ATTACHMENT 1

CONSUMERS POWER COMPANY
BIG ROCK POINT PLANT
DOCKET 50-155

REVISION 4 - FINAL SAFETY HAZARDS SUMMARY

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ATTACHMENT 2

CONSUMERS POWER COMPANY
BIG ROCK POINT PLANT
DOCKET 50-155

REVISION 4 - FINAL SAFETY HAZARDS SUMMARY

<u>Page Changes</u>

122 Pages

CHAPTER 2

SITE CHARACTERISTICS

2.1 GEOGRAPHY AND DEMOGRAPHY

2.1.1 SITE LOCATION AND DESCRIPTION

The Big Rock Point Nuclear Plant Site Plan for the facility is shown in Drawing 0740G20003.

The site property consists of gently sloping wooded and cleared land at the western extremity of the southern shore of Little Traverse Bay. The site is 228 miles NNW of Detroit and 262 miles NNE of Chicago.

Figure 2.1 shows the location of the site with respect to the over-all view of the state of Michigan and its surroundings.

Figure 2.2, Site Map, indicates the property owned by Consumers Power Company, in relation to the nearby highway and former railroad. Figure 2.2 also indicates the location of the reactor on the site.

2.1.1.1 Immediate Environs

The immediate environs of the site are sparsely occupied and little utilized. The gently sloping, partly wooded land with no significant topographic features found on the site itself, continues for several miles. To the south, at a distance of about three miles, is Lake Charlevoix, an inland extension of Lake Michigan of significant size.

The size and shape of the site and the location of the reactor enclosure on it insure that no residences or commercial facilities are within one-half mile of the reactor. Only scattered rural or resort residences and a few commercial facilities are found within several miles of the site. Commercial and cultural facilities and important residential areas are found in Charlevoix, about four miles southwest of the site; and at Petoskey, about eleven miles east of the site. Outside of such cities there are no nearby significant industrial operations, except for a cement plant about six miles to the west.

2.1.1.2 Site Access

Access to the site is available by US Michigan Route #31 which passes the site at a distance of one-half to one mile from the reactor location and connect the cities of Charlevoix and Petoskey. Access to the plant is by a winding access road running west from U.S. 31.

2.1.1.3 Plant Features

The Big Rock Point Nuclear Power Plant consists of a direct cycle, forced circulation boiling water reactor, a power extraction system, and associated serviced facilities. The principal structures include:

A 130 foot diameter spherical containment vessel

°Reactor Building (T-1)

A Turbine Generator Building (B-3)

A structure housing water intake facilities and diesel generator

°Screen, Well and Pump House (B-4)

°Emergency Generator Room (B-5)

A 240 foot stack (chimney) (B-1)

A Alternate Shutdown Panel Building (ASPB) (B-24)

A Security Building (B-16)

Waste Storage Vaults (Liquid) (B-11)
(Solid) (B-10)

Reference BRP Drawing 0740G20003 Site Plan for the Building and Structure locations and to Figure 2.3 for general Plant Facility Identifications.

The containment vessel houses the reactor, recirculation piping, pumps, steam drum, fuel pool, and equipment for removal of shutdown heat. The turbine-generator and other conventional plant components are housed in a separate adjoining building.

2.1.1.4 Surrounding Area

Charlevoix County, with a land area of about 400 square miles, has farm earnings (Reference 3) of about \$4.2 million per year, with /
about 17% of its land area in agricultural use. Produce is principally /
forest, dairy and poultry products, and fruit. Statistics on the economy of the three counties around the site (the approximate thirty-mile radius), are shown in the following table.

TABLE 2.1

STATISTICS OF SURROUNDING AREA
(Reference 3)

County	Antrim	Charlevoix	Emmet	
Land Area, sq mile	477	417	468	/
Population 1990	18,185	21,488	25,040	/
Population/sq mile	38.1	51.5	53.5	/
% of Population Increase 1960-1970	21.6%	23.2%	15.3%	
% of Population Increase 1970-1980	28.4%	20.3%	25.4%	
% of Population Increase 1980-1990	12.3%	7.8%	8.9%	/
% of Urban Population 1990	~ 30%	~ 35%	~ 30%	/
Persons/Household 1990	2.58	2.59	2.58	/
Total Number of Households	6,980	8,243	9.516	/
Manufacturing Establishments, 1987	26	61	48	/
% With Over 20 Employees	38.5%	29.5%	33.3%	/
Average Annual Manufacturing Employment 1987	~ 600	~ 2200	~ 1500	/
Farms, 1987	248	232	211	/
Average Size Farms, Acres	222	180	213	/
Value of Farm Products Sold, Average per farm ($)	46,335	18,189	22,061	/
Including % Farm Crops	48.5%	24.1%	31.7%	/
% of Livestock and Poultry Products	51.5%	75.9%	68.3%	/

Typical of most of the northern portion of the southern peninsula of Michigan, and because of comparatively moderate summer climate and abundant lake frontage, the general region of the site is an important summer vactionland. However, this summer occupancy is not a significant factor within about two miles of the plant site.

2.1.2 EXCLUSION AREA AUTHORITY AND CONTROL (Reference 1)

The Big Rock Point Nuclear Power Plant is located on the shore of Lake Michigan in Charlevoix County in the northern part of Michigan's lower peninsula. The plant site is approximately three and one half miles northeast of the city of Charlevoix and eleven miles west of the city of Petoskey, Michigan. The site exclusion area is defined by the site property limits and thus the exclusion area boundary lines are identical to the plant property lines shown on the Site Map. The nearest boundary of the exclusion area on the landward side of the plant is 2,680 feet.

The approximately 600 acres of property within he exclusion area boundaries including the mineral rights is owned by the Licensee. Parts of the exclusion area are traversed by US Route 31 and the former Chesapeake and Ohio Railroad, portions of which were owned by the Michigan Department of Transportation as shown in Figure 2.2. Arrangements have been made to control traffic on Route 31 in the event of a plant emergency, as documented in the Site Emergency Plan (Reference 2). Similar arrangements, however, have not been made regarding the former railroad line as the access from the west has been rendered impossible by removal of the Pine River Rail trestle and access from the east is currently impossible due to washout of the tracks near Petoskey. Further, sections of track have been removed and portions were abandoned.

The Plant under Michigan law, owns to the water's edge and has the right to control access from the landward side to the lakeshore frontage within the exclusion area. The exclusion area is not defined over the waters of Lake Michigan adjacent to the site. While Big Rock Point has not specifically defined an exclusion area over the water, arrangements have been made with the US Coast Guard, as documented in the Site Emergency Plan (Reference 2), for the control of water traffic offshore of the plant in the event of an emergency.

<u>Evaluation Summary</u>

The topic of Exclusion Area Authority and Control was evaluated by the NRC as part of the Systematic Evaluation Program topic number II-1.A. This review resulted in an assessment and evaluation (Reference 1) which found that the arrangements with the U.S. Coast Guard meet the intent of the criteria in Part 100 and, therefore, the lack of a defined exclusion area over the water does not constitute a significant safety issue for the SEP review.

This evaluation concluded that Big Rock Point has the proper authority, with one exception, to determine all activities within the exclusion area, as required by 10 CFR Part 100. The exception concerned the lack of an arrangement to control traffic on the former Chesapeake and / Ohio Railroad line which traversed a part of the exclusion area. / This was a departure from current criteria but was not considered a significant safety issue in view of the location of the railroad line in relation to the plant, the then low volume of traffic on the line, and the stated intention of the Licensee to include such an arrangement (* Note 1) in the new Site Emergency Plan. This completed the evaluation of the SEP topic.

*NOTE 1 Since that evaluation was completed, the need to include this arrangement in the Site Emergency Plan has become moot as described in this report. If in the future the railroad line is reopened, arrangements for control of traffic on the line in the event of a plant emergency will be included in the Site Emergency Plan.

2.1.3 POPULATION DISTRIBUTION

The site is remote from any large metropolitan areas, and has generally favorable low surrounding permanent population as shown in Figure 2.4 which was extracted from Reference 4.

2.1.3.1 Population Within Five (5) Miles

A survey of the population within a five mile radius of the plant indicates the following ring population estimates (Reference 4). /

TABLE 2.2

Ring Mile	Permanent Residents	Seasonal Residents * Note 3	Transient * Note 1	Special Facility * Note 2	Total Population
0-1	11	0	388	0	399
1-2	166	0	8	0	174
2-3	802	562	1,430	795	3,589
3-4	1,283	658	877	0	2,818
4-5	2,765	405	3,125	1,095	7,390
				Total Cumulative	14,370

* Note 1 - Persons in work force, Hotel/Motel Guests and Visitors to Recreation Areas.

* Note 2 - School, Medical and Nursing Homes includes about 60 in 0-5 mile radius for private care.

* Note 3 - Based on 1980 Census, Seasonal Resident data was not compiled in the 1990 Census.

The preponderance of population toward the southwest coincides with a minimum wind direction probability in that direction.

2.1.3.2 Population Within Thirty (30) Miles

The region surrounding the Big Rock Point Plant is generally of low population density and rural to suburban in character. The total population within the counties of Charlevoix, Emmet, and Antrim, which covers the majority of the area within 30 miles of the plant, based on 1990 census data, was about 65,000. This region has experienced an overall average increase of 9.7% in their resident population between 1980 and 1990 (Refer to Table 2.1). The majority of this population increase is attributed to in-migration primarily from other regions of Michigan.

2.1.3.3 Seasonal Population

Seasonal population is an important factor in the area surrounding the plant as this part of Michigan attracts a large number of visitors year round with the peak occurring in the summer season. The seasonal population (ie, seasonal residents overnight tourists, and daily visitors) in the three county area is established to increase the population by 75% during the height of the season (Reference 6).

2.1.3.4 Low Population Zone and Emergency Planning Zones

The low population zone specified for Big Rock Point site is the area within two and one half (2.5) mile radius of the plant; the primary emergency planning zone is the five (5) mile radius; and the secondary emergency planning zone extends to a thirty (30) mile radius (Reference 2).

2.1.3.5 Population Centers

TABLE 2.3

Principal urban areas within 60 miles are:

	Population					
Urban Center	1960	1970	1980	*1990	Distance From Site	Direction From Site
Charlevoix	2,751	3,519	3,296	3,116	4 Miles	SW
Harbor Springs	1,433	1,662	1,567	1,540	11 Miles	ENE
Petoskey	6,138	6,342	6,097	6,056	11 Miles	E
Boyne City	2,797	2,969	3,348	3,478	14 Miles	SE
East Jordan	1,919	2,041	2,185	2,240	14 Miles	SSE
Gaylord	2,569	3,012	3,011	3,256	33 Miles	SE
Cheboygan	5,859	5,553	5,106	4,999	40 Miles	NE
St Ignance	3,334	2,892	2,632	2,568	42 Miles	NNE
Traverse City	18,432	18,048	15,516	15,116	45 Miles	SSW
Grayling	2,015	2,143	1,792	1,944	52 Miles	SSE

* Population figures are 1990 Census (Reference 5)

Charlevoix is the closest urban center and does not presently nor foreseeably fall within the population center definition of 10 CFR Part 100.

2.1.3.6 Population Density

By applying the Seasonal Population increase to the three county 1990 Census Resident Population, the cumulative population of the majority of the area within thirty (30) miles of the plant is about 114,000 people for a population density of about eighty three (83) persons per square mile. This Population Density is not expected to approach the 10 CFR Part 100 Guideline Limits during the Plant lifetime.

2.1.3.7 Evaluation Summary

The topic of Population Distribution was evaluated by the NRC as part of the Systematic Evaluation Program Topic number II-1.B. This review resulted in an assessment and evaluation (Reference 1) which found that based upon an examination of present and projected population data and on observations made during a visit to the site in July 1979, that neither Charlevoix nor any other city within 30 miles of the plant is now, or is likely to become in the foreseeable future, a population center, (more than 25,000 residents), as defined in 10 CFR Part 100. Further, the NRC concluded that the low population zone and population center distances specified for the Big Rock Point site remain valid and the site is in conformance with the distance requirements of 10 CFR Part 100 in that the population center distance is more than one and one-third times the distance from the reactor to the outer boundary of the low population zone.

This completed the evaluation of this SEP Topic. Since the plant site conforms to current licensing criteria, no additional SEP review is required.

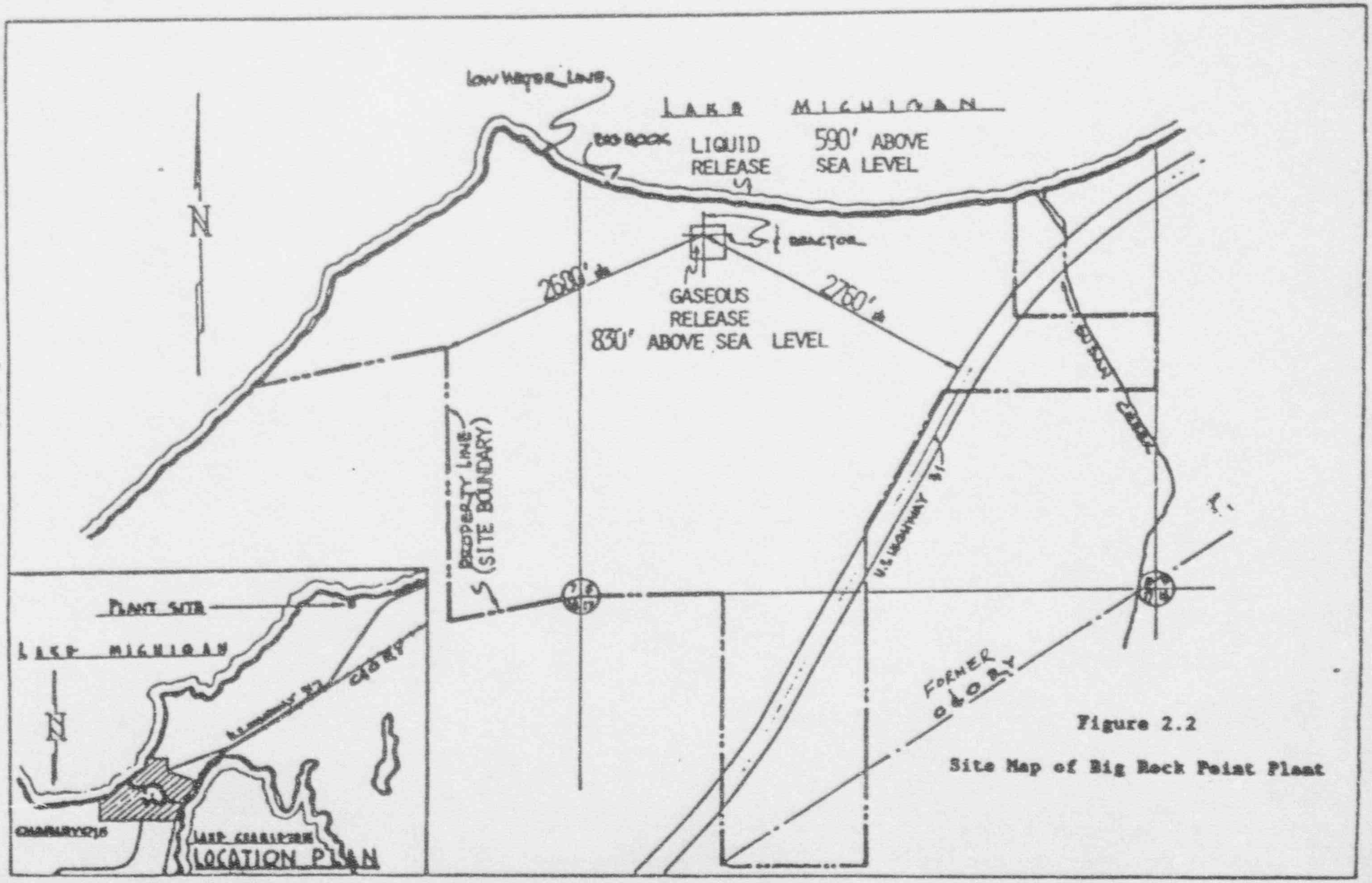
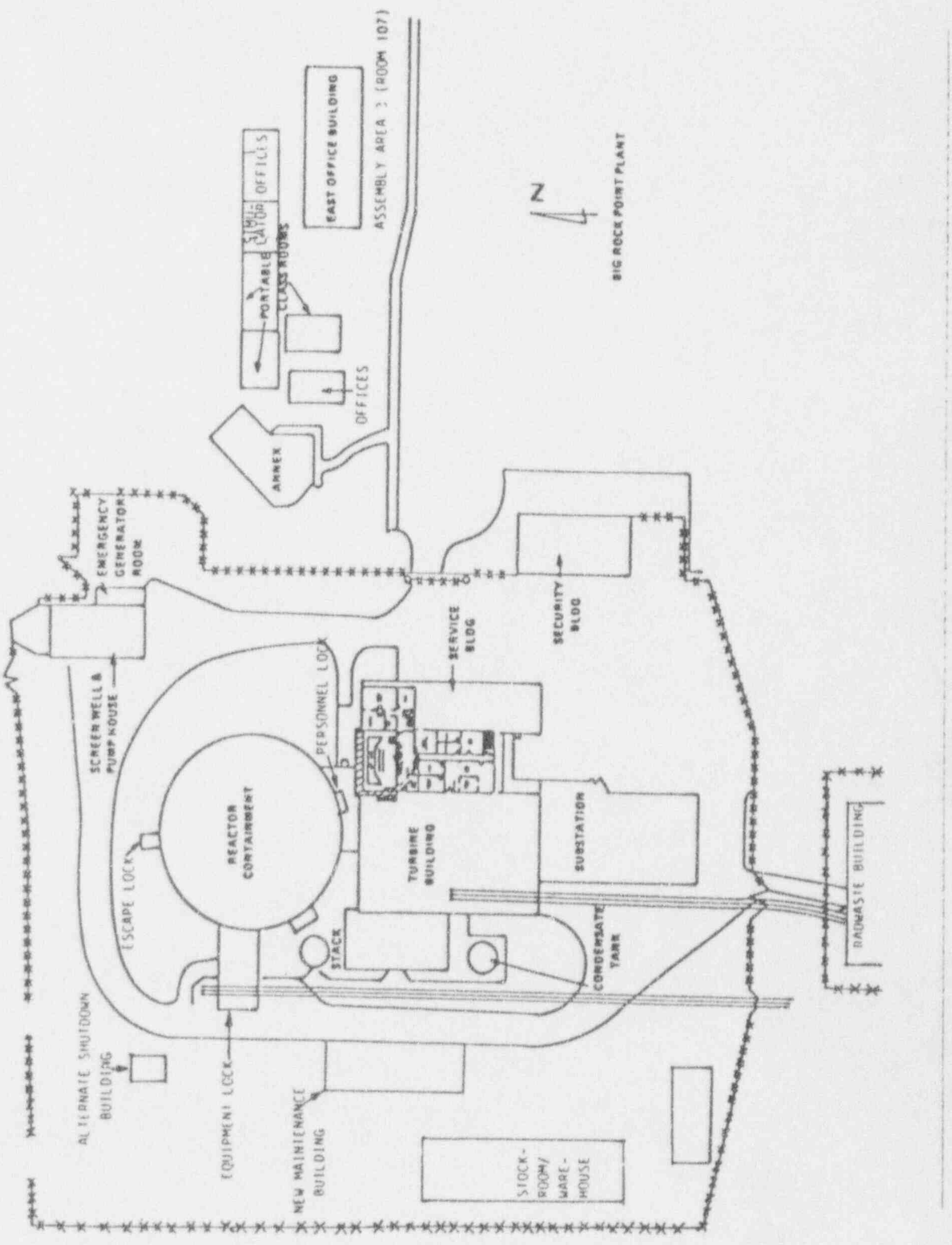


Figure 2.2

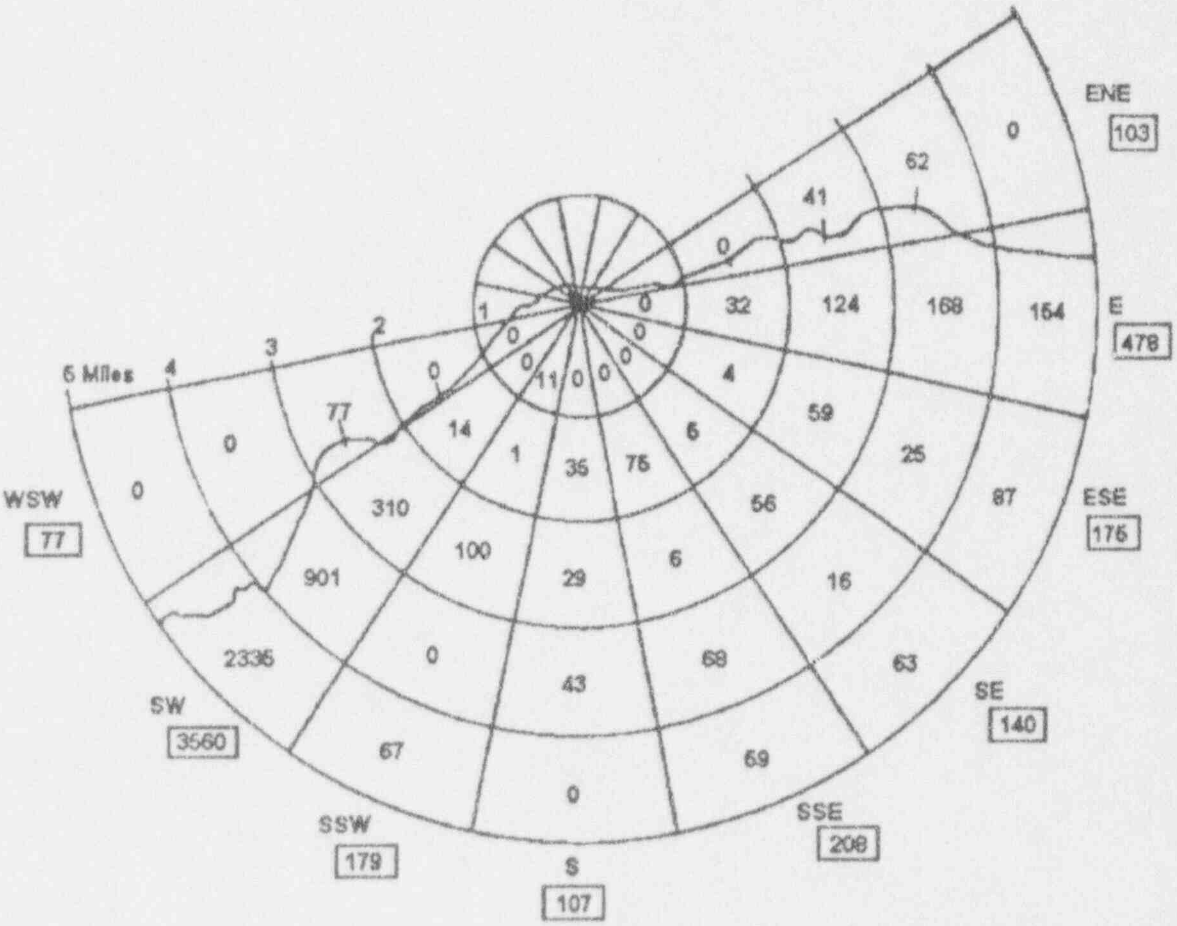
Site Map of Big Rock Point Plant

FIGURE 2.3

PLANT FACILITY IDENTIFICATION



1990 PERMANENT POPULATION WITHIN THE
BIG ROCK POINT PLUME EXPOSURE EPZ



PERMANENT POPULATION

RING MI.	RING POP.	CUM. POP.
0 - 1	11	11
1 - 2	166	177
2 - 3	802	979
3 - 4	1283	2262
4 - 5	2765	5027

2.2 NEARBY INDUSTRIAL, TRANSPORTATION, AND MILITARY FACILITIES

2.2.1 LOCATIONS AND ROUTES

Figure 2.5 provides a listing of manufacturing plants in the five (5) mile radius of the Big Rock Point Plant.

Figure 2.6 provides additional listing for the City of Charlevoix which falls within the southwest quadrant from the Big Rock Point Plant.

These Figures were extracted from February 1984 HMM Document No. 83-600, Evacuation Time Estimates for the Big Rock Point Plant. The document was updated in 1993, refer to Reference 4. /

Industrial activity in the vicinity of the Big Rock Point Plant consists primarily of small manufacturing companies. There are two cement plants and quarries in the area, one operating plant about six miles to the south-southwest and one plant which as discontinued mining operation about nine miles to the east from the Big Rock Point Plant.

Low level military training route (VR-634 and VR-664) currently pass 10 miles from the Big Rock Point Plant. A former military low level training route (IR 600/601) a simulated radar bomb scoring range over Lake Michigan has been discontinued. /

2.2.2 EVALUATION SUMMARY

The topic of Potential Hazards Due to Nearby Industrial, Transportation and Military Facilities was evaluated by the NRC as part of the Systematic Evaluation Program Topic Number II-1.C. This resulted in a safety evaluation (Reference 7) as follows:

2.2.2.1 Industrial Activity

Industrial activity in the vicinity of the Big Rock Point Plant consists primarily of small manufacturing companies. There are also some cement plants and quarries in the area. The closest industrial facility is a manufacturing plant located about one mile east where 105 employees (currently about 200) are engaged in producing custom molded plastic fixtures. An inventory of approximately 100,000 pounds of thermoplastic materials is stored at the facility. These materials are not an explosive hazard but could produce toxic combustion products if a fire should occur. The severity of this event with regard to safe operation of the nuclear plant, in particular, the habitability of the control room, would depend on many factors including source parameters, wind speed and direction, cloud plume rise, and protective actions taken by plant operators. (Control Room Habitability is addressed in Chapter 6 of this updated FHSR.) /

An industrial park is located about 2.5 miles southwest of the plant. Several light manufacturing companies employing a total of about 200 persons are located in the park. No hazardous materials in quantities of the plant posed by highway accidents involving toxic chemicals is sufficiently remote so that such accidents need not be considered as a design basis event.

A former Chesapeake & Ohio Railroad branch line was approximately 5,600 feet south of the plant at its closest point. Information obtained from the railroad company indicated that three freight trains per week provided only local service use for the line. The railroad company identified propane as the only hazardous material shipped on the line. We have evaluated the consequences of a postulated explosion on the railroad in accordance with the guidance in Regulatory Guide 1.91, Revision 1. We find that the separation distance between the railroad line and the plant exceeds the minimum distance criteria given in the Regulatory Guide for railroad shipments of explosive materials and, therefore, was acceptable. (Note: As explained in Section 2.1.2 of this updated FHSR, this line is no longer in use.)

2.2.2.3 Pipelines

The nearest pipeline to the plant is a six (6) inch diameter natural gas line which is located about 1.5 miles south. At this distance, pipeline accidents will not affect the safe operation of the plant, based on evaluations of pipeline accidents done in previous licensing reviews. There are no gas or oil production fields, underground storage facilities, or refineries in the vicinity of the plant.

2.2.2.4 Waterways

There are no large commercial harbors near the plant but some commercial shipping does take place at Charlevoix Harbor which is approximately four miles southwest of the plant. While the great majority of the cargo consists of non-hazardous commodities such as coal and limestone, some gasoline and fuel oil is shipped from the harbor by barge. All of the gasoline and fuel oil is shipped from the barges from trucks for shipment to Beaver Island which is some 25 miles northwest of Charlevoix. Two barge line companies, each with one barge, are engaged in this trade. Between them, they make about 20 trips per year and the captains estimate that they come no closer than about three to four miles from the plant. Thus, the occurrence of a barge accident with consequences severe enough to affect the safe operation of the plant is extremely unlikely and does not constitute a credible risk to the plant. Similarly, the main shipping route in Lake Michigan which is located about 40 miles northwest of the plant is not a threat to plant operation.

2.2.2.5 Airports

The nearest airport to the plant is Charlevoix Municipal Airport which is located approximately five miles southwest. The airport has one paved runway 3,500 feet in length oriented in an east-west direction and two turf runways. Charlevoix Municipal is a general aviation facility used primarily by light single engine aircraft. There were a total of 16,800 itinerant and local operations at the field in 1976 and this is projected to increase to 71,000 operations in 1997 according to the airport master plan. The master plan recommends that Charlevoix Municipal Airport should be upgraded to a basic transport facility, i.e., one capable of handling turbojet powered aircraft up to 60,000 pounds gross weight. Using the analytical model given in SRP 3.5.1.6, we conservatively calculate the probability of an aircraft from Charlevoix Airport crashing into the Big Rock Point Plant is 8.5×10^{-7} per year. Conservatisms in our calculation include the use of the projected 1997 level of operations, the assumption that all aircraft arriving or departing the airport fly over the plant area, and the consideration of the entire plant as a potential "target area". In fact, since the vast majority of aircraft operating at Charlevoix Airport are expected to be light, general aviation aircraft, only a small fraction of postulated aircraft strikes would seriously affect the safety of the plant. The probability of an accident resulting in severe radiological consequences would, therefore, be even lower than the probability value given above. We conclude that the Charlevoix Airport does not represent an undue risk to the safe operation of the nuclear plant.

