0.02	
3.4	0.20	0.05	
1.6	0.25	0.11	0.03
0.7	0.28	0.14	0.14
0.3	0.29	0.14	0.04
0.2	0.3	0.15	0.04
>0	0.31	0.17	0.05

Example--As in the case of the release after 10,000 seconds the probability of at least 4 quads (≥ 15 reactors) receiving a dose of 1.6 rem is 3.0×10^{-6} , about once every 330,000 years.

TABLE C-6. Probability $\times 10^{-4}$ that at Least M Quads Would be Involved Following an Accident at an HNEC. Involvement is defined as the dose rates inside reactor building from ground contamination outside on same day as the accident.

<u>Dose Rate</u>	<u>Probability</u>			
	<u>Same Quad</u>	<u>≥ 2 Quads</u>	<u>≥ 3 Quads</u>	<u>≥ 4 Quads</u>
2.62 rem/hr	1.6			
1.2 rem/hr	1.6	0.01		
0.56 rem/hr	1.6	0.03		
262 mrem/hr	1.6	0.07		
120 mrem/hr	1.6	0.11	0.02	
56 mrem/hr	1.6	0.20	0.05	
26 mrem/hr	1.6	0.25	0.11	0.03
12 mrem/hr	1.6	0.28	0.14	0.04
7 mrem/hr	1.6	0.29	0.14	0.04
3 mrem/hr	1.6	0.3	0.15	0.04
>0 mrem/hr	1.6	0.31	0.17	0.05

Example--On the same day of the accident, the probability of at least 3 quads having 56 mrem/hr within the reactor building is 5×10^{-6} , i.e., at a frequency of once about every 200,000 years.

TABLE C-7. Probability $\times 10^{-4}$ that at Least M Quads
Would be Involved Following an Accident at
an HNEC. Involvement is defined as the dose
rates inside reactor building following the
accident by 7 days

Dose Rate	Probability			
	Same Quad	≥ 2 Quads	≥ 3 Quads	≥ 4 Quads
2.0 rem/hr	1.6			
0.93 rem/hr	1.6	0.01		
0.43 rem/hr	1.6	0.03		
200 mrem/hr	1.6	0.07		
93 mrem/hr	1.6	0.11	0.02	
43 mrem/hr	1.6	0.20	0.05	
20 mrem/hr	1.6	0.25	0.11	0.03
9 mrem/hr	1.6	0.28	0.14	0.04
4 mrem/hr	1.6	0.29	0.14	0.04
2 mrem/hr	1.6	0.3	0.15	0.04
>0 mrem/hr	1.6	0.31	0.17	0.05

Example--The probability of at least 4 quads having 20 mrem/hr
inside the buildings 7 days after the accident is 3×10^{-6} ,
or once about every 333,000 years.

TABLE C-8. Probability $\times 10^{-4}$ that at Least M Quads
Would be Involved Following an Accident at
an HNEC. Involvement is defined as the dose
rates inside reactor building following the
accident by 14 days.

<u>Dose Rate</u>	<u>Probability</u>			
	<u>Same Quad</u>	<u>≥ 2 Quads</u>	<u>≥ 3 Quads</u>	<u>≥ 4 Quads</u>
1.5 rem/hr	1.6			
0.71 rem/hr	1.6	0.01		
0.329 rem/hr	1.6	0.03		
150 mrem/hr	1.6	0.07		
71 mrem/hr	1.6	0.11	0.02	
33 mrem/hr	1.6	0.20	0.05	
15 mrem/hr	1.6	0.25	0.11	0.03
7 mrem/hr	1.6	0.28	0.14	0.04
3 mrem/hr	1.6	0.29	0.14	0.04
1.5 mrem/hr	1.6	0.3	0.15	0.04
>0 mrem/hr	1.6	0.31	0.17	0.05

Example--The probability of at least 4 quads (≥ 15 reactors) having
a 15 mrem/hr dose rate inside the building after 14 days
is 3×10^{-6} , or about once every 333,000 years.

TABLE C-9. Probability $\times 10^{-4}$ that at Least M Quads Would be Involved Following an Accident at an HNEC. Involvement is defined as the dose rates inside reactor building following the the accident by 30 days.

