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Nuclear Power Plant Operating Experience - 1982

Annual Report

Prepared by E. G. Silver

Oak Ridge National Laboratory

Prepared for
U.S. Nuclear Regulatory
Commission

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Prepared by
E. G. Silver

Oak Ridge National Laboratory
Oak Ridge, TN 37831

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PREVIOUS REPORTS IN THIS SERIES

OOE-ES-004, Nuclear Power Plant Operating Experience During 1973, USAEC, December 1974

NUREG-0227, Nuclear Power Plant Operating Experience, 1974–1975, USNRC, April 1977*

NUREG-0633, Nuclear Power Plant Operating Experience — 1976, USNRC, December 1977*

NUREG-0483, Nuclear Power Plant Operating Experience — 1977, USNRC, February 1979†

NUREG-0618, Nuclear Power Plant Operating Experience — 1978, USNRC, December 1979†

NUREG/CR-1496, ORNL/NUREG/NSIC-180, Nuclear Power Plant Operating Experience — 1979, USNRC, May 1981†

NUREG/CR-2378, ORNL/NSIC-191, Nuclear Power Plant Operating Experience — 1980, USNRC, October 1982†

NUREG/CR-3430, ORNL/NSIC-215, Vol. 1, Nuclear Power Plant Operating Experience — 1981, December 1983†

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EXECUTIVE SUMMARY

1. INTRODUCTION

This report summarizes the operating experience of 72 licensed nuclear power plants during 1982. Operating statistics and data are presented for each plant that was in commercial operation* at the end of the year. The authority to operate Three Mile Island 2 (TMI-2) was suspended by the Nuclear Regulatory Commission (NRC) on July 20, 1979, and it is not included in any of the listings or compilations in this report. Nevertheless, certain information on postaccident recovery activities during 1982 is presented.

At the end of 1982, 82 power reactors had been licensed to operate. One of these licenses, for Diablo Canyon, was granted in 1981 but subsequently suspended due to seismic safety questions. Of the remaining 81 licensed plants, 3 (Dresden 1, Humboldt Bay, and TMI-2) were shut down indefinitely; no decision has been made yet on whether they will operate again. Therefore, they are excluded from this analysis.† Of the remaining 78 reactors, 6 were not yet in commercial operation. (Two of these six, Grand Gulf 1 and San Onofre 3, were licensed only for fuel loading and low-power testing, not to exceed 5% of full power, at the end of 1982, while the other four, LaSalle 1, San Onofre 2, Susquehanna 1, and Summer 1, were approved for full-power operation but had not yet declared commercial operation as of the end of 1982.) The 72 reactors in commercial operation are the subjects of the analysis in this report. One of the 72 reactors, Sequoyah 2, first declared commercial operation on June 1, 1982, and thus was included for less than the full year.

The 72 plants include 24 boiling-water reactors (BWRs), 47 pressurized-water reactors (PWRs), and Fort St. Vrain, a plant equipped with a high-temperature gas-cooled reactor (HTGR). In comparison with the 1981 report (NUREG/CR-3430 Vol. 1), one new PWR plant has been added to bring the total to 72.

2. POWER GENERATION

In 1982 the total net electrical output for 72 nuclear power plants in commercial operation was 278.0 billion kWh, which is roughly 12% of the total electrical energy generated in the United States for the year from all sources.

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*See Appendix A for definition.

†The TMI-1 reactor also remained shut down during the entire year by NRC directive. However, it is expected to restart and therefore is included among the commercially operating reactors.

This represents an increase of 9.9 billion kWh over the 1981 production, a 3.7% increase that is somewhat less than the 6.8% increase in 1981 over 1980. Of the total net electrical energy output of nuclear power plants in 1982, 67.6% was produced by PWRs, 32.2% by BWRs, and 0.2% by the HTGR.

Plant Availability Factor for 1982

The average plant availability factor for all plants in 1982 was 65.9% for the 72 nuclear power plants in commercial operation. The average BWR and PWR availability factors for this period were 67.3 and 65.5%, respectively. The HTGR had an availability factor of 37.3%.

Plant Capacity Factors for 1982

Individual plant capacity factors were calculated using maximum dependable capacity (MDC)* and design electrical rating (DER),* both in megawatts electrical net. The weighted average capacity factors for the 72 commercial nuclear power plants were 58.7% using MDC and 57.1% using DER. These values are somewhat reduced by the low capacity factors of the HTGR, which were 19.7% using either definition. For the 24 BWRs, the plant-rating-weighted mean capacity factors were 59.1 and 58.0% for MDC and DER capacities, respectively. For the 47 PWRs, the same parameters had the values 58.2 and 56.7%, respectively.

3. PLANT OUTAGES

During 1982, the 24 operating BWRs experienced an average of 2,869.8 h of outage time compared with an average of 3,016.6 h for the 47 PWRs.† The percentage of forced outage time at BWRs was 12.6% compared with 11.1% at PWRs. The primary cause of forced outages at BWRs and PWRs was equipment failure.

Refueling was the primary cause of scheduled outages at both BWRs and PWRs, and maintenance or testing accounted for the second largest percentage of outage time at both types of light-water reactors.

Fort St. Vrain, an HTGR, had an availability factor of 37.3%, having experienced 13 forced outages and 2 scheduled outages for a total outage time of 5,493 h.

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*See Appendix A for definition.

†The PWR figure includes the full-year outage of TMI-1 but excludes TMI-2.

4. REPORTABLE OCCURRENCES

Licensee Event Reports (LERs)

The 72 commercially operating plants covered in this report submitted 3,737 LERs relating to 1982 events (excluding revisions and updates), a decrease of 326 from the 4,063 submitted for 1981. Of these, 1,355 were from the 24 BWRs, 2,329 were from the 47 PWRs, and 53 were from the single HTGR.

Abnormal Occurrences

An abnormal occurrence is an incident or event that the NRC determines is significant from the standpoint of public health or safety. Each quarter, the NRC submits to Congress a report listing any abnormal occurrences for that period, as required by Sect. 208 of the Energy Reorganization Act of 1974. The report contains the date and place, nature and probable consequences, cause or causes, and any action taken to prevent recurrence of each abnormal occurrence.

During 1982, there were six abnormal occurrences reported for commercial nuclear power plants. Four of these dealt with 1982 events, while two relate to 1981 events that took place too late for inclusion in the 1981 reports. A summary of each of these occurrences is given in this report. The titles and numbers assigned to these six abnormal occurrences are as follow:

- AO 82-1 Diesel generator engine cooling system failures at Dresden Units 2 and 3
- AO 82-2 Pressure transients during shutdown at Turkey Point Unit 4
- AO 82-3 Major deficiencies in management controls of Pilgrim Nuclear Power Station
- AO 82-4 Steam generator tube rupture at Ginna
- AO 82-5 Loss of auxiliary electric power at Quad Cities
- AO 82-7 Inoperable containment spray system at Farley 2

5. FUEL PERFORMANCE

The NRC does not monitor every fuel failure that occurs in licensed operating nuclear power plants. The approach taken is to (1) set up operating limits for radioactivity in the coolant (from fuel failures) that are stringent enough to ensure that the dose limits specified in the *Code of Federal Regulations* are not exceeded and (2) monitor only those fuel failures that are significant from the viewpoint of the number of fuel rods that failed or those in which the failure is due to a new fuel failure mechanism. Meetings are held periodically with the nuclear fuel vendors to review the operating experience of their fuel. Operating reactors typically have ~40,000 fuel rods, and the average fuel rod failure rate during the last few years has been near or below 0.02% per cycle,[1] excluding TMI-2. Fuel performance has continually improved, yet deviations from the normal occur occasionally.

Specific Fuel-Related Incidents

A number of fuel-related events in 1982 are described in NUREG/CR-3602, *Fuel Performance Annual Report for 1982*, and many of these also were reported in LERs. The most significant of these events are briefly summarized in this report.

6. RADIATION EXPOSURE

Occupational Radiation Exposure

Occupational radiation exposure data submitted to the NRC for workers employed at commercial nuclear power plants indicate that about 64% of the total collective dose (person-rem) was incurred by contractor personnel at BWRs, compared with 60% at PWRs. At both PWRs and LWRs, the largest portion of the collective dose was incurred in the course of special maintenance (44.1%, amounting to 10,010 person-rem in BWRs and 49.0%, amounting to 13,580 person-rem in PWRs), while routine maintenance gave rise to the second highest percentage contributions (33.7%, amounting to 7,730 person-rem in BWRs and 23.1%, amounting to 6,400 person-rem in PWRs).

The average annual dose for individuals who received measureable exposures was 0.62 rem, remaining less than 1 rem as it has every year since 1972.

The total collective dose at light-water reactors (LWRs) for 1982 (50,630 person-rem) decreased by 6.5% in comparison with last year's value of 54,142 person-rem. This significant decrease in collective dose reverses a three-year trend, which had seen large increases (16 and 35%, respectively) for 1979 and 1980 and a small increase (0.6%) for 1982.

Reference

1. F. Garzarolli, R. von Jan, and H. Steahle, "The Main Causes of Fuel Element Failure in Water-Cooled Power Reactors," *At. Energy Rev.* 17(1), 31 (March 1979).

NUCLEAR POWER PLANT OPERATING EXPERIENCE — 1982

E. G. Silver

ABSTRACT

This report is the ninth in a series of reports issued annually that summarizes the operating experience of nuclear power plants in commercial operation in the United States. Power generation statistics, plant outages, reportable occurrences, fuel element performance, and occupational radiation exposure for each plant are presented and discussed, and summary highlights are given. The report includes 1982 data from 72 plants: 24 boiling-water-reactor plants, 47 pressurized-water-reactor plants, and 1 high-temperature gas-cooled reactor plant.

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1. INTRODUCTION

This report summarizes the operating experience of 72 licensed nuclear power plants during 1981. Operating statistics and data are presented for each plant that was in commercial operation at the end of the year and had sufficient electrical generation for meaningful analysis. The authority to operate Three Mile Island 2 (TMI-2) was suspended by the Nuclear Regulatory Commission (NRC) on July 20, 1979. However, certain data on TMI-2 relating to the recovery and cleanup activities are included in this report.

At the end of 1982, 82 power reactors had been licensed to operate. One license, for Diablo Canyon, was issued on June 25, 1981, but then suspended on November 19, 1981, due to seismic safety considerations. Therefore, this reactor is not included in this year's analysis.

Three licensed reactors — Dresden 1, Humboldt Bay, and TMI-2 — were shut down indefinitely with no decision yet made as to their ultimate restart. These three units are also excluded from this analysis.*

Six reactors, shown in Table 1.1, were issued operating licenses prior to the end of 1983 but were not yet in commercial operation by that time and are, therefore, excluded from this report. The table lists their name, reactor type, nuclear steam supply system (NSSS) manufacturer, and the date the license was issued. Of these six units, two were licensed only for fuel loading and low-power testing, while four had full-power authorization but were still in the power ascension stage at year's end. Table 1.2 lists the 72 reactors to be analyzed, arranged by date of

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*However, the radiation dose contributions from these three units are included in the tabulation in Chap. 6.

Table 1.1. Licensed power reactors not yet in commercial operation as of December 31, 1982

Name	Type	Manufacturer	Date licensed	MW(e) net	
				DER[a]	MDC[b]
Licensed for fuel loading and low-power testing (<5%)					
Grand Gulf 1	BWR	General Electric	6/16/82	1,250	
San Onofre 3	PWR	Combustion Engineering	11/15/82	1,087	
Approved for full power (in power ascension phase)					
La Salle 1	BWR	General Electric	4/17/82		1,078
San Onofre 2	PWR	Combustion Engineering	2/16/82		1,127
Summer 1	PWR	Westinghouse	8/06/82		900
Susquehanna 1	BWR	General Electric	7/17/82		1,011

[a]DER = design electrical rating (see Appendix A for definition).

[b]MDC = maximum dependable capacity (see Appendix A for definition).

commercial operation and including the reactor type, NSSS manufacturer, and net maximum dependable capacity (MDC)* electrical rating.

One of these 72 units, Sequoyah 2, achieved commercial operation on June 1, 1982, and so is included only for 7 out of the 12 months.

The 72 plants reviewed include 24 boiling-water reactors (BWRs), 47 pressurized-water reactors (PWRs), and 1 high-temperature gas-cooled reactor (HTGR), Fort St. Vrain. Thus, this report represents an increase of 1 reactor over the 71 units included last year in the 1981 report (NUREG/CR-3430, Volume 1).

Operating statistics for each plant, such as plant availability and capacity factors and the percent of scheduled and forced outages, are presented. Because the definitions of these terms vary somewhat within the industry and government, a glossary is presented in Appendix A. Also included in this report are summaries of Licensee Event Reports (LERs) and summaries of abnormal occurrences, fuel performance, and occupational radiation exposures.

This report was prepared for the NRC by the Nuclear Operations Analysis Center (NOAC) at Oak Ridge National Laboratory (ORNL) under Interagency Agreement DOE No. 40-547-75, SOEW No. 80-82-028. The primary sources of information used in preparing this report were the Licensee's Operating Reports, LERs, Special Reports, and the NRC's Operating Units Status Report (the monthly "Gray Book"). These reports may be reviewed at the NRC Public Document Room, located at 1717 H Street NW, Washington, D.C. Documents pertaining to specific plants are also available at public document rooms located in the vicinity of each plant.

*See Appendix A for definition.

Table 1.2. Nuclear power plants in commercial operation — 12/31/82[a]

Plant name	Utility	Reactor type	NSSS[b]	Commercial operation began
Yankee-Rowe	Yankee Atomic Electric Co.	PWR	W	07/61
Big Rock Point	Consumers Power Co.	BWR	GE	03/63
San Onofre 1	Southern California Edison and San Diego Gas & Electric Co.	PWR	W	01/68
Haddam Neck	Connecticut Yankee Atomic Power Co.	PWR	W	01/68
La Crosse	Dairyland Power Cooperative	BWR	AC	11/69
Oyster Creek 1	Jersey Central Power & Light Co.	BWR	GE	12/69
Nine Mile Point	Niagara Mohawk Power Corp.	BWR	GE	12/69
Dresden 2	Commonwealth Edison Co.	BWR	GE	06/70
Ginna	Rochester Gas & Electric Co.	PWR	W	07/70
Point Beach 1	Wisconsin Electric Power Co. and Wisconsin-Michigan Power Co.	PWR	W	12/70
Robinson 2	Carolina Power and Light Co.	PWR	W	03/71
Millstone 1	Northeast Nuclear Energy Co.	BWR	GE	03/71
Monticello	Northern States Power Co.	BWR	GE	06/71
Dresden 3	Commonwealth Edison Co.	BWR	GE	11/71
Palisades	Consumers Power Co.	PWR	CE	12/71
Point Beach 2	Wisconsin Electric Power Co. and Wisconsin-Michigan Power Co.	PWR	W	10/72
Vermont Yankee	Vermont Yankee Nuclear Power Corp.	BWR	GE	11/72
Pilgrim 1	Boston Edison Co.	BWR	GE	12/72
Surry 1	Virginia Electric & Power Co.	PWR	W	12/72
Turkey Point 3	Florida Power & Light Co.	PWR	W	12/72
Maine Yankee	Maine Yankee Atomic Power Corp.	PWR	CE	12/72
Quad Cities 1	Commonwealth Edison Co. and Iowa-Illinois Gas & Electric Co.	BWR	GE	02/73
Quad Cities 2	Commonwealth Edison Co. and Iowa-Illinois Gas & Electric Co.	BWR	GE	03/73
Surry 2	Virginia Electric & Power Co.	PWR	W	05/73
Oconee 1	Duke Power Co.	PWR	BW	07/73
Turkey Point 4	Florida Power & Light Co.	PWR	W	09/73
Prairie Island 1	Northern States Power Co.	PWR	W	12/73
Zion 1	Commonwealth Edison Co.	PWR	W	12/73
Kewaunee	Wisconsin Public Service Corp.	PWR	W	06/74
Fort Calhoun 1	Omaha Public Power District	PWR	CE	06/74
Peach Bottom 2	Philadelphia Electric Co.	BWR	GE	07/74
Cooper Station	Nebraska Public Power District	BWR	GE	07/74
Browns Ferry 1	Tennessee Valley Authority	BWR	GE	08/74
Indian Point 2	Consolidated Edison Co.	PWR	W	08/74
Oconee 2	Duke Power Co.	PWR	BW	09/74
Three Mile Island 1	Metropolitan Edison Co.	PWR	BW	09/74
Zion 2	Commonwealth Edison Co.	PWR	W	09/74
Oconee 3	Duke Power Co.	PWR	BW	12/74
Arkansas 1	Arkansas Power & Light Co.	PWR	BW	12/74
Prairie Island 2	Northern States Power Co.	PWR	W	12/74
Peach Bottom 3	Philadelphia Electric Co.	BWR	GE	12/74
Duane Arnold	Iowa Electric Light & Power Co.	BWR	GE	02/75
Browns Ferry 2	Tennessee Valley Authority	BWR	GE	03/75
Rancho Seco	Sacramento Municipal Utility District	PWR	BW	04/75
Calvert Cliffs 1	Baltimore Gas & Electric Co.	PWR	CE	05/75
FitzPatrick	Power Authority of New York	BWR	GE	07/75
Cook 1	Indiana & Michigan Power Co.	PWR	W	08/75
Brunswick 2	Carolina Power & Light Co.	BWR	GE	11/75
Hatch 1	Georgia Power Co.	BWR	GE	12/75
Millstone 2	Northeast Nuclear Energy Co.	PWR	CE	12/75
Trojan	Portland General Electric Co.	PWR	W	05/76
Indian Point 3	Power Authority of New York	PWR	W	08/76
Beaver Valley 1	Duquesne Light Co.	PWR	W	10/76
St. Lucie 1	Florida Power & Light Co.	PWR	CE	12/76

Table 1.2 (continued)

Plant name	Utility	Reactor type	NSSS[b]	Commercial operation began
Browns Ferry 3	Tennessee Valley Authority	BWR	GE	03/77
Crystal River 3	Florida Power Corp.	PWR	BW	03/77
Brunswick 1	Carolina Power & Light Co.	BWR	GE	03/77
Calvert Cliffs 2	Baltimore Gas & Electric Co.	PWR	CE	04/77
Salem 1	Public Service Electric & Gas Co.	PWR	W	06/77
Farley 1	Alabama Power and Light Co.	PWR	W	12/77
North Anna 1	Virginia Electric & Power Co.	PWR	W	06/78
Davis-Besse 1	Toledo Edison Co.	PWR	BW	07/78
Cook 2	Indiana & Michigan Power Co.	PWR	W	07/78
Fort St. Vrain	Public Service Co. of Colorado	HTGR	GA	07/79
Hatch 2	Georgia Power Co.	BWR	GE	09/79
Arkansas 2	Arkansas Power & Light Co.	PWR	CE	03/80
North Anna 2	Virginia Electric & Power Co.	PWR	W	12/80
Sequoyah 1	Tennessee Valley Authority	PWR	W	07/81
Farley 2	Alabama Power and Light Co.	PWR	W	07/81
Salem 2	Public Service Electric & Gas Co.	PWR	W	10/81
McGuire 1	Duke Power Co.	PWR	W	12/81
Sequoyah 2	Tennessee Valley Authority	PWR	W	06/82

[a]Does not include TMI-2 because its license was suspended effective July 20, 1979 (see Vol. 44, No. 149, p. 45271 of the *Federal Register*); Dresden 1 and Humboldt Bay because they were shut down September 31, 1978, and July 2, 1976, respectively, and no decision has yet been made on future operation; and Diablo Canyon, whose license was both granted and suspended in 1981.

[b]Abbreviations of nuclear steam-supply system (NSSS) manufacturers:

AC	Allis-Chalmers Mfg. Co.	GA	General Atomic Co.
BW	Babcock & Wilcox Co.	GE	General Electric Co.
CE	Combustion Engineering, Inc.	W	Westinghouse Electric Corp.

2. POWER GENERATION

2.1 Introduction

Tables 2.1—2.3 summarize the plant availability* and net electrical capacity factors* for the BWRs, PWRs, and HTGR, respectively, for 1982. Table 2.4 is a composite of the power generation statistics for 1982. Similar information has been reported for the years 1973—1981 (see previous reports in this series).

2.2 Electrical Output for 1982

In 1982 the total net electrical output for 72 nuclear power plants in commercial operation was 278.0 billion kWh.[1] This represents a 3.8% increase in nuclear electricity over the previous year.

Of the total nuclear electricity produced during 1982, 32.2% was produced by BWRs, 67.6% by PWRs, and 0.2% by the HTGR.

Note that these production quantities were impacted by the fact that one of the 72 units, TMI-1, though not damaged during the accident to its sister unit in 1979, remained shut down during the entire year 1982 by NRC order.

2.3 Plant Availability Factors for 1982

The average plant availability factor for all plants in 1982 was 65.9% for the 72 plants in commercial operation, weighted by the design electrical rating (DER)* of the plants. The average BWR and PWR availability factors for this period were 67.3 and 65.5%, respectively. The HTGR had an availability factor of 37.3%.

The BWR availability factors range from 21.4% for Nine Mile Point to 96.0% for Vermont Yankee. Four BWRs (Brunswick 2 at 38.6%, Hatch 1 at 49.3%, La Crosse at 44.6%, and Nine Mile Point at 21.4%) had availability factors less than 50%, while ten reported availabilities greater than 70%.

The 21.4% availability for Nine Mile Point was due to an extended shutdown, begun in March 1982 and still continuing at year's end, to replace cracked recirculation piping. Brunswick 2's availability factor of 38.6% is ascribable chiefly to a 161-day refueling-plus-maintenance outage from late April through September plus another 35-day maintenance shutdown from late October into December.

The PWR availability factors ranged from 0 for TMI-1 to 97.3% for Salem 2. Seven PWRs (Beaver Valley 1 at 41.6%, Indian Point 3 at 22.5%, North Anna 1 at 34.6%, Oconee 3 at 32.3%, Robinson 2 at 48.9%, San Onofre 1 at 15.7%, and TMI-1 at 0%) had availability factors of less than 50%, while 22 units had availability factors of 70% or greater. TMI-1 remained shut down by NRC order due to the accident at TMI-2.

*See Appendix A for definition.

Table 2.1. BWR power generation statistics for 1982 (24 plants)

BWR plants	DER[a] [MW(e) net]	Electrical output [MWh(e) net]	Plant availability factor (%)	Plant capacity factor (%)		Plant age[c] (years)
				Using MDC[b]	Using DER	
Big Rock Point	72	359,883	70.8	64.2	57.1	20.1
Browns Ferry 1	1,065	7,880,870	91.0	84.5	84.5	9.2
Browns Ferry 2	1,065	4,450,929	54.5	47.7	47.7	8.3
Browns Ferry 3	1,065	4,892,858	57.3	52.4	52.4	6.3
Brunswick 1	821	2,921,621	62.0	42.2	40.6	6.1
Brunswick 2	821	1,910,099	38.6	27.6	26.6	7.7
Cooper Station	778	5,276,082	84.6	78.8	77.4	8.6
Dresden 2	794	5,123,040	92.4	75.8	73.7	12.7
Dresden 3	794	3,887,883	63.5	57.4	55.9	11.4
Duane Arnold	538	2,280,467	74.4	50.5	48.4	8.6
FitzPatrick	821	4,959,655	75.0	69.9	69.0	7.9
Hatch 1	777	2,877,575	49.3	43.3	42.3	8.1
Hatch 2	784	3,728,261	63.8	55.2	54.3	4.3
La Crosse	50	137,976	44.6	32.8	31.5	14.7
Millstone 1	660	4,078,277	79.9	71.2	70.5	12.1
Monticello	545	2,420,820	63.3	52.6	50.7	11.8
Nine Mile Point	620	1,134,758	21.4	21.2	20.9	13.1
Oyster Creek	650	2,013,090	62.5	37.1	35.4	13.3
Peach Bottom 2	1,065	4,794,414	58.1	52.1	51.4	8.9
Peach Bottom 3	1,065	8,532,319	95.6	94.1	91.5	8.3
Pilgrim 1	655	3,287,027	63.9	56.0	57.3	10.5
Quad Cities 1	789	3,224,824	68.0	48.2	46.9	10.7
Quad Cities 2	789	5,058,983	83.9	75.1	73.2	10.6
Vermont Yankee	514	4,174,255	96.0	94.5	92.7	10.3
Total	17,597	89,405,966				243.6
Average	733	3,725,249	67.3	57.7	56.3	10.1
Weighted average[d]			68.3	59.1	58.0	

[a]DER = design electrical rating.

[b]MDC = maximum dependable capacity.

[c]Computed from date of first electrical generation through December 31, 1982.

[d]Averages weighted by the DER.

Table 2.2. PWR power generation statistics for 1982 (47 plants)

PWR plants	DER [MW(e) net]	Electrical output [MWh(e) net]	Plant availability factor (%)	Plant capacity factor (%)		Plant age[a] (years)
				Using MDC	Using DER	
Arkansas 1	850	3,721,409	64.8	50.8	50.0	8.4
Arkansas 2	912	3,807,388	57.4	50.7	47.7	2.8
Beaver Valley 1	852	2,688,163	41.6	37.9	36.0	6.6
Calvert Cliffs 1	845	5,362,175	73.3	74.2	74.4	8.0
Calvert Cliffs 2	845	5,004,951	74.2	69.3	67.6	6.1
Cook 1	1,054	5,352,823	62.7	58.5	58.0	7.9
Cook 2	1,100	6,995,651	76.9	73.8	72.6	4.8
Crystal River 3	825	4,915,582	76.0	69.6	68.0	5.9
Davis-Besse 1	906	3,218,155	51.5	42.0	40.5	5.3
Farley 1	829	5,216,496	79.2	74.1	71.8	5.4
Farley 2	829	5,295,330	79.2	74.3	72.9	1.6
Fort Calhoun	478	3,482,164	89.7	83.2	83.2	9.4
Ginna	470	2,407,987	58.8	58.5	58.5	13.1
Haddam Neck	582	4,538,360	93.4	93.1	89.0	15.4
Indian Point 2	873	4,447,401	65.4	58.8	58.2	9.5
Indian Point 3	965	1,436,036	22.5	18.4	17.0	6.7
Kewaunee	535	3,824,851	87.6	84.9	81.6	8.7
Maine Yankee	825	4,524,228	69.1	63.8	62.6	10.1
McGuire 1	1,180	4,302,267	80.4	41.6	41.6	1.3
Millstone 2	870	5,009,081	70.6	66.2	65.7	7.1
North Anna 1	907	2,397,857	34.6	31.6	30.2	4.1
North Anna 2	907	4,047,202	57.0	51.9	50.9	2.0
Oconee 1	887	5,152,750	72.4	68.4	66.3	9.7
Oconee 2	887	3,437,387	52.3	45.6	44.2	9.2
Oconee 3	887	2,116,625	32.3	28.1	27.2	8.3
Palisades	805	3,345,123	54.7	60.1	47.4	11.0
Point Beach 1	497	2,701,830	81.8	62.3	62.1	12.2
Point Beach 2	497	3,605,501	86.8	83.1	82.8	10.4
Prairie Island 1	530	3,918,177	90.9	88.9	84.4	9.1
Prairie Island 2	530	3,857,949	89.6	88.1	83.1	8.0
Rancho Seco	918	3,366,508	53.3	44.0	41.9	8.2
Robinson 2	700	2,251,851	48.9	38.7	36.7	12.3
Salem 1	1,090	4,094,731	47.9	43.3	42.9	6.0
Salem 2	1,115	7,941,580	97.3	82.0	81.3	1.5
San Onofre 1	436	510,223	15.7	13.4	13.4	15.6
Sequoyah 1[b]	1,148	4,908,979	52.8	49.7	49.0	2.4
Sequoyah 2[c]	1,148	3,926,291	74.1	66.7	66.0	1.0
St. Lucie 1[d]	830	6,784,644	94.0	96.4	96.4	6.7
Surry 1	788	5,483,227	88.8	80.8	79.4	10.5
Surry 2	788	5,492,206	88.3	80.9	79.6	9.8
Three Mile Island 1[e]	819	0	0	0	0	8.5
Trojan	1,130	4,802,041	60.8	50.8	48.5	7.0
Turkey Point 3	693	3,765,886	64.1	66.5	62.0	9.2
Turkey Point 4	693	3,844,893	66.3	67.9	63.3	9.5
Yankee-Rowe	175	882,161	73.4	57.5	57.5	22.1
Zion 1	1,040	4,695,388	59.1	51.5	51.5	9.5
Zion 2	1,040	5,158,063	69.4	56.6	56.6	9.0
Total	38,510	188,039,571				376.9
Average	819	4,000,842	65.5	59.5	57.9	8.0
Weighted average[f]			64.6	58.2	56.7	

[a]Computed from date of first electrical generation through December 31, 1982.

[b]At the end of March 1982, the DER for Sequoyah 1 was increased from 1,128 to 1,148 MW(e) net.

[c]Data are given for the period June 1, 1982 (date when commercial operation began), through December 31, 1982.

[d]At the end of May 1982, the DER for St. Lucie 1 was increased from 802 to 830 MW(e) net.

[e]TMI-1 remained shut down during 1982 due to continuation of an NRC regulatory restraint order.

[f]Averages weighted by the design electrical capacity.

Table 2.3. HTGR power generation statistics for 1982 (1 plant)

HTGR plant	DER [MW(e) net]	Electrical output [MWh(e) net]	Plant availability factor (%)	Plant capacity factor (%)		Plant age[a] (years)
				Using MDC	Using DER	
Fort St. Vrain[b]	330	568,851	37.3	19.7	19.7	6.1

[a]Computed from date of first electrical generation through December 31, 1982.

[b]During 1982 Fort St. Vrain was restricted to an electrical generating capacity of 231 MW(e) net, pending resolution of in-core temperature fluctuations.

Table 2.4. Composite power generation statistics for 1982

Plants	DER [MW(e) net]	Electrical output [MWh(e) net]	Plant availability factor (%)	Plant capacity factor (%) Using MDC	Plant capacity factor (%) Using DER	Plant age (years)
24 BWRs	17,597	89,405,966	67.3	57.7 (59.1)[a]	56.3 (58.0)[a]	10.1
47 PWRs	38,510	188,039,571	65.5	59.5 (58.2)[a]	57.9 (56.7)[a]	8.0
1 HTGR	330	568,851	37.3	19.7	19.7	6.1
Total	56,437	278,014,388				
Average per plant	784	3,861,311				
Weighted average by plant			65.7	58.3	56.8	8.7
Weighted average by design electrical capacity			65.9	58.7	57.1	

[a]Average weighted by design electrical capacity.

The 15.7% availability for San Onofre 1 was due to a shutdown on February 27, 1982, for seismic refits and other maintenance that was originally expected to last 14 weeks but, in fact, extended past the rest of the year and included, at least, most of 1983 as well. At the time of this writing (November 1983), the unit was still awaiting approval by NRC of the seismic rework plans.

The 22.5% availability of Indian Point 3 had its cause in problems affecting the girth welds of one of its steam generators. The problem was discovered during a refueling outage begun on March 25, 1982; it kept the plant off line the rest of the year, continuing until June 1983.

Oconee 3 suffered two extended shutdowns, thus accounting for its 32.3% availability factor. The first of these lasted 42 days and was due primarily to a steam generator tube leakage problem. The second outage was for scheduled refueling plus a 10-year inspection and steam generator auxiliary feed ring modifications. This outage lasted for 162 days, extending from late April to early October.

North Anna 1's 34.6% availability was caused mainly by an extended refueling, maintenance, and repair outage that began in mid-May and lasted until early December. Almost as soon as the unit restarted in December, a transformer failure caused extensive damage to the main generator, requiring replacement of the three main transformers and the generator.

2.4 Plant Capacity Factors for 1982

Individual plant capacity factors were calculated using MDC and DER, both in net megawatts electric. The weighted* average capacity factors for the 72 commercial nuclear power plants were 58.7% using MDC and 57.1% using DER. These values include the relatively low capacity factors of the HTGR, which were 19.7% using either capacity factor definition.

The weighted average capacity factors for the 24 BWRs were 59.1 and 58.0% using MDC and DER, respectively. The MDC capacity factors varied from 21.2% for Nine Mile Point to 94.5% for Vermont Yankee; the DER capacity factors ranged from 20.9 to 92.7% with the same two plants recording the lowest and highest values, respectively. Based on the DER capacity factor, there were nine BWRs below 50% and seven plants above 70%.

The weighted average capacity factors for the 47 PWRs were 58.2 and 56.7% using MDC and DER, respectively. Both the MDC and DER capacity factors ranged from 0 to 96.4%, with TMI-1 accounting for the lower bound and St. Lucie 1 achieving the highest value.

Among the 47 PWRs, 12 MDC capacity factors were below 50% while 14 ranked above 70%. As for the DER figures among the PWRs, 16 units had factors below 50%, while 14 reactors had DER availabilities above 70%.

Power generation information for 1982 is summarized in Tables 2.1–2.4. More detailed information on individual plants is presented in Appendix B. Tables 2.5–2.8 give the distributions of availability and capacity factors as a function of age. Availability and capacity factor distributions are given in Table 2.9.

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*The weighting of the average capacity factor is based on plant size in terms of design electrical capacity.

Table 2.5. BWR plant availability and capacity factors as a function of plant age for 1982[a]

Plant age group (years)	Number of plants in age group	Average availability factor[b] (%)	Average capacity factor[b] (%)
0–0.9	0		
1–1.9	0		
2–2.9	0		
3–3.9	0		
4–4.9	1	54.3	63.8
5–5.9	0		
6–6.9	2	59.3	47.3
7–7.9	2	56.8	47.8
8–8.9	6	69.2	60.9
9–9.9	1	91.0	84.5
10–10.9	4	76.8	65.5
11–11.9	2	63.4	53.8
12–12.9	2	86.7	72.2
13–17.9	3	42.5	28.4
18+	1	70.8	57.1

[a]Based on DER, megawatts electrical.

[b]Average weighted by DER.

Table 2.6. PWR plant availability and capacity factors as a function of plant age for 1982[a]

Plant age group[b] (years)	Number of plants in age group	Average availability factor[c] (%)	Average capacity factor[c] (%)
0–0.9	0		
1–1.9	4	82.9	64.6
2–2.9	3	55.5	49.2
3–3.9	0		
4–4.9	2	57.8	53.4
5–5.9	3	68.4	59.5
6–6.9	5	54.6	50.4
7–7.9	3	64.2	56.7
8–8.9	7	53.7	47.5
9–9.9	10	69.8	62.6
10–10.9	3	80.6	73.6
11–11.9	1	54.7	47.4
12–12.9	2	62.6	47.2
13–17.9	3	59.7	57.2
18+	1	59.1	51.5

[a]Based on DER, megawatts electrical.

[b]Plant age is computed from date of first electricity generation.

[c]Average weighted by DER.

Table 2.7. HTGR plant availability and capacity factors as a function of plant age for 1982[a]

Plant age group (years)	Number of plants in age group	Average availability factor (%)	Average capacity factor (%)
6–6.9	1	37.3	19.7

[a]Based on DER megawatts electrical.

Table 2.8. Composite of plant availability and capacity factors as a function of plant age for 1982[a]

Plant age (years)	Number of age group	Average availability factor[b] (%)	Average capacity factor[b] (%)
0–0.9	0		
1–1.9	4	82.9	64.6
2–2.9	3	55.5	49.2
3–3.9	0		
4–4.9	3	59.5	53.7
5–5.9	3	68.4	59.5
6–6.9	8	55.1	48.0
7–7.9	5	61.6	53.6
8–8.9	13	61.4	54.1
9–9.9	11	72.3	65.2
10–10.9	7	78.4	69.0
11–11.9	3	60.1	51.4
12–12.9	4	75.8	60.9
13–17.9	6	51.6	43.7
18+	2	72.6	57.4

[a]Based on DER, megawatts electrical.

[b]Weighted by DER.

Table 2.9. Distribution of plant availability and plant capacity factors for 1982[a]

	Number of plants			
	BWRs	PWRs	HTGRs	Total
Plants with availability factors (in percent) of				
90 and over	4	4	0	8
80–90	2	8	0	10
70–80	4	10	0	14
60–70	7	8	0	15
50–60	3	9	0	12
Less than 50	4	8	1	12
Total	24	47	1	72
Average availability factors, % (weighted %)	67.3 (68.3)	65.5 (64.6)	37.3 (37.3)	65.7 (65.9)
Plants with capacity factors (in percent) using MDC of				
90 and over	2	2	0	4
80–90	1	8	0	9
70–80	4	4	0	8
60–70	2	10	0	12
50–60	7	10	0	17
Less than 50	8	13	1	21
Total	24	47	1	72
Average capacity factors using MDC, % (weighted %)	57.7 (59.1)	59.5 (58.2)	19.7 (19.7)	58.3 (58.7)
Plants with capacity factors (in percent) using DER of				
90 and over	2	1	0	3
80–90	1	7	0	8
70–80	4	6	0	10
60–70	1	9	0	10
50–60	7	8	0	15
Less than 50	9	16	1	26
Total	24	47	1	72
Average capacity factors using DER, % (weighted %)	56.3 (58.0)	57.9 (56.7)	19.7 (19.7)	56.8 (57.1)

[a]Averages weighted by the design electrical capacity.

Reference

1. U.S. Department of Energy, Energy Information Administration, *1982 Annual Report to Congress, Vol. 2: Energy Statistics*, DOE/EIA-0173(81)/2, 1982.

3. PLANT OUTAGES

3.1 Introduction

A review of the plant outages that occurred during 1982 provides a means of assessing the nature, number, and extent of the operating problems experienced at nuclear power plants during the year, as well as the principal systems and components involved. The data for this review were obtained from the data submitted by the licensees for the NRC's monthly publication *Licensed Operating Reactors, Status Summary Report* (NUREG-0020), as collected in the "Gray Book Data Base," a computerized collection of all the outage reports filed in the monthly reports.

In many cases, the outage type was classified differently than reported by the licensee. In numerous instances, the system and component code entries were either omitted or inappropriately entered. Where possible, based on available information, erroneous entries have been corrected, and all missing entries supplied. More than 30% of outage reports had either system or component information (or both) missing. Note also that different licensees attach very different interpretations to what constitutes a reportable outage, thus accounting at least in part for the great differences in the numbers of outages reported. Where reported outages were clearly outside the intention of the definitions, they were deleted; in doubtful cases, they were retained. The requirement for reporting power-level reductions greater than 20% of the previous day's power as zero-duration outages, in particular, was subject to widely different interpretations; these divergences were only partly resolvable in this analysis.

The tables in this chapter present plant outage data only for the 71 light-water-reactor (LWR) plants commercially operable in 1981. The outage experience for Fort St. Vrain, the single HTGR, is summarized in Sect. 3.5.4, and details can be found in the data sheets in Appendix B, which also contains detailed data sheets for all the 71 LWR plants in commercial operation in 1982. When the outage data are reviewed, note that there are significant differences in nuclear plant designs, even between plants of a given type; therefore, care should be used in interpreting the data.

3.2 Plant Outage Statistics

Care must be taken in counting outages and adding up outage hours because of the complications caused by outages that extend across month ends and year ends and by the definition of power reductions as zero-duration outages.

The following procedures have been adopted and used throughout the tables in this section:

1. Only those outages beginning in 1982 are counted in determining *numbers* of outages; outages begun in 1981 and extending into 1982 are not counted for 1982. Furthermore, outages continuing across month-end

boundaries are counted only once, even though an outage report is generated for each month into which the outage extends. These continuations are designated as outage method "4" and subtracted for the purpose of counting outages.

2. For the purpose of deriving outage hours, all hours in 1982 are counted, including the 1982 hours for outages begun in 1981 and excluding the 1983 hours for outages begun in 1982 and extending past midnight of December 31, 1982. Tables 3.1 and 3.2 list numbers of significant outages [i.e., outages lasting more than five days (120 h)]. For these tables, outages begun in 1981 that lasted 120 h or more in 1982 were counted (i.e., only the 1982 hours were counted in deciding whether the outage met the 120-h-or-more significance criterion).

3. In counting the numbers of outages (Tables 3.3 and 3.4), only real outages were counted (i.e., only those not of zero duration) because many of the power reductions were for periodic tests, for load adjustment, or of minor significance and thus not indicative of unit difficulties or unavailabilities. Clearly, the decision to include or exclude such zero-duration outages has no effect on total hours reported.

The following array shows the numbers of outages reported by the 71 LWR reactors covered in this report and defined as described above. In each listing the upper number is the number of nonzero-duration outages, the number below in parentheses is the number of power reductions (zero-duration outages), and the bottom number is their sum (i.e., the total number of reported outages):

	Forced outages	Scheduled outages	Total outages
PWRs	405	90	495
	(165)	(95)	(260)
	570	185	755
BWRs	175	46	221
	(146)	(248)	(394)
	321	294	615

Thus, in the 71 LWRs, there were 1,370 outages of which 654 were the zero-duration type and 716 were true outages. They lasted a total of 210,655.5 h, or 34.1% of the total year (including continuation of outages begun in 1981). Forced outage time for the LWRs averaged 11.7%, and scheduled outage time averaged 22.3%. The average total unit availability for the 71 LWRs was 71.8%.

Table 3.1 presents the 1982 performance data for BWRs and lists the systems and components involved in the major outages [i.e., outages lasting five days (120 h) or longer]. Table 3.2 presents similar information for PWRs. In the BWRs, in addition to 17 major outages for refueling, there were 11 major outages attributable to the main turbine generators, 9 caused by the reactor coolant system and 5 attributable to the engineered safety features. In the PWRs, aside from 29 major refueling outages, there were 29 caused by the steam and power conversion systems, 26

Table 3.1. Summary of BWR power plant outages during 1982

	Big Rock Point 1	Browns Ferry 1	Browns Ferry 2	Browns Ferry 3	Brunswick 1	Brunswick 2	Cooper	Dresden 2	Dresden 3	Duane Arnold	FitzPatrick	Hatch 1	Hatch 2	La Crosse	Millstone 1	Monticello	Nine Mile Point	Oyster Creek	Peach Bottom 2	Peach Bottom 3	Pilgrim 1	Quad Cities 1	Quad Cities 2	Vermont Yankee	Totals
Summary of performance data																									
Percent of year operational	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	
Percent of year in commercial operation	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	
Scheduled outages during commercial operation																									
Hours	1,639.6	0	3,700.3	2,437.5	704.5	3,901.0	1,138.3	107.9	2,925./	368.6	1,631.9	2,988.6	2,458.9	4,153.5	1,661.4	3,116.1	133.5	0	3,503.2	0	2,758.3	2,688.9	155.6	97.9	42,271.2
Percent	18.7	0	42.2	27.8	8.0	44.5	13.0	1.2	33.4	4.2	18.6	34.1	28.1	47.4	19.0	35.6	1.5	0	40.0	0	31.5	30.7	1.8	1.1	20.1
Forced outages during commercial operation																									
Hours	921.9	790.0	263.8	1,300.3	2,625.0	1,477.9	207.2	556.0	268.9	1,845.6	556.5	1,527.6	754.0	695.3	100.9	97.4	6,754.0	3,284.2	165.4	386.0	400.4	115.1	1,257.4	253.6	26,604.4
Percent	10.5	9.0	3.0	14.8	30.0	16.9	2.4	6.3	3.1	21.1	6.4	17.4	8.6	7.9	1.2	1.1	77.1	37.5	1.9	4.4	4.6	1.3	4.3	2.9	12.7
Total outage time during commercial operation																									
Hours	2,561.5	790.0	3,964.1	3,737.8	3,329.5	5,378.9	1,345.5	663.9	3,194.6	2,214.2	2,188.4	4,516.2	3,212.9	4,848.8	1,762.3	3,213.5	6,887.5	3,284.2	3,668.6	386.0	3,158.7	2,804.0	1,413.0	351.5	68,875.6
Percent	29.2	9.0	45.2	42.7	38.0	61.4	15.3	7.6	36.5	25.3	25.0	51.6	26.4	55.3	20.1	36.7	78.6	37.5	41.9	4.4	36.1	32.0	16.1	4.0	32.8
Unit availability in commercial operation																									
Percent	70.8	91.0	54.5	57.3	62.0	38.6	84.6	92.4	63.5	74.4	75.0	49.3	63.8	44.6	79.9	63.3	21.4	62.5	58.1	95.6	63.9	68.0	83.9	96.0	67.3
Systems and components causing major outages (figures indicate number of outages lasting five days or longer)																									
Fuel inspection or replacement	2		1	1	1	1	1		1		1	1	1	1	1	1			1		1	1			17
Engineered safety features		1		1	1	1				1															5
Reactor coolant system										2		1	1					2	2				1		9
Implement requirements of NRC																									0
Electric power													1												1
Reactor and control rods																									0
Instrumentation and controls	1					2						1													4
Main generator and turbine	1			1				1			2	1	1	1		1				1	1				11
Shock suppressors and supports					1																				1
Steam and power conversion systems			1						1								2								4
Auxiliary water																									0
Other										1						1		1							3

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Table 3.2. Summary of PWR power plant outages during 1982

	Arkansas 1	Arkansas 2	Beaver Valley 1	Calvert Cliffs 1	Calvert Cliffs 2	Cook 1	Cook 2	Crystal River 3	Davis-Besse 1	Farley 1	Farley 2	Fort Calhoun
Summary of performance data												
Percent of year operational	100	100	100	100	100	100	100	100	100	100	100	100
Percent of year in commercial operation	100	100	100	100	100	100	100	100	100	100	100	100
Scheduled outages during commercial operation												
Hours	2,338.0	2,203.3	4,906.3	2,202.9	1,847.2	2,178.9	982.5	46.8	4,200.0	26.4	999.6	606.0
Percent	26.7	25.1	56.0	25.1	21.1	24.9	11.2	0.5	47.9	0.3	11.4	6.9
Forced outages during commercial operation												
Hours	749.3	1,528.8	205.3	134.9	414.3	1,090.4	1,036.8	2,105.0	51.6	1,843.1	824.5	296.5
Percent	8.6	17.5	2.3	1.5	4.7	12.4	11.8	24.0	0.6	21.0	9.4	3.4
Total outage time during commercial operation												
Hours	3,087.3	3,732.1	5,111.6	2,337.8	2,261.5	3,269.3	2,019.3	2,151.8	4,251.6	1,869.5	1,824.1	902.5
Percent	35.2	42.6	58.3	26.7	25.8	37.3	23.0	24.6	48.5	21.3	20.8	10.3
Unit availability in commercial operation												
Percent	64.8	57.4	41.6	73.3	74.2	62.7	76.9	76.0	51.5	79.2	79.2	89.7
Systems and components causing major outages (figures indicate number of outages lasting five days or longer)												
Fuel inspection or replacement	1	1	1	1	1	1	1		1		1	
Implement requirements of NRC												
Steam and power conversion systems	2	1	1				1					1
Instrumentation and controls	1	1										
Reactor coolant		2				1	1				1	
Electric power										1		
Auxiliary water systems								1				
Auxiliary process systems								1				
Engineered safety features								1				
Reactor and control rods		?			1							
Main generator and turbine						1						
Shock suppressors and supports												
Other				1								1

	Ginna	Haddam Neck	Indian Point 2	Indian Point 3	Kewaunee	Maine Yankee	McGuire 1	Millstone 2	North Anna 1	North Anna 2	Oconee 1	Oconee 2
Summary of performance data												
Percent of year operational	100	100	100	100	100	100	100	100	100	100	100	100
Percent of year in commercial operation	100	100	100	100	100	100	100	100	100	100	100	100
Scheduled outages during commercial operation												
Hours	2,517.8	39.2	2,576.6	6,745.0	1,050.5	2,609.5	367.7	1,781.8	4,834.9	2,320.3	203.5	3,157.2
Percent	28.7	0.4	29.4	77.0	12.0	29.8	4.2	20.3	55.2	26.5	2.3	36.0
Forced outages during commercial operation												
Hours	1,090.8	534.8	454.1	45.6	40.3	285.2	1,345.7	792.7	894.9	1,447.4	2,216.5	1,021.7
Percent	12.4	6.1	5.2	0.5	0.5	3.2	15.3	9.0	10.2	16.5	25.3	11.7
Total outage time during commercial operation												
Hours	3,608.6	574.0	3,030.7	6,790.6	1,090.3	2,894.7	1,713.4	2,574.5	5,729.8	3,767.7	2,420.0	4,178.9
Percent	41.2	6.6	34.6	77.5	12.4	33.0	19.6	29.4	65.4	43.0	27.6	47.7
Unit availability in commercial operation												
Percent	58.8	93.4	65.4	22.5	87.6	69.1	80.4	70.6	34.6	57.0	72.4	52.3
Systems and components causing major outages (figures indicate number of outages lasting five days or longer)												
Fuel inspection or replacement	1		1	1		1		1	1	1		1
Implement requirements of NRC												
Steam and power conversion systems	1								1	1		
Instrumentation and controls												
Reactor coolant	1						3	1			4	3
Electric power		1							1	1		
Auxiliary water systems												
Auxiliary process systems												
Engineered safety features			1									
Reactor and control rods											1	
Main generator and turbine		2						1			1	1
Shock suppressors and supports												
Other			1		1	1						1

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Table 3.2 (continued)

	Oconee 3	Palisades	Point Beach 1	Point Beach 2	Prairie Island 1	Prairie Island 2	Rancho Seco	Robinson 2	Salem 1	Salem 2	San Onofre 1	Sequoyah 1	Sequoyah 2	St. Lucie 1	Surry 1	Surry 2	Three Mile Island 1	Trojan	Turkey Point 3	Turkey Point 4	Yankee-Rowe	Zion 1	Zion 2	Totals
Summary of performance data																								
Percent of year operational	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	
Percent of year in commercial operation	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	
Scheduled outages during commercial operation																								
Hours	3,904.1	0	1,609.0	1,159.9	781.8	856.0	3,379.2	4,134.3	4,257.6	0	7,405.3	2,684.2	477.9	446.8	656.8	833.8	0	3,683.0	2,421.0	2,169.8	2,302.6	1,881.2	0	95,785.7
Percent	44.6	0	18.4	13.2	8.9	9.8	38.6	47.2	48.6	0	84.5	30.6	9.3	5.1	7.5	9.5	0	42.0	27.6	24.8	26.3	21.5	0	23.5
Forced outages during commercial operation																								
Hours	2,028.6	3,970.5	14.9	3.5	16.2	55.0	686.9	345.9	308.0	240.5	0	1,445.7	829.1	82.8	323.3	193.8	8,760.0	323.7	724.9	778.6	27.3	1,704.6	2,680.2	45,994.2
Percent	23.1	45.3	0.2	0	0.2	0.6	7.8	3.9	3.5	2.7	0	16.5	16.1	0.9	3.7	2.2	100.0	3.7	3.3	8.9	0.3	19.5	30.6	11.3
Total outage time during commercial operation																								
Hours	5,932.7	3,970.5	1,623.9	1,163.4	798.0	911.0	4,066.1	4,480.2	4,565.6	240.5	7,405.3	4,129.9	1,307.0	529.6	980.1	1,027.6	8,760.0	4,006.7	3,145.9	2,948.4	2,329.9	3,585.8	2,680.2	141,779.9
Percent	67.7	45.3	18.5	13.3	9.1	10.4	46.4	51.1	52.1	2.7	84.5	47.1	25.4	6.0	11.2	11.7	100.0	45.7	35.9	33.6	26.6	40.9	30.6	34.7
Unit availability in commercial operation																								
Percent	32.3	54.7	81.8	86.8	90.9	89.6	53.3	48.9	47.9	97.3	15.7	52.8	74.1	94.0	88.8	88.3	0	60.8	64.1	66.3	73.4	59.1	69.4	65.5
Systems and components causing major outages (figures indicate number of outages lasting five days or longer)																								
Fuel inspection or replacement	1		1	1	1	1		1	2			1						1			1	1		29
Implement requirements of NRC																	1							1
Steam and power conversion systems		3	1					1	1		1	1		1	2	2			2	3		2		29
Instrumentation and controls																1								3
Reactor coolant	4			1			1											1	1			1		26
Electric power		2										1												7
Auxiliary water systems		1							2															4
Auxiliary process systems																								1
Engineered safety features							1						1									1		5
Reactor and control rods																								4
Main generator and turbine				1								1	1							1			3	12
Shock suppressors and supports																								0
Other																		1						7

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Table 3.3. Summary of BWR and PWR nuclear power plant outages by type for 1982

Plant type (number of plants)	Forced outages		Scheduled outages		Total outages	
	Number of events	Outage duration (h)	Number of events	Outage duration (h)	Number of events	Outage duration (h)
BWR plants (24)	175	26,604.4	46	42,271.2	221	68,875.6
Average per BWR plant	7.3	1,108.5	1.9	1,761.3	9.2	2,869.8
Average outage duration per BWR plant		152.0		918.9		311.7
PWR plants (47)	405	45,994.2	90	95,785.7	495	141,779.9
Average per PWR plant	8.6	978.6	1.9	2,038.0	10.5	3,016.6
Average outage duration per PWR plant		113.6		1,064.3		286.4
All LWR plants (71)	580	72,598.6	136	138,056.9	716	210,655.5
Average per LWR plant	8.2	1,022.5	1.9	1,944.5	10.1	2,967.0
Average outage duration per LWR plant		125.2		1,015.1		294.2

Table 3.4. Proximate causes of outages at LWR units during 1982

Events	BWRs		PWRs		All plants[a]	
	Number of causes	Outage hours	Number of causes	Outage hours	Number of causes	Total outage hours
			Forced outages			
Equipment failure	120	19,046.5	266	28,581.6	386 (53.9)	47,628.1 (22.6)
Maintenance or test	14	5,378.6	35	5,325.4	49 (6.8)	10,704.0 (5.1)
Regulatory restrictions	2	275.8	1	8,767.3	3 (0.4)	9,043.1 (4.3)
Operational error	9	226.4	54	1,244.6	63 (8.8)	1,471.0 (0.7)
Administrative	0	0	2	301.3	2 (0.3)	301.3 (0.1)
Other	30	1,677.1	47	1,774.0	77 (10.8)	3,451.1 (1.6)
			Scheduled outages			
Maintenance or test	29	3,419.0	51	22,089.6	80 (11.2)	25,508.6 (12.1)
Refueling	13	38,481.3	29	70,300.4	41 (5.7)	105,081.4 (49.9)
Regulatory restrictions	0	0	0	0	0 (0)	0 (0)
Administrative	0	0	1	571.3	1 (0.1)	571.3 (0.3)
Equipment failure	4	370.9	7	685.2	11 (1.5)	1,056.1 (0.5)
Other	0	0	2	2,139.2	3 (0.4)	5,839.5 (2.8)
Total	221	68,875.6	495	141,779.9	716 (100)	210,655.5 (100)

[a]Numbers in parentheses represent percentages of total.

due to the reactor coolant systems, and 12 attributed to the main turbine generators.

Under "percent of the year operational," the figure given relate to the fraction of the year following first generation of electricity. However, the outages throughout this chapter are those with dates subsequent to the start of commercial operation only.

3.3 Types of Outages at LWRs

The data on forced and scheduled outages at the 24 BWRs and 47 PWRs in commercial operation in 1982 are summarized in Table 3.3. The average number of forced outages was 8.2 per plant, with each outage averaging 125.2 h. The average number of scheduled outages was 1.9 per plant, with each one averaging 1,015.1 h (compared with 876.6 h in 1981 — an increase of 15.8%). On the average, each plant experienced 10.1 outages with a mean duration of 294.2 h each.

3.4 Proximate Causes of Plant Outages at LWRs

Plant outages at LWRs and their proximate causes are summarized in Table 3.4. Each outage cause was assigned to one of the following eight categories: (1) refueling (scheduled), (2) equipment failure (forced), (3) maintenance or test (primarily scheduled), (4) operational error (forced), (5) regulatory restriction (forced and scheduled), (6) administrative (forced and scheduled), (7) training and licensing (scheduled), and (8) other. The operational error category includes any plant personsonnel errors that caused a forced outage. Scheduled refuelings required the most outage time of all causes — 105,081 h (49.9%). Equipment failures (forced) accounted for 47,628.1 h (22.6%) of total outage time. Regulatory restrictions (forced and scheduled) accounted for only 9,043.1 h (4.3%) of total outage time; it should be noted that 8,760 h of this (i.e., one whole year) was due to the shutdown of the TMI-1 reactor, which leaves only 283.1 h (0.1%) for all other regulatory shutdowns. It is worth pointing out, however, that this number of outage hours would not include any time for operation at reduced power due to regulatory restrictions, which would be listed as zero-duration outages and thus would not contribute to the total.

Although the number of LWR plants considered in this review increased by one (1.4%) from 1981 to 1982, the total outage time increased by 21,194.1 h (11.1%).

Table 3.5 lists the ratio of outage hours for various causes to 100 h of commercial operation. These numbers may also be considered as the percent of time expended for each cause. In 1982, all 24 BWRs were commercially operable 100% of the year (8,760 h); therefore, the total number of operating hours considered for BWRs was 210,240 h. For the PWRs, 46 units were commercially operable all year, and 1 unit (Sequoyah 2) began commercial operation on June 1, 1983, thus being in that condition

Table 3.5. BWR and PWR outage ratios (outage hours per 100 h of commercial operation)

	Type of plant	
	BWR	PWR
Refueling	16.5	17.2
Equipment failure	9.2	7.2
Maintenance or test	4.2	6.7
Regulatory restriction	0.1	2.1
Operational error	0.1	0.3
Administrative	0	0.2
Other	2.6	1.0
Total	32.8	34.7

for 0.5863 year = 5,136 h.* These hours added to the hours of 46 PWRs in operation all year give a total of 408,096 h of commercial operation for PWRs. The table indicates that PWRs (as a class) accumulated a slightly larger percentage of outage time than did BWRs for all causes combined but that the proportionate outages were very comparable for all categories except regulatory restriction, which is almost totally due to the all-year regulatory shutdown of TMI-1 (a PWR).

3.5 Systems and Components Associated with Plant Outages at LWRs

Visual representations of plant outages are shown in Tables 3.6 and 3.7 and in Fig. 3.1. The tables classify outages by type and identify the system, component, plant, and cause. Outage duration in hours and the percent of the total outage time are listed for major groupings. The system and component classifications used in these tables are listed in Appendix B.

The four columns in each table are interrelated. The first column separates outages by type, the second column shows the main systems involved within each type of outage, the third column breaks the systems category into components associated with the system, and the fourth column lists the specific reactors within each component group that account for the most hours. Residuals labeled "various" at each stage of the

*These hours are based on assuming that commercial operation began at midnight of the day commercial operation was declared (i.e., 24 h were counted on that day).

Table 3.6. BWR plant outages in 1982[a]

Outage type	Associated system	Associated component	Plants affected
Forced outages	Steam and power conversion	6,969.6 h Pipes 10.1%	6,754.0 h Nine Mile Point 9.8%
		1,882.7 h Turbines 2.7%	938.4 h Browns Ferry 3 1.4%
		869.3 h Generators 1.3%	605.0 h La Crosse 0.9%
		729.1 h Valves 1.1%	572.1 h Big Rock Point 0.8%
		328.8 h I&C 0.5%	556.5 h FitzPatrick 0.8%
		1,016.0 h Various 1.5%	282.5 h Brunswick 1 0.4%
			242.0 h Peach Bottom 3 0.4%
			236.8 h Dresden 2 0.3%
			231.6 h Pilgrim 1 0.3%
			213.2 h Hatch 2 0.3%
			196.9 h Browns Ferry 2 0.3%
			195.4 h Dresden 3 0.3%
			172.3 h Vermont Yankee 0.3%
	11,795.5 h 17.1%		598.8 h Various 0.9%
	Reactor coolant	2,984.9 h Valves 4.3%	2,756.1 h Oyster Creek 4.0%
		1,158.7 h Demineralizers 1.7%	1,434.4 h Duane Arnold 2.1%
			1,256.1 h Hatch 1 1.8%
		520.2 h Pumps 0.8%	1,217.5 h Quad Cities 2 1.8%
		1,883.8 h Various 2.7%	189.2 h Hatch 2 0.3%
			128.8 h Peach Bottom 2 0.2%
			128.1 h Pilgrim 1 0.2%
	7,675.8 h 11.1%		565.6 h Various 0.8%
	I&C	1,814.4 h I&C 2.6%	1,164.4 h Brunswick 2 1.7%
		230.1 h Valves 0.3%	235.0 h Browns Ferry 1 0.3%
		155.5 h Various 0.2%	202.7 h Duane Arnold 0.3%
			179.1 h Brunswick 1 0.3%
			147.2 h Big Rock Point 0.2%
	2,200.0 h 3.2%		271.6 h Various 0.4%
	Engineered safety features	563.1 h Valves 0.8%	391.8 h Browns Ferry 1 0.6%
		533.5 h N/A 0.8%	353.6 h Oyster Creek 0.5%
		353.6 h Heat exchangers 0.5%	267.5 h FitzPatrick 0.4%
			266.5 h Browns Ferry 3 0.4%
		256.6 h Pipes 0.4%	175.7 h Brunswick 2 0.3%
			147.7 h Dresden 2 0.2%
	1,706.8 h 2.5%		104.0 h Various 0.2%
	Electric power	266.6 h Generators 0.4%	218.8 h Hatch 2 0.3%
	392.2 h 0.6%	125.6 h Various 0.2%	173.4 h Various 0.3%
	Various	2,267.4 h N/A 3.3%	2,094.6 h Brunswick 1 3.0%
		566.7 h Various 0.8%	202.6 h Big Rock Point 0.3%
			174.5 h Oyster Creek 0.3%
26,604.4 h 38.6%	2,834.1 h 4.1%		362.4 h Various 0.5%
Scheduled outages	Reactor	Fuel elements	4,118.7 h La Crosse 6.0%
			3,899.7 h Brunswick 2 5.7%
			3,700.3 h Browns Ferry 2 5.4%
			3,173.4 h Peach Bottom 2 4.6%
			2,925.7 h Dresden 3 4.2%
			2,578.7 h Quad Cities 1 3.7%
			2,458.7 h Monticello 3.6%
			2,436.9 h Browns Ferry 3 3.5%
			2,332.6 h Pilgrim 1 3.4%
			2,269.9 h Hatch 2 3.3%
			2,013.1 h Hatch 1 2.9%
			1,661.4 h Millstone 1 2.4%
			1,639.6 h Big Rock Point 2.4%
			1,631.9 h FitzPatrick 2.4%
			1,138.3 h Cooper 1.7%
	38,481.3 h 55.9%	38,481.3 h 55.9%	502.4 h Brunswick 1 0.7%
	Steam and power conversion	1,186.5 h Turbines 1.7%	937.0 h Hatch 1 1.4%
		352.3 h Valves 0.5%	425.7 h Pilgrim 1 0.6%
		157.1 h Pumps 0.2%	236.4 h Monticello 0.3%
		163.5 h Various 0.2%	133.5 h Nine Mile Point 0.2%
	1,859.4 h 2.7%		126.8 h Various 0.2%
	Reactor coolant	387.0 h Valves 0.6%	329.8 h Peach Bottom 2 0.5%
		252.4 h Pumps 0.4%	176.5 h Hatch 2 0.3%
	668.0 h 1.0%	28.5 h Various <0.1%	161.7 h Various 0.2%
	Various	934.9 h N/A 1.4%	381.7 h Monticello 0.6%
		327.6 h Various 0.5%	368.6 h Duane Arnold 0.5%
			202.1 h Brunswick 1 0.4%
42,271.2 h 61.4%	1,262.5 h 1.8%		310.1 h Various 0.5%

[a]BWR plant outages totaled 68,875.6 h (100%).