2.2.2.6 Military Training Routes (Reference 8)

Military low level training routes (VR-634 and VR-664) pass approximately 10 miles from the Big Rock Point Plant. /

In the Big Rock Point Spent Fuel Pool Expansion Hearings, the Atomic Safety and Licensing Board (ASLB) concluded "...that the evidence has demonstrated that the risk from aircraft to the Big Rock Point Plant is sufficiently low so that it need not be considered further in the design of the plant,....."

2.2.3 SAFETY EVALUATION CONCLUSIONS (Reference 7)

We conclude that the Big Rock Point Plant is adequately protected and can be operated with an acceptable degree of safety with regard to industrial, transportation, and military activities in the vicinity of the plant.

NOTE: Further support for the NRC Staff's conclusions pertaining to military, general aviation, and Charlevoix Airport cumulative realistic probability of an aircraft crashing into the plant can be found in Reference 8 and was about 2×10^{-8} per year in 1984 and has since been further reduced by the closing of military training routes (IR-600/601 and VR-1634). /

2.3.3 ATMOSPHERIC TRANSPORT AND DIFFUSION ESTIMATES (Continued)

4-30 days. Since the radiation doses at the site boundary are very much below the limits given in 10 CFR 100 the actual difference between 4E-04 and 6E-04 is not significant with respect to meeting 10 CFR 100 limits.

The second use of the meteorological data was in the Big Rock Point Probabilistic Risk Assessment (PRA), submitted to NRC by CPCo letter of March 31, 1981. Doses to the public from dominant sequences were calculated using a variety of meteorological conditions with the CRAC code (same methodology as WASH-1400). The conditions were chosen using the sampling technique of WASH-1400. The values for X/Q were not listed in the output of the CRAC code. However, previous analyses of the meteorological tower data show that the worst case X/Q (worst 2-hour interval calculated in accordance with Regulatory Guide 1.145) at the site boundary, 7.5E-04 sec/m^3 is almost the same as that used in the FHSR. Control Room Habitability with regards to external events was also presented in the PRA. Habitability was demonstrated by showing that the operator could isolate the control room ventilation system prior to intake of excessive quantities of toxic gases, smoke, etc. Also, the probability of these events occurring along with the proper meteorological conditions and ventilation failure was small ($<10^{-4}$/yr).

The third use of the meteorological tower data was in the CPCo submittal of June 4, 1976 concerning 10 CFR 50, Appendix I. The meteorological data was used to obtain X/Q and D/Q (Note 2) values, wind roses, monthly and yearly joint frequency distributions, and an annual average X/Q. The methodology used was in accordance with Regulatory Guide 1.111. This data was then input into the GASPAR computer code for radiation dose calculations. The maximum annual average X/Q for an elevated release was found to be 2.5E-07 sec/m^3. This occurred in the East sector at 2414 m from the stack. Additional data may be found in Table 3.1 of the Appendix I submittal dated June 4, 1976.

CPCo Conclusions

Because the radiation doses calculated at the site boundary are small, the demonstration of compliance with 10 CFR 100 limits is not particularly sensitive to the X/Q values used. Consumers Power Company's intent is to continue with the use of onsite preoperational data for realistic analyses performed for PRA and environmental dose purposes. For all other calculations, Regulatory Guide 1.3 values will be used. Assuming a ground level release for all unknown accident conditions, the following values X/Q are applicable at 0.5 miles. Exclusion Area Boundary and Low Population Zone (EAB and LPZ):

0-8 hours	6.0 E-04
8-24 hours	2.2 E-04
1-4 days	7.4 E-05
4-30 days	1.8 E-05

CHAPTER 2 REFERENCES

1. USNRC letter dated June 6, 1980, SEP Topics II-1.A, II-1.B, and II-1.C (Big Rock Point)

2. Site Emergency Plan, Big Rock Point Plant, Docket No 50-155

3. 1993 City and County Extra, 2nd Edition, Bernan Press, Published 1992 /

4. HMM Document No. 3829-001, August 1993, Final Report, Evacuation Time Estimates for the Big Rock Point Power Plant Plume Exposure Pathway Emergency Planning Zone / / /

5. US Department of Commerce Bureau of Census Document 1990 CP-1-24 Michigan Census of Population, General Population Characteristics / /

6. Population Characteristics of Northwest Michigan Counties, Developed by Nancy Haywood, Director, Data Research Center, Incorporated. Traverse City, Michigan, June 1980

7. USNRC letter dated May 13, 1981, SEP Topic II-1.C, Potential Hazards Due to Nearby Industrial, Transportation and Military Facilities (Big Rock Point and Palisades)

8. USNRC Atomic Safety and Licensing Board Initial Decision (on all remaining issues) Docket No 50-155-OLA, (ASLBP No 79-432-11LA), served August 29, 1984, IV O'Neill Contention IID - Risks from Aircraft

9. USNRC letter dated December 17, 1980, SEP Topic II-2.A, Severe Weather Phenomena

10. CPCo letter dated March 9, 1981, SEP Topic II-2.A, Severe Weather Phenomena

11. USNRC letter dated August 3, 1981, SEP Topic II-2.A, Severe Weather Phenomena

12. CPCo letter dated March 1, 1982, SEP Topic II-2.A - Severe Weather Phenomena; III-2 - Wind and Tornado Loading; and III-4.A - Tornado Missiles

13. CPCo letter dated April 6, 1982, SEP Topic II-2.C, Atmospheric Transport and Diffusion Characteristics for Accident Analysis

14. USNRC letter dated October 26, 1982, SEP Topic II-2.C, Atmospheric Transport and Diffusion Characteristics for Accident Analysis

15. USNRC letter dated October 26, 1982, SEP Hydrology Topics II-3.A, II-3.B, II-3.B.1, II-3.C and III-3.B

16. CPCo letter dated June 23, 1983, SEP Topic II-3.A Hydrologic Description; II-3.B Flooding Potential and Protection Requirements; II-3.B.1 Capability of Operating Plant to Cope with Design Basis Floods; II-3.C Safety Related Water Supply (Ultimate Heat Sink); III-3.A Effects of High Water Levels on Structures - Response to Safety Evaluation Reports

Radwaste Vault

The bottom side of the radwaste vault floor is at elevation 577.75 feet. At a water level of 583.6 feet and without considering the structure roof or contents, the structural weight forces are approximately twice as great as the uplift forces.

Turbine Building

The elevations of the bottom of the structures support columns was reviewed. The greatest majority of these elevations exceeded an elevation of 583.6 feet.

NRC Evaluation Conclusions (Reference 11)

In the December 2, 1982 Revised SER, an evaluation of BRP Structures included an evaluation of the Stack which is at grade elevation of 596.6 feet, well above the design basis flood level.

Conclusion

We have concluded that the containment building, turbine building, core spray room, and the stack are adequately designed to withstand the effects of a DBFL.

As part of the May 1984 Integrated Plant Safety Assessment, NUREG-0828 (Reference 1), Section 4.6 for Topic III-3.A, Effects of High Water Level on Structures identified ground water loading conditions that had not been adequately considered in the original plant design. These conditions are addressed in NUREG-0828, Section 4.2.1, Design Basis Ground Water Level as follows: /

The original design value for ground water level at Big Rock Point was 583.6 feet MSL. In lieu of an analysis to determine the maximum ground water level, a ground water level at plant grade should be assumed when considering uplift and hydrostatic forces separately from seismic loadings. The staff's review of this topic indicates that plant structures can withstand ground water levels at plant grade, and, therefore, this issue is resolved to the staff's satisfaction.

CPCo Conclusions

The concerns over load combinations for seismic loads in combination with groundwater loads as identified in NUREG-0828, Section 4.2.1 and other load combinations will be resolved as part of the Integrated Assessment of open issues. The issue of High Water Level and uplift due to buoyancy is, in and of itself, adequately addressed to determine that such effects will not jeopardize the structural integrity of plant structures. /

3.4.1.2 Permanent Dewatering System - N/A BRP

Based upon an NRC letter dated December 26, 1980 the Systematic Evaluation Program Topic III-3.B, "Structural and Other Consequences (i.e., Flooding of Safety Related Equipment in Basements) of Failure of Underdrain Systems" has been deleted from the Systematic Evaluation Program (SEP) review of your facility. /

The topic is not applicable to your site because your site does not have a system whose function is to lower the groundwater table.

3.4.2 ANALYTICAL AND TEST PROCEDURES

Methods by which effects of design basis flood or groundwater conditions are applied to structures are addressed in Section 2.4 and 3.4.1 of this updated FHSR.

3.4.3 INSERVICE INSPECTION OF WATER CONTROL STRUCTURES

CPCo submitted an evaluation of Systematic Evaluation Program (SEP) Topic III-3.C, Inservice Inspection of Water Control Structures (Reference 12) on December 21, 1981.

The NRC evaluated the CPCo submittal on this topic and provided a Safety Evaluation Report (SER) based upon the NRC contractors Technical Evaluation Report (Reference 13) on October 12, 1982.

The following structures were determined to be "Safety Related Water Control Structures":

Cooling Water System Structures

These structures are those relating to the availability and protection of the Ultimate Heat Sink (UHS).

- Offshore Intake Structure
- Offshore Intake Line
- Screenhouse/Diesel Generator Room/Discharge Structure

The failure of the discharge canal will not prevent water from passing into the lake, and therefore will have no effect on the ability of the plant to shutdown. Further, although a riprap breakwater was constructed on the west side of the discharge canal, its failure would results only in gradual siltation of the discharge canal, and therefore these structures are not safety related.

Flood Protection Structures

These structures are related to prevention of flooding of the site and safety related equipment.

- Alternate Shutdown Panel Building (ASPB) Retaining Wall

  This retaining wall was installed around the perimeter of the ASPB to provide a "Hardened Protection" from Probable Maximum Flooding (PMF) via Facility Change FC-462J-2 operable in November 1985.

  The site drainage system can also prevent flooding of the site area. No credit was taken for this system in the analysis for flooding, and therefore, this system is not safety related.

NRC Evaluation Conclusion (Reference 1) Nureg-0828, May 1984, Section 4.7

CPCo, in a letter dated December 21, 1981 (Reference 12), described the current inspection program and the basis for the conclusion that an adequate program for periodic surveillance has been instituted at Big Rock Point.

The major differences identified in conjunction with the topic evaluation are:

1. The licensee should formalize the present program in the plant procedures. The licensee provided a formal commitment to modify plant procedures in a letter dated January 14, 1983. The staff finds this commitment acceptable.

2. The licensee does not have a program for inspecting the internal surfaces of the intake line. Considering (a) that the 1,470 ft of 5-ft-diameter pipe is buried below Lake Michigan, (b) that the required flow for safety equipment is only 2% of the normal flow, and (c) the risk to diver safety to conduct such an inspections, the staff concludes that implementation of this inspection requirement is not warranted. /

3.4.3.1 Inspection Program (Reference 12 and 14)

The formal program for Inservice Inspection of Water Control Structures is as follows:

1. The exterior of the offshore intake structure and those portions of the screenhouse structures (which include the diesel generator room, discharge structure and forebay) that are submerged, will be inspected on five year intervals in accordance with a formalized inspection program for structural integrity and siltation. The five year interval will commence after the conclusion of the screenhouse structures inspection conducted June 6, 1983. The results of such inspections shall receive an engineering review.

letter provided the results. The review was conducted in three phases, summarized as follows:

1. The structural elements listed under Section 13, Recommendations, from the FRC report, applicable to each Category 1 Structure at Big Rock were reviewed and evaluated. Attachment 1 of the February 10, 1989 letter presents the results of the review. The review concludes that the structural design was so conservatively done that the code changes do not significantly impact the margin of safety under the loads considered in the original design.

2. The second phase of the review examined those items tabulated with an "Ax" in the FRC report. The results of this examination are included as Attachment 2 of the February 10, 1989 letter. The examination concludes that the plant structures have an adequate safety margin under the combined seismic loads, but are vulnerable to the combined tornado wind load (in particular the Turbine building and the Screenhouse/Diesel Generator building). / However, the construction of the Alternate Shutdown Building required to meet Appendix R, and the addition of a portable pump to resolve Wind and Tornado Loading, provides additional safeguards against damage to these two buildings.

3. The third phase of the review resulted in an overall examination / of Appendix A to the FRC report. The results of this examination are presented in Attachment 3 of the February 10, 1989 letter. This review concludes that there exist some vulnerabilities from tornado loads to the Control Room, the Screenhouse/Diesel Generator building and to the Turbine building. Again, due to the Alternate Shutdown building and the portable pumping capabilities that was provided at Big Rock Point, the vulnerabilities of these structures are less of a weak-link to the safety of the plant than prior to the modifications.

The overall conclusion of this review, as presented below is that no additional plant modifications are required to address the topic of Design Codes, Criteria and Load Combinations. Modifications already completed for other reasons have adequately compensated for potential / weaknesses identified in this review. With this submittal Consumers Power Company considers that all actions related to SEP Topic III-7.B and Integrated Plan Issue BN-051 are now complete.

By letter dated June 12, 1991, the NRC Staff documented their resolution of SEP Topic III-7.B. They concluded that the licensee had adequately addressed this SEP Topic.

Evaluation Conclusions

Based upon the above evaluation and the following considerations, it can be concluded that changes in code provisions to not affect the safety margin of plant structures.

- Since control rod performance is affected by residence time and burn-up, the licensee has also committed to define a continuing surveillance program for future cycles based on results of the Cycle 22 inspections and to submit the program for NRC approval prior to continuing operation with these control blades after Cycle 22 operation. Further discussions on the design lifetime, including reactivity and mechanical design criteria of the new hafnium hybrid control blades, will also be provided at that time.

- On this basis, we conclude that the use of the hafnium hybrid control blades is acceptable for Cycle 22 operations.

The end of Cycle 22 Visual Examination Results of the NUCOM/Hafnium Control Blades were submitted to the NRC April 28, 1988 with the proposed continuing Surveillance Program for approval. The Surveillance Program will be implemented at the end of Cycle 23 and all subsequent refueling outages. Future changes to the Surveillance Program which may be required will be discussed with the NRC prior to implementation. The Surveillance Program will be implemented via approved BR PProcedures.

The end of Cycle 22 inspection results were as follows: No abnormalities were detected on any control blade handle, lower connector, or wing. No unusual wear patterns or signs of wing deformation were observed. No cracking or undercutting of spot welds were detected. In general, each of the six control blades was visually inspected to be free from any physical defect.

Continued utilization of the six Control Blades and use of two additional similar blades for Cycle 23 along with the use of the surveillance program for future cycles was evaluated in a September 7, 1988 NRC Safety Evaluation and are acceptable.

4.7.1.3 Boron Loss From BWR Control Blades (Reference IE Bulletin 79-26)

CPCo letters dated January 4, 1980 and October 10, 1980 provided the response to IE Bulletin 79-26. The responses addressed CRD Blade B^{10} depletion monitoring over the life of the blades; Blade replacement; Shutdown Margin Verification; and the performance of a destructive examination of the most highly exposed Blade to determine the extent of cracking and loss of BC.

CPCo evaluated the IE Bulletin and General Electric Company Services Information Letter (SIL) 157 dated March 1979 and by letters dated April 6 and 12, 1979 submitted information on the expected lifetime of CRD Blades to the NRC.

This SIL identified a new mechanism which could limit the expected lifetime of control rod blades due to stress corrosion cracking of the stainless steel tubing containing BC. This cracking occurs in regions which have received high neutron exposures and is a result of BC swelling. Subsequent leaching of the BC can reduce control rod lifetime.

4.7.4.2 Control Rod Drive Accumulators

Thirty-two gas-water accumulators, one for each control rod drive mechanism, are the sources of the hydraulic pressure required for the scram at low reactor pressures, while a shuttle valve within each drive mechanism admits reactor water to the drive when the reactor pressure exceeds accumulator pressure. The accumulators are charged with nitrogen gas to a pressure which will deliver enough water to scram a fully withdrawn rod at low reactor pressures. The charge on each accumulator is monitored continuously by a pressure switch. The water discharged from the drives during a scram is collected in a scram dump tank which is initially at atmospheric pressure. The accumulators and dump tank are isolated from the normal driving cir connected to each drive by scram valves which are held closed by solenoid-operated pilot valves.

Scram is initiated by de-energizing the scram pilot valves which allows the scram valves to open, thereby connecting the drives to the accumulators and scram dump tank. The large differential pressure between the accumulators and dump tank rapidly drives the rods into the core.

When the scram stroke is completed, the accumulator pressure continues to hold the rods in the reactor. If the accumulator charging system does not function, the internal rod drive shuttle valve shifts and applies reactor pressure under the piston, until the dump tank is filled and system pressures are equalized. When the differential pressure decays to a point where the rods can no longer be supported, the weight of the rods are supported by the locking mechanisms which are engaged to hold the rods at the fully inserted position. An interlock in the control system prevents withdrawal of any control rod until conditions have returned to normal, and safety circuits can be reset.

The hydraulic system is thus composed of a central system for driving individual control rods up and down, and a scram system for rapid insertion of all rods. The central system is supplied by two full capacity pumps.

Accumulator Gas Pressure

CPCo letter dated May 3, 1962, in response to NRC questions provided Amendment No. 10, Addenda to FHSR Technical Qualifications Amendment No. 8. The minimum gas pressure required on the scram accumulators to meet maximum scram timing was addressed as follows:

> The final minimum calculated scram accumulator gas pressure is 700 psig (see Technical Specifications, Section 6.2.1). This pressure is to be verified by tests at the site. Since there is a separate accumulator for each drive, the minimum pressure will vary according to the resistance offered by the piping arrangement and the characteristics of the drive. On the basis of test facility experience the minimum scram accumulator pre-charge gas pressure is expected to be about 500 psig.

Current Technical Specifications in relation to CRD Withdrawal Permissive System Interlocks state:

> ...Interlocks shall prevent control rod withdrawal when any of the following conditions exist:
>
> (a) When any two of the thirty-two scram accumulators are at pressure below 700 psig......

The minimum scram accumulator pre-charge gas pressure is approximately 640 psig. The top portion of the accumulator is then charged with filtered demineralized water from the CRD hydraulic system.

The waterside of the acculalator contains a bladder which separates the gas and water. Once the accumulator is charged with gas and water, the charge is sustained for prolonged periods with or without occurrence of scram. A water leak detector is provided along with a pressure indicating switch. The leak detection and the pressure switch annunciates in the control room and provide local indication at the accumulator. The pressure switch is conservatively set at a pressure above the 700 psia CRD withdrawal interlock pressure.

4.7.4.3 Scram Dump Tank

The scram dump tank serves as a container for water displaced from the 32 drive mechanisms during scram. It prevents draining the reactor after a scram, and will contain the water exhausted from the drive mechanisms. The horizontally-mounted tank has a capacity of 175 gallons which is sufficient to accommodate the maximum amount of water that would be exhausted if scram was initiated with all control rods fully withdrawn. Tank design pressure is 1875 psig at 325°F. The tank was designed, fabricated, tested, and stamped in accordance with ASME Boiler and Pressure Vessel Code, Section VIII - 1959 under Code Cases 1270 N and 1273 N. Original design was to an earthquake load of 5% of dead weight.

4.7.4.3.1 Scram Discharge Volume (SDV)

The active Scram Discharge Volume is totally within the Scram Dump Tank. The 175 gallon capacity is in excess of two full scram discharge quantities. The Scram Discharge Volume piping is maintained water filled at all times due to a loop seal immediately ahead of the Scram Dump Tank inlet. This piping is not considered as part of the volume required to accept scram discharge water during a scram event. The Scram Dump Tank has drain and vent valves which are normally open, and close upon reactor protection system trip. These valves assure full Scram Dump Tank capacity is available for the scram function. Thus, the tank is normally empty and vented to the atmosphere. The tank drains to the enclosure clean sump and vents to the enclosure dirty sump. In response to NRC IE Bulletin 80-17, a continuous atmospheric vent was installed on the vent piping.

Verification of Adequate Volume

As part of CPCo response to IE Bulletin 80-17, a Special Site Test was conducted which verified that adequate volume exists in the Scram Dump Tank to accept a full automatic scram of all control rods. Also, calculations were made to determine how many full scrams could be discharged into an empty dump tank. The calculations were based on General Electric GEI-56217 instructions. It was concluded from

2. The operating hydraulic water to the defective control rod has been tagged and valved out to prevent withdrawal of the control rod after an attempt has been made to insert the control rod.

3. The core shutdown margin requirement (described in 4.7.6.2 above) can be met with the remaining operable control rods. Evaluation of this requirement will be based on previous experimental measurements.

4.7.6.4 Rate of Change of Reactor Power During Power Operation (Technical Specifications)

Control rod withdrawal during power operation will be such that the average rate of change of reactor power is less than 50 MW_t per minute when power is less than 120 MW_t, less than 20 MW_t per minute when power is between 120 MW_t and 200 MW_t, and 10 MW_t per minute when power is between 200 MW_t and 240 MW_t.

4.7.6.5 Control Rod Withdrawal Permissive System (Technical Specifications)

The Control Rod Withdrawal Permissive System is considered to be encompassed by the Plant Safety and Monitoring Systems.

Interlocks

Interlocks prevent control rod withdrawal when any of the following conditions exist:

a) When any two of the thirty-two scram accumulators are at pressure below 700 psig.

b) When any one of the three power range monitor channels reads:

(1) Less than 1×10^{-7}% power, when reactor power is above the operating range of the source range monitoring channels.

(2) Greater than 105% power, or

(3) A reactor period less than 15 seconds.

c) When the scram dump tank is bypassed.

d) When the mode selector switch is in the shutdown position.

Operating Requirements

The control rod withdrawal permissive interlocks will always be operable when fuel bundles are in the reactor. No further withdrawal of control rods will be permitted if one of these circuits is found to be inoperable.

Permissive circuits will be functionally tested prior to each major refueling but no less frequently than every 18 months. However, the refueling interlocks will be functionally tested prior to each major refueling.

4.7.6.6 Refueling Operation CRD System Interlock (Technical Specifications)

The High Scram Dump Tank Level trip devices will be operative during all refueling operations.

Refueling Operation Controls

Interlocks shall be provided when fuel bundles are in the reactor to prevent all motion with any of the refueling cranes (namely, jib cranes, transfer cask winch) which are positioned over the reactor vessel whenever any control rod is not fully inserted in the core and the mode selector switch is in the "refuel" position. /

Operating Requirements

a) The High Scram Dump Tank Level safety system sensors and trip devices will be functionally tested at each major refueling shutdown and will be maintained in the specified condition during all refueling operations.

b) The refueling operation controls including position interlocks will be functionally tested at each major refueling shutdown.

4.7.6.7 Control Rod Drive Removal (Technical Specifications)

If fuel bundles are in the reactor, it shall be permissible to remove a control rod drive from the reactor vessel when the reactor is in the shutdown condition and the mode selector switch is locked in the "Shutdown" position. /

If fuel bundles are in the reactor, the core shutdown margin of 0.3% k_{eff}/k_{eff} with the strongest control rod out of the core shall have been met prior to the control rod drive removal; and in addition, the equipment will be properly tagged. The control rod drive that was removed will without delay be replaced by a spare control rod drive or the original control rod drive will be reinstalled. One control rod drive pump will be operating during removal and reinsertion and during the time the control rod drive is outside the reactor vessel. / /

4.7.6.8 Control Rod Drive Blade Assembly Removal (Technical Specifications)

Removal of a control rod blade from the core by means other than normal control rod drive movement requires the four fuel bundles surrounding the control rod to first be unloaded and that the control rod blade be properly reinstalled and checked out prior to reinsertion of the fuel bundles.

4.7.7 BWR SCRAM SYSTEM PIPE BREAKS (Reference CPCo June 1, 1981 letter)

NRC letter dated April 10, 1981 provided NRC evaluation of the above subject and requested both a generic and plant specific evaluation of its conclusions and recommendations. The concerns expressed in this evaluation appear to be two-fold. These are the abilities to provide reactor core cooling and to contain reactor water inside primary

Although sensitivity values for this system cannot be determined since response is governed by proximity to the source, the system has exhibited extremely good responsiveness to changes in containment atmospheric conditions.

The pipeway exhaust duct steam leak monitor utilizes the ventilation system as a medium to detect RCPB leakage. The pipeway and steam drum area, ion tubes, and reactor annulus are provided with two 1/2 capacity cooling units in parallel located at elevation 616 feet. Each unit is equipped with isolation dampers, water-type coils, filters and automatic controls. A variable amount of air, approximately 4000 - 6000 cfm, is continuously bled from this system and exhausted to the plant stack. An equal amount of air is introduced into the system by infiltration through minor openings and a make-up damper which is automatically controlled to maintain a slight negative pressure in the pipeway. Located of the dewcell in the pipeway exhaust duct places the dewcell in the only air stream leaving the pipeway area which provides adequate coverage of all areas where an RCPB leak could occur. All air leaving the steam drum, recirculating pump room, control rod drive room, and reactor annulus area must pass through the pipeway exhaust duct to reach the exhaust plenum.

This detection scheme functions in comparative manner looking at the dewpoint of the exhaust duct atmosphere and the dewpoint of containment atmosphere near the discharge of the supply air fans. These two dewpoint signals are compared and should a differential dewpoint setpoint be reached, the "pipeway steam leak" alarm, located in containment is actuated. Upon actuation of this alarm, a remote alarm is annunciated in the control room. At this time, operators can consult other leak detection information (temperature, sump run times, humidity) to quantify the leak or dispatch an auxiliary operator to the differential dewpoint recorder also located in containment.

Tests performed on the pipeway exhaust dewcell in previous years indicate that the dewcell will respond to a change in dewpoint of 1°F in less than 90 seconds (51°F to 52°F at ≈4600 cfm). /

This is extremely good sensitivity for moisture detection but two limitations exist due to characteristics inherent with dewcell design and operation. The exhaust air temperature during summer operation with both reactor recirculation pumps in service goes above the 120°F level and is out of the range for accurate interpretation. Also, at times the dewcell is difficult to interpret because of the lag in response when outside air moisture content changes. We have observed downscale readings on this reference type system when outside air increases in moisture content. Although the above limitations exist, it is not considered that they significantly affect the overall ability to detect leaks. Dewcell system inaccuracy due to such high or changing temperatures occurs infrequently. Also, additional systems exist which can detect leakage in the event that the dewcells become inaccurate.

beneficial from a risk reduction standpoint. Based upon the analysis performed, it was apparent that the addition of an acoustic monitoring system (proposed change for evaluation purposes) is not economical from the viewpoint of risk reduction.

5.2.5.6 NRC Safety Evaluation (Reference 12 and 13)

By letter dated June 13, 1983 the NRC provided a final evaluation of SEP Topic V-5, RCPB Leakage Detection.

Conclusion (Reference 12)

Our review indicated that systems employed at Big Rock Point to measure reactor coolant pressure boundary leakage do not meet all the recommendations of Regulatory Guide 1.45. Specifically, none of the systems are seismically qualified. All of the other recommendations have been met or equivalent alternatives have been provided.

The necessity for any leakage detection system modifications will be considered during the integrated safety assessment.

Integrated Safety Assessment Conclusions (Reference 13)

NUREG-0828, May 1984, Section 4.16 provided the NRC assessment of SEP Topic V-5, RCPB Leakage Detection as follows:

The staff review of this topic indicates that Big Rock Point satisfies current criteria with the exception of seismic requirements. The licensee's Technical Review Group has concluded that the emergency operating procedures will be revised to require a leak test in the event of a confirmed seismic event. Further, if the leak detection equipment is inoperable (after the event), Big Rock Point Plant would be shutdown (limiting condition for operation) until such time that the equipment can be returned to service. The licensee has committed to complete these changes by the end of June 1984. The staff finds this commitment to be an acceptable resolution.

CPCO Resolution

The BRP Operating Procedures - Emergency for Earthquake, have been revised and currently require the following "Subsequent Operator Actions" in the event earth vibration or movement is felt at the plant site:

Determine primary system leak rate per procedure. If the primary system leak rate cannot be determined because of leak detection equipment being inoperable, the Plant shall be brought to the hot shutdown condition within 12 hours, and to the cold shutdown condition within the following 24 hours.

be placed in the center of a fuel assembly rather than in the corner location previously used.

CPCo by letter dated January 18, 1971 provided information which indicates that the startup channels will respond to fission neutrons rather than source neutrons even when the auxiliary neutron sources are placed very close to the start-up detectors. This indicates that the restriction on the location of the fuel bundles with auxiliary neutron sources is unnecessary.

In terms of changing the source location to the center of the fuel assembly, the licensee has performed analyses to demonstrate that there will be no reduction in safety margin associated with the thermal hydraulic, fuel design limits (minimum critical heat flux ratio) or the ECCS performance analyses (maximum average planer linear heat generation rage).

Auxiliary Neutron Source Design (Reference 19)

The neutron source material is a homogeneous mixture of 50-50, by volume, antimony-beryllium compacted to a minimum packing fraction of 80%. The source material is first encapsulated in a 0.374 inch OD steel tube (Type 304L SS) with a 0.028 inch wall thickness. The overall length of the source tube is 70.110 inches with the source material located in the middle 44.26 inches, held there by a hollow, steel tube spacer at each end. The remaining space in the source tube is void volume. The source tube is encapsulated in a zirconium alloy fuel tube of the same quality and dimensions as tubing used for fuel rods.