<u>Dose Rate</u>	<u>Probability</u>			
	<u>Same Quad</u>	<u>≥ 2 Quads</u>	<u>≥ 3 Quads</u>	<u>≥ 4 Quads</u>
1 rem/hr	1.6			
470 mrem/hr	1.6	0.01		
218 mrem/hr	1.6	0.03		
100 mrem/hr	1.6	0.07		
47 mrem/hr	1.6	0.11	0.02	
22 mrem/hr	1.6	0.20	0.05	
10 mrem/hr	1.6	0.25	0.11	0.03
4.7 mrem/hr	1.6	0.28	0.14	0.04
2.2 mrem/hr	1.6	0.29	0.14	0.04
1.0 mrem/hr	1.6	0.3	0.15	0.04
>0 mrem/hr	1.6	0.31	0.17	0.05

Example--The probability of at least 2 quads (≥ 7 reactors) having 10 mrem/hr inside the reactor building 30 days after the accident is 2.5×10^{-5} , or about once every 40,000 years.

TABLE C-10. Probability $\times 10^{-4}$ that at Least M Quads Would be Involved Following an Accident at an HNEC. Involvement is defined as the dose rates inside reactor building following the accident by 60 days.

<u>Dose Rate</u>	<u>Probability</u>			
	<u>Same Quad</u>	<u>≥ 2 Quads</u>	<u>≥ 3 Quads</u>	<u>≥ 4 Quads</u>
757 mrem/hr	1.6			
351 mrem/hr	1.6	0.01		
163 mrem/hr	1.6	0.03		
75.7 mrem/hr	1.6	0.07		
35.1 mrem/hr	1.6	0.11	0.02	
16.3 mrem/hr	1.6	0.20	0.05	
7.6 mrem/hr	1.6	0.25	0.11	0.03
3.5 mrem/hr	1.6	0.28	0.14	0.04
1.6 mrem/hr	1.6	0.29	0.14	0.04
0.8 mrem/hr	1.6	0.3	0.15	0.04
>0 mrem/hr	1.6	0.31	0.17	0.05

Example--The probability of at least 3 quads (≥ 11 reactors) having 7-1/2 mrem/hr inside the reactor building 60 days after the accident is 1.1×10^{-5} , or at a frequency of once about every 90,000 years.

APPENDIX D

EVALUATION OF THE CONSEQUENCES

APPENDIX D

EVALUATION OF THE CONSEQUENCES

One of the predictable consequences of a class nine accident at an HNEC is loss of generating capacity for finite periods of time following the accident.

Estimates of the consequences have been predicted based on several assumptions. All twenty of the projected reactors are in place. At any one time at least four are down for refueling or maintenance. Emergency procedures in place at the time of the accident may force every reactor to shut down at least to hot standby. After two days as an average, all units not affected or affected only to low levels of contamination are back in service. Some units may be back in service within hours while others destined to early return to service may take longer.

Using these assumptions, maximum and minimum probable losses of generating capacity were developed. The results are given in the following tables.

TABLE D-1. Maximum Outage Occurrence. Energy generation loss from 16 units out of service due to the accident for the indicated lengths of time.

<u>Time Required to Decontaminate, Days</u>	<u>Outage Description</u>	<u>Generation Loss, GW-hr</u>
45	5 Unit Site (includes site of accident)--all units up at time of accident	6480 ^(a)
15	4 Unit Adjacent Quad All units up	1728
10	4 Unit Quad Beyond All units up	1152
7	4 Unit Quad beyond the above 3 of 4 units up	<u>605</u>
		9965

(a) 6480 GW-hr = 45 days x 24 hr/day x 1.2 GW/unit x 5 units.

In a similar manner, the total generation loss for the different involvement of the reactors was determined. Involvement included both number of quads involved plus the maximum and minimum of reactors involved in one of the quads, with all units up at the time of the accident. The variability of involvement is assumed to be a result of an arbitrary wind direction and orientation of the reactors.

TABLE D-2. Summary of Energy Generation Loss

<u>Number of Quads Involved</u>	<u>Maximum Loss, GW-hr</u>	<u>Minimum Loss, GW-hr</u>	<u>Probability of Occurrence in Units of 10⁻⁴</u>
4	19.1	2709	0.04
3	17.6	2708	0.11
2	14.5	2593	0.25
1	9.5	2016	1.6

The probability of occurrence, column four in Table 6 was obtained from a table essentially equal to Table C-9 but computed for a 45-day decay period. The data from Table D-2 is shown in graphical form in Figure 3. The capacity, in gigawatts shown as the abscissa, refers to the amount of generating capacity lost from the various quads depending on their involvement. The lower ordinate gives the corresponding energy generation loss in gigawatt-hours (GW-hr). The upper coordinate gives the probabilities that are associated with different capacity loss (quads involved).

The dotted horizontal line assumes a fixed probability of loss of any amount of capacity due to administrative procedures that force an extended shutdown of all units at an HNEC if an accident occurs. The top curve is the expected probabilities assuming that administrative procedures permit those reactors not involved to continue service after a brief interruption.

FIGURE 3. Energy Generation Loss

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