Table 3.7. PWR plant outages in 1982[a]

Outage type	Associated system	Associated component	Plants affected		
Forced outages 45,994.2 h 32.4%	Steam and power conversion 12,870.4 h 9.1%	Turbines 4,432.3 h 3.1%	2,003.3 h	Zion 2	1.4%
			770.9 h	Cook 1	0.5%
			683.6 h	Sequoyah 1	0.5%
			974.5 h	Various	0.7%
		Heat exchangers 4,381.9 h 3.1%	1,141.0 h	Palisades	0.8%
			1,086.8 h	North Anna 2	0.8%
			1,070.5 h	Ginna	0.8%
			1,083.6 h	Various	0.8%
		Pumps and pipes 1,293.9 h 0.9%	677.3 h	Palisades	0.5%
			616.6 h	Various	0.4%
		I&C 734.1 h 0.5%	734.1 h	Various	0.5%
		Blowers 692.2 h 0.5%	692.2 h	Sequoyah 2	0.5%
		Various 1,237.4 h 0.9%	1,237.4 h	Various	0.9%
	Reactor coolant 11,864.2 h 8.4%	Heat exchangers 6,289.8 h 4.4%	2,018.8 h	Oconee 3	1.4%
			1,144.3 h	Oconee 1	0.8%
			1,031.3 h	McGuire 1	0.7%
			2,095.4 h	Various	1.5%
		Pumps and pipes 2,403.4 h 1.7%	752.5 h	Zion 1	0.5%
			704.6 h	Farley 2	0.5%
			946.3 h	Various	0.7%
		Valves 1,535.1 h 1.1%	1,535.1 h	Various	1.1%
		Motors 975.1 h 0.7%	975.1 h	Various	0.7%
		Various 660.8 h 0.5%	660.8 h	Various	0.5%
	N/A 9,680.0 h 6.8%	N/A 9,676.6 h 6.8%	8,760.0 h	TMI-1	6.2%
			916.6 h	Various	0.6%
		Various 3.4 h 0%	3.4 h	Various	<0.1%
	Electric power 4,308.3 h 3.0%	Generators 2,069.0 h 1.5%	1,614.1 h	Farley 1	1.1%
			454.9 h	Various	0.3%
		Transformers 1,521.5 h 1.1%	635.4 h	North Anna 1	0.4%
			886.1 h	Various	0.6%
		Various 717.8 h 0.5%	717.8 h	Various	0.5%
	Auxiliary water systems 1,941.4 h 1.4%	Pumps 1,273.0 h 0.9%	1,273.0 h	Palisades	0.9%
		Various 668.4 h 0.5%	668.4 h	Various	0.5%
	I&C 1,714.1 h 1.2%	I&C 1,385.6 h 1.0%	1,385.6 h	Various	1.0%
		Various 328.5 h 0.2%	328.5 h	Various	0.2%
	Engineered safety features 1,537.2 h 1.1%	Valves 797.5 h 0.6%	789.3 h	Crystal River 3	0.6%
			8.2 h	Various	<0.1%
		Various 739.7 h 0.6%	739.7 h	Various	0.6%
	Auxiliary process 690.2 h 0.5%	Heat exchanger 608.7 h 0.4%	608.7 h	Crystal River 3	0.4%
		Various 81.5 h 0.1%	81.5 h	Various	0.1%
	Various 19.9 h <0.1%	Various 19.9 h <0.1%	19.9 h	Various	<0.1%
Scheduled outages 95,785.7 h 67.6%	Reactor 68,550.3 h 48.3%	Fuel elements 68,550.3 h 48.3%	6,745.0 h	Indian Point 3	4.8%
			4,734.9 h	North Anna 1	3.3%
			4,560.0 h	Beaver Valley 1	3.2%
			4,184.3 h	Davis-Besse	3.0%
			4,071.7 h	Robinson 2	2.9%
			3,904.1 h	Oconee 3	2.8%
			3,438.8 h	Salem 1	2.4%
			3,070.1 h	Trojan	2.2%
			2,684.2 h	Sequoyah 1	1.9%
			2,519.9 h	Indian Point 2	1.8%
			2,306.6 h	North Anna 2	1.6%
			2,302.6 h	Yankee-Rowe	1.6%
			2,132.5 h	Cook 1	1.5%
			2,082.9 h	Arkansas 2	1.5%
			1,969.4 h	Maine Yankee	1.4%
			1,904.6 h	Calvert Cliffs 1	1.3%
			1,881.2 h	Zion 1	1.3%
			1,865.8 h	Ginna	1.3%
			1,847.2 h	Calvert Cliffs 2	1.3%
			1,763.0 h	Millstone 2	1.2%
			1,554.0 h	Oconee 2	1.1%
			1,274.0 h	Arkansas 1	0.9%
			1,166.7 h	Point Beach 1	0.8%
			991.2 h	Farley 2	0.7%
			982.5 h	Cook 2	0.7%
			975.3 h	Point Beach 2	0.7%
			856.0 h	Prairie Island 2	0.6%
			781.8 h	Prairie Island 1	0.6%
	Steam and power conversion 13,488.9 h 9.5%	Heat exchangers 12,505.6 h 8.8%	7,395.2 h	San Onofre 1	5.2%
			2,379.6 h	Turkey Point 3	1.7%
			1,993.2 h	Turkey Point 4	1.4%
			737.6 h	Various	0.5%
		N/A 627.1 h 0.4%	627.1 h	Various	0.4%
		Various 356.2 h 0.3%	356.2 h	Various	0.3%
	Reactor coolant 5,377.3 h 3.8%	Heat exchangers 2,843.5 h 2.0%	1,064.0 h	Arkansas 1	0.8%
			645.3 h	Ginna	0.5%
			1,134.2 h	Various	0.8%
		Vessel 1,272.0 h 0.9%	1,272.0 h	Oconee 2	0.9%
		Valves 630.7 h 0.4%	630.7 h	Various	0.4%
		Various 631.1 h 0.4%	631.1 h	Various	0.4%
	Engineered safety features 3,872.7 h 2.7%	Pipes 3,338.1 h 2.4%	3,338.1 h	Rancho Seco	2.4%
		Various 534.6 h 0.4%	534.6 h	Various	0.4%
	N/A 2,354.0 h 1.7%	N/A 2,354.0 h 1.7%	1,044.1 h	Kewaunee	0.7%
			606.9 h	Maine Yankee	0.4%
			703.0 h	Various	0.5%
	Auxiliary water 672.0 h 0.5%	Heat exchanger 672.0 h 0.5%	672.0 h	Salem 1	0.5%
	Various 1,179.3 h 0.8%	Other components 606.0 h 0.4%	606.0 h	Fort Calhoun	0.4%
		Various 573.3 h 0.4%	573.3 h	Various	0.4%

[a]PWR plant outages totaled 141,779.9 h (100%).

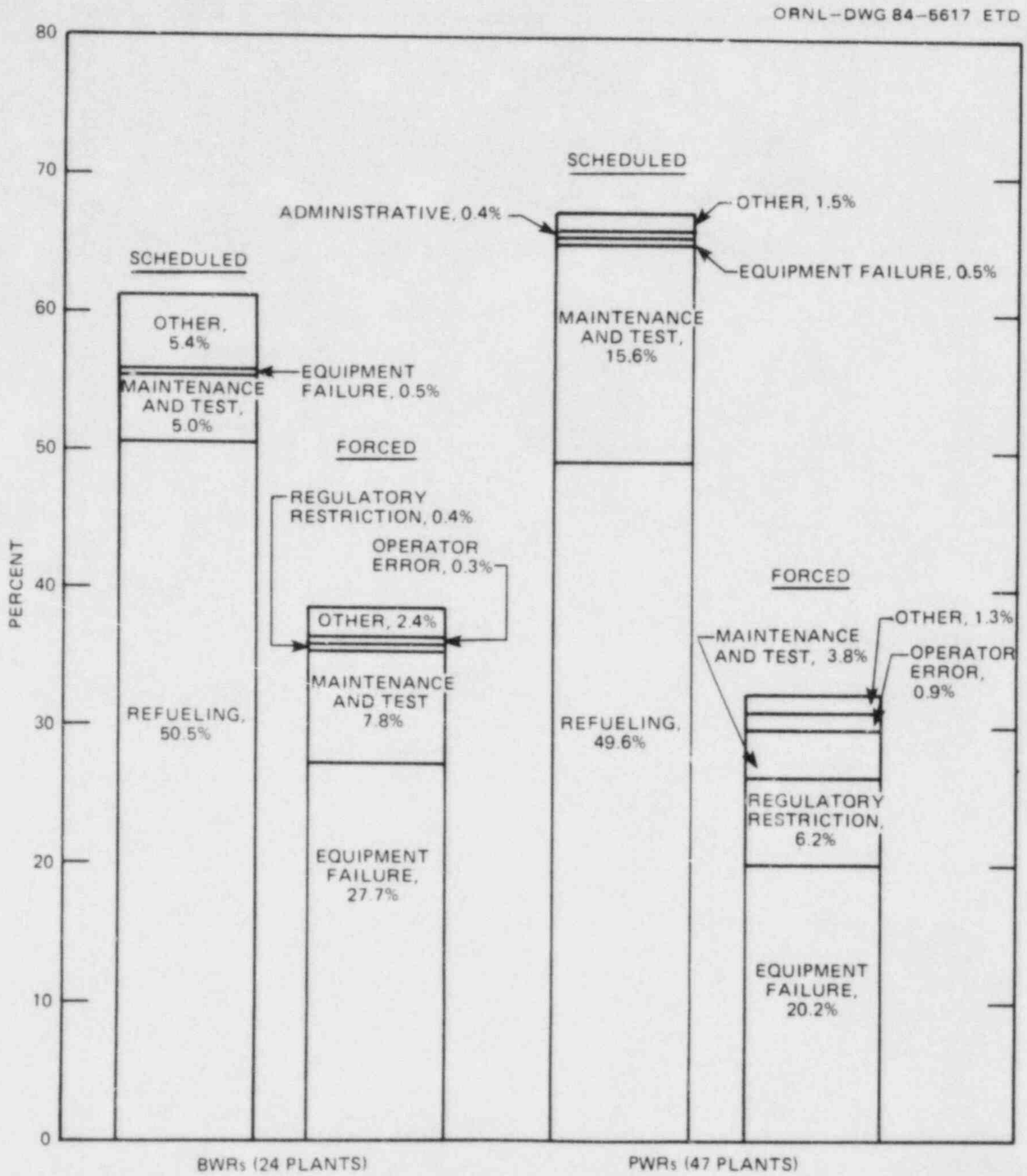

Fig. 3.1. Relative time losses due to outages in BWRs and PWRs by proximate outage cause (total outage duration for each reactor type is 100%); 1982 totals.

breakdown group the many minor contributors too numerous and insignificant in total for separate listing.

For example, in Table 3.6 we see that of the 26,604.4 forced outage shutdown hours in BWRs (38.6% of all BWR shutdown hours), 7,675.8 h (11.1% of all) involved the reactor coolant system (RCS), and of these, 1,158.7 h (1.7% of the total shutdown hours) involved demineralizers. Note that individual reactor figures in column 4 relate to system, not to component classification. In Table 3.7, on the other hand, with somewhat larger numbers of plants to cover, the last column (individual reactors) relates directly to the component column that, in turn, is a subdivision of the systems listing (second column).

Because of the fundamental differences between BWRs and PWRs, they are discussed separately below.

3.5.1 Boiling-water reactors

Forced outages. Table 3.6 shows that forced outages accounted for 38.6% of the total outage time at BWRs in 1982. Figure 3.1 shows that equipment failure was responsible for 27.7%, maintenance and test 7.8%, operating errors 0.3%, and other causes 2.8%, making up this 38.6% total. The major systems involved were the steam and power conversion systems (17.1%), the reactor cooling system (11.1%), instrumentation and controls (3.2%), and the engineered safety features (2.5%). All other systems, cited as responsible for forced outages, together added up to 4.7%.

For RCS outages, the dominant components were valves, accounting for 2,984.9 h; among the steam and power conversion system outage hours more than half (6,969.6 h) were associated with pipes; instruments were the single most significant component type among the electric power system outages.

Scheduled outages. Scheduled outages at BWRs totaled 42,271.2 h (61.4%) of total outage time. Refuelings accounted for 38,481.3 h (55.9%). Other activities such as maintenance were often carried out concurrently with refueling. Scheduled BWR outages not related to refueling were frequently due to the steam and power conversion system (1,859.4 h) with the turbines listed as the most common component (1,186.5 h) within that system.

3.5.2 Pressurized-water reactors

Forced outages. Forced outages accounted for 32.4% of the total PWR outage time in 1982 (i.e., 45,994.2 of 141,779.9 h). Most of the forced outage time was devoted to the steam and power conversion system (12,870.4 h) and the RCS (11,864.2 h). The dominant components were pumps, heat exchangers, and valves.

Figure 3.1 shows that equipment failures accounted for 28,581.6 h in 1982, a significant *decrease* of 9,022.5 h (a 23% proportionate improvement) over 1981. The 8,767.3 h of regulatory restriction were almost entirely (8,760 h) due to the year-long shutdown of the TMI-1 reactor.

Scheduled outages. Scheduled outages in PWRs totaled 95,785.7 h in 1982 (67.6% of total PWR outage time), an increase of 22,286 h (a 30%

porportionate change) compared to 1981. The reactor system accounted for 68,550.3 h, all of it for refueling.

The second leading system with respect to scheduled PWR outage hours [13,488.9 h (9.5%)] was the steam and power conversion system, with heat exchangers as the most significant component (12,505.6 h).

3.5.3 Comments on BWR and PWR outages

Forced outages. Twenty-four BWR plants experienced 26,604.4 h of forced outage — an overall average of 1,108.5 h per plant. Forty-seven PWR plants experienced 45,994.2 h of forced outage — an overall average of 978.6 h per plant.

Table 3.8 details the systems and components involved in forced outages at both BWRs and PWRs. The percentage figures shown are calculated with respect to all forced outages in BWRs and PWRs, respectively. The average number of hours per plant makes comparison between BWR and PWR experience possible, even though the number of plants of each type are quite different. In BWRs, pipes and pumps were the most significant component type, accounting for 383.3 h/plant out of a total of 1,108.5 h/plant. Valves, turbines, and instrumentation were among the other dominant component types. Along with motors, generators, and transformers, these eight categories of components accounted for 72.6% of BWR forced outage hours.

In the 47 PWRs, the dominant components figuring in forced outages were heat exchangers, which accounted for 252.3 h/plant, and pipes and pumps, which took another 114.4 h/plant. Together heat exchangers, pipes, pumps, valves, turbines, and valve operators accounted for 53.6% of PWR forced outage hours.

Scheduled outages. The 24 BWRs had 42,271.2 h of scheduled outage time for an average of 1,761.3 h/plant. The 47 PWRs accumulated 95,785.7 h for an average of 2,038.0 h/plant. The scheduled outages in the two types of reactors are compared in Table 3.9 on the basis of percentage of outage time and average number of hours per plant for the components in each reactor type.

Fuel elements, the components involved in refueling, far outweighed the sum of all other components at each of the two types of reactors. The average outage time due to fuel elements at BWRs was somewhat greater than that at PWRs, averaging 144.9 h (10%) longer. Aside from fuel elements, turbines were the components requiring the most scheduled outage time at BWRs. At PWRs, heat exchangers ranked second behind fuel elements, requiring an average of 342.1 h per plant.

3.5.4 HTGR outage experience summary

The Fort St. Vrain unit was in commercial operation throughout 1982. The unit generated 568,851 MWh net. It had an availability factor of 37.3% and a unit capacity factor of 19.7% for both MDC and DER.

Fort St. Vrain experienced 16 outages during the year, of which 13 were forced and 3 scheduled (one was a continuation of a scheduled outage

Table 3.8. Systems and components involved in forced outages in 1982

System	Components	BWRs (24)		PWRs (47)	
		Percent[a]	Average hours per plant	Percent[a]	Average hours per plant
Reactor	Fuel elements	0.8	8.4	0.1	1.1
	Control rods	0.1	0.7	0.8	7.4
	Control rod drives	0.0	0.0	1.9	18.8
	Other	0.1	0.7	0.2	1.9
Reactor coolant system	Valves and valve operators	11.4	126.4	3.3	32.7
	Pumps, pipes, and fittings	6.2	68.7	5.2	51.1
	I&C	0.4	4.7	0.8	8.2
	Demineralizers	4.4	48.3	0.0	0.0
	Heat exchangers	0.0	0.1	13.7	133.8
	Motors and generators	0.0	0.0	2.1	20.7
	Other	6.5	71.6	0.6	5.8
Engineered safety features	Valves and valve operators	2.1	23.5	1.8	17.3
	Pumps, pipes, and fittings	1.0	10.7	0.9	8.3
	Other	3.3	37.0	0.7	7.0
Instruments and controls	I&C	6.8	75.6	3.0	29.5
	Valves and valve operators	0.9	9.6	0.0	0.0
	Other	0.6	6.5	0.7	7.0
Electric power systems	Motors and generators	1.0	11.1	4.5	44.0
	Transformers	0.2	2.1	3.3	32.4
	Wiring and circuit breakers	0.0	0.0	0.7	6.4
	Other	0.3	3.1	0.9	8.9
Steam and power conversion	Pumps and pipes	27.0	299.0	2.8	27.5
	Turbines	7.1	78.4	9.6	94.3
	Motors and generators	3.3	36.2	0.3	2.8
	Valves and valve operators	2.7	30.4	1.0	9.3
	Heat exchangers	0.9	10.4	9.5	93.2
	I&C	1.2	13.7	1.6	15.6
	Wiring and circuit breakers	0.2	2.6	0.6	5.4
	Other	1.7	19.1	2.6	25.6
Other and N/A	N/A	8.5	94.5	21.0	206.0
	Other	1.4	15.5	5.8	56.4
Total		100.1[b]	1,108.5	100.0	978.6

[a]Percent of forced outage hours for each reactor type.

[b]Numerical deviation is due to rounding off of numbers.

Table 3.9. Systems and components involved in scheduled outages in 1982

System	Components	BWRs (24)		PWRs (47)	
		Percent[a]	Average hours per plant	Percent[a]	Average hours per plant
Reactor	Fuel elements	91.0	1,603.4	71.6	1,458.5
Reactor coolant system	Pumps, pipes, and fittings	0.6	10.5	0.2	3.6
	Valves and valve operators	0.9	16.1	0.7	13.4
	Heat exchangers	0.0	0.2	3.0	60.5
	Other	0.1	1.0	1.8	36.9
Engineered safety features	Supports and, pipes	0.5	8.4	3.5	71.0
	Heat exchangers	0.0	0.0	0.1	1.2
	Other	0.0	0.0	0.5	10.2
Instruments and controls	I&C	0.0	0.0	0.3	5.5
	Other	0.0	0.1	0.0	0.9
Steam and power conversion systems	Turbines	2.8	49.4	0.1	1.3
	Heat exchangers	0.3	5.4	13.1	266.1
	Pumps, pipes and fittings	0.4	6.5	0.0	0.4
	Valves and valve operators	0.9	14.7	0.0	0.2
	Other	0.1	1.5	1.2	25.2
Other and N/A	N/A	2.2	39.0	2.5	50.1
	Other	0.3	5.2	1.6	33.0
Total		100.0	1,761.3	100.2[b]	2,038.0

[a]Percent of scheduled outage hours for each reactor type.

[b]Numerical deviation is due to rounding off of numbers.

begun the prior year). None of these outages were of the zero-duration* type; thus, all 16 were true outages. The hours associated with these outages were 2,891.8 h of scheduled outages (33.0% of the year) and 2,601.0 h of forced outages (29.6% of the year). This reactor was restricted to power levels no greater than 70% of rated power during the entire year by NRC order, pending resolution of observed power oscillations. (Further details of Fort St. Vrain's outage experience are contained in the individual plant data sheets in Appendix B.)

3.5.5 Summary

During 1981, the 24 operating BWRs experienced an average of 2,869.8 h of outage time per plant compared with an average of 3,016.6 h for the 47 operating PWRs. The percentage of forced outage time at BWRs was 12.7% compared with 11.2% at PWRs. The primary cause of forced outages at both BWRs and PWRs was equipment failure. The second largest reason for forced shutdowns at BWRs was maintenance and testing, while at PWRs the second most significant reason was operator error, with maintenance and testing ranking third. Refueling was the primary reason for scheduled outages at both BWRs and PWRs. Maintenance or testing accounted for the second largest percentages of the scheduled outage time at both types of plants.

Fort St. Vrain, an HTGR, had an availability factor of 37.3%, having experienced 13 forced outages and 3 scheduled outages of nonzero duration for a total outage time of 5,492.8 h.

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*For definition, see Appendix A under "power reduction."

4. REPORTABLE OCCURRENCES

4.1 Introduc ion

The NRC collects and evaluates operational and environmental information concerning licensed nuclear facilities. Incidents or events that occur are brought to the attention of the NRC through a variety of reporting requirements or by NRC inspection, and appropriate enforcement and corrective measures are taken if necessary. The Technical Specifications for each plant include a section on reporting requirements detailing the types of operational and environmental events that must be reported. The NRC Regulatory Guides are used as guidelines for an acceptable reporting program, but they are not substitutes for the plant's Technical Specifications with which compliance is mandatory. The NRC is undergoing a program to standardize Technical Specifications, including reporting requirements. Standardization was not completed during the period covered by this report; thus, the plants reviewed herein operated under reporting requirements that varied from plant to plant. It would be inappropriate, therefore, to compare the performance of plants only on the basis of the number of reports submitted.

Data from these reports are stored in the NRC's LER file for further analysis and evaluation and for public dissemination. The information reported in the LERs conveys primarily negative aspects of plant operations. An extensive knowledge of normal operations, which is the situation most of the time, is needed to put these events in proper perspective. A large number of events of one type may not be significant in terms of safety, whereas a single event of another type may be very significant in terms of its safety implications. The LER data should be considered as only one of several types of input to the overall evaluation of plant performance.

The LERs from which the data are taken may be reviewed at the NRC's Public Document Room. (All reports required by the NRC are filed in the NRC's Public Document Room located at 1717 H Street NW, Washington, D.C. Documents relevant to individual power plants are also available at local public document rooms located in the vicinity of each plant.) Computer printouts summarizing reportable occurrences are included in the monthly publication *Licensee Event Report (LER) Compilation,* NUREG/CR-2000 (ORNL/NSIC-200). Data from these reports are stored for NRC for further analysis and evaluation in a computer file maintained by the Nuclear Operations Analysis Center located at ORNL.

4.2 Licensee Event Reports

4.2.1 Introduction

Licensee Event Reports are used to form the basis for comparing performance with design intent and to assess the safety aspect of operation. They include reports of incidents or events that involve system, component, or structural failure; malfunctions; personnel errors; design deficiencies; management deficiencies; and other matters that are related to plant operational safety.

Because nuclear power plant designs employ multiple levels of protection (or defense in depth) including the provision of redundant safety systems and components, LER events do not generally affect safety directly, nor do they have an actual impact on or consequence for the health and safety of the public. However, the information reported in LERs is useful for enhancing the safe operation of the plants.

4.2.2 Reporting requirements

Plant Technical Specifications include a section on reporting requirements detailing the types of events that should be reported (1) as promptly as possible (within 24 h, with written follow-up within 14 days) or (2) within 30 days. Reporting requirements may be summarized as follows.

Prompt notification:

1. Failure of the reactor protection system, or other systems subject to limiting safety system settings, to initiate the required protective function by the time a monitored parameter reaches the set point specified in the Technical Specifications, or failure to complete the required protective function.

2. Operation of the unit or affected systems when any parameter or operation subject to a limiting condition for operation is less conservative than the least conservative aspect of the limiting condition for operation established in the Technical Specifications.

3. Abnormal degradation discovered in fuel cladding, reactor coolant pressure boundary, or primary containment.

4. Reactivity anomalies involving disagreement with the predicted value under steady state conditions during power operation greater than or equal to 1% $\Delta k/k$; a calculated reactivity balance indicating a shutdown margin less conservative than specified in the Technical Specifications; short-term reactivity increases that correspond to a reactor period of less than 5 s or, if subcritical, an unplanned reactivity insertion of more than 0.5% $\Delta k/k$; or occurrence of any unplanned criticality.

5. Failure or malfunction of one or more components that prevents or could prevent, by itself, the fulfillment of the functional requirements of system(s) used to cope with accidents analyzed in the Safety Analysis Report.

6. Personnel error or procedural inadequacy that prevents or could prevent, by itself, the fulfillment of the functional requirements of systems required to cope with accidents analyzed in the Safety Analysis Report.

7. Conditions arising from natural or man-made events that, as a direct result of the event, require plant shutdown, operation of safety systems, or other protective measures required by Technical Specifications.

8. Errors discovered in the transient or accident analyses or in the methods used for such analyses, as described in the Safety Analysis

Report or in the bases for the Technical Specifications, that have or could have permitted reactor operation in a manner less conservative than assumed in the analyses.

9. Performance of structures, systems, or components that requires remedial action or corrective measures to prevent operation in a manner less conservative than that assumed in the accident analyses in the Safety Analysis Report or Technical Specifications bases; or discovery during plant life of conditions not specifically considered in the Safety Analysis Report or Technical Specifications that require remedial action or corrective measures to prevent the existence or development of an unsafe condition.

30-day reports:

1. Reactor protection system or engineered safety feature instrument settings that are found to be less conservative than those established by the Technical Specifications but that do not prevent the fulfillment of the functional requirements of affected systems.

2. Conditions leading to operation in a degraded mode permitted by a limiting condition for operation, or plant shutdown required by a limiting condition for operation.

3. Observed inadequacies in the implementation of administrative or procedural controls that threaten to cause reduction of degree of redundance provided in reactor protection systems or engineered safety feature systems.

4. Abnormal degradation of systems designed to contain radioactive material resulting from the fission process.

As a result of action taken by the NRC staff following the accident at TMI on March 28, 1979, a new rule was published requiring the immediate reporting of significant events by telephone. The purpose of the new rule is to ensure the timely and accurate flow of information from licensees of operating nuclear power reactors following a significant event.[1]

The rule was published in Title 10 of the *Code of Federal Regulations*, Part 50, as Sect. 50.72 and became effective February 29, 1980. Section 50.72 requires licensees to notify the NRC Operations Center by telephone as soon as possible and in all cases within 1 h of the occurrence of any significant event listed in the section. The 12 kinds of significant events requiring immediate reporting are the following.

1. Any event requiring initiation of the licensee's emergency plan or any section of that plan.

2. The exceeding of any Technical Specification safety limit.

3. Any event that results in the nuclear power plant not being in a controlled or expected condition while operating or shut down.

4. Any act that threatens the safety of the nuclear power plant or site personnel or the security of special nuclear material, including instances of sabotage or attempted sabotage.

5. Any event requiring initiation of shutdown of the nuclear power plant in accordance with Technical Specification limiting conditions for operation.

6. Personnel error or procedural inadequacy that, during normal operations, anticipated operational occurrences, or accident conditions,

prevents or could prevent, by itself, the fulfillment of the safety function of those structures, systems, and components important to safety that are needed to (a) shut down the reactor safely and maintain it in a safe shutdown condition, (b) remove residual heat following reactor shutdown, or (c) limit the release of radioactive material to acceptable levels or reduce the potential for such release.

7. Any event resulting in manual or automatic actuation of engineered safety features, including the reactor protection system.

8. Any accidental, unplanned, or uncontrolled radioactive release. (Normal or expected releases from maintenance or other operational activities are not included.)

9. Any fatality or serious injury occurring on the site and requiring transport to an offsite medical facility for treatment.

10. Any serious radioactive contamination of personnel requiring extensive onsite decontamination or outside assistance.

11. Any event meeting the criteria of 10 CFR 20.403 for notification.

12. Strikes of operating employees or security guards or the honoring of picket lines by these employees.

4.2.3 LERs submitted to the NRC in 1982

Introduction. Data taken from the LER file maintained at ORNL's NOAC have been tabulated to (1) relate the number of LERs bearing event dates falling within 1982 to (a) the nuclear plant and system in which the event occurred, (b) the component involved in the event, and (c) the cause of the event; and (2) relate the number of LERs involving personnel errors to the system affected or involved. Tables 4.1–4.8 present the data for BWR and PWR plants only. The data for the single HTGR (Fort St. Vrain) are presented separately in Sect. 4.2.4.

The systems, subsystems, and component types used to categorize the LERs are listed in Appendix B.

The LWR plants considered for review in this report with respect to LERs include the 24 BWR reactors (number unchanged since the previous year), the 46 PWRs that were in commercial operation for the entire year, plus Sequoyah 2, which began commercial operation during the year. For this reactor, all the LERs relating to 1982 events, even those occasioned by events prior to declaration of commercial operation, are included.

The U.S. power reactors submitted 3,737 LERs relating to events during 1982, 1,355 that relate to BWRs, 2,329 that come from PWRs, and 53 that were filed by the HTGR. (For comparison, the figures for 1981, the prior year, were 1,530 from BWRs, 2,533 from PWRs, and 71 from the HTGR.) Thus, we see a reduction in LER numbers for all three reactor types, despite the fact that one more PWR is included in the list.

It will be noted that the LER totals in Tables 4.1 and 4.2, which list the reports separately for each reactor, are somewhat higher than the figures just cited. This reflects the fact that some LERs from multiunit power stations refer to more than one reactor and are then counted for each, leading to multiple counting for those LERs. (This occurs, for example, in a case where an LER deals with problems in a "swing" diesel generator, that is, an emergency power supply that can be used to supply either of two reactors on the same site.) This counting method was

Table 4.1. BWR plant LERs vs system

	Reactor	Reactor coolant and connected systems	Engineered safety features	Instrumentation and controls	Electric power systems	Fuel storage and handling	Auxiliary water systems	Auxiliary process systems	Other auxiliary systems	Steam and power conversion systems	Radioactive waste management systems	Radiation protection systems	Other systems	System code not applicable[a]	Totals	Percent of total number of LERs (1,402)	Number relative to average number (58.4)
Big Rock Point	2	1	18	2	3	0	3	0	5	0	1	0	0	0	35	2.5	0.60
Browns Ferry 1	6	9	19	15	10	0	0	1	8	0	13	8	0	1	90	6.4	1.54
Browns Ferry 2	1	9	12	12	7	0	0	0	4	0	5	0	1	0	51	3.6	0.87
Browns Ferry 3	4	1	5	21	7	0	1	0	3	0	15	0	0	1	58	4.1	0.99
Brunswick 1	5	16	61	42	14	0	2	1	8	0	0	0	0	0	149	10.6	2.54
Brunswick 2	12	17	58	32	12	1	3	1	4	0	0	0	0	0	140	10.0	2.40
Cooper Station	0	9	5	4	5	0	0	0	1	0	0	0	1	0	25	1.8	0.43
Dresden 2	1	8	23	10	2	0	1	1	0	0	5	0	0	0	51	3.6	0.87
Dresden 3	5	12	16	6	4	0	1	1	0	0	2	0	0	0	47	3.4	0.81
Duane Arnold	0	28	33	11	6	0	2	0	2	0	3	1	0	0	86	6.1	1.47
FitzPatrick 1	4	8	13	14	6	0	0	2	1	1	0	0	0	5	54	3.9	0.93
Hatch 1	1	14	21	26	5	2	7	1	12	3	3	1	1	6	103	7.4	1.76
Hatch 2	11	31	36	26	11	0	7	3	15	0	4	1	0	4	149	10.6	2.55
La Crosse	1	2	9	1	1	0	0	0	5	1	1	0	0	0	21	1.5	0.36
Millstone 1	0	5	13	2	7	0	0	0	2	0	1	2	0	1	33	2.4	0.57
Monticello	0	7	5	0	1	0	0	0	0	0	0	0	0	0	13	0.9	0.22
Nine Mile Point 1	0	2	9	1	2	0	0	0	2	2	1	0	0	4	23	1.6	0.39
Oyster Creek	6	12	17	11	5	0	2	1	1	0	8	0	2	1	66	4.7	1.13
Peach Bottom 2	0	5	19	4	2	0	0	0	11	0	0	1	0	0	42	3.0	0.72
Peach Bottom 3	1	3	8	7	0	0	0	0	3	0	2	1	0	1	26	1.9	0.45
Pilgrim	2	15	15	4	3	0	0	1	11	1	0	0	2	1	55	3.9	0.94
Quad Cities 1	0	13	8	3	7	0	0	0	3	1	1	1	0	1	38	2.7	0.65
Quad Cities 2	1	8	8	2	2	0	0	0	0	0	0	0	0	0	21	1.5	0.36
Vermont Yankee	1	6	7	6	3	0	0	2	0	0	0	1	0	0	26	1.9	0.45
Total	64	241	438	262	125	3	29	15	101	9	65	17	7	26	1,402	100.0	24.0
Percent of 1,402	4.6	17.2	31.2	18.7	8.9	0.2	2.1	1.1	7.2	0.6	4.6	1.2	0.5	1.9	100.0		

[a]Indicates an operational error or procedural deficiency rather than failure of a system.

Table 4.2. PWR plant LERs vs system

	Reactor	Reactor coolant and connected systems	Engineered safety features	Instrumentation and controls	Electric power systems	Fuel storage and handling	Auxiliary water systems	Auxiliary process systems	Other auxiliary systems	Steam and power conversion systems	Radioactive waste management systems	Radiation protection systems	Other systems	System code not applicable[a]	Totals	Percent of total number (2,351)	Fraction relative to average number (50.02)
Arkansas 1	4	4	5	3	3	2	2	1	3	1	0	0	0	0	28	1.2	0.56
Arkansas 2	2	5	5	10	4	0	1	5	2	14	1	1	0	0	50	2.1	1.00
Beaver Valley 1	5	3	17	8	5	0	6	1	5	4	1	0	1	2	58	2.5	1.16
Calvert Cliffs 1	4	15	16	18	5	0	5	2	5	5	0	4	0	0	79	3.4	1.58
Calvert Cliffs 2	3	7	9	16	7	0	3	1	0	2	1	1	2	4	56	2.4	1.12
Cook 1	0	4	24	12	7	0	6	2	36	10	5	3	0	0	109	4.6	2.18
Cook 2	3	14	16	9	11	0	7	8	28	7	3	7	0	1	114	4.8	2.28
Crystal River 3	0	17	20	18	8	0	0	1	0	2	2	4	1	1	74	3.2	1.48
Davis-Besse 1	3	9	19	13	4	1	4	4	6	2	0	4	0	0	69	2.9	1.38
Fort Calhoun 1	1	2	6	3	1	0	2	0	1	2	2	1	0	0	21	0.9	0.42
Ginna	1	4	8	1	0	0	1	1	7	2	0	3	0	0	28	1.2	0.56
Haddam Neck	0	2	3	1	2	0	0	0	0	2	0	0	0	0	10	0.4	0.20
Indian Point 2	1	1	20	5	3	0	2	10	0	4	2	0	1	1	50	2.1	1.00
Indian Point 3	0	2	0	1	0	0	0	0	0	1	0	0	0	0	4	0.2	0.08
Farley 1	1	7	23	11	4	0	1	0	6	2	3	4	0	0	62	2.6	1.24
Farley 2	1	11	24	12	5	0	3	0	1	4	4	1	0	0	66	2.8	1.32
Kewaunee	0	5	12	7	1	0	2	2	4	1	1	1	0	0	36	1.5	0.72
Maine Yankee	1	6	12	1	4	2	1	0	0	6	0	1	0	2	36	1.5	0.72
McGuire 1	7	8	19	15	7	2	1	3	12	0	7	2	0	0	83	3.5	1.66
Millstone 2	6	5	12	8	4	0	3	3	4	2	1	3	0	0	51	2.2	1.02
North Anna 1	10	13	18	18	4	0	4	0	13	3	2	3	0	0	88	3.7	1.76
North Anna 2	7	15	21	18	10	0	0	1	11	1	0	1	0	0	85	3.6	1.70
Oconee 1	0	4	7	4	2	0	0	0	1	2	0	0	0	0	20	0.8	0.40
Oconee 2	3	3	4	0	0	1	0	0	0	2	0	0	0	0	13	0.6	0.26
Oconee 3	2	6	3	2	0	1	0	0	0	1	0	0	0	0	15	0.6	0.30
Palisades	6	5	22	3	4	0	1	0	4	4	0	0	0	0	49	2.1	0.98
Point Beach 1	0	3	3	11	3	1	0	0	2	3	1	0	0	0	27	1.2	0.54
Point Beach 2	0	0	1	6	1	0	1	3	0	1	0	0	0	0	13	0.6	0.26
Prairie Island 1	1	2	1	1	1	0	2	2	3	0	0	0	0	0	13	0.6	0.26
Prairie Island 2	1	1	4	1	2	0	0	0	0	1	0	1	0	0	11	0.5	0.22
Rancho Seco	0	6	7	3	2	0	0	4	3	2	2	0	3	3	35	1.5	0.70
Robinson 2	0	4	5	5	0	0	0	4	1	1	0	0	0	0	20	0.8	0.40
Salem 1	4	9	20	12	5	1	4	5	15	5	7	2	0	0	89	3.8	1.78
Salem 2	3	18	76	28	10	0	2	2	5	5	0	5	0	2	156	6.6	3.12
San Onofre 1	0	5	4	2	1	0	3	1	5	2	2	0	0	1	26	1.1	0.52
Sequoyah 1	2	4	22	17	6	0	3	0	5	11	10	0	1	1	82	3.5	1.64
Sequoyah 2	1	3	28	18	7	0	1	2	1	6	2	0	0	0	69	2.9	1.38
St. Lucie 1	5	12	10	18	12	0	1	5	3	1	1	1	0	1	70	3.0	1.40
Surry 1	11	9	32	14	1	0	12	4	4	6	24	0	0	0	117	5.0	2.34
Surry 2	1	9	22	3	4	0	18	5	3	4	2	0	0	1	72	3.1	1.44
Three Mile Island 1	0	2	1	1	0	0	0	0	4	1	5	2	0	0	17	0.7	0.34
Trojan	2	3	7	5	2	1	2	0	1	0	3	0	0	0	26	1.1	0.52
Turkey Point 3	3	0	3	0	2	0	1	2	4	2	1	0	1	0	19	0.8	0.38
Turkey Point 4	0	1	4	1	1	1	2	2	0	2	0	0	0	0	14	0.6	0.28
Yankee-Rowe	1	4	6	14	2	0	0	0	7	2	3	3	0	0	42	1.8	0.84
Zion 1	0	5	13	14	2	0	0	2	4	1	2	5	0	2	50	2.1	1.00
Zion 2	1	2	3	14	2	0	1	2	0	0	3	1	0	0	29	1.2	0.58
Total	107	279	617	405	171	13	108	90	219	142	104	64	10	22	2,351	99.9[b]	
Percent of 2,351	4.6	11.9	26.2	17.2	7.3	0.6	4.6	3.8	9.3	6.0	4.4	2.7	0.4	0.9	99.9[b]		

[a]Indicates an operational error or procedural deficiency rather than failure of a system.

[b]Difference from 100.0 is due to round-off error only.

Table 4.3. LWR systems reported in LERs for 1982

System	BWRs		PWRs	
	Number of reports	Percent of total reports	Number of reports	Percent of total reports
Reactor	64	4.7	107	4.6
Reactor coolant and connected systems	237	17.5	276	11.9
Engineered safety features	427	31.5	607	26.1
Instrumentation and controls	255	18.8	401	17.3
Electric power systems	115	8.5	166	7.1
Fuel storage and handling	3	0.2	13	0.6
Auxiliary water systems	27	2.0	113	4.9
Auxiliary process systems	15	1.1	90	3.9
Other auxiliary systems	93	6.9	217	9.3
Steam and power conversion systems	9	0.7	140	6.0
Radioactive waste management systems	60	4.4	103	4.4
Radiation protection systems	17	1.3	64	2.7
Other systems	7	0.5	10	0.4
System code not applicable[a]	26	1.9	22	0.9
Total	1,355	100.0	2,329	100.1[b]

[a]Indicates an operational error or procedural deficiency rather than failure of a system.

[b]The difference from 100.0 is due to round-off error only.

selected because Tables 4.1 and 4.2 show primarily the number of LERs for each reactor, and a multiple-reference LER is therefore properly counted as referring to each reactor to which it applies. In all the other LWR tables of this chapter (Tables 4.3–4.8), each LER is counted exactly once so that the totals in these tables correctly count the LERs.

In a few instances, licensees have issued more than one LER report bearing the same LER number, augmented by additional descriptive designations, when similar events on different components at different dates were involved. These reports are counted separately.

In Table 4.1, the LERs that relate to individual BWR plants are shown vs the systems involved. Table 4.2 presents the same data for PWR plants. The last column in Tables 4.1 and 4.2 shows the ratio of the number of LERs reported for each plant to the average number of LERs for units of the same kind, or, in other words, a comparison to the mean number of LERs at all BWR or PWR units, respectively. Table 4.3 lists the

Table 4.4. Systems and subsystems involved in LWR LERs for 1982

System and subsystem	BWRs		PWRs		Total	
	Number of reports	Percent of total reports	Number of reports	Percent of total reports	Number of reports	Percent of total reports
Reactor	64	4.7	107	4.6	171	4.7
Reactor vessel internals	2	0.1	3	0.1	5	0.1
Reactivity control systems	53	3.9	64	2.8	117	3.2
Reactor core	9	0.7	40	1.7	49	1.3
Reactor coolant system and connected systems	237	17.5	276	11.9	513	14.0
Reactor vessels and appurtenances	4	0.3	6	0.3	10	0.3
Coolant recirculation systems and controls	32	2.4	93	4.0	125	3.4
Main steam systems and controls	20	1.5	26	1.1	46	1.3
Main steam isolation systems and controls	30	2.2	7	0.3	37	1.0
Reactor core isolation cooling systems and controls	48	3.5	2	0.1	50	1.4
Residual heat removal systems and controls	60	4.4	33	1.4	93	2.5
Reactor coolant cleanup systems and controls	19	1.4	15	0.6	34	0.9
Feedwater systems and controls	7	0.5	42	1.8	49	1.3
Reactor coolant pressure boundary leakage detection systems	10	0.7	16	0.7	26	0.7
Other coolant subsystems and their controls	7	0.5	36	1.5	43	1.2
Engineered safety features	427	31.5	607	26.1	1,034	28.1
Reactor containment systems	67	4.9	93	4.0	160	4.4
Containment heat removal systems and controls	21	1.6	121	5.2	142	3.9
Containment air purification and cleanup systems and controls	23	1.7	26	1.1	49	1.3
Containment isolation systems and controls	94	6.9	102	4.4	196	5.3
Containment combustible control systems and controls	61	4.5	8	0.3	69	1.9
Emergency core-cooling systems and controls	122	8.9	161	6.9	283	7.7
Control room habitability systems and controls	13	1.0	42	1.8	55	1.5
Other engineered safety feature systems and their controls	26	1.9	54	2.3	80	2.2
Instrumentation and controls	255	18.8	401	17.3	656	17.8
Reactor trip systems	81	6.0	177	7.6	258	7.0
Engineered safety feature instrument systems	79	5.8	86	3.7	165	4.5
Systems required for safe shutdown	23	1.7	12	0.5	35	1.0
Safety-related display instrumentation	33	2.4	44	1.9	77	2.1
Other instrument systems required for safety	30	2.2	51	2.2	81	2.2
Other instrument systems not required for safety	9	0.7	31	1.3	40	1.1
Electric power systems	115	8.5	166	7.1	281	7.6
Offsite power systems and controls	8	0.6	5	0.2	13	0.4
Onsite power systems and controls (AC)	16	1.2	31	1.3	47	1.3
Onsite power systems and controls (DC)	17	1.3	24	1.0	31	1.1
Onsite power systems and controls (composite AC and DC)	5	0.4	15	0.6	20	0.5
Emergency generator systems and controls	68	5.0	82	3.5	150	4.1
Emergency lighting systems and controls	0	0.0	0	0.0	0	0.0
Other electric power systems and controls	1	0.1	9	0.4	10	0.3

Table 4.4 (continued)

System and subsystem	BWRs		PWRs		Total	
	Number of reports	Percent of total reports	Number of reports	Percent of total report	Number of reports	Percent of total reports
Fuel storage and handling systems	3	0.2	13	0.6	16	0.4
New-fuel storage facilities	0	0.0	0	0.0	0	0.0
Spent-fuel storage facilities	1	0.1	5	0.2	6	0.2
Spent-fuel-pool cooling and cleanup systems and controls	1	0.1	5	0.2	6	0.2
Fuel handling systems	1	0.1	3	0.1	4	0.1
Auxiliary water systems	27	2.0	113	4.9	140	3.8
Station service water systems and controls	19	1.4	59	2.5	78	2.1
Cooling systems for reactor auxiliaries and controls	3	0.2	31	1.3	34	0.9
Demineralized water makeup systems and controls	2	0.1	2	0.1	4	0.1
Potable and sanitary water systems and controls	0	0.0	1	0.0	1	0.0
Ultimate heat sink facilities	1	0.1	5	0.2	6	0.2
Condensate storage facilities	1	0.1	5	0.2	6	0.2
Other auxiliary water systems and their controls	1	0.1	10	0.4	11	0.3
Auxiliary process systems	15	1.1	90	3.9	105	2.9
Compressed air systems and controls	2	0.1	1	0.0	3	0.1
Process sampling systems	7	0.5	6	0.3	13	0.4
Chemical, volume control, and liquid poison systems and controls	6	0.5	80	3.4	86	2.3
Failed-fuel detection systems	0	0.0	0	0.0	0	0.0
Other auxiliary process systems and their controls	0	0.0	3	0.1	3	0.1
Other auxiliary systems	93	6.9	217	9.2	310	8.3
Air conditioning, heating, cooling, and ventilation systems and controls	7	0.5	34	1.5	41	1.1
Fire protection systems and controls	86	6.4	181	7.7	267	7.2
Communication systems	0	0.0	0	0.0	0	0.0
Other auxiliary systems and their controls	0	0.0	2	0.1	2	0.1
Steam and power conversion systems	9	0.7	140	6.0	149	4.0
Turbine generators and controls	0	0.0	2	0.1	2	0.1
Main steam-supply system and controls	4	0.3	39	1.6	43	1.1
Main condenser systems and controls	2	0.1	1	0.0	3	0.1
Turbine-gland-sealing systems and controls	0	0.0	0	0.0	0	0.0
Turbine bypass systems and controls	0	0.0	0	0.0	0	0.0
Circulating water systems and controls	1	0.1	7	0.3	8	0.2
Condensate cleanup systems and controls	2	0.1	1	0.0	3	0.1
Condensate and feedwater systems and controls	0	0.0	73	3.1	73	2.0
Steam generator blowdown systems and controls	0	0.0	14	0.6	14	0.4
Other features of steam and power conversion systems	0	0.0	3	0.1	3	0.1

Table 4.4 (continued)

System and subsystem	BWRs		PWRs		Total	
	Number of reports	Percent of total reports	Number of reports	Percent of total reports	Number of reports	Percent of total reports
Radioactive waste management systems	60	4.4	103	4.4	163	4.4
Liquid radioactive waste management systems	11	0.8	19	0.8	30	0.8
Gaseous radioactive waste management systems	8	0.6	22	0.9	30	0.8
Process and effluent radiological monitoring systems	41	3.0	60	2.5	101	2.7
Solid radioactive waste management systems	0	0.0	2	0.1	2	0.1
Radiation protection systems	17	1.3	64	2.7	81	2.2
Area monitoring systems	4	0.3	15	0.6	19	0.5
Airborne radioactivity monitoring systems	13	1.0	49	2.1	62	1.7
Other systems	7	0.5	10	0.4	17	0.5
System code not applicable[a]	26	1.9	22	0.9	48	1.3
Total[b]	1,355	100.0	2,329	100.0	3,684	100.0

[a]Indicates an operational error or procedural deficiency rather than a failure of a system or subsystem.

Table 4.5. LWR components reported in LERs for 1982

Components	BWRs		PWRs[a]	
	Number of reports	Percent of total reports	Number of reports	Percent of total reports
Accumulators	20	1.5	53	2.3
Air dryers	1	0.1	0	0.0
Annunciator modules	4	0.3	3	0.1
Batteries and chargers	13	1.0	24	1.0
Blowers	3	0.2	19	0.8
Circuit closers/interrupters	57	4.2	100	4.3
Component code not applicable[b]	73	5.4	113	4.9
Control rod drive mechanisms	5	0.4	11	0.5
Control rods	7	0.5	13	0.6
Demineralizers	2	0.1	3	0.1
Electrical conductors	20	1.5	26	1.1
Engines, internal combustion	14	1.0	44	1.9
Filters	14	1.0	28	1.2
Fuel elements	9	0.7	38	1.6
Generators	9	0.7	15	0.6
Hangers, supports, shock suppressors	25	1.8	58	2.5
Heat exchangers	17	1.3	90	3.9
Heaters, electric	5	0.4	45	1.9
Instrumentation and controls	545	40.2	666	28.6
Mechanical function units	12	0.9	8	0.3
Motors	7	0.5	11	0.5
Other components	19	1.4	49	2.1
Penetrations, primary containment	30	2.2	120	5.2
Pipes and/or fittings	59	4.4	107	4.6
Pumps	70	5.2	134	5.8
Recombiners	0	0.0	2	0.1
Relays	56	4.1	64	2.7
Transformers	0	0.0	3	0.1
Turbines	2	0.1	1	0.0
Valve operators	73	5.4	98	4.2
Valves	182	13.4	378	16.2
Vessels, pressure	2	0.1	5	0.2
Total[c]	1,355	100.0	2,329	99.9[c]

[a]For Sequoyah 2, which began commercial operation in 1982, LERs are included for all events in 1982 including those prior to commercial operation.

[b]Indicates an operational error or procedural deficiency rather than a component failure.

[c]Numerical deviation is due to rounding off of numbers.

number of LERs for each system for both types of LWRs to show the relative involvement of the various systems in reportable occurrences. Note that engineered safety features were involved in more reportable occurrences than any other system at both BWRs and PWRs; instrumentation and controls and the reactor coolant system were also involved in a large number of reportable occurrences. This is not surprising, since these two systems and the electric power system are the dominant systems with respect to their extent and importance to safety. Table 4.4 presents a further breakdown of the data to indicate the subsystems involved in the reportable occurrences. As expected, the emergency core cooling system

Table 4.6. LERs arranged by cause[a]

	BWRs		PWRs		HTGR		Total	
	Number of reports	Percent of BWR reports	Number of reports	Percent of PWR reports	Number of reports	Percent of HTGR reports	Number of reports	Percent of all reports
Personnel errors Failure, operator errors Licensed operator Nonlicensed operator Radiation protection personnel Construction personnel Contractor personnel	167	12.3	322	13.8	7	13.2	496	13.3
Design/fabrication error Failure, design error Failure, fabrication error Failure, installation error	109	8.0	238	10.2	0	0	347	9.3
External cause Flood, lightning, destructive wind Weather, severe	12	0.9	19	0.8	0	0	31	0.8
Defective procedures Procedures and manuals Failure, administrative control	155	11.4	214	9.2	4	7.5	373	10.0
Component failure Failure, component Failure, equipment Failure, instrument	1,321	97.5	2,286	98.2	53	100.0	3,660	97.9
No failure cause stated	16	1.2	27	1.2	0	0.0	43	1.2
Total causes	1,780[b]	131.3[c]	3,106[b]	133.4[c]	64[b]	120.7[c]	4,950[b]	132.5[c]
Total LERs	1,355		2,329		53		3,737	

[a]For reactors beginning commercial operation in 1982, all LERs for the year are included.

[b]Because of multiple cause assignments, this total is substantially larger than the number of LERs.

[c]Since these percentages are relative to the number of LERs, multiple cause assignments result in totals greater than 100%.

Table 4.7. Personnel errors vs system for LWR plants in 1982

System	BWRs		PWRs		BWRs and PWRs	
	Number of reports	Percent of total reports	Number of reports	Percent of total reports	Total reports	Percent of total reports
Reactor	10	6.0	16	5.0	26	5.3
Reactor coolant and connected systems	19	11.4	26	8.1	45	9.2
Engineered safety features	49	29.3	96	29.8	145	29.7
Instrumentation and controls	18	10.8	26	8.1	44	9.0
Electric power systems	19	11.4	25	7.8	44	9.0
Fuel storage and handling	1	0.6	2	0.6	3	0.6
Auxiliary water systems	4	2.4	16	5.0	20	4.1
Auxiliary process systems	4	2.4	9	2.8	13	2.7
Other auxiliary systems	25	15.0	57	17.7	82	16.8
Steam and power conversion systems	1	0.6	19	5.9	20	4.1
Radioactive waste management systems	7	4.2	16	5.0	23	4.7
Radiation protection systems	2	1.2	8	2.5	10	2.0
Other systems	3	1.8	1	0.3	4	0.8
Not applicable	5	3.0	5	1.6	10	2.0
Total[a]	167	100.1[a]	322	100.2[a]	489	100.0

[a]Numerical deviations are due to rounding off of numbers.

Table 4.8. Personnel errors at LWR plants for the years 1971–1982

System	Number of personnel errors (plus % of errors by system for last 6 years)																		System totals[a]
							1977		1978		1979		1980		1981		1982		
	1971	1972	1973	1974	1975	1976	No.	%	No.	%	No.	%	No.	%	No.	%	No.	%	
Reactor	2	8	16	27	26	36	31	6.0	21	4.4	40	9.5	38	7.6	36	6.8	26	5.3	307
Reactor coolant and connected systems	9	16	34	39	73	61	85	16.3	56	11.7	60	14.2	61	12.2	56	10.6	45	9.2	595
Engineered safety features	11	16	42	80	104	96	115	22.1	118	24.7	99	23.5	114	22.8	136	25.7	145	29.7	1,076
Instrumentation and controls	0	6	20	31	28	40	63	12.1	60	12.6	41	9.7	[illegible]	12.2	39	7.4	44	9.0	433
Electric power systems	6	8	13	30	32	42	48	9.2	42	8.8	42	10.0	56	11.2	45	8.8	44	9.0	408
Fuel storage and handling	0	3	6	6	4	5	4	0.8	6	1.3	4	0.9	0	0.0	1	0.2	3	0.6	42
Auxiliary water systems	1	3	1	9	15	22	23	4.4	11	2.3	13	3.1	21	4.2	31	5.8	20	4.1	170
Auxiliary process system	2	2	12	19	16	19	19	3.7	23	4.8	13	3.1	9	1.8	17	3.2	13	2.7	164
Other auxiliary systems	0	0	0	3	3	5	8	1.5	33	6.9	35	8.3	44	8.8	71	13.4	82	16.8	284
Steam and power conversion systems	3	9	13	26	18	11	20	3.8	13	2.7	4	0.9	12	2.4	18	3.4	20	4.1	167
Radioactive waste management systems	6	7	17	40	46	28	29	5.6	11	2.3	15	3.6	22	4.4	37	7.0	23	4.7	281
Radiation protection systems	0	0	1	2	3	7	8	1.5	14	2.9	8	1.9	9	1.8	18	3.4	10	2.0	80
Other systems	0	0	3	1	2	6	14	2.7	18	3.8	5	1.2	6	1.2	2	0.4	4	0.8	61
System code not applicable[b]	2	2	8	3	27	42	53	10.2	51	10.7	43	10.2	48	9.6	23	4.3	10	2.0	312
Total (by year)	42	80	186	316	397	420	520	99.9[c]	477	99.9[c]	422	100.1[c]	501	100.0	530	100.0	489	100.0	4,380

[a]These totals include LERs for all of 1982 for Sequoyah 2, which began commercial operation in that year.

[b]Primarily occurrences in which operating personnel failed to perform surveillance tests within a specified time interval.

[c]Deviations from 100.0% are due to round-off error only.

(ECCS) was involved in a large number of occurrences, indicating the importance of this system and the attention it consequently receives.

Components involved in the reportable occurrences. Table 4.5 presents data on the components involved in the reportable occurrences. Instrumentation and valves were reported as being involved in more occurrences than any other components; this is to be expected because of the large number of these components in a plant and their complexities.

Cause. Table 4.6 presents data on the cause of reportable occurrences. It should be noted that the totals come to more than the total number of LERs. This is due to the assignment of multiple causes to many LERs. It must also be kept in mind in considering this table that the percentages are given relative to the number of LERs in each reactor category, not the number of cause listings. Thus, again due to multiple cause assignments, the percentage totals are much greater than 100%. Observe the near universal inclusion of procedure defects for almost all LERs for all three reactor types. The table indicates a listing of the LER keywords used to gather the data for each of the causes listed. The cause information for Fort St. Vrain, the country's only licensed operating HTGR, is also included.

Personnel errors. Table 4.7 breaks down the first line of Table 4.6 for the LWRs by systems associated with the personnel errors shown there. The first two pairs of columns give total and percentage data about BWRs and PWRs, respectively, and the last two columns combine the two. As might be expected, the largest number of errors made involved the engineered safety features system, an extensive and complex system subject to close control.

Table 4.8 presents a historical accounting of personnel errors vs system. For the years 1971—1976, only the numbers of LERs involving personnel errors are shown, by system and total per year. For the six most recent years (1977—1982), this information is supplemented by a column showing what percentage of the personnel-error LERs are assigned to each system, year by year. The smaller numbers in the earlier years (1971—1973) merely reflect the fact that there were fewer units reporting occurrences during that period. From 1977 through 1979, a steady decline in personnel errors is noted. The 501 events reported as personnel errors during 1980, however, represent an increase over the numbers in the three previous years. While the 1981 figure shows a further increase from 501 to 530 (a 5.5% increase), this is a somewhat smaller percentage increase than that in the number of reactors (67 to 71), a 6.0% increase. For 1982 there is again a decrease (7.7%) in the number of personnel errors, despite a one-reactor increase (1.4%) in the number included in the count. The overall relative increase in recent years is most likely due at least in part to increased concern and awareness of personnel errors since the TMI accident in 1979. The errors listed for "system code not applicable" are primarily occurrences in which operating personnel failed to perform surveillance tests within a specified time interval.

4.2.4 HTGR (Fort St. Vrain) LERs

The only commercial HTGR in operation (Fort St. Vrain) submitted 53 LERs in 1982. The number of LERs vs the system involved in the reported occurrences were as follows:

System	Number of LERs	Percent of total
Reactor	2	3.8
Reactor coolant system	19	35.8
Engineered safety features	1	1.9
Instrumentation and controls	7	13.2
Electric power systems	5	9.4
Fuel storage and handling	1	1.9
Auxiliary water systems	0	0.0
Auxiliary process systems	1	1.9
Other auxiliary systems	2	3.8
Steam and power conversion	11	20.8
Radioactive waste systems	2	3.8
Radiation protection systems	0	0.0
Other systems	1	1.9
Systems code not applicable	1	1.9
Total	53	100.1*

The number of LERs vs the components involved were as follows:

Components	Number of LERs	Percent of total
Compressors, gas circulators, fans, and ventilators	1	1.9
Circuit closers/interruptors	1	1.9
Control rod drive mechanisms	1	1.9
Control rods	1	1.9
Electric wires, cables, and buses	1	1.9
Fuel elements	2	3.8
Hangers. pipe supports, scrubbers, etc.	6	11.3
Heat exchangers	3	5.7
Instrumentation and controls	12	22.6
Internal combustion engines	1	1.9
Other components	1	1.9
Penetrations (airlocks, personnel access, electrical, etc.)	1	1.9
Pipes and fittings	3	5.7
Pumps	2	3.8
Relays and switchgear	1	1.9
Valves	10	18.9
Vessel	3	5.7
Not applicable	3	5.7
Total	53	100.3*

*Total does not equal 100% because of rounding numbers to the nearest tenth of a percent.

The causes for the reportable occurrences and the associated number of LERs are shown in Table 4.6. Note that the assignments of multiple causes results in 64 causes being listed for only 53 LERs.

4.2.5 Operational events acted on by the NRC

Licensee Event Reports are assessed by the NRC for their significance relative to safety and performance according to the design intent. Those events considered to be significant from the standpoint of public health and safety are reported to Congress quarterly (see Sect. 4.3). Events of possible significance to safety are reported to the other licensees (and other interested parties) for their information and for corrective action and response if necessary. Three types of reports, distributed by the Office of Inspection and Enforcement (I&E) of the NRC, are directed specifically to licensees: (1) I&E Information Notices, (2) I&E Circulars, and (3) I&E Bulletins. A fourth type of report, Power Reactor Events, is directed more to the general public and persons interested in the nuclear industry; these reports are distributed by the NRC's Office for the Analysis and Evaluation of Operational Data (AEOD).

4.3 Abnormal Occurrences

An abnormal occurrence (AO) is an unscheduled incident or event at, or associated with, any facility that is licensed or otherwise regulated pursuant to the Atomic Energy Act of 1954, as amended, or to the Energy Reorganization Act of 1974, which the NRC has determined is significant from the standpoint of public health or safety.

The NRC developed the following criteria by which abnormal occurrences are to be determined: (1) events involving an actual loss of the protection provided for the health and safety of the public and (2) events involving a major reduction in the degree of protection provided for the health and safety of the public.

Each quarter the NRC submits to Congress a report listing any abnormal occurrences for that period,[2–5] as required by Sect. 208 of the Energy Reorganization Act of 1974. The report contains the date and place, nature and probable consequences, cause or causes, and any action taken to prevent recurrence of each abnormal occurrence.

During 1982 six abnormal occurrences were reported to Congress. Four of these took place during 1982, while two dealt with events during 1981 that occurred too late for inclusion in the 1981 report and are therefore covered here. A brief description of each occurrence is given below. Also included is updated information on previously reported occurrences.

4.3.1 Diesel generator engine cooling system failures (AO 82-1) (Ref. 2)

Dresden Nuclear Power Station, operated by the Commonwealth Edison Company, includes two operating nuclear power reactors, Dresden 2 and

Dresden 3. As part of the redundant emergency power supply system, there are three diesel generators that supply electricity to the plants for required services in the event that normal offsite ac power becomes unavailable. One diesel unit (DG 2) is dedicated to Dresden 2, another unit (DG 3) is dedicated to Dresden 3, and a third unit (DG 2/3) is a "swing" unit that can supply either of the reactors as required.

On October 23, 1981, in the course of monthly surveillance testing, both DG 2 and DG 2/3 tripped on high engine temperature after running for some time. In both cases air binding of the cooling-water pumps was suspected, but venting of the pumps did not reveal air escaping. Nevertheless, the pump discharge pressure was abnormally low, and there was also abnormally low vent flow, abnormally low levels of pump noise and vibrations, and an abnormally warm stator cooling line. After several attempts to cycle DG 2/3, the pump noise increased and so did the pump discharge pressure. The pump was then declared to be operating normally, and the unit was returned to service.

On November 19, 1981, in the course of another surveillance test of DG 3, similar problems involving a unit trip due to high temperature appeared, the pump was then declared inoperable, and DG 3 was taken out of service.

On December 1, 1981, the DG 2/3 water pump exhibited a slow decrease in indicated discharge pressure, accompanied by increasing noise and vibration levels. The immediate cause of this problem was found to be excessive wear on the pump motor bearings, and the pump and motor were replaced.

Investigations of the October 23 and November 19 events relating to DG 3 revealed that a check valve on the DG 3 pump discharge line had broken in such a manner that the valve disk had broken completely free of its pivot arm and had lodged in the discharge side of the valve body, restricting nearly all flow. As a result of this finding, the same valve on DG 2/3 was examined in the course of the pump replacement undertaken to deal with the December 1 event. This valve was also found to have failed, with the disk separated from the pivot; however, the disk had not lodged in the valve but was free to move within it.

Although the DG 2 unit had given no indication of problems in the time period in which these events occurred, the discharge check valve on this unit was also inspected, and it too was found to be broken. However, in this valve the break was at a different point. The valve hinge broke and the pivot hinge remained attached to the valve disk.

These events were unique in that all three check valves were found to be broken during a short period of time, diagnosis of the valve failures was delayed due to poorly designed instrumentation, both diesel generators of Unit 3 were simultaneously affected (and made inoperable) on October 23, 1981, and the potential existed for all three diesel generators to be affected simultaneously had the DG 2 check valve broken in the same manner as the other two.

The diesel generators were rendered inoperable due to insufficient cooling water flow. In two of the events, the degraded flow was directly caused by broken check valves. In one event, even though the check valve was broken, it was not restricting flow; the decrease in discharge pressure was caused by worn bearings on the cooling water pump. In two instances the valve disk had broken free of the pivot arm; in the third case the pivot arm remained attached to the valve disk but was broken at the hinge to the valve body.

It is not known how long these check valves were broken before the failures were detected, since the broken DG 3 and DG 2/3 check valve disks were free to move within the valve bodies and may have been that way for some time before coming to rest in a position that would restrict flow enough to cause the diesels to trip on high engine temperature.

Commonwealth Edison conducted an investigation of the events and took the following specific actions:

1. All three discharge check valves were replaced.
2. Instrumentation changes for the cooling water systems for all three diesels were made to provide a more accurate indication of system flow.
3. Plant procedures were changed to lower the probability of air leakage into the pumps or inadvertent shutting of the pump suction valves. In addition, motor bearing tolerances for the pumps, which are checked annually, are being recorded for trend analysis purposes.
4. The electrical supply and control systems were extensively tested. While no negative results were found, the pump motor electrical overload devices were changed so that they will reset automatically instead of manually.
5. Plans were instituted to examine and test each of the DG water pump check valves annually.

The NRC issued a series of Confirmation of Action Letters to the licensee to provide adequate assurance that onsite emergency power would be available in the event of an accident, while the licensee continued to investigate the cause of the cooling water insufficiencies.