Design Life (Reference 19)

The in-reactor design life of the auxiliary neutron sources is 15 years. Sufficient void volume has been incorporated into the design to attain this objective. Based on an assumption of 1.5×10^{13} n/cm^2-s for the flux of neutrons with energies greater than the 2.7 MeV threshold for the (n, 2n) and (n, alpha) reactions in beryllium, approximately 2.5×10^{22} He atoms would be generated in 15 years. Using 799.5°F as the temperature of the outer surface of the stainless steel capsule and assuming conservative conductivity values, the peak temperature in the source material would be 870°F. The internal capsule pressure developed, after 15 years of irradiation, would be 1127 psia. The minimum wall thickness of 0.027 inch exceeds the minimum thickness specified by the ASME Pressure Vessel Code for 304L SS stressed under the above conditions of pressure and temperature. (Rules of Construction of Pressure Vessels, Division 1, 1971 Edition, ASME Boiler and Pressure Vessel Code Section VIII and supplements through summer 1972.)

Control Rod Blade Rollers and Pins

Each control rod contains a maximum of eight (8) rollers to a minimum of four (4) rollers of either a nominal 0.485 inch or 0.567 inch diameter. The bottom four (4) rollers, which can be eliminated, move in a minimum interfuel channel space of 0.628 inch.

After the loss of several bottom rollers, (described in the February 11, 1965 Technical Specification Change), a decision was made to remove the bottom four (4) rollers and/or to reduce the diameter of the rollers for new control rods. The function of the rollers on the control rod is to reduce the metal-to-metal contact between the control rod sheath and the support-tube-and-channel assemblies and thus minimize long term wear. A reduction in the diameter of these rollers has not increased the wear noticeably. Also, the operation of control rods with bottom rollers missing has not changed the wear pattern significantly and has had no adverse effect on scram time or normal operating characteristics of the control rods.

Technical Specification Amendment Number 6 dated July 18, 1974 allowed removal of all four bottom rollers on the peripheral (type 1) blades. When new type 1 blades were installed for cycle 18 core reload, the bottom rollers were removed via Specification Field Change 82-004.

The type 1 and 2A control blades utilize Haynes 25 Pins and Stellite 3 Rollers. The Hybrid type 2 control blades utilize PH13-8 Mo Pins and Inconel x 750 rollers.

Control Rod Blade Poison Tubes

Poison tubes are type 304 or 348 stainless steel tubes, with welded end plugs and with approximately 68" poison length of natural boron carbide powder or 51" boron carbide powder plus 17" Hafnium. The poison tubes also contain steel balls, crimped in position at regular intervals to compartmentalize the boron carbide and minimize the possible effects of densification or settling of the B_4C powder.

The poison tubes are contained in a structure composed of a central core and four sheaths which form the cruciform shape. This cruciform, along with a handle, and a connector which contains the coupling to the drive, make up the control rod. Holes are placed in the sheaths to allow coolant to flow by the poison tubes.

Control Rod Stress and Distortion Analysis

The probable limit to the life of the control rod is internal pressure build-up due to release of helium formed by B^{10} (n,α) Li^7 reaction. /

energy for plate materials varied from 27 to 30 ft-lbs in the transverse (weak) direction. These values are considered to be about average for this type of steel.

- Based on chemistry and expected fluence, the limiting material is estimated to be weld metal. There is limited information (refer to Section 5.3.1 above) on the type or batch of filler metal or flux used to make the vessel welds. Therefore, at present we will consider all welds to be representative of the material surveillance weld and having the chemistry reported above. Based on data from unirradiated specimens in the material surveillance program, the initial valve of RT_{NDT} of the weld material is about -50°F. The initial upper shelf energy of the weld metal is about 90 ft-lbs.

5.3.3.1 Generic Safety Items Applicable to the Reactor Vessel (NUREG-0569)

Generic safety items applicable to Big Rock Point are vessel material low upper shelf toughness and sensitized stainless steel safe ends. The feedwater nozzle and CRD return line nozzle cracking problems are not applicable to this plant. There is no CRD return line to the reactor vessel. The excess water from the control rod drive system flows into either the recirculation system or the cleanup system. The feedwater nozzles on Big Rock Point are located on the steam drum. Condensate from the turbines is pumped by the feedwater pumps to the steam drum Water from the steam drum is pumped to the reactor vessel by the recirculation pumps. At normal operating conditions, the temperature of the water entering the vessel is 570°F. This is about [illegible]°F lower than the vessel temperature so thermal stresses will be very low. For transient conditions the temperature differential between the inlet fluid and the vessel wall is also relatively low. Since the initial crack growth in feedwater nozzles is due to thermal stresses, Big Rock Point should have no problem regarding cracks in the recirculation nozzles on the reactor vessel (the feedwater inlet nozzles are called recirculation nozzles). To date, no flaws have been detected in the recirculation nozzles of Big Rock Point.

There are sensitized stainless steel safe ends on the Big Rock Point reactor vessel. These safe ends are made from 304 stainless steel. We requested information on these safe ends and Consumers Power Company responded by letter dated September 11, 1970. Through 1970, no flaws had been detected in these safe ends. The 304 stainless steel was made with low carbon content with increases its resistance to stress corrosion cracking. Since the 1970 review of the safe ends, no flaws or cracks have been found in the sensitized safe ends. We conclude that, since the vessel has been operating for 15 years (currently over 30), if a corrosion problem existed there would be throughwall flaws in these safe ends by now. We also realize that inservice examinations of these safe ends have been limited (as of the date of the NUREG).

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CHAPTER 6: ENGINEERED SAFETY FEATURES (ESF)

probability at Big Rock Point. The staff concludes that the testing developed under IPSAR Section 4.20.4 will be sufficient to demonstrate leakage integrity and no further testing is necessary. (NOTE: The testing of Instrument Air and Service Air Check Valves is addressed in Section 6.2.2.3.4. of this Updated FHSR.

The service water and heatin- cooling systems are addressed in IPSAR Section 4.20.6 (and a r Section 6.2.2.3.6 of this Updated FHSR). The shutdown ...ing line and the ILRT reference volume were not identified in Topic VI-4 as requiring additional isolation provisions. These lines are only used when the plant is shut down and are isolated during power operation. During power operation both lines are closed to the containment atmosphere. For leakage to occur outside containment thr -ither line requires passive failure of the line and a blank er pipe cap. The results of the limited PRA indicate that ...re of these lines is not a significant contributor to the overall containment failure probability for Big Rock Point. Therefore, the staff concludes that Type C leak testing of these lines would not significantly improve safety and need not be conducted.

NRC action on any necessary exemption requests resulting from these findings will be completed following issuance of the Final Integrated Plant Safety Assessment Report.

The most recent exemption was issued January 8, 1986. By letter dated March 12, 1986 the NRC staff recognized other facility systems, as presented in IPSAR Section 4.20, were deemed sufficient when considering the entire facility design and overall component accident risk contribution, and, therefore, warrant exemption from certain regulations.

6.2.3.2.4 Spare Penetration Testing (IPSAR 4.20.7.4)

CPCo committed to seal-weld the threaded pipe caps used to seal spare containment penetrations. This commitment resolves the issue of spare penetration testing because Type C leak testing is not required for welded pipe caps.

CPCo Resolution/Action

Containment penetrations H-91, H-93, H-94 and H-95 were modified via Specification Field Change (SFC) 83-009 to have welded pipe caps. Subsequent SFC 84-005 changed H-91 back to a threaded cap. The penetrations with threaded caps (H-80, H-88 and H-91) and penetration H-77 which was modified by Facility Change FC-654 to have blind flanges are leak tested per Appendix J. Penetration H-92 is not capped (used for RDS N2) and also is leak tested per Appendix J.

analyses that indicate that, under the most adverse circumstances (ie, complete core melt and maximum hydrogen generation from radio lysis and the decomposition of paints and coatings), the hydrogen concentration would approach combustible limits in a few weeks. However, under these conditions, other failure modes (eg, isolation valve failures) tend to dominate risk. Under more likely accident scenarios (and recognizing that the BRP coatings do not contain zinc), the hydrogen evolving would not approach combustible concentrations until well after the staff would expect accident recovery operations to be under way. Therefore, the staff agrees with the licensee's conclusion and considers this issue resolved.

Resolution/Conclusion

CPCo letter dated May 4, 1984 concluded that long-term hydrogen monitoring is unnecessary due to 1) the results of analyses which show that the maximum concentration of hydrogen generated from metal-water reactions and radiolysis would be 8% by volume after approximately 3 years (combustion of hydrogen in air occurs at concentrations of 8% by volume or greater) and, 2) radiolytic production of hydrogen over the first several weeks of an accident would result in changes on the order of 0.1% by volume to the concentration of H_2. Furthermore, coated surfaces inside the containment are painted with organic paints, whereas only inorganic paints would generate hydrogen under accident conditions.

NRC letter dated October 5, 1984 concluded that the installation inside containment of post-accident hydrogen monitoring equipment is not required for BRP. Therefore NUREG 0737, Item II.F.1(6) is considered to be resolved.

6.2.12 CONTAINMENT VENTILATION

Ventilation is provided through two full-capacity fans, each rated at 30,000 cfm, located in the ventilation stack. Ventilation air to and from the containment sphere is via equipment located within the ventilating room. This room is located outside the containment sphere and contains the ventilation isolation valves, air heating equipment, filters and necessary controls. The filters are provided for cleaning inlet air. Flow of air is from areas of lowest contamination probability toward areas of highest contamination probability, and then out the stack.

6.2.13 CONTAINMENT HEAT-UP /

As part of the resolution to the Station Blackout Issue, a containment heat-up analysis (Reference 14) was performed. The analysis assumed 46 gpm recirc pump seal leakage occurred as a result of the station blackout. The heat-up analysis showed that the temperature inside containment rose from an initial 120°F to to 129°F in 4 hours. This slight increase in temperature does not approach the EEQ temperature limit of 235°F and therefore containment heat-up during a station blackout is of no concern. /

power failure and can be operated from the control room. Refer to Section 9.5.1 of this Updated FHSR for CV-4101 operability requirements.

Another source of water from the Fire Protection System can be remote manually routed from the core spray heat exchanger shell inlet to the channel outlet which supplies either of the two Core Spray Systems. Heat exchanger bypassing is accomplished through a dc motor operated valve (MO-7072) actuated by remote-manual control from the control room.

Basket strainers are installed at three locations in the Fire System to prevent any debris from reaching the spray nozzles. All three strainers have differential pressure (dp) alarms to notify the control room of strainer buildup and initiate cleaning activities.

The reactor vessel schematic provided in Chapter 5 (Figure 5.2) indicates the location of the core spray ring sparger and the backup core spray nozzle array within the reactor vessel. Chapter 5, Section 5.3 of this Updated FHSR provides further details on the sparger and nozzle.

6.3.1.2.2 <u>Core Spray Recirculation</u>

The Core Spray Recirculation System consists of two full capacity pumps and a heat exchanger. The pumps take suction from strainers located in the lower levels of containment and discharge through the core spray heat exchanger to the core and containment spray headers.

The water to the core spray ring is initially from the Fire System headers. Core spray recirculation is initiated when the level of water in the sphere reaches elevation 587'. At this time Fire Header System supply valves will be closed. The water in the sphere will then be recirculated from the suction strainers that are located within the following areas at elevation 577'.

1 - Control Rod Drive Pump Room
1 - Immediately below reactor vessel (control rod drive room)
2 - Accumulator Room
1 - Recirculating Pump area

The suction strainers drain into a common header through two locked open 6" valves into the suction side of the core spray pumps through an 8" locked open valve. Four screen door barriers are installed (Reference FC-644) in the following locations to protect strainers against debris blockage during post-LOCA recirculation: /

- Spent Fuel Pool Heat Exchanger Room /
- East Upper Accumulator Room /
- West Upper Accumulator Room /
- West Lower Accumulator Room /

These barriers provide secondary protection to three of five suction strainers, two of which are located in the CRD accumulator room and one in the CRD pump room. Only three strainer inlets are required /

for full capacity. There are no inlet and discharge valves as such on the pumps. However, the discharge lines are equipped with 4" check valves. The discharge of the core spray pumps is through the core spray heat exchanger. The heat exchanger is cooled from the Fire System header through either parallel motor operated valve (MO-7066 or MO-7080) remotely operated from the control room. The discharge of the heat exchanger will flow through two 4" locked open valves, then it divides and goes to the primary and secondary core spray and containment spray headers.

Emergency cooling water is also supplied to the spent fuel pool when operating in this mode. A line from the discharge of the heat exchanger provides this makeup. Refer to Section 9.1.3.4 of this Updated FHSR for details on this makeup line.

Although normal cooling water is supplied to the heat exchanger from the Fire System through MO-7066 or MO-7080, cooling water to the core spray heat exchanger may be supplied by fire hose in an emergency. A dedicated hose is on a hose cart located in the screenhouse. In order to achieve required flow, the hose shall be 300 to 305 feet in length and 2½" in size. Surveillance requirements for this hose are addressed in Section 9.5.1 of this Updated FHSR.

A core spray test tank is provided so that pump suction conditions and flow characteristics can be periodically tested and also to add chemicals (rust inhibitor) to the lower portion of the suction line of the pumps which cannot be drained. The tank receives its water supply from the discharge line of the heat exchanger through operation of two locked closed valves, one 2" and the other 4", or it can be filled manually. The tank discharge line is connected to the suction line of the core spray pumps and has an 8" locked closed valve in it. There is a drain line with a 1" valve on the tank that drains to the floor drain.

6.3.1.2.3 Enclosure Sprays

The Enclosure Spray System consists of two parallel spray lines from the fire system which are aligned with the ECCS nozzle and ring spray lines. Both the primary and back-up four inch piping enclosure spray headers are located high in the containment and circle the steam drum cavity. The spray headers are equipped with numerous fog nozzles which spray out into containment thereby quenching steam and lowering containment temperature. Both systems also contain fog nozzles that spray directly into the steam drum cavity, (reference Facility Change FC-515).

The primary containment spray consists of six inch piping reduced to four inch piping before the isolation valve leading to the spray nozzles. Automatic initiation occurs upon opening of the primary spray isolation valve on a one out of two taken twice logic. Initiation takes place when containment pressure reaches 2.2 psig. The back up containment spray consists of four inch piping and an isolation valve leading to the spray nozzles. The backup enclosure spray system is remote-manual initiated and is placed in service from the control room by opening the isolation valve.

6.3.1.3 Functional Requirements

6.3.1.3.1 Core Spray

The core spray ring and nozzle spray lines discharge their water to the reactor core when two isolation valves placed in series in each line are commanded to open. The valves receive a signal to open when there exists a coincident trip signal of reactor low water (≤ 2'9" above the top of the active fuel) and reactor low pressure (≤ 200 psig. The diesel driven and the electric fire pumps provide water for core spray (reference Section 9.5.1 of this FHSR for fire pump design specifications). Both of the fire pumps can provide the ECCS specified pressure and flow rate. The primary (spray ring) system is designed to deliver 400 gpm flow at a nozzle pressure of 115 psia. The backup (nozzle) system is designed to deliver 470 gpm at a nozzle pressure of 115 psia.

The minimum acceptable bundle spray flows are indicated in Amendment 26 to the Operating License, dated April 10, 1979. The minimum spray flows are based on conservative estimates of the highest bundle radial peaking factor and worst reactor vessel pressure conditions. Under the most limiting conditions, the ring spray provides 292 gpm and the nozzle spray provides 296 gpm to the core at a reactor pressure of 75 psig. A test program was undertaken to demonstrate both the nozzle spray and ring spray flow adequacy and acceptable performance characteristics (Reference CPCo submittals dated March 28, 1979 and August 9, 1977, results of NUS Corp core spray tests). The tests performed resulted in an optimized core spray sparger aiming pattern which delivered maximum bundle spray flow at all LOCA usage conditions. Two bundles received flows slightly below the minimum acceptable spray flow limit. However, the Technical Specifications specifying maximum bundle power was developed with sufficient conservatism to ensure that the reactor will operate within the capability of either the ring or nozzle spray. Among the conservatisms incorporated into the calculation of maximum bundle power were use of a power reduction factor of 1.2 to lessen the calculated bundle power, the assumption of no core spray flow until time of rated spray is reached, and the assumption that all bundle power at the time of rated spray must be removed by vaporization (Reference Amendment 26, April 10, 1979).

An evaluation of the Big Rock Point Emergency Core Cooling System (ECCS) MPR-557, MPR Associates, August 1977 (resubmitted by letter dated July 25, 1979), was performed to determine the hydraulic performance of this system under various LOCA conditions. This analysis is the basis for all subsequent BRP ECCS analyses. An internal analysis (Reference EA-BRP-ECCS-88016-GFP, September 21, 1988, of Deviation Report D-BRP-86-15D) evaluated RDS valve differential pressure operation in relation to ECCS flow requirements. This analysis concludes that the ECCS is adequate based on a differential pressure of 35 psi between the reactor vessel and containment. The most limiting flow condition in this evaluation is governed by failure of the diesel fire pump.

The above analysis indicated that rated core spray occurs below reactor pressures of 65 psig (ring) and 64 psig (nozzle) rather than

75 psig as previously used; this only affects time to reach rated spray since the flow requirements remain the same. For analyzed breaks of .244 ft^2 and smaller the time to rated core spray is limited by reactor pressure; for breaks of .375 ft^2 and larger the time to rated spray is governed by the core spray valves' opening times. The additional time required to reach rated spray flow for breaks .244 ft^2 and smaller is not significant to cause additional fuel damage. The .375 ft^2 break was shown to be the limiting break with peak clad temperature determined to be 2138°F (Reference XN-NF-78-53 submitted July 25, 1975) while the peak clad temperature for the .244 ft^2 break was calculated to be 1801°F. In the long term, reactor pressure will not exceed 55 psig prior to subsequent operation of RDS valves, based on a containment pressure of 20 psig and a RDS differential pressure of 35 psid between containment and the reactor vessel.

An internal analysis performed subsequent to MPR-557 described above indicated that rated core spray occurs at a reactor pressure of 65 psig (ring) and 68.8 psig (nozzle) rather than 75 psig. This does not affect the time to rated core spray flow for analyzed breaks of .375 ft^2 and greater since the time to rated flow for large breaks is governed by the core spray valves opening times. The .375 ft^2 break was shown to be the limiting break with peak clad temperature determined to be 2138°F (Reference XN-NF-78-53 submitted July 25, 1975). For the next smallest analyzed break (.244 ft^2) and all smaller breaks the time to rated core spray becomes limited by reactor pressure. The peak clad temperature for the .244 ft^2 break was calculated to be 1801°F. Internal analysis indicates that by assuming rated ring spray flow takes place at 65 psig rather than 75 psig the time to rated flow will increase by 1.65 seconds. In the short term prior to the initiation of the RDS the additional heat-up occurring in the fuel during the 1.65 seconds should not jeoparidize its integrity any further. In the long term, following RDS blowdown, containment pressure will remain less than or equal to 15 psig. With RDS initiation occurring upon a differential pressure of 50 psi between containment and the reactor vessel, reactor pressure will not exceed 65 psig prior to the onset of RDS and the reactor core will experience rated core spray flow.

6.3.1.3.2 Core Spray Recirculation

To mitigate the effects of a loss-of-coolant (LOCA) accident, the core spray system brings water from the plant fire protection system to the sparger ring and the nozzle array within the reactor and sprays water directly on the core. In order to protect the containment sphere from increasing water level, transfer from the injection mode to the recirculation mode of emergency core cooling occurs when level in containment reaches 587'. Because Big Rock Point does not have the capability of automatic transfer, switchover to recirculation cooling is actuated manually from the control room. In the recirculation mode water to the sparger ring and nozzle array is provided by two core spray pumps. Water addition to the containment sphere is manually stopped before the accumulated water level reaches an elevation of 596', above which containment integrity could be jeopardized by reaching a stress limit (reference NRC Safety Evaluation Report for Systematic Evaluation Program (SEP) Topic VI-7.B, ESF Switchover from Injection to Recirculation dated May 20, 1982).

6.3.1.3.3 Enclosure Sprays

The enclosure or containment spray system serves to maintain containment temperatures below the Electrical Equipment Qualification (EEQ) temperature envelope in the event of a LOCA which releases steam to containment. Containment response to a LOCA was calculated using a computer code that models the containment sprays by removing from a superheated atmosphere that quantity of energy required to raise the 70°F spray water to saturate steam at containment conditions. A delay of 75 seconds was assumed to account for starting of the fire pumps and filling of the spray line. A spray flow of 50 gpm was chosen to establish minimum flow. Computer calculations show a 50 gpm spray flow is sufficient to cool the superheated atmosphere. The computer code used modeled containment as a single compartment. However, the steam drum cavity is actually a separate room with a leakage area of approximately 100 square feet to the rest of containment. Since nearly all steam lines are located within the steam drum cavity, a steam line break is more probable in this area. The net effect of this is that for a total spray flow of 50 gpm the temperature outside the steam drum cavity will be less than predicted by the single compartment model while those temperatures inside will be somewhat greater than predicted. The atmospheric temperature following a large steam line break will exceed 235°F for less than two minutes. For this short period, the thermal capacity of vital equipment within containment is considered sufficient to assure their operability for the period required. It should be noted that containment air temperatures exceed 235°F only for the hypothetical large steam line break and not for the more probable small breaks (Reference CPCo December 5, 1980 submittal). Hydraulic analysis of the ECCS result in containment sprays of more than 50 gpm to areas of containment both inside and outside the steam drum cavity (reference EA-BR-ECCS-88016-GFP, September 21, 1988).

For small steam line breaks with flows of 50 lb/sec or less containment pressure will not reach the containment high pressure trip setpoint of 1.0 psig due to the containment ventilation system which acts to maintain containment pressure. For this class of breaks the reactor must be manually scrammed and containment sprays manually initiated. Containment response to this size break is addressed in Section 6.2.1.3.4 of this Updated FHSR. The analysis and containment response took no credit for operator action before 10 minutes after onset of the break. Reactor coolant pressure boundary leak detection components are addressed in Section 5.2.5 of this Updated FHSR. The operator is expected to take appropriate action based upon the leak detectors and alarm settings in the event of a leak.

In addition to these indications, the operator would probably hear the small break; particularly if the break were large enough to cause rapid heating of the containment and still not cause automatic containment isolation (ie, 50 lbm/sec steam leaks). For breaks of this size, containment air and dew point temperatures both inside and outside the steam drum cavity would rise very rapidly causing an immediate high-temperature/dew point recorder alarm labeled "Containment Building High-Temp.", on the control room front panel. The loss of steam to the turbine would result in an approximate reduction of 10 MWe in turbine generator output and partial closing of the turbine control valves. These changes would result in step changes on the steam flow and turbine cam position charts.

Feedwater flow would probably stay the same. The operator would respond at once by noting the chart readings and power output of the generator. With the control panels and console situated as they are in the control room at Big Rock Point, all indications can be seen from one location. The farthest distance between charts is about 20 feet. The containment pressure indicator as well as the control switches for scram, emergency condenser, and enclosure spray are within five feet; therefore, the actual time to perform necessary actions would be short and well within 10 minutes.

Nevertheless, no credit is taken for operator action before 10 minutes and the results of this action at 600 seconds is depicted on Figure 3-4 in Chapter 3 of this Updated FHSR.

The containment sprays were originally expected to function as a means to provide iodine washout. Analysis has indicated, however, that post-LOCA dose rates are less than 10 CFR 100 thyroid exposure limits even when no credit is taken for washout by containment sprays (Reference CPCo Submittal dated June 2, 1982 for Systematic Evaluation Program (SEP) Topic XV-19). As such, containment sprays are no longer assumed to provide an iodine washout function and secondary sprays are activated in the event of a failure of the primary spray system.

6.3.2 SYSTEM DESIGN

6.3.2.1 Component Description

6.3.2.1.1 Core Spray

As indicated previously, water for the core spray system is provided by the Fire Protection System. A description of the fire pumps is given in Section 9.5.1 of this Updated FHSR. The two isolation valves located in the primary core spray line are dc motor operated valves which can be operated manually from the control room. The two backup core spray isolation valves are ac motor operated valves and can also be manually operated from the control room.

The core spray sparger is constructed of two inch diameter Type 316 stainless steel piping. It is octagonal in shape and clamped to the reactor vessel steam baffle assembly. The sparger ring contains 36 nozzles aimed at the core.

The nozzles attached to the sparger are 15° injector type full jet nozzles. The nozzles were originally designed to use an interior spinner. However, to prevent jamming or locking of the spinners during operation, the spinners were tack welded in a set position. In addition, the exit orifice of each nozzle was reamed to 0.221 inch diameter. For further details, refer to CPCo March 28, 1979 submittal and Facility Change FC-464.

The core spray nozzle array through which the backup core spray line provides water to the core is based upon a multiple nozzle concept. The nozzle assembly consists of twelve identical one inch nozzles.

The twelve one inch nozzles are arranged in two concentric circular arrays. The outer array consists of eight nozzles each mounted in a 90° street ell. The street ells are equally spaced around a plane circle protruding from a central hub-type manifold. The nozzles are

Evaluation: CPCo stated in a letter to the staff dated January 19, 1977, that the nozzles used in the BRP nozzle spray and ring spray systems provide course spray (large diameter droplets) and should not be significantly affected by the presence of a steam environment. However, to verify the adequacy of the nozzle spray system, as required by the Commission Order, CPCo conducted a test program to measure experimentally the spray distribution in a steam environment. The tests showed that the existing single nozzle did not provide adequate spray distribution; therefore, a new nozzle design was constructed and tested. The results were presented to the staff in a report, "Big Rock Point Core Spray Test Report, Single Nozzle Test and Development Program," August 1977.

The staff has evaluated the performance of the BRP nozzle spray system, as described in the CPCo submittals dated August 1977 and September 15, 1977. Based on our evaluation, as discussed in the supplementary Safety Evaluation Report, the staff concludes that the BRP nozzle spray system is acceptable.

6.3.5.8 Ring Spray System Performance

The adequate performance of the ring spray system at BRP was an inherent assumption in the Commission's granting the lifetime exemption discussed above. However, information recently submitted to the staff regarding steam effects on spray distribution, including the report on the performance of the BRP nozzle spray system, led the staff to request CPCo to investigate the ring spray performance in a steam environment.

As a result of scoping calculations that indicated questionable ring sparger performance, and the lack of sufficient test or design data to prove the ring sparger adequacy, CPCo requested an exemption until the 1978 Cycle 16 startup from the failure criterion requirements of 10 CFR 50.46 and Appendix K as applied to the nozzle spray system. The exemption requested under the provisions of 10 CFR 50.12 by CPCo letter dated September 15, 1977 would allow sufficient time for CPCo to complete testing of the ring sparger system.

CPCo Clarification

As discussed in Sections 6.3.1 through 6.3.4 above, testing was completed. NRC Amendment 26 to the Operating License dated April 10, 1979 determined that the core ring spray system was acceptable.

NRC Amendment 26 Summary

The tests performed at the Bartow test facility resulted in an optimized sparger aiming pattern which delivered maximum bundle spray flow at all LOCA usage conditions. Two bundles received flows slightly below the Minimum Allowable Bundle Spray (MABS), but the licensee has developed maximum bundle power technical specifications which conservatively ensure the reactor will be operated within the comfort. This change was accomplished via Facility Change FC-545 and the use of Well Water System cooling was operable in June of 1986 and subsequent periods when lake water cooling via the Service Water System loses its ability to adequately cool the control room because of high lake water temperatures. This issue was closed in the Integrated Plan in the February 28, 1986 submittal to the NRC.

The control room temperature was also evaluated as part of the Control Room Design Review (CRDR), (Reference Chapter 18 of this Updated FHSR). As described in Volume V of the CRDR, Human Engineering Deficiencies (HED) remain open for control room temperature and will be resolved as discussed in Section 18.1.3 of this Updated FHSR. The discrepancies have to do with "temperatures too high in summer and too low or too high in winter and requiring constant adjustment."

6.4.4 CONTROL ROOM HEAT-UP TEST

A special site test (Control Room Heat-Up Test, SST-37) was performed to provide heat-up data for the Station Blackout Issue (10CFR50.63). Specifically, to show that a loss of control room ventilation during a four hour station blackout will not render the control room inoperable.

The test predicted a temperature increase of 6°C in four hours, concluding that loss of ventilation during a station blackout is not a concern (Reference 14).

a. Isolation Valve - The isolation valve is a 6" - 1500 lb gate valve with buttweld ends manufactured by Anchor Darling. The valve is operated by an air cylinder mounted on top of the valve. Compressed air from the plant instrument air system is used for normal operation of the valve. The valve is normally closed and fails open on the loss of compressed gas. In order to maintain the valves closed in the event of loss of plant instrument air, a backup compressed nitrogen supply was installed via Facility Change FC-572. Air to the valve air cylinder is controlled by a 125 VDC solenoid operated three-way valve. In its de-energized position, air pressure is admitted to the isolation valve air cylinder, maintaining it in its normally closed position. The open and closed positions of the valve are displayed on the RDS control panel in the control room. Two limit switches mounted on the valve and actuated by a plate affixed to the piston/valve stem connecting rod provide the source of the open/close position indication.

