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Station Service Power Supply for a Hanford Nuclear Energy Center (HNEC)

R. L. Richardson
W. J. Dowis

December 1976

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

R. L. Richardson
W. J. Dowis, Consultant

December 1976

Battelle
Pacific Northwest Laboratories
Richland, Washington 99352

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

PARTIAL DIAGRAM SHOWING POSSIBLE
CONNECTION POINTS BETWEEN GRID
AND STATION SERVICE CIRCUITS:

- NORMAL CIRCUIT
- ALTERNATE CIRCUIT - CONCEPT A
- ALTERNATE CIRCUIT - CONCEPT B

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 off-site 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 south-west 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)

Topic	Concept A	Concept B	Relative Merit
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)

	Discount Rate		
	0	5%	10%
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. RB 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.1. Hanford Area 230 kV System with 180 MW Load at Hanford, Gable Mt., and Ashe. 115-kV system sectionalized between Midway and Franklin.

FIGURE C.2. Hanford Area 230 kV System with 180 MW Load at Hanford, Gable Mt., and Ashe. 115-kV system sectionalized.

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

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