After the licensee's investigations and corrective actions were considered adequate, the licensee was verbally released from the requirements of the letters on December 24, 1981.

On January 22, 1982, NRC Region III forwarded its inspection report of the events to the licensee. No items of noncompliance with NRC requirements were identified during the course of the inspection.

4.3.2 Pressure transients during shutdown at Turkey Point 4 (AO 82-2) (Ref. 2)

On November 28 and 29, 1981, two RCS pressure transients took place in Turkey Point 4 while the reactor was shut down and preparing to go from cold-shutdown to hot-shutdown conditions. In this circumstance, the RCS is "solid," that is, the entire reactor coolant volume, including the pressurizer, is filled with water so that even a small flow into the system at high pressure, such as is supplied by the positive-displacement charging pumps, can produce very large pressure increases. To prevent overpressurization there is normally a letdown path for excess water, controlled by a pressure control valve. In Indian Point 4 the letdown path was through the residual heat removal (RCH) system, which can be valved off from the RCS system by a block valve, and which is set to close automatically when the pressure reaches 464 psig to protect the RHR system. As added protection there are also two parallel (redundant) overpressure mitigation systems (OMSs), which sound an alarm when the system pressure reaches 400 psig, and which automatically open a power-operated relief valve (PORV) when the pressure exceeds 415 psig. Each OMS operates a separate PORV. However, at the time of the November 28 incident, one of the two OMS systems was inoperable due to the closing of a block valve in series with, and upstream of, its PORV to permit maintenance on that train, a permissible condition.

Before detailing the events that resulted in overpressurization, a brief discussion will be given on why such an event is significant, especially when the reactor is "cold" (i.e., at about ambient temperature of approximately 100°F). The steel of which a reactor pressure vessel is made becomes brittle as the temperature is lowered, and this would make it potentially possible for such a vessel to fail by brittle fracture, that is, catastrophically, if the temperature were below the embrittlement point (the so-called null-ductility transition point) at the same time that a pressure transient occurred (if a large flaw were also present in a highly stressed region of a vessel). Normally the transition point lies far below normal ambient temperature so that brittle failure would not be a problem. However, as the steel in the pressure vessel is irradiated with fast neutrons from the reactor core within it, the null-ductility transition temperature rises and could be higher than room temperature in an old plant, which has had much neutron irradiation over the years, in the belt-line region around the vessel directly adjacent to the center of the reactor core.

All three conditions, embrittled steel due to irradiation, low temperature, and a significant flaw, would have to be present before a pressure transient could pose a serious problem. If the metal is in the ductile state (its normal state under operating conditions), it can accommodate the pressure surge and no risk exists. At Turkey Point 4 no such embrittled condition existed, so there was no direct risk; however, because of the potential safety significance of similar events after embrittlement has progressed further, the NRC is concerned with preventing cold pressure transients.

At Turkey Point 4, on November 28, 1981, the reactor was in cold shutdown mode following a refueling outage, and the operators started the heatup by starting a reactor coolant pump. This normally causes an initial pressure rise from the normal value of about 340 psig, which is normally controlled by the OMS. However, in this instance neither OMS train functioned. One train, as already mentioned, was shut down and blocked off for maintenance, and the other failed to work because an isolation valve had been shut, preventing the pressure from being sensed by the pressure sensor in that train; a temperature summator, needed to establish the pressure set point in that train, had also failed high. Either condition alone would have rendered this OMS train inoperable.

Without the OMSs working to open either of the PORVs, the pressure surge due to the reactor cooling pump start, coupled with the operation of one of the three direct-displacement charging pumps, allowed the system pressure to rise above the 465-psig level, thus causing the block valve to the RHR system to close and preventing letdown flow through that system. With no path for water to leave the system now, the continued operation of the charging pump caused the pressure to increase. The operators, noting the pressure increase, stopped the charging pump and manually opened a PORV, thus terminating the event. The operators noted the closed valve that had isolated the pressure sensor that would have opened the PORV automatically and opened it. However, they did not note that the temperature summator had failed on that same system, so when they attempted heatup again the next day, November 29, 1981, the same sequence of events caused another overpressurization since the PORV still could not open automatically. However, while the first event reached a peak pressure of about 1,100 psig, increased operator awareness of the problem the next day limited this excursion to only 750 psig.

A fracture mechanics analysis performed later by Westinghouse showed that the integrity of the reactor vessel was not impaired by these transients and that its fatigue life was not significantly affected. An independent consultant reviewed the analysis and concurred with its conclusions. The fact that there was no thermal stress present was a beneficial factor in the analysis.

After the first pressure transient, attempts were made to restore the redundant OMS loop to operating condition, but this was not accomplished by the time the second pressure transient occurred. The immediate corrective action during both events consisted of reducing the RCS pressure to a value within the Technical Specification limits. Subsequent to the second event, the licensee notified the NRC of the incidents and confirmed that the unit would not be restarted until the NRC had reviewed the matter.

4.3.3 Major deficiencies in management controls at Pilgrim Nuclear Power Station (AO 82-3) (Ref. 2)

A combination of three violations involving inadequate management controls resulted in the issuance of this Abnormal Occurrence report and a proposed imposition of a $550,000 civil penalty against the Boston Edison Company, the licensee for the Pilgrim Nuclear Power Station, on January 18, 1982. The fine was imposed because of management control deficiencies involving control of combustible gases inside containment and maintenance activities pertaining to the reactor core isolation cooling system. On February 4, 1982, the licensee was further cited for various violations, including inadequate management controls, for operation of the plant with dry-well temperatures in excess of design values.

These three occurrences indicated continuing serious deficiencies in management control of certain licensee activities. Two of the occurrences involved time periods of several years. Although different in nature, these three occurrences demonstrated a recurring lack of management attention to licensee activities important to safety.

The first item involved the failure, from November 27, 1978, to June 5, 1981, to comply with regulations regarding the ability to control combustible gas mixtures following postulated accidents. The safety significance of this item is that the ignition of an uncontrolled accumulation of combustible gases inside containment could have resulted in deflagration and a pressure surge of the containment atmosphere, which might breach the containment and release substantial quantities of radioactive material to the environment.

The second item concerned that improper management control of maintenance activities on safety-related electrical power supplies, which resulted in a degradation of the containment automatic isolation control logic, partially disabling two isolation valves, and thereby significantly reducing assurance that the valves would automatically close when required. The safety aspect of this item is that failure of these valves to close as required during certain accident sequences could cause a significant increase in the amount of radioactive materials released to the environment.

The third item involved operation of the facility at various times from plant startup in 1972 until September 26, 1981, with the primary containment dry-well temperature greater than stipulated in the Final Safety Analysis Report. Not only had the licensee been aware of the situation for several years, but there was no evidence that safety evaluations had been made as required by 10 CFR 50.59. The safety significance of this item is that operation at the elevated temperatures for sustained periods could result in detrimental effects (e.g., premature aging) to equipment required to shut the reactor down safely and to mitigate certain postulated accidents.

The root cause of these three items of concern was attributed to serious deficiencies in management controls of licensed activities.

The first item, in itself a series of major deficiencies in management controls, resulted in a protracted failure of the Pilgrim facility to comply with regulatory requirements. This condition existed due to management's failure to conduct a proper design review of the capabilities of the atmosphere control system. However, the licensee erroneously informed the NRC in a letter dated October 19, 1979, that the equipment installed in Pilgrim 1 was in full compliance with the requirements of 10 CFR 50.44. Later, apparently as a result of an October 30, 1979, NRC letter requesting details of Pilgrim's compliance with 10 CFR 50.44, the licensee took steps to design and install a modification to the system that would bring Pilgrim into compliance. This modification was installed during the May 1980 outage; however, because of a failure of management to initiate an essential procedural change, the modified system was not fully operational until June 5, 1981.

The second item involved a breakdown in the control of planned maintenance activities. There was a failure to review and control safety-related activities at the facility properly.

The third item, the problem of apparent erroneous level oscillations, was determined to be caused by flashing of the level instrument reference legs at reduced reactor pressure because of the high dry-well operating temperature (240°F), which was in excess of that specified (150°F). Dry-well temperatures higher than this limit were attributed to ineffective dry-well cooling due to a degraded condition of the ventilation system (ducting, coolers, cooling water). The high temperatures and degraded condition of the cooling systems had been observed by Pilgrim operating personnel on many previous occasions and were considered to have been allowed to continue as a result of inadequate preventive maintenance and management controls.

To correct the first item, the licensee restored the system to its original design and initiated an investigation to determine the cause of the unauthorized maintenance. Also, a procedural revision was made to permit effective remote operation of the system. The licensee proposed and the NRC approved Technical Specification changes concerning operability and surveillance requirements of the modified hydrogen control system.

To deal with the third item, corrective maintenance was initiated on the dry-well cooling systems to restore the original design capacity during a refueling outage in September 1981. Dry-well equipment insulation was repaired, and additional instrumentation was installed to monitor the temperature and the performance of the cooling systems. At the request of the NRC, the licensee proposed Technical Specifications limiting dry-well temperatures. In addition, the licensee looked for damage to safety-related equipment resulting from the sustained abnormally high temperature. Certain equipment, such as instrument limit switches, electrical cables, and solenoids, were found to be affected and were either repaired or replaced.

The licensee submitted to the NRC for review and approval a performance improvement program that involves a comprehensive action plan of tasks and milestones to correct the identified deficiencies. The program includes an independent appraisal of site and corporate organizations and functions, modifications in organizational structure, improvements to be made in management control and oversight systems, and programs designed to improve individual performance.

The licensee has restructured corporate functions within its nuclear organization. All nuclear activities at Boston Edison have been reassigned to an organizational unit directed by a Senior Vice-President who has no other function or line responsibilities. Also, a new position of Director—Nuclear Operations Review having responsibility for corporate management oversight of onsite safety-related activities was established and filled.

Based on its findings and previous deficiencies in regulatory performance, the NRC concluded that long-term operation of the plant would require significant changes in the control of licensed activities. As a result, the NRC issued an Order Modifying License Effective Immediately on January 18, 1982, requiring Boston Edison Company to develop and submit for NRC review and approval a comprehensive plan of action that would yield an independent appraisal of site and corporate management controls and oversight, and a review of previous safety-related activities to evaluate compliance with NRC requirements.

The NRC has approved safety evaluation reports submitted by the licensee for the modified containment atmosphere control system and for past operation at elevated dry-well temperatures. It has agreed that the modified containment atmosphere control system and maintenance actions to replace components possibly degraded by the high dry-well temperature meet regulatory requirements and has approved the Technical Specifications submitted by the licensee that limit dry-well temperature during plant operation.

4.3.4 Steam generator tube rupture at Ginna (AO 82-4) (Ref. 2)

On January 25, 1982, a tube in the steam generator at the R. E. Ginna Nuclear Power Plant ruptured extensively, thus allowing water from the primary coolant loop to flow into the secondary (steam) circuit, depressurizing the primary system and resulting in minor releases of radiation off site.

Offsite releases were estimated to be less than 25% of the limit for unrestricted areas. The maximum recorded individual radiation dose was 240 mrem, which is well below the 1,250 mrem/quarter limit set by the NRC for occupational exposure.

Postincident examination of the failed steam generator tube indicated that the tube wall had been thinned by mechanical fretting from the external (steam) side of the tube and that this was caused by mechanical wear due to a foreign object that had apparently been left in the shell side of the steam generator at the time of steam generator modifications in 1975. The foreign object had apparently rubbed against an outer-row tube, causing it to leak and be plugged. The plugged tubes then eventually collapsed and in turn mechanically damaged adjacent tubes, which were also plugged. This type of repeated damage transfer eventually reached the failed tube, which was affected in such a manner that it ruptured radically before giving indication of imminent failure by leaking.

Prior to the tube rupture, the plant had been operating at 100% power with normal operating temperature and pressure. No indications of primary-to-secondary leakage existed. At 9:25 a.m., multiple control room alarms alerted the operators to a rapid RCS depressurization. The air ejector radiation monitor alarm indicated the existence of a steam generator tube rupture; other alarms indicated that the rupture was probably in the B steam generator. The operators commenced a rapid turbine power reduction and an increase in the number and speed of the operating charging pumps. At 9:28 a.m., the continuing RCS pressure drop resulted in an automatic reactor trip and automatic safety injection actuation, causing all three high-pressure safety injection pumps to start. Also, an automatic containment isolation occurred, and the operating charging pumps automatically tripped. All safety systems operated as required. Both reactor coolant pumps were manually stopped, and natural circulation cooling developed in both RCS loops. The pressurizer emptied, and the RCS reached a minimum pressure of about 1,200 psig. A small steam bubble briefly formed in the upper head during natural circulation. This bubble subsequently collapsed as safety injection flow refilled the reactor coolant system.

Initially operators cooled down the plant by sending steam from both steam generators to the main condenser while they identified the fault to be in the B steam generator. This steam generator was isolated at about 9:40 a.m., and natural circulation in the B loop terminated shortly thereafter. Although all sources of feedwater to the B steam generator had been cut off, its water level continued to rise because of the flow through the tube rupture. At 9:55 a.m., the narrow-range water level indicator on the B steam generator went off-scale high, and shortly thereafter the B main steam line started to fill.

At 9:57 a.m., the safety injection actuation circuitry was switched off to allow the containment isolation system to be inactivated. Then instrument air to the containment and, therefore, control of the air-operated valves inside containment, was restored.

At 10:07 a.m., the operators attempted to stop the flow through the tube rupture by equalizing the pressure on both sides of the rupture.

They did this by opening a pressurizer PORV, which operated successfully three times. During its fourth operation, the valve opened on command but then remained in the open position. The operator then manually closed a block valve to prevent excessive depressurization of the RCS. During these operations, the pressurizer level had risen rapidly and the level instrument was now indicating off-scale high.

Operation of the pressurizer PORV resulted in the formation of steam voids in the reactor vessel upper head and in the top of the tubes in the B steam generator. The size of the void in the reactor vessel was estimated to be about 300 ft^3. The total void volume in the steam generator tubes was smaller. The growth of these voids during the depressurization of the RCS, along with increased safety injection flow, had caused the rapid filling of the pressurizer. Natural circulation in the A loop and core cooling were not adversely affected by the existence of these voids.

A B steam generator code safety valve lifted and closed three times as a result of continued break flow into the B steam generator; however, the safety valve may have leaked steam starting after the first lift. At 10:38 a.m., safety injection was terminated to prevent further safety valve lifts.

At 10:40 a.m., the condensate system was shut down to prevent further radioactive contamination of the condensate storage tanks and the condensate demineralizers. The original contamination was due to the dumping of steam to the condenser from the damaged steam generator earlier in the event. To continue the plant cooldown, the operators vented the A steam generator to atmosphere using its PORV.

At 11:07 a.m., one safety injection pump was started to provide a buffer for the anticipated drop in RCS pressure that the plant staff expected to occur as a result of the restart of the A reactor coolant pump. At 11:19 a.m., a B steam generator safety valve lifted and closed again. However, by this time the steam line had flooded sufficiently to cause water rather than steam to be released. At about 11:21 a.m., the A reactor coolant pump was started. The resulting coolant flow cooled and collapsed any remaining steam voids in the reactor and the B steam generator. At about 11:37 a.m., a fifth lift of the B steam generator safety valve occurred, and the safety injection pump was stopped. The safety valve closed but apparently continued to leak water at about 100 gpm.

At 11:52 a.m., the pressurizer level dropped back on scale as a result of the continued flow from the RCS into the B steam generator. At 12:02 p.m., normal letdown from the RCS to the chemical and volume control system was reestablished. Because the B steam generator safety valve continued to leak, the tube rupture continued to drain reactor coolant into the B steam generator. The rate of decrease of pressurizer level resulting from this continued flow through the break prompted the operators to restart one safety injection pump at about 12:12 p.m. This pump was then intermittently run to control pressurizer level until about 12:35 p.m. By then the B steam generator safety valve had apparently stopped leaking so that the safety injection pump was no longer needed to control pressurizer level after this time.

At 12:27 p.m., the RCS and B steam generator pressures equalized. The operators then maintained RCS pressure about 25 psi below B steam generator pressure to induce reversed flow through the break. At 6:40 p.m., the B steam generator water level returned on scale on the narrow-range indicator. The B steam generator was then cooled by a feed-and-bleed operation with auxiliary feedwater being intermittently supplied while backflow through the break was allowed to continue.

At 7:00 a.m., January 26, the RHR system was placed in operation, and at 6:53 p.m., on that day, the licensee declared the plant to be in a cold shutdown condition.

4.3.5 Loss of auxiliary electric power at Quad Cities (AO 82-5) (Ref. 4)

The Quad Cities Nuclear Power Station utilizes two BWRs and, like the two units at Dresden discussed in Sect. 4.3.1 of this report, makes use of three diesel generators to act as auxiliary power sources in case of loss of offsite power. One of these, DG 1, is dedicated to Unit 1, another, DG 2, serves Unit 2, and the third, DG 1/2 is a "swing" unit that can feed either of the two reactors as needed.

On June 22, 1982, a sequence of events occurred, as a result of which normal offsite sources of ac power were available for Unit 1, but neither DG 1 nor DG 1/2 were available; simultaneously, all normal offsite sources of ac power to Unit 2 were lost for approximately 40 min, and only DG 2 was available. For both units, such loss of power sources can be considered a major degradation of essential safety-related equipment.

At the time of the event, Unit 2 was operating at approximately 95% and Unit 1 at 60% power. DG 1 was out of service for maintenance; however, DG 2 and DG 1/2 were operable. While preparing to remove the Unit 2 reserve auxiliary transformer from service for elective repairs, an equipment operator mistakenly pulled out the fuses for a 4-kV bus instead of pulling the transformer fuses. (When the plant is producing electricity, the plant and its instrumentation are powered by the plant's main generator via an auxiliary transformer. The reserve auxiliary transformer is available to provide offsite power when the plant is not operating.)

This operator error disconnected power to certain plant systems, including a Unit 2 reactor feedwater pump. The reduced feedwater flow caused a low water level, which automatically initiated a reactor trip. The Unit 2 main generator subsequently tripped, resulting in the loss of all normal ac power to Unit 2, since the reserve auxiliary transformer was already out of service. Both DG 2 and DG 1/2 started automatically and began to supply power to essential plant systems.

As part of the normal consequences of the reactor trip, the pressure in the RCS temporarily increased, causing automatic opening of safety relief valves. The released steam was condensed in the pressure suppression pool water, thus heating up this water. Therefore, at 5:47 a.m., 22 min after the event began, the reactor operators started an RHR pump to cool this water down.

DG 1/2 tripped when the RHR service water pump was being started, cutting off power to various instrumentation and safety systems. The cause of the trip was the actuation of underexcitation relays that protect the diesel generator. Power continued to be supplied from DG 2.

Loss of DG 1/2 resulted in numerous alarms and loss of several control room instrument indications. In addition, the loss of DG 1/2 left Unit 1, which was still operating, without any backup source of power (since DG 1 was already out of service for maintenance) should it experience a loss of offsite power.

At 5:50 a.m., an unusual event was declared under the licensee's emergency plan, and appropriate notifications were made.

Pressure in the Unit 2 containment increased from the normal 1.3 psig to about 4.3 psig, primarily because of leaking gaskets on the discharge lines of the main steam relief valves, multiple relief valve actuations to control reactor pressure, and shutdown of the dry-well coolers. The latter occurred, as designed, as a result of an ECCS initiation signal that actuates at a dry-well pressure of about 2 psig. Also as a result of this ECCS initiation signal, the high-pressure coolant injection (HPCI) system started automatically and began to pump water into the reactor vessel.

Licensee personnel in the meantime were restoring the reserve auxiliary transformer to service. By 6:04 a.m., 39 min after the event began, the transformer was operable and offsite power was restored for all plant systems.

Reactor pressure was controlled by manual operation of the relief valves, and at 6:15 a.m., suppression pool cooling was established using the RHR system. Cold shutdown was achieved at about 5:00 p.m.

The plant returned to service on June 24, 1982, after appropriate maintenance and testing activities were completed.

As stated previously, the station's auxiliary electrical power system utilizes a swing diesel that will automatically align itself to the unit that requires it. With this arrangement, the removal of a dedicated diesel generator from service would mean the potential unavailability of all automatic onsite emergency power sources of one unit. The removal of the swing diesel generator causes unavailability of onsite power to one division of the emergency electric sources between both units. Because of this interdependence of onsite power sources between both units, any scheduled maintenance of the offsite power system of either unit would affect the overall electrical power system availabilities of both units. The reserve auxiliary transformer is the primary source of offsite power for the plant. Therefore, the licensee's decision to remove the transformer from service for elective maintenance while the plant was in operation, and particularly with DG 1 already out of service for maintenance, was nonconservative although it was not prohibited by the plant's technical specifications.

Following loss of offsite power to Unit 2, DG 2 and DG 1/2 started as designed. However, later when the operator attempted to start an RHR service water pump for suppression pool cooling, DG 1/2 tripped. Succeeding attempts by the control room operator to start DG 1/2 failed. The cause of the trip was a design error in the diesel generator control logic system. An underexcitation relay had been installed in all three diesel generators in 1981 to protect the diesel generators during testing when the diesel generator is loaded to an energized bus, but this function should have been automatically blocked out when an auto-start signal actuates the diesel generator. Due to a design error, this trip was not blocked out when the operator started the RHR pump. Actuation of the underexcitation relay also tripped the diesel generator lock-out relay, and the diesel generator could not restart until the relay was manually reset. Resetting the relay was delayed because the equipment operator had been sent to the switchyard to expedite restoration of offsite power to Unit 2.

The licensee has taken appropriate measures to minimize the possibility for similar operating errors, including a review of procedures and additional training for operating personnel.

The underexcitation relays have been removed, and the licensee is planning modifications to all three diesel generators to prevent protective trips in an emergency situation. The licensee also replaced the leaking gaskets on the relief valve discharge lines, which had contributed to the rise in containment pressure.

4.3.6 Inoperable containment spray system at Farley 2 (AO 82-7) (Ref. 5)

During a refueling and maintenance outage that began on October 24, 1982, it was discovered that a block valve on each of the two independent redundant containment spray systems was closed and locked in the closed position, thus preventing operation of the containment spray had it been called on to function.

The containment spray system is part of the reactor accident response system. It sprays cool borated water into the containment building in the event of a loss-of-coolant accident (LOCA) to limit the pressure in the building to permissible levels and to help scrub radioactive iodine from the containment atmosphere to reduce emissions of radioactive contamination. A separate pair of fan cooler systems also removes heat from the containment building, and because of conservative design, even if only the fan cooler system were to function, and even that system with only one of its two fans, the integrity of the containment in an LOCA would be maintained. However, the iodine scrubbing function would be lost if neither of the two spray systems were operable. Of course, since no LOCA occurred, the spray system was never called upon in earnest, so that no actual harm was done.

Investigation by the licensee to determine the duration of this condition led to the tentative conclusion that these valves had been locked closed since at least the time the plant first achieved criticality on May 8, 1981.

A probable contributing factor to this occurrence was that the valve supplier had redesigned the valves for possible motor operation, which involved lengthening the valve stems and threading an extended portion of the stem. The result was that the valves had the visual appearance (i.e., long exposed threaded stem) of being open when they were in fact closed. (Investigation of the other unit at the plant, with identical valves, showed these to be locked properly open.)

One serious aspect of this situation is that these valves, which must be operated manually, are located inside the containment building, and thus would not have been accessible for correction of the misalignment had there been an LOCA requiring the use of the containment spray system.

To prevent any possible recurrence of such an event, the licensee obtained concurrence from Westinghouse Corporation to cut the excess stem off the valves to conform with design drawings and with other rising stem gate valves throughout the plant. In addition, as a further safeguard to prevent recurrence, plant administrative procedures covering valve position verification have been changed to require that manual valves that are locked open will be moved in the shut direction to verify their position; then the valve will be returned, if applicable, to the original position.

Based on their investigation of this event, NRC Region II (Atlanta) proposed imposition of a civil penalty of $40,000, which was paid by the licensee on February 28, 1983.

4.3.7 Updates on previously issued abnormal occurrence reports

The NRC, the NRC licensees, and other concerned parties (including reactor vendors and architect-engineers) continued the implementation of actions resulting from previously reported abnormal occurrences. Updated information on these occurrences is briefly summarized below. The numbers and descriptive titles correspond to those used in the original reports of the occurrences to Congress.

Cracks in Pipes at Boiling Water Reactors, Events at Several BWRs (AO 75-5). This occurrence was originally reported in NUREG-75/090, *Report to Congress on Abnormal Occurrences: January–June 1975*, and then updated in later reports in this series, namely Vol. 1, No. 3; Vol. 2, Nos. 2 and 4; and Vol. 3, Nos. 2 and 4. In the last-named report this event was closed out, but it was reopened in Vol. 5., No. 2 to report the following case of pipe cracking that required a significant plant outage to repair.

On March 23, 1982, the Niagara Mohawk Power Corporation reported an event involving leakage from welds on two nozzles connecting recirculation system piping to the reactor vessel at Nine Mile Point, which utilizes a General Electric-designed BWR.

The leakage was discovered during performance of a routine hydrostatic pressure test prior to return to operation from a scheduled maintenance outage. At a test pressure of 900 psig, leakage was observed near two of the ten recirculation-piping-to-reactor vessel nozzles. Upon depressurization and removal of thermal insulation, three small leaks were observed on the Loop #11 discharge nozzle safe end and one leak on the Loop #15 suction nozzle safe end. Each of the leaks appeared to be in the heat-affected zone of the nozzle safe-end-to-pipe weld. Samples were obtained from one of the safe ends in the vicinity of the throughwall cracks and sent to General Electric and Battelle Laboratories for evaluation. The results confirmed the presence of intergranular stress corrosion cracking (SCC).

Inspections then were made of the recirculation pump discharge-casting-to-riser elbow welds. Again cracks were found. Testing confirmed the presence of intergranular SCC there also. The licensee decided to inspect all of the remaining welds where radiation fields permitted and found cracking in many of them.

Based on these investigations, it was decided to replace the 28-in. recirculation piping in all five recirculation loops, all ten safe ends, and, if warranted, the branch piping, with material less susceptible to intergranular SCC.

The replacement program required extensive work. The plant was expected to be shut down for at least a year. Even with the reactor core removed and the RCS drained and decontaminated, it was estimated that a collective dose to workers of over 2,000 person-rem would be accumulated. More precise numbers were to be developed as details of the replacement program became better defined.

This abnormal occurrence report was further updated later in the year, in NUREG-0090, Vol. 5, No. 4, to report results of the augmented inspections of the recirculation piping at all BWRs required by NRC Inspection and Enforcement Bulletin 82-03, issued October 14, 1982, and revised on October 28 (Ref. 6).

The inspection undertaken at the Monticello reactor in response to that requirement, which included an examination of all the welds in the recirculation and connecting piping, found indications of cracks in five welds. The flaws were repaired and the plant resumed power generation. Subsequently, indications of cracks were found in seven welds at Hatch Unit 1, and indications were found in two welds in the large diameter piping in the recirculation system piping at Browns Ferry Unit 2. Crack indications were also found in weld locations in the reactor coolant recirculation system at Dresden Unit 2 (one weld) and Brunswick Unit 1 (three welds). The NRC closely monitored the corrective actions of the licensees and made evaluations to ensure that the plants were safe to restart.

Steam Generator Feedwater Flow Instability at Pressurized Water Reactors (AO 75-7). This occurrence was originally reported in NUREG-75/0090, *Report to Congress on Abnormal Occurrences: January–June 1975*, updated in later reports in the same series (NUREG-0090-1, Vol. 1, No. 4; and Vol. 2, No. 2). A further update, which closed the reporting of this occurrence, was reported in Vol. 5, Nos. 2 and 3, as follows.

The earlier reports on this problem cited steam generator water hammer (SGWH) concerns in the feedwater lines at Zion 1 and San Onofre 1. Since then modifications and other measures have been implemented at these two plants.

Because of the continuing occurrence of SGWHs in some Westinghouse (W) and Combustion Engineering (CE) plants, the NRC in September 1977 requested that all W and CE PWR licensees submit proposed hardware and procedural modifications necessary to prevent or mitigate SGWH. Licensee responses were subsequently evaluated by the NRC staff, and conclusions were presented in safety evaluation reports and letters to licensees. As a result of these evaluations, the NRC staff prepared Branch Technical Position ASB 10-2, "Design Guidelines for Water Hammers in Steam Generators with Top Feedring Designs," and incorporated this position into Section 10.4.7 of NRC's Standard Review Plan, NUREG-0800. Since Babcock and Wilcox (B&W) plants had not reported damaging SGWHs, these plants were not required to make changes. However, during April 1982 some B&W steam generators were found to have damaged internal auxiliary feedring and support structures. These findings were discussed in NUREG-0900, Vol. 5, No. 2.

Occupational Overexposure During Entry to Reactor Cavity at Zion 1 (AO 76-2). This abnormal occurrence was previously reported and closed in NUREG-0090-3, *Report to Congress on Abnormal Occurrences, January—March 1976*, under the title "8 Rem Occupational Whole Body Exposure." It was reopened and updated in Vol. 5, No. 2, of the same report series because a similar event took place at the same reactor on March 25, 1982.

The 1982 incident resulted in an occupational overexposure and was potentially very hazardous because of the very high radiation levels (over 1000 R/h in some areas) in the reactor cavity area when irradiated incore detector thimbles were retracted in the area. However, in this instance the overexposure received was less than the abnormal occurrence reporting threshold.

On March 25, 1982, Zion 1 was in a scheduled refueling outage, and attempts were being made to flood the refueling pool. However, several leaks were experienced, principally around cover gaskets in the refueling pool floor which provide access to the excore nuclear instrumentation. The operators verified the leakage by entering the reactor cavity area, the area below the reactor vessel and refueling pool, which is normally locked.

The health physicist on duty authorized an exposure of 500 mrem for a shift engineer to make the leakage inspection. Two rad/chem technicians (one was a trainee) were assigned to assist the shift engineer, one to survey and one to keep time. The details of the proposed inspection were not discussed.

After obtaining the required radiation protection clothing and full face masks, the three entered the radiation zone above the reactor cavity. This area contained the entrance opening to a ladder extending down to the reactor cavity. One rad/chem technician climbed down the ladder first to survey the dose rate at the bottom, which was about 50 R/h. He did not leave the ladder because there was about 6 in. of water on the floor, and he assumed the shift engineer would not leave the ladder either. The rad/chem traineee stayed at the top of the ladder to keep time. He was told to start upon a signal from the first rad/chem technician. He then was supposed to call down when necessary to keep the shift engineer within his 500-mrem approved dose.

After timekeeping began, however, the shift engineer left the base of the ladder and moved into an area that had not been surveyed for radiation levels. He walked approximately 6 to 8 ft away from the ladder. The timekeeper, unaware that the shift engineer had left the base of the ladder, calculated the exposure using 50 R/h. After approximately 30 s, the timekeeper signaled to call the shift engineer back. The second rad/chem technician did so, waited approximately 10 s, and called again. The timekeeping stopped at 67 s when the shift engineer was back on the ladder. The timekeeper calculated the shift engineer's total exposure to be 931 mrem (50 R/h × 67 s).

When the health physicist was informed that the shift engineer may have been in an area where the exposure rates exceeded 50 R/h, the film badge was sent to a contractor for emergency processing on March 26. The next day, the contractor called in a reading of 3,700 mrem, which was double-checked and confirmed. Further evaluation indicated that the dose received was about 5 rem, because the highest dose was at the knee and the film badge was worn between chest and waist.

As stated in the written report of the event, the corrective actions included: (1) requiring that thimbles be reinserted prior to personnel entry into the reactor cavity beyond the base of ladders extending into the cavity area, that a special lock be placed on the door to the cavity when the thimbles are removed, and that locations of thimbles and incore detectors during outages be posted in the rad/chem office; (2) reviewing and supplementing operations and radiation personnel training; (3) requiring a radiation work permit (which includes a written description of work to be performed) for individual jobs exceeding 50 mrem; (4) revising radiation protection procedures to include specific requirements for issuing high-range (500 mrem and over) dosimeters; and (5) maintaining in the rad/chem department additional high-range detectors calibrated to 1,000 R/h and a limited number of dose rate ionization chamber instruments with lighted dials for work in dark areas.

Steam Generator Problems (AO 76-11). This occurrence was originally reported in NUREG-0090-5, *Report to Congress on Abnormal Occurrences: July-September 1976*, and updated in subsequent reports in the series, that is, NUREG-0090-8, Vol. 1, No. 4; Vol. 2, Nos. 3 and 4; Vol. 3, Nos. 1, 2, 3, and 4; and Vol. 4, No. 1.

As reported in NUREG-0090, Vol. 3, No. 4, reporting on the progress of the generic studies on steam generator tube integrity is provided quarterly in NUREG-0606, *Unresolved Safety Issues Summary, Aqua Book*. Reports on unique operating experience or problems with various aspects of steam generators are made as appropriate in the quarterly abnormal occurrence reports to Congress (NUREG-0900 series) under this section, which has been retitled "Steam Generator Problems" (from "Steam Generator Tube Integrity").

PWR steam generators have been experiencing a variety of tube degradation problems for a number of years, caused by either corrosion or mechanical damage. Degradation experience prior to the mid-1970's included wastage (localized thinning of tube walls) and caustic SCC on the secondary side due to difficulties in adequately controlling the chemistry of secondary water with sodium phosphate and to impurities carried into the steam generators by the feedwater. The establishment of all-volatile treatment (AVT) control succeeded in arresting any further significant wastage, but SCC has continued as a concern, particularly in plants with a significant period of phosphate operation prior to conversion to AVT. All PWRs have been converted to or have operated exclusively with AVT control except Robinson 2 and San Onofre 1.

Another form of degradation is denting, which is the squeezing of tubes caused by the buildup of corrosion products between the tubes and their carbon steel supports. This results in tube leaks due to SCC initiating from the primary side. At least 23 W and CE PWRs have reported denting, including 8 where denting is considered extensive. Copper oxide has been demonstrated to be a catalyst, and plants with copper in their secondary cycles have increased susceptibility to denting. The earliest date for a plant using all-ferritic-stainless-steel supports, which will reduce the susceptibility to denting, is 1983. The B&W design of antivibration supports with minimum contact area, along with virtually copper-free systems and full flow condensate polishing, have combined to maintain once-through steam generators free of significant denting to date.

Cracking has occurred in the small-radius, inner-row U-bends in steam generators. Some of this is associated with denting, which leads to support plate deformation and eventual closure of the support plate flow slots. At Surry 2, this caused a tube rupture in 1976. The current industry practice of plugging all row-1 tubes on the observance of upper flow slot closure has prevented similar failures in other extensively dented steam generators. In some cases, cracks have been observed where there has been no denting; this is attributed to residual stresses introduced during fabrication of the tubes.

Corrosion crevices between the tubes and the tubesheets have been experienced in at least 7 of the 17 plants where the tubes were not expanded to the full depth of the 24-in.-thick tubesheet. General intergranular attack has also been reported at two units in a region of sludge accumulation on the tubesheet. A new pitting phenomenon has recently been observed at Indian Point 3 and at Millstone 2, affecting large numbers of tubes. Localized wall thinning at the tube supports on the cold leg has been observed since 1979 at Prairie Island 2, affecting over 100 tubes. (After NUREG-0886 was issued, a similar problem was found at Salem 1 in January 1982.) Robinson 2, which continues to operate with phosphate secondary water chemistry control, has also experienced local wall thinning in the U-bends, which possibly is phosphate wastage related.

Leakage in the new W Model D steam generators at Ringhals 3 in Sweden caused its shutdown in October 1981. Significant tube wall reductions in the preheater section of that plant and of Almaraz 1 in Spain have been indicated by eddy current testing. This was caused by wearing down of tube walls from vibrational rubbing against baffle plates. To date, McGuire 1 is the only domestic operating plant with Model D steam generators, and the licensee pursued a cautious power escalation and test program with frequent shutdowns for inspection to determine susceptibility to this vibration phenomenon.

Until recently, the principal degradation modes of B&W units involved circumferential fatigue cracking and erosion-corrosion. However, extensive corrosion-induced cracking on the primary side in the upper tubesheet region has recently been observed at TMI-1.

Steam generator problems are generally detected by inservice inspections and primary-to-secondary leakage of coolant. Corrective actions generally involve plugging the degraded tubes or the use of a sleeving process. The advantage of sleeving is that it permits the tube to remain in service. Extensive tube degradation can lead to significant downtime to perform steam generator inspections. Eventually, so many tubes may be plugged that the plant must be derated. To avoid these problems, some utilities have elected either to replace their severely degraded steam generators or are considering doing so (e.g., Surry 1 and 2, Turkey Point 3 and 4, and Robinson 2).

Thus, steam generators from each of the three PWR vendors have experienced various forms of tube degradation resulting from a combination of inadequate design and fabrication, nonoptimal construction material, and poor operating practices, especially in secondary water chemistry control and condenser maintenance. In addition, the inspection, repair, and replacement efforts needed to deal with these problems have been the cause a major portion of each facility's annual occupational radiation dose. Industry-sponsored research has helped to identify the causes and mechanisms for several different types of tube degradation phenomena that subsequently led to design and operating improvements. It is anticipated that tube degradation will continue, but at a slower rate, primarily because of better controls of variables leading to the problems rather than because of corrections to design deficiencies and construction materials. Although some steam generator vendors have recently developed new steam generator models that are expected to provide significantly greater margins against tube degradation during operation, all plants scheduled to receive an operating license by 1984 have steam generators similar to those currently in service.

The PWR vendors, the affected utilities, and the NRC staff are continuing to evaluate new areas where the potential for tube degradation exists and to improve condenser integrity, secondary water chemistry control, steam generator and secondary plant designs, and nondestructive inspection capabilities to minimize forced outages caused by steam generator tube failures. The NRC staff has been evaluating adverse experience on a case-by-case basis and has concluded that continued operation and licensing do not constitute an undue risk to the health and safety of the public.

The significant problems encountered during 1982 that have not already been discussed above are described below.

Steam Generator Auxiliary Feedwater Header Damage in Certain B&W-Designed Plants. A unique problem, resulting in steam generator tube leakage, was discovered at Davis-Besse 1. On April 13, 1982, Toledo Edison Company notified the NRC that evidence of auxiliary feedwater (AFW) header damage was observed in the No. 1 steam generator of this reactor. Later inspections also showed damage to the header of the No. 2 steam generator. Subsequent inspections on April 19–20, 1982, and April 29, 1982, at Rancho Seco[1] and Oconee 3 showed similar damage to the AFW headers. Davis-Besse 1, Rancho Seco 1, and Oconee 3 all utilize B&W-designed PWRs.

The AFW system is used to provide emergency heat removal capacity upon loss of the normal feedwater to the secondary (shell) side of the steam generators. B&W-designed plants utilize once-through steam generators (OTSGs) in which the coolant water flows from the reactor through the loop hot leg to the tube side of the OTSG, where heat is transferred to the shell side to produce steam.

AFW enters a distribution header, which for the B&W-designed OTSGs is located either inside or outside the steam generator. External AFW headers are used at the following plants that have accumulated operational experience of over 22 reactor years: Oconee 1 and 3, Arkansas Nuclear 1, Crystal River 3, and TMI 1. B&W utilized an internal header design at Davis-Besse 1, Rancho Seco 1, Oconee 2, TMI 2, and Midland 1 and 2.

The internal AFW header design is shown in Fig. 4.1, which shows a longitudinal section of the design for Davis-Besse 1. This header is a rectangular torus fabricated of welded plate segments. It is positioned on the upper end of the upper shroud, and serves as a continuation of the upper shroud to separate the tube bundle from the steam annulus. It is positioned by eight sets of inner and outer brackets welded to the bottom of the header and match drilled through the shroud. A dowel pin passes through each set of brackets and is welded to the inner bracket.

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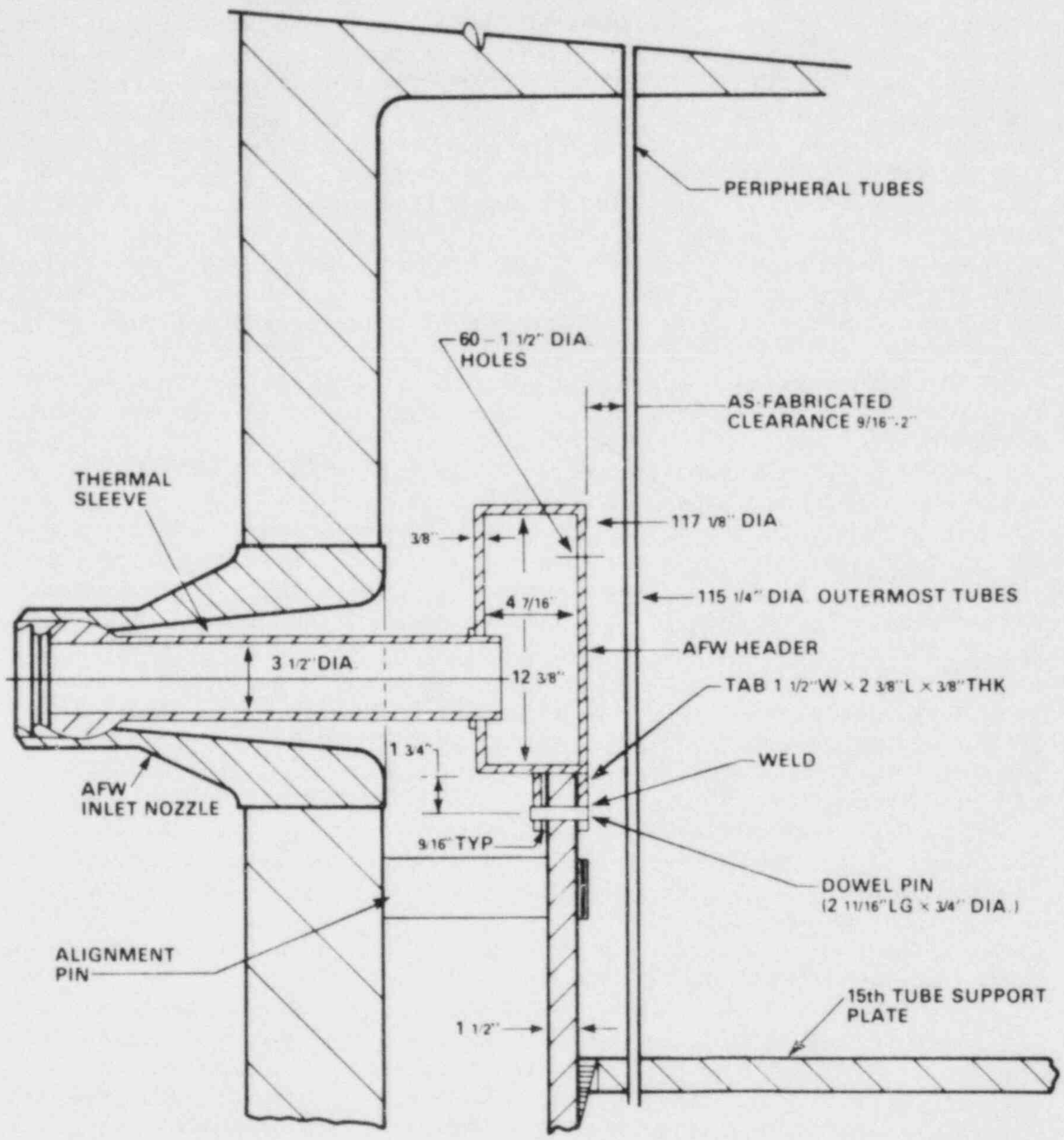

Fig. 4.1. Internal AFW header design (longitudinal section) for Davis-Besse Unit 1.

A single 3-1/2-in.-diam AFW nozzle delivers water to the header via a thermal sleeve that fits into the header. Water leaves the header through 60 1-1/2-in.-diam flow holes that are equally spaced around the circumference of the inner header wall, which also is supplied with 8 1/4-in.-diam drain holes. During power operation, the internal AFW header, thermal sleeve, and a portion of the horizontal piping are filled with dry superheated steam.

In April 1981, tube leakage was experienced at Davis-Besse 1. An eddy current inspection determined that two adjacent peripheral tubes were leaking, with the leaks in line with a header bracket pin. An expanded eddy current inspection carried out near the other pins identified one additional tube diameter reduction correlated to a dowel pin location.

In May 1981, tube leakage was found at Rancho Seco 1. Although the leaking tube was not related to the header, an eddy current inspection was performed at all dowel pin locations and recorded dings in tubes at five of the eight sites.

In February 1982, a leaking tube at the bundle periphery was noted at Oconee 3. An eddy current inspection performed at four of the eight dowel pin locations found no indentations.

As a result of these indications, more eddy current inspections of the peripheral tubes in the OTSG at Davis-Besse 1 were done during the 1982 refueling outage, and visual examinations were made on the internal headers to check for loose dowel pins in the brackets attaching the header to the steam generator shroud. It was this inspection that first detected header and bracket damage. The results of this inspection led to the inspections at Rancho Seco 1 and at Oconee 3. With one exception, the inspection results from all three plants were that the outer vertical wall of the header was distorted inward toward the center of the OTSG, the support brackets were bent or damaged, and the dowel pins were either out of position or missing. The exception was the presence of three holes in the header plates of steam generator "B" at Oconee 3. Also, cracks were found in the corner welds of the headers at Oconee 3 and Rancho Seco 1.

Eddy current inspection at Davis-Besse 1 showed that 24 peripheral tubes in both OTSGs exhibited evidence of contact with the internal header assembly at some time. In three tubes the diameter reductions exceeded the Technical Specification plugging limits.

A visual inspection of the internal header at Davis-Besse 1, followed by a 360° remote video inspection, showed that the shell side of the header was distorted inward as much as 4.5 in. In addition, the inner vertical wall was bent inward in some locations. In one case, the thermal sleeve was disengaged from the inlet hole of the header and was offset from the center of that opening. It was also noted that certain header support brackets were bent, the bottom ligament was torn out or broken off, and there was evidence of wear and/or distress on dowel pins and brackets. Dowel pins were missing at the majority of the eight bracket locations in both OTSGs. All brackets and all but one dowel pin have been located and retrieved.

There were a number of safety concerns associated with these design problems. For one, there was a potential for tube rupture due to the interaction of the damaged headers with the peripheral tubes. There was also the potential for damage to the tubes and various other primary system components from loose parts. In addition, there was the potential for degraded flow of AFW, which could have led to an inadequate heat sink for the reactor under certain off-normal conditions. AFW flow might also be diverted to the steam lines. However, during the operational history of the plants, no such adverse effects were noted during many actuations of the AFW systems.

It has been concluded that the most likely cause was rapid-condensation-induced high-pressure differential. Stress calculations performed by the licensees concluded that a pressure differential in excess of 200 psi could cause collapse of the internal headers. The design of the internal AFW header was such that during operation of the plant, prior to AFW actuation, the header would be filled with steam. When AFW was actuated, there would be a sufficient flow of subcooled water to result in a rapid condensation of trapped steam inside the header. It was also concluded that rapid flooding of the header with cold AFW when the steam generator was at operating conditions produced high thermal stress, which could contribute to the distortion. Tube damage occured due to interactions of the header, brackets, and dowel pins with the tubes.

Corrective actions consisted of (1) stabilizing the existing internal feedwater headers to preclude further interaction with the steam generator tubes and discontinuing its use for flow distribution; (2) installation of an external AFW header with six injection nozzles (eight at Davis-Besse) to provide AFW flow, similar to the AFW ring header design that exists at five other B&W plants; (3) removal of loose parts that could be located (those that could not be found had to be shown not to pose a safety problem); and (4) the use of surveillance programs to ensure absence of further degradation.

Weld Cracking in Steam Generator Shells. On March 27, 1982, while Indian Point 3 was in cold shutdown during a refueling outage, its operators observed a leak in the girth weld between the upper shell and the transition cone of one of the plant's steam generators. Inspection showed an oval-shaped hole approximately 5/8 by 1/8 in. Subsequent ultrasonic examinations of the corresponding weld in all four steam generators revealed that each had extensive cracking. An average of 170 cracks per steam generator were found with an average depth of 3/4 in., a maximum depth of about 1-1/2 in., and lengths of 2 to 4 in. About 40% of the cracks were reported to be in weld metal.

Preliminary information indicates that the cracks were caused by corrosion fatigue, probably accelerated by aggressive water chemistry and/or existing fabrication flaws. Determining the exact interrelationships among these aspects will require extensive evaluation.

The significant factors that distinguish these welds from others in Westinghouse steam generators are (1) a difficult final-closure weld, (2) a local postweld heat treatment rather than a furnace treatment, (3) a location near the normal water line, and (4) a location near the feedwater ring that may therefore be subjected to thermal cycling. No other reportable indications of cracking have been found in other steam generator welds.

Indian Point 3 has a long history of condenser leakage problems, resulting in a small continuing inleakage of impurities even when major condenser leaks were not identified. Constituents in the sludge suggest that oxygen control in the feedwater/steam generator train may have been poor for a considerable period because the licensee minimized the use of hydrazine due to environmental concerns. In January 1981, a turbine blade failed and fragments entered the condenser, causing a massive inleakage of chlorides that reached 325 parts per million in the steam generator blowdown.

Internal Corrosion of Steam Generator Tubes. On November 21, 1981, it was found that a B&W-designed OTSG for TMI-1 had a primary-to-secondary leak. The tube degradation was determined to be due to intergranular stress corrosion but was different from that typically encountered in other PWR plants in that the corrosion proceeded from the inside (primary side) of the tubes outward, indicating that the corrosion cause was in the primary coolant water.

The corrosion resulted in the formation of circumferential intergranular cracks, approximately 98% of which occurred in a 2 to 3 in. region at the upper end of the tubes within the upper tubesheet near the roll transition area and the heat-affected zone of the upper seal weld. The number of affected tubes was estimated at 16,000 to 20,000 of the total of 31,000.

Metallographic analyses of portions of 19 removed tubes confirmed that reduced sulfur was the agent causing the attack. The sulfur source was thiosulfate from the reactor building spray system, which entered the primary system at various times in 1981. The thiosulfate leaked past shut isolation valves in the spray system and entered the RCS during testing involving cross connections of various systems.

The licensee believes that the attack occurred near the end of plant cooldown in September 1981 following hot functional testing, when conditions of susceptible material, aggressive chemical environment, and high stress existed. The attack was rapid, occurred primarily in the region where the tubes were exposed to air when the system water level was lowered, and probably terminated when the concentration of the aggressive sulfur species was reduced. Sulfur levels at the time of the corrosion are believed to have been on the order of several parts per million.

The thiosulfate tank was drained and flushed. Sulfur levels in the primary system then were less than 0.1 part per million. There is no evidence that the corrosion continued since it was first discovered in late November 1981. The licensee decided to perform an explosive expansion of the top several inches of each tube within the 24-in. thickness of the upper tubesheet (UTS), thereby closing the crevice area between the sheet and the tube and thus establishing a seal between the primary and secondary fluid. By mid-1982, the licensee completed preliminary qualification testing of the explosive expansion repair technique. Following recommendations by B&W and Foster Wheeler, it was decided to expand the top 17 in. of all tubes within the 24-in. UTS and establish a 6-in. sealed area free of defects, which will be the load-carrying seal. By this method, all tubes with defects within the top 11 in. of the UTS could be saved.

A full-scale test on an OTSG at Mount Vernon, Indiana, was conducted during August 1982. During this test, a significant number of tubes were expanded using the prototypical process intended for use at TMI-1. Expansions of tubes in the OTSGs at TMI-1 commenced in November 1982. Tubes that could not be saved by this repair technique were to be plugged, removing them from service.

Loose Parts in Steam Generators. Numerous instances of loose parts and/or foreign objects in steam generators were discovered in 1982. In some cases, considerable damage was done to the steam generator tubes. Many of the cases were due to design deficiencies or inadequate maintenance/repair activities. Table 4.9 lists the loose-part problems discovered in 1982.

Table 4.9. Steam generator loose parts problems found in 1982

Plant	Date	Licensee	NSSS	Comments
Ginna 1	1/82	Rochester Gas & Electric Corp.	W	Problems described in AO 82-4 in NUREG-0090, Vol. 5, No. 1
Zion 1	2/82	Commonwealth Edison Co.	W	Fragments of a primary system nozzle cover found in SGs 1B and 1D (primary side). Some damage resulted to some SG 1D tube ends
Davis-Besse 1	4/82	Toledo Edison Co.	B&W	Problem described in this report
Rancho Seco 1	4/82	Sacramento Municipal Utility District	B&W	Problem described in this report
Oconee 3	4/82	Duke Power Co.	B&W	Problem described in this report
North Anna	5/82	Virginia Electric & Power Co.	W	
San Onofre	5/82	Southern California Edison Co.	W	Loose parts found in SGs A and B
Cook 1	7/82	Indiana & Michigan Electric Co.	W	Loose parts found in SGs 11, 12, and 13
Turkey Point 4	7/82	Florida Power and Light Co.	W	Loose parts found in SGs A, B, and C

Steam Generator Tube Leaks. Several instances of steam generator tube leaks have occurred in 1982. These are summarized in Table 4.10. Most were caused by mechanisms discussed above. Some leaks, such as at San Onofre 1, Calvert Cliffs 1, and Robinson 2, were most likely caused by inadequate previous maintenance/repair activities. The tube leaks described in Table 4.10 are in addition to those reported above.

Other Problems.

1. Arkansas 1 — Arkansas Power & Light Company has derated the unit because the pressure drop across the secondary side of the B&W OTSG had

Table 4.10. Steam generator tube leakage in 1982

Plant	Date	Licensee	NSSS[a]
Oconee 1	2/82	Duke Power Co.	B&W
Oconee 3	2/82	Duke Power Co.	B&W
Zion 1	3/82	Commonwealth Edison Co.	W
Indian Point 3	3/82	Power Authority of State of New York	W
Millstone 2	3/82	Northeast Nuclear Energy Co.	CE
Palisades 1	3/82	Consumers Power Co.	CE
Oconee 1	3/82	Duke Power Co.	B&W
Point Beach 1	3/82	Wisconsin Electric Power Co.	W
San Onofre 1	3/82	Southern California Edison Co.	W
Arkansas 1	5/82	Arkansas Power and Light Co.	B&W
Calvert Cliffs 1	5/82	Baltimore Gas and Electric Co.	CE
Yankee-Rowe 1	6/82	Yankee Atomic Electric Co.	W
Cook 2	7/82	Indiana & Michigan Electric Co.	W
Robinson 2	7/82	Carolina Power & Light Co.	W
Turkey Point 4	7/82	Florida Power & Light Co.	W
Beaver Valley 1	8/82	Duquesne Light Co.	W

[a]Nuclear steam system supplier (and vendor of steam generator).

increased to the point where full flow could not be achieved. The problem is due to a crud (iron oxide) buildup between support plates on the tubes in the secondary side of the steam generator. Other B&W-designed plants may possibly be subject to the same problem.

2. Maine Yankee 1 — On March 10, 1982, the Maine Yankee Atomic Power Company reported that during a plant shutdown for maintenance, 6 of 20 steel studs failed during routine disassembly of one of the #2 CE-designed steam generator primary side manways. Ultrasonic inspection identified four more studs that were cracked. The studs exhibited evidence of surface corrosion attack, possibly as a result of an interaction associated with stud preload, lubricant, Furmanite, and primary coolant leakage environment. All 20 studs were replaced.

NRC I&E Notice No. 82-06 was issued to licensees on March 12, 1982, to alert them of the event. This was followed on June 2, 1982, by NRC I&E Bulletin No. 82-02, which treated the problem as a generic issue. The Bulletin mentions that preliminary analysis by CE indicated that the failure mode was SCC. It required certain actions involving maintenance procedures, selection of materials, and information to be submitted for NRC review.

3. McGuire 1 — As mentioned, McGuire 1 (operated by Duke Power Company) is the only domestic operating plant utilizing the new-design Model D steam generators. Inspections have shown tube wear due to tube vibration against the tube baffle plates similar to that found at Ringhals 3 in Sweden and Almaraz 1 in Spain, both of which use similar Model D steam generators. McGuire 1 is restricted to 50% power pending possible corrective actions. Possible fixes are being actively pursued and/or reviewed by W, the W Owners Group of affected licensees, and the NRC. The affected plants include not only McGuire 1 but also plants still under construction that plan to use steam generators based on the Model D design.

Environmental Qualification of Safety-Related Electrical Equipment Inside Containment (AO 77-9). The following occurrence was originally reported in NUREG-0090-10, *Report to Congress on Abnormal Occurrences: October–December 1977*, and updated in subsequent reports in this series, that is, Vol. 1, Nos. 1 and 2; Vol. 2, No. 2; Vol. 3, No. 2; and Vol, 4, No. 2.

The environmental qualification of electrical equipment for 71 operating reactors was evaluated by the NRC staff and its contractors. Sufficient information has been supplied by all 71 licensees to enable the contractors to prepare a Technical Evaluation Report for each operating reactor. A total of 33 Technical Evaluation Reports have been issued. Based on the findings presented, the NRC staff was preparing Safety Evaluation Reports for each operating reactor. It was anticipated that all Safety Evaluation Reports would be completed by mid-1983. Discussions among the licensees, the NRC staff, and its contractors would then resolve any identified deficiencies.

With regard to the environmental qualifications for operating license applications, 37 plants are under review. Ten Safety Evaluation Reports were issued, and the remaining environmental qualification reviews of the operating license applications were at various stages of completion.

As previously reported, the NRC issued an order on May 23, 1980, that required all safety-related electrical equipment in all operating plants to be qualified no later than June 30, 1982. The NRC planned to issue, early in 1983, a final rule in regard to environmental qualification of electrical equipment important to safety for nuclear power plants. The final rule, when issued, will be applicable to all nuclear power plants.

Since the NRC was unable to promulgate the final rule by June 30, 1982, and because licensees should not be in jeopardy of enforcement action pending promulgation of a revised schedule for implementation of equipment qualification requirements, the NRC issued an interim rule on June 30, 1982, that suspended the June 30, 1982, deadline for the licensees pending publication of the final rule. The NRC determined that continued operation of these plants pending completion of the equipment qualification program would not present undue risk to public health or safety.

Loss of Containment Integrity (AO 78-5). This occurrence was originally reported in NUREG-0900, Vol. 1, No. 4, *Report to Congress on Abnormal Occurrences: October–December 1978*, and updated in subsequent reports in the series, namely Vol. 2, Nos. 2 and 4.

Review of this generic concern continued. The most recent past update stated that the NRC's "Interim Position for Operability of Containment Vent and Purge Valves" was being sent to all licensees in October 1979. All licensees' responses to the interim position have since been reviewed and found acceptable on an interim basis. The regional offices are monitoring licensees for continued compliance with these interim commitments.

Degraded Engineered Safety Features (AO 79-1). This abnormal occurrence was originally reported in NUREG-0090, Vol. 2, No. 1, *Report to Congress on Abnormal Occurrences: January–March 1979*, and updated in a subsequent report in this series, Vol. 2, No. 2.

As discussed in the previous update, the following three safety concerns emerged from the analysis of the event that occurred at Arkansas Nuclear One (ANO) on September 16, 1978.

1. The offsite power supply for ANO 1 engineered safety feature loads was deficient in that degraded voltage could have resulted in the unavailability of engineered safety feature equipment, had it been needed.
2. The design of the ANO electrical system that provides offsite power to Units 1 and 2 did not fully meet the NRC's regulations, because in certain circumstances a failure of one of the two offsite power circuits would also result in a failure of the other such circuit.
3. Deficiencies existed in the operation of the Unit 2 inverters that convert battery power to AC power for certain safety-related equipment.

The licensee submitted proposed corrective actions addressing these three matters.

Nuclear Accident at Three Mile Island (AO 79-3). This occurrence was originally reported in NUREG-0900, Vol. 2, No. 1, *Report to Congress on Abnormal Occurrences, January–March 1979*, and has been updated in every issue of that publication since then, including the four issues of Vol. 5, which cover 1982.

Reactor Building Entries. The recovery and cleanup operations during 1982 covered a wide range of activities, many of which involved entries into the reactor building. During the year more than 70 entries were made, some of them for a single purpose, but many with multiple objectives. The following are among the major tasks accomplished by the building entries during calendar year 1982.

1. Installation of supports for, and assembly and testing on, an electrically powered lift that could be used for transporting personnel and equipment from the refueling floor to the polar crane.

2. Inspections, refurbishing, and testing of the polar crane, with a view to ultimately demonstrating its capability to lift the reactor vessel head and the upper internals, a necessary preparation for defueling the damaged core. This work involved replacement of electric cabling, uncoupling and testing electric drive motors, and testing control functions.

3. Documenting conditions in various areas of the reactor building. These activities included radiation surveys, sample collection from such areas as the building sump and floors, videotaping the physical appearance of many areas of the building, drilling and collecting concrete samples, and collecting samples of the gas and liquid from the reactor head vent.

4. Preparations for, and performance of, trial decontamination activities to establish methods of gross decontamination. This work included the installation of decontamination hoses through building penetrations, decontamination of test areas of concrete floors by such methods as mechanical scrubbing with a detergent solution or with phosphoric acid solutions, applying and removing strippable coatings from various other surfaces, low-pressure water flushing (water pressure of 1,000 psig at the tip of the spray nozzle), high-pressure water flushing (up to 6,000 psig pressure at the nozzle tip), and spraying portions of the reactor building dome with hot (140°F) water.

5. Gross decontamination, based on the results of the tests described above. This effort included remote decontamination efforts at the basement level (282-ft elevation), overall building dome and wall decontamination, remote spraying in the lower building areas (below the 305-ft elevation) where the activity levels are highest, and examination of the basement level by closed-circuit television.

All these decontamination activities used water that had been previously decontaminated and was thus added back to the liquid in the building sump for repeated removal and purification. The spraying of the building interior added about 60,000 gal of processed water to the building sump. This water was then pumped to the submerged demineralizer system (SDS) feed tank for reprocessing (see below).

6. Removal of the water from the basement and sump by installing a jet pump in the in-core instrumentation trough in the basement floor, with which the last 6 in. of water could be removed. Removal of this water, however, did not greatly affect the activity level at the 305-ft elevation (13 ft above the basement floor), except for areas such as stairwells and metal gratings that were not well shielded from the basement.

7. Installation and/or refurbishment of a number of systems required for safety and information. This included the in-containment nitrogen system, which was tested and found operable; testing of reactor building smoke detectors, found not to be working but then repaired and at least partially restored to function; installation of strings of thermoluminescent detectors for monitoring radiation levels; and installations of acoustic monitors to detect the noise resulting from movement of the axial power-shaping rods.

8. In-core examinations and evaluations. During 1982, the first visual examination of the interior of the damaged reactor by means of remote television was accomplished in project "Quick Look." After suitable preparation by venting the RCS to equalize pressure and uncoupling a central control rod, a camera was lowered into the upper core region. Water turbidity limited vision to 2 to 3 in., but the surface of the rubble bed was seen. In later phases of this activity, cameras were lowered into other control rod drive openings to view other parts of the core.

9. Disconnection of control rod lead screws. As a necessary preliminary to eventual lift of the reactor vessel head, attempts were made to decouple the lead screws from all the 61 control rods and 8 axial power shaping rods by disconnecting the bayonet-type connections between the lead screws and the spider assemblies. The disconnect was successful in all but three cases.

Submerged Demineralizer System. During the year, the SDS was used routinely to clean up the water in the reactor building basement and sump and to begin cleaning the water in the primary reactor loop. The SDS is located underwater in the spent fuel pool. Early in the year (January 20, 1982), an increase of radioactivity in the pool water signaled a leak from the SDS into the pool; this was traced to a worn gasket that was replaced. By the end of the first quarter of 1982, 600,000 gal of sump water had been processed, and preparations were being made for batch treatment of the primary loop water by a "feed-and-bleed" method in which 50,000-gal batches of core water would be processed and returned to the system. By the end of the second quarter, 196,400 gal had been processed and by the end of the third quarter of 1982 a total of 1,205,000 gal of water had been processed, including 250,000 gal of RCS water. Late in the year, the SDS was continuing to process both core water and water from the building sump resulting from cleanup and decontamination activities, as well as a total primary system leakage rate of about 100 gal/day.

EPICOR II Prefilter Shipments. The EPICOR II demineralizers have been used to "polish," that is, decontaminate still further, the effluents from the SDS, other than those dealing with primary system coolant. During 1982, 15 of the 49 EPICOR prefilters were shipped from TMI to the Idaho National Engineering Laboratory (INEL), and one was shipped to Battelle-Columbus Laboratories. In all instances, the Department of Energy took possession of the 50-ft^3 ion-exchange vessels on the TMI site and planned to use them for research and development activities. These shipments were made in special transport casks designed to maintain their integrity in the event of transportation accidents, and with an inert-gas atmosphere inside to avoid any possibility of the production of combustible gas mixtures by radiolysis during shipment. All the shipments arrived safely at their intended destination.