<u>Valve/associated Component Modifications</u>

In addition to the backup nitrogen supply that was installed (FC-572), two other significant modifications were made that affected the isolation valves: (1) an air amplifier was installed in the instrument air supply to the isolation valves (FC-539) to boost the control air from 90 to 130 psig. This change was made to provide greater closing forces for the isolation valves. During subsequent routine surveillance testing several of the isolation valves failed to open and the air amplifier was removed from service (Specification Change SC-84-006); (2) an air filter was added to the instrument air line (FC-555) to reduce dirt buildup on check valve seats causing them to fail. Other less significant modifications associated with the RDS isolation valves are described in FC-451, SFC-78-003, SFC-78-022, SPC 82-032, SC-83-040, SC-83-042, SC-85-020, SC-86-020 and SC-92-21 in the BRP Internal Modification files.

b. Depressurizing Valve - The Target Rock Model 73V Depressurizing Valve is a 6" inlet/10" outlet flanged valve that consists of two principal assemblies; a solenoid operated pilot valve section, and a main valve section. These two units are directly connected to provide a unitized, remote actuated Depressurizing Valve. The pilot valve section is the control element, and the main valve is a hydraulically actuated follower valve which provides the pressure relief function. Energization of the solenoid pilot valve opens the pilot valve, venting the main piston chamber, permitting the system pressure to fully open the main valve, at full rated flow with essentially no pressure accumulation. The Depressurizing Valve does not contain the overpressure-self actuation feature normally found in safety relief valves.

CHAPTER 6 REFERENCES

Reference

1. NRC letter dated February 1, 1982, Systematic Evaluation Program (SEP) Topic VII-2, Engineered Safety Features System Control Logic and Design, Safety Evaluation for BRP.

2. NUREG-0828 Final Report dated May 1984, Integrated Plant Safety Assessment Systematic Evaluation Program.

3. CPCo letter dated March 16, 1982, SEP Topic VI-1, Organic Materials and Post Accident Chemistry (CPCo Evaluation).

4. CPCo letter dated January 18, 1985, BRP Plant Integrated Assessment - Issue 22A Organic Materials (SEP Topic VI-1).

5. NRC letter dated June 13, 1985, Integrated Plant Safety Assessment Report (IPSAR) Section 4.19.1, Organic Materials (NRC Safety Evaluation).

6. NRC letter dated June 10, 1982, Systematic Evaluation Program (SEP) - Evaluation Report on Topics VI-2.D Mass and Energy Release For Possible Pipe Breaks Inside Containment, and VI-3 Containment Pressure and Heat Removal Capability.

7. CPCo letter dated August 26, 1980, Big Rock Point Plant - Steam Phase Breaks.

8. CPCo letter dated November 19, 1982, Response to Request for Additional Information - Containment Purging/Venting.

9. NRC letter dated June 28, 1983, Completion of Generic Item B-24, Containment Purging/Venting During Normal Operations (NRC Safety Evaluation Report).

10. NRC letter dated November 23, 1982, Containment Leak Testing (NRC Safety Evaluation Report, Technical Evaluation Report and 10 CFR 50 Appendix J Exemption).

11. NRC letter dated January 8, 1986, Exemption From Appendix J to 10 CFR Part 50 - Reactor Containment Airlock Door Seals Testing (after use).

12. NRC letter dated November 24, 1981, Systematic Evaluation Program (SEP) Topic VI-4, Containment Isolation System (Electrical). (NRC Safety Evaluation).

13. CPCo letter dated May 4, 1979, Response to IE Bulletin 79-08 Events Relevant to BWRs Identified During Three Mile Island.

14. Special Site Test, SST-37 Control Room Heat Up Test Following Loss of Ventilation, Performed/Completed October 2, 1992 /

If one wide range monitor is in a "Neutron Flux Hi Hi Scram" condition, and another wide range monitor has a downscale trip, a control rod scram is initiated.

There are no bypass features for these trip inputs.

7.2.3.10 Manual Scram

A manual trip is provided to enable the operator to scram the reactor in case of an unusual or unforeseen emergency. Depressing the switch opens contacts to both protection channel logic units, initiating a control rod scram. Additional contacts in the manual trip circuit deenergizes the undervoltage relays in each protection channel.

7.2.3.11 Loss of Auxiliary Power Supply

Each protection bus has a circuit breaker (CB-RE11A and CB-RE11B) / which contains an undervoltage release device which opens breaker / contacts in the 115 volt ac circuit to the master scram pilot valve solenoids and to the control rod scram power switch components. The undervoltage release trips at 63 ± 21 VAC. Refer to Section 7.2.5.3 / of this Updated FHSR for further details.

The reactor protection system is supplied from the AC auxiliary power system through isolating motor-generator sets which have enough energy stored in their flywheels to carry them through power system disturbances lasting approximately 10 seconds. If power is unavailable, the reactor will be scrammed. Drawing 0740G30743 and Section 7.2.5 of this Updated FHSR provides details on the RPS power.

7.2.4 REACTOR MODE SELECTOR SWITCH

Certain Reactor Protection System bypassing is accomplished by the reactor mode selector switch. The switch is key-locked and has four positions; shutdown, refuel, bypass dump tank, and run. Reactor Protection System trip functions bypassed by the selector switch are shown below:

Mode Selector Switch Position	Trip Functions Bypassed
Run	None[e]
Bypass Dump Tank[a]	Low Steam Drum Water Level Recirculation Waterline Valves Closed Steam Line Backup Isolation Valve Closed High Water Level in Scram Dump Tank[b] High Condenser Pressure
Refuel[d]	Low Steam Drum Water Level Recirculation Waterlines Valves Closed Steam Line Backup Isolation Valve Closed High Condenser Pressure

control is interlocked so that only one of these three buses can be supplied at any one time from Panel 1Y.

This alternate supply (Panel 1Y) is normally fed from the 30 Kva Instrument and Control Transformer 1A on Bus 1A unless this source of power is lost, in which case an automatic throwover operates to supply power from the Instrument and Control Transformer 2B on Emergency Bus 2B.

The control rod position indication is normally fed through Panel 1Y; however, a third MG set can supply power to the control rod position indication system in the event of total loss of power to Panel 1Y. This MG set, which starts automatically upon loss of power to Panel 1Y, is powered by the station battery at 125 volts dc and has a single-phase 115 volts ac output.

With the power selection switch in the "Pull For Bus 3" position, this MG set is interlocked off and Instrument and Control Transformer 1A supplies power to the control rod position indication system through Panel 1Y via alternate contacts.

7.2.5.3 RPS Bus Undervoltage

Each protection bus has a circuit breaker (CB-RE11A and CB-RE11B) / which contain an undervoltage release device which opens the CB-RE11 / contacts in the 115-volt, ac circuit to the scram pilot valve solenoids, the master scram solenoid valve, the scram dump tank solenoid vent, drain and equalizing vent valves and the turbine trip and sphere ventilation trip relays. These undervoltage devices / operate at a RPS bus voltage of 63 ± 21 volts and require manual / reset upon tripping, (these breakers were replaced via SC-92-013). / It should also be noted that the balance of the automatically actuated containment isolation valves will close upon a sustained loss of power to both protection channels by de-energization of the isolation valve control relays K-1K4A, K-1K4B, K-2K4A and K-2K4B.

7.2.6 REACTOR PROTECTION SYSTEM LOGIC UNIT AND POWER SWITCHES

7.2.6.1 Logic Unit

The logic unit is a transistorized unit that performs a rapid low-power switching function upon receipt of a trip signal from a sensor or combination of sensors. LU-RE03A serves Protection Channel 1 and LU-RE03B serves Protection Channel 2.

The logic unit contains circuit breakers and push-button switches which can be operated manually to simulate sensor operation (contact opening) for testing purposes.

The self-contained logic unit power supply is a solid-state, 26 volt, dc supply which powers the contact-type sensor circuits and also supplies power to the logic circuitry at a level of 16 volts dc.

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CHAPTER 8 - ELECTRIC POWER

8.3 ONSITE AC POWER SYSTEM

8.3.1 FUNCTIONAL DESIGN DESCRIPTION

A regulated 2400 VAC supply from the station power regulator is fed to the 2400 VAC main plant bus. In addition to supplying the large plant motors, the 2400 VAC bus supplies two step-down transformers to supply the two 480 VAC load groups (Load Center Bus 1 and Bus 2). These two load centers feed all the 480 VAC buses in the plant except for the loads fed from station power transformer #77. Where needed the 480 VAC buses feed step-down transformers to supply panels used for lighting and low voltage loads.

Under loss of offsite power conditions, two emergency 480 VAC diesel generators are available at the plant site. The emergency diesel generator located at the plant screenhouse automatically starts and supplies voltage to bus 2B on loss of normal voltage. This diesel can also supply voltage to the 10 CFR 50 Appendix R safe shutdown loads directly through switching circuits should bus 2B be unavailable. The standby diesel generator located near the plant well house can be used to supply bus 2B. This unit is considered a back-up and must be manually started and connected to the bus.

Consumers Power Drawings 0740G30101, 0740G30102 Sh #1 and Sh #2 provide an outline of the Onsite AC Power System.

Resolution of the Station Blackout Rule /

On July 21, 1988, the NRC amended its regulation in 10 CFR Part 50. A new section 10 CFR 50.63 was added which requires that each light-water-cooled nuclear power plant be able to withstand and recover from a station blackout of a specified duration. /

CPCo responded to the rule on April 17, 1989, detailing Big Rock Point's unique design features and response to a station blackout. The safe shutdown method utilized during a SBO is completely ac power independent. The shutdown method removes 100% of the decay heat using the dc operated emergency condenser valves and ac independent emergency condenser make-up. The diesel fire pump provides primary system inventory make-up when reactor pressure has decayed. Two additional responses followed dated March 28, 1990 and October 9, 1991 to NRC request for additional information. /

A Staff Safety Evaluation was presented as an enclosure to letter dated March 9, 1992 which concluded that Big Rock was not in compliance with the requirements of 10 CFR 50.63. /

As a result of two meetings between Big Rock Point Staff and representatives of the Office of Nuclear Reactor Regulation (NRR), a revised response to the Station Blackout Rule was submitted July 3, 1992. NRR reviewed this revised response and issued a revised Safety Evaluation dated October 7, 1992. The revised /

response was found to be acceptable, except for the verification of the adequacy of station and alternate shutdown batteries at low temperature conditions, and the completion of additional analyses addressing control room and containment heat-up and primary system emergency cooldown rate (300°F/hr) with respect to Appendix G pressure/temperature limits, to which Consumers Power committed to perform.

8.3.2 2400 VAC BUS

8.3.2.1 Description

The 2400 VAC Bus/Switchgear is fed from the station power regulator and located in the air compressor/electrical equipment room. The switchgear housing is comprised of seven units containing a 2400 VAC Air Circuit Breaker (ACB). These ACBs can be closed or tripped from the Control Room or locally. The loads associated with the seven ACB are:

Breaker	Load
152-101	#1 Reactor Recirc Pump Motor (400 HP)
152-102 (1199)	Station Power Transformer #11 (750 KVA)
152-103	#1 Reactor Feed Pump Motor (1500 HP)
152-104 (1136)	Incoming Feed for the Station Power Regulator
152-105	#2 Reactor Feed Pump Motor (1500 HP)
152-106 (2299)	Station Power Transformer #22 (750 KVA)
152-107	#2 Reactor Recirc Pump Motor (400 HP)

8.3.2.2 2400 VAC Switchgear Protective Relaying

Relays, monitoring the 2400 volt Station Power Bus, protect various plant equipment from operating during undervoltage conditions. These relays also provide the necessary station power time sequencing for undervoltage load shedding and returning of associated equipment to service.

Three undervoltage relays (K-127-10XY, K-127-10YZ, K-127-ZX) in combination with time-delay relay (K-127-9) provide undervoltage protection for the 2400 VAC Bus and equipment on the 480 volt buses caused from a postulated degraded grid. This modification (Facility Change 468) is discussed in Section 8.2.3.5.

Relays K-127-1 and K-127-2 load shed the Reactor Recirculating Pumps 1 and 2, respectively, for loss of voltage conditions via tripping of each pumps associated ACB (ie, ACB 152-101 and 152-107, respectively). Both of the ACBs require manual closure after a trip. Relays K-127-3 and K-127-4 load shed the Reactor Feedwater Pumps 1 and 2, respectively, for loss of voltage conditions after a time delay of 2 seconds. Both of these ACBs require manual closure after a trip.

Relays K-127-5 and K-127-6 load shed the Condensate Pumps 1 and 2, respectively, for loss of voltage conditions following a time delay of 2 seconds. Both of these ACBs will automatically reclose after a time delay of 6 seconds upon return of voltage, unless manually tripped. Relays K-127-7 and K-127-8 load shed the Condenser Circulating Water Pumps 1 and 2, respectively, for loss of voltage conditions following a time delay of 4.5 seconds. Both ACBs will automatically reclose after a time delay of 2 seconds upon return of voltage, unless manually tripped.

These relays and associated time-delay circuits were installed in 1968 as part of the 46 kV line addition. Load shedding of the large motors is essential to prevent an overcurrent/undervoltage condition during transfer from the 138 kV to 46 kV source.

The 2400 VAC switchgear bus is equipped with ground indication and alarms. The scheme provides local indication and an alarm in the control room. Actuation of the relay requires a manual reset to clear both the trip target and alarm.

8.3.3 480 VAC BUSES

8.3.3.1 Description

The 480 VAC Buses at Big Rock Point are supplied by Station Power Transformers 11 and 22. Transformer 11 supplies Load Center Bus 1 and Transformer 22 supplies Load Center Bus 2. Each load center contains four 480 VAC circuit breakers each with internal overcurrent device, with the motor control center feeder breakers having delayed overcurrent tripping and the motor feeder breakers having overload alarms and instantaneous overcurrent tripping. These breakers can be closed or tripped from the control room or tripped locally at the switchgear unit. The loads associated with Load Centers 1 and 2 are:

Load Center Bus 1

Breaker	Load
52-11	Condenser Circulating Water Pump #1 (200 HP)
52-12	Condensate Pump #1 (200 HP)
52-1A	MCC Bus 1A
52-1F	Bus 1F

Load Center Bus 2

Breaker	Load
52-21	Condenser Circulating Water Pump #2 (200 HP)
52-22	Condensate Pump #2 (200 HP)
52-2A	MCC Bus 2A
52-2F	Bus 2F

All the remaining MCCs are fed from buses 1A, 1F, 2A or 2F, with 1A and 1F associated with Load Center Bus 1 and 2A and 2F associated with Load Center Bus 2.

Circuit breakers utilized within the MCCs are appropriately sized to satisfy the load current of the equipment they supply.

The remaining plant buses and 480 V panels are fed from the above four MCCs as follows:

Bus	Description	Supply
MCC Bus 1C	Screenhouse	Bus 1A
MCC Bus 2C	Screenhouse	Bus 2F
MCC Bus 1D	Ventilation System (Turbine Bldg)	Bus 1F
MCC Bus 2D	Ventilation System (Rx Bldg)	Bus 2F
MCC Bus 1E	Radwaste	Bus 1F
Panel 1P	Shop Power	Bus 1F
Panel 31L	Well House	Bus 1C
Panel 2E	Utility Loads	Bus 2F
Panel 2P	Reactor Building	Bus 2A

The 480 VAC MCC-2B is considered the Emergency Bus at Big Rock Point and is located in the Air Compressor/Electrical Equipment Room. MCC-2B is normally fed from bus 2A but it can be fed from MCC Bus 1A, the Emergency Diesel Generator, or the Standby Diesel Generator. Table 8-6 identifies the Bus 2B equipment and power distribution.

8.3.3.2 480 VAC Bus Protective Relaying

Motor Control Center buses 1A and 2B are equipped with ground indication and alarms. Ground indication and alarm for Bus 2A is provided through its normal connection to bus 2B. The schemes provide local indication and an alarm in the control room. Actuation of the ground relays require a manual reset to clear both the trip target and alarm.

Loss of voltage relays are connected to selected large load circuits. These relays provide the necessary station power time sequencing for loss of voltage load shedding and returning of the associated equipment to service. These relays and associated circuits were installed in 1968 as part of the 46 kV line addition to permit successful auto-transfer from the 138 kV to 46 kV source. The 480 VAC loads having this feature are as follows:

Breaker	Load Description
52-1A34	Air Compressor #1
52-1A35	Air Compressor #2
52-2A35	Air Compressor #3
52-1A57	Control Rod Drive Pump #1
52-2A58	Control Rod Drive Pump #2
52-1C15	Service Water Pump #1
52-2C15	Service Water Pump #2
52-1A41	Reactor Cooling Water Pump #1
52-2A41	Reactor Cooling Water Pump #2
52-1D15	Plant Exhaust Fan #1
52-1D26	Plant Exhaust Fan #2
52-2A25	Auxiliary Oil Pump
52-2A22	AC Bearing & Seal Oil Pump
* 52-2F2D	Ventilation Bus 2D
* 52-1F1E	Radwaste Bus 1E
52-1C22	Screen Wash Pump

Each of the above loads shed on loss of voltage via time delay tripping. Restarting will occur automatically upon return of voltage and after a time delay provided the associated control switches are not in the "OFF" position. Loads identified with an asterisk (*) automatically trip on loss of voltage but do not reclose which requires a manual reset at the motor control center.

Voltage and frequency indication of Bus 2B is also provided in the control room to monitor bus parameters during diesel generator operation.

8.3.3.3 Thermal-Overload Protection for Motors of MOV's

SEP Topic III-10.A "Thermal-Overload Protection For Motors of Motor-Operated Valves" was evaluated for Big Rock Point to provide assurance that the application of thermal-overload protection devices does not result in needless hindrance of the performance of valve safety functions.

In a letter (Reference 21), CPCo justified the present design for most MOVs on the basis that they are not required to function during an accident. For the remaining six (6) valves listed below, modifications were completed via Facility Change FC-573 which permits bypassing of the thermal overloads during normal operation. Thermal overload circuits are administratively controlled to only be in service during surveillance and testing.

- MO-7052, MO-7062: Emergency Condenser Inlet Valves
- MO-7070, MO-7071: Back-Up Core Spray Valves
- MO-7066, MO-7080*: Firewater to Core Spray Heat Exchanger
- MO-7068: Back-Up Containment Spray Valve

* This valve was added via Facility Change FC-578.

Accordingly, the staff concluded that Big Rock Point satisfies the current licensing criteria for safety-related valve functions (Reference 12).

8.3.4 EMERGENCY DIESEL GENERATOR

8.3.4.1 Description

The Emergency Diesel Generator (EDG) provides three phase 480 volt ac emergency power to the 480 volt ac emergency bus, MCC-2B, to support essential loads in the event of a loss of off-site power. Equipment in addition to those on the 2B bus can be powered from the emergency diesel generator via selective manual breaker manipulations provided that the emergency diesel generator output rating is not exceeded.

The emergency diesel generator output can be manually disconnected from the 480 volt emergency bus MCC-2B and connected to the alternate shutdown system should the 2B bus become inoperable due to fire. This transfer is accomplished via a manual transfer switch located in the emergency diesel generator room.

Provisions for full load testing of the emergency diesel generator are provided.

The diesel engine is rated at 319 horse power at 1800 rpm. The generator has a full load rating of 200 kW (ie, 250 kVA at an 80 percent power factor) at the rated generator speed of 1800 rpm. A static exciter is an integral part of the generator, providing 18.5 amps at 125 volt dc for generator excitation. The generators output is 480 volt ac, three phase at a frequency of 60 hertz. Generator output voltage can be adjusted via a hand rheostat located on the east side of the exciter cabinet. The DC starting system for the diesel generator is discussed in Section 8.4.4.

Diesel Engine cooling is achieved via a closed loop cooling system and heat exchanger. The cooling system is further discussed in Section 9.5.7.

The Diesel Fuel Oil Storage is discussed in Section 9.5.4. The fuel oil to operate the diesel is pumped via a diesel driver pump from the storage tank. A day tank is utilized to ensure a positive source of fuel during the initial starting of the unit.

The lube oil system is self-contained using a shaft mounted pump.

Facility Change FC-544 installed in 1983 added improved ventilation to the Emergency Diesel Generator room to reduce room heat load during long term operation. This system is discussed in Section 9.4.5.

The ventilation installed under Facility Change FC-544 was upgraded under Specification Change SC-93-002. The upgrade was in response to Notice of Deviation - Inspection Report No. 92019 (EDSFI, RFI Number CG-34 and Concern CGC-4).

8.3.4.2 Operation

The emergency diesel can be started manually or automatically upon loss of bus 2B voltage. Two undervoltage relays monitor voltage on bus 2B. On loss of potential, a start permissive is received by diesel unit. Once the diesel is started and at rated speed, an output voltage relay initiates shedding of 2B bus by opening tie-breakers to buses 1A and 2A. Following isolation the emergency diesel generator output breaker automatically closes energizing bus 2B. No load shedding and sequencing is utilized on the bus and all loads are simultaneously re-energized. Additional loads, other than those on bus 2B, can be added via manual breaker operations up to the rated output of 200 kW. The starting circuit for the emergency diesel generator is shown on Consumers Power Drawings 0740G30105 and 0740G30869 Sh #2.

Operation of the diesel generator in conjunction with the alternate shutdown system is discussed in Section 9.6.

SEP Topic VIII-2 evaluated diesel generator loading against the criteria in Regulatory Guide 1.9. The maximum loading of the diesel-generator will occur 12 hours after the loss of offsite power during a LOCA. At that time, the diesel-generator loading is expected to be 215.8 KVA. The maximum automatically connected load of 166.1 KVA will occur after the diesel-generator has started and attained operating voltage and frequency. The diesel-generator full load rating is 200 kW at 0.8 PF or 250 KVA. The maximum predicted load is 86% of the full load rating and is, therefore, in compliance with current licensing criteria. However, the frequency decrease encountered when starting the electric fire pump is less than the 95% of nominal frequency required by Paragraph C.4 of NRC Regulatory Guide 1.9 and is, therefore, not in compliance with current licensing criteria.

In responding to frequency concern (Reference 20) CPCo concluded that the output frequency (91% of nominal) during the loading transient is acceptable on the following basis. First, it is the opinion of CPCo that the performance of any of the loads comprising the EDG initial step load group is not degraded below their minimum requirements (which is consistent with IEEE 387-1977). Second, current licensing criteria allows frequency excursions beyond 95% of nominal frequency in circumstances not unlike those at Big Rock Point.

Regarding the quality of the EDG output frequency during load assumption, the output frequency remains within the Regulatory Guide recommended tolerance of 95% of nominal throughout the entire transient with the exception of only 0.65 seconds. During this 0.65-second period, the frequency drops to a minimum value of 91% and then recovers and rises above the lower 95% recommended limit. It is the opinion of CPCo that this frequency excursion will have an insignificant effect on the individual loads that comprise the EDG initial step load group.

During starting conditions, the electric fire pump alone comprises between 80% and 90% of the total starting kVA load imposed on the EDG. For these reasons, CPCo feels justified in stating that the Big Rock Point EDG carries only one large connected load. Paragraph 5.1.2(5) of the IEEE Standard states that a diesel generator unit shall be capable of "maintaining voltage and frequency at the generator terminals within limits that will not degrade the performance of any of the loads comprising the diesel load below their minimum requirements, including the duration of transients caused by load application or removal." It is the opinion of CPCo that the Big Rock Point EDG provides an output in accordance with this criteria.

The NRC Safety Evaluation to SEP Topic VIII-2 (Reference 17) supported the conclusions discussed above as acceptable in meeting the NRC criteria.

8.3.4.3 Instrumentation and Relaying

Temperature switches monitor the diesel cooling system. Upon actuation of both switches exceeding a setpoint of 200 ± 10°F, the engine is tripped and alarm in the control room (Facility Change FC-401).

Engine lube oil pressure is monitored by two pressure switches. Actuation of both switches upon decreasing pressure below the setpoint of 20 psig cause an engine trip and control room alarm (Facility Change FC-401).

The engine is equipped with an overspeed trip switch set to actuate when the engine speed exceeds 115% of rated (2070 ± 36 rpm). Actuation causes engine trip and control room alarm.

Three overcurrent relays monitor (Facility Change FC-401) each phase of the generator output. Actuation of two out of three will cause the time delay relay to energize (Facility Change FC-670) which in turn will cause an engine trip and alarm in the control room.

Facility Change FC-434 added an alarm scheme to notify plant operators of conditions that prevent the diesel from starting to an automatic start signal. Loss of 125 VDC control voltage or placement of the selector switch in the "OFF" position actuate the alarm.

Further description of the Emergency Diesel Generator Alarm and Control Circuitry is provided in Section 9.5.6.

8.3.4.4 Diesel Engine Start Time

The start time requirement for the Diesel Generator is 31.2 seconds and is measured from open indication of the tie-breaker until closure of the emergency diesel generator output breaker. This time is based on assumptions made in the derivation of ECCS limits (ie, MAPLHGR and Maximum Bundle of Section 5.2.1 of the Big Rock Point Technical Specifications) for Exxon fuel types.

In performing the ECCS analysis, the Design Basis Accident (DBA) and .375 ft breaks yield peak cladding temperatures closest to the 2200°F limit established by 10 CFR 50, Appendix K. All other break sizes yield lower peak cladding temperatures and would therefore not be as restrictive as to equipment actuation times. The 15 second core spray valve opening time is most important for the .375 ft break where valve actuation is delayed by the attaining of the low reactor pressure condition at 46.5 seconds (low reactor water level occurs within seconds of low drum level for breaks this large). The fire pump start time assumption (45 seconds), on the other hand, is most critical for the largest break (DBA) where rated spray is not assumed until low drum level actuation signal is generated (1.2 seconds) plus the time required for the pump to start and come up to speed (for a total of 46.2 seconds to rated spray).

The emergency diesel generator start time criteria is dictated by DBA requirements. Assuming that rated spray is required at 46.2 seconds as dictated by the diesel fire pumps start time assumption, and assuming that ac core spray valves are effectively full open 15 seconds after the 2B bus is energized, the diesel generator start time is simply the difference between these two values (46.2 seconds - 15 seconds = 31.2 seconds).

8.3.4.5 Testing Requirements

The testing and surveillance requirements for the diesel generator and associated electrical circuits are contained in Section 11.3.5.3 of the Big Rock Point Technical Specifications.

NRC Generic Letter 84-15 "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability" was reviewed and changes implemented to attain the goals of the staff actions.

CPCo concurred with the NRC objective for reducing "cold fast starts" and returned the surveillance testing back to that described in the Technical Specifications. Previous commitments to Regulatory Guide 1.108 which resulted in starts approximately every three (3) days were withdrawn.

Big Rock Point maintains an Emergency Diesel Generator reliability program containing the principal elements, or their equivalent (i.e., target level consistent with the SBO rule, surveillance testing, monitoring programs, maintenance programs, data collection and management oversight) outlined in USNRC Regulatory Guide 1.155 Station Blackout, Regulatory Position 1.2.

8.3.4.6 Onsite Emergency AC Power Sources (Emergency Diesel Generators) - Station Blackout Rule (SBO)

On July 21, 1988, the Nuclear Regulatory Commission (NRC) amended its regulation in 10 CFR, Part 50. A new section, 50.63, was added which requires that each light-water-cooled nuclear power plant be able to withstand and recover from a station blackout (SBO) of a specified duration. The issue of station blackout involves the the likelihood and duration of the loss of offsite power, the redundancy and reliability of onsite emergency ac power systems, and the potential for severe accident sequences after a loss of all ac power.

By letter dated April 17, 1989; March 28, 1990, and October 9, 1991, Consumers Power Company (CPCo) provided its response to the Station Blackout Rule. The NRC issued their Safety Evaluation related to the Station Blackout Rule on March 9, 1992. The NRC Staff had determined that CPCo's proposed method of coping with an SBO did not conform to the SBO rule, and listed several recommendations to bring the plant into conformance with the Rule. In response, CPCo met with the NRC Staff on April 10 and May 27, 1992. A revised response was submitted by a letter dated July 3, 1992. In regards to the Emergency Diesel Generator, the following evaluation was performed as part of conforming to the SBO Rule, and is documented in a Supplemental Safety Evaluation (SSE) to the Station Blackout Rule dated October 7, 1992.

Station Blackout Duration

In the Safety Evaluation, the Staff concluded that Big Rock Point had an offsite alternating current (ac) power design characteristic of "P3"," and an essential alternating current (EAC) power configuration of Group "C," resulting in a minimum target reliability of 0.95 and a required coping duration of 16 hours, or a minimum emergency diesel generator (EDG) target reliability of 0.975 and a required coping duration of 8 hours. As a result, the staff recommended the following:

Staff Recommendation

The licensee should select an EDG target reliability of 0.975 and evaluate the plant for a minimum coping duration of 8 hours, or an EDG target reliability of 0.95 and a coping duration of 16 hours.