Further reports on the progress of the TMI-2 cleanup and defueling activites will be made.

Loss of Salt Water Cooling System at San Onofre 1 (AO 80-7). This abnormal occurrence was previously reported and declared closed in NUREG-0900, Vol. 3, No. 3, *Report to Congress on Abnormal Occurrences, July-September 1980*, but was reopened in Vol. 5, No. 2 to report another incident in the same system at the same plant.

During a shutdown for various inspections, modifications, and maintenance items, work was scheduled for the removal of the south salt water cooling pump (SWCP) for maintenance. The reactor was in cold shutdown, and the reactor coolant piping had been drained for steam generator tube inspection. The upper component cooling water heat exchanger had been removed from service and was open, and the south SWCP motor had been removed earlier in the day. The auxiliary SWCP circuit breaker was removed for maintenance, and the pump's flow path was isolated. This isolation was needed for south SWCP maintenance and upper component cooling water heat exchanger maintenance. The north SWCP was operating and removing reactor decay heat from the component cooling water system via the lower component cooling water heat exchanger. The north and south screen wash pumps were operable in their normal alignment. (The screen wash pumps can be manually cross-connected to provide backup to the SWCPs, but they are of a lower capacity and are not qualified as safety-related equipment).

At approximately 8:00 a.m. on May 13, 1982, a crane removed the pump. Ocean water immediately entered the intake structure through the resulting hole in sufficient quantity to prevent personnel from reseating the pump on its foundation. Flooding continued until 8:42 a.m. when the level in the intake structure rose to sea level, approximately 5 ft above the floor of the intake structure. At this time maintenance personnel were able to partially remount the pump and begin to reduce the water level in the intake structure using a portable pump.

All salt water cooling was lost from 8:18 a.m. until 8:42 a.m. when operators completed manual valve alignment to allow the north screen wash pump to supply salt water cooling to the lower component cooling water heat exchanger. At 8:29 a.m., a spare breaker for the auxiliary SWCP was installed, and the auxiliary SWCP was considered available if needed. Licensee personnel, however, decided not to use the auxiliary SWCP because the north screen wash pump was operating and adequately removing decay heat from the reactor.

Salt water flow was lost from the north SWCP because the control operator secured the north SWCP when the pump amperage and the pump discharge valve began to cycle erratically. When flooding ceased, the intake structure water level was approximately 2 in. below the pump motor vents for the north salt water and the south screen wash pumps and approximately 18 in. below the north screen wash pump motor vents.

The north SWCP was returned to service at 1:14 p.m. but failed at 2:34 p.m. because of a failed-shut discharge valve. Salt water cooling was briefly interrupted until the north screen wash pump was aligned to supply salt water cooling. This abnormal alignment was maintained until 6:45 p.m. when the north SWCP was returned to service. Apparently, the pump discharge valve failed closed due to residual moisture in the pressure switch and melted insulation in an associated time delay relay.

During the 24-min period when no salt water cooling was available, reactor coolant core outlet temperature did not rise perceptibly, reactor coolant inlet temperature rose 1.5°F, and component cooling water outlet temperature rose 15°F.

The procedure specified for this work had one precaution to prevent flooding: "To prevent flooding, remove and install the pump at the low tide only." This precaution was inadequate because no specific tide level was defined.

Maintenance personnel had used a tide chart for Los Angeles (Outer Harbor), 45 miles northwest of San Onofre, to estimate the time of low tide as 8:06 a.m. on May 13, 1982. The maintenance foreman and watch engineer estimated that the tide level would be approximately 2 ft up the 3-ft-tall pedestals of the SWCPs. In fact, the water level reached was 3 ft higher than this. This technical error resulted in the flooding and is considered the principal cause for the event.

The licensee is upgrading the applicable procedures and has requalified maintenance and operations personnel in the proper implementation of equipment control. Formal checklists for equipment removal and restoration will be established for the salt water cooling system.

Subsequently, on August 13 and 19, 1982, two more incidents involving this system occurred. On August 13, while restoring the south SWCP to service from the May 13 event, with the north SWCP supplying flow to the lower component cooling water heat exchanger, the discharge valve on the south SWCP opened unexpectedly. This allowed much of the north SWCP flow to flow in reverse through the idle south SWCP, bypassing the heat exchanger. This valve was immediately shut by an operator at the valve, restoring full flow to the heat exchanger. The brief reduction of the flow through the heat exchanger did not observably increase core temperatures; however, the incident was of concern because the pump discharge valves had been observed to be occasionally unreliable and erratic. This was first noted by the NRC during the March 10, 1980, event review and, more recently, following reviews of January 18, February 1, and March 19, 1982, incidents.

On August 19, 1982, the north SWCP had to be removed from service due to a smoking lower motor bearing. At the time of this incident, the south SWCP remained out of service from the May 13, 1982, incident. The nonsafety-related auxiliary SWCP was started to maintain sufficient salt water flow to the upper heat exchanger. Temporary repairs to the north SWCP were made using a spare motor for this pump. During this period of several hours, the nonsafety-related auxiliary SWCP and screen wash pumps were used to provide salt water flow. Subsequent investigation of the pump motor determined that the inside of the motor was rusty, muddy, and oily, the lower motor bearing was wiped, and the pump upper bearing was excessively worn.

These losses and reductions of salt water cooling had no adverse effects on public health or safety. However, as shown in a case study report prepared by the NRC's Office for Analysis and Evaluation of Operational Data for the event on March 10, 1980, a complete loss of the salt water cooling system during the early stages of RHR operation could lead to damage to some safety-related equipment within a few minutes. Such single-failure vulnerablility of cooling water systems is under review as part of the NRC's systematic evaluation program.

Failure of High Pressure Safety Injection System (AO 81-4). This abnormal occurrence was originally reported in NUREG-0900, Vol. 4, No. 3, *Report to Congress on Abnormal Occurrences: July–September 1981*.

The modified safety injection system at San Onofre 1 was tested in accordance with the accelerated surveillance schedule applicable during this operating cycle on November 24, 1981, and February 27, 1982. In each case, the valves operated satisfactorily, with no measurable increase in opening force and no apparent "set in" effect.

The licensee has developed a schedule for procurement and installation of eight replacement valves. According to this schedule, installation would be completed in the first half of 1985. One significant factor in the extended schedule is the time required for inspection and testing of the valves (14 months after completion of fabrication). The licensee is also performing an engineering study on an alternative system that would utilize dedicated safety injection pumps and thereby eliminate some of the complexities inherent in the present design. If the licensee determines that such a redesign is warranted, the replacement of the present valves will be considered as part of the redesign effort.

Seismic Design Errors at Diablo Canyon Nuclear Power Plant (AO 81-8). This occurrence was originally reported in NUREG-0900, Vol. 4, No. 4, *Report to Congress on Abnormal Occurrences: October–December 1981*. It was further discussed in Vol. 5, Nos. 1 and 3.

The independent design reverification program for Diablo Canyon was being performed in two phases. The first involved the reverification of seismic design activities performed prior to June 1978. Phase II involved reverification of seismic design activities after June 1978 and other design activities performed by the licensee and his contractors.

The seismic reverification program plan, with certain modifications, was approved by the NRC on March 4, 1982. In March 1982, Teledyne Engineering Services was approved as the reverification program manager. This company then submitted a comprehensive plan to the NRC that details Phase I of the reverification; in June 1982, the licensee submitted a program plan for the second phase of the reverification.

Concurrent with the independent design reverification program, the licensee employed the Bechtel Power Corporation to act as project completion manager. A revised project quality assurance program reflecting the joint PE&E/Bechtel organization was approved in August 1982. The objective of the joint organization is to fulfill all requirements for reinstating the low-power license for Diablo Canyon Unit 1 and for meeting all full-power license requirements for both units.

The independent design verification program and the licensee/Bechtel internal technical review program have identified a number of errors and open items to date. As of September 1982, the independent program had identified 199 technical concerns requiring resolution. A number of these were subsequently resolved, and 13 were classified as errors in which design criteria or operating limits of safety-related equipment could have been exceeded; physical modifications, changes in operating procedures, more realistic calculations, or retesting are required to bring the plant into conformance with the original design. In addition, the licensee/Bechtel organization identified 33 concerns within their program. Six were resolved and 27 were classified as errors. It should be noted, however, that, according to the licensee, none of these errors would have prevented any system, structure, or component from performing its intended safety function in the event of the postulated earthquake.

4.3.8 Other events of interest

Descriptions of the following events are included in this report because they may possibly be perceived by the public to be significant with regard to public health. The events did not involve a major reduction in the level of protection provided for public health or safety and therefore were not reportable as abnormal occurrences.

Temporary Total Loss of High Head Safety Injection Capability (NUREG-0090, Vol. 5, No. 2) (Ref. 3). On February 12, 1982, while operating at 50% power, all three charging pumps at McGuire 1 became inoperable, resulting in the total loss (for a period of 38 min) of the functions associated with these pumps, including high head safety injection for system pressure above 1500 psig.

McGuire 1 utilizes three pumps, all with a common suction, to supply makeup flow (charging) to the RCS. One of these pumps is a positive displacement pump (PDP), while the other two are centrifugal charging pumps (CCPs). During normal operations, most of the reactor coolant is circulated through the RCS by the reactor coolant pumps. However, a portion of the coolant flows out through the chemical and volume control system and then enters the common suction of the charging pumps. During normal operations, either the PDP or one of the CCPs is used for charging. From the pump discharge, the flow is split into two paths — one for reactor coolant pump seal injection and the other for charging flow through one of the cold legs of the primary loop.

The two CCPs also serve the high head safety injection system, which provides protection against small RCS breaks in which the pressure remains above 1500 psig for an extended time period. Should RCS pressure drop to 1500 psig or less, the intermediate head safety injection system would provide additional injection flow.

This system is typical of several Westinghouse plants. The McGuire 1 system, however, had an additional feature that was directly involved in the February 12, 1982, event. Due to the pulsating suction flow characteristic of reciprocating pumps, the PDP was equipped with a suction damper consisting of a vertical section of 12-in. pipe, containing water with a hydrogen gas cover providing overpressure. The water level is controlled by two solenoid valves that add hydrogen if the water level rises too high or vent it if the water level drops too low. These valves can be controlled automatically by water level switches or manually by switches mounted on a local panel.

On February 12, 1982, the plant was operating with the PDP out of service for modification; charging flow was being provided by CCP-1A. During an attempt to fill and vent the PDP suction piping in preparation for returning the pump to service, the opening of the suction isolation valve to the PDP resulted in air and hydrogen entering the PDP pump suction piping and the common suction of the two CCPs. Later investigation indicated that the damper level control system had malfunctioned, resulting in a continuous supply of hydrogen to the damper and a consequent displacement of water (later estimated to be about 50 ft^3) by the gas. Control room personnel, observing oscillation of the CCP-1A motor current and charging flow, switched to CCP-1B. About 30 s later, when similar indications were also observed for CCP-1B, that pump was also shut down, and letdown was isolated.

With both CCPs inoperable, there was no emergency core cooling capability above 1500 psig. The plant Technical Specifications require the reactor to be shut down within 1 h under those conditions. However, plant personnel were able to get CCP-1B restarted and operating properly in about 38 min, so no shutdown was required.

During the event, reactor coolant inventory was decreasing due to the normal reactor coolant pump seal leakage of about 12 to 15 gpm. No makeup capability existed since all three charging pumps were inoperable. A significant decrease in the RCS average temperature would have resulted in a further drop in pressurizer level (due to contraction of the coolant), although system pressure could have been maintained by pressurizer heaters until pressurizer level dropped below 17%; at this point, the heaters would automatically shut off to prevent their overheating. If the restoration of reactor coolant makeup had been delayed until after the pressurizer inventory was lost or had a transient occurred, forcing a loss of pressurizer inventory, a reactor shutdown would have occurred.

Had a reactor shutdown occurred because of low pressure, an automatic safety injection signal would have started the intermediate head safety injection pumps to provide adequate core cooling.

This event was caused by failures in the nonsafety-related suction damper for the PDP, which resulted in the loss of both CCPs. After the event, the licensee examined the suction damper level control system, and found an empty reference leg in the system; this resulted in a continuous flow of hydrogen to the damper. The cause of the reference leg drainage could not be determined; no leaks were found when it was refilled.

As corrective actions, the licensee isolated the PDP and suction damper from the charging system. The licensee is evaluating the system design to determine what temporary and/or permanent changes are necessary to prevent recurrence of this type of event. The PDP will not be returned to service until such a temporary or permanent change is made.

The NRC's concerns about this event include the lack of specific procedures and the lack of a safety analysis for such an event. However, it should be noted that some designed plants do not use the charging pumps for a safety injection above 1500 psi. These plants use only an "intermediate" head system to mitigate small or large pipe breaks. The probability for the simultaneous loss of all charging flow together with a small (or large) pipe break is very low.

Multiple Diesel Generator Failures at Calvert Cliffs (NUREG-0900, Vol. 5, No. 2 (Ref. 3). On June 2, 1982, the Baltimore Gas and Electric Company (the licensee) notified the NRC that all three diesel generators (DGs) at Calvert Cliffs were simultaneously inoperable from 7:05 until 7:35 a.m. on that date and only one offsite power circuit was operable. The Calvert Cliffs Station has two Combustion Engineering PWRs.

That morning, with Unit 1 shut down for refueling and Unit 2 at full power, a series of events occurred that inactivated all the emergency power sources at the station for a period of 11 min. The Unit 1 DG (DG-11) was out of service for maintenance. Before a 500-kV electrical distribution bus was removed from service for the annual routine maintenance on a transformer, the other two of the three onsite emergency DGs (DG-12 and DG-21) were tested successfully. Following the performance test, the swing diesel (DG-12) was returned to standby status, and the Unit 2 diesel (DG-21) continued to run fully loaded in parallel with the grid. The 500-kV transformer was then taken out of service, leaving only a single circuit capable of providing offsite power to the station. DG-21 then tripped off due to voltage regulator drift. DG-12 was then started and fully loaded to demonstrate its operability. At 7:05 a.m., DG-12 tripped as a consequence of an operator error while the operator raised the main generator voltage in response to a request from the electrical load dispatcher. The DG trips were reset and both diesels restarted at 7:16 a.m. Following a 15-min load test for operability, DG-12 was declared operable at 7:35 a.m. and DG-21 operable at 8:00 a.m. This terminated the incident.

Both of the DG trips occurred during parallel operation of the diesel generators and involved the action of a loss-of-field protective relay. This relay is not active when the generator is in the emergency mode and therefore not paralleled with other electrical sources. The diesel generators would therefore have been available, after the lockout relays were manually reset at the diesel, in event of loss of offsite power.

The safety implication of the simultaneous inoperability of three diesel generators bears on availability of emergency power in event of an accident. If such an accident had involved loss of offsite power, it would have resulted in a temporary loss of power at the facility until the diesel generators could have been reset and manually restarted in their accident mode. The event did not result in any adverse effects on health and safety of the public or licensee personnel.

Steam Extraction Line Rupture (NUREG-0090, Vol. 5, No. 3) (Ref. 4). On June 28, 1982, while at 95% power, a steam extraction line ruptured at Oconee 2. The escaping steam caused burns to two persons, who were hospitalized overnight and released.

The rupture occurred in the outside radius of a 375-mil-thick 90° elbow where the 24-in. steam extraction line branches off a 42-in. high-pressure turbine exhaust line. The rupture size was about 4 ft^2 (approximately 2 ft by 2 ft).

Upon hearing the explosion and observing an apparent loss of main steam turbine header pressure, the operators suspected that a main steam line break had occurred. Nine seconds after the rupture, the reactor was manually tripped, initiating an automatic turbine trip. The failure was downstream of the main steam stop valves; thus, the turbine trip cut off the steam supply to the extraction line. Systems and related parameters responded as expected following the reactor trip and subsequent recovery operations.

The steam escaping through the rupture destroyed a motor control center; however, it supplied no safety-related loads or any essential loads, which precluded routine plant shutdown. Steam impingement also destroyed several nonsafety-related instruments that were mounted on a panel board located 6 ft from the failure. Two or four turbine steam header pressure transmitters were among the instruments destroyed and were the reason for the loss of indication of steam header pressure. Safety-related steam generator header pressure instruments were not affected.

Seven minutes into the event, the process computer ceased to function for a period of 3.5 min. Since the reactor coolant subcooling margin monitors are supplied from the process computer, they were inoperable for that period. During that time, the operators ascertained subcooling from RCS temperature and pressure indications that were available in the control room. Loss of the computer posed no major impediment to the safe shutdown of the plant.

The rupture was attributed to piping degradation resulting from steam erosion, accelerated by sustained reduced power operation, resulting in lower quality steam in the line. Ultrasonic thickness testing performed on the elbow in March 1982 had revealed significant erosion thinning, but it was judged then that the elbow was still serviceable. At that time, the thinnest area recorded was 170 mils; micrometer readings performed after the rupture revealed a thickness of 17 mils at the edge of the failure. The inspection program performed in March 1982 may have missed the section where the wall was thinnest.

The ruptured elbow was replaced. The licensee inspected 15 extraction line fittings on Units 1 and 2. A detailed 4- by 4-in. grid map was marked on the areas being examined, providing for test correlation/comparison and more detailed analysis. The examination of extraction piping on Oconee 1 revealed an area of approximately 4 by 4 in. that had been eroded from 375 to 100 mils (which is below the minimum wall thickness for that schedule pipe). Unit power was reduced, a patch was welded on, and power was returned to 100%. The licensee plans to replace the elbow during the next outage of adequate duration.

There were no radiological consequences associated with this event. The rupture did not degrade equipment required for safe shutdown of the plant. Since all systems responded as expected following the reactor trip and during subsequent recovery operations, this event was not reportable as an abnormal occurrence.

Degraded Safety Relief Valves (NUREG-0900, Vol 5, No. 3) (Ref. 4). On July 3, 1982, an event occurred at Hatch 1 in which reactor pressure increased, but none of the 11 safety relief valves actuated at their prescribed set points.

Hatch 1 was operating at 100% power when a spurious high-pressure signal caused a reactor scram. The main turbine had not tripped when the main steam isolation valves, the main steam drain isolation valves, and the recirculation loop sample isolation valves closed. High-pressure coolant injection and reactor core isolation cooling (RCIC) automatically started, and the recirculation pumps tripped. The main turbine was then manually tripped. When vessel water level recovered and reached the high-water-level trip set point, HPCI, RCIC, and the feedwater pump turbines tripped.

Gradual vessel repressurization continued beyond the high-pressure scram setpoint (1,035 psig) at a rate of 0.5 psi/s ramp without relief valve actuation. At about 1,180 psig, three of the eight safety relief valves (SRVs) did actuate, relieving vessel pressure rapidly. Once they had reclosed, the main steam isolation valves were manually reopened, and the reactor was cooled and depressurized to cold shutdown. During cooling and depressurizing, the remaining eight SRVs were manually actuated and functioned properly.

The SRVs installed on Hatch 1 are two-stage Target Rock valves, model #7567F. The three SRVs that opened automatically were located on the same steam line and were the only valves on that line. Their set points were 1080, 1080, and 1090 psi. The remaining eight SRVs were set at 1080, 1090, or 1100 psi. All had been refurbished and steam-set at Wyle Labs during the previous refueling outage and had most recently been actuated in August 1981.

Following the July 3, 1982, event, the pilot sections of all the SRVs were removed and sent to Wyle Labs, where they were tested in the as-received condition. Six passed their first test, four passed on retest, and the final valve passed on the second retest — all without set point spring adjustment. The average first-actuation pressure was 0.9% above nominal value, ranging up to 4.1% above nominal. No abnormal leakage characteristics were observed for any of the valves. No apparent mechanical failure was found at Wyle Labs or in the valve bodies inspected at Hatch.

Three other licensees, TVA, Northeast Nuclear Energy Company, and Boston Edison, had reported that two-stage Target Rock valves, tested in the as-received condition at Wyle Labs, failed to actuate within 1% of the set point. The Hatch 1 event was potentially the most significant in terms of both the number of valves that failed to open at their set point and the excess pressure required for actuation.

General Electric and the Target Rock Company then joined Georgia Power in attempting to determine the cause of the failures. A General Electric analysis suggested that the most likely cause was some combination of friction in the labyrinth seal area and sticking of the pilot disk in its seat. The slow repressurization ramp and the extended period during which the valves were not actuated are also considered possible contributors to the incident.

To define the problem and to improve the probability of actuation of the SRVs, Georgia Power has instituted a program at Hatch to exercise 9 of the 11 Unit 1 valves regularly. Two valves will not be exercised and will be utilized for possible future testing. Unit 2 valves will be subjected to a similar program. Georgia Power has also arranged with General Electric and with other licensees for screening tests to be done on additional safety relief valves at Wyle Labs. Any valves that undergo pressure increases at a rate of 0.5 psi/s up to 103% of the set-point value rating without actuating will undergo diagnostic testing to determine the magnitude of forces at the disk-to-seat interface and in the labyrinth seal area. Further, examination of interior surfaces will be conducted to locate any physical damage. Two candidates for such tests have been found among the safety relief valves at Millstone 1.

Although the SRVs opened at a higher than expected pressure, system pressure was maintained significantly below the Technical Specification safety limit of 1,325 psig and therefore was not considered reportable as an abnormal occurrence.

Control Rod Drive Failure and Reactor Trip (NUREG-0900, Vol. 5, No. 4) (Ref. 5). On September 30, 1982, Commonwealth Edison Company experienced a control rod insertion problem at Zion 1 while the plant was operating at full power.

At about 4:45 p.m., one of two main feedwater pumps failed because of a nonsafety-related power problem in the auxiliary building. The operators immediately ran the turbine back to 50% power in an effort to keep the reactor from tripping. The control rod drive system, which should have automatically stepped the control rods inward in response to the increasing reactor coolant temperature, failed to do so. The operator then attempted to insert rods in the manual mode; however, the rods still did not move. Seeing that the primary system pressure and temperature were still increasing and that the control rods were not responding, the shift engineer ordered a manual trip of the reactor, which was successfully achieved at 4:50 p.m.

The power failure in the auxiliary building had also disabled the turbine bypass valves, which would normally have diverted steam directly to the condenser. With these valves inoperable and the turbine valves closed by the reactor trip, the energy in both primary and secondary systems could be released only via the steam generator code safety valves, and, indeed, all 20 safety valves lifted for approximately 30 s.

Immediately after the reactor trip, operators observed that the full insertion lights had not come on for five of the control rods. In accordance with approved operating procedures, the operators commenced emergency boration of the RCS until all rods were verified to be inserted. The emergency boration lasted about 6 min. Within 3 min after the reactor trip, power to the steam dump valves was restored, making them available for decay heat removal.

The peak RCS temperature, pressure, and pressurizer level recorded during the transient were 581°F, 2,355 psig, and 62%, respectively; no plant safety limits were exceeded.

The rod control system failure was found to be due to a nonsafety-related circuit malfunction. The control rod scram circuits, which *are* safety related, remained operable throughout the event. The problem could have existed undetected for some time. The loss of power in the auxiliary building that initiated the event was found to have been caused by a short circuit.

Since no plant safety limits were exceeded, the reactor protection system performed as designed, and the licensee responded in a satisfactory manner, there was no impact on public health or safety; therefore, the event was not considered reportable as an abnormal occurrence.

References

1. U.S. Nuclear Regulatory Commission, *Notification of Significant Events*, I&E Information Notice 80-06, February 27, 1980

2. U.S. Nuclear Regulatory Commission, *Report to Congress on Abnormal Occurrences January–March 1982*, NUREG-0090, Vol. 5, No. 1, August 1982.*

3. U.S. Nuclear Regulatory Commission, *Report to Congress on Abnormal Occurrences, April–June 1982*, NUREG-0090, Vol. 5, No. 2, December 1982.*

4. U.S. Nuclear Regulatory Commission, *Report to Congress on Abnormal Occurrences, July–September 1982*, NUREG-0090, Vol. 5, No. 3, January 1983.*

5. U.S. Nuclear Regulatory Commission, *Report to Congress on Abnormal Occurrences, October–December 1982*, NUREG-0090, Vol. 5, No. 4, May 1983.*

6. U.S. Nuclear Regulatory Commission, *Stress Corrosion Cracking in Thick-Wall Large-Diameter, Stainless-Steel Recirculation Piping at BWR Plants*, I&E Bulletin 82-03, Oct. 14, 1982; Rev. 1, Oct. 26, 1982.

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*Available for purchase from the NRC/GPO Sales Program, U.S. Nuclear Regulatory Commission, Washington, DC 20555, and/or the National Technical Information Service, Springfield, VA 22161.

5. FUEL PERFORMANCE

5.1 Introduction

The NRC does not monitor every fuel failure that occurs in licensed operating nuclear power plants. The approach taken is to set up operating limits for radioactivity in the coolant (due to fuel failures) that are stringent enough to ensure that the dose limits specified in the *Code of Federal Regulations* are not exceeded and to monitor only those fuel failures that are significant from the viewpoint of the number of fuel rods that failed or those in which the failure is due to a new fuel failure mechanism. Periodic meetings are held with the nuclear fuel vendors to review the operating experience of their fuel. Operating reactors typically have 40,000 fuel rods, and the average fuel rod failure rate during the last few years has been near or below 0.02% per cycle.[1] (This excludes the TMI-2 reactor, which is estimated to have a large portion of its fuel damaged as a result of the 1979 accident.) Fuel performance has continually improved, yet deviations from the normal occur occasionally.

5.2 Specific Fuel-Related Incidents

Several events related to fuel performance were reported during calendar year 1982. One was considered significant enough to be included in NRC's *Report to Congress On Abnormal Occurrences* (NUREG-0090 series). The history of fuel performance for 1982 is discussed in the report NUREG/CR-3602 (PNL-4817), *Fuel Performance Annual Report for 1982*;[2] fuel failure events are also reported in LERs. A summary of significant fuel-related incidents culled from these sources is presented in this chapter.

5.2.1 Reactor fuel degradation at Trojan

This occurrence, although not severe enough to be classified as an abnormal occurrence, was nevertheless of sufficient significance to be included in the category of "Other Items of Interest" in the report series *Report to Congress on Abnormal Occurrences*, NUREG-0090, appearing in Vol. 5, No. 2 of that series (April–June 1982).

This event was also documented in Ref. 2 (p. 40, Sect. 5.1.2 PWR Baffle Jetting) and also gave rise to Trojan LER 82-006.

On April 26, 1982, scheduled inspections of reactor fuel assemblies at Trojan identified abnormal degradation of several 17 × 17 assemblies. Trojan utilizes a W PWR and is located in Columbia County, Oregon.

In late 1981, during Cycle 4 operation, higher than normal fission product and gross activity levels were detected in the reactor coolant. These levels were carefully monitored and were observed to increase slowly (except during periods of plant shutdown and power reduction) until the facility began a planned refueling outage in April 1982. The observed coolant activity levels remained below the limits provided in the facility license.

The inspections performed by the licensee identified eight damaged peripheral assemblies by visual examination using an underwater television camera. Nine other fuel failures, not obvious to visual examination, were detected by fuel sipping, a technique that checks for the release of fission products from the fuel assembly.

An investigation of the fuel failures determined them to be caused by fuel rod vibration. All the damaged rods were located in peripheral locations in the core, and the damage was found to have been caused by water jetting through joints in the core baffle, a bolted steel assembly that surrounds the reactor core.

To prevent a recurrence of such failures, the licensee replaced a number of the fuel rods most subject to vibration (in peripheral assemblies) with solid stainless steel rods. Additional stiffener grids were installed on fuel assemblies adjacent to the baffle joints. These modifications have had a negligible effect on core performance; this was verified by testing during plant startup. During a future refueling outage, the licensee plans to modify the core baffle to eliminate the baffle jetting phenomenon.

The observed fuel failures had no effect on public safety or the environment and did not result in radioactivity levels or effluent releases in excess of those allowed by the operating license.

NRC I&E Information Notice 82-27 (Ref. 3) was issued on August 5, 1982, to inform licensees of this event.

5.2.2 Iodine spiking and gas release incidents

Iodine spiking (i.e., a temporary increase in coolant iodine concentration) is frequently observed at reactors where leaking fuel rods are present. These temporary increases in iodine concentrations have been observed to occur following shutdowns, startups, rapid power changes, and coolant depressurization. Iodine spikes are characterized by a rapid increase in coolant concentration by as much as three orders of magnitude, followed by a return to prespike concentration. The latter characteristic distinguishes the spiking phenomenon from a stepwise permanent increase in coolant activity level caused by the sudden failure of one or more fuel rods.

Many Technical Specifications for primary coolant iodine concentrations make allowance for iodine spikes by permitting temporary excursions (not to exceed 48 h) above the equilibrium concentration limit. For each excursion above the equilibrium limit, an LER is required. Four BWRs (Brunswick 1 and 2, Hatch 2, and La Crosse) and approximately one-half of the operating PWRs have this type of Technical Specifications.

During 1982, such events occurred at 11 plants, which included 1 BWR and 10 PWRs, as shown below:

Reactor	Reactor type	
	BWR	PWR
Brunswick 2	x	
Calvert Cliffs 1		x
Cook 2		x
Davis-Besse 1		x
Farley 1		x
Millstone 2		x
North Anna 1		x
Palisades		x
Prairie Island 1		x
St. Lucie 1		x
Surry 2		x

It is important to note that there are differences in reporting requirements. A number of BWRs have allowable limits on coolant activity that are substantially higher than those for many of the PWRs. Summaries of these events follow.

Brunswick 2 (Ref. 2 and Brunswick LER 82-036). The stack release rate for more than 48 h (beginning November 9, 1981) exceeded the limit specified in the Environmental Technical Specifications. The sources of the noble gas activity were fuel cladding deficiencies during normal plant operation. The major component of this activity was xenon-138.

The reactor coolant activity exceeded the Technical Specification limit of 0.2 μCi/g dose-equivalent of iodine-131 on December 18, 1981, and on January 13, 17, and 21, and March 14, 1982.

The increase in coolant fission product inventory was originating from leaking fuel rods. In each coolant activity case, the iodine activity was returned to within specifications by using the reactor water cleanup (RWCU) system and/or increasing reactor power. Some fuel bundles were sipped during the next refueling outage, and leaking bundles were removed from the core.

The licensee indicated to the NRC that the iodine spike on March 14, 1982, was associated with 7 by 7 fuel assemblies (25% of the core was of this type). On May 13, 1982, the reactor was down for refueling, and fuel was being sipped by a new technique. All of the 7 by 7 fuel was replaced during that outage. Among the 8 by 8 and 8 by 8R fuel assemblies, three suspect leakers (two 8 by 8 and one 8 by 8R) were found and not reinserted. Several fuel assemblies (including one of the 8 by 8 suspects) were visually inspected, but no indications were noted.

Calvert Cliffs 1 (Ref. 2 and Calvert Cliffs 1 LER 82-020). On April 17, 1982, following a reactor shutdown, an RCS sample indicated an iodine dose-equivalent value of 1.31 μCi/g, which exceeded the Technical Specification limit of 1.0 μCi/g.

Depressurization shock associated with the shutdown had precipitated the iodine spike. The dose-equivalent iodine level returned to within specification in less than 17 h. Other than purification of the system, no other corrective action was deemed necessary.

Cook 2 (Ref. 2 and Cook 2 LERs 82-004, 82-018, 82-078, 82-079, and 82-093). The RCS dose-equivalent iodine-131 concentration exceeded the 1.0 μCi/g steady state limit of Technical Specification 3.4.8 on January 16, February 22, March 11, August 1, August 24, September 18, September 30, and November 21, 1982. The last iodine spike occurred during a controlled shutdown for the scheduled Cycle 3/4 refueling outage.

Fuel sipping was performed during the Cycle 3/4 refueling outage, and the leaking fuel assemblies were replaced. Among 92 fuel assemblies sipped, 8 leakers (all Region 5 fuel — this was their first cycle of irradiation) were found.

Davis-Besse 1 (Ref. 2). Iodine spikes occurred on December 4, 1982. The iodine level in the RCS samples taken in accordance with the Technical Specifications at the time of these events exceeded the limit of 1.0 μCi/g dose-equivalent iodine-131.

The cause of the event was slight leakage of fission products through the fuel cladding. Following the event, the level was monitored to ensure that it decreased below the limits. The licensee indicated that corrective action was not applicable. A Technical Specification revision to change the limit is being evaluated.

Farley 1 (Ref. 2 and Farley 1 LER 82-045). The specific activity of the primary coolant on August 11, 1982, during reactor startup was determined to be 1.35 μCi/g dose-equivalent iodine-131, which exceeds the 1.0-μCi/g Technical Specification limit.

Contributing factors to the high iodine level were loss of letdown compounded by suspected fuel leakage. The specific activity of the primary coolant was determined to be below the Technical Specification limit within 4 h and 4 min. Farley 1 was shut down for refueling in January 1983. Visual inspection and sipping identified 15 damaged and leaking fuel assemblies. The fuel failures were caused by baffle jetting. Modifications to reduce or eliminate the problem were planned for early 1983.

Millstone 2 (Ref. 2 and Millstone 2 LERs 82-019 and 82-028). On June 9, 1982, higher than normal concentrations of iodine-131 indicated probable fuel cladding defects (estimate was 10 to 30 rods). The Technical Specification limit of 1.0 μCi/g dose-equivalent iodine-131 in the RCS was exceeded on July 12, 1982, and was probably exceeded on September 18, 1982.

The events were reported to be caused by a small number of defective fuel rods. The cause of the fuel cladding defects is unknown, but it has been speculated that a fuel pellet-cladding interaction (PCI) mechanism or fretting may be involved.

To prevent additional defects, power ramp rate and control rod movement restrictions were instituted. Increases in power were limited to 3% per hour on a trial basis. During the May 1983 refueling outage, all the fuel was sipped with the result that 26 fuel assemblies were believed to contain at least one leaking fuel rod per fuel assembly. Of the 26 leaking assemblies, 5 were made by Combustion Engineering and 21 by W (16 of the 21 had completed their first cycle of irradiation).

North Anna 1 (Ref. 2 and North Anna 1 LERs 82-010, 82-013, and 82-061). The specific activity of the primary coolant exceeded the Technical Specification limit of 1.0 μCi/g dose-equivalent iodine-131 on January 23, February 23, April 1, and April 16, 1982. These events were caused by known, yet not specifically located, fuel element defects in the core. In the first event, the Technical Specification sample frequency was met, but the special reporting requirement was overlooked. Procedural changes have been made that will ensure proper review. In each of the other events, the accelerated sampling frequency required by the Technical Specifications was implemented until the RCS specific activity returned to less than the allowable limit. The licensee felt there were no generic implications from these events. Minor fuel defect leakage has been experienced with fuel elements of this type. The licensee indicated that no further corrective action was required.

Palisades (Ref. 2 and Palisades LER 82-041). On October 17 and 30, 1982, samples of the RCS indicated 2.21 and 1.38 μCi/g dose-equivalent iodine-131, which exceeded the Technical Specification limit of 1.0 μCi/g. In the former case, the normal iodine increase following a plant trip on October 16 was aggravated by the purification demineralizers being out of operation due to boron equalization problems. In the latter case, the event was caused by iodine spiking following a change in thermal power.

After the first event, the purification flow was restored and the need for preventive measures following plant trips was reviewed with appropriate supervisors. Following the second event, purification was increased, the posttransient sampling frequency was increased, and a plan was developed to provide more timely increase in letdown purification flow.

Prairie Island 1 (Ref. 2 and Prairie Island 1 LER 82-016). Following a reactor trip on September 6, 1982, a spike up to 1.38 μCi/g dose-equivalent iodine-131 occurred in the RCS activity, thus exceeding the limit of 1.0 μCi/g in the Technical Specifications. The plant had been operating since early in Cycle 7 with known fuel defects (it was at that time estimated that there were 5 to 20 leaking rods, which were believed to be located in Region 9, the region of newest fuel). There was no evidence of new defects being formed as a result of this transient. Cleanup flow was increased to 80 gpm until the activity had decreased below the limit. The licensee planned to remove the suspected Region 9 fuel from the core during the Cycle 7/8 refueling outage (starting in November 1982) for repair.

The failures were believed to be in TOPROD* fuel. When the first activity occurred about one month after Cycle 7 startup, the plan was to remove all the Cycle 7 TOPROD fuel and replace it. The removed fuel would be sipped later to identify the leakers and reconstituted for use in a subsequent cycle. When the fuel was sipped, it was found that three assemblies had leaks (one rod in each assembly). Two of the assemblies were reconstituted for later reinsertion into the core. At the time, the cause

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*The TOPROD fuel program involves assemblies incorporating axial blankets of natural urania at each end; it includes five characterized assemblies at Prairie Island 2 and a full reload at Prairie Island 1.

of the failures was unknown; the fuel vendor, Exxon Nuclear, was conducting an investigation. A report from Exxon Nuclear indicated that the increased coolant activity was related to the failure of one urania fuel rod in each of the three fuel assemblies.

St. Lucie 1 (Ref. 2 and St. Lucie 1 LER 82-017). The iodine concentration in the RCS exceeded the Technical Specification limit of 1.0 μCi/g dose-equivalent iodine-131 on May 6, June 5, August 16, September 2, September 7, and November 14 and 26, 1982. The event on November 26 was the thirteenth occurrence of this type. The events were attributed to power transients after extended periods of operation with a "nominal level" of fuel leakage.

Surry 1 (Ref. 2 and Surry 1 LERs 82-050, 82-051, 82-057, and 82-082). Specific activity samples of the RCS indicated dose-equivalent iodine-131 levels that exceeded the limit in the Technical Specifications on January 6; March 25; April 13, 14, 15, 25, and 26; July 13, 14, and 15; August 24; and November 4 and 29, 1982. The events were caused by reactor transients and fuel element defects in the core. An accelerated sampling frequency was implemented until the RCS activity returned to less than the Technical Specification limit. To eliminate all leaking Cycle 6 fuel assemblies from use in Cycle 7 a redesign of Cycle 7 core was initiated. An intensive fuel examination program took place during the Cycle 6/7 refueling outage, including visual examination by remote video camera, fuel sipping, and ultrasonic measurements (to detect water in the fuel rods) on the fuel assemblies in the spent fuel pool following defueling. Some 36 of the 157 fuel assemblies were determined to be defective. Blisters and through-wall holes were visually observed on several fuel rods. The fuel rod end cap or top plug was missing from three fuel rods, where the upper spring was visible.

5.2.3 Accelerated corrosion at Browns Ferry 2 and Hatch 2 (Ref. 2)

Fuel rod failures due to accelerated waterside corrosion have been reported in previous years. During 1982, similar kinds of fuel rod failures were observed at Browns Ferry 2 and Hatch 2; they are discussed below.

Browns Ferry 2. Full core sipping of Cycle 4 fuel revealed the presence of 31 leaking fuel assemblies, 19 of which were from reload 2 fuel and were reinserted as had been intended.

Tests indicated that crud-induced localized corrosion caused the failures and that it affected both gadolinia and nongadolinia rods. Except for four damaged ones, all fuel assemblies were restored to conditions acceptable for continued core operation. Sufficient rod lots were evaluated and cleared to allow reloading of Browns Ferry 2 without reconstitution. However, it was reported that reconstitution of some of the reload 2 fuel and/or fuel currently in Browns Ferry 1 probably would be required.

Hatch 2. Because fuel bundle leakage was causing high off-gas activity, the reactor power was reduced in mid-January 1983 to meet the next refueling outage, which began in early April 1983. In discussions with the NRC, it was indicated that there were 19 confirmed leakers in the reload 1 fuel (fresh fuel that had completed its first cycle of irradiation). This was unexpected by the licensee as this was low-power region fuel. There may be some leakers in the reload 2 fuel, but that fuel had not been sipped yet.

5.2.4 Control rod drive guide tube support pin failures at North Anna 1 (Ref. 4)

The first failures of Inconel X-750 support pins were detected in early 1978 at Japan's Mihama-3. Inspections there in 1980 revealed SCC in the W-supplied control rod guide tube support pins.

In September 1981, France's Gravelines B-1 reactor was taken out of service to repair a broken control rod guide tube support pin. Subsequently, broken support pins were found at Fessenheim-1, Bugey-2, and Bugey-4 in France.

The first and only domestic support pin failures to date occurred in May 1982 at North Anna 1 (Ref. 4). Unlike the French, who see the split-pin fatigue problem in nearly all of their standard 900-MW PWRs after around 25,000 h of operation, W sees no reliable pattern in split-pin problems on its reactors. One W official stated that approximately 29 plants (domestic and foreign) have pins that could have problems.

At North Anna 1 loose parts initiated a shutdown on May 17, 1982. They were identified as split-pin retaining nuts and were found in the steam generators. These nuts hold the control rod guide tube support pins in the reactor vessel internals.

The exact cause of the loose split-pin retaining nuts is not presently known. However, two possible causes have been postulated: (1) the retaining clip came loose and the nut backed off the split pin, and (2) the split pin failed. All 122 control rod guide tube pins were replaced.

The NRC issued I&E Information Notice 82-29 (Ref. 4) on July 23, 1982, dealing with these failures.

5.2.5 PWR hold-down springs on B&W fuel assemblies

Failed hold-down springs were initially discovered on B&W fuel assemblies in 1980. In 1982, over 600 Inconel X-750 irradiated springs were examined, and 6 of those were found to be failed. All of the failed springs were replaced, restoring full function to the affected assemblies. The failure mechanism appeared to be identical to that observed on previously examined springs. B&W has developed a new hold-down spring (Mark-B10) that incorporates a larger wire diameter and a stronger, more fatigue-resistant alloy. B&W expects that the change to the Mark-B10 spring will eventually eliminate these spring failures when all springs of the old design currently in use are discharged. B&W has prepared a paper[5] that describes the metallurgical factors affecting the failure of Inconel X-750 hold-down springs.

Broken hold-down springs were noted in 1982 at four PWRs. These cases are discussed below.

Oconee 1 and 2 (Ref. 2 and Oconee 2 LER 82-003). Video inspection on February 2, 1982, revealed broken hold-down springs on four fuel assemblies:[4] three Oconee 2, Batch 7 fuel assemblies and one Oconee 1, Batch 4 fuel assembly. All the spring breaks occurred in one or both of the interface regions between the compressed and normal regions of the coil. Apparent cause of the spring failures was fatigue-induced cracking at an existing surface flaw, which then propagated. The broken hold-down springs on the three Oconee 2, Batch 7 assemblies were replaced prior to reloading these assemblies in the core. A hold-down spring inspection program will be continued until future data and inspection results justify ending the program.

Oconee 3 (Ref. 2 and Oconee 3 LER 82-007). Video inspection on May 5, 1982, revealed broken hold-down springs on two fuel assemblies. All the spring breaks occurred in one or both of the interface regions between the compressed and normal regions of the coil. The cause appeared to be fatigue-induced cracking at an existing surface flaw, which then propagated. The broken springs were replaced before the assemblies were reloaded into the core. A hold-down spring inspection program will be continued until future data and inspection results justify ending the program.

Davis-Besse 1 (Ref. 2). One broken hold-down spring was observed during the refueling outage in early 1982. The fuel assembly was discharged, and the broken spring was sent to the vendor for evaluation.

5.2.6 Top nozzle broken off at Prairie Island 1 (Ref. 1 and Prairie Island 1 LER 81-031)

On December 16, 1981, the top nozzle of a spent W fuel assembly separated from the remainder of the assembly as it was being lifted out of a storage rack in the spent fuel pool. The assembly did not fall, but tipped over approximately 30° from the vertical and came to rest in a slot in the wall of the spent fuel pool. The fuel vendor designated the apparent cause of the event as intergranular SCC of the stainless steel sleeves, which are welded to the top nozzle and are mechanically joined to the Zircaloy control rod guide thimbles in this fuel assembly (the sleeves and thimbles are the load-bearing members when the assembly is lifted). The cracking is believed to have developed during pool storage.

The fuel assembly was subsequently lifted and inserted into a storage position. As noted in the fuel performance annual report for 1981, a total of 27 assemblies were examined at Prairie Island, and 12 showed evidence of corrosion; there were no additional nozzle failures when the assemblies were moved.

5.2.7 Alpha activity in coolant at La Crosse (Ref. 2 and La Crosse LERs 82-006 and 82-014)

The reactor was shut down on June 6, 1982, because of high RCS activity. The gross alpha activity of the primary coolant sample exceeded the limit of 5×10^{-6} μCi/g in the Technical Specifications. It was reported that degraded fuel cladding experienced during previous cycles had contributed to the presence of irradiated fuel particles in the RCS.

The alpha activity came from residual irradiated fuel material that entered the system as a result of degraded stainless steel cladding experienced primarily on fuel rods during Cycle 4 (and to a much lesser degree during Cycle 5) and subsequent handling of the irradiated fuel assemblies during refueling. Work on the primary system during shutdown resulted in more general distribution of the suspended alpha-bearing material in the coolant.

Operation of the purification system reduced the concentration of the material suspended in the coolant to an allowable value.

Inspection of one fuel assembly during reactor refueling on April 20, 1982, following Cycle 7 operation revealed one fuel rod with a 5.5-in.-long degraded segment, which was caused by pellet/cladding interaction with oxygen-assisted stress corrosion of the stainless steel cladding. This assembly was one of two Allis-Chalmers assemblies in use; both were replaced with Exxon Nuclear assemblies.

5.2.8 Cladding degradation on PWR fuel rods at Salem 1 (Ref. 2 and Salem 1 LERs 82-005 and 82-090)

While conducting a fuel assembly television visual and dimensional survey at Salem 1 on January 31, 1982, a W fuel inspection team discovered degradation of the fuel cladding on a fuel assembly that had been in Cycle 3. Fuel pellets were visible during the fuel rod scan. W identified the cause as excessive rod growth due to fuel lockup. A fuel pellet was wedged in the top several inches of the fuel column, which resulted in excessive diametral strain and swelling.

This fuel assembly, which had been scheduled to be discharged from the core, was placed in the spent fuel pit. All assemblies of the same type scheduled for reuse in the core and ten other assemblies were inspected. The fuel vendor conducted an evaluation of the failure, concluded that this occurrence was isolated in nature, and deemed that no further corrective action was necessary.

On November 21, 1982, during routine refueling operations, video inspection of removed fuel assemblies revealed cladding ruptures on one rod in a fuel assembly, which had been in the core for three cycles. Cause of the cladding failure was not known at that time.

This fuel assembly was transferred to the spent fuel pit; it will not be used in future cycles. The vendor (W) performed a more detailed inspection. A report submitted to the NRC indicated that the rod appears to have failed due to secondary hydriding, without any apparent implications or correlations with respect to other fuel in Salem 1 or in the same batch. As a result, the licensee assumed this failure also to be an isolated case and deemed that no further action was necessary.

5.2.9 Hydriding of PWR fuel rods at Indian Point 2 (Ref. 2 and Indian Point 2 LER 82-045)

On November 8, 1982, W (who made the fuel) notified the licensee that a review of videotapes obtained during the Cycle 5/6 refueling outage of fuel assembly F44, a W 15 by 15 (9 grid) fuel assembly, had revealed that the upper end plug had separated from the cladding on one fuel rod.

The plug was lodged between the upper ends of adjacent fuel rods in the assembly. The end spring of the affected rod was visible, indicating that the fuel pellets remained contained inside the rod. A related event, which involved a fuel rod with a hydride defect, was reported in LER No. 81-005 and discussed in Ref. 6.

The detailed review of the videotapes obtained during the Cycle 5/6 refueling outage identified a total of six fuel rods with defects in four Region 5 assemblies and one Region 6 assembly. The licensee and the fuel vendor (W) believe that the most probable cause of the cladding degradation observed in these 15 by 15 (9 grid) fuel assemblies is hydriding. A traceability study performed for the defective fuel rods did not identify any manufacturing abnormalities. Only one of the affected assemblies had been scheduled for reuse in Cycle 6; it was replaced by a nondegraded assembly.

5.2.10 BWR fuel rods broken during visual inspection at Browns Ferry 2 and Hatch 1 (Ref. 2)

Browns Ferry 2 (Ref. 2). During an inspection of reload 2 fuel between October 23 and November 1, 1982, one rod broke in two as it was being withdrawn from its fuel assembly for visual inspection (this assembly was one of the leakers discussed in Sect. 5.2.3, and this event illustrates the severity of the degree of cladding degradation caused by waterside corrosion). The two halves of the rod were returned to the assembly; five small flakes of spent UO_2 fuel found on the fuel preparation machine were placed in a stainless steel bucket, under a lead brick, and stored in the spent fuel pool.

Hatch 1 (Ref. 2 and Hatch 1 LER 82-097). A failed spent fuel rod was broken during visual inspection of several spent fuel bundles on November 16, 1982. The rod had been removed from a bundle (LJE516) and broken into two pieces as it was being placed in the inspection fixture. The lower piece fell into a control rod blade holder; the upper piece remained attached to the handling tool. No fuel or gases were released when the rod broke. Handling of the rod was sufficient to cause it to break at the point of degradation (severe localized waterside corrosion again). The rod was placed back into the fuel bundle and the bundle was flagged in the plant records to prevent its reuse.

5.2.11 BWR fuel assembly attached to its support plate at Quad Cities 1

Quad Cities-1 (Ref. 2). While attempting to lift a fuel assembly out of the core during normal refueling operations on September 16, 1982, it was found that the assembly had become attached to its fuel support piece and the two could not be separated. The support piece is normally positioned by guide pins on the lower core plate and supports four assemblies. (The other three assemblies that rest on this piece had already been removed.) The two units were removed together and transferred to the spent fuel pool via the refueling trolley grapple (because of the attached support, the assembly could not be removed to the pool through normal methods). General Electric (the NSSS) was notified.

5.2.12 Closing of PWR fuel rod shoulder gap at Arkansas 2 (Ref. 2 and Arkansas 1 LER 82-030)

Fuel inspections on September 22, 1982, following Cycle 2 operation of Arkansas 2 indicated that the rate of closure of the fuel rod shoulder gap (i.e., the space between the top of the fuel rods and the bottom of the upper flow plate) for some Batch C fuel assemblies had exceeded that previously predicted by CE. No fuel rod failures occurred. According to a statement by the licensee, the gap clearances on certain Batch C fuel assemblies may be too small to prevent fuel rod contact during the next fuel cycle (Cycle 3).

A combination of two factors was said to have led to this circumstance. First, the design models used by CE to predict fuel rod growth underpredicted the actual rod growth. Second, the annealed guide tubes grew at a rate less than predicted.

Cycle 3 operation involved Batch C, D, and E fuel assemblies. The excessive rate of gap closure necessitated a modification (installing shims between the control element assembly guide tubes and flow plate) to 30 Batch C fuel assemblies. Batch D and E fuel assemblies did not require modification because of prior design changes to accommodate higher exposures.

5.2.13 Axial movement of grid spacers on PWR fuel assembly at Oconee 2 (Ref. 2 and Oconee 2 LER 82-005)

During postirradiation examinations on March 12, 1982, the intermediate Zircaloy spacer grids 1 through 5 on an experimental Mark BZ demonstration fuel assembly irradiated in Cycle 5 were found to have moved upward about 2 in. from their normal position, resulting in loss of grid-to-grid contact with adjacent Mark B4 fuel assemblies. The problem was caused by grid springs that were too weak to retain adequate contact pressure with the fuel rods and by too large a growth gap in the spacer sleeves.

The licensee indicated to the NRC that even though the preliminary evaluation performed indicated that reinserting this fuel assembly might have been acceptable, it was believed prudent not to reinsert it. Instead, the licensee reinserted an assembly from the spent pool that had similar reactivity and consequently resulted in minimal perturbation to the next fuel cycle.

References

1. F. Garzarolli, R. von Jan, and H. Stehle, "The Main Causes of Fuel Element Failure in Water-Cooled Power Reactors," *At. Energy Rev.* 17(1), 31 (March 1979).

2. W. J. Bailey and M. Tokar, *Fuel Performance Annual Report for 1982*, prepared for Div. of Systems Integration, ONRR, U.S. Nuclear Regulatory Commission, NUREG/CR-3602 (PNL-4817), March 1984.

3. U.S. Nuclear Regulatory Commission, *Fuel Rod Degradation Resulting from Baffle Water-Jet Impingement*, I&E Information Notice, 82-27, Aug. 5, 1982.

4. U.S. Nuclear Regulatory Commission, *Control Rod Drive (CRD) Guide Tube Support Pin Failures at Westinghouse PWRs*, I&E Information Notice 82-29, July 23, 1982.

5. D. L. Baty et al., "Metallurgical Factors Affecting the Failure of Alloy X-750 Hold-down Springs," *International Symposium on Environmental Degradation of Materials in Nuclear Power Systems — Water Reactors*, Myrtle Beach, South Carolina, August 22–25, 1983.

6. W. J. Bailey and M. Tokar, *Fuel Performance Annual Report for 1981*, NUREG/CR-3001 (PNL-4342), December 1981.

6. RADIATION EXPOSURE

6.1 Occupational Radiation Exposure

This section reviews the data on occupational radiation exposure of personnel at BWR and PWR commercial nuclear power plants. Data from 75 plants are considered based on their completion of at least one year of commercial operation as of December 31, 1982. Both Fort St. Vrain (an HTGR) and Indian Point 1 (although defueled) are included in the review and in this total.*

The primary sources of information on occupational radiation exposure are two types of annual reports that are required to be submitted to the NRC in March of each year:

1. A report indicating the number, job description, and collective dose (person-rem) of those individuals whose annual whole-body dose exceeded 100 mrem is required by the Technical Specifications of each plant. The standard format for the report is given in NRC's Regulatory Guide 1.16.

2. A statistical summary report indicating the total number of individuals monitored and the number of individuals whose annual whole-body dose fell into certain dose ranges is required by *Code of Federal Regulations*, Title 10, Part 20.407.

Tables 6.1 and 6.2, derived primarily from the first type of annual report, contain results similar to those found for 1981. Workers at the 26 BWRs received a collective dose of 22,929 person-rem, while workers at the 48 PWRs incurred a collective dose of 27,709 person-rem. They also show that most of the total collective dose (about 62%) continues to be incurred by contractor personnel. Table 6.3 presents a breakdown of these collective doses by work function for the last nine years. One can see that workers performing routine and special maintenance activities continue to receive most of the collective dose (76.6% in 1981 and 74.7% in 1982). Table 6.4 shows the percentage of the collective dose incurred by different types of personnel at BWRs and PWRs by work function. At PWRs, the largest portion of the collective dose (49.0%) was incurred by workers involved in special maintenance activities, as has been the case for the last few years. In 1982, this was also true for BWRs, with 44.1% of the collective dose being incurred by workers involved in special maintenance activities, whereas in 1981 about 42% of the collective dose was due to routine maintenance activities.

Table 6.5 summarizes the exposure information reported pursuant to 10 CFR 20.407 by commercial reactors during the last ten years. In 1982, the average annual dose for individuals receiving measurable doses was found to be 0.62 rem, remaining less than 1 rem as it has every year since 1972.

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*Note that the group of 75 reactors covered in this chapter does not correspond exactly to the group of 72 included in the rest of this report. As stated, the reactor (Sequoyah 2) that started operation in 1982 is not included here, but Dresden 1, Humboldt Bay, Indian Point 1, and TMI-2, none of which were in operation in 1982, are included here, though excluded in the rest of this report.

Table 6.1. Annual whole-body doses at BWRs — 1982[a]

Plant name	Plant and utility personnel: Number of workers with doses >0.1 rem	Plant and utility personnel: Collective dose (person-rem)	Contractor personnel: Number of workers with doses >0.1 rem	Contractor personnel: Collective dose (person-rem)	Total: Number of workers with doses >0.1 rem	Total: Collective dose (person-rem)
Big Rock Point	200[b]	239	75[b]	62	275[b]	301
Browns Ferry 1, 2, 3	2,123[b]	1,483	365[b]	247	2,488[b]	1,730
Brunswick 1, 2	775	930	1,976	2,781	2,751	3,711
Cooper Station	220[b]	169	261[b]	337	481[b]	506
Dresden 1, 2, 3	1,019	1,163	858	1,689	1,877	2,852
Duane Arnold	65[b]	70	185[b]	228	250[b]	298
FitzPatrick	484[b]	327	1,049[b]	862	1,533[b]	1,189
Hatch 1, 2	664[b]	348	1,557[b]	934	2,221[b]	1,282
Humboldt Bay	40	15	0	0	40	15
La Crosse	74	186	18	16	92	202
Millstone 1	343[b]	345	648[b]	591	991[b]	936
Monticello	365[b]	220	593[b]	720	958[b]	940
Nine Mile Point	569[b]	377	429[b]	1,110	998[b]	1,487
Oyster Creek	448[b]	307	405[b]	403	853[b]	710
Peach Bottom 2, 3	796	580	1,200	1,241	1,996	1,821
Pilgrim	416	329	1,371	810	1,787	1,139
Quad Cities 1, 2	730	1,059	1,569	2,546	2,299	3,605
Vermont Yankee	154[b]	125	166[b]	80	320[b]	205
Total	9,485	8,272	12,725	14,657	22,210	22,929

[a]Includes only those reactors that had been in commercial operation for at least one year as of December 31, 1982.

[b]Data presented are taken from the annual reports submitted in accordance with Regulatory Guide 1.16 except where the reported number of personnel receiving doses greater than 0.1 rem deviates by 15% or more from the number of personnel reported pursuant to 10 CRF 20.407. For these plants, the total number of personnel shown in the table is the number of workers whose doses exceeded 0.1 rem, as determined from the 10 CFR 20.407 reports. This total was broken down into the number of each type of personnel by assuming that the proportion of each type was the same as that shown in the Regulatory Guide 1.16 reports.

Table 6.2. Annual whole-body doses at PWRs — 1982[a]

Plant name	Plant and utility personnel		Contractor personnel		Total	
	Number of workers with doses >0.1 rem	Collective dose (person-rem)	Number of workers with doses >0.1 rem	Collective dose (person-rem)	Number of workers with doses >0.1 rem	Collective dose (person-rem)
Arkansas 1, 2	391[b]	249	580[b]	421	971[b]	670
Beaver Valley	259	111	880	454	1,139	565
Calvert Cliffs 1, 2	715[b]	583	582[b]	358	1,297[b]	941
Cook 1, 2	279	208	708	435	987	643
Crystal River	147	49	190	93	337	142
Davis-Besse	90[b]	39	328[b]	224	418[b]	263
Farley 1, 2	444[b]	266	377[b]	180	821[b]	446
Fort Calhoun	156[b]	76	113[b]	64	269[b]	140
Ginna	583	577	291	531	874	1,108
Haddam Neck	196	101	70	21	266	122
Indian Point 1, 2	654	807	991	947	1,645	1,754
Indian Point 3	206[b]	154	923[b]	1,276	1,129[b]	1,430
Kewaunee	118[b]	44	74[b]	45	192[b]	89
Maine Yankee	214[b]	157	548[b]	459	762[b]	616
McGuire 1	408[b]	279	85[b]	57	493[b]	336
Millstone 2	348	195	1,276	1,227	1,624	1,422
North Anna 1, 2	629[b]	748	790[b]	1,276	1,419[b]	2,024
Oconee 1, 2, 3	1,404[b]	1,647	312[b]	421	1,716[b]	2,068
Palisades	213[b]	92	335[b]	147	548[b]	239
Point Beach 1, 2	210	225	388	359	598	584
Prairie Island 1, 2	305[b]	149	124[b]	63	429[b]	212
Rancho Seco	211[b]	116	270[b]	212	481[b]	328
Robinson 2	334	448	742	880	1,076	1,328
Salem 1, 2	523[b]	314	1,317[b]	745	1,840[b]	1,059
San Onofre	157	96	996	685	1,153	781
Sequoyah	1,000	256	74	28	1,074	284
St. Lucie	314[b]	132	163[b]	83	477[b]	215
Surry 1, 2	586[b]	892	541[b]	459	1,127[b]	1,351
Three Mile Island 1, 2	647[b]	564	443[b]	428	1,090[b]	992
Trojan	416	210	288	142	704	352
Turkey Point 3, 4	453	610	1,925	2,182	2,378	2,792
Yankee-Rowe	278[b]	251	153[b]	209	431[b]	460
Zion 1, 2	444	385	715	1,568	1,159	1,953
Total	13,332	11,030	17,592	16,669	30,924	27,709

[a]Includes only those reactors that had been in commercial operation for at least one year as of December 31, 1982.

[b]Data presented are taken from the annual reports submitted in accordance with Regulatory Guide 1.16 except where the reported number of personnel receiving doses greater than 0.1 rem deviates by 15% or more from the number of personnel reported pursuant to 10 CRF 20.407. For these plants, the total number of personnel shown in the table is the number of workers whose doses exceeded 0.1 rem, as determined from the 10 CFR 20.407 reports. This total was broken down into the number of each type of personnel by assuming that the proportion of each type was the same as that shown in the Regulatory Guide 1.16 reports.

Table 6.3. Percentages of total collective doses incurred by workers at LWRs by work function for 1974–1982

Work function	Percent of total collective dose								
	1974	1975	1976	1977	1978	1979	1980	1981[a]	1982
Reactor operations and surveillance	14.0	10.8	10.4	10.5	13.2	12.2	9.5	8.9	9.4
Routine maintenance	45.4	52.5	31.7	28.1	31.5	29.2	35.5	36.1	27.9
In-service inspection	2.7	2.9	5.7	6.4	7.7	9.0	5.5	5.3	6.5
Special maintenance	20.4	19.0	39.5	42.5	35.9	39.4	40.6	40.5	46.8
Waste processing	3.5	6.9	4.8	5.8	5.0	3.6	3.0	4.2	5.0
Refueling	14.0	7.7	7.9	6.7	6.5	6.6	6.1	5.0	4.4

[a]Figures for 1981 are changed to reflect corrections submitted by several utilities.

Table 6.4. Percentages of collective doses incurred by types of workers at BWRs and PWRs by work function in 1982

Work function	BWR personnel		PWR personnel	
	Plant and utility	Contractors	Plant and utility	Contractors
Reactor operations and surveillance	7.0	2.1	6.6	3.1
Routine maintenance	14.9	18.8	11.3	11.8
In-service inspection	1.2	3.1	2.8	5.5
Special maintenance	8.7	35.4	14.1	34.9
Waste processing	2.9	3.3	1.7	2.3
Refueling	1.4	1.3	3.3	2.6
Total	36.1	63.9	39.8	60.2

The total collective dose at LWRs for 1982 (52,190 person-rem) was slightly less than that found for 1981 (54,142 person-rem). Major contributors to the collective dose included in-service inspections and steam generator repairs and plant modifications such as pipe hangers, snubbers, and safe-end replacements.

For additional information refer to the NRC report, *Occupational Radiation Exposure at Commercial Nuclear Power Plants — 1982* (NUREG-0713, Vol. 4), available from the National Technical Information Service.

Table 6.5. Summary of annual doses reported by nuclear power facilities, 1974–1982[a]

Year	Reactor type	Number of reactors included	Total collective dose (person-rem)	Number of workers with measurable doses	Total megawatt-years generated	Average annual dose (rem/worker)	Average collective dose per reactor (person-rem)	Average number of workers per reactor	Average person-rem per megawatt-year
1974	PWR	20	6,627	9,697	6,824	0.68	331	485	1.0
	BWR	14	7,095	8,769	4,059	0.81	507	626	1.7
	LWRs	34	13,722	18,466	10,883	0.74	404	543	1.3
1975	PWR	26	8,268	10,884	11,983	0.76	318	419	0.7
	BWR	18	12,611	14,607	5,786	0.86	701	812	2.2
	LWRs	44	20,879	25,491	17,769	0.82	475	579	1.2
1976	PWR	30	13,807	17,588	13,325	0.79	460	586	1.0
	BWR	23	12,626	17,859	8,586	0.71	549	776	1.5
	LWRs	53	26,433	35,447	21,911	0.75	499	669	1.2
1977	PWR	34	13,469	20,878	17,346	0.65	369	614	0.8
	BWR	23	19,042	21,388	9,098	0.89	828	930	2.1
	LWRs	57	32,511	42,266	26,444	0.77	570	742	1.2
1978	PWR	39	16,713	25,720	19,840	0.65	429	659	0.8
	BWR	25	15,096	20,278	11,774	0.74	604	811	1.3
	LWRs	64	31,809	45,998	31,614	0.69	497	719	1.0
1979	PWR	42	21,437	38,828	18,249	0.55	510	924	1.2
	BWR	25	18,322	25,245	11,671	0.73	733	1,010	1.6
	LWRs	67	39,759	64,073	29,920	0.62	593	956	1.3
1980	PWR	42	24,266	46,237	18,287	0.52	578	1,101	1.3
	BWR	26	29,530	34,094	10,868	0.87	1,136	1,311	2.7
	LWRs	68	53,796	80,331	29,155	0.67	791	1,181	1.8
1980	HTGR	1	3	58	83	0.05	3	58	0.0
1981	PWR	44	28,671	47,351	20,552	0.61	652	1,076	1.4
	BWR	26	25,471	34,832	10,899	0.73	980	1,340	2.3
	LWRs	70	54,142	82,183	31,451	0.66	773	1,174	1.7
1981	HTGR	1	1	31	94	0.03	1	31	0.0
1982	PWR	48	27,753	52,147	22,141	0.53	578	1,086	1.3
	BWR	26	24,437	32,235	10,655	0.76	940	1,240	2.3
	LWRs	74	52,190	84,382	32,796	0.62	705	1,139	1.6
1982	HTGR	1	0	22	73	0.02	0	22	0.0

[a]The figures in this table are based on the number of nuclear power reactors that had been in commercial operation for at least one year as of December 31 of each of the years indicated. Indian Point 1, although defueled, is counted.

Appendix A

GLOSSARY

Abnormal occurrence	See Sect. 4.3 and Appendix C.
Average daily power level, MW(e) net	The net electrical energy generated during the day (measured from 001 to 2400 h, inclusive) in megawatt-hours divided by 24 h.
Licensed thermal power, MW(t)	The maximum thermal power of the reactor authorized by the NRC, expressed in megawatts.
Date of commercial operation	Date unit was declared by utility owner to be available for the regular production of electricity: usually related to satisfactory completion of qualification tests, as specified in the purchase contract, and to accounting policies and practices of utility.
Design electrical rating (DER), MW(e) net	The nominal net electrical output of the unit specified by the utility and used for the purpose of plant design.
Forced outage	An outage required to be initiated no later than the weekend following discovery of an off-normal condition.
Forced outage hours	The clock hours during the report period when a unit is unavailable due to forced outages.
Gross electrical energy generated, MWh	Electrical output of the unit during the report period as measured at the output terminals of the turbine generator, in megawatt-hours.
Gross hours	The clock hours from the beginning of a specified situation until its end. For outage durations, the clock hours during which the unit is not in power production.
Gross thermal energy generated, MWh	The thermal energy produced by the unit during the report period as measured or computed by the licensee, in megawatt-hours.

Hours generator on-line	Also, "unit service hours." The total clock hours in the report period during which the unit operated with breakers closed to the station bus. These hours added to the total outage hours experienced by the unit during the report period shall equal the hours in the report period.
Hours in report period	For units in power ascension at the end of the period, the gross hours from the beginning of the period or the first electrical production, whichever comes last, to the end of the period. For units in commercial operation at the end of the period, the gross hours from the beginning of the period or of commercial operation, whichever comes last, to the end of the period or decommissioning, whichever comes first.
Hours reactor critical	The total clock hours in the report period during which the reactor sustained a controlled chain reaction.
Maximum dependable capacity (gross) (MDC gross), MW(e) gross	Dependable main-unit gross capacity, winter or summer, whichever is smaller. The dependable capacity varies because the unit efficiency varies during the year due to variations in cooling water temperature. It is the gross electrical output as measured at the output terminals of the turbine generator during the most restrictive seasonal conditions (usually summer).
Maximum dependable capacity (net)	Maximum dependable capacity (gross) less the normal station service loads.
Nameplate rating, gross MW(e)	The nameplate power designation of the generator, in megavolt-amperes (MV-A), times the nameplate power factor of the generator. Note that the nameplate rating of the generator may not be indicative of the maximum or dependable capacity, since some other item of equipment of a lesser rating (e.g., turbine) may limit unit output.
Net electrical energy generated	Gross electrical output of the unit, measured at the output terminals of

	the turbine generator during the report period, minus the normal station service electrical energy utilization. If this quantity is less han zero, a negative number should be recorded.
Outage	A situation in which no electrical production takes place.
Outage duration	The total clock hours of the outage measured from the beginning of the report period or the outage, whichever comes first.
Period hours	See "hours in report period."
Power reduction	A reduction in the average daily power level of more than 20% from the previous day. All power reductions are defined as outages of zero hours duration for the purpose of computing unit service and availability factors and forced outage rate.
Regulatory restriction	Special restrictions imposed by the NRC or other state or federal regulatory agencies limiting power level to less than authorized until the restrictive condition is resolved. Does not include self-imposed operating restrictions.
Restricted power level	Maximum net electrical generation to which the unit is restricted during the report period due to the state of equipment, external conditions, administrative reasons, or a directive from the NRC.
Scheduled outage	Planned removal of a unit from service for refueling, inspection, training, or maintenance. Those outages that do not fit the definition of "forced outage" are perforce "scheduled outages."
Startup and power-ascension-test phase	Period following initial criticality during which the unit is tested at successively higher levels, culminating with operation at full power for a sustained period and completion of warranty runs. Following this phase, the utility generally considers the unit to be available for commercial operation.

Unit	The set of equipment uniquely associated with the reactor, including turbine generators and ancillary equipment, considered as a single electrical energy production facility.
Unit age	The elapsed time from the date of first electrical generation through December 31 of the current year.
Unit available hours	The total clock hours in the report period during which the unit operated on-line or was capable of such operation. (Unit reserve shutdown hours plus hours generator on-line.)
Unit availability factor	$\frac{\text{Unit available hours} \times 100}{\text{Period hours}}$
Unit capacity factors	
Using licensed thermal power	$\frac{\text{Gross thermal energy generated} \times 100}{\text{Period hours} \times \text{licensed thermal power}}$
Using nameplate rating	$\frac{\text{Gross electrical energy generated} \times 100}{\text{Period hours} \times \text{nameplate rating}}$
Using DER	$\frac{\text{Net electrical energy generated} \times 100}{\text{Period hours} \times \text{DER}}$
Using MDC gross*	$\frac{\text{Gross electrical energy generated} \times 100}{\text{Period hours} \times \text{MDC gross}}$
Using MDC net*	$\frac{\text{Net electrical energy generated} \times 100}{\text{Period hours} \times \text{MDC net}}$
Unit forced outage rate	$\frac{\text{Forced outage hours}}{\text{Unit service hours} + \text{forced outage hours}}$
Unit reserve shutdown	The removal of the unit from on-line operation for economic or other similar reasons when operation could have been continued.
Unit reserve shutdown hours	The total clock hours in the report period during which the unit was in reserve shutdown mode.
Unit service factor	$\frac{\text{Unit service hours} \times 100}{\text{Period hours}}$
Unit service hours	See "hours generator on-line."

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*Note: If MDC gross and/or MDC net have not been determined, the DER is substituted for this quantity of unit capacity factor calculations.

Appendix B

INDIVIDUAL PLANT SUMMARIES FOR 1982

Summaries of the 1982 operating experience for each plant are presented in this appendix. The system descriptions are given in Table B.1, and the component types are defined in Table B.2. The individual plant summaries are arranged alphabetically by plant name. The information provided includes plant operating and outage statistics, details on each outage, and highlights of operating experience.

In addition to true outages (i.e., events that result in total shutdown of the reactors), licensees report power reductions of more than 20% (and in some cases power increases) as zero-duration outages, regardless of the actual duration of the reduction. Since these power reductions are not true outages, they are not included in these listings.

Only those outages beginning in 1982 are included in the number of outages to avoid double counting of outages extending across year ends. However, all 1982 outage hours are included in the hour totals. Footnotes flag those instances where hours from outages initiated in the prior year form part of the 1982 totals. For outages extending past the end of the year, only the 1982 hours are included.

Symbols used in the table provided for each summary are as follows: under "Type," F is used for forced outage and S is used for scheduled outage. Under "Cause," the following symbols are used:

A	equipment failure
B	maintenance or test
C	refueling
D	regulatory restriction
E	operator training and license exams
F	administrative
G	operational error
H	other

Under "Shutdown method," 1 is manual, 2 is manual scram, 3 is automatic scram, 4 is continuation, and 9 is other.

The daily average power curves for the year, presented with the plant summaries, are based on maximum dependable capacity (MDC) of the plants as of December 31, 1982; under optimum conditions, the average power may exceed 100% of the MDC.

Table B.1. System descriptions

System	Code
Reactor	RX
Reactor vessel internals	RA
Reactivity control systems	RB
Reactor core	RC
Reactor coolant system and connected systems	CX
Reactor vessels and appurtenances	CA
Coolant recirculation systems and controls	CB
Main steam systems and controls	CC
Main steam isolation systems and controls	CD
Reactor core isolation cooling systems and controls	CE
Residual heat removal systems and controls	CF
Reactor coolant cleanup systems and controls	CG
Feedwater systems and controls	CH
Reactor coolant pressure boundary leakage detection systems	CI
Other coolant subsystems and their controls	CJ
Engineered safety features	SX
Reactor containment systems	SA
Containment heat removal systems and controls	SB
Containment air purification and cleanup systems and controls	SC
Containment isolation systems and controls	SD
Containment combustible gas control systems and controls	SE
Emergency core-cooling systems and controls	SF
Control room habitability systems and controls	SG
Other engineered safety feature systems and their controls	SH
Instrumentation and controls	IX
Reactor trip systems	IA
Engineered safety feature instrument systems	IB
Systems required for safe shutdown	IC
System-related display instrumentation	ID
Other instrument systems required for safety	IE
Other instrument systems not required for safety	IF
Electric power systems	EX
Offsite power systems and controls	EA
AC onsite power systems and controls	EB
DC onsite power systems and controls	EC
Onsite power systems and controls (composite AC and DC)	ED
Emergency generator systems and controls	EE
Emergency lighting systems and controls	EF
Other electric power systems and controls	EG
Fuel storage and handling systems	FX
New fuel storage facilities	FA
Spent-fuel storage facilities	FB
Spent-fuel-pool cooling and cleanup systems and controls	FC
Fuel handling systems	FD

Table B.1 (continued)

System	Code
Auxiliary water systems	WX
Station service water systems and controls	WA
Cooling systems for reactor auxiliaries and controls	WB
Demineralized water makeup systems and controls	WC
Potable and sanitary water systems and controls	WD
Ultimate heat sink facilities	WE
Condensate storage facilities	WF
Other auxiliary water systems and their controls	WG
Auxiliary process systems	PX
Compressed air systems and controls	PA
Process sampling systems	PB
Chemical, volume control, and liquid poison systems and controls	PC
Failed-fuel detection systems	PD
Other auxiliary process systems and their controls	PE
Other auxiliary systems	AX
Air conditioning, heating, cooling, and ventilation systems and controls	AA
Fire protection systems and controls	AB
Communication systems	AC
Other auxiliary systems and their controls	AD
Steam and power conversion systems	HX
Turbine generators and controls	HA
Main steam-supply system and controls (other than CC)	HB
Main condenser systems and controls	HC
Turbine-gland-sealing systems and controls	HD
Turbine bypass systems and controls	HE
Circulating water systems and controls	HF
Condensate cleanup systems and controls	HG
Condensate and feedwater systems and controls (other than CH)	HH
Steam generator blowdown systems and controls	HI
Other features of steam and power conversion systems (not included elsewhere)	HJ
Radioactive waste management systems	MX
Liquid radioactive waste management systems	MA
Gaseous radioactive waste management systems	MB
Process and effluent radiological monitoring systems	MC
Solid radioactive waste management systems	MD
Radiation protection systems	BX
Area monitoring systems	BA
Airborne radioactivity monitoring systems	BB

Table B.2. Component types

Component type	Component type includes
Accumulators	Scram accumulators, safety injection tanks, surge tanks, holdup/storage tanks
Air dryers	Alarms, bells, buzzers, claxons, horns, gongs, sirens
Batteries and chargers	Chargers, dry cells, wet cells, storage cells
Blowers	Compressors, gas circulators, fans, ventilators
Circuit closers/interrupters	Circuit breakers, contactors, controllers, starters, switches (other than sensors), switchgear
Control rods	Poison curtains
Control rod drive mechanisms	
Demineralizers	Ion exchangers
Electrical conductors	Buses, cables, wires
Engines, internal combustion	Butane, diesel, gasoline, natural gas, and propane engines
Filters	Strainers, screens
Fuel elements	
Generators	Inverters
Heaters, electric	Heat tracers
Heat exchangers	Condensers, coolers, evaporators, regenerative heat exchangers, steam generators, fan coil units
Instrumentation and controls	Controllers, sensors/detectors/elements, indicators, differentials integrators (totalizers), power supplies, recorders, switches, transmitters, computation modules
Mechanical function units	Mechanical controllers, governors, gear boxes, varidrives, couplings
Motors	Electric motors, hydraulic motors, pneumatic (air) motors, servomotors

Table B.2 (continued)

Component type	Component type includes
Penetrations, primary containment	Air locks, personnel access, fuel handling, equipment access, electrical, instrument line, process piping
Pipes and/or fittings	
Pumps	
Recombiners	
Relays	Switchgear
Shock suppressors and supports	Hangers, supports, sway braces/ stabilizers, snubbers, antivibration devices
Transformers	
Turbines	Steam turbines, gas turbines, hydro turbines
Valves	Valves, dampers
Valve operators	Explosive squib
Vessels, pressure	Containment vessels, dry wells, pressure suppression chambers, pressurizers, reactor vessels

ARKANSAS 1

I. Summary

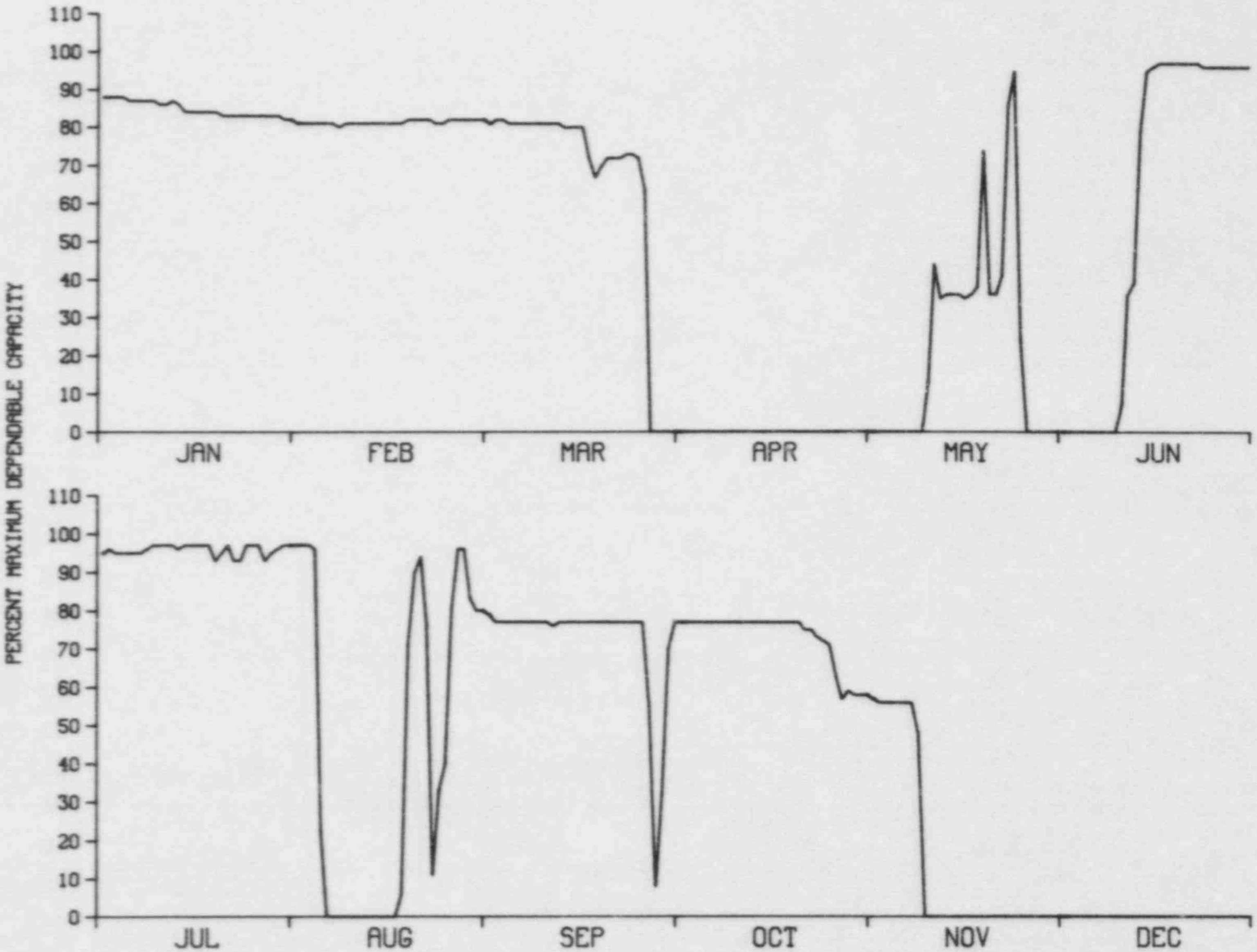
Description	Performance	Outages
Location: Russellville, Arkansas	Net electrical energy generated (MWh): 3,721,409	Total No.: 6
Docket No.: 50-313	Unit availability factor (%): 64.8	Forced: 4
Reactor type: PWR	Unit capacity factor (%) (using MDC): 50.8	Scheduled: 2
Maximum dependable capacity [MW(e)-net]: 836	Unit capacity factor (%) [using design MW(e)]: 50.0	Total hours: 2,087 (35.2%)
Commercial operation: 12/19/74		Forced: 749 (8.6%)
Years operating experience: 8.4		Scheduled: 2,338 (26.7%)

II. Highlights

Arkansas 1 operated continuously from the start of 1982 to the last week of March, when a six-week shutdown was begun to replace the feedwater nozzles in one of the two once-through steam generators. In late May, only about two weeks after coming back on line from the first outage, the unit again had to be shut down for more than two weeks to deal with a tube leak in the same steam generator. A total of ten tubes required plugging on that occasion. In August about ten days were lost due to an instrument problem that caused a trip on an erroneous loss-of-feedwater signal. On November 8, 1982, the unit began a refueling outage that extended beyond the end of the year.

Details of plant outages for Arkansas 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	3/26/82	1,064.0	S	Unit was brought to cold shutdown to replace the feedwater nozzles in the "A" OTSG.	B	1	Reactor coolant (CC)	Heat exchangers
2	5/25/82	390.5	F	A tube leak developed in the "A" OTSG. Unit was brought to cold shutdown. One tube was leaking. Eddy current testing revealed nine additional tubes that required plugging. Eddy current was used to verify the integrity of other tubes.	A	1	Reactor coolant (CC)	Heat exchangers
3	8/05/82	320.1	F	Malfunction of the main feedwater anticipatory trip system during a power runback for dropped rod recovery caused the unit to trip on false indication of loss of both main feedwater pumps.	A	3	Instrumentation and controls (IA)	Instrumentation and controls
4	8/22/82	17.1	F	ICS overcorrection to header pressure oscillations caused by a malfunction of the main turbine overspeed protection circuit initiated an RPS trip for high reactor power.	A	3	Steam and power conversion (HA)	Turbines
5	9/26/82	21.6	F	Group 6 control rod drive programmer failed causing Group 6 to insert continuously. Reactor was manually tripped.	A	1	Instrumentation and controls (IF)	Instrumentation and controls
6	11/08/82	1,274.0	S	1-R5 refueling outage commences.	C	1	Reactor (RC)	Fuel elements



DESIGN ELEC. RATING - 850 MAX. DEPEND. CAP. - 836 (100%) ARKANSAS 1

ARKANSAS 2

I. Summary

Description	Performance	Outages
Location: Russellville, Arkansas	Net electrical energy generated (MWh): 3,807,388	Total No.: 18
Docket No.: 50-368	Unit availability factor (%): 57.4	Forced: 15
Reactor type: PWR	Unit capacity factor (%) (using MDC): 50.7	Scheduled: 3
Maximum dependable capacity [MW(e)-net]: 858	Unit capacity factor (%) [using design MW(e)]: 47.7	Total hours: 3,732 (42.6%)
Commercial operation: 3/26/80		Forced: 1,529 (17.5%)
Years operating experience: 2.8		Scheduled: 2,203 (25.1%)

II. Highlights

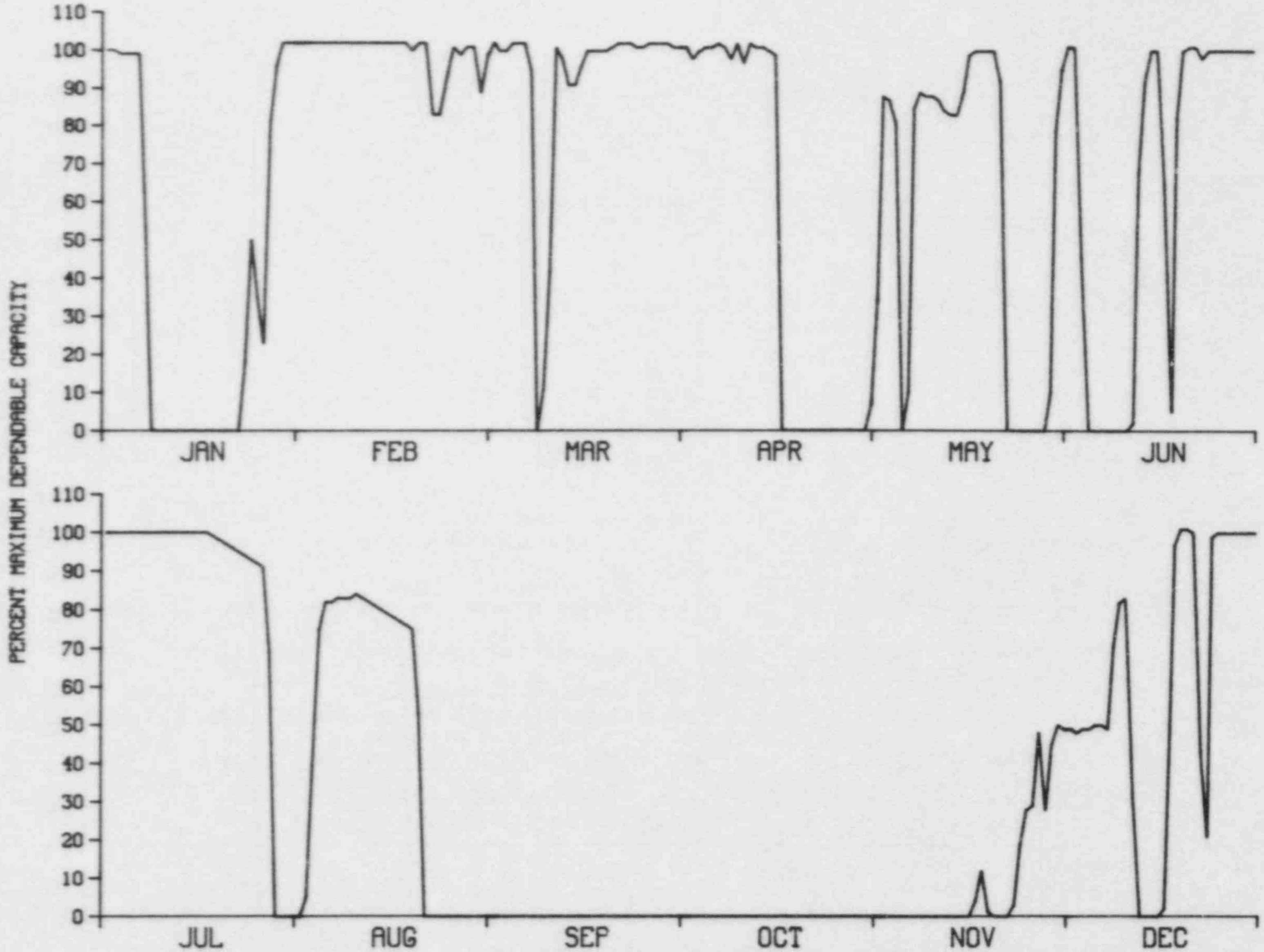
In January 1982 a 16-day shutdown was caused by dryout of coupling fluid in some of the coolant temperature sensors, which led to unacceptably long response times and required replacements of couplant and cleanup activities. A steam generator blowdown piping leak resulted in a two-week outage in late April, and an extended refueling and maintenance outage lasted from August 20 to mid-November. Other significant outages were due to a control-valve failure (six days in May), a packing leak in a motor-operated isolation valve (six days in June), and two control rod drops due to gripper coil failures (six days starting at the end of July and six days in December).

Details of plant outages for Arkansas 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/07/82	370.2	F	RCS RTDs failing response time testing. See LER 50-368/82-001.	A	1	Instrumentation and controls (ID)	Instrumentation and controls
2	1/24/82	6.5	F	Plant trip when both MFW pumps tripped.	A	2	Reactor coolant (CH)	Valves
3	1/25/82	9.9	F	Plant trip when both MFW pumps tripped. Control valve actuator repaired.	A	2	Reactor coolant (CH)	Valves
4	3/07/82	36.2	F	Turbine runback to approx. 20 MW(e) initiated by stator cooling pressure/temperature/flow limits. Reactor tripped on high steam generator level.	A	3	Steam and power conversion (HA)	Instrumentation and controls
5	4/16/82	342.0	F	Steam generator blowdown piping leak. A design change and piping replacement were made.	A	1	Reactor coolant (CC)	Pipes and/or fittings
6	5/04/82	41.7	F	Both MFW pumps tripped on high discharge pressure. This occurred when a regulating valve was inadvertently closed. Operators were counseled concerning the event.	G	3	System code not applicable (ZZ)	Codes not applicable
7	5/22/82	181.0	F	Both MFW pumps tripped on low suction pressure. This was due to a FW flow upset when a valve failed to control properly.	A	3	Reactor coolant (CH)	Valves
8	6/03/82	197.2	F	Packing leak on a motor-operated isolation valve. The valve was repacked.	A	1	Reactor coolant (CA)	Valves

Details of plant outages for Arkansas 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
9	6/16/82	21.3	F	The unit tripped on DNBR. The exact cause is unknown.	H	3	System code not applicable (ZZ)	Codes not applicable
10	7/27/82	138.4	F	PLCEA No. 28 dropped and the unit tripped on low DNBR. The dropped rod was due to a failure of the CEDM upper gripper coils.	A	3	Reactor (RB)	Conrol rod drive mechanisms
11	8/20/82	2,082.9	S	Refueling/maintenance.	C	1	Reactor (RC)	Fuel elements
12	11/12/82	8.6	S	Low power physics testing.	B	9	System code not applicable (ZZ)	Codes not applicable
13	11/15/82	8.6	F	Power supply (PS-12) to "B" channel PPS failed. Power supply was replaced.	A	9	Reactor coolant (CB)	Instrumentation and controls
14	11/16/82	8.0	F	Unit tripped on high SG level during low power operations.	H	3	Steam and power conversion (HB)	Heat exchangers
15	11/18/82	111.8	S	Unit shutdown to repair in-core detectors and MSR safety valve.	B	1	Instrumentation and controls (IA)	Instrumentation and controls
16	11/27/82	9.4	F	Unit trip on low DNBR after an RCP trip due to sensitive relay. The relay was replaced.	A	3	Reactor coolant (CB)	Relays
17	12/11/82	131.1	F	Dropped CEA due to a failed upper gripper coil. The coil was replaced.	A	3	Reactor (RB)	Conrol rod drive mechanisms
18	12/22/82	27.3	F	Spurious trip. The exact cause was undetermined.	H	3	System code not applicable (ZZ)	Codes not applicable



DESIGN ELEC. RATING - 912 MAX. DEPEND. CAP. - 858 (100%) ARKANSAS 2

BEAVER VALLEY 1

I. Summary

Description

Location: Shippingport, Pennsylvania
Docket No.: 50-334
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 810
Commercial operation: 10/01/76
Years operating experience: 6.6

Performance

Net electrical energy generated (MWh): 3,688,163
Unit availability factor (%): 416
Unit capacity factor (%) (using MDC): 37.9
Unit capacity factor (%) [using design MW(e)]: 36.0

Outages

Total No.: 11
- Forced: 9
- Scheduled: 2

Total hours: 5,112[a] (58.3%)
- Forced: 205 (2.3%)
- Scheduled: 4,906[a] (56.0%)

II. Highlights

Beaver Valley 1 remained off line for more than the first half of 1982 in a refueling and major modification outage that had begun the previous year on December 25. After startup in mid-July, the plant experienced only minor difficulties for the rest of the year, with the exception of a two-week shutdown in August and September which began as the result of an apparent drop of a control rod and then was extended to permit repair of tubes in one of the steam generators.

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[a]Includes 4,560 h in 1982 from continuation of 12/25/82 shutdown.

Details of plant outages for Beaver Valley 1

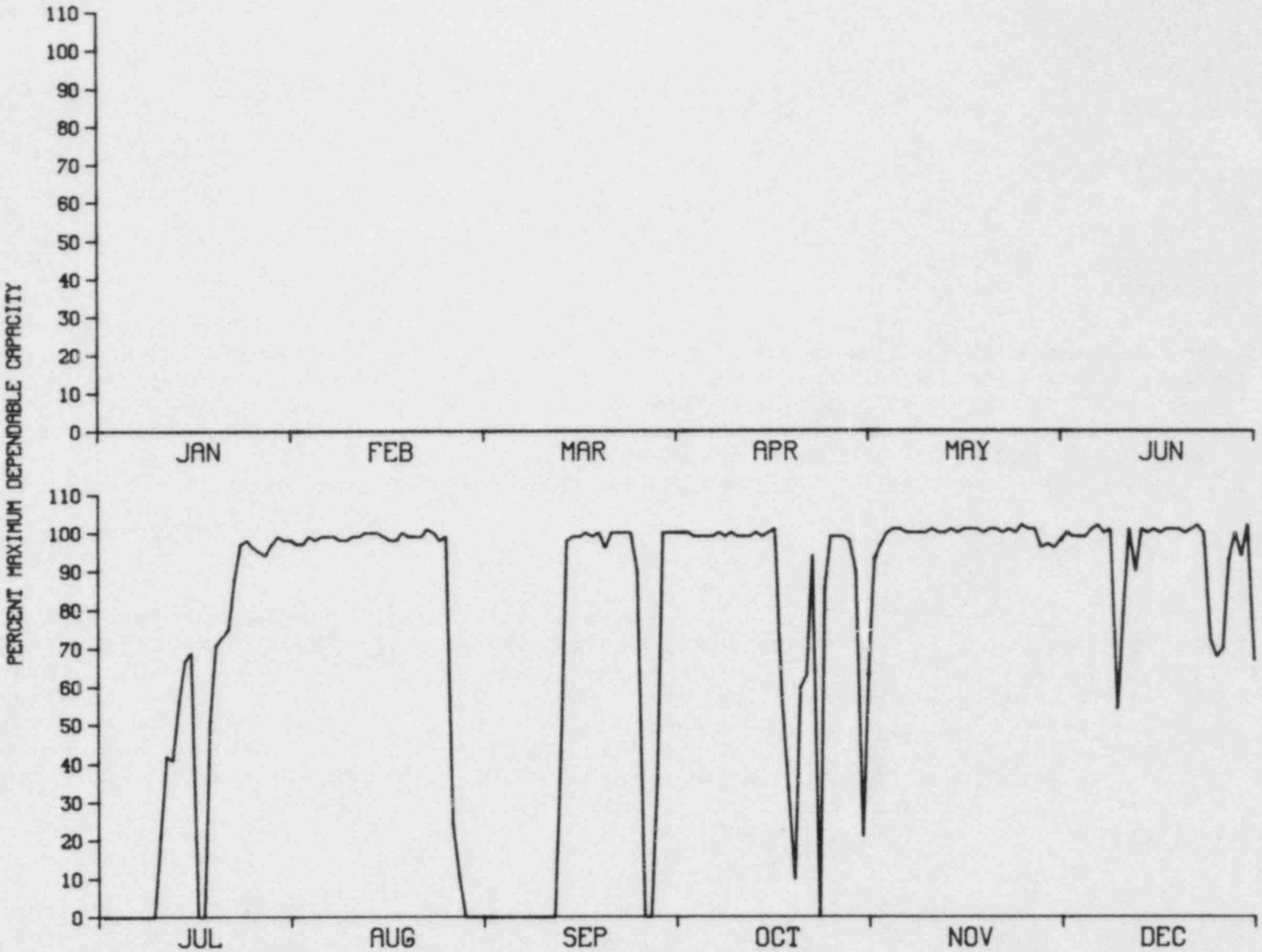
No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	12/25/81	4,560.0	S	Conclusion of second refueling and major modification outage.	C	4	Reactor (RC)	Fuel elements
2	7/10/82	1.8	S	Turbine overspeed trip test. Main unit generator taken off line, but the reactor was not tripped.	B	9	System code not applicable (ZZ)	Codes not applicable
3	7/15/82	51.8	F	Water was found in the cable and connector of the N-41 detector (model No. WL-23-743). Both the N-41 detector, its associated cable, and the field cable connector were replaced. The water was a result of in-leakage through the refueling cavity seal during the last refueling outage.	A	1	Instrumentation and controls (IA)	Instrumentation and controls
4	7/18/82	1.5	F	Control problems with bypass flow control valves in the automatic mode. Station tripped on high/high B steam generator level.	A	3	Reactor coolant (CH)	Valve operators
5	8/26/82	10.7	F	Main feedwater regulating valve (FCV-1FW-478) closed after the air inlet nipple to the valve diaphragm was sheared off, resulting in the loss of air pressure to the valve diaphragm, the valve closure, and the loss of feedwater flow to the 1A main steam generator. The sheared nipple was replaced and air pressure to the valve diaphragm was restored.	A	3	Reactor coolant (CH)	Valves

Details of plant outages for Beaver Valley 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
6	8/27/82	344.5	S	Manually tripped the reactor due to an apparent dropped rod. Plant remained shut down for scheduled steam generator (RC-E-1C) tube repair.	B	2	Reactor coolant (CC)	Heat exchangers
7	9/11/82	3.0	F	Tripped on low-low level indication in the 1C steam generator due to slow response time of the bypass feedwater control valves. Investigation is under way to reduce response time.	A	3	Reactor coolant (CH)	Valves
8	9/11/82	19.1	F	Turbine trip due to high level indication in the 1B steam generator, again due to slow response of bypass feedwater control valves in manual.	A	3	Reactor coolant (CH)	Valves
9	9/25/82	58.7	F	While troubleshooting the main feedwater regulating valve (FCV-FW-4981) (because it was not controlling at its programmed set point), the programmed signal was removed. This also removed the programmed signal from the bypass feedwater regulating valve (FCV-FW-499) causing it to close.	G	3	Reactor coolant (CH)	Valves
10	10/18/82	26.4	F	Tripped on a high-high level in the "B" steam generator due to control problems with the "B" main feedwater regulating valve.	A	3	Reactor coolant (CH)	Valves

Details of plant outages for Beaver Valley 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
11	10/21/82	7.6	F	The inadvertent closure of IA-115, on the outlet of the instrument air bypass filters (IA-FD-1, 2) with the instrument air dryers in the bypass mode, resulted in low air pressure in the instrument air receiver tank and the temporary loss of instrument air.	G	3	Auxiliary process (PA)	Air dryers
12	10/22/82	26.5	F	Reduced reactor power to below 10% and tripped the turbine to investigate possible reactor coolant pump (RC-P-1A) seal failure.	A	3	System code not applicable (ZZ)	Codes not applicable



DESIGN ELEC. RATING - 852 MAX. DEPEND. CAP. - 810 (100%) BEAVER VALLEY 1

BIG ROCK POINT

I. Summary

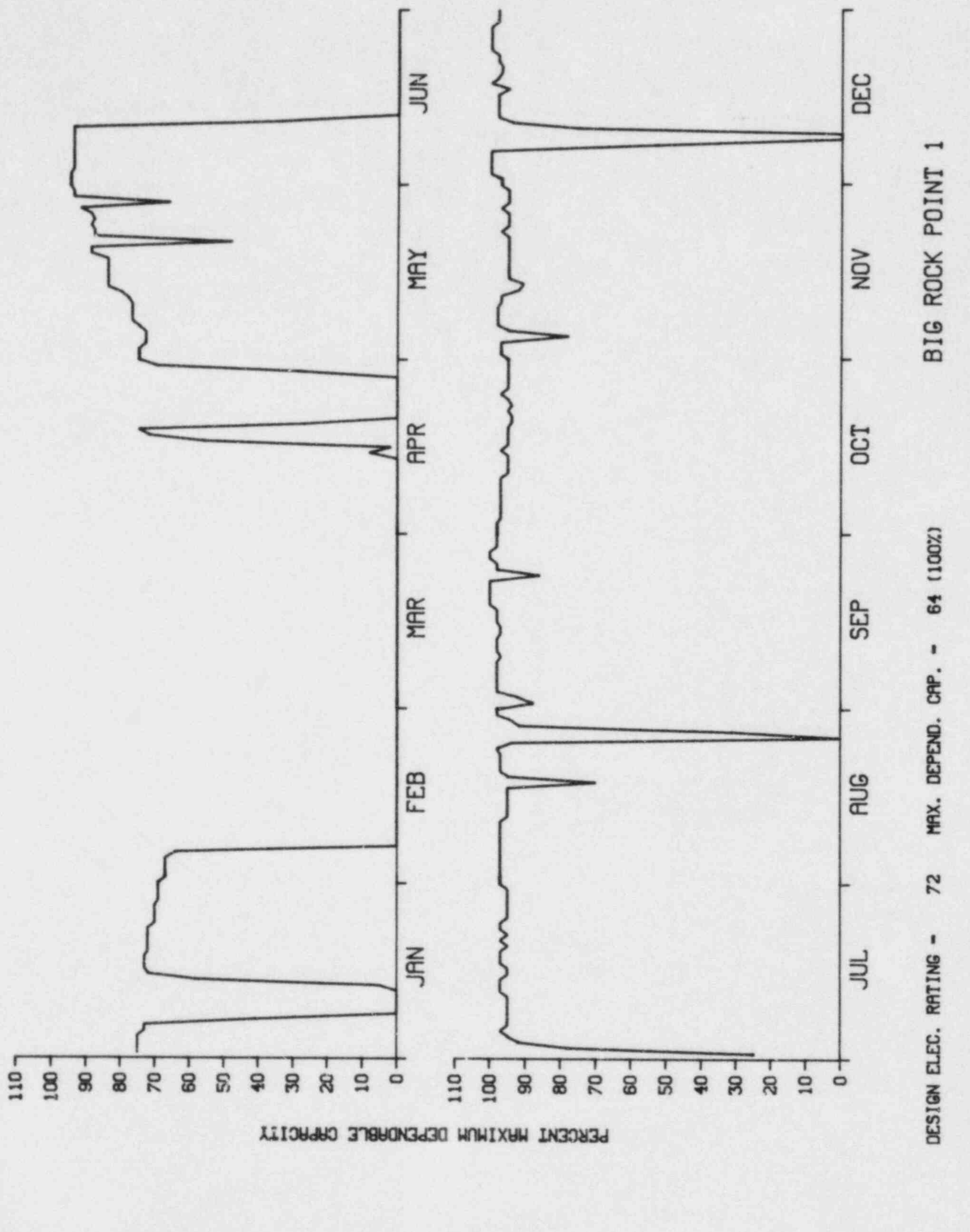
Description	Performance	Outages
Location: Charlevoix, Michigan	Net electrical energy generated (MWh): 359,383	Total No.: 6
Docket No.: 50-155	Unit availability factor (%): 70.8	Forced: 5
Reactor type: BWR	Unit capacity factor (%) (using MDC): 64.2	Scheduled: 1
Maximum dependable capacity [MW(e)-net]: 63	Unit capacity factor (%) [using design MW(e)]: 57.1	Total hours: 2,562 (29.2%)
Commercial operation: 3/29/63		Forced: 922 (10.5%)
Years operating experience: 20.1		Scheduled: 1,640 (18.7%)

II. Highlights

Big Rock Point operated with very few major shutdowns during 1982, except for a refueling/maintenance outage which began in early February and lasted about ten weeks. A steam leak from an isolation valve caused a renewed shutdown in April shortly after the termination of the refueling outage, and a fire in an electrical generator exciter in June caused a further loss of 20 days. This plant, the oldest operating boiling-water reactor in the United States, with a very small power rating as compared with those of later designs, achieved plant availability and capacity factors above the national average for BWR plants.

Details of plant outages for Big Rock Point 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/07/82	147.2	F	Caused by a faulty reset switch on channel 2.	A	2	Instrumentation and controls (IA)	Instrumentation and controls
2	2/05/82	1,639.6	S	Entered refueling and maintenance outage.	C	1	Reactor (RC)	Fuel elements
3	4/19/82	202.6	F	Steam leak on isolation valve.	A	1	Reactor (RC)	Fuel elements
4	6/11/82	475.3	F	Fire in the exciter.	A	2	Steam and power conversion (HA)	Generators
5	8/26/82	35.6	F	Extraction line repair.	B	1	Steam and power conversion (HA)	Pipes and/or fittings
6	12/07/82	61.2	F	Broken terminal block created a false turbine stop valve close signal to the main generator output breaker. This caused a turbine trip and subsequent reactor scram on high flux. The broken terminal block was replaced.	A	3	Steam and power conversion (HB)	Circuit closers/ interrupters


PERCENT MAXIMUM DEPENDABLE CAPACITY
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DESIGN ELEC. RATING - 72 MAX. DEPEND. CAP. - 64 (100%)
BIG ROCK POINT 1

BROWNS FERRY 1

I. Summary

Description	Performance	Outages
Location: Decatur, Alabama	Net electrical energy generated (MWh): 7,880,870	Total No.: 17
Docket No.: 50-259	Unit availability factor (%): 91.0	Forced: 17
Reactor type: BWR	Unit capacity factor (%) (using MDC): 84.5	Scheduled: 0
Maximum dependable capacity [MW(e)-net]: 1,065	Unit capacity factor (%) [using design MW(e)]: 84.5	Total hours: 790 (9.0%)
Commercial operation: 8/01/74		Forced: 790 (9.0%)
Years operating experience: 9.2		Scheduled: 0 (0%)

II. Highlights

Browns Ferry 1 operated very reliably during 1982, achieving the second-highest total electricity output among the BWRs of the United States and an availability factor above 90% (a level reached by only 4 among the 24 BWRs). This record was due in part to the absence of a refueling outage during the year. The longest outage, about 11 days in August, was due to a containment capability problem and was also used for other maintenance and repairs. A four-day outage in November was originally caused by an instrument fault that falsely signaled excessive turbine vibration; this outage was also used for a variety of other maintenance activities.

Details of plant outages for Browns Ferry 1

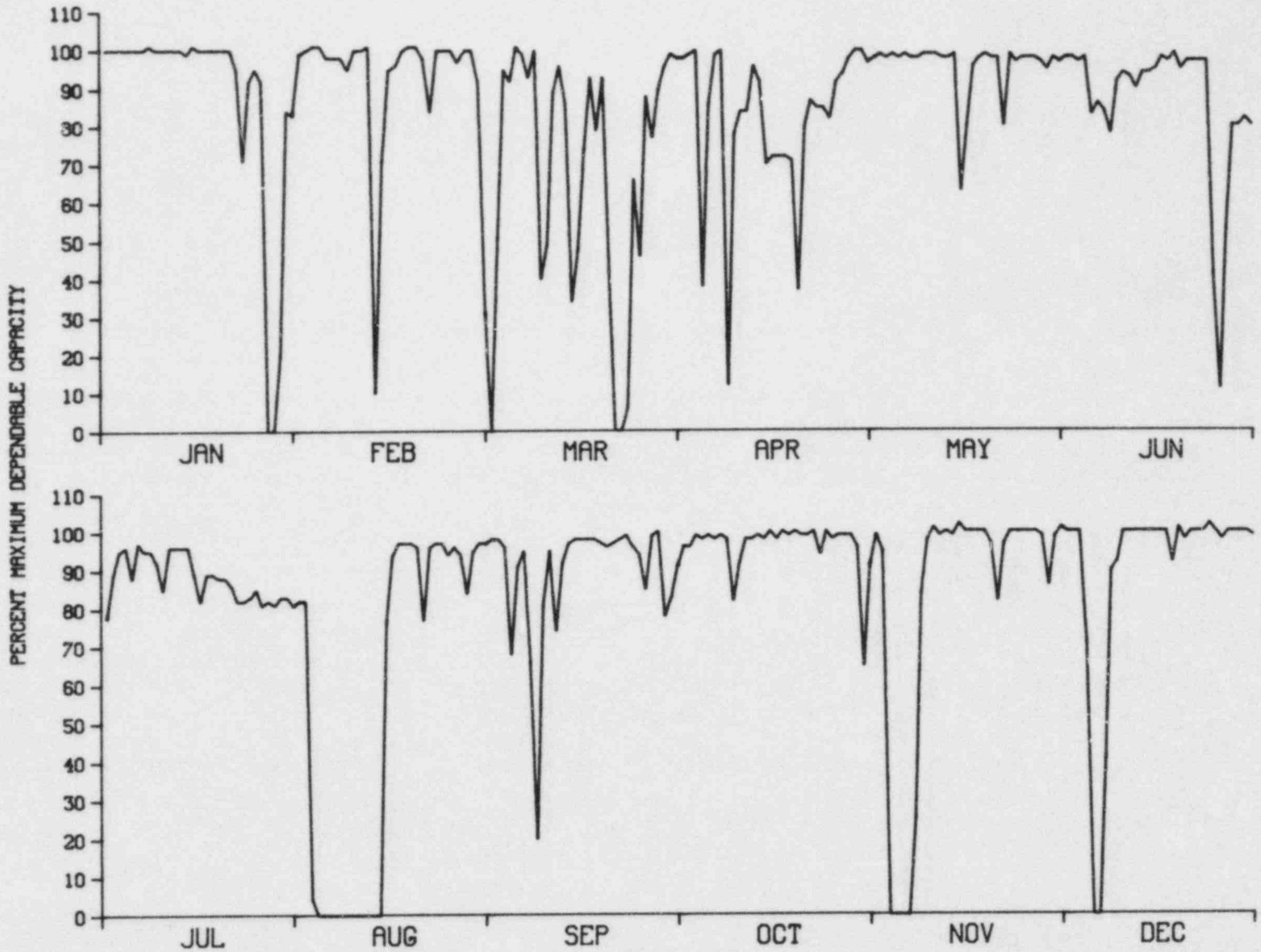
No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/26/82	63.4	F	Reactor scram when maintenance dropped a wrench on panel 25-6a causing reactor high pressure signal.	H	3	Instrumentation and controls (IB)	Instrumentation and controls
2	2/12/82	19.0	F	Reactor scram when turbine tripped on moisture separator high level.	A	3	Steam and power conversion (HA)	Other components
3	2/28/82	43.9	F	Reactor scram due to control air leak in dry well. Leak was in solenoid for core spray testable check valve 1-75-26.	A	2	Engineered safety features (SB)	Valves
4	3/09/82	20.0	F	Reactor scram due to loss of EHC oil pressure when maintenance personnel were attempting to change oil filter.	G	3	Instrumentation and controls (IE)	Pipes and/or fittings
5	3/14/82	13.5	F	Reactor scram due to false indication of steam line low pressure.	A	3	Instrumentation and controls (IE)	Instrumentation and controls
6	3/15/82	11.9	F	Reactor scram on reactor high water level when maintenance personnel were performing SI 4.2.B-69.	G	3	System code not applicable (ZZ)	Codes not applicable
7	3/20/82	80.9	F	Reactor scram when vent line on valve 1-69-1 broke causing high dry-well leakage.	A	2	Engineered safety features (SB)	Pipes and/or fittings
8	3/25/82	8.5	F	Reactor scram to repair leak on EHC control valve servo valve.	A	2	Instrumentation and controls (IE)	Valves
9	4/04/82	13.6	F	Reactor scram on generator load reject due to activation of the generator field ground relay.	A	3	Steam and power conversion (HA)	Relays

Details of plant outages for Browns Ferry 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
10	4/08/82	18.6	F	Reactor scram when the turbine tripped on generator power load unbalance.	A	3	Steam and power conversion (HA)	Generators
11	4/19/82	13.1	F	Reactor scram due to operator error. While "C" hot-well pump was off and tagged, "A" RFP was tripped for maintenance. The operator inadvertently closed steam to "C" RFP.	G	3	Reactor coolant (CB)	Codes not applicable
12	6/24/82	26.2	F	Reactor scram due to A-1 and A-2 high-pressure feedwater heater leaks.	A	2	Reactor coolant (CH)	Heaters, electric
13	8/03/82	267.0	F	Reactor scram due to failure of SI 4.7.C.1, containment capabilities, maintenance on IRMs and PDI-15 and 16.	B	2	Engineered safety features (SD)	Codes not applicable
14	9/07/82	20.9	F	Reactor scram due to low scram pilot air header pressure.	H	3	Instrumentation and controls (IA)	Valves
15	11/03/82	108.7	F	Reactor scram due to false high turbine vibration. The unit remained off-line for change-out of spare 500-kV transformer to 1B, replacement of HEPA filter on primary containment purge assembly, replacement of connectors on (A and B) IRMs, and replacement of coil on "B" IRM drive light.	A	3	Instrumentation and controls (IF)	Turbines

Details of plant outages for Browns Ferry 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
16	12/04/82	53.9	F	Reactor scram to repair leak on discharge line of "B" reactor feedwater pump.	B	1	Steam and power conversion (HH)	Pipes and/or fittings
17	12/06/82	6.9	F	Reactor scram on "A" and "F" IRM spike when control rod 18-51 double-notched.	A	3	Reactor (RB)	Control rods



DESIGN ELEC. RATING - 1065 MAX. DEPEND. CAP. - 1065 (100%) BROWNS FERRY 1

BROWNS FERRY 2

I. Summary

Description	Performance	Outages
Location: Decatur, Alabama	Net electrical energy generated (MWh): 4,450,929	Total No.: 12
Docket No.: 50-260	Unit availability factor (%): 54.5	Forced: 11
Reactor type: BWR	Unit capacity factor (%) (using MDC): 47.7	Scheduled: 1
Maximum dependable capacity [MW(e)-net]: 1,065	Unit capacity factor (%) [using design MW(e)]: 47.7	Total hours: 3,964[a] (45.2%)
Commercial operation: 3/01/75		Forced: 264[a] (3.0%)
Years operating experience: 8.3		Scheduled: 3,700 (42.2%)

II. Highlights

The unit was operating with diminishing power during the first seven months of 1982, as it coasted along toward the refueling outage that began on July 30 and lasted all the rest of the year. Prior to the refueling outage, the operation was almost completely free of shutdowns, except for some brief interruptions in January mostly involving moisture separator problems.

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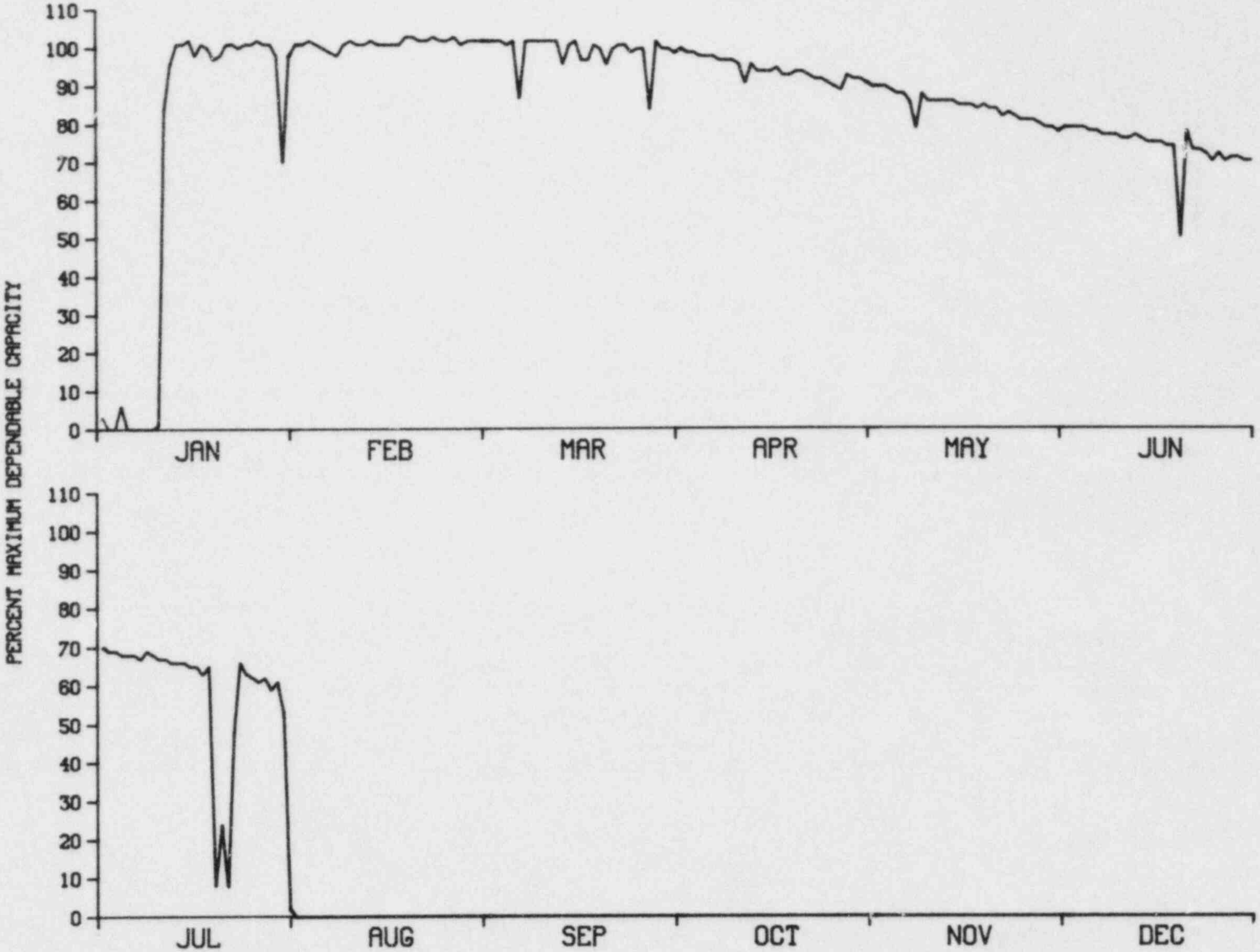
[a]Includes 8 h in 1982 from continuation of the 12/29/81 outage.

Details of plant outages for Browns Ferry 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	12/29/81	8.5	F	The unit remained down for maintenance on No. 2 main transformer.	G	4	Electric power (EA)	Transformers
2	1/01/82	9.3	F	Reactor scram when IRMs G and H exceeded 120/125 of their selected range.	A	9	Reactor (RB)	Control rods
3	1/01/82	14.2	F	Reactor scram when turbine tripped on moisture separator high level.	A	9	Steam and power conversion (HA)	Other components
4	1/01/82	2.7	F	Turbine trip for work on PCB-224 (no reactor scram).	A	9	Steam and power conversion (HA)	Instrumentation and controls
5	1/02/82	36.4	F	Reactor scram for maintenance on A2 moisture separator high level dump valve.	A	9	Reactor coolant (CC)	Valves
6	1/04/82	18.3	F	Turbine trip (manual) due to water chemistry problem and to repair condenser tube leaks.	A	2	Auxiliary process (PC)	Heat exchangers
7	1/05/82	132.2	F	Reactor scram to repair condenser tube leaks.	A	9	Steam and power conversion (HC)	Heat exchangers
8	7/19/82	23.6	F	Reactor scram due to failure of the main steam pressure sensing line for the EHC system.	A	3	Steam and power conversion (HA)	Instrumentation and controls
9	7/20/82	12.5	F	Reactor scram while performing SI 4.1.A.11 (MSIV isolation valve closure).	H	3	Reactor coolant (CD)	Codes not applicable
10	7/21/82	11.2	F	Reactor scram on condenser low vacuum (no generator synch.).	H	3	Steam and power conversion (HC)	Codes not applicable
11	7/21/82	9.6	F	Reactor scram on condenser low vacuum.	H	3	Steam and power conversion (HC)	Codes not applicable

Details of plant outages for Browns Ferry 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
12	7/22/82	1.8	F	Turbine tripped due to isolation of third stage SJAE "B" (no reactor scram) (generator off-line).	H	9	Steam and power conversion (HA)	Other components
13	7/30/82	3,700.3	S	Reactor scram to accommodate EOC-4 refuel outage.	C	2	Reactor (RC)	Fuel elements



DESIGN ELEC. RATING - 1065 MAX. DEPEND. CAP. - 1065 (100%)

BROWNS FERRY 2

BROWNS FERRY 3

I. Summary

Description	Performance	Outages
Location: Decatur, Alabama	Net electrical energy generated (MWh): 4,892,858	Total No.: 8
Docket No.: 50-296	Unit availability factor (%): 57.3	Forced: 7
Reactor type: BWR	Unit capacity factor (%) (using MDC): 52.4	Scheduled: 1
Maximum dependable capacity [MW(e)-net]: 1,065	Unit capacity factor (%) [using design MW(e)]: 52.4	Total hours: 3,738[a] (42.7%)
Commercial operation: 3/01/77		Forced: 1,300 (14.8%)
Years operating experience: 6.3		Scheduled: 2,438[a] (27.8%)

II. Highlights

Browns Ferry 3 started 1982 in a refueling outage that had already occupied the last two months of 1981 and extended to mid-May 1982. Thereafter the plant operated with very few interruptions for the rest of the year. In August the plant was down during two outages totaling about two weeks due to problems with assurance of secondary containment capability and for a variety of other maintenance and repair activities. Thereafter operation was virtually uninterrupted for the rest of the year.

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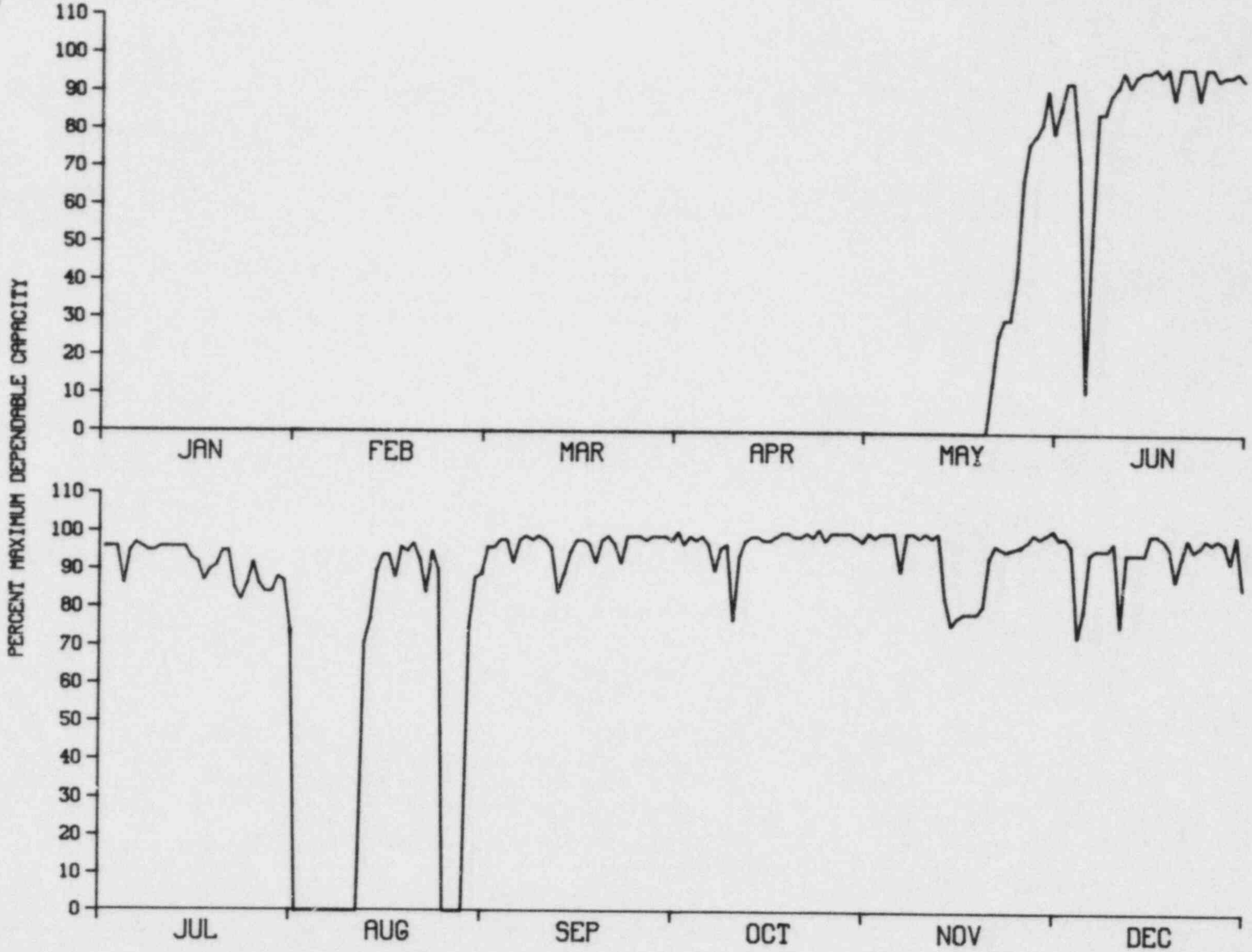
[a]Includes 2,347 h in 1982 from continuation of 10/30/81 outage.