Licensee Response

In their response, the licensee claimed an offsite ac power design characteristic of "P2," and an EAC power configuration of Group "A," resulting in a minimum target reliability of 0.95 and a required coping duration of 4 hours. The "P2" grouping was based on an extremely severe weather (ESW) grouping of "1," a severe weather (SW) grouping of "3," and an offsite power grouping of "I3." The determination of the EAC power configuration was based on the plant requiring no EDGs for loss of offsite power (LOOP) shutdown, but having one EDG available. Although NUMARC 87-00, Part 2.C does not consider this particular configuration, the licensee claims the "A" configuration based on a highly redundant and independent EAC source. In particular, the licensee notes Big Rock Point's load rejection capability and lack of need for EAC power during a LOOP event. /

Staff Evaluation

The Staff notes an error in its SE and agrees with the licensee that the offsite ac power design characteristic is "P2." With respect to the EAC classification, the Staff based its "C" classification for the EAC power configuration on two EDGs available, with one required for LOOP shutdown. The Staff's position of one EDG required for LOOP shutdown was based primarily on the assumption that one EDG was required to keep the control room functional during a LOOP. After the SE was issued, the licensee met with the Staff, and presented further information in its July 3, 1992, written response to demonstrate that no EDGs are required to keep the control room functional during a LOOP or during a SBO. Therefore, the Staff accepts the licensee's EAC classification of "A," resulting in a required 4-hour coping duration with an 0.95 EDG target reliability. The Staff considers this issue to be resolved. /

<u>Station Blackout Coping Capability</u> /

Staff Recommendation /

If the licensee selects an EDG target reliability of 0.95, the licensee needs to reevaluate the plant for a 16-hour coping duration and submit the supporting analyses for NRC review. /

Licensee Response and Staff Evaluation /

This issue has been resolved. See Staff evaluation above in Station Blackout Duration (4-hour coping duration with an 0.95 EDG target reliability). /

8.3.5 STANDBY DIESEL GENERATOR

8.3.5.1 <u>Description and Operation</u>

The standby diesel generator is powered by a diesel rated at 415 HP at 1800 rpm to provide 480 VAC back-up emergency power to bus MCC-2B. A standby diesel generator is required to be available for operation within 24 hours after a loss of coolant accident. This requirement is based upon the NRC evaluations (Reference 18) which are needed to assure the availability of AC power:

> "Modify the emergency procedures to assure a second emergency diesel will be obtained and operational within 24 hours after a LOCA."

Following the modifications performed via Facility Change FC-511C, the standby diesel generator was located at the plant well house with permanent wiring and transformers to tie the unit to bus MCC-2B. The transformers are necessary to raise the tie voltage to 2400 VAC in order to reduce the voltage drop incurred due to the distance between the standby diesel and bus 2B. A manually operated circuit breaker provides the connection to 2B bus. This breaker is padlocked in the open position to ensure isolation from 2B bus until needed.

Cooling for the unit is achieved via a closed loop cooling system utilizing a forced air radiator. DC starting system is discussed in Section 8.4.4.1 and fuel storage in Section 9.5.4.3.

The unit is manually started at the well house prior to tie-in at 2B bus. Use of the standby diesel in Alternate Safe Shutdown is discussed in Section 9.5.4.3.

8.3.5.2 Instrumentation and Relaying

Indication of cooling system temperature, lube oil pressure, fuel oil pressure, charging current, and generator output are provided at the diesel generator unit. Actuation of high temperature, low oil pressure switches or a mechanical or electrical overspeed trip will result in an automatic engine shutdown.

8.3.5.2 Instrumentation and Relaying

Indication of cooling system temperature, lube oil pressure, fuel oil pressure, charging current, and generator output are provided at the diesel generator unit. Actuation of high temperature, low oil pressure switches or a mechanical or electrical overspeed trip will result in an automatic engine shutdown.

TABLE 8-6

480 VAC MOTOR CONTROL CENTER 2B

Position/Breaker	Load Description
2B11	480V System Ground Detector Relay
	480V System Ground Indication Lights
2B12	480V System Undervoltage Relay
52-2B13	Distribution Panel 4Y
2B14	(Main Lug) 2B Feed From MCC-1A (52-1A2B)
	(Main Lug) 2B Feed From MCC-2A (52-2A2B)
52-2B21	ac Gland Seal Cond Exhauster 2
52-2B22	Personnel Lock
52-2B23	Instr and Control Pwr Transf 2B (Pnl 1Y, 2Y, 3Y)
52-2B24	Emerg Lighting Transf LT3
52-2B25	Equipment Lock
52-2B26	Fire Pump
52-2B27	Emergency Diesel Generator
2B31	Space
2B32	Space
2B33	Space
2B34	Space
2B35	Space
2B36	Space
2B41	Space
52-2B42	MO-7071 Reactor Emerg Clg Spray Vlv
52-2B43	MO-7070 Reactor Emerg Clg Spray Vlv
52-2B44	Spare
52-2B45	MO-7068 Reactor Bldg Emerg Spray Backup Valve
52-2B46	Distribution Panel 5Y (Pnl 5Y)
52-2B47	LE-RE08 and LE-RE09 Heat Tracing
2B48	Space
2B49	Space
52-2B51	Standby Diesel Generator
52-2B52	Spare
52-2B53	Spare
2B54	Space
2B61	Space
52-2B62	MO-7080 Fire Wtr to Redundant Core Spray
52-2B63	Spare
2B64	Space

8.4.1.2 Station Battery Load Profile /

The Station battery capacity is sized assuming a large break Loss of Coolant Accident (LOCA) coincident with a Loss of Offsite Power (LOP). The battery sizing calculations also include loads associated with the restoration of station power. Battery sizing calculations are provided in Reference 25 and were performed to the criteria provided in IEEE standard 485-1983. The Station Battery Load Profile (Reference 7) was revised using the values provided herein plus margin as detailed in Reference 25. The load profile is shown on Figure 8.1. The following will summarize the present load profile components. /

The load profile is made of five discrete parts. Each will be discussed below with details provided in Reference 25. /

a. Continuous two hour loads /
b. First minute loads /
c. Second to 60th minute loads /
d. 61st to 120th minute loads /
e. Last minute loads /

Continuous Two Hour Loads /

The continuous two hour loads are those on during the entire load profile. From Reference 25 the total two hour continuous load is 18.63 Amps. /

First Minute Loads /

The first minute load consists of four parts, the loads which have a distinct sequence to contend with a LOP, those which have a distinct sequence to contend with a LOCA, those which have no distinct sequence, and the continuous two hour load. These four will be discussed below. /

Sequence To Contend With A LOP:

During a LOP the following distinct sequence will take place: /

t = -0.5 s Loss of Power /

t = 0.0 s 480 V bus voltage = zero /
Trip signal to #1 RCP (152-101)..........6 A /

t = 0.1 s Trip signal to #2 RCP (152-107)..........6 A /

t = 0.17 s CRD Indication MG set starts (inrush)...35 A for 2.33 seconds /

t = 1.0 s 116 breaker trip... ....11.1 A /

Sequence To Contend With A LOP: (Continued)

t = 1.5 s Emergency DC oil pump starts (inrush)..240 A for 2 seconds

t = 2.0 s 52-12 trip (condensate pump)............1.9 A
52-22 trip (condensate pump)............1.9 A

t = 2.11 152-103 trip (feedwater pump)...........6 A
152-105 trip (feedwater pump)...........6 A

t = 2.5 s CRD Indication MG set running...........4.8 A

t = 3.1 s 1126 trip..............................10 A
7726 (152-106) close...................24 A

t = 3.5 s Emergency DC oil pump first step
inrush...............................100 A for 2.3 seconds

t = 4.5 s 52-11 trip (circ water pump)............1.9 A
52-21 trip (circ water pump)............1.9 A

t = 5.8 s Emergency DC oil pump second step
inrush...............................225 A for 0.7 seconds

t = 6.5 s Emergency DC oil pump running..........90 A

t = 10.0 s 152-104 (1136) trip.....................6 A

It can be seen from this summary that the maximum instantaneous load occurs at t = 2.1 seconds, where the instantaneous load is 287 amps. Per IEEE Standard 485-1983, Section 4.2.3, this sequenced maximum instantaneous load (287 A) will be considered to last for the full first minute of the event.

Sequence to Contend With a LOCA:

During a LOCA the following distinct sequence will take place:

t = 0.0 s LOCA
VOP-7064 starts (inrush)...............65 A for 5 seconds
VOP-7067 starts (inrush)...............45 A for 5 seconds

t = 5.0 s VOP-7064 running.......................4 A for 45 seconds
VOP-7067 running.......................4.5 A for 30 seconds

t = 21 s VOP-7051 starts (inrush)...............39 A for 5 seconds
VOP-7061 starts (inrush)...............39 A for 5 seconds

Sequence to Contend With a LOCA: (Continued) /

t = 26 s	VOP-7051 running	6 A for 15 seconds	/
	VOP-7061 running	6 A for 15 seconds	/

It can been seen from the table that the maximum instantaneous load for this sequence of events occurs at t = 0 to t = 5 seconds, where the load is 110 A. Per IEEE Standard 485-1983, Section 4.2.3, this maximum instantaneous load will be considered to last for the full first minute of the event. /

Non-Sequenced First Minute Loads: /

Reference 25 provides a summary of the non-sequenced first minute loads which contributes a total of 29.12 Amps. /

First Minute Load Summary /

Sequence to contend with a LOP............287.00 Amps /
Sequence to contend with a LOCA...........110.00 Amps /
Non-sequenced loads........................29.12 Amps /
Continuous two hour load...................18.63 Amps /

TOTAL First Minute Load...................444.75 Amps /

Second to 60th Minute Loads /

This time period contains the continuous two hour load (18.63 Amps) plus the normal running loads for this period of 125.60 Amps (detailed in Reference 25). This provides a total load for this time period of 18.63 + 125.60 = 144.23 Amps. /

61st to 120th Minute Loads /

This time period contains the continuous two hour load (18.63 Amps) plus the normal running loads for this period of 27.52 Amps (detailed in Reference 25). This provides a total load for this time period of 18.63 + 27.52 = 46.15 Amps. /

LAST MINUTE LOADS /

The last minute load consist of three parts, the two hour continuous load, the normal running load and the load to restore AC power (which has a distinct sequence). The normal running loads are 27.42 Amps and the two hour continuous load is 18.63 as detailed in Reference 25. The sequence for the restoration of AC power is provided below: /

t = x	199 breaker closed	6.06 A
t = x + 5 s	7726 breaker opened	10 A
t = x + 10 s	1126 breaker closed	24.034 A
t = x + 20 s	1199 breaker opened	6 A
t = x + 30 s	2299 breaker opened	6 A
t = x + 40 s	1136 breaker closed (power restored to 2400 V bus)	95 A
t = x + 50 x	2299 breaker closed (power restored to 480 V bus 2)	58 A

The sequence above shows that the maximum instantaneous load in the final minute due to these restoration of power actions is 95 A at 40 seconds. Per IEEE Standard 485-1983, Section 4.2.3, this maximum instantaneous load will be considered to last for the full last minute of the event.

<u>Last Minute Load Summary</u>

AC restoration loads	95.00 Amps
Normal Running Loads	27.42 Amps
Continuous two hour loads	<u>18.63 Amps</u>
TOTAL Last Minute Loads	141.05 Amps

Reference 8, Amendment 94 to the Technical Specifications approved the design load profile interval of two hours which meets the criterion of SEP Topic VIII-3.A. NRC review of load profile, sizing calculation, and assumed two hour scenario concluded consistency with current staff guidance and requirements.

8.4.1.3 <u>Station Battery Testing Requirements</u>

SEP Topic VIII-3.A: Station Battery Capacity Test Requirements (Reference 9) evaluated the BRP Technical Specification testing requirements against the industry standards (IEEE Std. 450-1975). This review concluded that the surveillance/test requirements for the station battery satisfy current licensing requirements. Surveillance requirements are contained in the BRP Technical Specifications.

8.4.1.4 <u>Station Blackout Rule</u>

In order to comply with the Station Blackout (SBO) rule (10CFR50.63), a battery sizing calculation was performed to assure that the station batteries have the capacity to meet SBO loads for a 4 hour duration. The load profile used in the sizing calculation is based on a large break loss of coolant accident, and was modified to represent the demands during a station blackout (Reference 24).

The changes made to the LOCA load profile to accomodate SBO require- /
ments were removal of P-29 from service in 1 hour instead of 2 hours. /
ONP-2.36 was changed to give this directive. /

Because of the change made to ONP-2.36, the actual loads during a LOCA /
have changed. A new LOCA load profile will be developed (D-BRP-92-069B)/
and incorporated in the FHSR. /

The loads developed for the Station Blackout load profile represent a /
licensing basis issue and must be considered when adding battery loads /
or changing the system design. /

8.4.1.5 DC Power System Bus Monitoring /

SEP Topic VIII-3.B (Reference 10) evaluated BRP to assure the design adequacy of the DC Power System Battery and Bus Voltage Monitoring and annunciation schemes such that the operator can (1) prevent loss of an emergency DC Bus; or (2) take timely corrective action in the event of loss of an emergency DC bus. Control Room monitoring of the 125 VDC Station Battery System consists of a "125 VDC System Trouble" alarm which activates on the following:

- Battery/Battery Charger overcurrent
- Positive or Negative bus ground
- Loss of charger input supply voltage
- 125 V DC Bus undervoltage

Additionally, an indicator light in the control room monitors battery voltage is greater than 125 VDC. Local indication consists of charger output current and bus voltage, current, and ground.

In responding to the deficiencies identified in the SEP Topic VIII-3.B review, Consumers Power (Reference 11) procedural changes were implemented to provide assurance that the system is ready to perform its intended function. The staff was concerned since the plant staff does not have an adequate means to verify at frequent intervals that the 125 VDC station battery output terminals and cell-to-cell connections are free of corrosion. According to the staff, corrosion could conceivably result in significant resistance and cause voltage drops and current reduction to occur in the system when the battery is called upon to carry plant load (normal plant load is carried by the in-service charger with only a trickle charge supplied to the battery).

Procedural changes were implemented to control the charger transfer such that information regarding the condition of battery connections can be observed and recorded.

The changes accomplish the desired results in the following manner:

1. Battery voltage, charger current and 125 VDC system current is recorded prior to removing the charger from service.

2. The in-service charger is removed and the same parameters are recorded. Acceptance criteria specifies that the 125 VDC load current should remain essentially the same (at this time, the battery is carrying station load).

3. The alternate charger is placed in service and the same parameters are again recorded. Acceptance criteria specifies that the charging current must be equal to or greater than the load current thereby verifying that the charger-to-battery connections are good and the battery charge is being replenished.

NRC review of these changes are documented in Reference 12 as being acceptable with logging of weekly pilot cell readings to assure operability of the DC System.

8.4.2 ALTERNATE SHUTDOWN (ASD) BATTERY SYSTEM

8.4.2.1 Function/Description

The ASD Battery System was installed in 1985 to provide a feeder circuit to safe shutdown equipment independent of the Station Battery as part of modifications (Facility Change 462J) to comply with 10 CFR 50 Appendix R requirements.

The ASD battery consists of 60 single cell (lead calcium) batteries, each required to have a cell voltage of $\geq$ 2.1 volts and a specific gravity of $\geq$1.215 $\pm$0.010 at 77 degrees Fahrenheit. The battery type utilizing Allied C&D type KC-7 or KCR-7 cells having an eight hour discharge rate of 250 amp hours.

The ASD battery system is located in the Alternate Shutdown Building. The output of the ASD Battery is connected to the 125 VDC distribution panel 2D. Drawing 0740G30102 Sh 2 provides a one-line description of the system.

The ASD battery charger, is an Allied C&D auto-regulator model designed to float charge a battery while supplying a continuous load. This charger is designed to provide up to 25 amps of continuous current, a float voltage of 132-135 volts dc and an equalizing voltage of 140-143 volts dc. The charger is equipped with input and output protection via an ac circuit breaker and a dc circuit breaker respectively, each appropriately sized for the associated loads. The charger is further protected on its output via a current limiting device, high voltage shutdown and a current walk-in device.

8.4.2.2 Alternate Shutdown Battery Load Profile

The ASD battery capacity is sized to, without support from its associated charger, operate associated continuous loads for nine days followed by three days of fire protection loads, all with battery cell temperature of only 25 degrees Fahrenheit. Battery sizing was calculated in accordance with IEEE Std 485-1978. The Alternate Shutdown Battery Load Profile is shown on Figure 8.2 and the following summarizes these loads per Reference 13.

The design of the bank assumes a period of nine days (216 hours) with a load of .25 amps without a battery charger at the beginning of the load profile. This provides assurance that a redundant charger is not necessary in that nine days is enough time to repair or replace the charger if a failure should occur. This 216 hour, .25 amp normal loads (converter and miscellaneous indicating lights) is represented as an equivalent four hour, 14 amp load step at the beginning of the profile.

Profile For 4 Hour to 4 Hour + 1 Minute

Description	Duration	Amps
Normal ASD Load	1 min	.25 A
MO-7050 MSIV	1 min	37.4 A
MO-7053 ECS Valve	1 min	7.9 A
MO-7063 ECS Valve	1 min	7.9 A
Emergency Lights	1 min	0.6 A
		54.05 Amps

Profile For 4 Hour, 1 Minute to 4 Hour, 2 Minutes

Description	Duration	Amps
Normal ASD Load	1 min	.25 A
MO-7053 ECS Valve	1 min	7.9 A
MO-7063 ECS Valve	1 min	7.9 A
Emergency Lights	1 min	0.6 A
		16.65 Amps

Profile From 4 Hour, 2 Minutes to 4 Hour, 14 Minutes

Description	Duration	Amps
Normal ASD Loads	12 min	.25 A
Emergency Lights	12 min	.6 A
		.85 Amps*

* This value is conservatively shown as 2 amps on the test profile.

Profile From 4 Hour, 14 Minutes to 4 Hours, 15 Minutes

Description	Duration	Amps
Normal ASD Loads	1 min	.25 A
MO-7053 ECS Valve	1 min	7.9 A
MO-7063 ECS Valve	1 min	7.9 A
Emergency Lights	1 min	.6 A
		16.65 Amps

Profile From 4 Hours, 15 Minutes to 8 Hours

This portion of the profile represents an equivalent loading for the remaining 72 hours of the design interval. The 72 hour duration is based on 10 CFR 50 Appendix R III.L.1.(d) "achieve cold shutdown conditions within 72 hours." Until cold shutdown is achieved, the ASD battery supports maintaining hot shutdown. Besides the normal ASD Load and Emergency Lights, the additional load is the operation of SV-4947 to provide fire water make-up to the Emergency Condenser. Since continuous make-up is not required, the total load is adjusted to reflect operation 10 minutes out of every 30 minutes.

Description	Duration	Amps
Normal ASD Loads	72 hours	.25 A
Emergency Lights	72 hours	.6 A
SV-4947	-	.5 A

Total Equivalent load is then calculated as follows:

Ieq = Total amps (min SV-4947 operates/hr) + total amps - SV-4947 (min SV-4947 does not operate/hr)

$$I_{eq} = 1.35 \text{ amps } \left(\frac{20 \text{ min}}{60 \text{ min}}\right) + 0.85 \text{ amps } \left(\frac{40 \text{ min}}{60 \text{ min}}\right)$$

$$I_{eq} = 1.016 \text{ amps}$$

For testing purposes, this 1.02 amp load for 72 hours is represented as an equivalent loading of 20 amps over the 3 hour, 45 minute time period on the profile.

8.4.2.3 Alternate Shutdown Battery Testing Requirements

Testing requirements for the ASD Battery System were developed to comply with the evaluation contained in SEP Topic VIII-3.A and IEEE Std. 450-1975. The testing and surveillance requirements are described in the Big Rock Point Technical Specifications to compensate for low design temperature of the battery a discharge current correction factor of (K = 1.52 per IEEE Standard 450-1980) is used to establish a test current profile at 77°F.

8.4.2.4 Alternate Shutdown Battery System Monitoring

Charger operation is monitored via local metering and status indicators. Remote alarming of the charger is also provided in the control room (Alternate Shutdown Building Trouble Alarm).

An ammeter and a voltmeter, located on the front of the charger, is provided for monitoring the chargers dc output. Loss of ac input extinguishes the chargers ac failure lamp, actuates an amber indicating lamp (Loss of AC Voltage) on the alternate shutdown control panel C-31 and alarms in the control room (Alternate Shutdown Building Trouble Alarm). Indication of high voltage, low voltage and/or no charge current conditions are provided on the charger via the illumination of an associated red indicating lamp. These conditions are also alarmed on the alternate shutdown control panel C-31, via the illumination of associated amber indicating lamps identified as "Battery Charger High Voltage", "Battery Charger Low Voltage" and "No Charge From Battery Charger", and in the control room (Alternate Shutdown Building Trouble Alarm).

Positive and negative ground conditions are also alarmed on the alternate shutdown control panel C-31, via the illumination of associated amber indicating lamps identified as "Ground On Positive Leg" and "Ground On Negative Leg", and in the control room (Alternate Shutdown Building Trouble Alarm).

Additional alarms which annunciate on the C-31 panel and the control room are the alternate shutdown building "Low Temperature" and "Loss of Ventilation Flow."

8.4.3 RDS UNINTERRUPTIBLE POWER SUPPLIES

8.4.3.1 Function/Description

Four (4) Uninterruptible Power Supplies (UPS) were installed in 1976 via Facility Change FC-315, as part of the Reactor Depressurization System Modification.

Each UPS is made up of a 50 amp battery charger, a bank of batteries to provide 125V dc and an inverter to convert the 125V dc to 120V ac. The units supply power to the sensor cabinets, actuation cabinet, and RDS valves associated with each channel (A-D). UPS A supplies power to SCA, AC1 and Channel 1 valves. UPS B supplies power to SCB, AC1 and Channel 2 valves. UPS C supplies power to SCC, AC3 and Channel 3 valves. UPS D supplies power to SCD, AC4 and Channel 4 valves. The UPS A 125V dc output is also used in the emergency diesel generator circuitry and for 480V indication in the Control Room.

A single-line drawing of the power supplies is shown on <u>Drawing 0740G31001</u>.

The UPS are single-failure proof, in that a loss of one unit will not cause an inadvertent blowdown and the remaining three units can complete the required safety function. The UPS are Seismic qualified in accordance with IEEE 344-1971 with details provided in Specification No. 34490-1600-402 of Facility Change FC-315.

8.4.3.2 UPS Battery Load Profiles

The UPS Battery Load Profiles represent the loads experienced by each UPS battery bank during a LOCA with RDS actuation coincident with a loss of offsite power. The service cycle is one hour, consistent with the UPS specification. The load profile for UPS Batteries B, C and D is shown on <u>Figure 8.3</u>. The load profile for UPS Battery A which also supplies the Diesel Generator actuation scheme is shown on <u>Figure 8.4</u>. The load profiles were developed as discussed in

Reference 14. Modifications performed in 1986 (Specification Change SC-86-021) which installed larger solenoid tops and the depressurization valves increased the current demand by 0.5 amps in the 2 through 60 minute period.

The load demand for the diesel generator circuit on UPS-A was determined by test in 1976 (Maintenance Order MO #76-EPS-183-05). The results showed a load of 8.3 amps during the starting sequence (<1 minute) following a loss of offsite power and a normal load for indicating lights of 0.1 amps.

8.4.3.2.1 UPS A Load Profile

Description	Time	Duration	Amps
Emergency Diesel Start	t=0	1 min	8.3 A
RDS Actuation (includes fire pump relay in rush = .07A)	t=0	1 min	6.6 A
TOTAL	t=0	1 min	14.9 Amps
RDS Actuation	t=1	1 min	6.5 A
Emergency Bus Indication	t=1	1 min	0.1 A
TOTAL	t=1	1 min	6.6 Amps
RDS Actuation After Trip (includes output relay in rush = 0.1 Amps)	t=2	58 min	8.1 A
Emergency Bus Indication	t=2	58 min	.1 A
TOTAL	t=2	58 min	8.2 Amps

8.4.3.2.2 UPS B, C and D Load Profile

Description	Time	Duration	Amps
RDS Actuation (includes fire pump relay in rush = .07 A)	t=0	2 min	7.0 A
RDS Actuation After Trip (includes output relay in rush = 0.1 A)	t=2	58 min	8.1 A

8.4.3.3 UPS Battery System Testing Requirements

The UPS Batteries were included within SEP Topic VIII-3.A; Station Battery Capacity Test Requirements (Reference 9) which evaluated the BRP Technical Specification requirements against the industry standard (IEEE Std 450-1975). This review concluded that the surveillance/test requirements including the one hour service period satisfy current licensing requirements. Surveillance requirements are contained in the BRP Technical Specifications.

8.4.3.4 UPS System Bus Monitoring

SEP Topic VIII-3.B (Reference 10) evaluated BRP to assure the design adequacy of the bus voltage monitoring. Control Room monitoring of the UPS consists of a "UPS Abnormal" alarm; local indication consists of battery output current, charger output current and voltage, inverter input current, and inverter output current, voltage, and frequency. Although the control room monitoring does not meet current guidelines, the NRC staff concluded (Reference 12) that additional monitoring of the UPS battery system is not necessary because of the small loads, short load duration, and multiple redundancy provided in the RDS design. The small loads and short load duration make it less likely that a DC system failure that can be masked by battery charger performance will occur.

8.4.4 DIESEL STARTING SYSTEMS

8.4.4.1 Function/Description

Three diesel starting systems using 24V dc battery banks are utilized at Big Rock Point for the following units:

- The Emergency Diesel Generator
- The Standby Diesel Generator
- The Diesel Fire Pump

The emergency diesel control circuit is powered by a battery charger with additional current capacity; via two, six cell, 12 volt (lead acid) series connected batteries providing a combined battery voltage of 24 volts and a current capacity rating of 225 amp hour.

The emergency diesel generator battery charger is capable of providing up to six amperes of current, a nominal float voltage of 26.4 volts dc (2.2 volts per cell) and a high rate (or equalize) voltage of 28.4 volts dc at 77°F. The charger is an automatic two rate charger, cycling to the high rate once every twelve hours and also whenever the engine starter is energized by either manual engine control or the automatic engine controller; thus, the batteries are maintained at full charge. Both the floating and equalizing voltages can be adjusted, if required. The charger operates on 120 v ac powered from Panel 10L.

The standby diesel control circuit is also powered via two, six cell, 12 volt (lead acid) series connected batteries providing a combined battery voltage of 24 volts and a current capacity rating of 225 amp hours. The standby diesel generator batteries are located next to the engine.

The standby diesel is equipped with a 24 volt alternator, capable of providing 35 amp for diesel operation and battery charging. Should the standby diesel generator batteries require a freshening charge, a portable charger is used.

The diesel fire pump electrical system (24V dc) has three separate circuits: the charging circuit, the starting circuit and the low amperage circuit. Some of the electrical system components are used in more than one circuit. The batteries, circuit breaker, ammeter, cables and wires from the battery are all common in each of the circuits. The charging circuit is in operation when the engine is running. An alternator provides the means for the charging circuit.

The system utilizes two separate 24V dc storage batteries equipped with a battery charger powered by panel 1Y. The charger is an on-off device, wherein each of the two batteries is placed on charge periodically. A timing switch alternates the charger connections to each battery and initiate charging in the automatic mode, operation in the manual mode stops all automatic functions and places the selected battery on continuous charge.

8.4.4.2 Battery Loading and Test Requirements

SEP Topic VIII-3.A Station Battery Capacity Test Requirements (Reference 9) evaluated the need to perform discharge tests on the batteries for the diesel units. The staff concluded that discharge tests are not required based upon the following:

1. Battery ratings are based on discharge rates (and discharge efficiencies) that are considerably different from those experienced during engine cranking.

2. The monthly starting tests (essentially service tests) are of a sufficient test of cranking battery capability because batteries that have too high an internal resistance for cranking service can still provide ample power for lesser current demands such as those encountered in the traditional discharge testing of standby batteries that are seldom used.

3. The five year test discharge requirement is not appropriate or needed for the starting batteries because their function is to start the engines and their ability to perform that function is tested every month.

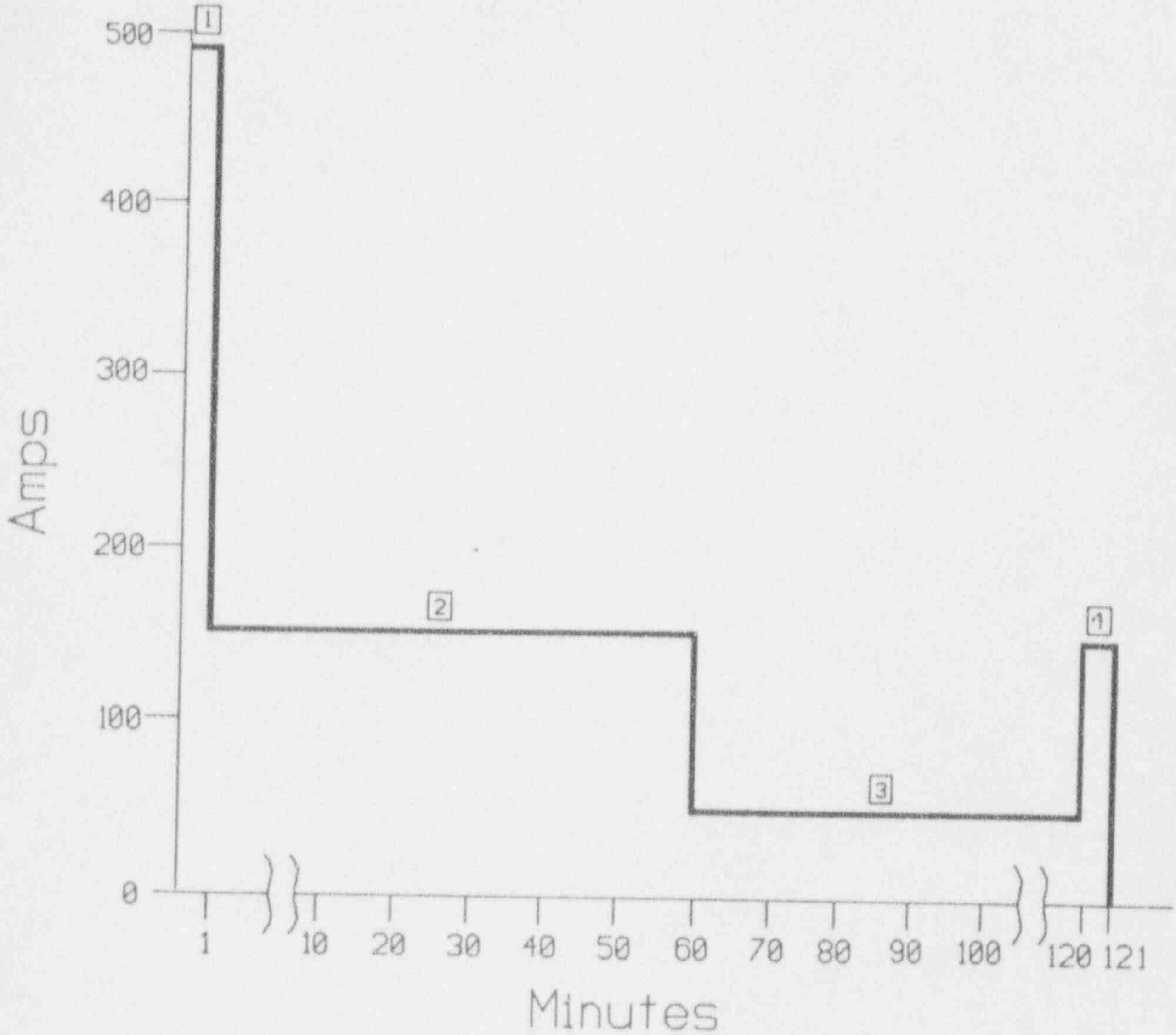
Surveillance and test requirements for the batteries associated with the diesel units are contained in the BRP Technical Specifications. Although not addressed in Technical Specifications, the Standby Diesel Generator is also started once a week and battery conditions is monitored periodically.

8.4.4.3 Diesel Starting System Monitoring

Control room monitoring of the Diesel Generator and Diesel Fire Pump starting systems consists of an "Emergency Generator Engine Trouble" alarm and a "Diesel Fire Pump Trouble" alarm, respectively. SEP Topic VIII-3.B as discussed in the BRP Integrated Plant Safety Assessment (Reference 12) concluded that since the batteries for the diesel generators and diesel fire pump are load tested during the monthly diesel starts; therefore, additional instrumentation is not recommended.

Figure 8-1

Station Battery Service Test Load Profile



	Drain Current	Duration
[1]	= 490 A	1 minute (beginning at t = 0)
[2]	= 150 A	59 minutes (beginning at t = 1 minute)
[3]	= 50 A	60 minutes (beginning at t = 60 minutes)
[4]	= 150 A	1 minute (beginning at t = 120 minutes)

Chapter 8 References

1. Letter to AEC dated 6/24/68 - Semi-Annual Report

2. Letter from NRC dated 9/21/81 - SEP Topic VII-6

3. Letter from NRC dated 11/30/81 - Adequacy of Station Electrical Distribution System Voltages

4. Letter from NRC dated 7/8/82 - Adequacy of Station Electrical Distribution System Voltages and Degraded Grid Protection for Class 1E Power Systems and SEP Topic VIII-1.A

5. Letter to NRC dated 5/18/82 - BRP - Station Electrical Distribution System Voltages

6. Letter to CPCo dated 3/8/82 - Technical Specification Amendment 51

7. Big Rock Point Engineering Analyses; EA-E-BRP-86-05 and EA-SC-87-023-1, (Internal Analyses discussed in Reference 8 and the latter was submitted by CPCo letter dated October 26, 1989 - Station Battery Service Test)

8. Letter from NRC dated 2/15/89; Technical Specification Amendment 94

9. Letter from NRC dated 2/17/81; SEP Topic VIII-3.A

10. Letter from NRC dated 2/22/82; SEP Topic VIII-3.B

11. Letter to NRC dated 3/10/83; Response to SEP Topic VIII-3.B

12. NUREG-0828, May 1984; BRP Integrated Plant Safety Assessment

13. Big Rock Point Engineering Analysis; EA-FC-462J-02, (Internal Analysis)

14. BRP O.S.A. No A-BR-76-35-01 dated 2/2/77, (Internal Analysis)

15. Letter to NRC dated 2/25/80 - ECCS Equipment Timing Requirements

16. Letter from NRC dated 4/7/77

17. Letter from NRC dated 9/2/82 - SEP Topic VIII-2

18. NRC Memorandum and Order to CPCo dated 5/26/76

19. NRC letter to CPCo dated 10/17/77 - Amendment 15

20. Letter to NRC dated 8/3/82 - Response to SEP Topic VIII-2

21. Letter to NRC dated 2/14/83 - Response to SEP Topic VII-10.A

22. Letter to NRC dated 4/25/83 - Response to SEP Topic VIII-4

23. Deviation Report D-NS-82-01 dated 2/23/82

24. EA-E-BRP-86-05A, Revised Station Battery Load Profile to Demonstrate a 4 Hour Capacity During a Station Blackout, 11/19/92 /

25. EA-93-BAT1-01 Revision 1, Station Battery Loads Summary/Profile /

there will also be a group of irradiated fuel rods stored in the pool.

Fuel Pool Floor Loading (Reference Bechtel Letter February 14, 1964)

Bechtel Corporation calculations show that as much as 5,000 psf could be loaded onto the entire bottom of the pool, in addition to the water, without overstressing the steel or concrete. Because this amount of load could introduce eccentricity in the foundation, permissible loading of the entire pool floor was arbitrarily established at 1500 psf in addition to the water. Any portion of the pool floor is capable of carrying the load of a 75 ton cask occupying 42 square feet of floor area.

Fuel Pool Walls

The fuel pool walls vary in thickness from three feet six inches to six feet nine inches.

9.1.2.1 Spent Fuel Pool Design

The spent fuel pool is a concrete structure which was modified via Facility Change FC-244 in 1974 to resolve blistering problems with the original phenolic coating. The modification consisted of lining the walls and floor with 3/16 inch stainless steel plate-type 304 and adding a leak chase system to detect fuel pool leakage. In order to install the liner, one inch of lead and six inches of concrete were added to the fuel pool floor below the liner. The original four inch drain line is now used for the routing of the eight zone leak chase tubing. The drain is also covered with a section of 3/16 inch stainless steel plate and six inches of concrete grout and thus offers no means of escape for pool water. The liner plate enclosure added an inner boundary to contain the water which did not exist in the original design. Postulating a liner plate rupture still allows for water to be contained by the concrete walls and floor. This change was reported in the BRP Twentieth Semi-Annual Report August 29, 1974.

The spent fuel pool is considered essentially leaktight. No significant leakage from the spent fuel pool has been encountered since initial operation of the plant in 1962. Some moist areas were identified from time to time, but no collectible amounts of water resulted. Since installation of a stainless steel liner no liquid attributable to the spent fuel pool has been observed.

The leakage detection system consisting of stainless steel channels imbedded between the concrete pool structure and the stainless steel liner was installed along with the liner. Any leakage from the liner flows through the channels into collection lines (with normally open manual valves) terminating at an open basin. Periodic inspection is made at the collection lines by observation for any flow. Any such

TABLE 9-2

SPENT FUEL POOL COOLING SYSTEM
SINGLE ACTIVE FAILURE ANALYSIS

Component	Failure Mode	Consequence: Normal Refueling Heat Load 1.3×10^6 BTU/hr	Consequence: Full-Core Offload Heat Load 3.79×10^6 BTU/hr
Spent Fuel	Mechanical	Second Pump is operational. Complete inventory of spares available for rapid pump repairs, if needed. However, maximum pool temperature will reach 93°F.	Second pump is operational. Maximum pool water temperature will be 132°F with one heat exchanger in operation.
Offsite Power	Electrical Failure	Emergency power is not available. Pool will begin to boil in 70 hours. Makeup water is available for 2.8 gpm evaporation rate.	Emergency power is not available. Pool water will begin to boil in 20 hours. Makeup water is available for 7.8 gpm evaporation rate.
Reactor Cooling Water Pump	Mechanical Failure	Same as above	Same as above

Section 9.4.1, Control Room ventilation system, discusses the area ventilation. An additional evaluation was completed in response to NUREG-0737, Issue III D.3.4, ventilation aspects of "Control Room Habitability." The conclusions from that evaluation are provided in Chapter 6, Section 6.4 of this Updated FHSR.

9.4.1 CONTROL ROOM AREA VENTILATION SYSTEM

The control room area ventilation system provides a controlled environment for the control room and the control room panels. The system utilizes a mixture of fresh air and recirculated air which is filtered after mixing in the mix plenum. The air will then be heated from the heat coil supplied from the steam boiler heating system or cooled from the cooling coil supplied from the service water pumps feeding from the lake or from the well water system. The air is then humidified and delivered into the control room with a blower fan. Reference Drawing 0740G40124 for schematic of control room area ventilation system.

The control room ventilation system will not function following loss of offsite power as it does not have emergency power available. Room temperature increases due to high ambient temperatures and operating equipment was shown not to cause failure of equipment. This was demonstrated by a Special Site Test (SST-37) to address the Station Blackout Rule concerns. This area was not considered hostile in our submittals on Environmental Qualification dated 10/31/80 and 1/30/81. As a nonhostile environment, the area would experience an insignificant rise in temperature due to operating equipment heat loss.

Typically, Big Rock Point equipment is designed to operate in ambient temperatures up to 104°F. Exterior daytime temperatures at the Plant normally range from 75°F to 90°F during the months of July and August. Therefore, these temperatures would not affect the operation of equipment following a failure of the ventilation system.

NRC SER Conclusions

The function of the Control Room Area Ventilation System is to provide a controlled environment for the comfort and safety of control room personnel and to assure the operability of control room components during normal operating, anticipated operational transient and design basis accident conditions.

NOTE - CPCo Clarification

As discussed in Section 9.4, additional evaluations are provided in response to NUREG-0737 in Chapter 6 of this Updated FHSR for Control Room Habitability.

A fan will deliver air into several areas including the tool crib, shop, storeroom, condenser area, pipe tunnels and the decontamination washdown areas. An additional outside air intake supplies airflow to the pipe tunnel and the area under the turbine. Equipment in this area is not required to operate in a post-accident condition.

The equipment room area ventilation system provides cooling to the heating and ventilating equipment room and the air compressors and electric equipment room. The system recirculates air within the room through a cooling unit and supplies ventilation to the lube oil storage room and the turbine lube oil tank.

The equipment room contains equipment that will be required to operate post accident. Ventilation will not remove contaminates, therefore, the area will be evacuated in a post-accident situation.

With loss of offsite power, the ventilation system and the station power transformers, which are the primary source of heat, will not operate. Ventilation and temperature control for the equipment room under the above condition may be adequately maintained by opening any one of three doors in this area to the outside environment.

Minimum temperatures in the station power room during a loss of ventilation event were considered in Special Site Test SST-37. Room temperature data was collected from a breaker change out procedure that took place during a loss of ac power. SST-37 concluded that the temperature in the station power room does not fall below 60°F during a loss of ventilation during the winter months, therefore station battery operability is not compromised. /

The turbine and service building ventilation systems are forced-draft induced systems with draft induction, the result of two exhaust fans which also push the exhaust air through the exhaust ventilation stack. The turbine building and service building will not require post-accident ventilation for either heat or contamination removal. Reference Drawing 0740G40124 for schematic representation of turbine and service building ventilation system.

NRC SER Conclusions

- Based on the results of the contractors evaluation, we have determined the condensate pump room ventilation subsystem to be non-essential...(as defined in Regulatory Guide 1.105 and thus, is not a system important to safety).

- The shop area ventilation subsystem provides tempered outside and recirculated air to the various shop areas. It also provides ventilation for the four reactor depressurization system battery cubicles that have been added to the shop area in recent years. During normal operation the shop area ventilation system provides a means of removing the hydrogen produced by the batteries, because this system is not powered from emergency source, the licensee should provide assurance that adequate ventilation is provided by other means during a loss of offsite power event during which the shop ventilation system will not function.

The electrical equipment room ventilation subsystem services essential equipment which includes the main plant batteries, two motor-generator sets, air compressors for instrument air, 480V switchgear, and cable spreading. The ventilation system is mainly a service-water-cooled, recirculating room cooler which is neither redundant or powered by the emergency diesel.

Because of the importance of the equipment located in this room, the licensee should either demonstrate that ventilation of this equipment is not required or provide procedures to ventilate (eg, open doors).

<u>NRC Resolution</u> (Reference NUREG-0828 Section 4.26.1)

The depressurization system batteries are ventilated by the shop area system. The plant battery is ventilated by the electric equipment room ventilation system. All of the battery chargers are sequenced onto the diesel generator, but neither ventilation system is. Hydrogen generation occurs as a result of battery charging. The staff is concerned that a hydrogen fire may result from a lack of adequate ventilation. The licensee has calculated that it will take more than 3 hours to reach the 4% hydrogen concentration flammability point. The licensee proposed in a letter dated March 31, 1983, to change operating procedures to open the roll-up door and a door to the electric equipment room if the normal ventilation systems cannot be restarted after a loss of offsite power.

The limited PRA for these two systems ranked the loss of ventilation to be of high risk significance. This result was based on the assumption that the contained equipment required immediate cooling to function. Such an assumption is overly conservative because the thermal capacity of the shop walls will probably provide adequate cooling and major electrical equipment room heat sources, such as the motor-generator sets, trip on loss of offsite power.

It is the staff's judgment, based on the small heat loads and the large volume of the spaces, the air circulation resulting from the opening of doors to mitigate the hydrogen buildup will provide sufficient cooling for these areas. The licensee has completed an analysis of the hydrogen buildup from the RDS batteries. As a result of this analysis the staff has concluded that sufficient time is available to open the doors in the machine shop and RDS equipment area. The licensee by a letter dated August 31, 1983, submitted a similar study of the plant battery and the electric equipment room. The results show that opening the doors to this room is sufficient to limit hydrogen concentration. The staff considers this issue resolved.

9.4.5 ENGINEERED SAFETY FEATURE VENTILATION SYSTEM

Three areas to be considered under the engineered safety feature ventilation system are the emergency diesel generator room, the screenhouse and the core spray pump room.

The emergency diesel generator room, located in the screenhouse, has a passive ventilation system. The passive ventilation system consists of ventilation louvers which allow outside air to enter the emergency diesel generator room. Exhaust from the diesel engine is through the roof of the building. This area is not adjacent to either the containment or turbine buildings and is not exposed to radioactive contaminates during normal or post-accident conditions; therefore, ventilation for the purpose of reduction of contamination is not necessary. Heat rise from the diesel generator will not impair its operation however, access doors could be opened to ventilate the room.

The screenhouse contains the fire safety system (diesel and electric fire pumps). The ventilation system consists of ventilation louvers on the outside walls with circulation fans inside the screenhouse. The screenhouse is a separate building located away from the containment and turbine buildings and is not exposed to radioactive contaminates during normal or post-accident conditions of the Plant; therefore, ventilation for the purpose of reduction of contamination is not necessary. Since the heat load from the fire pumps (only major equipment running under post-accident condition with loss of off-site power) is relatively low, and since there are numerous heat sinks in the room, operability should not be impaired by a loss of ventilation. Again, however, doors can be opened to allow passive ventilation of the room.

The core spray pump room houses the core spray pump and a heat exchanger with supplies emergency cooling water to the reactor vessel and the containment building. This area is not ventilated. The heat rise in the core spray pump room area following an accident due to recirculation of the containment sump water is not expected to raise the room temperature greater than 152°F (reference CPCo submittal to NRC dated 10/31/80 and 1/30/81). This heat load is not detrimental to the operation of the core spray pump. This room is not exposed to radioactive contaminates during normal or accident plant operation; therefore, ventilation for the purpose of reduction of contamination is not necessary. The room also is not habitated during operation of the equipment.

<u>NRC SER Conclusions</u>

- Screenhouse Ventilation

  The diesel and electric fire pumps, which are located in the screenhouse, are major elements of both the post-incident cooling and fire protection water system. This ventilation system consists of ventilation louvers on the outside walls with circulation fans inside the screenhouse. These fans are not powered by emergency sources, therefore, their operation is not assured following an event. However, based on the building volume to heat load ratio and the non-leak tight nature of this building, the staff has determined that an active ventilation system is not required.

° Core Spray System Ventilations

The core spray pump room houses the core spray pump and a heat exchanger which supplies emergency cooling water to the reactor vessel and the containment building. This area is not ventilated. The heat rise in the core spray pump room area following an accident due to recirculation of the containment sump water is not expected to raise the room temperature greater than 152°F (reference CPCo submittals to NRC dated 10/31/80 and 1/30/81). This heat load is not detrimental to the operation of the core spray pump.

° Reactor Depressurization System Instrumentation

Instrumentation for the reactor depressurization system was observed during a plant visit to be located in the computer room. Cooling for the room is provided by service-water-cooled air conditioning equipment in an alcove opening off the room. Power to the air conditioning equipment is not supplied by diesel generator essential buses, and the equipment will not function upon loss of offsite power. Recognizing that this reactor depressurization instrumentation will not be needed over a long term and that any temperature increase in the room would take place over a longer period of time, the acceptance criteria for this review are satisfied. (CPCo Clarification - An air conditioner has been added via Facility Change FC-651 to cool other non-essential equipment.)

° Emergency Power System

The main emergency diesel generator room, located adjacent to the screenhouse, has a passive ventilation system. The passive ventilation system consists of ventilation louvers which allow outside air to enter the emergency diesel generator room. Exhaust from the diesel engine is through the roof of the building.

While the diesel engine is cooled by service water, the radiant heat from the engine will produce a temperature rise in the diesel generator room. The licensee should either demonstrate that ventilation of the electrical equipment panel in the room is not required or provide procedures to ventilate (eg, open doors), the engine for periods of sustained (as compared to periodic test) operation.

<u>CPCo Clarification</u> (Reference CPCo August 31, 1983 letter)

Facility Change FC-544 installed a thermostatically controlled ventilation system (exhaust fan and supply air damper) to assure adequate ventilation is provided in the Diesel Generator Room. Further, additional insulation was installed on the diesel generator muffler.

The installed thermostatically controlled fan and supply air damper were replaced under Specification Change SC-93-002 in response to Notice of Deviation - Inspection Report No. 92019 (EDSFI, RFI Number CG-34 and Concern CGC-4). The fan and supply air damper replaced were of greater capacity.

NRC Resolution (Reference NUREG-0828 Section 4.26.2)

The diesel generator room has a passive ventilation system. After a 24-hour diesel generator run, the licensee noted that the tar roof had started to melt. An automatic exhaust fan and new air intake louvers were installed. The new system is temperature controlled and powered from the diesel generator. The licensee has also insulated the muffler. The licensee currently has no plans to move the muffler. However, if the licensee decides to move it to the roof, the staff will require that the licensee evaluate the consequences of muffler damage resulting from strong winds or missiles on engine operability.

Aside from the muffler concern, the staff believes that the licensee's approach of demonstrating the adequacy of proposed ventilation modifications by preoperational testing ensures adequate cooling for the electrical equipment in the diesel enclosure.

- Backup Diesel Generator Ventilation

  A backup diesel generator is mounted in a trailer van located at the site of domestic water well. When needed, this backup diesel is connected manually to the emergency electrical power bus. Ventilation of the diesel is provided by opening large doors to expose the diesel engine and generator to the atmosphere on two sides and rear end of the trailer. This means of ventilation for the backup diesel satisfies all acceptance criteria for this technical review.

9.4.6 CONTAINMENT SPHERE VENTILATION

The following information was provided in proposed Technical Specification Change 32 submitted June 30, 1972 in response to a March 28, 1972 NRC request. The design information was provided in support of leak detection limits for primary coolant recirculation system.

Ventilation air to the reactor building is supplied at design rates varying from 0 cfm to 14,500 cfm and is so controlled as to maintain a slight (-0.5" H_2O) negative pressure within the containment sphere. Normal flow rate during operation is approximately 11,000 cfm to 12,000 cfm.

The ventilation system is a forced-induced system, the stack exhaust fans acting as the induced fans to draw containment sphere exhaust air through the 24" exhaust duct. Two full-capacity ventilation supply air fans are provided as forced draft fans and discharge ventilation air directly into the general areas of the containment sphere.

A ventilation building, or air shed, attached to the containment sphere in a line between the containment sphere and stack, contains the outdoor air louvers, filters, and air heating coils for tempering incoming air. Each supply air fan suction has an open-shut damper positioner with initiation integral to the fan-starting circuit, and inlet vanes controlled by the differential pressure existing between the inside and outside of the containment sphere. Ventilation airflow through the reactor building rooms and passages is equal to the induced draft exhaust flow to the building exhaust plenum created by the plant exhaust fans in the stack.

The pipeway and steam drum area, ion tubes and reactor annulus are provided with two 1/2 capacity cooling units in parallel located at elevation 616'. Each unit is equipped with isolation dampers, water type cooling coils, filters and automatic controls. A variable amount of air, approximately 4,000 cfm to 6,000 cfm, is continuously bled from this area and exhausted to the plant stack. An equal amount of air is introduced into the area by infiltration through minor openings and a makeup damper which is automatically controlled to maintain a slight negative pressure in the pipeway.

The cooling units utilize plant service water as the cooling medium and each unit is capable of removing 740,000 Btu/h with a discharge rate of 13,700 cfm air. Entering air at 120°F DB is cooled and discharged at 70°F DB and cooling water entering at 55°F achieves a 21°F temperature rise during its pass through the cooling coils. Each cooling fan is driven by a 10-hp motor. Design temperatures for the pipeway and steam drum compartment are 120°F maximum (summer) and 50°F minimum (winter). Inlet cooling water flow to the cooling units is manually controlled and the discharge flow control is automatic, with the sensing device located in the inlet air duct.

Ventilation air to the reactor room, control rod drive room and steam drum cavity is supplied through the containment sphere pipeway and steam drum area cooling units. A total of approximately 30,000 cfm cooling air is discharged into this area with 2,000 cfm to the reactor annulus on a level with the bottom of the extension tank, 1,000 cfm below the reactor (control rod drive room), and 1,000 cfm into the ion tubes which discharge back into the reactor annulus. The remainder of this air (~26,000 cfm) is discharged into the pipeway and steam drum area at four elevations (595', 616', 635' and 650') through ductwork (with remotely operated dampers) along the south wall of the pipeway and steam drum enclosure, (the dampers at elevations 616' and 635' have been closed since original plant startup). This air is recirculated through the pipeway and steam drum cooling units by exhausting through a return duct located above the steam drum. Exhaust air from the pipeway, steam drum area and associated areas within the scope of the cooling units is removed from the lower elevations of the pipeway to provide greater cooling for the reactor recirculating pumps. Exhaust flow to the containment sphere exhaust plenum occurs at a rate of 4,000 cfm to 6,000 cfm.

Makeup air at a rate equal to the air exhausted (4,000 cfm to 6,000 cfm) is constantly being introduced into this system by infiltration through minor openings and through a makeup damper which is controlled by a differential pressure-controller set to maintain a slightly more negative pressure in the pipeway and steam drum area than in the containment sphere itself. This exhaust air is representative of all primary system enclosures (reactor vessel compartment, recirculation pump room, control rod drive room and steam drum cavity) with the exception of the clean-up demineralizer and regenerative and non-regenerative heat exchanger rooms which utilize free flow ventilation of 200 cfm directly to the containment sphere exhaust plenum.

The containment sphere heating and cooling system utilizes a closed loop, recirculated water, heating and cooling agent to the various area heating and cooling units. There is no humidity control in the containment sphere to provide for the addition or removal of moisture.

For heating and cooling the general area of the containment sphere (area outside the concrete structure), four floor-mounted air-conditioning units are provided (two at elevation 599' and two at elevation 616'). A fifth unit mounted adjacent to the reactor head shield plug is provided for spot cooling this area during the refueling operation. Each of the units is equipped with filters, combination heating or cooling coils and automatic temperature controls. Intake air for each unit comes from the surrounding areas.

Two 100% capacity heat exchangers are provided to furnish either heating water at 180°F maximum or cooling water at 65°F minimum to the units. The heat exchangers are identical in size and construction and are connected to permit either heat exchanger to be used for heating or cooling the closed loop supply. Both are equipped with relief valves which drain to the reactor dirty sump. The primary heating medium is 15 psig steam which is supplied from the plant heating boiler. The primary cooling medium is service water which is supplied from the plant service water system. Both of these mediums are connected to the tube side of the heat exchangers, with the secondary or closed loop water system connected to the shell side of the heat exchangers. Two 100% capacity recirculating pumps are provided with this system.

Water supply to the closed loop system is maintained by an expansion tank mounted at elevation 660'-6". Makeup water for this system comes from the demineralized water system through a float control valve.

If both fire pumps (electric and diesel) or the piping systems are inoperable:

1. Initiate procedures to provide a backup Fire Suppression Water System within 24 hours by notifying the Charlevoix Fire Department to standby, and

2. Restore the inoperable fire pump or piping system to operable status within 14 days or, in lieu of any other report required by Technical Specification 6.9.2, prepare and submit a Special Report to the Commission pursuant to Technical Specification 6.9.3 within the next 30 days outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the pump or piping system to operable status.

b. If, during power operation condition or refueling condition both fire pumps (electric and diesel) and the piping system to the core spray system tie-ins are inoperable:

A normal orderly shutdown shall be initiated within 24 hours and the reactor shall be shut down as described in Technical Specification 1.2.5(a) within twelve (12) hours and shut down as described in Technical Specification 1.2.5(a) and (b) within the following 24 hours.

<u>Fire Suppression Water System Surveillance Requirements</u>

The fire suppression water system will be demonstrated to be operable:

a. Once per 7 days verifying the Intake Bay water level is above 570' elevation.

b. At least once per 92 days by verifying that a sample of diesel fuel from the fuel storage tank, obtained in accordance with ASTM-D270-65, is within the acceptable limits specified in Table 1 of ASTM-D975-74 with respect to viscosity, water content and sediment, (reference Section 9.5.4.4 of this Updated FHSR).

c. Once per 18 months:

1. By a system flush and by verifying that each valve in the flow path that is not locked, sealed or otherwise secured in position, is in its correct position.

2. Subjecting the diesel driver to an inspection in accordance with procedures prepared in connection with its manufacturer's recommendations for the class of service.

d. Once per 3 years by performing flow tests to meet or exceed the requirements of Section 11, Chapter 5 of the Fire Protection Handbook, 14th Edition published by National Fire Protection Association.

Fire Suppression System Bases

The operability of the fire suppression systems ensures that adequate fire suppression capability is available to confine and extinguish fires occurring in any portion of the facility where safety related equipment is located. The fire suppression system consists of the water system, spray and/or sprinklers, and fire hose stations. The collective capability of the fire suppression system is adequate to minimize potential damage to safety related equipment and is a major element in the facility fire protection program.

In the event that portions of the fire suppression system are inoperable, alternate backup fire fighting equipment is required to be made available in the affected areas until the inoperable equipment is restored to service.

In the event the fire suppression water system becomes inoperable, immediate corrective measures must be taken since this system provides the major fire suppression capability of the plant. The requirement for a twenty-four hour report to the Commission provides for prompt adequate fire suppression capability for the continued protection of the nuclear plant.

In the case of the core spray system, water flow from the fire suppression suppression system for fire suppression or for normal uses and testing for which the time and flow are restricted has a negligible effect on availability and is not a cause for declaring the system inoperable.

9.5.1.2.2 Fire Pumps

Both the electric and diesel vertical centrifugal fire pumps have a rated capacity of 1000 gpm at 110 psig (254 foot head). Appendix A, Item E.2(e) of Branch Technical Position APESB 9.5-1 "Fire Protection Water Supply Systems", requires that the flow rate of the fire system be calculated on the basis of the longest expected flow rate for a period of two hours, but not less than 300,000 gallons (2500 gpm). Since the largest open head deluge system (Switchyard) requires ~ 1160 gpm at 52 psig combined with 1000 gpm for manual hose streams totals approximately 2160 gpm, the 2500 gpm evaluation criteria is assumed.

Each of the two fire water pumps is capable of delivering approximately 1350 gpm at 72 psig. Therefore a combined pump flow rate of approximately 2700 gpm at 72 psig, available from Lake Michigan is considered adequate to meet this criteria.

The pumps are separated by about 15 feet at their suction lines in the screenhouse water bay and are separated by a sheet metal radiant energy shield.

An electric jockey pump and an accumulator are provided to maintain pressure on the fire water system. The fire pumps are arranged to start automatically when the fire loop pressure drops due to a large water demand.

The diesel fire pump driver was replaced via Facility Change FC-607 when parts could no longer be obtained for the original. This change was reported by CPCo letter dated January 9, 1987.