Details of plant outages for Browns Ferry 3

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	10/30/81	2,436.9	S	End of cycle 4 refueling outage.	C	4	Reactor (RC)	Fuel elements
2	4/02/82	921.5	F	Tripped main turbine due to high vibration. Manually scrammed reactor due to high vibration on main turbine.	A	9	Steam and power conversion (HA)	Turbines
3	5/21/82	0.6	S	Generator off line for turbine overspeed trip test.	B	1	Steam and power conversion (HA)	Turbines
4	6/05/82	22.3	F	Reactor scram while changing a blown fuse in 250-V trip bus causing a turbine trip.	A	3	Instrumentation and controls (IA)	Instrumentation and controls
5	7/31/82	266.5	F	Reactor scram due to failure of SI 4.7.c.1 (secondary containment capabilities).	H	2	Engineered safety features (SA)	Codes not applicable
6	8/24/82	73.1	F	Reactor scram due to steam leak in dry-well. Also, installed temporary vibration instrumentation on "B" recirculation pump, replaced MSRV air operators and ADS valves, and repaired HCV 69-500.	H	2	Reactor coolant (CG)	Valves
7	8/28/82	11.7	F	Tripped turbine due to problems with stop and control valves; no reactor scram. Also investigated problems with EHC system.	A	9	Steam and power conversion (HB)	Valves
8	8/28/82	4.2	F	Turbine tripped due to No. 2 stop valve not going fully closed; no reactor scram.	A	9	Steam and power conversion (HB)	Valves
9	8/28/82	1.0	F	Turbine tripped; No. 2 stop valve closed; no reactor scram.	A	9	Steam and power conversion (HB)	Valves



DESIGN ELEC. RATING - 1065 MAX. DEPEND. CAP. - 1065 (100%)

BROWNS FERRY 3

BRUNSWICK 1

I. Summary

Description

Location: Southport, North Carolina
Docket No.: 50-325
Reactor type: BWR
Maximum dependable capacity [MW(e)-net]: 790
Commercial operation: 3/18/77
Years operating experience: 6.1

Performance

Net electrical energy generated (MWh): 2,921,621
Unit availability factor (%): 62.0
Unit capacity factor (%) (using MDC): 42.2
Unit capacity factor (%) [using design MW(e)]: 40.6

Outages

Total No.: 13
  Forced: 11
  Scheduled: 2
Total hours: 3,330 (38.0%)
  Forced: 2,625 (30.0%)
  Scheduled: 705 (8.0%)

II. Highlights

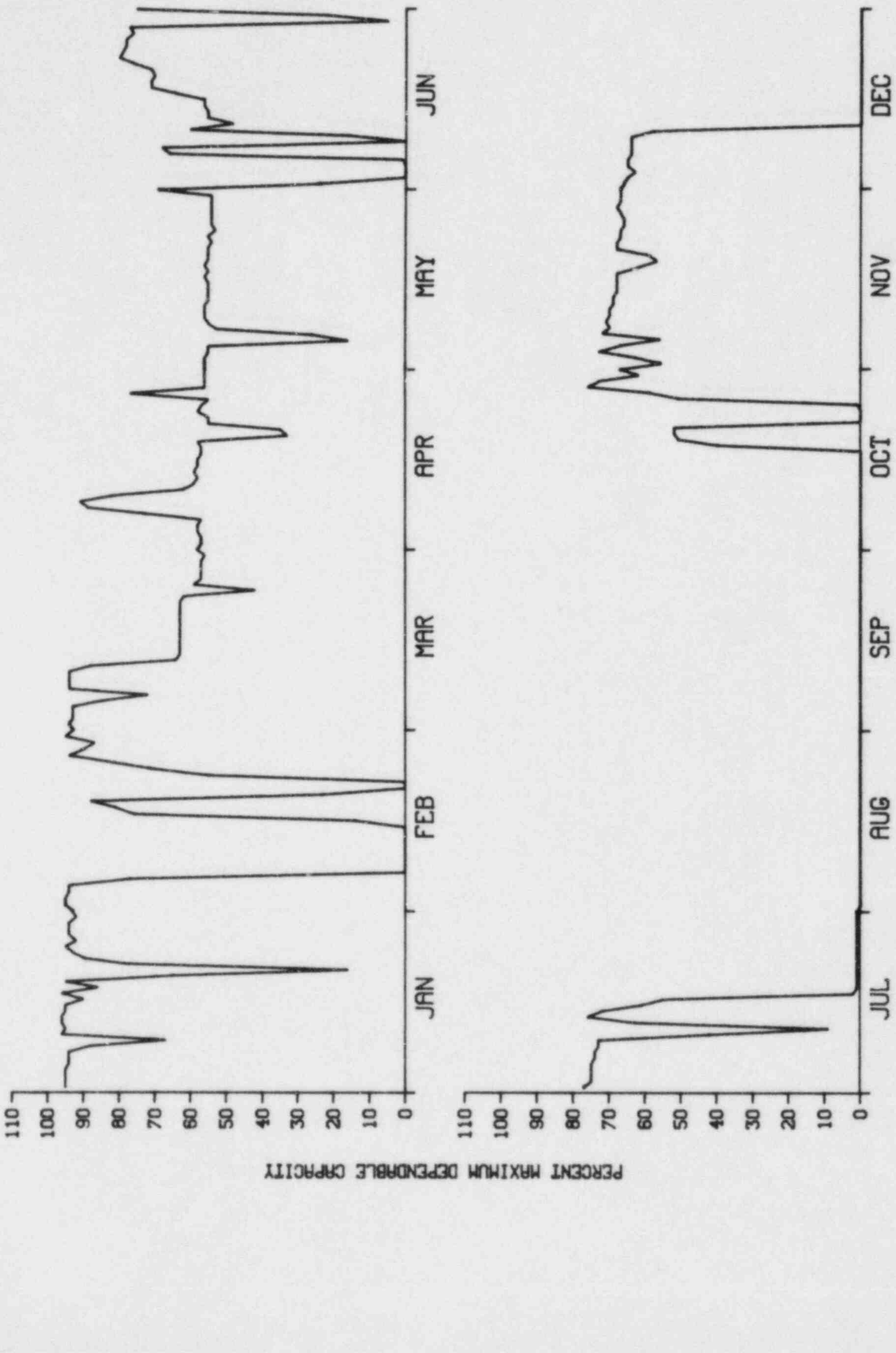
During 1982 Brunswick 1 operated at less than maximum rated power for extended periods in order to defer the end-of-cycle shutdown and refueling outage which finally began on December 11. From mid-July to mid-October the plant was shut down for in-service inspection and leak rate testing. These were the only major outages during the year.

Details of plant outages for Brunswick 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	2/05/82	202.1	S	Snubber outage. Periodic inspection of safety-related snubbers are a requirement under Tech. Spec. 3/4.7.5 to ensure operability of snubbers.	B	1	Engineered safety features (SH)	Shock suppressors and supports
2	2/18/82	58.2	F	Control valve testing to get No. 2 turbine control valve to close beyond 95% open point. No. 2 turbine control valve has been electrically gagged shut until the valve can be inspected and repaired during an outage. 1B reactor recirc. seal leakage to DWEDT.	A	3	Steam and power conversion (HA)	Turbines
3	4/19/82	16.0	F	The dc breaker inadvertently opened causing loss of dc and reactor trip. Shift had a meeting to train on the clearance procedures and to discuss past problems.	G	3	Reactor (RB)	Circuit closers/ interrupters
4	5/05/82	25.6	F	Low condenser vacuum switch D failed. Replaced low condenser vacuum switch 56D with a new switch.	A	3	Other (XX)	Circuit closers/ interrupters
5	6/01/82	105.8	F	Condenser low vacuum turbine caused pressure transmitter failure. Checked connections and covers on all switches and flex in the area. Covers were put back in place.	A	3	Steam and power conversion (HC)	Instrumentation and controls
6	6/07/82	37.0	F	Reactor scram, blown fuse to MSIV. (Report will be submitted when investigation is complete.)	A	3	Reactor coolant (CC)	Circuit closers/ interrupters

Details of plant outages for Brunswick 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
7	6/28/82	31.8	F	Reactor scram while attempting to start 1A CW pump. (Corrective action incomplete. Complete report will be submitted when investigation is complete.)	A	3	Reactor coolant (CB)	Pumps
8	7/10/82	24.2	F	Turbine trip as a result of defective tracking rectifier. Defective rectifier was taken out of service. Presently EHC is being fed by alternate until rectifier can be repaired.	A	3	Steam and power conversion (HA)	Turbines
9	7/16/82	2,053.0	F	Local leak rate testing.	B	1	Other (XX)	Codes not applicable
10	10/10/82	101.0	F	Reactor scram (manual) due to relief valve F013J stuck open. I&C replaced solenoid valve, and as a precautionary measure mechanical maintenance replaced the pilot assembly.	A	9	Instrumentation and controls (IE)	Valves
11	10/14/82	78.1	F	Reactor shutdown due to problems with F013D and "E" safety relief valve. Action dependent on outcome of root cause investigation.	A	9	Instrumentation and controls (IE)	Valves
12	10/21/82	94.3	F	Reactor scram. Turbine load unbalance test with CV closure.	B	3	Steam and power conversion (HA)	Turbines
13	12/11/82	502.4	S	Refueling/maintenance outage.	C	2	Reactor (RC)	Fuel elements



DESIGN ELEC. RATING - 821 MAX. DEPEND. CAP. - 790 (100%)

BRUNSWICK 1

BRUNSWICK 2

I. Summary

Description	Performance	Outages
Location: Southport, North Carolina	Net electrical energy generated (MWh): 1,910,099	Total No.: 11
Docket No.: 50-324	Unit availability factor (%): 38.6	Forced: 9
Reactor type: BWR	Unit capacity factor (%) (using MDC): 27.6	Scheduled: 2
Maximum dependable capacity [MW(e)-net]: 790	Unit capacity factor (%) [using design MW(e)]: 26.6	Total hours: 5,379 (61.4%)
Commercial operation: 11/03/75		Forced: 1,478 (16.9%)
Years operating experience: 7.7		Scheduled: 3,901 (44.5%)

II. Highlights

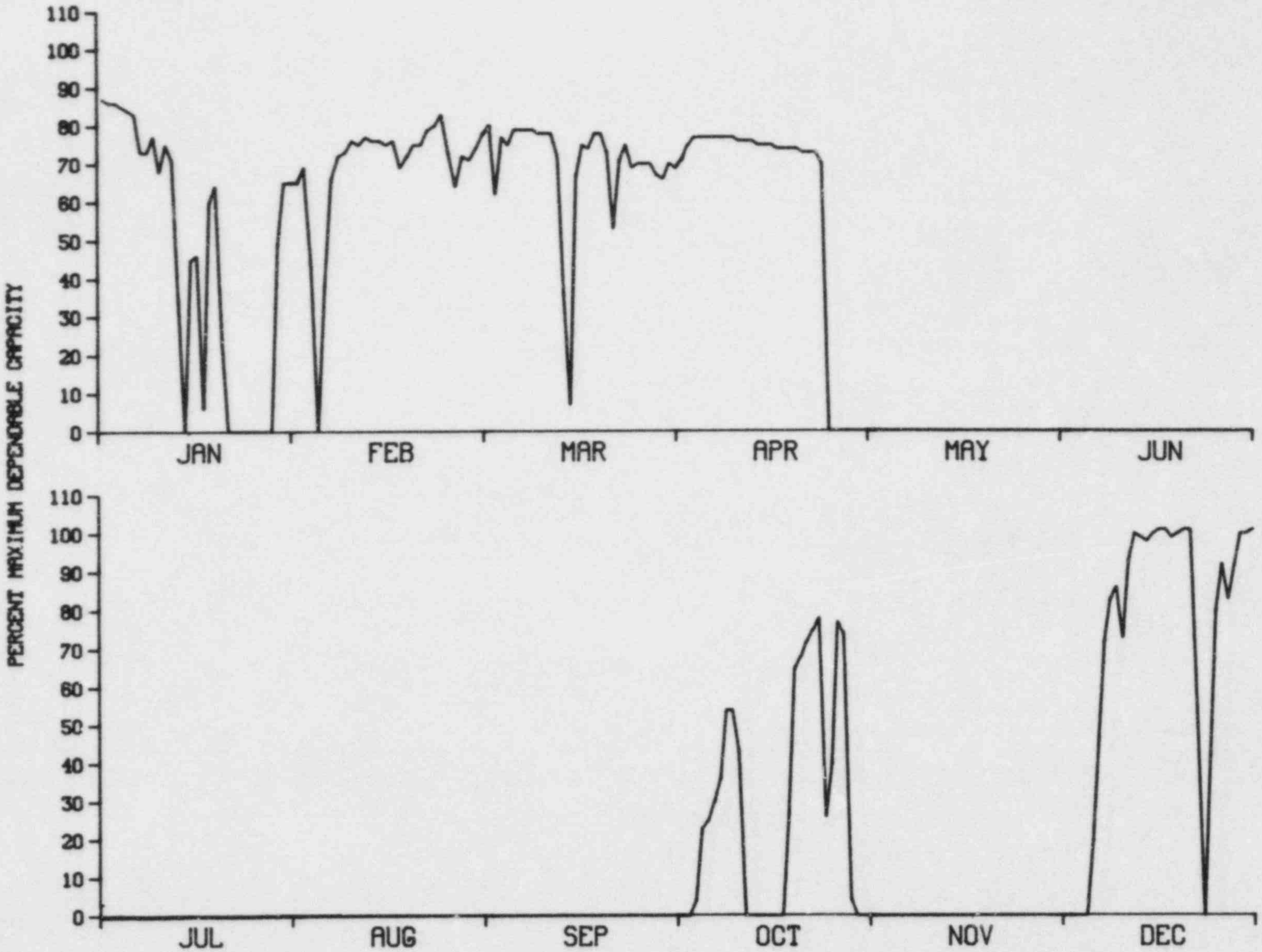
Brunswick 2 was shut down for a refueling outage for almost half a year from late April into October. A second major outage in late October that extended all through November and into December (a total of five and a half weeks) was caused by difficulties with a traveling in-core probe (TIP). Mechanical vibrations caused by pipe hanger modification work affected nearby scram discharge volume level switches, causing an eight-and-a-half-day outage in January, and cracks in heater drain piping required a one-week shutdown in October. As a result, Brunswick 2's annual average capacity factor was below 30%.

Details of plant outages for Brunswick 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/13/82	38.5	F	Reactor scram-recirc. pump runaway. Checked operation of 2A scoop tube positioner MS/V converter and control loop. Also inspected feedback tach brushes/commutator.	A	3	Reactor coolant (CB)	Pumps
2	1/16/82	25.1	F	I&C replaced SJAE low-pressure switch 2-MS-PSL-890. Replaced FJ3 in cabinet J17 to restore SJAE logic. Complete installation of new switch as per plant mod. which upgrades pressure capacity of switch.	H	3	Instrumentation and controls (IB)	Instrumentation and controls
3	1/20/82	205.0	F	Vibration on scram discharge volume level switches during pipe hanger mod. caused scram. Workers were told to finish hanger mod. on switches while unit was down. No work on hangers by the switches if unit is up.	H	3	Instrumentation and controls (IE)	Instrumentation and controls
4	2/03/82	36.0	F	Reactor scram — main steam line high radiation trip. RC&T called to sample reactor coolant (feedwater, heater drains and RWCU return). Main steam line also if possible. Followed EI 31 and 21.	A	3	Reactor coolant (CC)	Penetrations, primary containment
5	3/13/82	23.6	F	Reactor scram on LLI signal at a more conservative set point than required while placing a second RFP in service. N017 level switches were calibrated and set points readjusted.	A	3	Instrumentation and controls (IA)	Instrumentation and controls
6	4/24/82	3,899.7	S	Refueling.	C	2	Reactor (RC)	Fuel elements

Details of plant outages for Brunswick 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
7	10/10/82	175.7	F	Reactor scram. Cracks in heater drain piping. Loss of E-3 bus. #3 Diesel generator output breaker would not close on E-3 bus.	A	3	Engineered safety features (SB)	Pipes and/or fittings
8	10/21/82	1.3	S	Unit separated from grid for routine overspeed trip test.	B	1	Instrumentation and controls (IE)	Other components
9	10/24/82	15.5	F	Normal reactor shutdown in order to lower delta T between steam dome saturation temperature and bottom head drain.	A	2	Other (XX)	Other components
10	10/28/82	910.7	F	TIP outage in progress.	A	2	Instrumentation and controls (IA)	Instrumentation and controls
11	12/22/82	47.8	F	Reactor scram, power unbalance scram. Determined cause of scram to be technician error. Restarted unit and (1) required relay crew technicians working at BSEP to use BSEP procedures (2) required relay calibration be done at shutdown.	A	3	Electric power (EB)	Generators



DESIGN ELEC. RATING - 821 MAX. DEPEND. CAP. - 790 (100%)

BRUNSWICK 2

CALVERT CLIFFS 1

I. Summary

Description

Location: Lusby, Maryland
Docket No.: 50-317
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 810
Commercial operation: 5/08/75
Years operating experience: 8.0

Performance

Net electrical energy generated (MWh): 5,362,175
Unit availability factor (%): 73.3
Unit capacity factor (%) (using MDC): 74.2
Unit capacity factor (%) [using design MW(e)]: 74.4

Outages

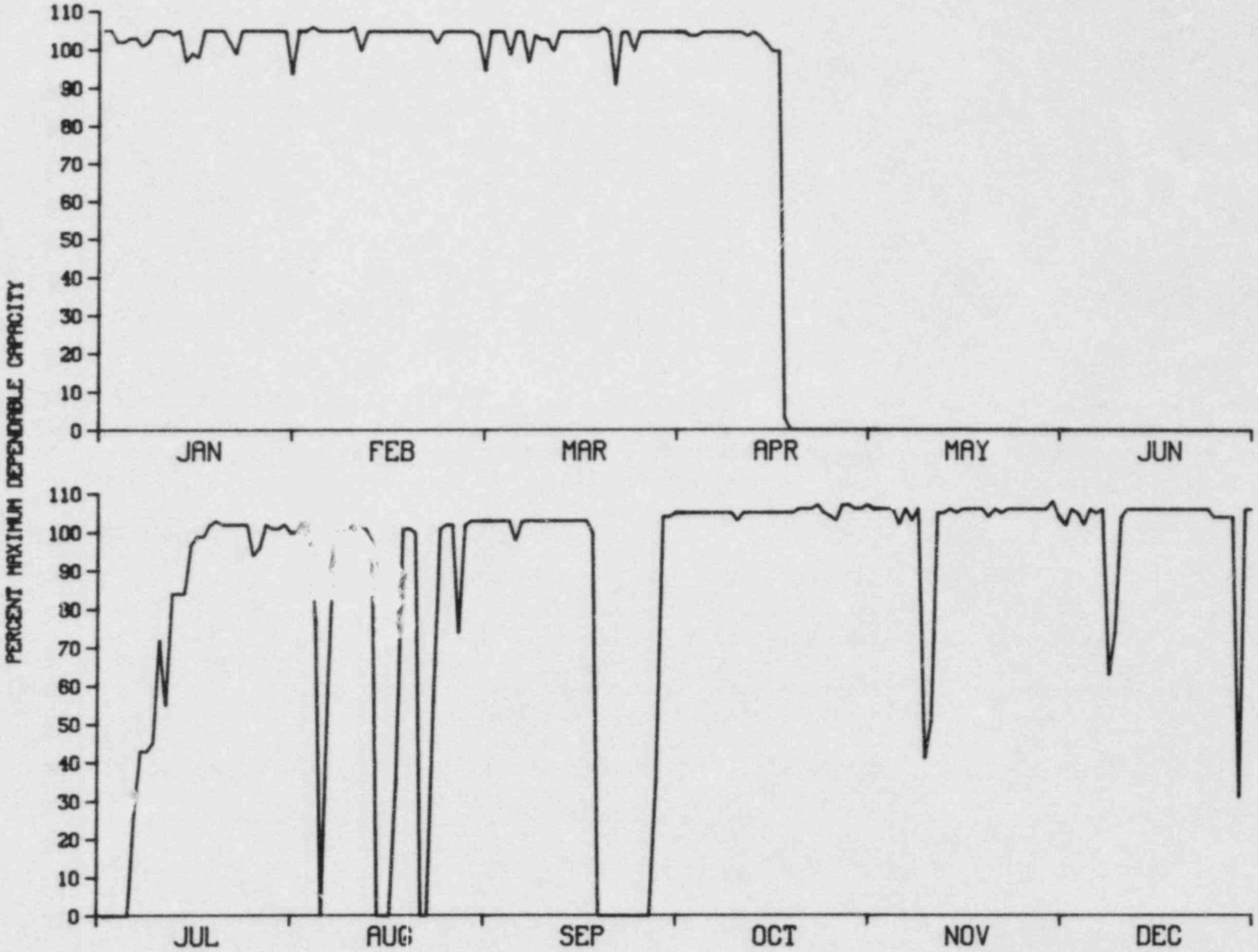
Total No.: 11
Forced: 8
Scheduled: 3
Total hours: 2,338 (26.7%)
Forced: 135 (1.5%)
Scheduled: 2,203 (25.1%)

II. Highlights

Calvert Cliffs 1 was shut down in mid-April for an 11-week refueling outage which terminated in the first week of July. Prior to that time there had been no shutdowns at all, and only brief outages occurred thereafter. The longest, on September 18, was for replacement of a reactor coolant pump shaft seal and for other miscellaneous maintenance. The long refueling outage was also utilized for other inspection and maintenance and for retubing the condenser. Despite the refueling outage, the plant achieved an availability factor above 70% for the year.

Details of plant outages for Calvert Cliffs 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	4/17/82	1,904.6	S	Refueling, unit general inspection and retube condenser.	C	1	Reactor (RC)	Fuel elements
2	7/05/82	5.6	F	Reactor tripped on high steam generator level due to loss of No. 11 feed pump.	A	3	Steam and power conversion (HH)	Pumps
3	7/11/82	4.6	F	Tripped while conducting power-to-load unbalance test.	A	3	Other (XX)	Codes not applicable
4	8/04/82	28.5	F	Tripped due to an undervoltage spike on reactor bus.	A	3	Auxiliary water (WA)	Instrumentation and controls
5	8/14/82	80.9	S	Repair reactor coolant system leak.	B	1	Reactor coolant (CB)	Codes not applicable
6	8/21/82	44.9	F	Repair leaking upper seal pressure sensing line on No. 12B reactor coolant pump.	A	1	Steam and power conversion (HF)	Pumps
7	8/22/82	8.9	F	Tripped on low steam generator level due to loading the main turbine too rapidly.	G	3	System code not applicable (ZZ)	Codes not applicable
8	9/18/82	217.4	S	Replaced No. 12B reactor coolant pump shaft seal and other miscellaneous maintenance.	A	1	Other (XX)	Pumps
9	11/09/82	18.6	F	Loss of power to feedwater regulating valves.	A	3	Reactor coolant (CH)	Codes not applicable
10	12/08/82	12.8	F	Low voltage to control rods.	A	3	Reactor (RB)	Control rods
11	12/29/82	11.0	F	Low oil level on No. 12B reactor coolant pump motor.	A	1	Other (XX)	Motors



DESIGN ELEC. RATING - 845 MAX. DEPEND. CAP. - 825 (100%)

CALVERT CLIFFS 1

CALVERT CLIFFS 2

I. Summary

Description

Location: Lusby, Maryland
Docket No.: 50-318
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 825
Commercial operation: 4/01/77
Years operating experience: 6.1

Performance

Net electrical energy generated (MWh): 5,004,951
Unit availability factor (%): 74.2
Unit capacity factor (%) (using MDC): 69.3
Unit capacity factor (%) [using design MW(e)]: 67.6

Outages

Total No.: 9
Forced: 8
Scheduled: 1
Total hours: 2,262 (25.8%)
Forced: 414 (4.7%)
Scheduled: 1,847 (21.1%)

II. Highlights

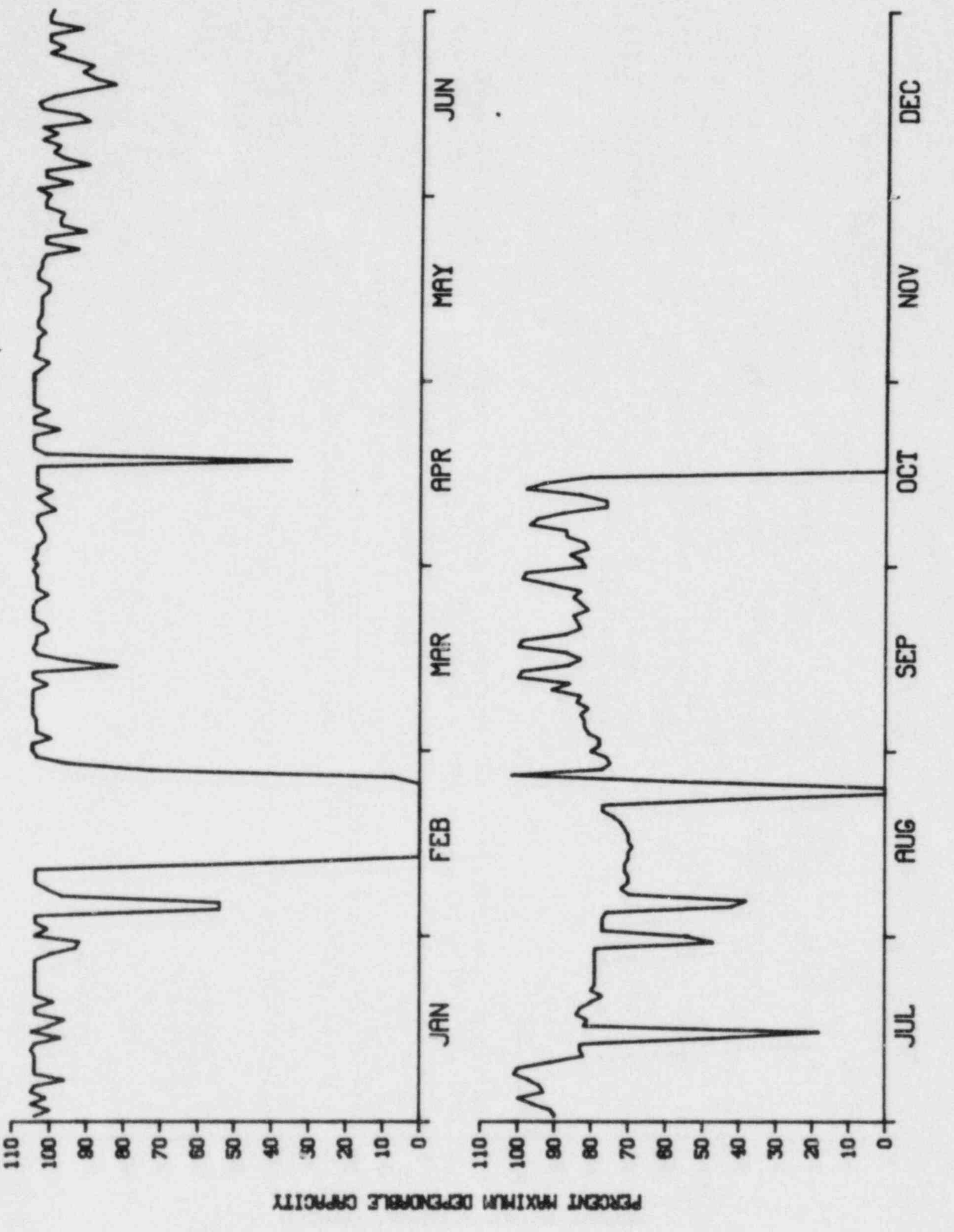
Calvert Cliffs 2 began a refueling outage in mid-October 1982, which then lasted the rest of the year and on into 1983. The primary purpose of this long outage was refueling, but it also served for general inspection and for condenser retubing. The only other substantial outage during the year was a ten-day shutdown in February, caused by the need to repair a sticking control rod that was hung up at the 8-in. withdrawn position.

Details of plant outages for Calvert Cliffs 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	2/05/82	20.5	F	Loss of No. 22 main feedwater pump.	A	1	Reactor coolant (CH)	Pumps
2	2/12/82	0.3	F	Loss of No. 22 main feedwater pump.	A	1	Reactor coolant (CH)	Pumps
3	2/12/82	251.0	F	Control rod sticking at 8-in. withdrawn position.	A	9	Reactor (RA)	Control rods
4	2/22/82	37.9	F	Excessive steam leakage on the bonnet pressure seal of No. 22 main steam isolation valve.	A	9	Reactor coolant (CD)	Valves
5	2/24/82	8.8	F	While troubleshooting the automatic control circuit on No. 21 feedwater regulating valve, reactor tripped on low steam generator level (maintenance error).	H	9	Steam and power conversion (HH)	Codes not applicable
6	4/17/82	13.3	F	Technician error caused reactor to manually trip when two control element assemblies dropped to bottom of core.	G	1	System code not applicable (ZZ)	Codes not applicable
7	7/14/82	21.7	F	Failure of the signal integrator supplied the speed control on both main feed pumps. No. 2 unit has been reduced to various load levels almost the entire month due to condenser tube leaks.	A	3	Steam and power conversion (HH)	Instrumentation and controls
8	8/23/82	60.8	F	Tripped due to loss of high-pressure oil pressure on No. 22 SG feed pump. No. 2 unit was reduced to various load levels almost the entire month due to condenser tube leaks.	A	3	Steam and power conversion (HJ)	Pumps

Details of plant outages for Calvert Cliffs 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
9	10/16/82	1,847.2	S	Reactor refueling, unit general inspection, and condenser retubing.	C	1	Reactor (RC)	Fuel elements



CALVERT CLIFFS 2

DESIGN ELEC. RATING - 845 MAX. DEPEND. CAP. - 825 (100%)

COOK 1

I. Summary

Description

Location: Bridgeman, Michigan
Docket No.: 50-315
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 1,044
Commercial operation: 8/27/75
Years operating experience: 7.9

Performance

Net electrical energy generated (MWh): 5,352,823
Unit availability factor (%): 62.7
Unit capacity factor (%) (using MDC): 58.5
Unit capacity factor (%) [using design MW(e)]: 58.0

Outages

Total No.: 7
Forced: 4
Scheduled: 3
Total hours: 3,269[a] (37.3%)
Forced: 1,090[a] (12.4%)
Scheduled: 2,179 (24.9%)

II. Highlights

Cook 1 began the year in a continuation of a December 29, 1981, outage which was caused by a leak in the reactor cooling system and was extended to complete other maintenance and upgrading work inside the containment building. A turbine blade failure, which necessitated turbine repair, occurred on January 31, 1982, and took all of February to repair. The plant then operated almost continuously until it was taken down on July 3 for a twelve-and-a-half-week refueling outage (end of cycle 6) during which other maintenance and modification tasks were also performed. After its restart at the beginning of October, the plant operated almost without problems the rest of the year.

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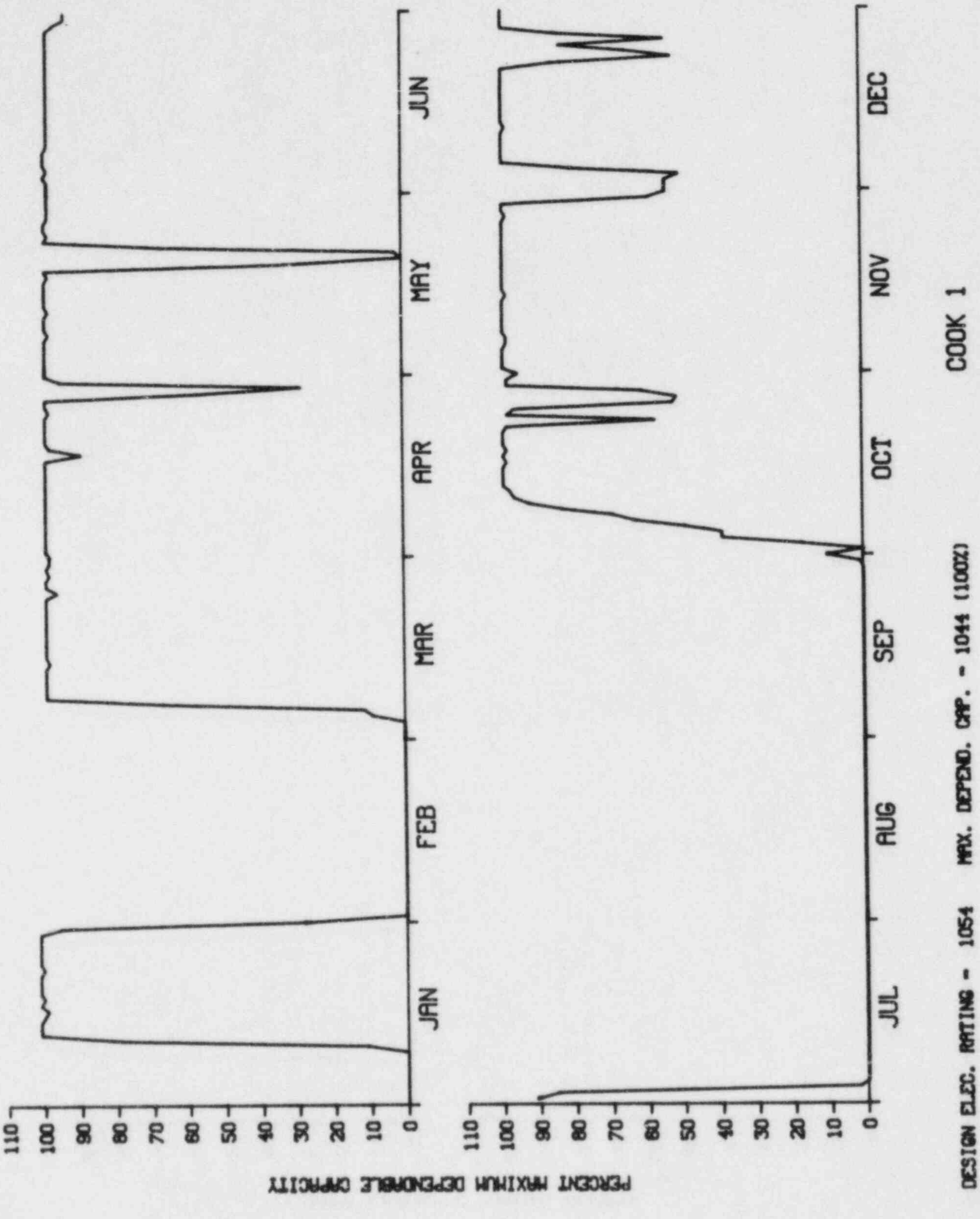
[a]Includes 230 h in 1982 from continuation of 12/29/81 shutdown.

Details of plant outages for Cook 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	12/29/81	229.9	F	The unit was shut down to repair RCS leak. The unit was kept in cold shutdown to complete work inside containment on NUREG-0737 items. The unit was returned to service on 1/10/82 and reached 100% reactor power on 1/11/82.	A	4	Reactor coolant (CB)	Valves
2	1/31/82	770.9	F	Unit trip on high turbine vibration. A blade failure in the "turbine end" first stage was found. Turbine placed on turning gear 3/2/82 after reblading of both first stages. Unit was paralleled to grid and brought to 25% on 3/4/82.	A	3	Steam and power conversion (HA)	Turbines
3	3/04/82	0.8	S	Unit removed from service to perform turbine overspeed test.	B	1	Steam and power conversion (HA)	Turbines
4	3/05/82	15.0	F	Unit tripped due to reactor trip from low-low level in No. 1 steam generator. Low level in steam generators was a result of a 300-MW load rejection caused by problems with turbine initial pressure limiter. Initial pressure limiter was removed from service and unit returned to service the same day.	A	3	Reactor coolant (CC)	Instrumentation and controls
5	4/27/82	15.8	F	Turbine/reactor trip due to low condenser vacuum. Low vacuum condition was caused by a false "closed" position indication on "A" condenser startup air ejector motor-operated isolation valve, SMO-405, permitting a sudden air in-leakage when hand valve was opened.	A	3	System code not applicable (ZZ)	Codes not applicable

Details of plant outages for Cook 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
6	5/19/82	58.8	F	Turbine/reactor trip due to an indicated "stator water cooling low flow" signal. Actual cooling water flow was not lost. Control air supply for stator cooling water instrumentation was inadvertently lost when attempting to valve out a branch line to office building. Branch line was removed from air header. Unit remained out of service to repair a feedwater isolation valve until 5/21/82. Reactor power of 100% was reached on 5/22/82.	G	3	System code not applicable (ZZ)	Codes not applicable
7	7/03/82	2,132.5	S	The unit was removed from service at 0146 hours for scheduled cycle VI—VIII refueling and maintenance outage, plus installation of several major design changes. The estimated duration of the outage was 57 days.	C	1	Reactor (RC)	Fuel elements
8	9/30/82	45.6	S	Unit was removed from service for turbine overspeed testing and to repair body-to-bonnet leak on pressurizer auxiliary spray valve, QRV-51. The unit was returned to service 10/2/82, and the power escalation testing program was commenced. Reactor power of 100% was reached on 10/11/82.	B	1	Reactor coolant (CB)	Valves


PERCENT MAXIMUM DEPENDABLE CAPACITY
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COOK 1
DESIGN ELEC. RATING - 1054   MAX. DEPEND. CAP. - 1044 (100%)

COOK 2

I. Summary

Description

Location: Bridgeman, Michigan
Docket No.: 50-316
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 1,082
Commercial operation: 7/01/78
Years operating experience: 4.8

Performance

Net electrical energy generated (MWh): 6,995,651
Unit availability factor (%): 76.9
Unit capacity factor (%) (using MDC): 73.8
Unit capacity factor (%) [using design MW(e)]: 72.6

Outages

Total No.: 9
  Forced: 8
  Scheduled: 1
Total hours: 2,019 (23.0%)
  Forced: 1,037 (11.8%)
  Scheduled: 983 (11.2%)

II. Highlights

In 1982 Cook 2 achieved the second-highest electricity production among all the American PWR power reactors, second only to Salem 2. This record was achieved by having only three outages of significant length during the year. The first, which lasted just over 20 days in March, was for replacement of one of the circulating pump motors, which had been running at its maximum permissible temperature. The second long outage occupied 17 days in July and was due to primary-to-secondary leakage resulting from a failed tube in one of the steam generators. The leaking tube, plus an adjacent tube also indicating problems based on eddy-current testing, were plugged. Finally, on November 21 the unit began its end-of-cycle-3 refueling outage which lasted past the end of the year.

Details of plant outages for Cook 2

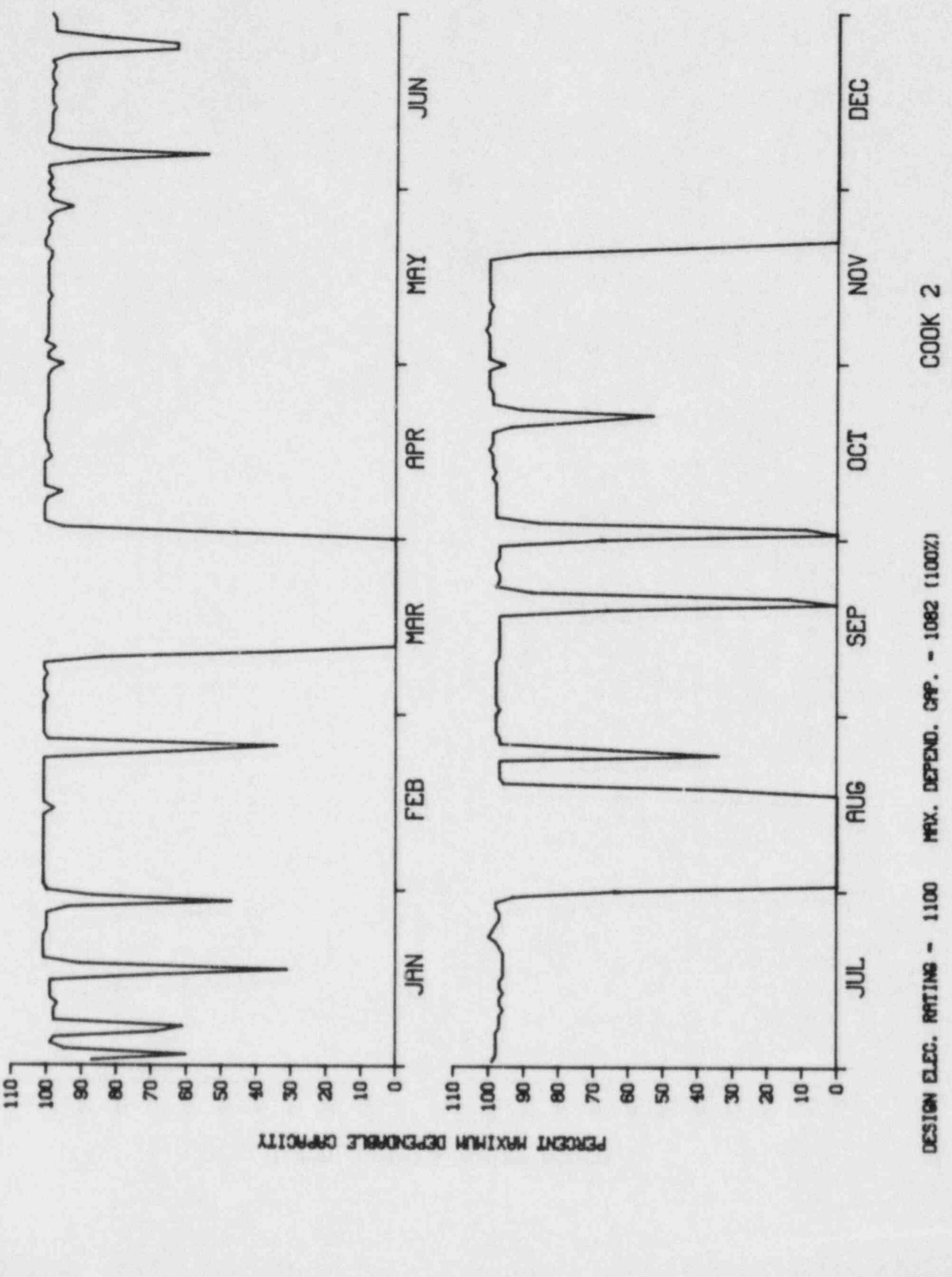
No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/16/82	10.9	F	Unit tripped from a turbine trip. The exact cause has not been determined. It appears that the cause was a closed valve in the impulse line to the stator cooling water low-flow instrument combined with low ambient temperatures.	H	3	Steam and power conversion (HA)	Instrumentation and controls
2	2/22/82	14.4	F	Unit tripped due to low vacuum. The low vacuum condition occurred when the B-north half condenser was removed from service to repair condenser tube leaks. Later investigation revealed the "B" condenser air take-off line shut-off valve to be closed. The unit was returned to service on 2/23/82. with 100% power reached on 2/24/82.	G	3	Steam and power conversion (HC)	Valves
3	3/11/82	489.4	F	A power reduction was started on March 10, 1982, due to No. 23 RCP motor temperatures being at their maximum limit. On March 11, 1982, the decision was made to remove the unit from service due to the high motor temperature problem and indications of excessive leakoff from the No. 2 seal on the No. 23 RCP. A two-week ice condenser ice basket weighing surveillance outage scheduled for early April was rescheduled to the present outage.	B	1	Reactor coolant (CB)	Motors

Details of plant outages for Cook 2 (continued)

No	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
4	7/31/82	415.3	F	The unit was removed from service due to primary to secondary leakage. The calculated leak rate was 0.17 gpm. A single tube located in row 1, column 71, steam generator 2-1 was identified as leaking. Eddy current testing showed an indication in the row 1, column 72 tube. Both tubes were plugged using mechanical plugs. The unit was returned to service on 8/18/82 and reached 100% reactor power on 8/19/82.	B	1	Reactor coolant (CC)	Heat exchangers
5	8/24/82	13.7	F	Reactor/turbine trip due to failure of vital bus CRID IV inverter. The inverter was found to have a defective oscillator board, which was replaced. The unit was returned to service the same day and reached 100% reactor power on 8/25/82.	A	3	Electric power (ED)	Instrumentation and controls
6	9/18/82	32.9	F	Reactor/turbine trip. The reactor trip was due to low level coincident with steam/feedwater flow mismatch in No. 21 steam generator caused by No. 21 SG feedwater reg. valve failing closed. Rain water during roof repairs had entered solenoid valve for feedwater reg. valve, causing it to short and the valve to fail closed. The unit was parallelled at 0412 hours on 9/20/82.	A	3	Steam and power conversion (HB)	Valves

Details of plant outages for Cook 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
7	9/20/82	14.2	F	Turbine/reactor trip due to high-high level in No. 24 SG during manual steam generator level control. Troubleshoot of the control systems did not reveal the problem. During a subsequent outage, problems were found in the feedwater regulating valve booster relay. The unit was returned to service at 1830 hours on 9/20/82 and reached 100% reactor power on 9/21/82.	H	3	Steam and power conversion (HB)	Relays
8	9/30/82	46.0	F	Unit removed from service to repair a weld leak at the root weld for a drain line on the feedwater to No. 21 SG. The drain line is located between the SG and the isolation check valve.	A	1	Steam and power conversion (HH)	Pipes and/or fittings
9	11/21/82	982.5	S	The unit was removed from service at 0127 hours for scheduled cycle III—IV refueling/maintenance outage. Several major design changes related to the TMI action plan were also being installed. The power reduction was started at 0553 hours at 2% per hour when a marked increase in the calculated ST primary-to-secondary leak rate was experienced.	C	1	Reactor (RC)	Fuel elements


PERCENT MAXIMUM DEPENDABLE CAPACITY
110
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DESIGN ELEC. RATING - 1100 MAX. DEPEND. CAP. - 1082 (100%)

COOPER STATION

I. Summary

Description

Location: Brownsville, Nebraska
Docket No.: 50-298
Reactor type: BWR
Maximum dependable capacity [MW(e)-net]: 764
Commercial operation: 7/01/74
Years operating experience: 8.6

Performance

Net electrical energy generated (MWh): 5,276,082
Unit availability factor (%): 84.6
Unit capacity factor (%) (using MDC): 78.8
Unit capacity factor (%) [using design MW(e)]: 77.4

Outages

Total No.: 6
  Forced: 5
  Scheduled: 1
Total hours: 1,346 (15.3%)
  Forced: 207 (2.4%)
  Scheduled: 1,138 (13.0%)

II. Highlights

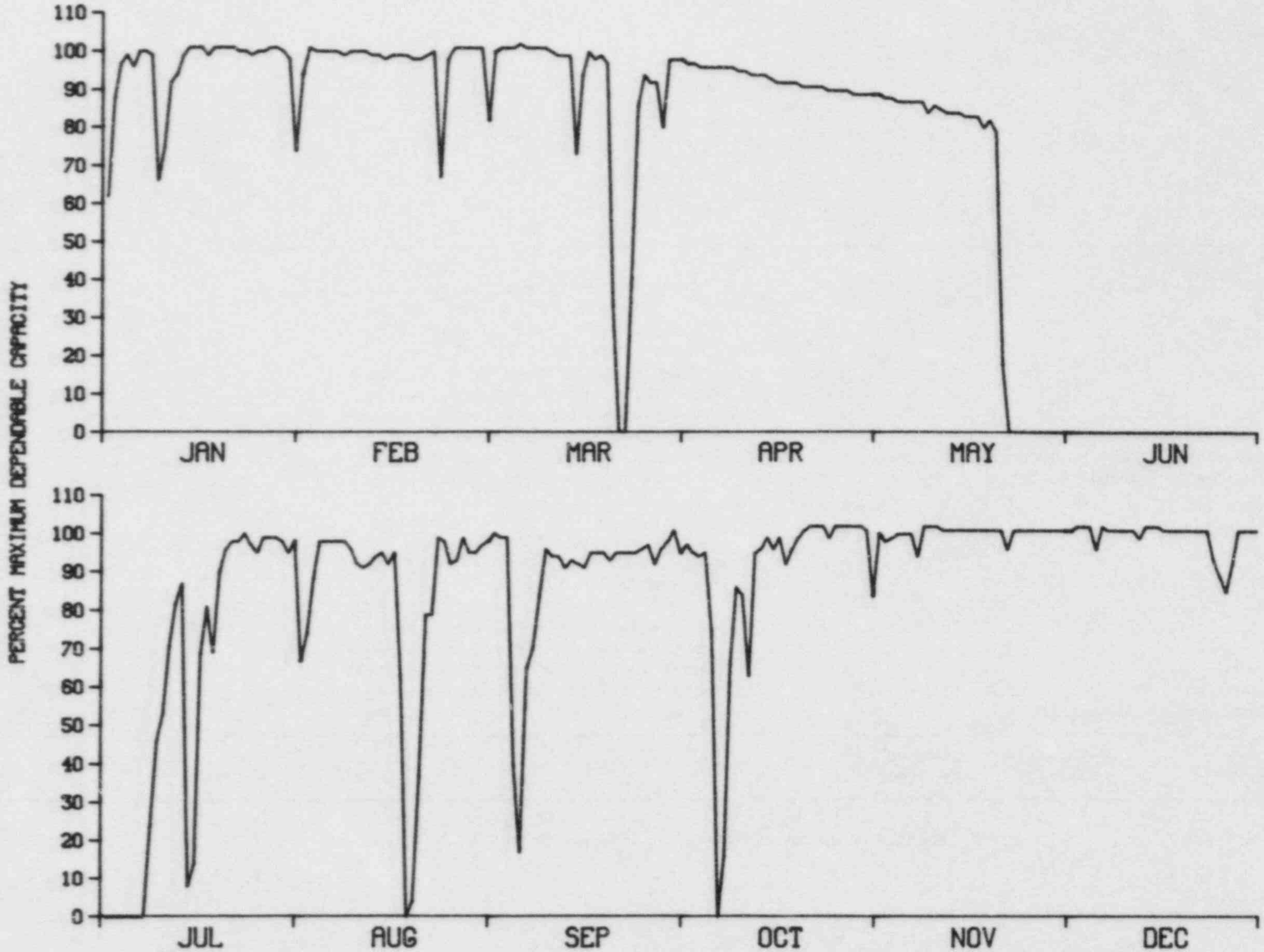
Cooper Station achieved the third-highest electricity output among the BWRs during 1982, even though its design electrical rating of 778 MW(e)-net ranks it only thirteenth among the BWR reactors. This excellent performance was due to the fact that the plant had only a single outage of considerable length, a refueling outage completed in the relatively brief time of under seven weeks, which began on May 21. Plant power began to decline by late March as the unit approached the end of the core life, and the unit could no longer maintain full rated power even with all rods fully withdrawn.

Details of plant outages for Cooper Station

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	3/20/82	64.7	F	An intermittent source of spikes and fluctuations in the main generator voltage regulator system in the automatic mode of operation was noticed in January and February 1982. To stop these spikes, the voltage regulator control system was transferred from automatic to manual operation and a generator trip resulted.	A	3	Steam and power conversion (HA)	Instrumentation and controls
2	5/21/82	1,138.3	S	Reactor shutdown to start the 1982 refueling and maintenance outage.	C	2	Reactor (RC)	Fuel elements
3	7/14/82	34.7	F	A feedwater heater level control valve failed closed (stem snapped), causing instabilities in feedwater heater system. The reactor was shut down to repair valve and investigate cause of failure. Two seismic supports were found damaged and were also repaired.	A	2	Reactor coolant (CH)	Valves
4	8/17/82	43.1	F	A failure in the turbine control system caused the main steam control valves to close. The pressure transient caused by the control valve closure resulted in a neutron flux spike and a reactor scram. A bad circuit card was replaced in the turbine control system and the plant was returned to operation.	A	3	Instrumentation and controls (IF)	Instrumentation and controls

Details of plant outages for Cooper Station (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
5	9/04/82	23.5	F	An electronic component in the "A" feedwater pump controller shorted out causing the "A" FW loop flow to reduce to nearly zero flow. The reactor water level decreased to the trip level and the reactor scrammed. The failed component in the FW pump controller was replaced and the plant was returned to operation.	A	3	Reactor coolant (CH)	Instrumentation and controls
6	10/05/82	41.2	F	Electrical insulation for the control cable for the turbine control valves deteriorated from exposure to heat and radiation of a nearby main steam line and shorted out, causing the turbine control valves to close. Turbine control valve fast closure initiated a reactor scram. The bad cable was replaced and the plant was returned to operation.	A	3	Steam and power conversion (HA)	Electrical conductors



DESIGN ELEC. RATING - 778 MAX. DEPEND. CAP. - 764 (100%) COOPER STATION

CRYSTAL RIVER 3

I. Summary

Description

Location: Red Level, Florida
Docket No.: 50-302
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 782
Commercial operation: 3/13/77
Years operating experience: 5.9

Performance

Net electrical energy generated (MWh): 4,915,582
Unit availability factor (%): 76.0
Unit capacity factor (%) (using MDC): 69.6
Unit capacity factor (%) [using design MW(e)]: 68.0

Outages

Total No.: 17
  Forced: 16
  Scheduled: 1
Total hours: 2,152 (24.6%)
  Forced: 2,105 (24.0%)
  Scheduled: 47 (0.5%)

II. Highlights

Crystal River 3 operated without a refueling shutdown during 1982. The most significant outages had a variety of causes, several of them originating outside the plant or from the nonnuclear portion of the facility. At the end of January, a 33-day outage resulted from a leak that was traced to a cracked weld near one of the high-pressure injection (HPI) nozzles. The cracked weld was repaired, and the other HPI nozzles were also checked before startup. A crack in a cooling pump seal housing was also discovered and repaired. In mid-October a two-week shutdown was caused by a failure of the coolers in a reactor drain tank, which coupled with a relief valve leak into the same drain tank caused it to overflow into the reactor building sump. The leaking relief valve and the cooler were repaired. In late November a three-and-a-half-week outage was needed to replace both letdown coolers.

Details of plant outages for Crystal River 3

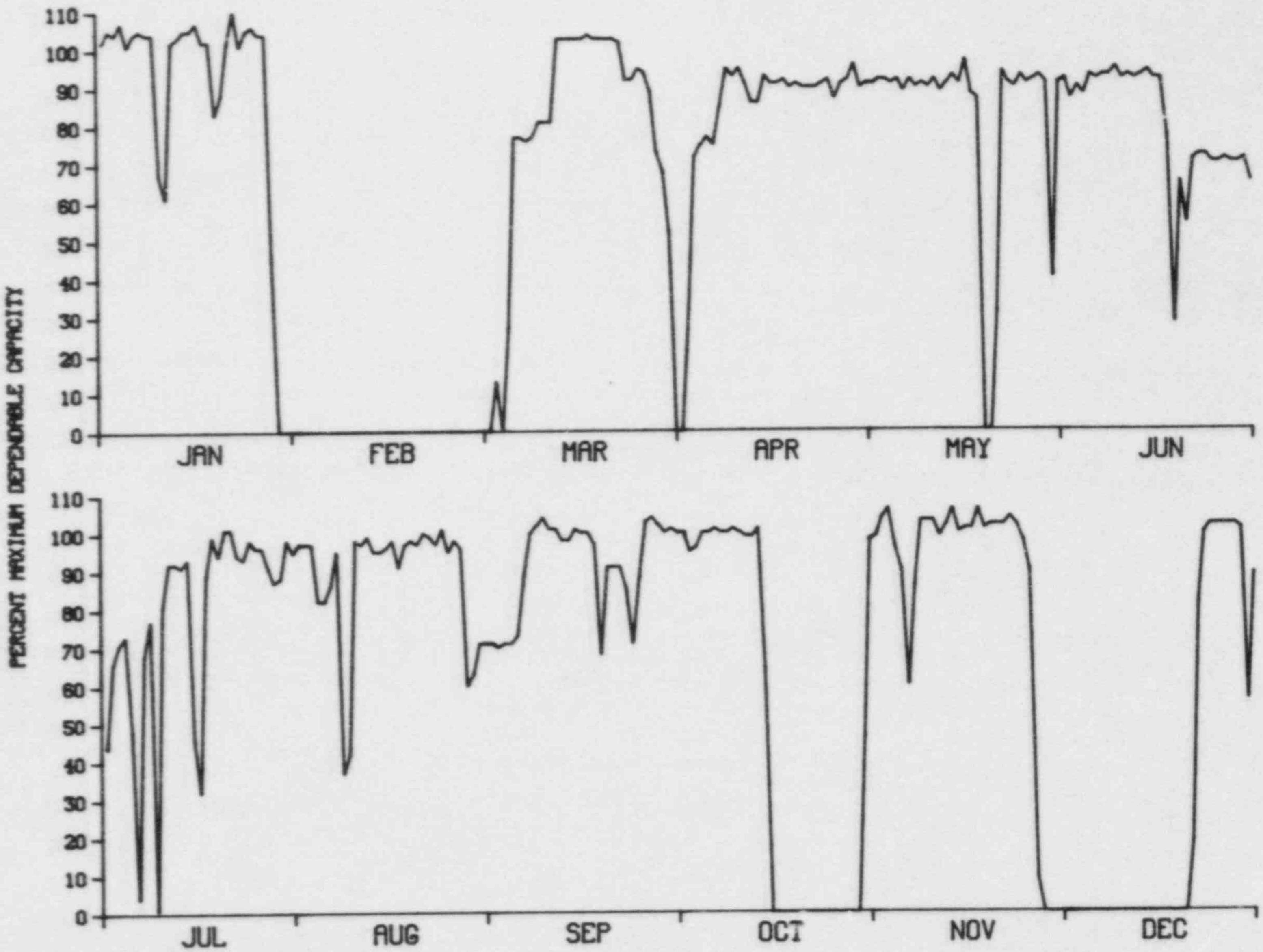
No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/10/82	14.9	F	FWV-31 failed to stroke during a monthly feedwater functional test. This resulted in the trip of "A" mainfeed pump and eventually in a trip of the unit on high pressure.	A	3	Reactor coolant (CH)	Valves
2	1/18/82	46.8	S	Dropped power to clean all four condenser water boxes.	B	5	Steam and power conversion (HF)	Heat exchangers
3	1/28/82	789.3	F	Unidentified leakage >1 gpm. After shutting down, the leak was discovered to be a crack in the weld between MUV-43 and the HPI nozzle on loop A. Plan to check the other nozzles for cracking as well as repair the known crack before starting up. Also, a crack was discovered in RCP A seal package. The seal will be rebuilt.	A	1	Engineered safety features (SF)	Valves
4	3/02/82	43.0	F	Plant tripped by the RC pump power monitors. Exact reason unknown.	A	3	Instrumentation and controls (IA)	Instrumentation and controls
5	3/30/82	62.8	F	An upset in the electrical transmission system caused the RC pump power monitors to trip the plant.	A	3	Instrumentation and controls (IA)	Instrumentation and controls
6	5/19/82	60.6	F	Shutdown to add oil to RCP-1D motor.	B	1	Reactor coolant (CB)	Motors
7	5/30/82	11.8	F	Grounding brushes on turbine generator shaft had worn out causing arcing when the rotor position was being checked with a micrometer. The turbine generator trip mechanism was jarred, causing a turbine, and thereby reactor, trip.	A	3	Steam and power conversion (HA)	Other components

Details of plant outages for Crystal River 3 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
8	6/17/82	17.6	F	Roof joint leak caused a ground fault on RC pump B, resulting in a reactor/turbine RPS trip.	A	3	Instrumentation and controls (IA)	Relays
9	6/20/82	4.2	F	Operator accidentally closed the main steam isolation valves causing reactor/turbine trip on high pressure.	G	3	Reactor coolant (CD)	Codes not applicable
10	6/30/82	7.3	F	Discovered that conduits carrying some HPI controls were not seismically qualified. Declared HPI inoperable, entered 1-hour action statement, manually shut down the reactor. EHC system problems delayed startup.	D	1	Engineered safety features (SF)	Shock suppressors and supports
11	7/05/82	28.1	F	Lightning strike on the output breakers.	H	3	Electric power (EA)	Circuit closers/interrupters
12	7/09/82	23.0	F	Removed plant from the line to repair the turbine control (EHC) system.	A	1	Steam and power conversion (HA)	Instrumentation and controls
13	7/15/82	25.8	F	RCS flow transmitter failed resulting in a reactor trip.	A	3	Reactor coolant (CB)	Instrumentation and controls
14	8/08/82	23.7	F	Flow indicator in "A" loop of the RCS failed, causing the system to change FW flow with a final result of a reactor trip on high pressure.	A	3	Reactor coolant (CB)	Instrumentation and controls

Details of plant outages for Crystal River 3 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
15	10/14/82	376.2	F	RC drain tank cooler failed requiring SW cooling to the tank to be secured. Pressurizer relief valves leaked into the drain tank, eventually causing the RC drain tank to relieve to the reactor building. The unit was shut down to correct the cooler leak and replace the pressurizer valves.	A	1	Auxiliary water (WB)	Heat exchangers
16	11/26/82	608.7	F	Shutdown to replace both letdown coolers.	A	2	Auxiliary process (PC)	Heat exchangers
17	12/30/82	8.0	F	Experienced a system grid upset due to losing St. Lucie nuclear plant. This caused a turbine trip, which in turn caused a reactor trip.	H	3	Electric power (EA)	Codes not applicable



DESIGN ELEC. RATING - 825 MAX. DEPEND. CAP. - 806 (100%) CRYSTAL RIVER 3

DAVIS-BESSE 1

I. Summary

Description

Location: Oak Harbor, Ohio
Docket No.: 50-346
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 890
Commercial operation: 11/20/77
Years operating experience: 5.3

Performance

Net electrical energy generated (MWh): 3,218,155
Unit availability factor (%): 51.5
Unit capacity factor (%) (using MDC): 42.0
Unit capacity factor (%) [using design MW(e)]: 40.5

Outages

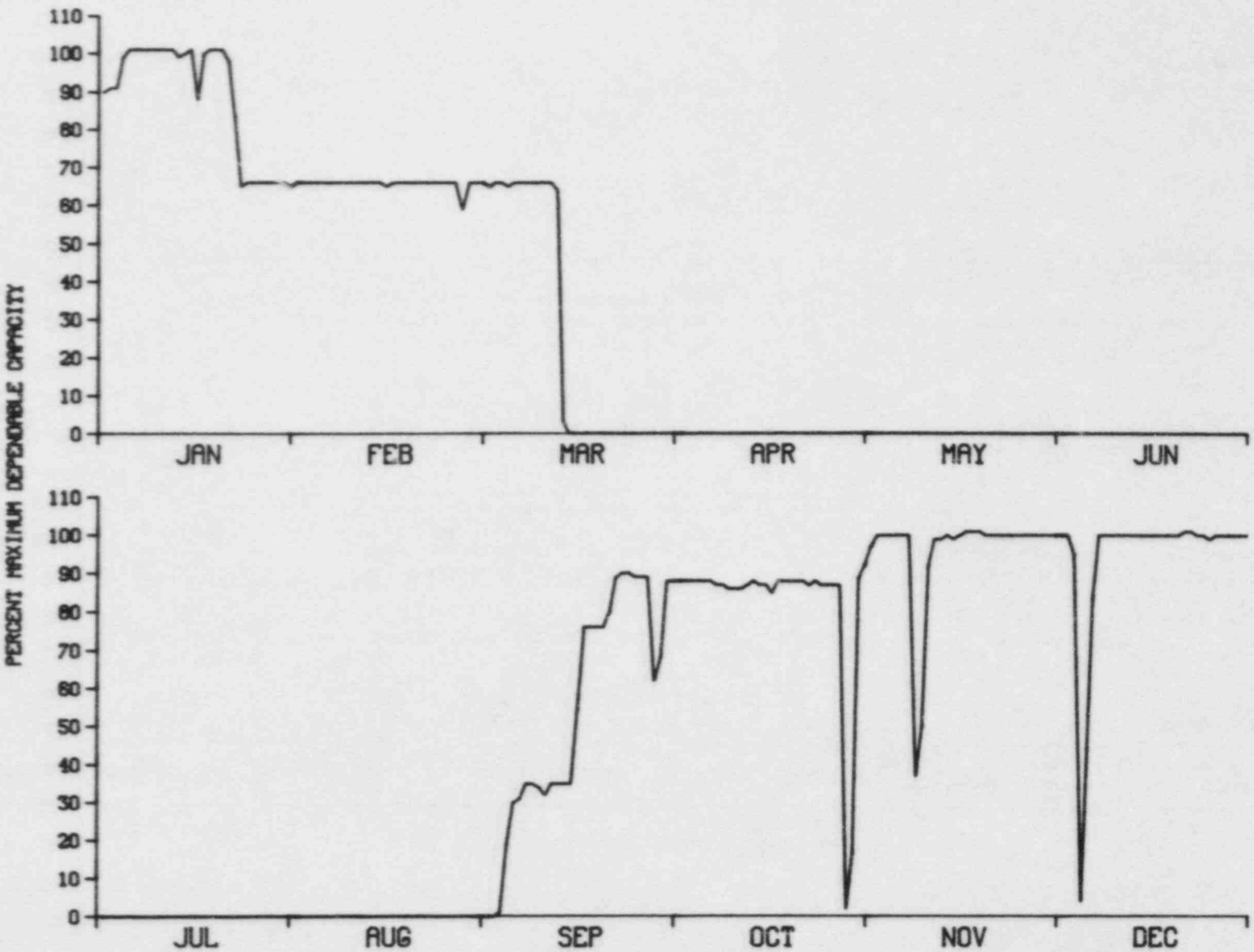
Total No.: 5
Forced: 2
Scheduled: 3
Total hours: 4,252 (48.5%)
Forced: 52 (0.6%)
Scheduled: 4,200 (47.9%)

II. Highlights

Davis-Besse operation during 1982 was restricted by a 25-week refueling and maintenance outage which began in mid-March and was not completed until early September. On January 22 the power was reduced to 68% of full power due to a leak in one of the steam extraction line expansion bellows, and this power reduction remained in effect until the plant was shut down for refueling in March. Once the unit was brought back on line in September, it operated with little difficulty for the remainder of the year.