Fire Pumps Single Active Failure Analysis

There are two redundant fire pumps, one electric driven pump and one diesel driven pump. A single failure in either pump, driver, power supply, discharge check or isolation valve will not affect the redundant pump. A failure of a discharge check valve in the open position will bypass flow from the other pump and may require manual closure of the associated isolation valve.

Certain fire operability, surveillance, and bases requirements for operation are addressed under the Fire Suppression System in 9.5.1.2.1 above.

IE Bulletin 79-15: Deep Draft Pump Deficiencies

In letter dated October 17, 1990, the NRC provided a safety evaluation which concluded that safety concerns regarding the two Worthington fire pumps installed at Big Rock Point were resolved. A review of test data collected from the past fire (5) years showed no signs of performance degradation in either pump thus providing the basis that the Bulletin 79-15 deficiencies did not adversely impact these pumps.

Diesel Fire Pump Surveillance Requirements

The fire pump diesel starting 24-volt battery bank and charger shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that:

   1. The electrolyte level of each battery is above the plates, and

   2. The overall battery voltage is $\geq$ 24 volts.

b. At least once per 92 days by verifying that the specific gravity is appropriate for continued service of the battery.

c. At least once per 18 months by verifying that:

   1. The batteries and battery racks show no visual indication of physical damage or abnormal deterioration, and

overcurrent, utilizing two independent sensors and coincident logic, while maintaining the engine overspeed trip as is.

Conversations with the emergency diesel generator manufacturer indicate that diesel generator destruction, under loss of oil pressure, would occur rapidly; therefore, the necessity to retain this trip is mandatory. Presently, there are two oil pressure sensing units in use in the diesel control circuitry, the original unit and a redundant scheme added in 1971. By use of auxiliary and spare contacts a coincident logic scheme will be provided for both of the low oil trip circuitries, and each circuit will utilize two independent sensors, (these changes were accomplished via FC-401).

Because of past problems associated with high emergency diesel generator cooling water temperatures (Reference CPCo letters April 15, 1976 and June 9, 1976), it is prudent to retain this trip function. In order to meet the Branch Technical Position an additional temperature switch will be installed in the diesel cooling water jacket. This switch will be connected in series with the existing temperature switch making it necessary for both elements to sense a high temperature condition prior to diesel generator trip. This scheme meets the dual sensor coincident and logic criteria, (an additional temperature switch was added via FC-401).

The final trip that will be maintained is the overcurrent trip. The emergency power system at Big Rock Point is an underground three-phase system. Original design allowed a single overcurrent relay (single-phase fault) to trip the emergency diesel generator. This was modified (via Facility Change FC-401) to require a two-phase fault (phase-to-phase short) for a trip to occur. This would eliminate any trip caused by a single signal, such as a relay failure or single phase-to-ground short, but still prevent major damage should a dual phase fault occur. A time delay relay (installed via Facility Change FC-670) is in series with the overcurrent trip network allowing a bus fault to clear, while maintaining the generator on-line.

Concerning the diesel driven fire pump, the only parameter that could cause a unit trip is engine overspeed which was not utilized on the original fire pump diesel driver and consequently was not connected on the new diesel fire pump driver installed via Facility Change FC-607, (reference Section 9.5.1.2.2 above).

The NRC evaluation and review of the protective trips was documented in Technical Specification Amendment 15 dated October 17, 1977 which concluded:

> Based on our review, the modification to the emergency diesel generator are acceptable because they: (1) satisfy the criteria of BTP EICSB 17, (2) significantly enhance the reliability of the onsite power system, and (3) comply with Section (3)(iii) of the Memorandum and Order, dated May 26, 1976.

The emergency diesel generator alarms on overload current in the control room from a different sensor than the overcurrent trip logic above on an annunciator labeled "Emergency Generator Overload."

The EDG does not utilize manual shutdown lockout relays in its control scheme, thus, no alarm for this condition is needed.

9.5.7 EMERGENCY DIESEL GENERATOR COOLING WATER

The EDG cooling water system is shown on Drawing 0740G40123. The cooling water is from the circulating water discharge bay by a self-priming engine driven centrifugal cooling water pump.

Priming water is being supplied continuously to the cooling water pump via the service water system. A backup supply of priming water also exists from the fire water and domestic water systems, thus assuring an adequate supply of priming water. The pump discharges cool water through the diesel engine lube oil cooler and excess priming water is discharged via this same route. Details on the system are contained in a letter to NRC dated May 18, 1973.

On May 8, 1978 the cooling water pump packing and lantern ring were replaced with a mechanical seal, thus eliminating the need for sealing water (Reference SFC-78-006). Cooling water to the mechanical seal is provided via the shaft sealing water line.

The water pump suction inlet is cleaned periodically as a preventative maintenance item.

The cooling water suction line contains an electric heating element, used when freezing weather is a possibility, which is checked for circuit reliability periodically.

obtained from a 60 cell Alternate Shutdown System battery located in the ASB.

The cabling for the entire system is routed in conduits which are run separately from the normal circuits and do not pass through any common fire areas. The instrumentation is independent of the Control Room, Cable Spreading Room, Electrical Equipment Room, Exterior Cable Penetration Area and Turbine Generator Building. The 125V DC control power for the EDG is supplied through a circuit breaker which is considered to be an isolation device.

The capability to monitor the following parameters has been provided in the ASB:

- Steam Drum Level, LI-6819 /
- Steam Drum Pressure, PI-6819 /

Indicating lights are used to monitor the Emergency Condenser Level and the fire water makeup to the Emergency Condenser.

10.2.3.2 Turbine Bypass Valve Testing

The turbine bypass valve control system circuitry is tested periodically during normal plant operation. The test will not result in any disturbance in the reactor system. During refueling shutdown, a turbine bypass valve system functional test is performed to test features and associated components.

10.2.3.3 Pressure Regulator Set-Point Changing

Fast changes in the initial pressure regulator set point may cause a pressure and resultant flux transient within the reactor. With a sufficiently rapid change in set point, a flux transient would result, which could be large enough to scram the reactor at 125% of rated power. The rate of change will be limited by operating procedures to a value that will not cause such a flux transient.

Increasing the set point of the initial pressure regulator causes the turbine admission valve to close momentarily; this results in increasing the pressure of the system, and the turbine admission valve then reopens to stabilize the pressure at the new set point.

10.2.3.4 Turbine Bypass Isolation Valve

A direct current motor-operated isolation valve was installed in the bypass line between the main steam line and ahead of the turbine bypass valve. Installation was completed in March of 1968. The turbine bypass isolation valve provides the ability to terminate blowdown caused by inadvertent bypass valve opening and failure to reclose. This valve is one of several valves which provides backup isolation for the Main Steam Isolation Valve (MSIV). Vacuum interlocks as part of the valve control system close the valve on loss of condenser vacuum. Valve closure is also automatic on complete loss of Reactor Protection System Motor Generator Power and on Reactor Protection System Containment Isolation from High Containment Pressure or Low Reactor Water Level. The isolation valve installation and low vacuum closure features were reported in the Eighth Semi-Annual Report dated June 24, 1968.

The single MSIV performs the qualified Containment Isolation System (CIS) function (FHSR Section 6.2.2.3.5) and is ultimately relied upon as the qualified isolation value for terminating blowdown on main steam piping rupture (FHSR Section 10.3.4, 15.1.1, 15.1.3, and the reference section for FHSR 15.6.3). Therefore, the Turbine Bypass Isolation Valve serves as a nonqualified backup for these functions.

10.2.3.5 Turbine Bypass Valve Electrohydraulic System

As part of the Integrated Plant Safety Assessment Report (IPSAR) NUREG 0828, Final Report dated May 1984, Section 5.3.3.1, a study of the reliability of the Turbine Bypass Valve Control System electrohydraulic control (EHC) system was proposed. Based upon this study, the servo-amplifier gain for the control system was reduced to provide a slightly overdamped valve signal to eliminate oscillation in valve control. Following valve testing, it was

11.1 SOURCE TERMS

Radioactive material from the operation of the plant arises from two sources. First, the products of nuclear fission are generally radioactive. Some may escape from the fuel from time to time. A small number of fission reactions also occur outside of the fuel from uranium as an impurity existing on or in the components near the reactor core and the cooling water flowing through the core. Second, a small fraction of the neutrons available from the fissioning process are captured by various materials near the reactor core including impurities in the circulating primary coolant. Many of these products of neutron capture become radioactive. With the exception of times of steam leakage they generally remain in the circulating coolant and hence, add to the source of liquid effluents and solid wastes. The products of fission entering the coolant are generally soluble and can be volatile allowing some to primarily add to the source of gaseous waste.

The License (Technical Specifications) for the plant includes requirements that gaseous radioactive dose rates be limited to no more than 500 mrems per year to be delivered at any point in the off-site environment. Liquid releases are to be limited so that it was unlikely that any individual would be exposed to radiation in excess of that permitted by regulations. (Exposure greater than permissible concentrations of 10 CFR 20.) /

The liquid and gaseous waste systems installed at the plant provide flexibility and processing capability to meet this criterion. The operational history of the plant, particularly during the period of significant fuel failures, has validated the design in that effluent limitations based upon the limiting dose criterion were never approached.

On June 4, 1976 Consumers Power Company submitted the necessary information to permit the USNRC to evaluate the effectiveness of the radioactive waste treatment systems at the plant in accordance with the then, newly established Appendix I to 10 CFR 50. This submittal was supplemented by submittals of December 3, 1979, August 28, 1980, June 7, 1982 and September 29, 1982. On May 15, 1981 the NRC published their evaluation and concluded that the installed systems are capable of maintaining releases within the design objectives of Appendix I. The requirements of Appendix I much more severely limit radioactive effluents than the original limits imposed on the plant. These limits, called Design Objective Annual Quantities, are defined in the Off-Site Dose Calculation Manual and establish the long term upper limit for radioactive materials concentrations in effluent streams.

Maximum permissible radionuclide concentrations in the primary coolant system have not been specifically calculated, which, when applied to the available liquid and gaseous waste processing would result in releases to the environment approaching Appendix I to

11.4 SOLID WASTE MANAGEMENT SYSTEM

Solid radioactive wastes (other than spent nuclear fuel) are composed of ion exchange resins, equipment that is in contact with the primary coolant, radioactive waste systems or neutron field from the reactor core, filters that filter radioactive gaseous or liquid streams and worn out protective clothing, plastic sheeting, tape, absorbant paper and the like which are used in working on, storing or isolating radioactive equipment. Storage of these solids is accomplished in three separate areas of the plant.

11.4.1 DESIGN BASES

The solid waste management system is designed to accept radioactive solids and store them safely in sufficient volume to accommodate several shipments. Shielding is provided to minimize radiation exposure to workers while handling and shipping the wastes. System design capacity allows the accumulation of several years of wastes so that decay of the shorter lived material can occur prior to shipments, and to permit continued plant operation in the event shipment and disposal is temporarily not possible.

Since December 1990, Michigan has been denied access to three operating burial grounds. Michigan has also been excluded from the Midwest Compact. It is possible that Big Rock Point will have to store solid radioactive waste until the expiration of the operating license and beyond. The operating philosophy is to stabilize the waste as much as possible and package in accordance with current requirements to allow shipment to a burial site as possible should access be regained. /

11.4.2 SYSTEM DESCRIPTION

The solid waste management system consists of a water filled pool that accepts relatively highly radioactive components from the reactor such as fuel channels, control rod blades and other vessel internals; a 10,000 gallon tank located in an underground vault containing the liquid waste management system that accepts spent resins from the reactor clean-up, condensate and liquid radioactive waste system demineralizers; and a separate building used for storing lower level solid wastes. /

The spent fuel pool is utilized to temporarily store, underwater, highly radioactive solid reactor components. Components are transferred to the pool from the reactor by use of a shielded fuel transfer cask. When sufficient volume accumulates to accommodate at least one shipment, a transport cask is lowered into the pool, filled with waste, removed from the pool, decontaminated and loaded onto the shipping vehicle.

Resins, when exhausted, are sluiced to the 10,000 gallon tank, and, when close to full, shipments are made by pumping the resins from their underground location to casks on waiting shipping vehicles or into concrete liner storage modules. /

The Radwaste Building located within a security fenced area of the plant (reference Chapter 2, Figure 2.3), has a shipping bay, crane, shielded areas for higher level wastes and sufficient storage capacity for several years accumulation of plant produced radioactive wastes. Compactible and incinerable wastes are normally accumulated in plastic bags, transported to and stored in the radwaste building prior to shipment to an offsite processor for incineration or supercompaction. /

Other non compactible solids are simply boxed and stored until sufficient volume accumulates to efficiently ship them to off-site disposal locations or processing facility for decontamination or other volume reduction method. /

Filter media may also be stored in onsite shielded liner storage modules, designed specifically for the purpose of temporary storage prior to disposal. These containers have been analyzed and designed to withstand the elements without additional shelter, including seismic, winds and floods. /

11.4.3 RADIOACTIVE SHIPMENTS

Shipments of radioactive solids to off-site disposal or processing locations have consistently averaged five per year from 1985 to 1990. Since 1990 shipments of radioactive solids to off-site processing facilities have averaged three per year. Table 11-6 provides a summary of these shipments. /

TABLE 11-6
TYPICAL SOLID WASTE SHIPMENTS
Annual Average

Solid Type	Class	Volume (ft^3)	Radioactivity (Ci)
Spent Resins and Filter Cartridges	A	145	12
	C	36	160
Dry Compressible Waste	A	1890	2.8
Irradiated Components	B	9	290
	C	74	500

TYPICAL SOLID WASTE SHIPMENTS FOR PROCESSING /
Annual Average /

Dry Active Waste (Uncompacted)	A	4160	1

11.5 AREA, PROCESS AND EFFLUENT MONITORING AND SAMPLING SYSTEMS

The area, process and effluent monitoring systems installed at Big Rock Point provide indications of the presence of radiation and radioactive material in areas, ventilation and liquid streams. Monitors are provided to measure radiation fields and the presence of radioactive materials for normal operations and under accident conditions.

11.5.1 DESIGN BASES

The area monitoring system detects, indicates and records gamma radiation in selected areas throughout the plant primarily for personnel protection. Two monitors, the new and spent fuel storage monitors, (reference Section 15.7.1 of this Updated FHSR) provide a safety actuation function closing the containment building ventilation valves (reference Section 6.2.4 of this Updated FHSR), when either of their setpoints are exceeded. Their setpoints are established between 5 and 20 mrem/hr in accordance with 10 CFR 70.24. CPCo letter / dated October 2, 1973 requested an exemption from the requirements of 10 CFR 70.24 which permits temporarily raising the alarm set points on these monitors above the 20 mrem/hr allowed. The exemption was / granted by the Atomic Energy Commission (AEC) by letter dated February 26, 1974. The settings and alarm trip points along with the setpoint exemption criteria are reflected in the Technical Specifications. Operability requirements during refueling are addressed in the Technical Specifications and in Section 9.1.4.3 of this Updated FHSR. The area monitoring system includes a 20 point recorder and a common alarm indication in the control room when a predetermined radiation level is exceeded. Four selected monitors also have local alarms and indicating lights. Each monitor is capable of responding to gamma radiation levels over three orders of magnitude. The operable three decade range for each monitor is chosen to correspond to expected operational occurrences. An additional "accident monitor" is included which is capable of measuring radiation levels in the containment building during accidents including those which severely damage the reactor core and release large amounts of radioactive material to the containment. Its range covers seven orders of magnitude. Table 11-7 identifies each monitor, location, range, and function. The process monitoring system detects, indicates and records levels of radioactive materials in plant liquid and gaseous effluent streams and other selected liquid streams. The system is designed to be able to detect radioactive materials in effluents below the limits of Technical / Specifications. For those monitors in non-effluent streams detection / capability is provided to warn plant operators of changes in radiation levels. The system includes a common alarm indication in the control room when a predetermined level is exceeded. Each monitor is capable of responding to concentrations of radioactive material over seven orders of magnitude. The operable range for each monitor is chosen to correspond to the expected level of radioactive material in each stream. An additional "accident monitor" is included which is capable of measuring radioactive materials releases from the plant's ventilation stack during /

severe accident conditions. Its range covers twelve orders of magnitude. Table 11-8 identifies each monitor, location, range and function. /

The design and construction of the area and process monitoring systems is consistent with the Uniform Building Code which includes a specification for a 0.025g static horizontal load. The containment and ventilation stack accident monitors are designed and constructed to the seismic classification of USNRC Regulatory Guide 1.60.

TABLE 11-7
AREA MONITORING SYSTEM

Detector Element	Detector Location (Aux Function)	Range mrem/hr	Local Indicator, Alarm and Alarm Light	Containment Vent Valve Closure When Setpoint Exceeded
RE-8261	Personnel Lock	0.1-100	No	
RE-8259	Spent Fuel Storage Pool (Criticality Monitor)	1-1000	Yes	Yes
RE-8253	Condenser - Access Area	0.1-100	No	
RE-8268	Office Corridor	0.01-10	No	
RE-8264	Air Compressor Room	0.01-10	No	
RE-8258	New Fuel Storage Area (Criticality Monitor)	1-1000	Yes	Yes
RE-8254	Condensate Demineralizer Entrance	0.1-100	No	
RE-8269	Shop Area	0.1-100	No	
RE-8252	Control Room	0.01-10	No	
RE-8260	Sphere Laydown Area	0.1-100	No	
RE-8266	NW Wall Sphere Elevation 573'	0.1-100	No	
RE-8257	Condenser	1-1000	Yes	
RE-8256	Laundry Room	0.01-10	No	
RE-8276	Exhaust Plenum Elevation 592'	0.1-100	No	
RE-8262	Locker Room	0.01-10	No	
RE-8255	Turbine Shield Wall	1-1000	No	
RE-8263	Rad Waste Area Behind Panel	1-1000	Yes	
RE-8265	Access Control Entrance	0.01-10	No	
RE-8277	Emergency Condenser Vent - East (Effluent via Condenser Vent)	0.1-100	No	
RE-8270	Emergency Condenser Vent - West (Effluent via Condenser Vent)	0.1-100	No	
RE-8280	Exterior Containment Penetration Rm	$1\text{-}10^7$ rem/hr	No	
RE-8281	Exterior Containment Penetration Rm (These last two are Containment High Range Accident Monitors)	$1\text{-}10^7$ rem/hr		

11.5.2 SYSTEM DESCRIPTION

The area radiation monitoring system is made up of equipment capable of monitoring gamma levels at 20 locations throughout the Plant. Two monitors, Numbers 20 and 21, are dedicated to emergency condenser vent monitoring and are covered later. The location of the 19 remaining monitors functioning as area monitors are listed on Table 11-7.

The monitor units are divided into 3 groups determined by their level monitoring ranges: 0.01 mrem/hr to 10 mrem/hr; 0.1 mrem/hr to 100 mrem/hr; 1 mrem/hr to 1000 mrem/hr. The detectors are then positioned within the Plant where radiation levels are expected to be within these ranges.

Drawing 0740F30762 provides an elementary diagram of the system. The detection chain is made up of; a detector unit, located in a specific area of the Plant; area radiation monitor unit, located in the control room; recorder, located in the control room. Four units are also provided with local meters, alarms and alarm lights. These four (4) units are identified on Table 11-7.

The scintillation detector uses a plastic scintillator as a gamma sensitive device. The scintillator is comprised of a terphenyl-impregnated polystyrene base.

The detector units are housed in wall mounted aluminum cases, which are water and vapor proof. The detector units are equipped with thermoelectrical coolers and forced air fan heat exchangers, along with a dc power supply to provide current for thermoelectric coolers.

There are four area radiation monitor units located in the Main Control Panel. Each unit contains amplifier channels (one for each of the five detectors connected to the unit). Each unit also contains the necessary dc power supplies and trip units.

Mounted on the front panel of each unit are indicators for each channel, indicating lights for power and fuse failures; alarm trip reset switch with corresponding alarm indicating light; trip test switch; trip adjustment and high-voltage test switch.

The amplifiers have solid-state circuitry except for the electrometer input tube. Sensitivity of the amplifiers is different for the radiation flux level range being monitored.

A trip on any detector channel results in a red indicating lamp lighting below its respective indicator. The trip circuit must be reset manually.

Trip set adjustments are located on the front panel of each monitor for each respective channel.

to trap particulates. The filter elements are replaced weekly and taken to the Chemistry Laboratory for analysis.

The normal range NaI Gamma Detector is located to monitor activity of the normal range particulate/radioiodine filter. The detector readout in the Control Room contains high and high-high radiation alarm points and an equipment failure alarm point. The high and high-high radiation setpoints are not used, as all they indicate is high filter activity, and the filter is removed and analyzed weekly no matter what the activity. The equipment failure alarm causes the green FAIL/RESET pushbutton on the readout to extinguish and activates the control room stack gas system trouble annunciator. This alarm can be triggered by loss of power, circuit failure, detector failure, or low background noise.

The normal range scintillation chamber Beta Detector has an indication range of approximately 4×10^{-6} Ci/sec to 4 Ci/sec. High radiation, high-high radiation, and equipment failure alarms are provided with the scintillation chamber Beta Detector readout located in the Control Room. The high and high-high radiation setpoints are adjustable and located internal to the readout. The high alarm is normally set at approximately 30,000 μCi/sec. This limit is based on 10 CFR 50 Appendix I criteria. The high-high alarm is normally set at approximately 3.3 Ci/sec. This limit is based on Technical Specification criteria. Trip test pushbuttons, internal to the readout, allow test of the alarm and control functions. The equipment failure alarm causes the green FAIL/RESET pushbutton on the readout to extinguish and activates the Stack Gas System Trouble Annunciator. Again, the alarm can be triggered by loss of power, circuit failure, detector failure, or low background noise.

A 150 mL Grab Sample Bottle is provided in the normal range monitoring loop. The bottle is normally isolated by an inlet solenoid valve and outlet solenoid valve. Upon a high radiation level alarm from the normal range noble gas detector isolation valves open while the normal flow valve closes to direct flow through the grab sample bottle for approximately 30 seconds. After 30 seconds, the isolation valves close to isolate the grab sample bottle for future analysis while the normal flow valve opens to reestablish normal flow path conditions. The grab sample bottle is supplied with manual shutoff valves for isolation of the sample and quick disconnects for bottle removal and replacement.

The Automatic Accident Filter is a filter change mechanism that is electric motor operated with a cam drive allowing step operation, changing one filter at a time. Actuation of filter change is made normally from the remote station in the Control Room. The filter can also be changed from the local normal skid control station or from the filter panel pushbutton. A maximum of 45 filter cartridges can be stacked on the feeder to the filter change wheel. Upon filter change, the spent filter is dropped into a lead shielded cask for count verification at a later date or ultimate disposal.

and control the sample flow rate through the Automatic Accident Filter at approximately 780 ± 80 sccm. The Transmitter provides local indication of sample flow rate and actuates a yellow alarm light at 700 sccm low flow, which actuates the stack gas system trouble annunciator in the Control Room.

The Process Liquid Monitor System, employing gamma scintillation detector channels, is provided to give indication of radioactivity trends in process liquid streams normally containing radioactive liquids. It also serves to warn the operator of radioactivity in those process liquid streams that do <u>not</u> normally contain radioactive liquids.

The process liquid streams which shall be monitored are:

a. Radioactive Waste System Effluent to Canal
b. Reactor Enclosure Cooling Water
c. Main Condensate Demineralizer Influent
d. Circulating Water Discharge
e. Service Water Return From Reactor Enclosure

Alarms on Monitors a and d are set so as to warn the control room operator via a common annunciator when concentrations are present which exceed predetermined levels corresponding to technical specification limits. The alarms for b, c and e also annunciate on this same common annunciator. The set points for b, c and e are set based on experience, and the alarms are to alert operators to unexpected changes of radioactivity levels in these process streams. The setpoint for d is normally set to detect permissible effluent concentration from 10 CFR 20. The reactor enclosure cooling water monitor is capable of detecting levels of chrome consistently experienced, while the radioactive waste system effluent to canal monitor is capable of detecting 5×10^{-5} microcuries per milliliter of Cs-137.

Radiation levels of all five (5) process liquid streams are recorded on a multipoint recorder which is located in the control room.

Monitors for the five (5) process liquid streams are of the fixed gamma type consisting of a scintillation detector mounted in a lead-lined stainless steel pig, a high-voltage power supply and a Linear Count Rate Meter (LCRM).

This detector has a scintillator (sodium-iodide thallium activated crystal), a light pipe, a photocathode and a photomultiplier tube. Each is located in a detector shield.

The shielding consists of a large tee (commonly referred to as a "pig") made of stainless steel and lined with lead. The detector is

12.1 ENSURING OCCUPATIONAL ALARA

The Big Rock Point Nuclear Plant radiation safety program is based upon the presumption that any exposure to ionizing radiation involves some risk. As a result part of the normal work process involving people in radiation controlled areas is to ensure that the Total Effective Dose Equivalent (TEDE) is kept as low as reasonably achievable (ALARA). /

12.1.1 POLICY CONSIDERATIONS

The Policy of Consumers Power Company, and that of the Big Rock Point Nuclear Plant is to present a Radiation Safety Program which controls radiation dose (external and internal) in a manner that avoids unnecessary and accidental doses, maintains doses to workers within regulatory limits and assures that doses to workers remain as low as reasonably achievable (ALARA). /

The organizational structure for conducting the radiation safety program and minimum qualifications of the individuals occupying positions within that structure are defined in the Technical Specifications of the Big Rock Point plant's operating license. Responsibilities of management and individual workers in carrying out the policy of ALARA are defined in the Radiation Safety Plan. This plan is a Corporate Level document, and provides requirements and guidance to the plant in all areas of radiation protection. In addition to responsibilities the plan contains standards relating to management policy, radiation safety training, dose control, contamination control, surveys, instrumentation and incident investigation and analysis.

Policy guidance in Regulatory Guide, 1.8 relating to personnel selection and qualification, has been incorporated into Consumers Power Company Human Resources Department policies.

The guidance of Section C.1 of Regulatory Guides 8.8 on ALARA and 8.10 on the Occupational Radiation Safety Program have been incorporated in the aforementioned radiation safety plan.

12.1.2 DESIGN CONSIDERATIONS

Design considerations for the Big Rock Point Plant to maintain the TEDE ALARA include: 1) shielding for radioactive components and systems; 2) location of equipment controls in low radiological dose areas; and 3) equipment design to allow quick maintenance in higher radiation dose areas. /

Shielding for components and equipment containing radioactive material is based upon the existence of penetrating neutron and gamma radiation produced by the reactor during operation, gamma radiation in the reactor coolant and other appropriate systems during both operation and shutdown and penetrating radiations from the fuel while stored in the spent fuel pool. In addition to neutrons and gamma radiation

In addition, access to high and very high radiation areas is governed by administrative procedures and controlled by appropriate marking. Certain high and very high radiation areas may also be locked.

Areas in which the general radiation field is expected to remain at a level higher than 1 rem/hour are provided with locked doors. Large areas established temporarily which are over 1 rem/hour may be barricaded and posted with a flashing light to warn personnel against unauthorized entry. Entry through locked doors is controlled by a set of keys which are normally in the possession of the Radiation Protection Supervisor.

Persons not qualified to monitor for the presence and amount of radiation are not permitted to enter any high or very high radiation area unless accompanied by a person qualified in Radiation Protection procedures.

Administrative Procedures require all new procedures involving work within a radiologically controlled area to have an ALARA review.

All work in radiation areas and all entries to high radiation contamination, and airborne areas requires the use of a Radiation Work Permit (RWP). The RWP specifies the radiation protection requirements for the job and incorporates ALARA philosophy and knowledge from past similar jobs. Each worker is responsible for following the requirements of the RWP and minimizing their radiation dose to the maximum extent practicable. They are also obligated to inform radiation protection personnel when a specific activity is not ALARA.

Shielding from the spent fuel is adequate to reduce the radiation dose rates at the water's surface and at the exterior walls to negligible levels. At one location on the south wall its thickness tapers to accommodate storage of the spent fuel transfer cask. Storage of spent fuel in the pool immediately adjacent to the tapered portion of the south wall is not permitted until such fuel has been out of the reactor for at least one year.

Shielding from nitrogen 16 and other nuclides contained in the turbine and its moisture separator is provided by a heavy concrete shield wall between the turbine and the normally occupied administrative areas of the plant.

12.2.2 AIRBORNE SOURCES

Airborne radioactive material during plant operation arises from leakage of reactor coolant. Inadvertent leakage is managed by elimination through repair when possible or ventilation controls, as described in Chapter 11, to minimize occupational uptake of radioactive material. Planned leakage, is always cooled to avoid dispersion into the plant's atmosphere, collected in sumps and routed to the plant's liquid radioactive waste processing system. During plant shutdown reactor head removal, fuel movement and the venting of any system containing radioactive materials may result in additional temporary airborne sources of radioactive materials. Occupational dose control through monitoring, ventilation and other processes is performed. Respiratory protection at all times of plant operation or shutdown is used only when engineering and other controls are not practical to reduce airborne concentrations to less than .3 Derived Air Concentration (DAC) and when use of respiratory protection is necessary to maintain TEDE ALARA. The plant is designed with both the reactor coolant loop as well as the condensate and feedwater trains within concrete enclosures vented to the plant stack. As a result airborne radioactive material of notable concentrations have been virtually non-existent in normally or occasionally occupied areas. During plant shutdowns including refueling outages, airborne activity is generally well below the levels specified in Appendix B of 10CFR20 within a few days of shutdown. A measure of the success of Big Rock Point's design and operating philosophy to minimize internal radiation exposure due to airborne sources of radioactive material can be seen by examining the data in <u>Table 12.2</u>.