Details of plant outages for Davis-Besse 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	3/13/82	4,184.3	S	A unit outage was initiated to perform scheduled maintenance and refueling work.	C	1	Reactor (RC)	Fuel elements
2	9/03/82	1.1	S	Turbine overspeed trip test.	B	9	Steam and power conversion (HA)	Codes not applicable
3	10/28/82	32.7	F	The reactor tripped by the anticipatory reactor trip system (ARTS) during the performance of PT 5193.01 main turbine steam valves test.	H	3	Instrumentation and controls (IA)	Codes not applicable
4	11/08/82	18.9	F	Reactor tripped due to the ARTS caused by an erroneous moisture separator reheater high water level signal.	A	3	Steam and power conversion (HJ)	Instrumentation and controls
5	12/04/82	14.6	S	The turbine was taken off line for balancing of the low pressure turbine rotor, but the reactor stayed critical.	B	2	Steam and power conversion (HA)	Codes not applicable



DESIGN ELEC. RATING - 906 MAX. DEPEND. CAP. - 874 (100%)

DAVIS-BESSE 1

DRESDEN 2

I. Summary

Description

Location: Morris, Illinois
Docket No.: 50-237
Reactor type: BWR
Maximum dependable capacity [MW(e)-net]: 772
Commercial operation: 6/09/72
Years operating experience: 12.7

Performance

Net electrical energy generated (MWh): 5,123,040
Unit availability factor (%): 92.4
Unit capacity factor (%) (using MDC): 75.8
Unit capacity factor (%) [using design MW(e)]: 73.7

Outages

Total No.: 12
 Forced: 10
 Scheduled: 2
Total hours: 664 (7.6%)
 Forced: 556 (6.3%)
 Scheduled: 108 (1.2%)

II. Highlights

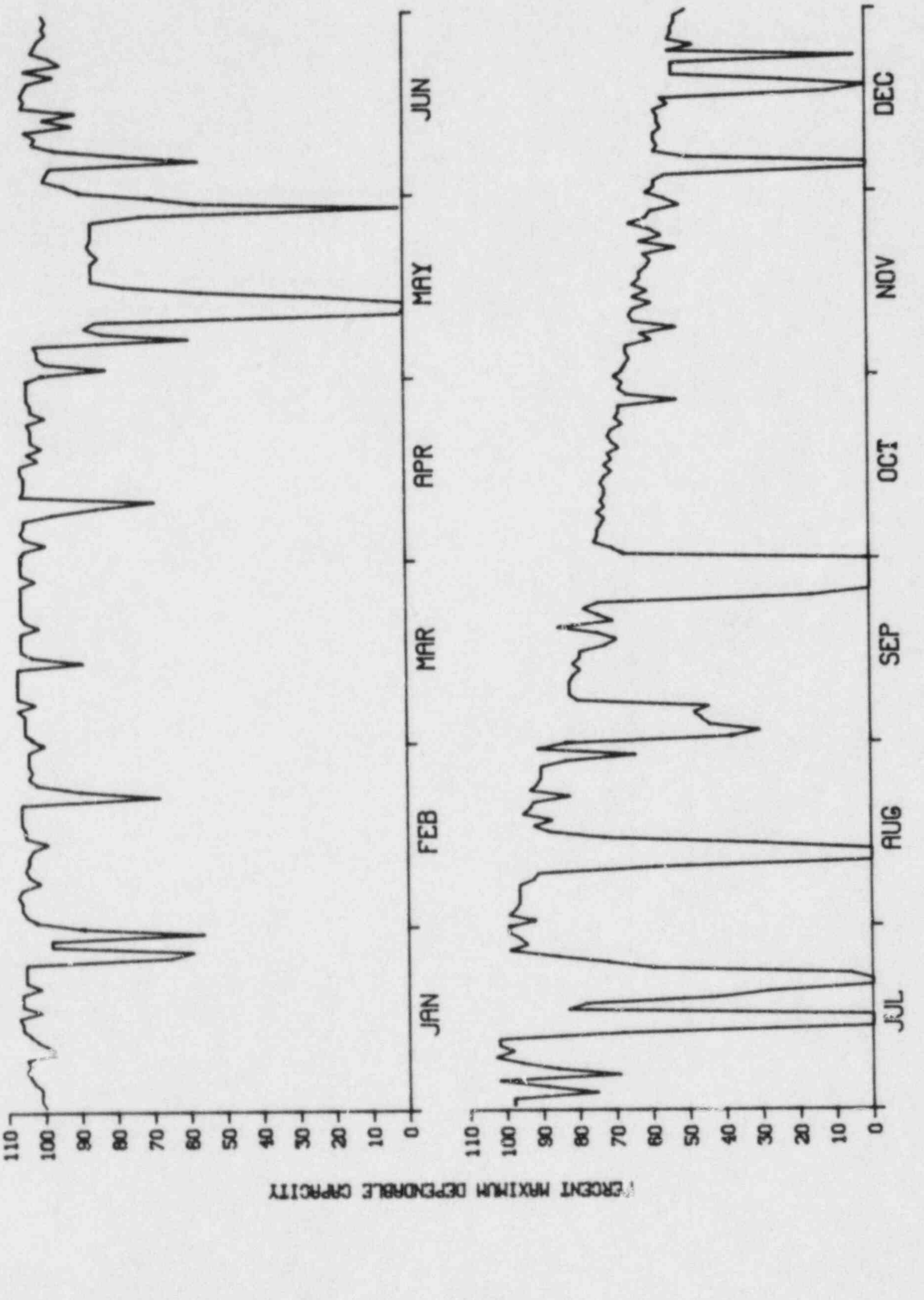
Dresden 2 achieved an excellent availability factor above 90% for 1982; in fact it had the third-highest availability among the 24 BWRs in the United States during this year. This record was achieved, in part, because the plant did not undergo a refueling outage in 1982. The somewhat lower capacity factors (in the 75% range) were due to the fact that from mid-year on the reactor power coasted downwards as its fuel became depleted, with the power level having decreased to about 50% of full power by the end of the year. There were no really extended shutdowns; the longest was a seven-day outage caused by an electrical generator problem in which a generator hydrogen cooling system failure allowed water to leak into current transformers, shorting them.

Details of plant outages for Dresden 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/26/82	13.6	F	Contractor error. Contractor dropped scaffolding by reactor pressure transmitter, giving pressure spike causing scram.	H	3	Instrumentation and controls (IA)	Instrumentation and controls
2	5/06/82	18.7	F	Contractor error. Contractor (Bechtel) opened cubicle for pot fuses on bus-23-1.	H	3	Instrumentation and controls (IA)	Codes not applicable
3	5/11/82	84.3	S	GE/GECO has required that the necessary equipment be installed to conduct a chemistry test injecting H2 into reactor.	B	1	System code not applicable (ZZ)	Codes not applicable
4	5/29/82	23.6	S	Change oil in recirc. pumps.	B	2	Steam and power conversion (HF)	Pumps
5	7/13/82	60.7	F	MO 2301-4 valve failed to close. Repaired.	A	1	Engineered safety features (SF)	Valves
6	7/20/82	74.0	F	Loss of oil pump for "B" recirc. pump. Repaired.	A	1	Steam and power conversion (HF)	Pumps
7	8/10/82	87.0	F	Reactor scram while operating HPCI 2301-8 and 9 valve. Pipe vibration shook inst. rack 2202-10C. Removed brace between pipe guide and inst. rack.	H	3	Engineered safety features (SF)	Valves
8	9/01/82	18.3	F	Low water level caused by 2A RFP tripping on low oil pressure. Mechanical shaft seal failed. Repaired.	A	3	Reactor coolant (CH)	Pumps

Details of plant outages for Dresden 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
9	9/24/82	162.8	F	Main generator output breakers tripped. Caused by short in current transformers which became water soaked from leak on hydrogen cooling system. Replaced current transformers and repaired water leak.	A	3	Steam and power conversion (HA)	Transformers
10	12/04/82	49.1	F	Flooding of Crib House due to rising river (heavy rains).	H	1	Auxiliary water (WA)	Pumps
11	12/17/82	50.2	F	2D3 feedwater heater had a cracked weld in emergency spill to condenser. Rewelded.	A	2	Reactor coolant (CH)	Pipes and/or fittings
12	12/23/82	21.6	F	Low air pressure to scram valve. Investigated.	A	2	Instrumentation and controls (IC)	Valves



DRESDEN 2

DESIGN ELEC. RATING - 794 MAX. DEPEND. CAP. - 772 (100%)

DRESDEN 3

I. Summary

Description

Location: Morris, Illinois
Docket No.: 50-249
Reactor type: BWR
Maximum dependable capacity [MW(e)-net]: 773
Commercial operation: 11/16/71
Years operating experience: 11.4

Performance

Net electrical energy generated (MWh): 3,887,883
Unit availability factor (%): 63.5
Unit capacity factor (%) (using MDC): 57.4
Unit capacity factor (%) [using design MW(e)]: 55.7

Outages

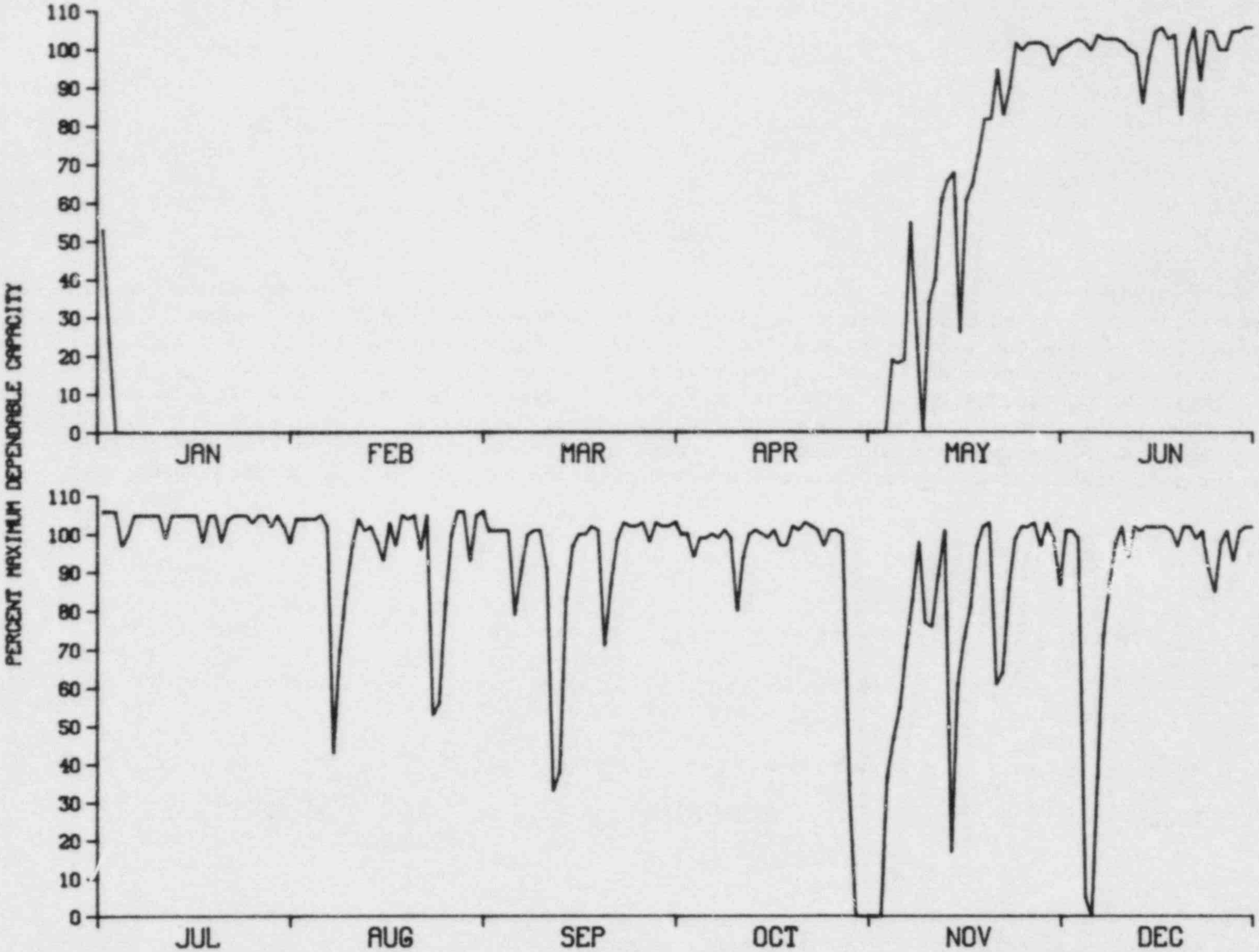
Total No.: 9
 Forced: 8
 Scheduled: 1
Total hours: 3,195 (36.5%)
 Forced: 269 (3.1%)
 Scheduled: 2,926 (33.4%)

II. Highlights

Almost at the very beginning of 1982, on January 2, Dresden 3 began a refueling and turbine overhaul outage which lasted more than 17 weeks until early May. Thereafter the unit operated with very few and brief outages for the rest of the year. The only other outage of significant length began on October 28, when a failed recirculating pump shaft seal required about five and a half days to repair.

Details of plant outages for Dresden 3

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/02/82	2,925.7	S	Refueling and turbine overhaul outage.	C	1	Reactor (RC)	Fuel elements
2	5/08/82	40.4	F	Trip of turbine while testing turbine trip system. EHC failure.	A	3	Steam and power conversion (HA)	Instrumentation and controls
3	5/15/82	10.2	F	Low-pressure feedwater heater control problems. Calibrated and adjusted control valves.	A	1	Reactor coolant (CH)	Valves
4	8/23/82	9.4	F	No. 4 control intercept valve had oil leak on oil line fitting. Repaired.	A	1	Steam and power conversion (HA)	Instrumentation and controls
5	9/12/82	6.6	F	EHC system experienced electronic control problems. Repaired.	A	3	Steam and power conversion (HA)	Instrumentation and controls
6	10/28/82	133.0	F	3B recirc. pump shaft seal failed. Replaced seal.	A	1	Steam and power conversion (HF)	Pumps
7	11/05/82	6.0	F	Reactor remained critical. EHC oil leak. Repaired.	A	3	Steam and power conversion (HA)	Instrumentation and controls
8	11/13/82	15.0	F	Design error. Unable to properly vent feedwater reg. valve after repair. Will be modified by adding vent.	H	3	Reactor coolant (CH)	Valves
9	12/04/82	48.3	F	Flooding of Crib House due to rising river (heavy rains).	H	1	Auxiliary water (WA)	Pumps



DESIGN ELEC. RATING - 794 MAX. DEPEND. CAP. - 773 (100%) DRESDEN 3

DUANE ARNOLD

I. Summary

Description

Location: Palo, Iowa
Docket No.: 50-331
Reactor type: BWR
Maximum dependable capacity [MW(e)-net]: 515
Commercial operation: 2/01/75
Years operating experience: 7.6

Performance

Net electrical energy generated (MWh): 2,280,467
Unit availability factor (%): 74.4
Unit capacity factor (%) (using MDC): 50.5
Unit capacity factor (%) [using design MW(e)]: 48.4

Outages

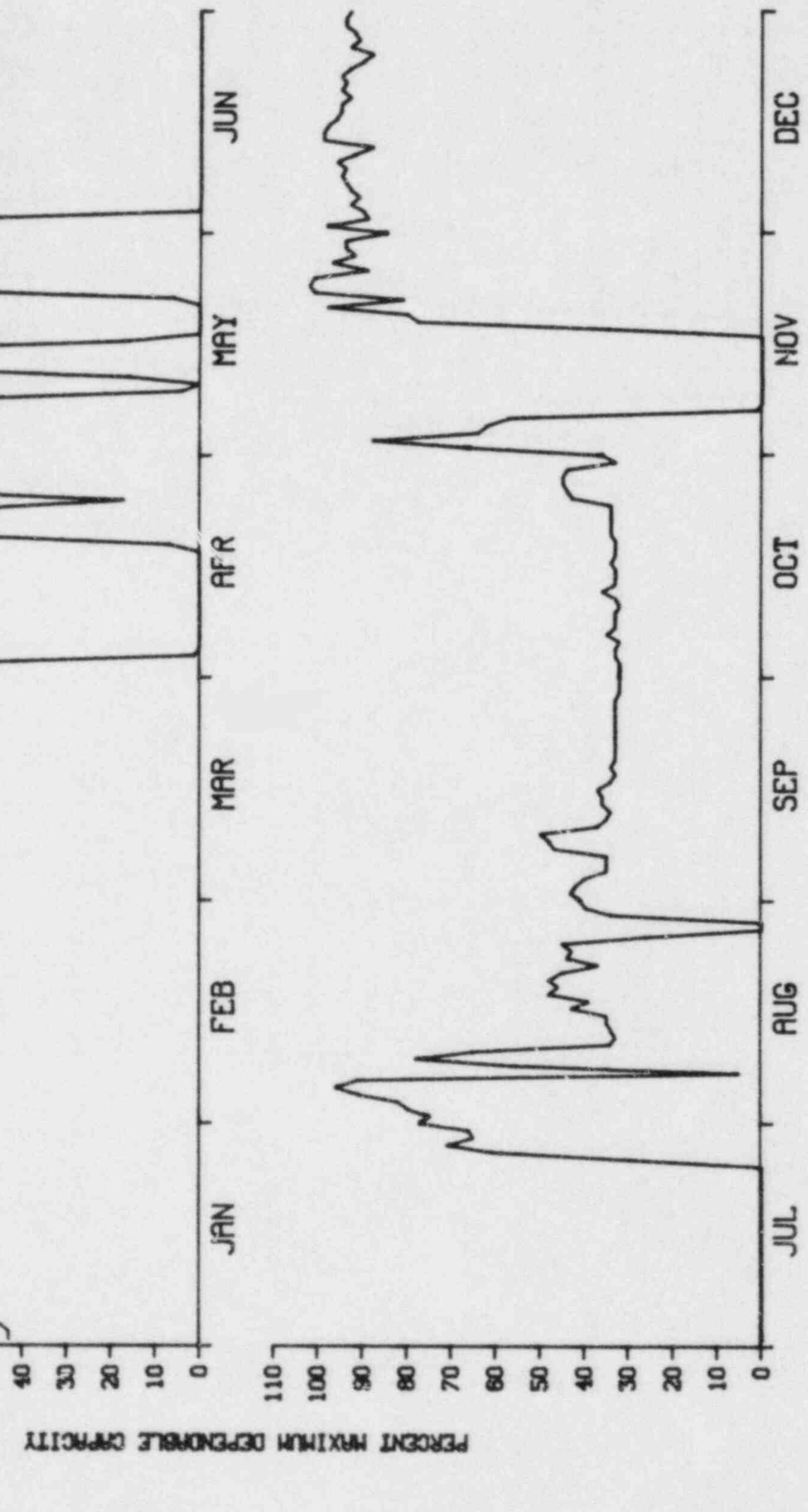
Total No.: 8
Forced: 7
Scheduled: 1
Total hours: 2,214 (25.3%)
Forced: 1,846 (21.1%)
Scheduled: 369 (4.2%)

II. Highlights

The longest outage in 1982 for the Duane Arnold plant was caused by operator error, resulting in a seven-and-a-half-week outage beginning early in June. The operators violated the proper sequence for opening the main steam isolation valves, resulting in a pressure transient that cracked two hydraulic speed control cylinders in the valve control system. During most of August, all of September, and much of October, the plant operated at less than 40% of full power due to low demand for electricity. There were two other significant shutdowns. The first, in April, lasted 15 days and was for the purpose of general maintenance. The second, on November 5, was for the repair of one of the core spray valves and other core components.

Details of plant outages for Duane Arnold

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	4/01/82	368.6	S	Shutdown of the reactor for the April maintenance outage.	B	1	System code not applicable (ZZ)	Codes not applicable
2	4/23/82	14.0	F	Loose connection in the metering circuit of the auxiliary transformer. Block replaced and reconnected.	A	3	Electric power (EG)	Transformers
3	5/09/82	53.4	F	Reactor scram caused by generator loss of field.	A	3	Steam and power conversion (HA)	Generators
4	5/16/82	152.9	F	Failure of emergency bearing oil pump resulted in RPS trip and reactor scram. Replaced pump bearing.	A	3	Reactor coolant (CB)	Pumps
5	6/02/82	1,281.5	F	Procedure violation on MSIV opening sequence resulted in pressure transient that cracked two hydraulic speed control cylinders. Plant procedures and operating instructions to be reviewed and revised as necessary. A program will also be established for additional operator training.	A	1	Reactor coolant (CD)	Codes not applicable
6	8/07/82	19.3	F	Dry well and condenser bay inspection.	H	1	System code not applicable (ZZ)	Codes not applicable
7	8/26/82	57.0	F	Reactor scram from high level turbine trip.	D	3	Steam and power conversion (HA)	Turbines
8	11/05/82	267.5	F	Repair core spray valve and other components. Manual shutdown initiated, manual scram used finally.	A	2	Engineered safety features (SF)	Valves



DESIGN ELEC. RATING - 538 MAX. DEPEND. CAP. - 515 (100%)

DUANE ARNOLD

FARLEY 1

I. Summary

Description	Performance	Outages
Location: Dothan, Alabama	Net electrical energy generated (MWh): 5,216,496	Total No.: 9
Docket No.: 50-348	Unit availability factor (%): 79.2	Forced: 8
Reactor type: PWR	Unit capacity factor (%) (using MDC): 74.1	Scheduled: 1
Maximum dependable capacity [MW(e)-net]: 804	Unit capacity factor (%) [using design MW(e)]: 71.8	Total hours: 1,870[a] (21.3%)
Commercial operation: 12/01/77		Forced: 1,843[a] (21.0%)
Years operating experience: 5.4		Scheduled: 26 (0.3%)

II. Highlights

Farley 1 began 1982 in a continuation of an outage that had begun the previous September, which was for repair of the electric generator, requiring rewinding of the generator stator. This outage was also utilized for refueling the reactor. It ended in early March, and the unit operated for the rest of the year with very few shutdowns and none of extended duration.

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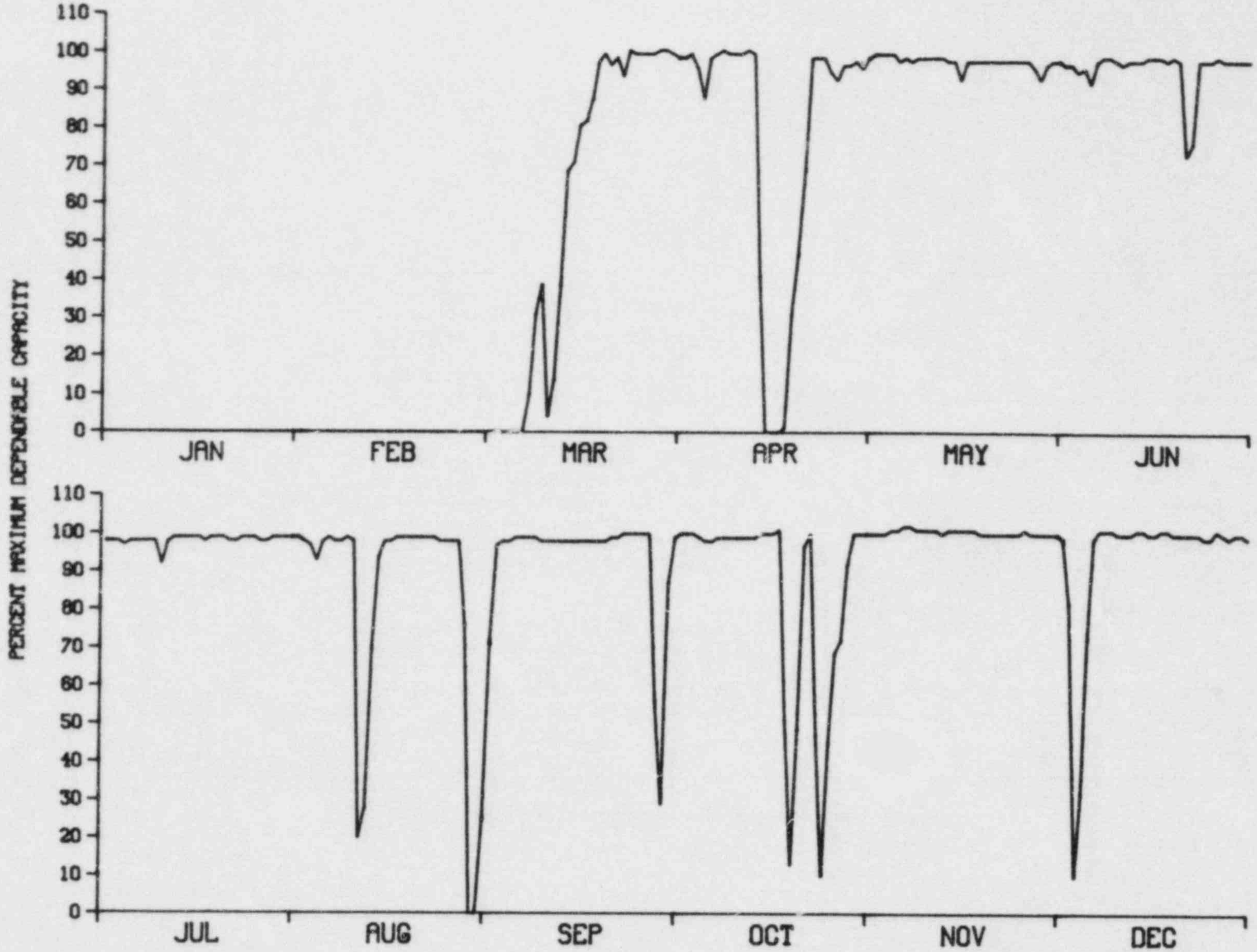
[a]Includes 1,614 h in 1982 from continuation of 9/10/81 outage.

Details of plant outages for Farley 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	9/10/81	1,614.1	F	Continued outage to repair damage to the main generator which occurred September 10, 1981. Refueling was scheduled to take advantage of the forced outage situation.	A	4	Electric power (EB)	Generators
2	3/10/82	26.4	S	Maintenance outage.	B	1	Electric power (EB)	Generators
3	4/13/82	87.8	F	Reactor trip. Lost "B" train due to inadvertent actuation of relays at the switchhouse during routine testing.	G	3	Electric power (ED)	Codes not applicable
4	4/17/82	9.7	F	Reactor trip, turbine trip. Inadvertent trip of the "A" feed pump while maintenance personnel were working in the area.	G	3	Reactor coolant (CH)	Pumps
5	8/11/82	17.4	F	Unit was manually shut down to repair letdown isolation valve 1-CVC-LCV-460 which failed to reopen when stroked during surveillance testing.	A	1	Auxiliary process (PC)	Valves
6	8/28/82	51.8	F	Unit tripped when the 1A SGFP tripped due to a faulty thrust bearing monitor.	A	3	Reactor coolant (CH)	Instrumentation and controls
7	9/27/82	12.7	F	A printed circuit card for a protective relay for a load center input breaker failed, hence de-energizing the load center. This resulted in an open indication on reactor coolant pump No. 1 breaker, thus causing a unit trip. Following the replacement of the printed circuit card, the unit was returned to service.	A	3	Electric power (EB)	Relays

Details of plant outages for Farley 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
8	10/18/82	14.8	F	Reactor trip due to an inadvertent manual trip of the 1A feedwater pump. A subsequent reactor trip occurred due to low steam generator level.	G	3	Reactor coolant (CH)	Pumps
9	10/23/82	22.0	F	While adjusting the voltage regulator, a generator trip occurred due to underexcitation of the main generator. Prior to returning the unit to service, two reactor trips occurred due to low steam generator level.	G	3	Electric power (EB)	Instrumentation and controls
10	12/02/82	12.8	F	Unit tripped due to the failure of a control driver card for 1A feed regulating valve power supply. A subsequent reactor trip occurred due to low-low SG level caused by operator error.	A	3	Reactor coolant (CH)	Instrumentation and controls



DESIGN ELEC. RATING - 829 MAX. DEPEND. CAP. - 804 (100%) FARLEY 1

FARLEY 2

I. Summary

Description

Location: Dothan, Alabama
Docket No.: 50-364
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 829
Commercial operation: 7/30/81
Years operating experience: 1.6

Performance

Net electrical energy generated (MWh): 5,295,330
Unit availability factor (%): 79.2
Unit capacity factor (%) (using MDC): 74.3
Unit capacity factor (%) [using design MW(e)]: 72.9

Outages

Total No.: 13
Forced: 11
Scheduled: 2
Total hours: 1,824 (20.8%)
Forced: 824 (9.4%)
Scheduled: 1,000 (11.4%)

II. Highlights

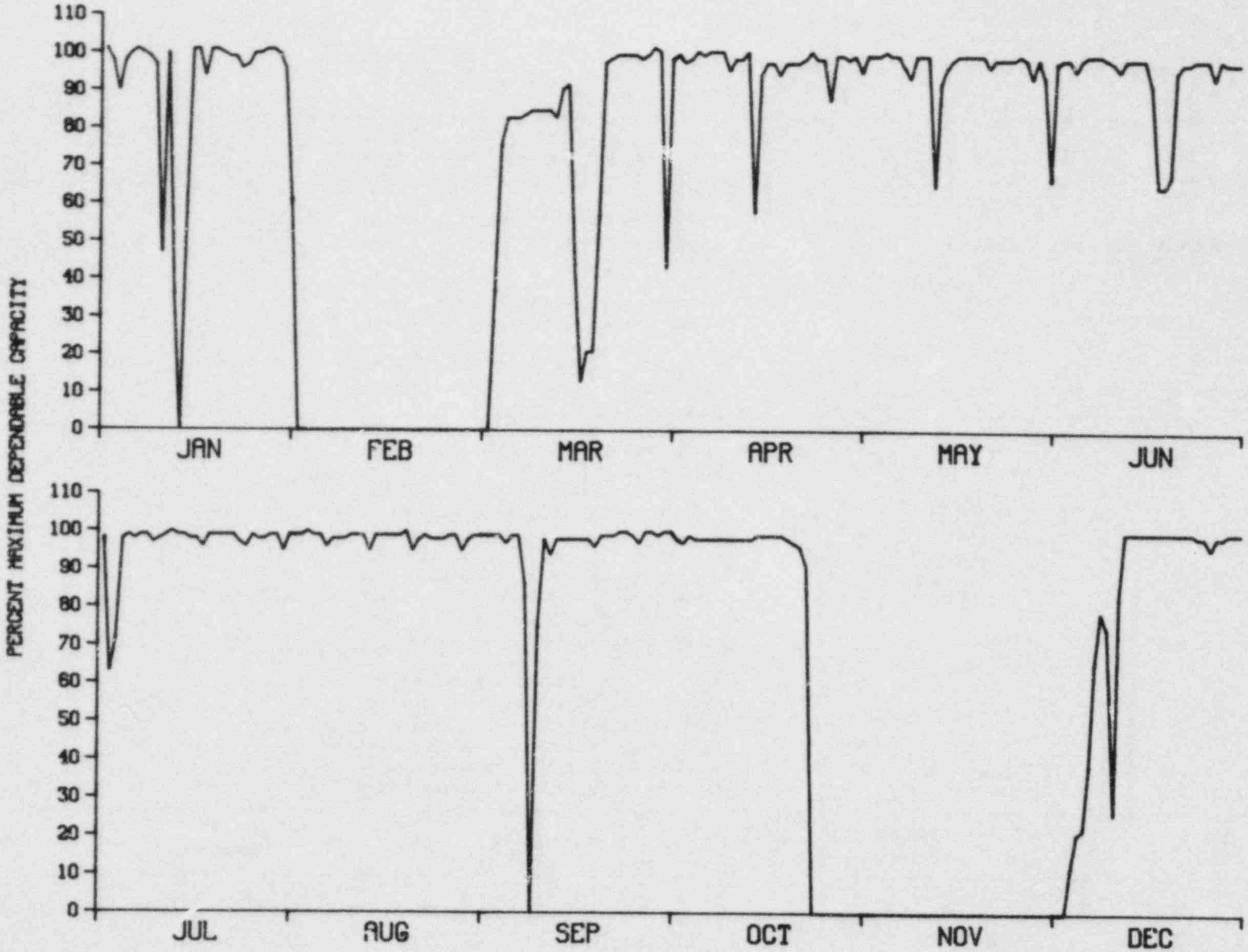
Farley 2 achieved a well-above-average availability factor in 1982 with only two extended outages during the year. A 28-day outage, which took almost the entire month of February, was caused by the need to repair a reactor coolant pump seal. Then, on October 22, the plant began its end-of-cycle 1 refueling shutdown which was completed in only 41 days, coming back on line in the first week of December. The other outages during the year were all brief, the longest being a one-day shutdown caused by operator error in switching electrical breakers.

Details of plant outages for Farley 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/08/82	7.0	F	Reactor trip due to malfunction of No. 4 governor valve during governor valve testing. Steam generator oscillations caused low-low SG level trip.	A	3	Steam and power conversion (HA)	Valves
2	1/11/82	45.0	F	Reactor trip due to frozen sensing lines on PT-494 and PT-496 (steam line differential pressure transmitters). Insulation added.	H	3	Instrumentation and controls (IA)	Instrumentation and controls
3	1/31/82	663.5	F	Unit shutdown due to reactor coolant pump seal leakage.	A	1	Reactor coolant (CB)	Pumps
4	2/28/82	13.7	F	Reactor trip due to the receipt of a "2A" steam generator low level signal caused by the cycling of the "2A" MFP miniflow. A consecutive reactor trip occurred when the unit was being synchronized to the grid due to a failure in the DEH system.	A	3	Reactor coolant (CH)	Pumps
5	2/28/82	21.9	F	Outage due to reactor trips caused by the cycling of the 2A MFP miniflow and a failure in the DEH system.	A	3	Reactor coolant (CH)	Pumps
6	3/15/82	19.7	F	Reactor trip, turbine trip, caused by an intermittent ground in the MSIV controls.	A	3	Steam and power conversion (HB)	Instrumentation and controls
7	3/30/82	5.5	F	Unit tripped due to a "B" steam generator feed pump trip.	A	3	Reactor coolant (CH)	Pumps
8	4/13/82	6.4	F	Reactor trip. Lost "B" train due to inadvertent actuation of relays at the switchhouse during routine testing.	G	3	Electric power (ED)	Codes not applicable

Details of plant outages for Farley 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
9	5/12/82	6.8	F	While switching from 2A to 2B start-up transformer, the breaker switch malfunctioned causing a LOSP on the 2G 4160-V bus and a reactor trip. The switch was repaired and the unit was returned to service.	A	3	Electric power (EB)	Electrical conductors
10	7/02/82	9.2	F	Printed circuit card I1 (voltage regulator) in rod control cabinet 2BD failed, causing a loss of power to the stationary gripper coils for shutdown bank B group 2 rod control assemblies. As a result, four assemblies dropped into the core causing an NIS negative rate reactor trip. Following the replacement of the card, the unit was returned to service.	A	3	Reactor (RB)	Instrumentation and controls
11	9/07/82	25.8	F	Reactor tripped due to startup transformer breaker DG-15-to-2G 4160-V bus inadvertently being opened at the time 2B diesel generator output breaker was being closed.	G	3	Electric power (EB)	Transformers
12	10/22/82	991.2	S	Unit was taken off line for the cycle I—II refueling outage.	C	1	Reactor (RC)	Fuel elements
13	12/10/82	8.4	S	Unit taken off line for the performance of the turbine overspeed trip test.	B	2	Steam and power conversion (HA)	Codes not applicable



DESIGN ELEC. RATING - 829 MAX. DEPEND. CAP. - 814 (100%) FARLEY 2

FITZPATRICK

I. Summary

Description

Location: Scriba, New York
Docket No.: 50-333
Reactor type: BWR
Maximum dependable capacity [MW(e)-net]: 810
Commercial operation: 7/28/75
Years operating experience: 6.9

Performance

Net electrical energy generated (MWh): 4,959,655
Unit availability factor (%): 75.0
Unit capacity factor (%) (using MDC): 69.9
Unit capacity factor (%) [using design MW(e)]: 69.0

Outages

Total No.: 4
  Forced: 4
  Scheduled: 0
Total hours: 2,188[a] (25.0%)
  Forced: 557 (6.4%)
  Scheduled: 1,632[a] (18.6%)

II. Highlights

FitzPatrick began 1982 in a refueling outage that lasted until the first week in March. Thereafter the plant operated very reliably with only three significant outages. In mid-July a turbine vibration-detection instrument failure resulted in a five-day interruption. On October 7 one of the main steam isolation valves failed, with the valve disk coming loose from the valve stem. This problem kept the plant off line for 11 days. Then, in mid-December the same valve experienced the same failure again, this time, however, requiring only six days for the repair.

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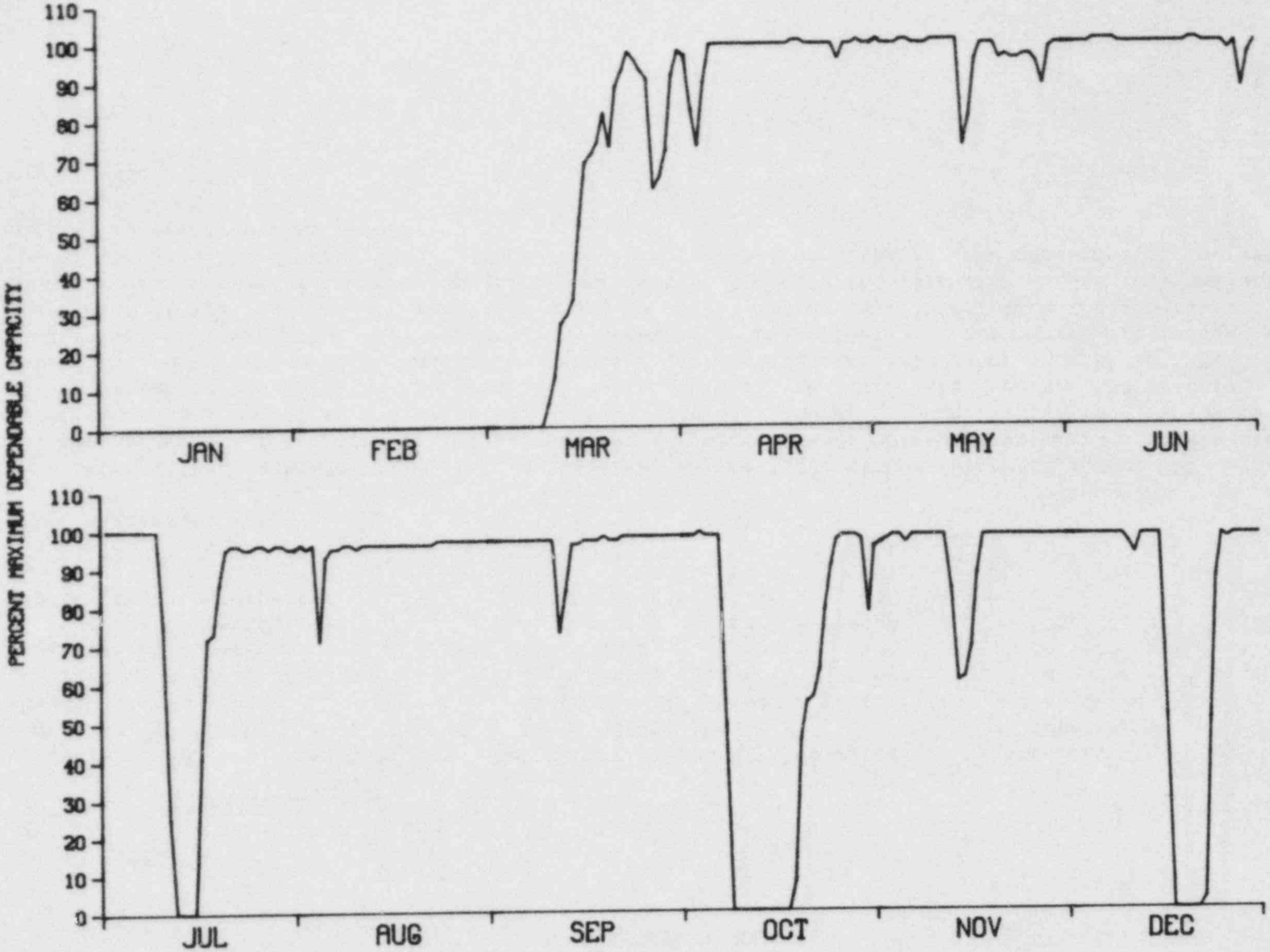
[a]Includes 2,188 h in 1982 from continuation of 10/31/81 shutdown.

Details of plant outages for FitzPatrick

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	10/31/81	1,631.9	S	Conclusion of refueling outage (cumulative hours 3,118.6).	C	4	Reactor (RC)	Fuel elements
2	3/10/82	26.6	F	Dirty filter to No. 2 main stop valve.	A	3	Steam and power conversion (HA)	Filters
3	7/11/82	112.9	F	Trip due to turbine vibration instrument failure.	A	3	Steam and power conversion (HA)	Turbines
4	10/07/82	266.5	F	"D" inboard MSIV failure due to disk separation from stem. Repaired valve with two antirotation pins.	A	3	Steam and power conversion (HB)	Valves
5	12/16/82	150.5	F	"D" inboard MSIV failure due to disk separation from system. Valve repaired and returned to service.	A	3	Steam and power conversion (HB)	Valves



DESIGN ELEC. RATING - 821 MAX. DEPEND. CAP. - 810 (100%)

FITZPATRICK

FORT CALHOUN 1

I. Summary

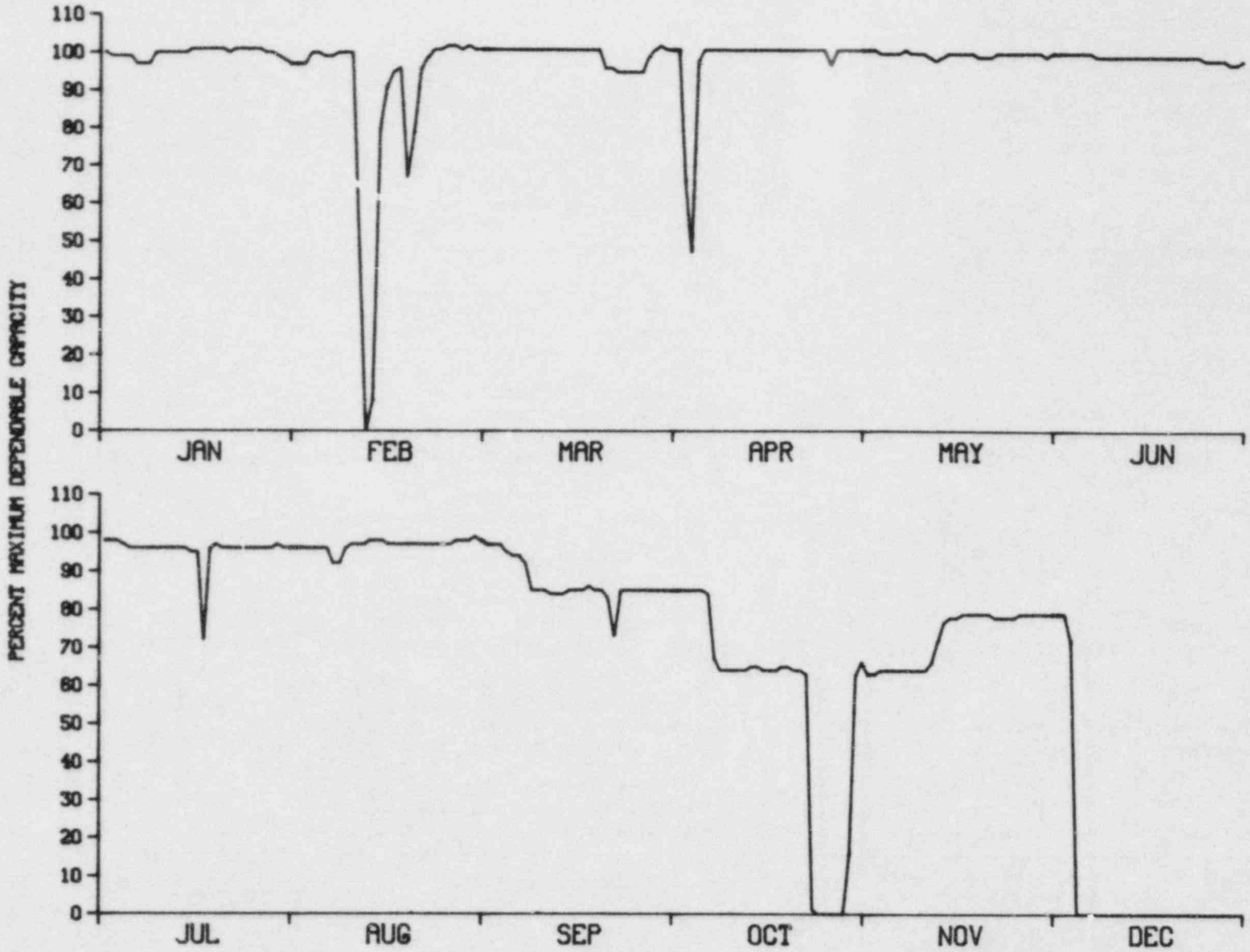
Description	Performance	Outages
Location: Fort Calhoun, Nebraska	Net electrical energy generated (MWh): 3,482,164	Total No.: 6
Docket No.: 50-285	Unit availability factor (%): 89.7	Forced: 5
Reactor type: PWR	Unit capacity factor (%) (using MDC): 83.2	Scheduled: 1
Maximum dependable capacity [MW(e)-net]: 457	Unit capacity factor (%) [using design MW(e)]: 83.2	Total hours: 902 (10.3%)
Commercial operation: 6/20/74		Forced: 297 (3.4%)
Years operating experience: 9.4		Scheduled: 606 (6.9%)

II. Highlights

Fort Calhoun achieved excellent availability during 1982, with a factor of almost 90%. There were no shutdowns at all between April 2 and October 23, when leakage through several hand-hole gaskets for instrumentation access to the secondary coolant loop and leakage through several root valves became large enough in the aggregate to require repair. This outage lasted three days. A 50-h outage in February due to a problem with a magnetic control rod clutch was the only other significant shutdown of the entire year until the very end when, on December 3, a first-stage rotor of the electric generator developed broken blades and resulted in wiped bearings. Three days later, with the generator clearly out for an extended period for repair, it was decided to begin the refueling outage that had originally been scheduled for January 1983. Hence the plant remained off line for the remainder of the year for refueling and generator repair.

Details of plant outages for Fort Calhoun 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	2/10/82	50.0	F	Control rod inserted into the core due to a faulty magnetic clutch. Replaced magnetic clutch.	A	1	Reactor (RB)	Control rods
2	2/17/82	9.0	F	A circuit card in the electro-hydraulic turbine control system malfunctioned. Replaced faulty circuit card.	A	3	Steam and power conversion (HA)	Instrumentation and controls
3	4/02/82	16.2	F	Generator tripped due to a transient on 345-kV power line. Probable cause was high winds from stormy weather. The district is continuing to investigate the event to determine if any corrective actions can prevent the incident from recurring.	H	3	Electric power (EA)	Codes not applicable
4	10/23/82	153.3	F	Leakage from the secondary side of steam generator RC-2A was at a rate to warrant shutting down the plant and effect repairs. The leakage was determined to have originated from three instrumentation handhole gaskets and several root valves. These components of RC-2A were repaired to eliminate the leakage.	F	1	Steam and power conversion (HB)	Other components
5	12/03/82	68.0	F	The reactor tripped because of high turbine vibration. After investigation, it was determined that the the first stage rotor of the high-pressure turbine had broken blades and wiped bearings.	A	3	Steam and power conversion (HA)	Turbines
6	12/06/82	606.0	S	Subsequently, it was decided as of December 6, 1982, to commence the 1983 refueling outage approximately one month early.	C	9	Other (XX)	Other components



DESIGN ELEC. RATING - 478 MAX. DEPEND. CAP. - 478 (100%) FORT CALHOUN 1

FORT ST. VRAIN

I. Summary

Description	Performance	Outages
Location: Platteville, Colorado	Net electrical energy generated (MWh): 568,851	Total No.: 15
Docket No.: 50-267	Unit availability factor (%): 37.3	Forced: 13
Reactor type: HTGR	Unit capacity factor (%) (using MDC): 19.7	Scheduled: 2
Maximum dependable capacity [MW(e)-net]: 330	Unit capacity factor (%) [using design MW(e)]: 19.7	Total hours: 5,493[a] (62.6%)
Commercial operation: 7/01/79		Forced: 2,601 (29.6%)
Years operating experience: 6.1		Scheduled: 2,892[a] (33.0%)

II. Highlights

Fort St. Vrain, the nation's only high-temperature gas-cooled power reactor, experienced considerable difficulties in 1982, which kept it shut down more than 60% of the time. The unit began the year in an extended outage which had begun the previous November for the purpose of accomplishing loop-split modifications. This outage ended in mid-April. Shortly thereafter, following some shorter outages, the unit was shut down again on April 20 to replace one of the control rod drives. This took ten and a half days. The reactor then operated almost continuously until the beginning of October when it was shut down by a turbine trip and remained off line for primary and secondary systems maintenance for the rest of the year. While the plant was operating, it was limited to 70% of full power pending resolution of temperature fluctuation problems.

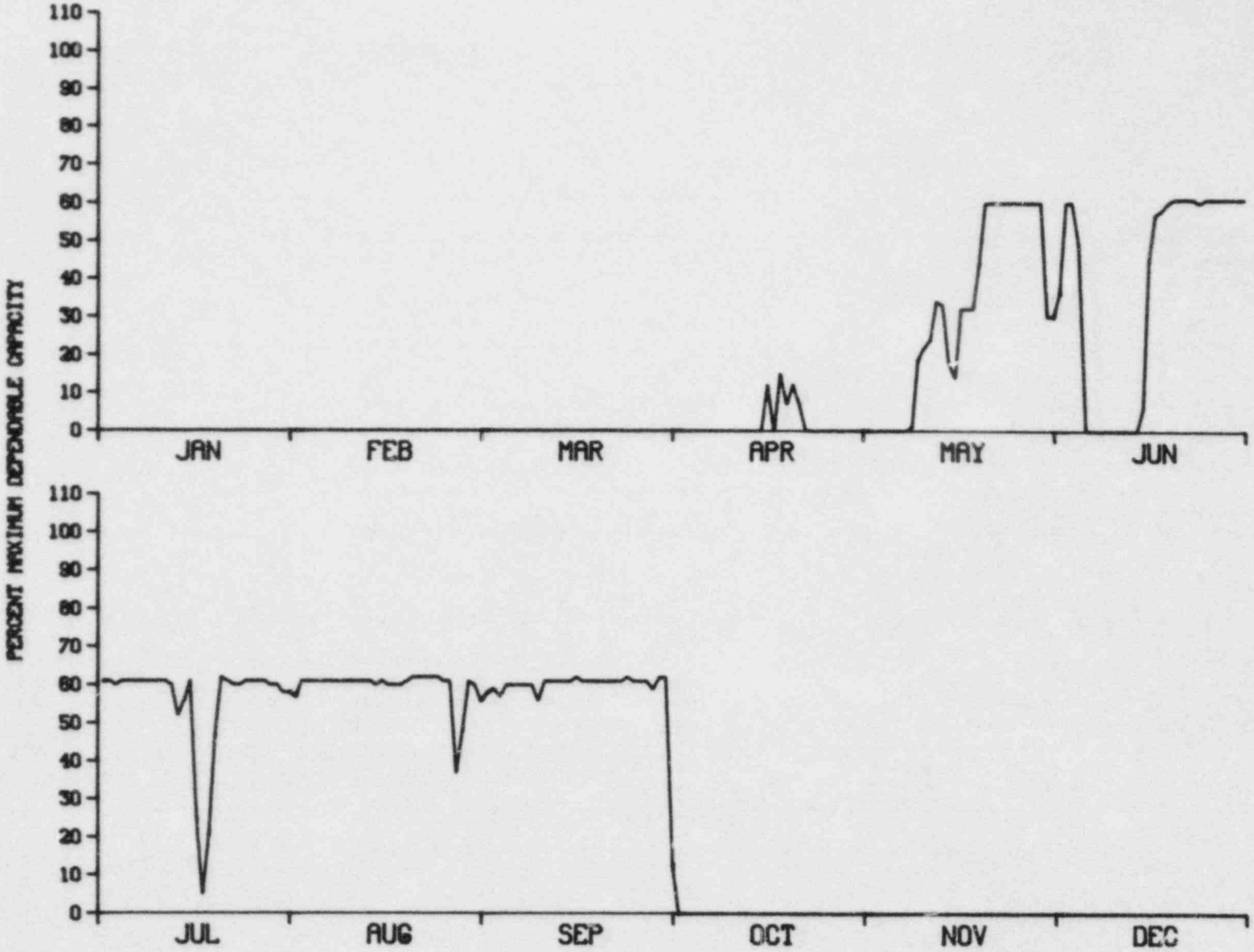
[a]Includes 2,491 h in 1982 from continuation of 11/09/81 outage.

Details of plant outages for Fort St. Vrain

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	11/09/81	2,491.3	S	Loop-split modification.	B	4	Reactor coolant (CB)	Other components
2	4/15/82	35.3	F	High-pressure scram — PPS.	F	3	Instrumentation and controls (IB)	Instrumentation and controls
3	4/18/82	10.0	F	Turbine manually tripped due to electrohydraulic control system upset during maintenance. Reactor remained critical.	H	9	Steam and power conversion (HB)	Instrumentation and controls
4	4/18/82	5.0	F	Turbine manually tripped for maintenance. Reactor remained critical.	A	9	Steam and power conversion (HB)	Valves
5	4/19/82	2.9	F	Turbine trip due to low hydraulic control pressure. Reactor remained critical.	A	9	Steam and power conversion (HB)	Instrumentation and controls
6	4/20/82	251.7	S	Manual shutdown to change out control rod drive (CRD) in region 19 as per request of NRC.	B	2	Reactor coolant (CJ)	Other components
7	5/01/82	148.8	S	Manual shutdown to change out CRD in region 19 as per request of NRC.	B	2	Reactor coolant (CJ)	Other components
8	5/07/82	35.1	F	Turbine manually tripped for maintenance to No. 2 main steam stop valve. Reactor remained critical.	B	9	Steam and power conversion (HB)	Valves
9	5/13/82	1.2	F	Turbine trip due to low hydraulic control pressure. Reactor remained critical.	H	9	Steam and power conversion (HB)	Instrumentation and controls
10	5/13/82	4.4	F	Turbine manually tripped for maintenance to No. 2 main steam stop valve. Reactor remained critical.	B	9	Steam and power conversion (HB)	Valves

Details of plant outages for Fort St. Vrain (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
11	5/14/82	1.5	F	Turbine manually tripped for inspection of servo-control valves by General Electric. Reactor remained critical.	B	9	Steam and power conversion (HB)	Valves
12	5/15/82	11.5	F	Turbine manually tripped for maintenance of hot reheat steam valves. Reactor remained critical.	B	9	Steam and power conversion (HB)	Valves
13	6/04/82	235.7	F	Loop 1 shutdown from spurious steam rupture signal. Reactor manually scrammed next day due to loss of 480-V essential buses.	A	2	Steam and power conversion (HB)	Instrumentation and controls
14	7/16/82	27.7	F	Reactor scram from plant protective system (hot reheat steam temperature) and plant recovery.	H	3	Instrumentation and controls (IB)	Instrumentation and controls
15	8/27/82	4.6	F	Turbine-generator trip during electrical maintenance. Reactor remained critical.	H	3	Steam and power conversion (HBD)	Turbines
16	9/30/82	2,226.1	F	Loop 1 shutdown followed by reactor scram and turbine-generator trip.	H	3	Instrumentation and controls (IB)	Instrumentation and controls



DESIGN ELEC. RATING - 330 MAX. DEPEND. CAP. - 330 (100%) FORT ST VRAIN

GINNA

I. Summary

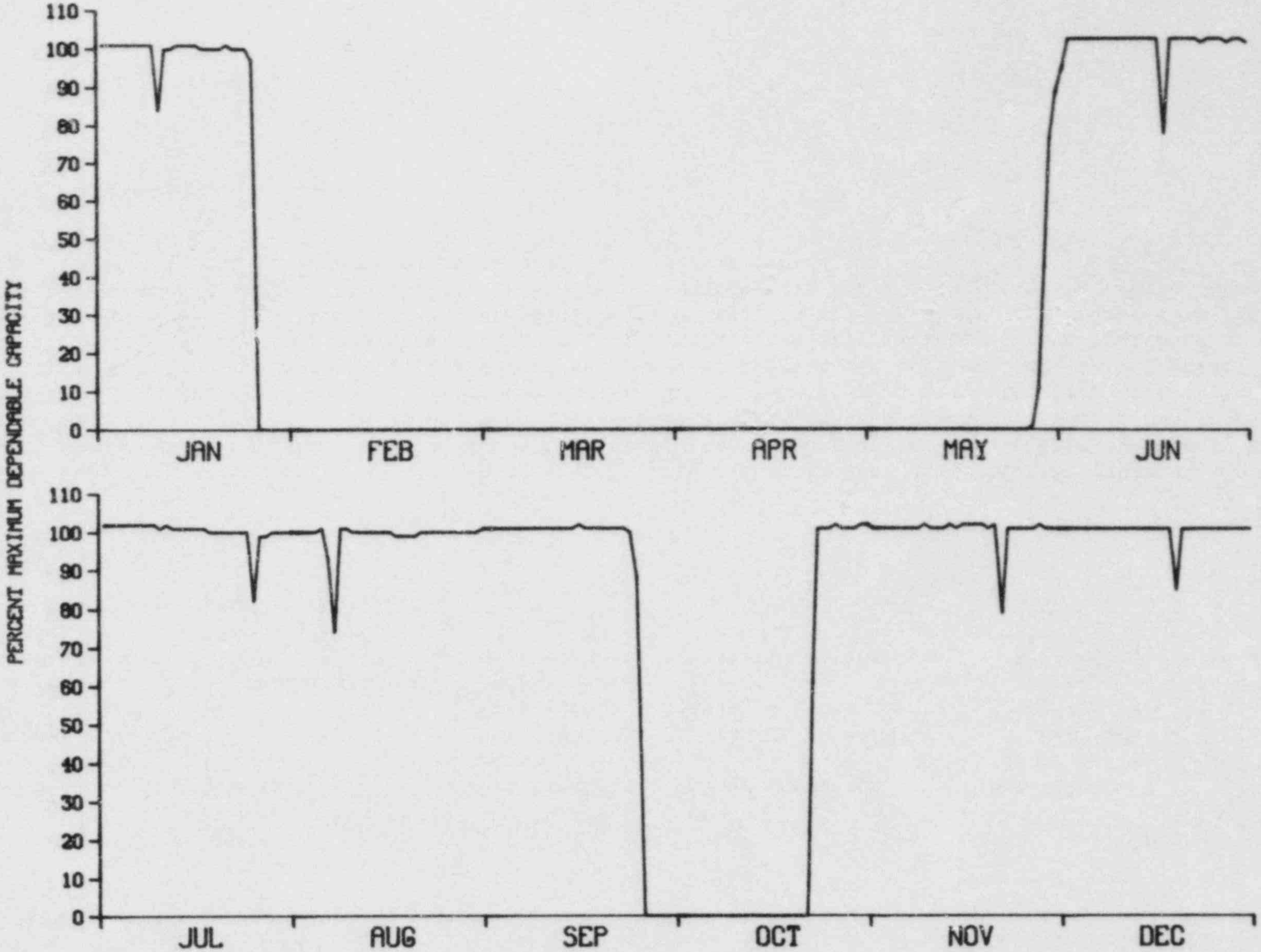
Description	Performance	Outages
Location: Ontario, New York	Net electrical energy generated (MWh): 2,047,987	Total No.: 6
Docket No.: 50-244	Unit availability factor (%): 58.8	Forced: 2
Reactor type: PWR	Unit capacity factor (%) (using MDC): 58.5	Scheduled: 4
Maximum dependable capacity [MW(e)-net]: 470	Unit capacity factor (%) [using design MW(e)]: 58.5	Total hours: 3,609 (41.2%)
Commercial operation: 7/01/79		Forced: 1,091 (12.4%)
Years operating experience: 13.1		Scheduled: 2,518 (28.7%)

II. Highlights

On February 22, 1982, Ginna experienced a major rupture of one steam generator tube, resulting in a site emergency and actuation of the safety injection system. This outage is described in detail in Chap. 4 of this report under Abnormal Occurrences. This outage lasted to the last week of May, about six and a half weeks. The reactor then operated almost entirely uninterruptedly for the remainder of the year, with the exception of a 27-day scheduled outage begun the last week of September for steam generator inspection. That the plant achieved almost 60% availability despite the major disruption is rather remarkable.

Details of plant outages for Ginna

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/25/82	1,865.8	S	Shutdown for normal refueling outage activities.	C	9	Reactor (RC)	Fuel elements
2	2/22/82	1,070.5	F	Tube leak in the "B" steam generator caused a rapid drop in reactor coolant system pressure which initiated a reactor trip and safety injection.	A	3	Steam and power conversion (HJ)	Heat exchangers
3	5/28/82	1.2	S	Turbine overspeed trip test. Generator off-line.	B	9	Steam and power conversion (HA)	Codes not applicable
4	5/28/82	5.5	S	Unit removed from service to obtain additional low power (1-3%) data on the Westinghouse metal impact monitoring system.	B	9	System code not applicable (ZZ)	Codes not applicable
5	8/06/82	20.3	F	Reactor trip, followed by turbine trip, due to a reactor pressurizer rate trip. This was caused by pressurizer level vent line venting during maintenance.	B	3	Instrumentation and controls (IA)	Vessels, pressure
6	9/25/82	645.3	S	Shutdown for steam generators inspection.	B	1	Reactor coolant (CA)	Heat exchangers



DESIGN ELEC. RATING - 470 MAX. DEPEND. CAP. - 470 (100%) GINNA

HADDAM NECK

I. Summary

Description

Location: Haddam Neck, Connecticut
Docket No.: 50-213
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 555
Commercial operation: 1/01/68
Years operating experience: 15.4

Performance

Net electrical energy generated (MWh): 4,538,360
Unit availability factor (%): 93.4
Unit capacity factor (%) (using MDC): 93.1
Unit capacity factor (%) [using design MW(e)]: 89.0

Outages

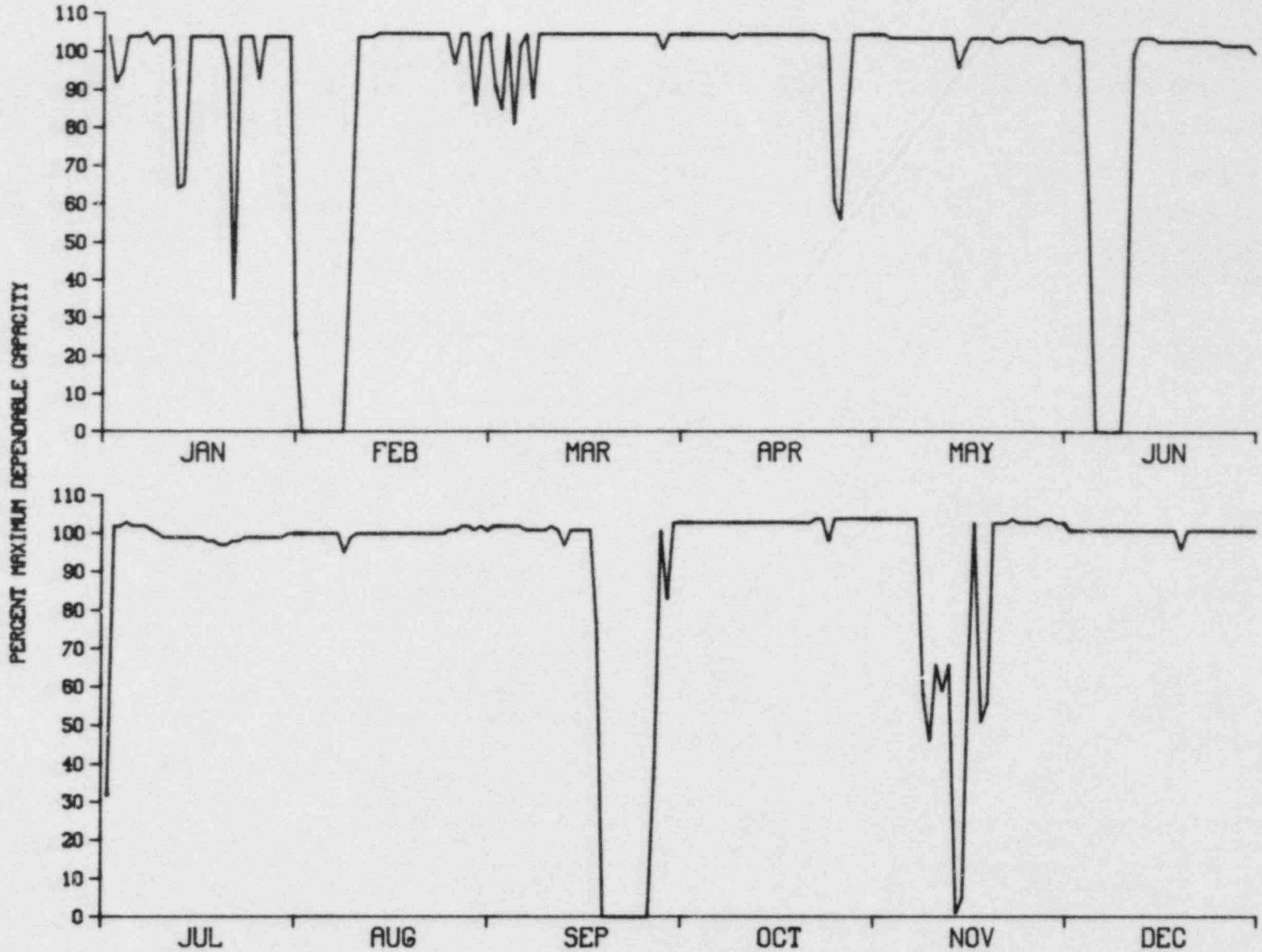
Total No.: 7
 Forced: 6
 Scheduled: 1
Total hours: 574 (66%)
 Forced: 535 (6.1%)
 Scheduled: 39 (0.4%)

II. Highlights

This venerable plant, the third-oldest operating reactor in the United States, achieved the third-highest availability factor of any PWR in the United States for the year 1982. There were only three shutdowns with significant duration, none longer than eight days. On January 31 some blown fuses on the main electric generator caused loss of the exciter field, resulting in a reactor trip that lasted almost eight days. Then, on June 4, a five-day outage resulted from an exciter loss due to an electric short in the unit. This outage was also used to repair a main steam trip isolation valve that hung up when it was in cooled-down condition. The last significant outage, in mid-September, was required to clean up moisture that had seeped into the oil of the main transformer. Aside from these three brief outages, the sum of all other shutdowns was just over 60 h for the entire year.