Table 12.2
Typical Internal Exposures
From Airborne Radioactive Sources

Occupational Group	Airborne Area Entered		Exposure (MPC Hours per Refueling Cycle) (Typical of Recent Fuel Cycles)
Maintenance	Reactor Operating Floor		1.40
	Turbine Condensate & Feed-water Train Pipe Tunnel		1.70
	Control Rod Drive Room		0.01
	Reactor Clean-up Sys Heat Exchanger Room		0.02
		Total	3.13
Operator	Turbine Condensate and Feedwater Train Pipe Tunnel		0.75
	Reactor Clean-up Sys Heat Exchanger Room		0.07
	Recirculating Pump Room		0.01
		Total	0.83
Radiation Safety Technician	Reactor Operating Floor		0.43
	Turbine Condensate & Feed-water Train Pipe Tunnel		1.10
	Control Rod Drive Room		0.03
	Reactor Clean-up Sys Heat Exchanger Room		0.21
	Recirculating Pump Room		0.01
	Steam Drum Room		0.33
	Decontamination Room 121		0.02
	Turbine Operating Floor		0.01
		Total	2.14
All Others	All Areas		Negligible Levels

NCTE: Typical concentrations are less than 0.1 MPC for the above areas and are calculated by radioactive analysis of filters obtained by portable air samplers. Air samples may be either general area or breathing zone.

NOTE: This data is pre-1993. Data collected after 1992 will be in terms of DAC hours. /
/

12.3 RADIATION PROTECTION DESIGN FEATURES

The Big Rock Point Plant incorporates both design features and procedural controls to minimize occupational dose to radiation. /

12.3.1 FACILITY DESIGN FEATURES

Two primary radiation dose reduction design features have been incorporated in the plant. All major components and interconnecting lines carrying or containing radioactive material are contained in shielded enclosures. Valves, instruments and controls for many of these components have been placed outside the shielded enclosures to permit observation, operation, and some maintenance without entering the more highly radioactive areas within the shielded enclosures. Specifically, pumps, valves, and control center to operate the liquid radioactive waste system have been placed outside the tank room. Control panel and remote valve operators for the cleanup system demineralizer, remote valve operators for the primary coolant recirculation pumps and condenser air ejectors, and a remote control panel for the condensate demineralizers have all been placed outside their respective shielded enclosures. In addition, instrumentation for much of the plant equipment has been placed outside of the shields. /

Regulatory position C.2 of Regulatory Guide 8.8 has generally been followed in the design of the plant. Specifically:

a. Access Control of Radiation Areas

Measurements of actual dose rates throughout the plant are made periodically. Radiation and High Radiation areas are generally confined to locations behind shield walls. Work is controlled in radiation areas by means of radiation work permits or by individuals specifically trained in radiation protection procedures. High Radiation area access is controlled by radiation work permit, and areas exhibiting exposure rates greater than 1 rem hour are locked when possible. /

Very high radiation areas (> 500 rads/hr), if entered, require additional controls. /

Changes in the status of any particular area are noted on the periodic surveys which are conspicuously posted on the radiological status signs at the entrance to each area.

Increases in radiation dose rates or levels of contamination, particularly in normally occupied areas, are dealt with quickly to reduce levels to historic averages.

The movement of large sources of radiation throughout the plant is normally accomplished by the use of shielding and/or planned to minimize dose to personnel. /

b. Radiation Shields and Geometry

Shielding to reduce radiation doses have been designed based upon the assumptions described in section 12.2.1. Shield thickness for various pieces of equipment are described further in section 12.3.2. Cubicles for individual pieces of equipment have generally not been provided. Sumps (turbine and containment) and lines to transmit radioactive water are all located within shielded enclosures or imbedded in concrete floors. /

c. Process Instrumentation and Controls

Process instrumentation and controls have been generally located outside of shielded enclosures. Some valves used to operate the condensate demineralizers are located within its shielded enclosure but contain local shields to reduce dose to operating personnel. /

d. Control of Airborne Contaminants and Gaseous Radiation Sources

Engineering control and ventilation flows are used to routinely reduce airborne contaminants. The use of respiratory protection to reduce dose is provided but used only when other methods are not practical and the use of respiratory protection is necessary to maintain TEDE ALARA. Section 12.2.2 and Chapter 11 describe further the policy and design of the facility to reduce exposure to airborne sources. / / /

e. Crud Control

The original design of the Big Rock Point Plant utilized admiralty metal in the feedwater heaters and reactor clean-up system heat exchangers. Heat exchanger tubes in these systems have since been replaced with stainless steel to reduce crud production and subsequent activation. With the exception of the main turbine condenser which is admiralty and the fuel cladding which is zircaloy the interior surface of major components in the primary coolant system consist of various stainless materials.

The production of activation products, particularly Co-58 and Co-60, as a result of using stainless steel exists but has been kept quite low. Use of low cobalt materials in equipment/component replacements is considered to the maximum extent practicable when these materials are available and based on current good engineering judgement. Oxygen control in the primary coolant, the use of full flow condensate demineralizers and use of the reactor clean-up system have also aided in the reduction of concentrations of these and other impurities in the primary coolant.

Crud traps have not been specifically minimized in the original plant design. Several exist and their removal is not practical. Their identity and location are well known to plant personnel. They are periodically monitored particularly if maintenance is to be conducted near these areas.

f. Isolation and Decontamination

Much of the plant equipment and interconnecting piping has not been specifically designed for ease of decontamination to reduce radiation fields in areas that may be occupied. As an alternative, two areas, one in the containment and the other in the turbine building near the machine shop have been specifically set aside for work on contaminated equipment that can be isolated and removed to these areas.

g. Radiation Monitoring Systems

The area and process monitoring systems installed at the plant are described in detail in Chapter 11.

h. Resin and Sludge Treatment Systems

The plant utilizes three demineralizer systems whose resins become radioactive. They are the reactor clean-up, condensate and liquid radioactive waste system demineralizers. All resins whose ion exchange capacity is exhausted are sluiced to the resin storage tanks in the liquid radioactive waste tank area for ultimate disposal as solid radioactive waste.

Filter systems within the plant for liquid streams, are either of the cartridge or sock strainer type. Backwashing is not practiced so sludge material is not transferred through piping systems. Cartridges and sock strainers are removed, placed in shielded casks then transported to the solid radioactive waste area for ultimate off-site disposal.

12.3.2 SHIELDING

Shield arrangement and thickness for the plant are shown on Drawings 0740G40100 through 0740G40104 inclusive. The design of the shielding is based on the assumption that the maximum permissible dose rate is five rems per year. The target weekly dose rate limit is taken as 100 mrems/week. In carrying out the above, the following maximum dose rates are established for the designated areas indicated on Drawing 0740G10052. /

Zone I Areas where access is not controlled: 0.5 mrem/hr. Such areas include the Control Room and adjacent areas, and outside areas around the process buildings. Thus, exposure in such areas for a 40-hour week will not contribute more than 20% of the working limit dosage of

Table 12.3

Location, Material and Thicknesses of Major Shields

Equipment Shielded	Material	Thickness
Liquid Radioactive Waste Tanks	Poured Concrete	3 Feet (Walls)
Liquid Radioactive Waste Sock Filter	Poured Concrete	2 Feet
Resin Disposal Tank	Poured Concrete	3 Feet
Liquid Radioactive Waste Demineralizer	Solid Concrete Block	4 Feet
Liquid Radioactive Waste Cartridge Filter	Steel	¼ Inch
Condensate Demineralizers	Poured Concrete	1.5-2 Feet
Condenser Off-Gas Lines	Lead and Concrete Block	½ Inch 6 Inches
Main Condenser and Condensate/ Feedwater Pipe Tunnel	Poured Concrete	2.5-3 Feet
Turbine and Moisture Separator	Poured Heavy Concrete	2 Feet
Recirculating Pump Room and Steam Drum Enclosure	Poured Concrete	3-4 Feet Walls 6 Feet Ceiling
Reactor Vessel	Poured Concrete	8 Feet Minimum
Shutdown Heat Exchanger Room	Poured Concrete	2 Feet
Spent Fuel Pool Filter	Solid Concrete Block	1.5 Feet (Wall Only) No shielding above Filter
Spent Fuel Pool Floor	Lead & Poured Concrete	1 Inch 6 Feet
Walls	Poured Concrete	5-6 Feet (South Wall Taper 3.5 Feet Min)
	Steel Liner	3/16 Inch

12.3.3 VENTILATION

The plant ventilation system is described in Chapter 9 and further discussed in Chapter 11 in relation to gaseous waste management.

12.3.4 AREA AND AIRBORNE RADIATION MONITORING INSTRUMENTATION

The area radiation monitoring system including accidental criticality monitoring, is described in Chapter 11. Monitoring for airborne radiation is accomplished by the use of mobile continuous air monitors and supplemented by grab samples followed by laboratory analysis. The continuous air monitors are capable of detecting airborne activity of at least 0.1 DAC. Alarms are included at two /
levels, a precautionary alarm at a sub DAC level and a "hi alarm" at /
or near DAC levels. Radioactive iodine and other specific particulate /
nuclide concentrations may also be measured by portable filter samplers with subsequent laboratory analysis.

A continuous air monitor is also measuring sphere exhaust radioactivity to aid in the early detection of leakage inside the containment enclosure.

12.4 DOSE ASSESSMENT

The over 30 year operating history of the plant has provided considerable information on actual occupational radiation doses received. Table 12.4 shows the annual collective total person rem doses since the plant began operation through 1992. /

TABLE 12.4

Big Rock Point Plant Annual Occupational Radiation Doses (Person Rem)

Year	Radiation Dose Person Rem	Average Dose Rem/Person[2]	Unusual Circumstances
1962	1.4		
1963	16		
1964	50		
1965	88		
1966	220		First Large Fuel Cladding Failures
1967	150		
1968	177		
1969	136	0.82	
1970	194	0.67	
1971	184	0.70	
1972	181	0.92	
1973	336	(3)	
1974	276	0.98	
1975	180	0.83	
1976	270	0.54	Reactor Depressurization Sys & In Service Inspection Program Added to Plant
1977	306	0.62	Significant Additional In-Service Insp Conducted
1978	165	0.38	No Refueling Outage
1979	377	0.60	Replaced Core Spray Sparger, Steam Baffle and Performed Significant Control Rod Drive (F-2) Work
1980	338	0.52	
1981	134	0.24	
1982	300	0.46	
1983	247	0.43	
1984	121	0.30	
1985	283	0.49	Performed 10CFR50 App R Modification-Alt Shutdown
1986	76	0.22	No Refueling Outage
1987	211	0.50	
1988	156	0.36	
1989	160	0.34	/
1990	221	0.51	/
1991	216	0.46	/
1992	262	0.50	/

12.5 HEALTH PHYSICS PROGRAM

12.5.1 ORGANIZATION

In addition to the positions described in Section 13.1, the Health Physics Organization also consists of an ALARA Coordinator whose responsibility is review/evaluation of activities and procedures with regard to dose reduction, and a supervisor in charge of routine radiation protection activities, supervision of radiation protection technicians, radiation instruments and surveys.

Other personnel with specialized training in radioactive waste disposal are maintained for the shipment of radioactive material.

12.5.2 EQUIPMENT, INSTRUMENTATION, AND FACILITIES

Portable radiation measuring instrumentation has been selected to adequately measure routine and accident conditions considering expected ranges of dose rates and radionuclide mixtures. Adequate supplies are on hand to cover normal and outage operations to meet the requirements of 10 CFR, Part 20, "Standards For Protection Against Radiation." Most all of the portable radiation measuring instruments are stored in Access Control, readily available for use by qualified personnel. Several instruments may also be stored at various locations in the plant for operational convenience. Portable gamma and neutron measuring instruments are calibrated semi-annually and functionally checked on a routine basis. Virtually all instruments are serviced onsite by the Instrumentation and Control group.

Redundant germanium gamma spectroscopy equipment is onsite to identify radionuclides and mixtures for compliance with 10 CFR, Part 20 and to meet industry standard lower levels of detection. Other laboratory equipment such as proportional counters, well detector and Geiger muller counters are available for other various types of analyses.

Instrument calibrations traceable to the National Bureau of Standards (NBS) are accomplished by a Cesium-137 well source or JLShepherd Model 89, Cesium-137 irradiator (both are calibrated with a Victoreen /
Radacon III traceable to NBS) or NBS traceable liquids purchased from /
various suppliers. Some calibrations may also be performed using sources quantified with our onsite gamma spectroscopy systems.

Access Control is located at the boundary of the radiologically controlled area and contains a shower and sink for decontamination purposes, hand-held contamination monitors, some radiation instruments (ion chamber type) and high sensitivity whole body friskers. The radiation protection technician office area is located adjacent to Access Control to allow ready observation of egress activities.

Respiratory protective equipment and anticontamination clothing is stored inside the radiologically controlled area close to Access Control. Different sizes of respirators and clothing are maintained to fit virtually all personnel and quantities are sufficient for normal and outage conditions.

The respiratory protection program also includes a quantitative respirator fit test station and a scanning whole body counter for bioassay measurements. A decontamination sink with automatic washer is provided for respirators inside the radiologically controlled area.

12.5.3 PROCEDURES

Procedures describe the frequency, sensitivity and acceptance criteria for routine radiation, contamination and airborne surveys. Surveys have been established to ensure the timely detection of activities or operations causing unplanned or unexpected radiation dose.

Varying levels of ALARA review are described in Section 12.1.3. Radiation Work Permits (RWPs) are used to specify radiological protection requirements for work in radiation areas, and entries to contamination, high radiation, and airborne areas.

Contamination control is maintained by routine surveys to ensure as much of radiologically controlled area is as clean as practicable. Contaminated areas above 1000 dpm/100cm² (removable) are posted as such or cleaned. In no event are personnel allowed to leave the radiologically controlled area with contamination greater than 5000 dpm/100cm² (fixed and/or removable) on their person without authorization of designated Health Physics personnel.

Radiation Protection training programs are provided to all personnel entering the protected area and are commensurate with the risk of radiation exposure. Radiation Protection training for radiation workers is obviously more rigorous than it is for guests or escorted workers.

Radiation Protection procedures are generally written to cover those activities described in Regulatory Guide 1.33.

Personnel monitoring is provided by using thermoluminescent dosimetry (TLD) as the primary external dose measurement and pocket ionization chambers as the secondary measurement. The primary dosimetry is accredited by the National Voluntary Laboratory Accreditation Program (NVLAP). Internal radiation dose assessment is provided through DAC-hour tracking by the use of air samples and respiratory protection (as appropriate). Whole body counting is the primary method of bioassay and is used to verify intakes of radioactive material are ALARA and to provide a measure of effectiveness for the respiratory protection program. Whole body counting is performed at least once per year for radiation workers who frequent radiologically controlled areas and whenever an intake is suspected.

Airborne radioactivity concentrations are determined by continuous air monitors and grab samples. Portable ventilation (particularly HEPA filters) are used where practicable.

The handling and storage of radioactive sealed sources is controlled by the Chemistry and Health Physics Department. /

13.1 ORGANIZATIONAL STRUCTURE

13.1.1 MANAGEMENT AND TECHNICAL SUPPORT ORGANIZATION

The offsite organization for management and technical support is described in the "Consumers Power Company Quality Assurance Program Description for Operational Nuclear Power Plants, CPC-2A," which is "Incorporated by Reference" as part of this Updated FHSR, as described in Chapter 17.

The offsite and onsite organization are further described in the "Big Rock Point Plant Technical Specifications," which is "Incorporated by Reference" as part of this Updated FHSR, as described in Chapter 16.

13.1.2 OPERATING ORGANIZATION RESPONSIBILITIES

The Plant organization is depicted on Figure 13.1, and the following provides a general discussion of responsibilities:

- The Plant Manager is responsible for overall plant safe operation and has control over those onsite activities necessary for safe operation and maintenance of the plant. He will delegate in writing the succession to this responsibility during his absence.

- The Operations Manager is responsible for plant operation. The Plant Safety and Licensing Director is responsible for plant licensing, operating experience, probabilistic risk assessment, end of license issues, performance engineering, special projects and planning of decommissioning/repowering. The Systems and Project Engineering Manager is responsible for reactor engineering, mechanical/civil and electrical engineering, turbine system, and security as well as other related engineering duties. The Maintenance Manager is responsible for mechanical/electrical and instrumentation and control maintenance, and material services. The Outage Planning and Scheduling Administrator is responsible for planning and outage coordination. The Chemistry/Health Physics Manager is responsible for radiation protection, plant chemistry, radioactive wastes and emergency planning. The responsibilities of others reporting to the Plant Manager are self explanatory.

  The Shift Supervisor will be responsible for the shift command function. A Management directive to this effect will be issued annually by the Vice President - Nuclear Operations.

13.1.3 QUALIFICATIONS OF NUCLEAR PLANT PERSONNEL

Staff qualifications are established consistent with the intent of ANSI Standard 18.1-1971 and are described in the Plant's Administrative Procedures.

a. Each member of the plant staff will meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable positions.

b. Either the Chemistry and Health Physics Manager or the Chemistry and Radiation Protection Supervisor will meet or exceed the qualifications of Regulatory Guide 1.8, September 1975. For the purpose of this section, "Equivalent," as utilized in Regulatory Guide 1.8 for the bachelor's degree requirement, may be met with four years of any one or combination of the following: (a) Formal schooling in science engineering, or (b) operational or technical experience/training in nuclear power. /

c. The On-Call Technical Advisor (OTA) will have a bachelor's degree or equivalent in a scientific or engineering discipline with specific training in plant design, and response and analysis of the plant for transients and accidents.

d. The Operations Manager will hold an SRO (Senior Reactor Operator License) and meet or exceed the minimum qualifications of ANSI-N18.1-1971 for the comparable position of Operations Manager. An SRO License is required to be responsible for directing the activities of licensed operators. /

13.1.4 PLANT ADDITIONAL SUPPORT

A. To support the Plant Organization shown on Figure 13.1, personnel knowledgeable in the following areas identified in ANSI N18.7-1976/ANS 3.2 will report at the discretion of the Plant Manager:

1. Nuclear Power Plant Mechanical, Electrical and Electronic Systems

2. Nuclear Engineering

3. Chemistry and Radiochemistry

4. Radiation Protection (Reports to Chem/HP Manager) /

B. Quality Assurance/Control activities will be in accordance with Consumers Power Company's Quality Program Description for Operational Nuclear Power Plants, (CPC-2A, as revised), (reference Chapter 17 of this Updated FHSR).

C. The Security Force will be supervised as described in the Security Plans (reference Section 13.6 of this Updated FHSR).

D. Fire Protection responsibilities for the Plant Fire Protection Program implementation are as described in the BRP Fire Plan and the Fire Protection Summary - BRP Plant Manual. Refer to Section 9.5.1 of this Updated FHSR.

e. All core alterations, after the initial fuel loading, will either be performed by a licensed Reactor Operator under the general supervision of a Senior Reactor Operator or a nonlicensed Operator directly supervised by a licensed Senior Reactor Operator (or Senior Operator Limited to Fuel Handling) who has no other concurrent responsibilities during this operation.

f. Fire Brigade composition and reuuirements are described in Section 9.5.1.4 of this Updated FHSR. The Fire Brigade will not include 2 members of the minimum shift crew necessary for safe shutdown of the plant and any personnel required for other essential functions during a fire emergency.

g. The minimum refueling crew during refueling operations will be four men. There will be a licensed operator in the control room at all times, and the Shift Supervisor will be in charge.

13.1.6 OVERTIME LIMITS AND GUIDELINES

Administrative procedures will in be effect to limit the working hours of plant staff who perform safety-related operation functions; ie, senior reactor operators, reactor operators, auxiliary operators, health physicists and key maintenance personnel.

Adequate shift coverage will be maintained without routine heavy use of overtime. However, in the event that unforeseen problems require substantial amounts of overtime to be used, the following guidelines will be followed:

1. An individual should not be permitted to work more than 16 hours straight, excluding shift turnover time.

2. An individual should not be permitted to work more than 16 hours in any 24-hour period, nor more than 24 hours in any 48-hour period, nor more than 72 hours in any 7-day period, all excluding shift turnover time.

3. A break, including shift turnover time, of at least eight hours should be allowed after continuous work periods of 16 hours duration.

4. Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on a shift.

   Deviation from the above guidelines will be authorized by the Plant Manager or his alternate (Operations or Maintenance Managers), or higher levels of Management, in accordance with established procedures and with documentation of the basis for granting the deviation. /

BIG ROCK POINT NUCLEAR PLANT
Organization Chart

- Plant Manager
  - Staff Secretary
  - Human Resource Director
    - Personnel Activities
    - Labor Relations
    - Personnel Safety
  - Public Affairs Director
    - Public Affairs
    - Employee Communication
  - Planng & Scheduling Admin
    - Plan/Outage Coordination
  - Administrative Supervisor
    - Payroll
    - DCC, Text Processing
    - Computer systems
    - Controller
    - Budget Functions
  - Operations Manager
    - Operations
    - On-Call Tech Advisor
  - Chem/HP Manager
    - Chemistry
    - Radiation Protection
    - Radwaste Shipping
    - ALARA
    - Dosimetry
    - Emergency Planning
  - Systems & Proj Engr Mgn
    - Reactor Engineering
    - Secondary Systems
    - Turbine Systems
    - Projects
    - Electrical Systems
    - Security
  - Maintenance Manager
    - Material Services
    - Maint Engr Support
    - Maint Planning
    - I&C
    - Mech & Elect Maint
  - Plant Safety & Lic Dir
    - Licensing
    - Operating Exp
    - PRA
    - End of License Issues
    - (Decommission/Repowering)

3. Properly enter and leave a contamination area, including whole body frisk (may be done in conjunction with donning and removing protective clothing).

4. Demonstrate the ability to work under a Radiation Work Permit (RWP).

An annual basic radiation worker requalification course is required for renewal of unescorted access authorization. The requalification course requires successful completion of a written examination. /

Basic Radiation Worker Training is certified to meet the intent of INPO 87-004 "Guidelines for General Employee Training," and was certified by INPO in April 1987 as part of General Employee Training above.

13.2.1.3 Reactor Operator Training Program

The Big Rock Point Operator Training Program is a comprehensive Integrated Training Program. The operator positions covered under this program include the Auxiliary Operator (AO), Control Room Operator (RO), Shift Supervisor (SRO) and the On-Call Technical Advisor (OTA). The On-Call Technical Advisor is the BRP Replacement for the Shift Technical Advisor/Shift Engineer (SRO) and requires the classroom portion of the Senior Reactor Operator and OTA task specific on-the-job training as well as portions of the requalification training of the Control Room Operator and Shift Supervisor.

The OTA will receive specific training in plant design, and response and analysis of the plant for transients and accidents.

The program was accredited by INPO on September 24, 1986.

13.2.1.4 Licensed Operator Training Program Certification

The Institute of Nuclear Power Operations (INPO) certification letters dated December 18, 1985 and September 24, 1986 indicated that the National Nuclear Accrediting Board awarded accreditation of the following (Operator) training programs for CPCo's Big Rock Point Plant, (reference CPCo letter dated May 26, 1987).

- Non-licensed Operator

- Reactor Operator

- Shift Reactor Operator/Shift Supervisor

- Shift Technical Advisor*

* Now referred to as the On-Call Technical Advisor (OTA).

13.5.2.3.4 Shutdown Procedures

Shutdown procedures to guide operations during and following controlled reactor shutdown or reactor trips, and to establish or maintain hot standby or cold shutdown conditions.

For extended shutdowns the following precautions will be in place.

To ensure that systematic control is maintained on the reactor and its primary heat sink as well as the turbine generator, reactor power shall be reduced by manipulation of the control rods, and the main generator load shall be decreased simultaneously. The turbine-generator shall be separated from the system.

To ensure that the reactor is in a cold shutdown condition all control rods shall be inserted.

To ensure the reactor vessel metal remains ductible and free of excessive thermal stress, the removal of reactor decay heat and the reduction of reactor pressure shall be accomplished by controlling reactor steam flow. The rate of cooling of the reactor vessel shall not be allowed to exceed 100°F per hour. Any two temperature measuring points on the reactor or any two on the steam drum are not to be allowed to exceed a differential temperature of $\geq$ 150°F.

To ensure a means of reactor decay heat removal, the reactor shutdown cooling system shall be placed in operation whenever reactor pressure drops below a pressure sufficient to maintain turbine seals. This system will complete the cooling of the reactor water to 125°F.

To ensure continuous monitoring of the reactor power level, a minimum of one source range monitor channel and one power range monitor channel shall be left in operation when fuel bundles are /
in the reactor. All instrumentation pertaining to control of /
activity release shall be left in operation.

13.5.2.3.5 Power Operation and Load Changing Procedures

Power operation and load changing procedures provide for steady-state power operation and load changes, including response to unanticipated load changes, use of control rods, or any other system available for long- or short-term control of reactivity, making deliberate load changes, responding to unanticipated load changes, and adjusting operating parameters.

For normal power operation the turbine initial pressure regulator will maintain the reactor pressure at its normal value by operating the turbine admission valves. The turbine load will be established by the reactor control rod positions. The principal functions of the operating personnel during this period will be the maintenance of a continuous watch in the control room for prompt attention to

1. No Mixing - Peaking Factor = 1.5, Core Decay = 12 Hours
2. No Mixing - Peaking Factor = 0.6, Core Decay = 5 Days
3. Full Mixing - Peaking Factor = 1.5, Core Decay = 12 Hours
4. Full Mixing - Peaking Factor = 0.6, Core Decay = 5 Days

As a result of utilizing these four sets of conditions, four sets of response time were determined. Since the actual mixing for the postulated accident would be expected to occur somewhere between the extremes of 0 and 100%, the actual response times would be bracketed between the calculated extremes.

The following assumptions were applied to the analysis:

1. Fuel was assumed to have an 80/20 U-235, PU-239 fission mixture.
2. Reactor operation was at 240 MW_t.
3. All gap activity from the damaged fuel is released. This consists of 10% of all noble gases and iodines in the rods, except Kr-85 and I-129 for which 30% is assumed.
4. A decontamination factor of 100 is assumed for all iodines.
5. Release occurs over a two hour period.
6. a. New fuel storage area monitor alarms at 85 mr/h /
   b. Spent fuel pool area monitor alarms at 160 mr/h /
7. Meteorological conditions assumed to exist were:

   a. Wind speed of 1 m/s
   b. Uniform wind direction
   c. A fumigation condition exists.

These assumptions and the methodology described in Appendix A were used to obtain dose results.

15.7.1.2 <u>ANALYSIS</u>

15.7.1.2.1 <u>FUEL TRANSFER CASK DROP</u>

The fuel transfer cask drop analysis was performed assuming that the crane cable or both cask slings break when the transfer cask is directly over the core at an elevation one foot above the floor level. It is further assumed that the refueling platform and water do not retard the free fall of the cask and that the cask hits the core structure with its smallest frontal area and penetrates it in

The time points selected for comparison were 60 seconds after initiation of a loss of feedwater ATWS without recirculating pump trip and 100 seconds after initiation of a loss of feedwater with recirculating pump trip. At these times thermal conditions are changing very slowly and assumed to be at steady-state. The BRP core simulator is a steady-state model and steady-state conditions from RETRAN were needed for comparison.

COMPARISON OF CORE POWER RESPONSE
AS PREDICTED BY RETRAN AND THE BRP CORE SIMULATOR

Case	Subcooling	Flow	Power RETRAN	Power Core Simulator
Initial Condition	24.5 Btu/lbm	100%	100%	100%
Loss of Feedwater ATWS without RPT (t = 60 sec)	3.2	98.1	61.3	61.5
Loss of Feedwater ATWS with RPT (t = 100 sec)	1.1	42.5	28.1	29.5

A second model was developed in order to assess the impact of proposed modifications to fix the secondary side instability problems encountered at Big Rock Point during blowdown to the main condenser. This model includes the primary system (reactor, steam drum and recirculating pumps) and the entire secondary side (turbine/generator, condenser, feedwater heaters, and feedwater pumps). This code was used to show the effects of tripping a recirculating pump in conjunction with the anticipatory signal sent to the bypass valve during load rejection transients. This modification, Facility Change FC-664 performed in November 1990, is expected to reduce the effects of secondary system instabilities for the major contributor to main condenser blowdowns (load rejections).

Tables in Reference 3 and in Appendix VII of the Probabilistic Risk Assessment (PRA) present plant and operators response times for the various ATWS transient categories. This table is reproduced here showing the effects of hotwell and steam drum inventory variations on plant and operator actions (see Table 15.8-1). Effects of hotwell inventory variations are shown in brackets [ ], drum inventory variations in parentheses ( ). Available operator response time to initiate poison injection varies by no more than 8 seconds as a result of drum level uncertainty and 11 seconds as a result of a hotwell level uncertainty. /

The risk based evaluations divided the plant response to an ATWS into four different categories: infinite feedwater, low level, high pressure with feedwater, and high pressure without feedwater. The following discussion of the responses is taken from the February 1981