Details of plant outages for Haddam Neck

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/31/82	184.5	F	Turbine and reactor trip. Trip caused by loss of generator field. Located six blown fuses on main exciter.	A	3	Steam and power conversion (HA)	Circuit closers/ interrupters
2	6/04/82	132.7	F	Reactor and turbine trip due to short circuit in exciter causing loss of exciter field. Repaired short circuit and verified all materials secured in exciter. Also, during this time period the No. 1 main steam trip isolation valve would not go closed when cooled down. Repaired and realigned tail link.	A	3	Steam and power conversion (HA)	Generators
3	9/17/82	195.1	F	Moisture in main transformer oil. Filtered oil. Repaired leaks, tested and returned to service. In addition, battery internal plates swelled, causing stress on battery casing and resulting in cracking of casing. Replaced battery.	B	1	Electric power (EB)	Transformers
4	11/08/82	10.4	F	Main feed pump trip, due to loss of suction. Verified system components operating properly.	A	3	Steam and power conversion (HB)	Pumps
5	11/13/82	39.2	S	Turbine right hand trip valve would not open. The pin holding the disk to the stem sheared and was replaced.	A	1	Steam and power conversion (HA)	Mechanical function units
6	11/17/82	9.8	F	Bank "C" rods dropped during rod motion checks. Cause undetermined.	A	2	Instrumentation and controls (IA)	Conrol rod drive mechanisms
7	11/17/82	2.3	F	RCP BUT transfer greater than 10% power. Discussed with operators.	G	3	Reactor coolant (CB)	Pumps



DESIGN ELEC. RATING - 582 MAX. DEPEND. CAP. - 555 (100%) HADDAM NECK

HATCH 1

I. Summary

Description

Location: Baxley, Georgia
Docket No.: 50-321
Reactor type: BWR
Maximum dependable capacity [MW(e)-net]: 764
Commercial operation: 12/31/75
Years operating experience: 8.1

Performance

Net electrical energy generated (MWh): 2,877,575
Unit availability factor (%): 49.3
Unit capacity factor (%) (using MDC): 43.3
Unit capacity factor (%) [using design MW(e)]: 42.3

Outages

Total No.: 16
Forced: 10
Scheduled: 6
Total hours: 4,516[a] (51.6%)
Forced: 1,528 (17.4%)
Scheduled: 2,989[a] (34.1%)

II. Highlights

Hatch 1 began the year in a turbine inspection outage which had begun the previous Christmas day. Once this outage ended in early February, the unit operated reliably until late April when high conductivity in the primary system water, indicative of impurities in it, forced a shutdown that lasted until mid-June. The cause of the high conductivity was found to be intrusion of ion exchange resin into the reactor system. An instrument problem, which resulted in an erroneous high-pressure signal for the primary system, caused an eight-and-a-half-day outage in July. The reactor then operated relatively uninterruptedly until it was shut down on October 9 for a normal refueling outage, which lasted for the rest of the year and on into 1983.

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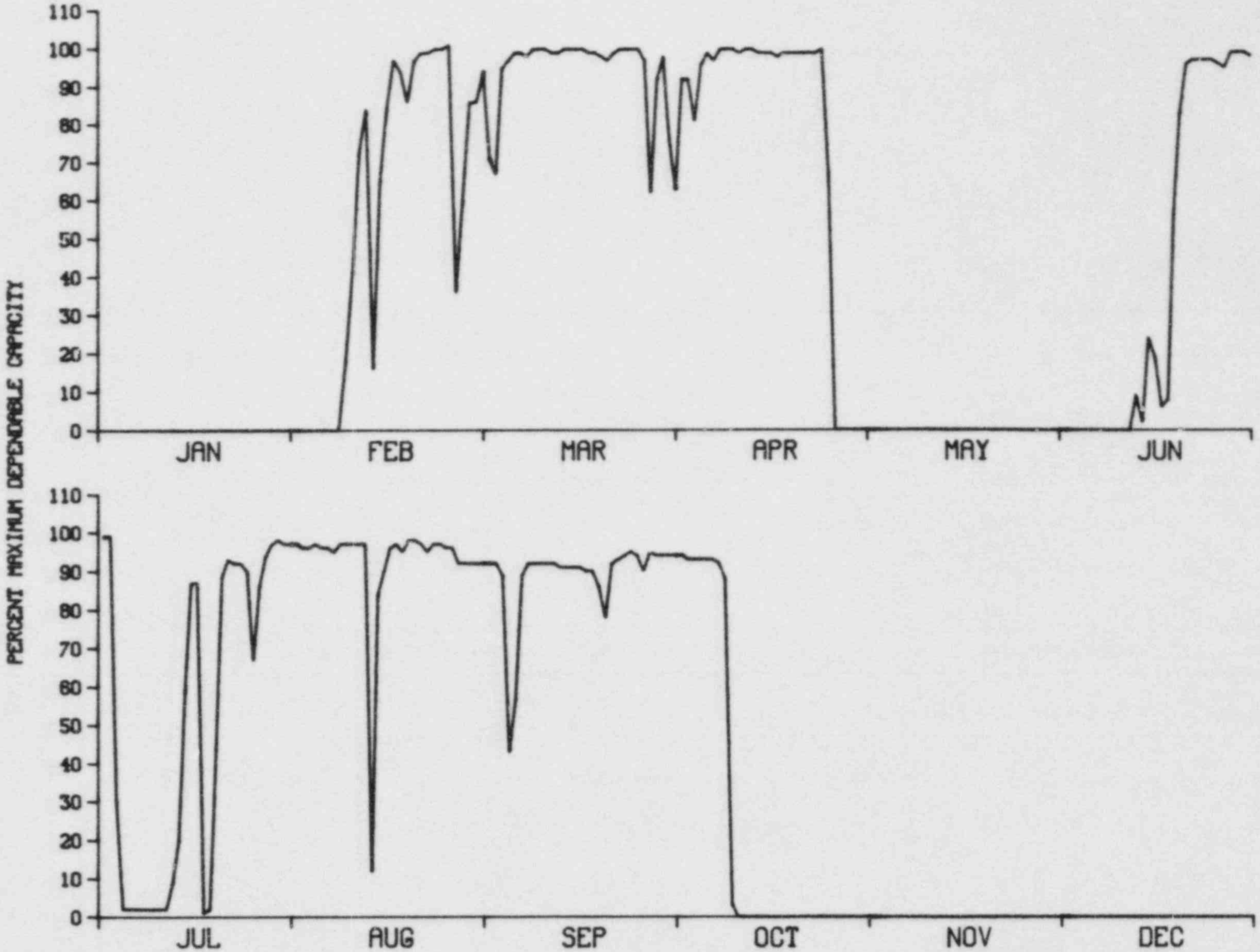
[a]Includes 918 h in 1982 from continuation of 12/25/81 outage.

Details of plant outages for Hatch 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	12/25/81	910.4	S	Continuation of normal shutdown for turbine inspection.	B	4	Steam and power conversion (HA)	Turbines
2	2/12/82	17.6	F	Reactor scram due to low reactor level.	A	3	Reactor coolant (CG)	Other components
3	2/24/82	14.5	F	Reactor scram due to low water level.	A	3	Reactor coolant (CB)	Other components
4	4/01/82	7.0	F	Condenser tube leak.	A	5	Steam and power conversion (HH)	Heat exchangers
5	4/02/82	38.5	S	Rod pattern adjustment.	B	5	Other (XX)	Other components
6	4/06/82	7.0	S	Daily turbine testing.	B	5	Steam and power conversion (HA)	Turbines
7	4/09/82	7.5	S	Daily turbine testing.	B	5	Steam and power conversion (HA)	Turbines
8	4/16/82	6.6	S	Daily turbine testing.	B	5	Steam and power conversion (HA)	Turbines
9	4/24/82	5.5	S	Daily turbine testing.	B	5	Steam and power conversion (HA)	Turbines
10	4/24/82	1,158.7	F	High conductivity; resin intrusion in reactor cavity.	A	2	Reactor coolant (CG)	Demineralizers
11	6/12/82	27.9	F	Reactor manual scram due to blown gasket on "A" water box.	A	2	Steam and power conversion (HF)	Heat exchangers
12	6/16/82	24.8	F	Turbine off line due to high water conductivity in water box "D."	H	1	Auxiliary water (WC)	Demineralizers

Details of plant outages for Hatch 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
13	7/03/82	202.7	F	Reactor scram due to false high reactor pressure indication.	A	3	Instrumentation and controls (IB)	Instrumentation and controls
14	7/12/82	9.1	F	Unit offline due to high H_2 content in off-gas.	H	1	Radioactive waste management (MB)	Recombiners
15	7/18/82	49.9	F	Reactor scram to repair reactor water cleanup valve.	A	2	Reactor coolant (CG)	Valves
16	8/13/82	15.4	F	Reactor scram due to moisture separator high level "A" and "B."	A	3	Reactor coolant (CC)	Codes not applicable
17	10/09/82	2,013.1	S	Normal reactor shutdown for refueling outage.	C	1	Reactor (RC)	Fuel elements



DESIGN ELEC. RATING - 777 MAX. DEPEND. CAP. - 762 (100%)

HATCH 1

HATCH 2

I. Summary

Description	Performance	Outages
Location: Baxley, Georgia	Net electrical energy generated (MWh): 3,728,261	Total No.: 18
Docket No.: 50-366	Unit availability factor (%): 63.8	Forced: 13
Reactor type: BWR	Unit capacity factor (%) (using MDC): 55.2	Scheduled: 5
Maximum dependable capacity [MW(e)-net]: 773	Unit capacity factor (%) [using design MW(e)]: 54.3	Total hours: 3,213 (26.4%)
Commercial operation: 9/05/79		Forced: 754 (8.6%)
Years operating experience: 4.3		Scheduled: 2,459 (28.1%)

II. Highlights

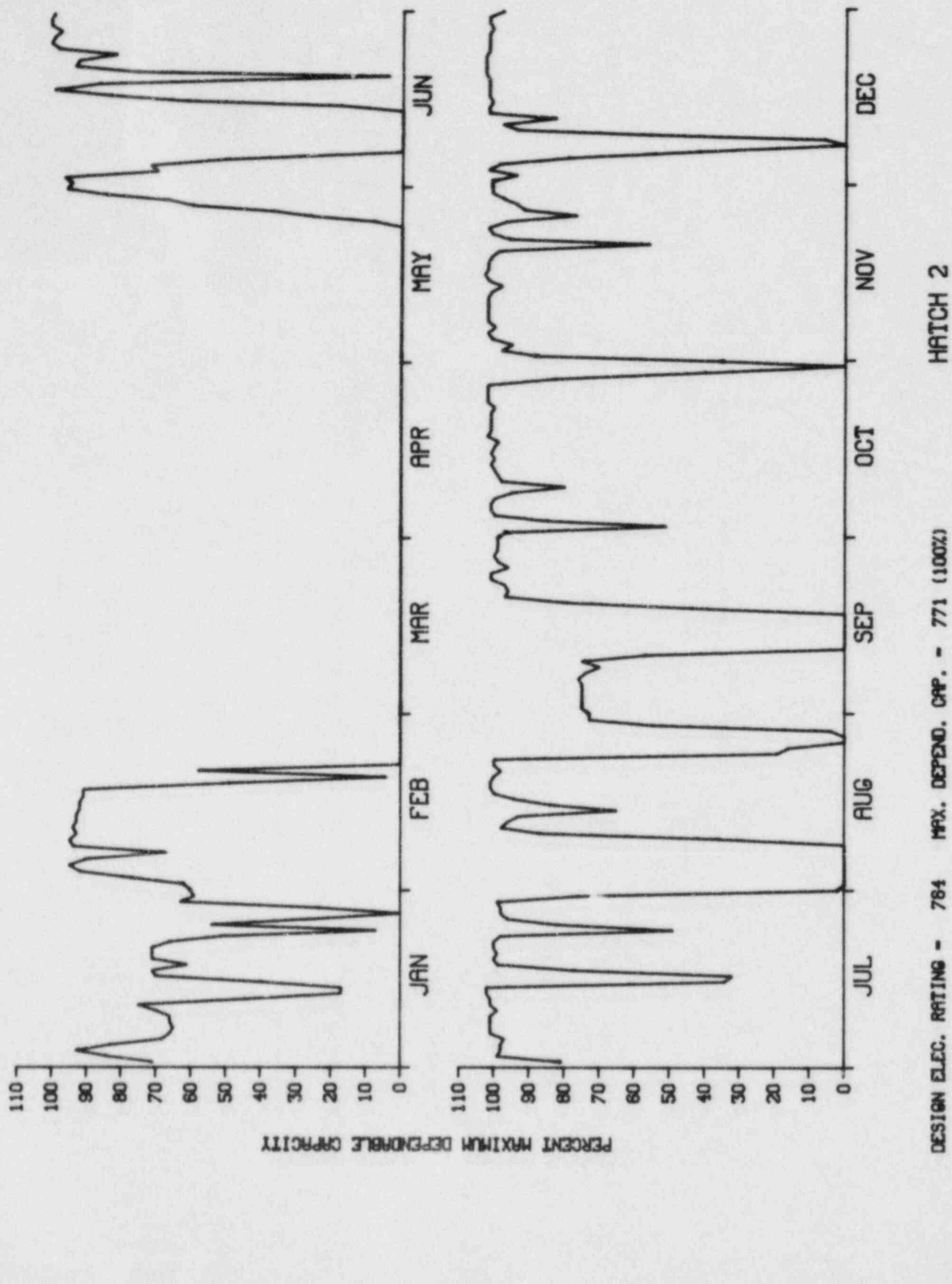
During 1982 Hatch 2 was beset by numerous outages, most of relatively brief duration, but cumulatively resulting in an availability factor of only about 64%. On February 19 the unit was shut down for a refueling outage, which lasted more than 13 weeks until the last week of May. In early June a failure of a reactor coolant level instrument caused a scram that kept the system off for nine days. At the end of July a diesel generator failure required the unit to be shut down for another nine days, and in mid-September repairs on a main steam isolation valve cost another week's operation. Quite a few other, shorter, interruptions also took place during the year.

Details of plant outages for Hatch 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/23/82	21.5	F	Reactor scrammed due to low reactor water level.	A	3	Reactor coolant (CB)	Other components
2	1/26/82	47.8	F	Generator off line due to water in the bus duct.	A	1	Other auxiliary (AA)	Heat exchangers
3	2/17/82	28.6	F	Reactor auto scram due to low water level.	A	3	Reactor coolant (CB)	Other components
4	2/19/82	2,269.9	S	Reactor scram for refueling outage.	C	2	Reactor (RC)	Fuel elements
5	5/25/82	7.0	S	Daily turbine testing.	B	5	Steam and power conversion (HA)	Turbines
6	5/26/82	12.0	F	TIP machine inoperable.	A	5	Instrumentation and controls (IF)	Instrumentation and controls
7	5/27/82	13.0	F	TIP machine inoperable.	A	5	Instrumentation and controls (IF)	Instrumentation and controls
8	5/28/82	4.0	S	Feedwater heater test.	B	5	Reactor coolant (CH)	Heat exchangers
9	5/28/82	5.5	S	Daily turbine testing.	B	5	Steam and power conversion (HA)	Turbines
10	5/30/82	3.0	F	MSRs out of service.	A	5	Reactor coolant (CC)	Heat exchangers
11	6/05/82	213.2	F	Reactor scram due to TSV fast closure due to reactor level controller failed upscale.	A	3	Steam and power conversion (HB)	Valves
12	6/18/82	21.9	F	Reactor scram due to low reactor water level.	A	3	Reactor coolant (CH)	Codes not applicable

Details of plant outages for Hatch 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
13	7/15/82	16.1	F	Reactor scram due to loss of suction from condensate demineralizer.	A	3	Auxiliary water (WC)	Demineralizers
14	7/30/82	218.8	F	Manual scram to repair 2C diesel generator.	D	2	Electric power (EE)	Generators
15	8/25/82	84.7	F	Reactor scram on group I isolation caused by high steam flow.	A	3	Reactor coolant (CD)	Valves
16	9/10/82	172.5	S	Repair MSIV.	A	1	Reactor coolant (CD)	Valves
17	10/30/82	29.5	F	Off line to repair "B" MSIV.	B	3	Reactor coolant	Valves
18	12/06/82	43.9	F	Problem with recirc. pump controller, unit off line.	A	3	Instrumentation and controls (IE)	Instrumentation and controls


PERCENT MAXIMUM DEPENDABLE CAPACITY
110
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DEC
DESIGN ELEC. RATING - 784 MAX. DEPEND. CAP. - 771 (100%)
HATCH 2

INDIAN POINT 2

I. Summary

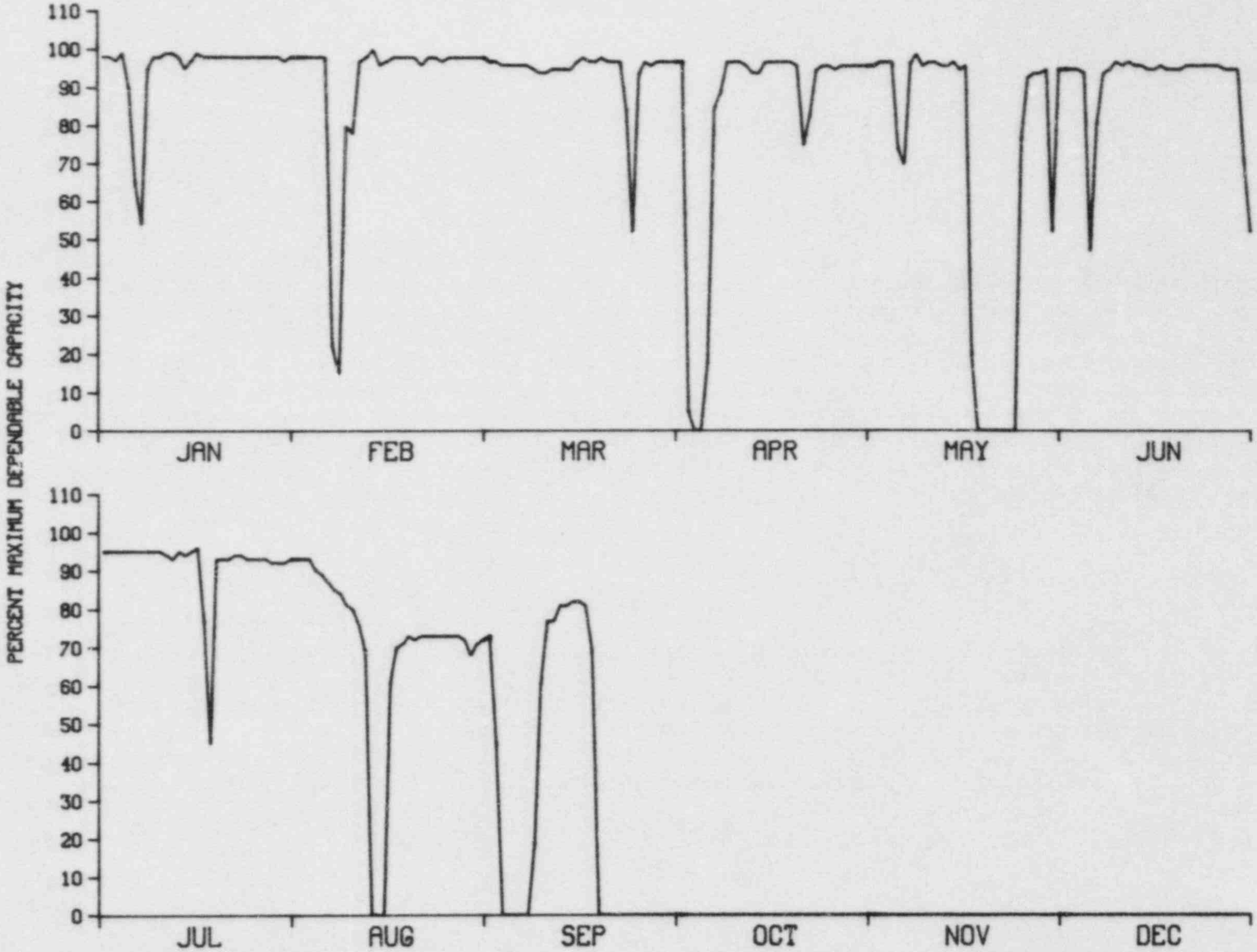
Description	Performance	Outages
Location: Indian Point, New York	Net electrical energy generated (MWh): 4,447,401	Total No.: 9
Docket No.: 50-247	Unit availability factor (%): 65.4	Forced: 7
Reactor type: PWR	Unit capacity factor (%) (using MDC): 58.8	Scheduled: 2
Maximum dependable capacity [MW(e)-net]: 864	Unit capacity factor (%) [using design MW(e)]: 58.2	Total hours: 3,031 (34.6%)
Commercial operation: 8/01/73		Forced: 454 (5.2%)
Years operating experience: 9.5		Scheduled: 2,577 (29.4%)

II. Highlights

Indian Point 2 operated with relatively few and brief interruptions in 1982, until it began a very long refueling and maintenance outage in mid-September, which extended from then on past the end of the year. The only earlier outages of significant duration were a seven-and-a-half-day outage in May due to feedwater system problems and two outages, one in August and one in September, which together totaled eight days and were caused by fan cooler problems in the containment cooling system.

Details of plant outages for Indian Point 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	2/06/82	31.7	F	Loss of 480-V bus section 2A replaced breaker overcurrent trip devices for phases A and C.	A	3	Electric power (EB)	Circuit closers/ interrupters
2	4/02/82	84.8	F	Unit trip due to No. 22 MBFP erratic governor control system.	A	3	Reactor coolant (CH)	Pumps
3	5/17/82	179.4	F	Trip on feedwater system perturbation.	G	3	System code not applicable (ZZ)	Codes not applicable
4	5/24/82	3.8	F	No. 22 SG high level.	A	3	Reactor coolant (CH)	Heat exchangers
5	5/30/82	4.0	F	No. 22 main boiler feed pump trip.	A	3	Reactor coolant (CH)	Pumps
6	8/12/82	13.4	F	No. 22 RCP seal return high flow faulty flow transmitter.	A	1	Reactor coolant (CB)	Instrumentation and controls
7	8/13/82	56.7	S	Unit shutdown extended for fan cooler unit repairs.	B	9	Engineered safety features (SB)	Heat exchangers
8	9/02/82	137.0	F	Fan cooler unit fan and coupling repairs.	A	1	Engineered safety features (SB)	Blowers
9	9/18/82	2,519.9	S	Refueling and maintenance outage.	C	1	Reactor (RC)	Fuel elements



DESIGN ELEC. RATING - 873 MAX. DEPEND. CAP. - 864 (100%)

INDIAN POINT 2

INDIAN POINT 3

I. Summary

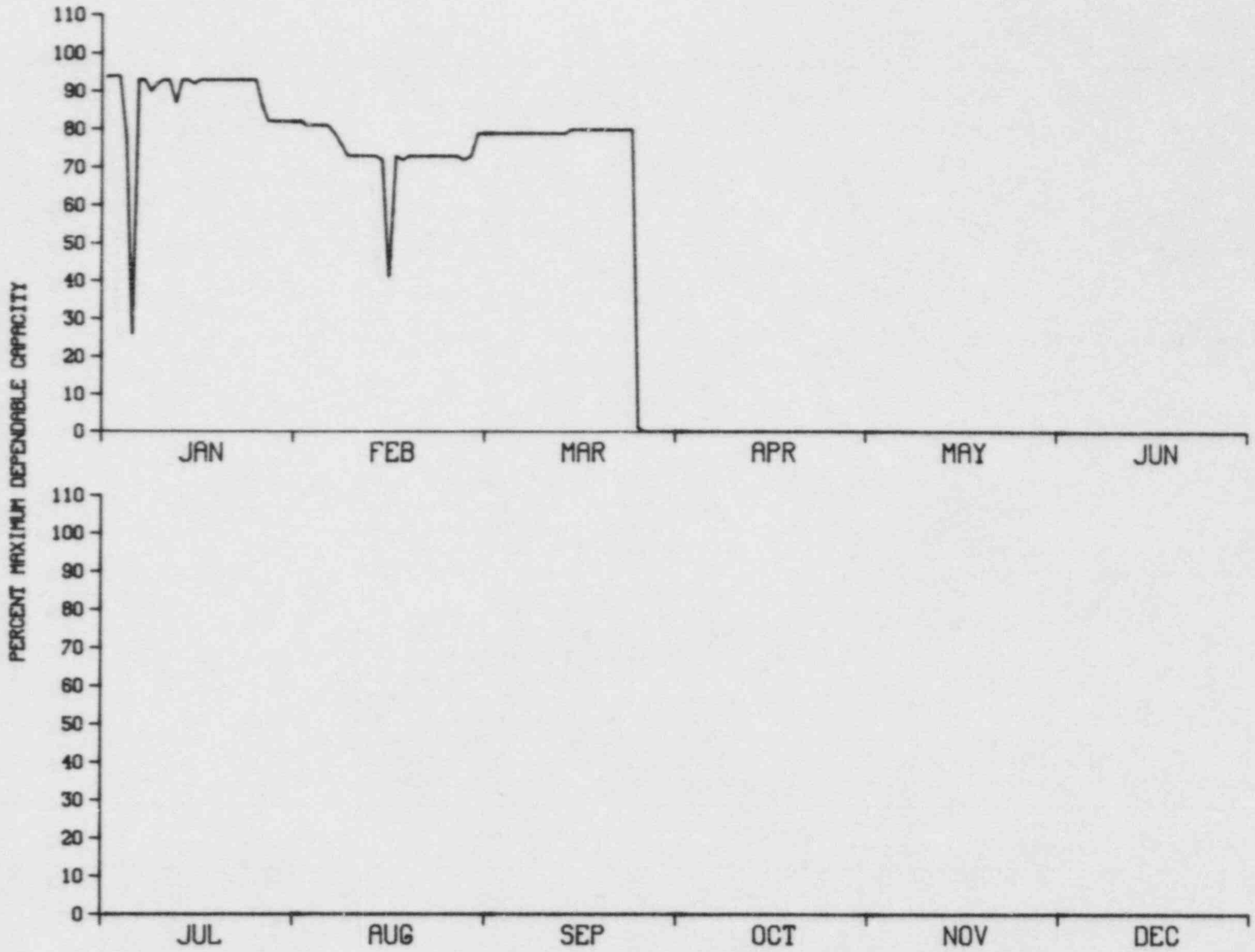
Description	Performance	Outages
Location: Indian Point, New York	Net electrical energy generated (MWh): 1,436,036	Total No.: 4
Docket No.: 50-286	Unit availability factor (%): 22.5	Forced: 3
Reactor type: PWR	Unit capacity factor (%) (using MDC): 18.4	Scheduled: 1
Maximum dependable capacity [MW(e)-net]: 965	Unit capacity factor (%) [using design MW(e)]: 17.0	Total hours: 6,791 (77.5%)
Commercial operation: 8/30/76		Forced: 46 (0.5%)
Years operating experience: 6.7		Scheduled: 6,745 (77.0%)

II. Highlights

Indian Point 3 ran smoothly in 1982 until it was shut down for a scheduled refueling and maintenance outage on March 25. While the unit power was being reduced on that date, a primary-to-secondary leak in one of the steam generators caused it to be taken to cold shutdown immediately. After shutdown a leak was discovered in the shell of the steam generator from the secondary side to the outside, located in one of the girth welds around the steam generator exterior shell. Nondestructive examinations were then performed on all the steam generator girth welds, with other problem spots identified. Leaking steam generator tubes were removed and the openings plug-welded. Since many tubes with potential problems were found, it was decided to sleeve approximately 3,000 tubes. Extensive research and testing was done to find a way to repair the steam generator girth welds. These steam generator problems extended the outage for the remainder of the year and well into 1983.

Details of plant outages for Indian Point 3

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/04/82	16.3	F	A voltage spike on No. 32 instrument bus, which was generated by a short circuit on weld channel and containment pressurization system solenoid valve, caused activation of dropped rod circuitry. Dropped rod indication automatically initiated turbine runback. Solenoid was replaced and startup commenced.	A	3	Engineered safety features (SD)	Valve operators
2	2/14/82	8.1	F	During repairs to No. 31 condensate pump ammeter, the wires were disconnected causing a protection relay to activate and trip the pump motor breaker. Loss of No. 31 condensate pump, concurrent with No. 32 condensate pump out of service for repairs, caused a low level on No. 34 steam generator, which resulted in a reactor and turbine trip.	G	3	Steam and power conversion (HH)	Instrumentation and controls
3	3/25/82	21.2	F	At 0147 hours the unit was removed from service and proceeded to a cold shutdown condition due to a primary to secondary leak in No. 33 steam generator. Prior to removing the unit from service, a load reduction was initiated at 2330 hours on March 24, 1982, in preparation for a manual shutdown.	A	1	Reactor coolant (CH)	Heat exchangers
4	3/25/82	6,745.0	S	At 2300 hours the unit commenced a scheduled cycle III-IV refueling outage.	C	1	Reactor (RC)	Fuel elements



DESIGN ELEC. RATING - 965 MAX. DEPEND. CAP. - 891 (100%) INDIAN POINT 3

KEWAUNEE

I. Summary

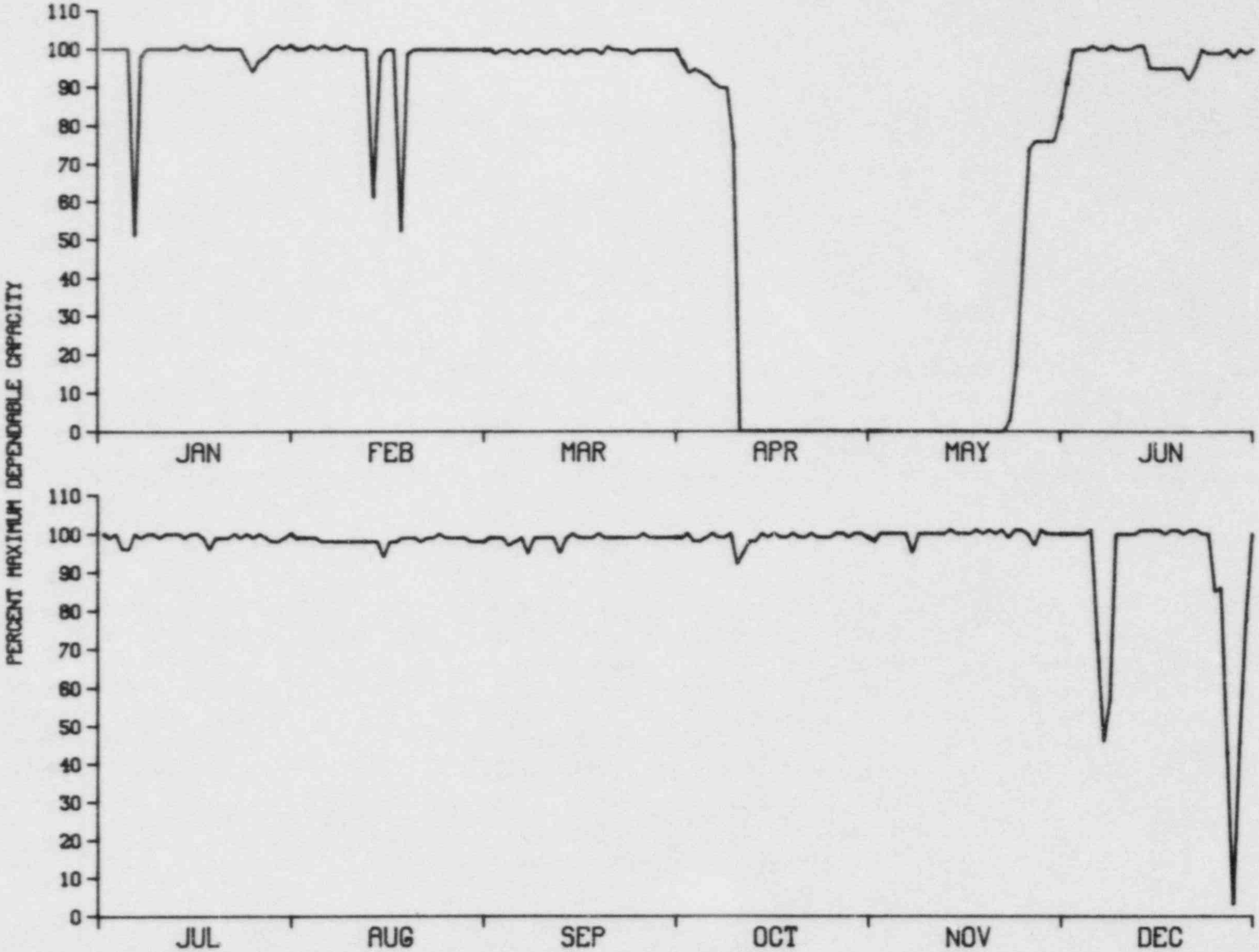
Description	Performance	Outages
Location: Carlton, Wisconsin	Net electrical energy generated (MWh): 3,824,851	Total No.: 4
Docket No.: 50-305	Unit availability factor (%): 87.6	Forced: 2
Reactor type: PWR	Unit capacity factor (%) (using MDC): 84.9	Scheduled: 2
Maximum dependable capacity [MW(e)-net]: 522	Unit capacity factor (%) [using design MW(e)]: 81.6	Total hours: 1,090 (12.4%)
Commercial operation: 6/16/74		Forced: 40 (0.5%)
Years operating experience: 8.7		Scheduled: 1,050 (12.0%)

II. Highlights

Kewaunee operated very reliably during 1982. The only major shutdown was a refueling outage that began on April 9 and was completed in only a little over six weeks. Once the system was back in operation in late May, it operated without any shutdowns until late December when a steam leak in a line from the moisture separator to the heater drain tank caused a one-and-a-half-day outage. This performance placed Kewaunee among the most reliably operating PWRs in the country for 1982. An achievement of almost 90% availability in a year which includes an entire refueling outage is unusually high.

Details of plant outages for Kewaunee

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	4/09/82	1,044.1	S	Commenced cycle VII-VIII refueling outage.	C	3	System code not applicable (ZZ)	Codes not applicable
2	5/23/82	6.6	F	Reactor/turbine trip occurred on low-low SG level during power ascension while transferring SG level control from manual to automatic.	G	3	Reactor coolant (CH)	Codes not applicable
3	5/24/82	5.9	S	Short outage was taken to perform turbine overspeed and torsion tests.	B	1	Steam and power conversion (HA)	Turbines
4	12/27/82	33.7	F	The reactor and turbine were manually tripped due to a steam leak in a line between a moisture separator and the heater drain tank.	A	2	Steam and power conversion (HJ)	Pipes and/or fittings



DESIGN ELEC. RATING - 535 MAX. DEPEND. CAP. - 515 (100%)

KEWAUNEE

LA CROSSE

I. Summary

Description

Location: Genoa, Wisconsin
Docket No.: 50-409
Reactor type: BWR
Maximum dependable capacity [MW(e)-net]: 48
Commercial operation: 11/01/69
Years operating experience: 14.7

Performance

Net electrical energy generated (MWh): 137,976
Unit availability factor (%): 44.6
Unit capacity factor (%) (using MDC): 32.8
Unit capacity factor (%) [using design MW(e)]: 31.5

Outages

Total No.: 10
  Forced: 7
  Scheduled: 3
Total hours: 4,849[a] (55.3%)
  Forced: 695[a] (7.9%)
  Scheduled: 4,154 (47.4%)

II. Highlights

La Crosse began the year in an outage for turbine repair which had started the previous December. Once it began 1982 operation in the last week of January, it operated with only minor problems, due mostly to turbine governor difficulties, until it was shut down for a refueling outage that began on April 9. The outage was originally scheduled to last 11 weeks, but it actually extended for almost 25 weeks, that is, almost half the year. After its restart in late September the reactor experienced only minor problems for the rest of the year.

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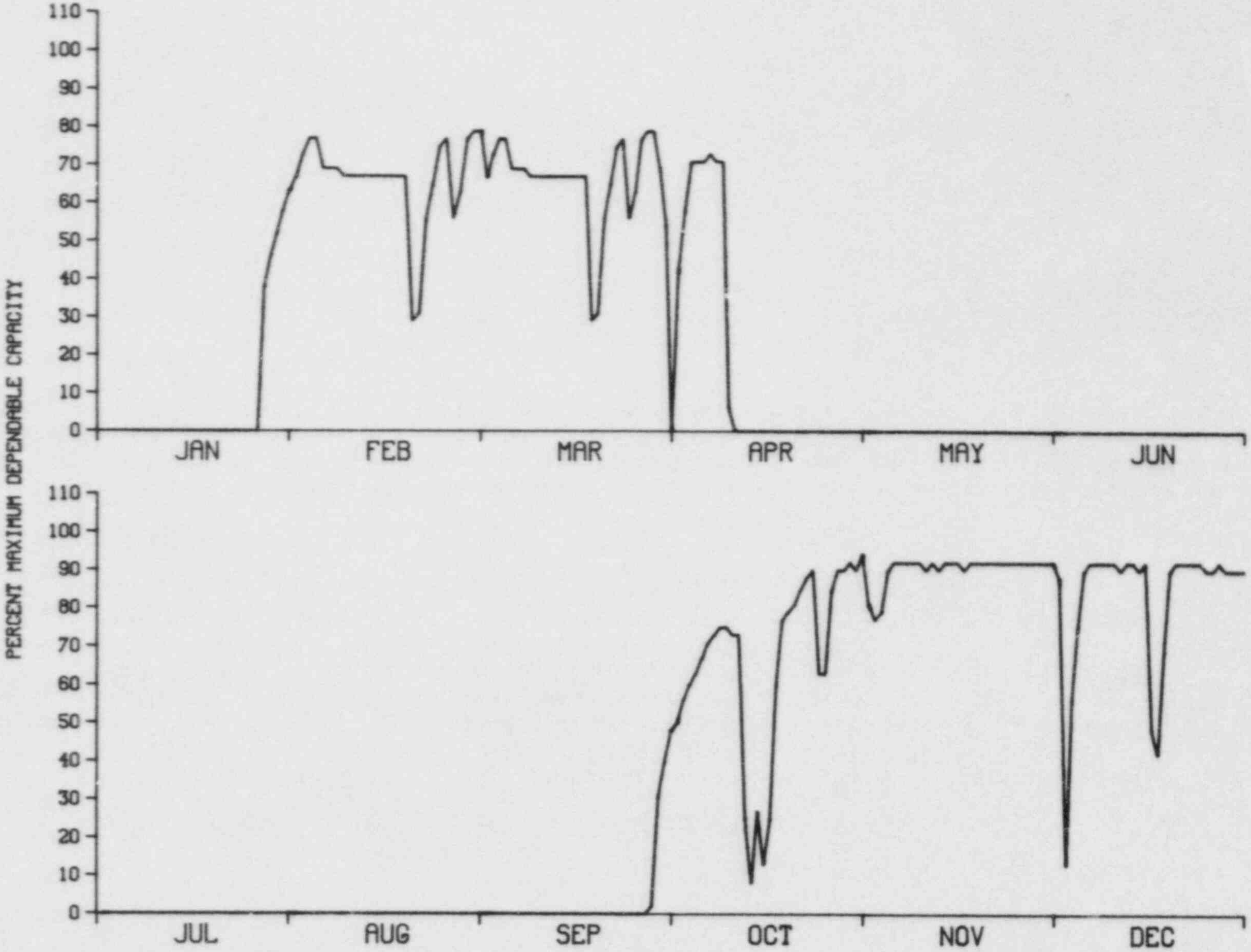
[a]Includes 597 h in 1982 from continuation of 12/23/81 outage.

Details of plant outages for La Crosse

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	12/23/81	597.2	F	Continuation of December 1981 turbine outage.	A	4	Steam and power conversion (HA)	Turbines
2	1/25/82	2.2	F	Malfunction of turbine governor system initial pressure regulator (IPR).	A	9	Steam and power conversion (HA)	Mechanical function units
3	1/26/82	0.3	F	Malfunction of turbine governor system initial pressure regulator (IPR).	A	9	Steam and power conversion (HA)	Mechanical function units
4	1/26/82	5.3	F	Malfunction of turbine governor system IPR.	A	9	Steam and power conversion (HA)	Mechanical function units
5	2/18/82	18.4	F	Spurious upward and downward spike, in indicated forced circulation flow, which was transmitted to power-flow safety channel No. 1, caused scram. Flow transmitter and converter were checked.	A	3	Reactor coolant (CB)	Instrumentation and conrols
6	3/30/82	28.2	F	Partial scram occurred as a result of actuation of device 86GL, generator tripping relay. This relay was energized by relay 151 GMTL CO-6, main power transformer neutral ground. The most probable cause of relay 151 action was high surface winds in the Dairyland system which caused numerous 69-kV transmission line breaker operations. Relays and transformer were checked.	H	3	Electric power (EB)	Transformers
7	4/09/82	4,118.7	S	Scheduled refueling outage. Expected duration of 11 weeks.	C	1	Reactor (RC)	Fuel elements

Details of plant outages for La Crosse (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
8	10/12/82	29.0	F	Burned out solenoid caused reactor main steam isolation valve to fail closed, resulting in scram.	A	3	Reactor coolant (CD)	Valve operators
9	10/15/82	20.5	S	Reactor power was reduced and turbine generator taken off line for work on turbine governor controls. During this period the reactor operator manually scrammed the reactor due to erratic operation of the main steam bypass valve.	B	2	Steam and power conversion (HA)	Instrumentation and controls
10	12/02/82	14.3	S	Power to reactor critical and main steam system isolated to facilitate repair of steam leak on manway for water storage tank.	B	1	Steam and power conversion (HJ)	Accumulators
11	12/16/82	14.7	F	The scram was the result of a burnout of a resistor in power supply, which supplies instrumentation. The reactor building steam isolation valve closed on an indicated low steam pressure signal.	A	3	Reactor coolant (CD)	Instrumentation and controls



DESIGN ELEC. RATING - 50 MAX. DEPEND. CAP. - 48 (100%) LA CROSSE

MAINE YANKEE

I. Summary

Description

Location: Wincasset, Maine
Docket No.: 50-309
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 810
Commercial operation: 12/28/72
Years operating experience: 10.1

Performance

Net electrical energy generated (MWh): 4,524,228
Unit availability factor (%): 69.1
Unit capacity factor (%) (using MDC): 63.8
Unit capacity factor (%) [using design MW(e)]: 62.6

Outages

Total No.: 17
- Forced: 12
- Scheduled: 5

Total hours: 2,895 (33.0%)
- Forced: 285 (3.2%)
- Scheduled: 2.610 (29.8%)

II. Highlights

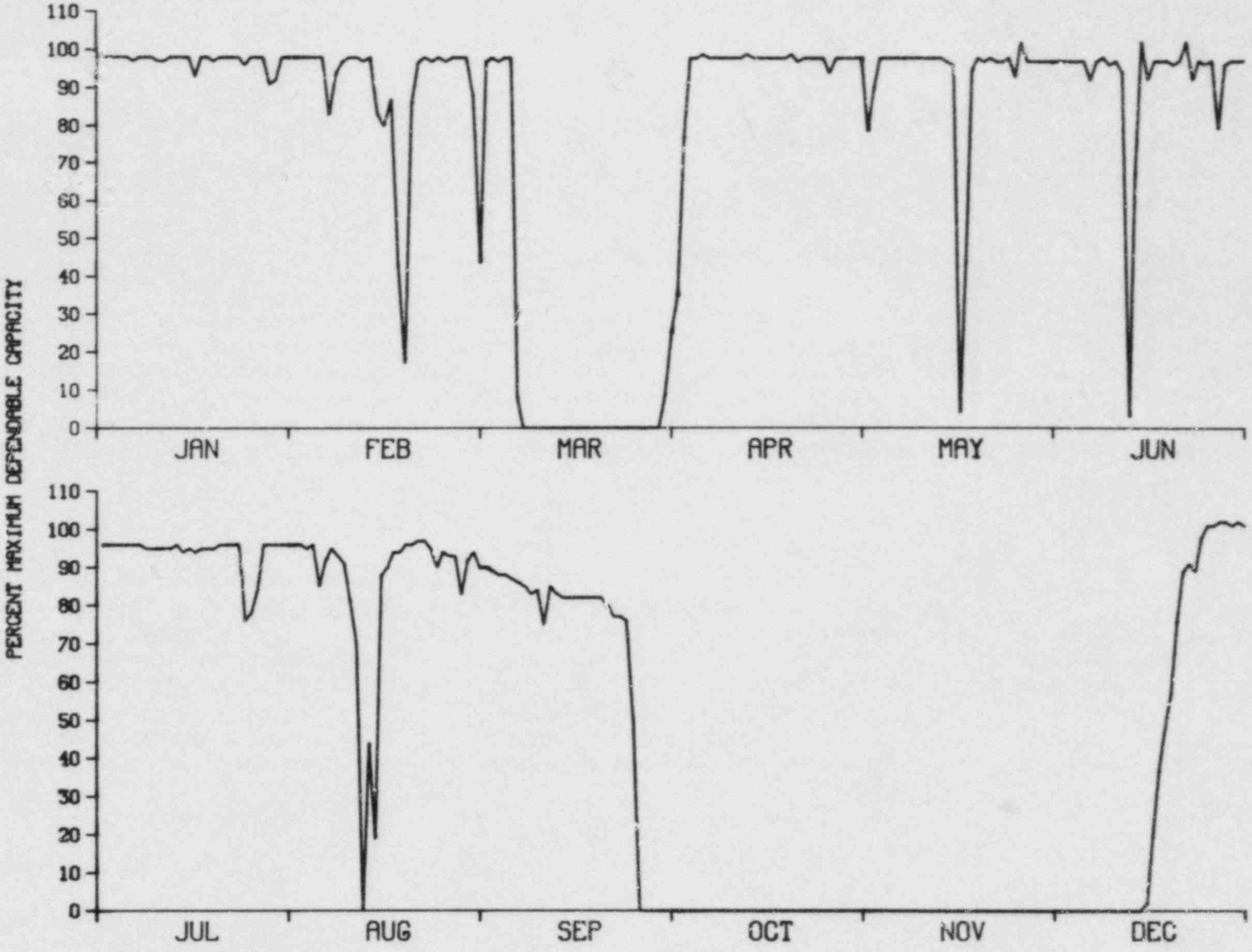
Maine Yankee operated with only two major outages during 1982. The first of these, which occupied most of the month of March (23 days), was for routine maintenance, including the replacement of the 20 bolting studs on a steam generator primary manway. Six of the studs had failed by intergranular stress corrosion. On September 24 the reactor shut down for 11 and a half weeks for a refueling outage.

Details of plant outages for Maine Yankee

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/16/82	9.8	S	Load reduction for turbine valve testing.	B	5	Steam and power conversion (HA)	Valves
2	1/28/82	15.8	F	Load reduction to investigate Cl in-leakage in condenser bay A.	B	5	Steam and power conversion (HF)	Heat exchangers
3	1/29/82	11.6	F	Load reduction to replace CEA No. 55 timer module subsequent to CEA No. 55 dropping.	A	5	Instrumentation and controls (IC)	Instrumentation and controls
4	2/06/82	28.8	F	Load reduction to investigate Cl in-leakage in condenser bay A.	B	5	Steam and power conversion (HF)	Heat exchangers
5	2/13/82	69.0	F	Load reduction to investigate Cl in-leakage in water boxes A, B, C, and D.	B	5	Steam and power conversion (HF)	Heat exchangers
6	2/16/82	11.6	F	Automatic unit shutdown initiated while performing dc ground isolation procedures.	A	3	Instrumentation and controls (IE)	Instrumentation and controls
7	2/16/82	33.3	F	Increasing power at reduced load.	A	5	Instrumentation and controls (IE)	Instrumentation and controls
8	2/17/82	9.7	F	While increasing power at reduced load, automatic unit shutdown due to high heater drain tank level.	A	3	Steam and power conversion (HJ)	Accumulators
9	2/27/82	9.7	F	Manual unit shutdown initiated due to P-2B automatic trip caused by failed low suction pressure switch.	A	2	Steam and power conversion (HH)	Instrumentation and controls
10	2/28/82	16.8	F	Increasing power at reduced load.	A	5	Steam and power conversion (HH)	Instrumentation and controls
11	3/06/82	544.7	S	Manual shutdown for scheduled maintenance.	B	1	System code not applicable (ZZ)	Codes not applicable

Details of plant outages for Maine Yankee (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
12	3/28/82	41.7	F	Manual shutdown of turbine due to high Cl levels in the condenser.	B	1	Steam and power conversion (HH)	Heat exchangers
13	4/01/82	8.0	F	Unanticipated closure of SCCW nonessential header isolation valves due to engineering design.	H	1	System code not applicable (ZZ)	Codes not applicable
14	5/15/82	29.2	F	Turbine shutdown completed to repair two gland steam lines off a high-pressure turbine cylinder head.	B	1	Steam and power conversion (HD)	Pipes and/or fittings
15	6/11/82	23.4	S	Manual shutdown completed to repair main feedwater reg. valves.	A	1	Reactor coolant (CH)	Valves
16	8/12/82	62.2	S	Manual shutdown for scheduled maintenance.	B	1	System code not applicable (ZZ)	Codes not applicable
17	9/24/82	1,969.4	S	Scheduled shutdown for refueling core 6/7.	C	1	Reactor (RC)	Fuel elements



DESIGN ELEC. RATING - 825 MAX. DEPEND. CAP. - 810 (100%)

MAINE YANKEE

MCGUIRE 1

I. Summary

Description

Location: 17 miles north of Charlotte, North Carolina
Docket No.: 50-369
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 1,180
Commercial operation: 12/01/81
Years operating experience: 1.3

Performance

Net electrical energy generated (MWh): 4,302,267
Unit availability factor (%): 80.4
Unit capacity factor (%) (using MDC): 41.6
Unit capacity factor (%) [using design MW(e)]: 41.6

Outages

Total No.: 23
 Forced: 22
 Scheduled: 1
Total hours: 1,713[a] (19.6%)
 Forced: 1,346[a] (15.3%)
 Scheduled: 368 (4.2%)

II. Highlights

McGuire 1, which only declared commercial operation on December 1, 1981, that is, one month before the beginning of 1982, operated much of the year at reduced power levels, either 50% or 75% of rated power, pending the resolution of steam generator problems. The need to perform eddy-current testing on steam generator tubes was also the reason for a 20-day outage which began at the very end of February, and the same cause was given for a further 23-day outage in late June and July. Yet another steam generator tube inspection required a 15-day outage in November.

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[a]Includes 32 h in 1982 from continuation of 12/02/81 outage.

Details of plant outages for McGuire 1

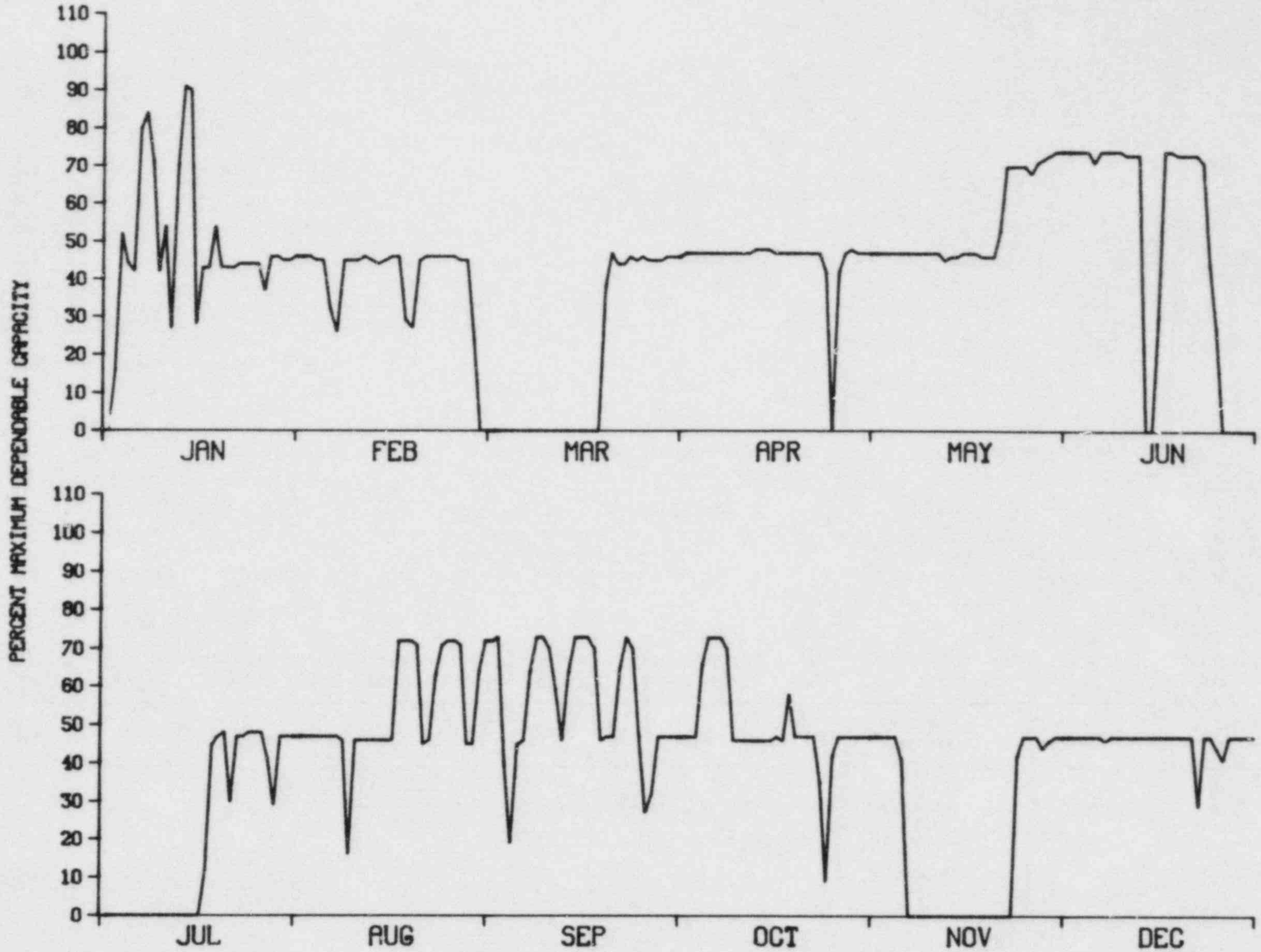
No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	12/02/81	31.7	F	Completion of generator drying and hydrogen cooler replacement.	A	4	Steam and power conversion (HA)	Turbines
2	1/03/82	10.0	F	An electrical switchgear problem caused a trip of the "A" FWPT, resulting in a low-low steam generator level tripping the reactor.	A	3	Electric power (EB)	Relays
3	1/05/82	6.8	F	Reactor tripped during a periodic test due to a procedure deficiency.	B	3	System code not applicable (ZZ)	Codes not applicable
4	1/09/82	11.7	F	During maintenance to the turbine controls (DEH), the turbine/generator tripped, tripping the reactor.	B	3	Steam and power conversion (HA)	Turbines
5	1/11/82	11.1	F	Frozen instrumentation caused a reactor trip and safety injection.	A	3	Instrumentation and controls (IA)	Instrumentation and controls
6	1/15/82	5.5	F	Operator tripped reactor on indication of "B" reactor coolant pump high vibration as procedure instructed.	A	2	Instrumentation and controls (IA)	Instrumentation and controls
7	2/05/82	12.4	F	Reactor tripped due to a procedure deficiency while performing a periodic test.	B	3	System code not applicable (ZZ)	Codes not applicable
8	2/16/82	13.4	F	Trip of condensate booster pumps resulted in a reactor trip.	A	3	Steam and power conversion (HH)	Pumps
9	2/26/82	5.6	F	The loss of a 125-V ac power supply resulted in a unit trip.	A	3	Electric power (EB)	Instrumentation and controls
10	2/26/82	484.2	F	Began a 16-day outage for steam generator tube EC and analysis.	B	1	Reactor coolant (CB)	Heat exchangers

Details of plant outages for McGuire 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
11	4/23/82	23.5	F	While reducing power for Tech. Spec. requirement, the feedwater pump tripped due to discharge pressure set-point trip being too low.	A	3	Reactor coolant (CH)	Instrumentation and controls
12	6/13/82	53.6	F	Loss of more than one reactor coolant (NC) flow transmitter caused unit trip.	A	3	Instrumentation and controls (IA)	Instrumentation and controls
13	6/24/82	547.1	F	Outage for inspection (eddy current) of steam generator tubes.	B	1	Reactor coolant (CB)	Heat exchangers
14	7/21/82	7.2	F	Turbine/reactor trip during periodic turbine trip test due to operator error.	G	3	Steam and power conversion (HA)	Turbines
15	7/27/82	8.3	F	Turbine off and reactor at hot shutdown to calibrate oil level indication on upper motor reservoir of 1B NC pump and added oil as necessary.	B	1	Reactor coolant (CB)	Instrumentation and controls
16	8/09/82	13.9	F	Loss of control power to 1TA caused 1A reactor coolant pump to trip.	H	3	Electric power (EC)	Circuit closers/ interrupters
17	9/03/82	21.6	F	Unit tripped on low condensate flow while switching Powdex cells.	G	3	Steam and power conversion (HG)	Demineralizers
18	9/25/82	8.2	F	Unit tripped following a false low oil level trip of 1A FWP.	A	3	Reactor coolant (CH)	Circuit closers/ interrupters
19	9/26/82	5.6	F	Reverse current trip on main generator caused by a bad card in the voltage regulator.	A	3	Steam and power conversion (HA)	Instrumentation and controls

Details of plant outages for McGuire 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
20	10/23/82	17.0	F	Unit shutdown to install spray system to assist the lower containment ventilation system to maintain temperature.	H	1	Engineered safety features (SB)	Other components
21	11/05/82	14.5	F	Unit tripped from 20% power due to nuclear instrumentation calibration while manually shutting down to work on containment spray heat exchanger hangers.	H	3	Engineered safety features (SB)	Shock suppressors and supports
22	11/06/82	26.8	F	Bad bearings in main turbine bearing oil pump.	A	9	Steam and power conversion (HA)	Pumps
23	11/07/82	367.7	S	Steam generator tube inspection.	B	9	Reactor coolant (CB)	Heat exchangers
24	12/22/82	6.0	F	RCS leakage over 1 gpm due to partially open vent valve on bit line. Valve shut and pipe cap installed.	A	1	Reactor coolant (CJ)	Valves



DESIGN ELEC. RATING - 1180 MAX. DEPEND. CAP. - 1180 (100%) MCGUIRE 1

MILLSTONE 1

I. Summary

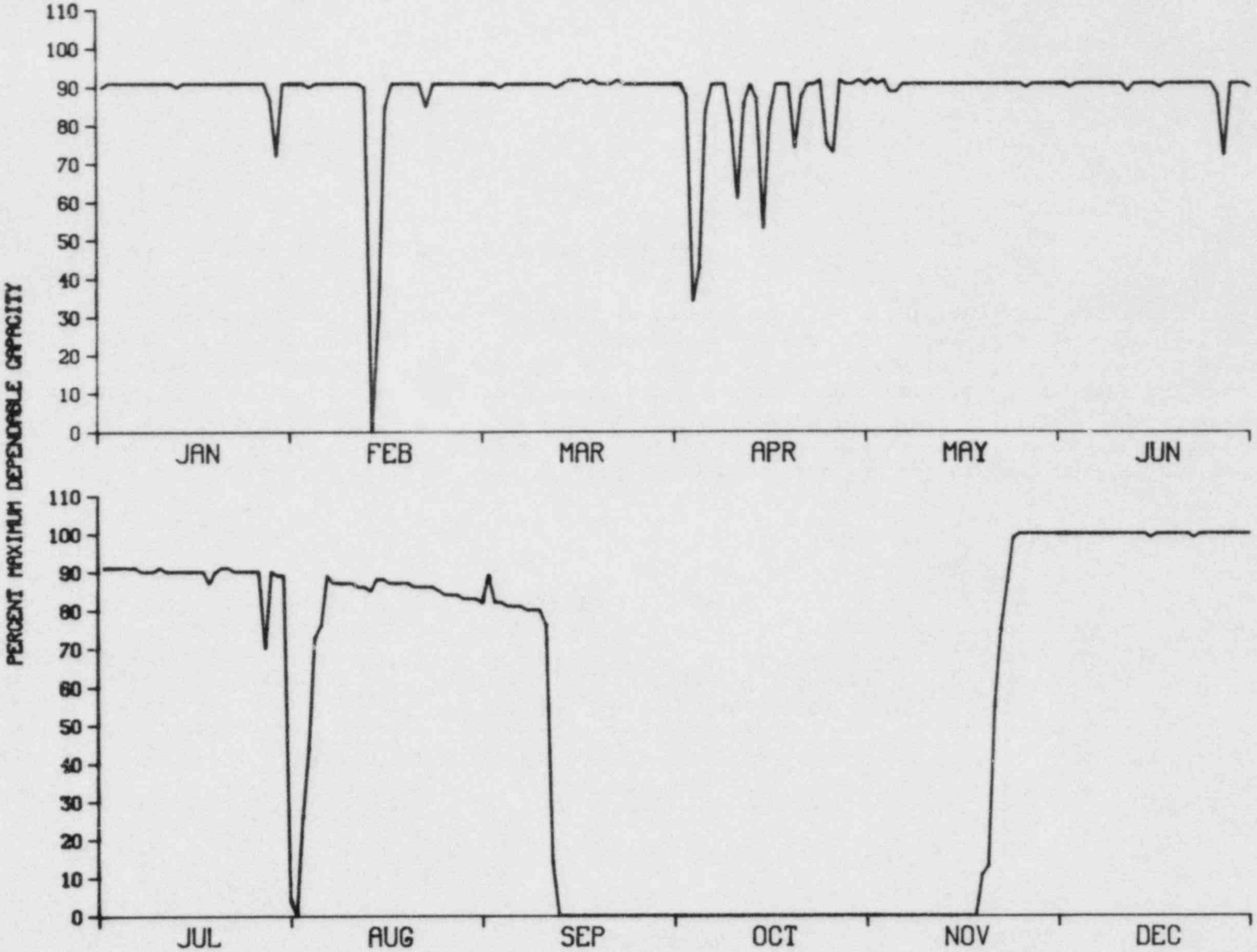
Description	Performance	Outages
Location: Waterford, Connecticut	Net electrical energy generated (MWh): 4,078,277	Total No.: 4
Docket No.: 50-245		Forced: 3
Reactor type: BWR	Unit availability factor (%): 79.9	Scheduled: 1
Maximum dependable capacity [MW(e)-net]: 654	Unit capacity factor (%) (using MDC): 71.2	Total hours: 1,762 (20.1%)
		Forced: 101 (1.1%)
Commercial operation: 3/01/71	Unit capacity factor (%) [using design MW(e)]: 70.5	Scheduled: 1,661 (19.0%)
Years operating experience: 12.1		

II. Highlights

Millstone 1 operated almost without any interruptions during 1982, except for a refueling outage that began in mid-September and lasted 10 weeks. During August and early September, prior to the refueling shutdown, the power level of the reactor drifted downward as the available reactivity declined due to fuel exhaustion. There were no other significant outages during the year.

Details of plant outages for Millstone 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	2/12/82	30.0	F	Scram occurred when "A feedwater regulation valve cycled open then closed.	A	3	Reactor coolant (CH)	Valves
2	4/13/82	17.8	F	A reactor recirculation pump trip was automatically initiated by division ATWS system. Trip resulted when 125-V dc circuit breaker supplying division 1 panel was switched off to enable varying battery charger output voltage without affecting associated ATWS channel in an attempt to locate a ground on 125-V dc power system.	G	2	Steam and power conversion (HC)	Heat exchangers
3	7/31/82	53.1	F	The generator out-of-step relay located in the switchyard malfunctioned and tripped open the switchyard breakers. This caused a full load reject followed by an ATWS division 1 scram.	H	3	Steam and power conversion (HA)	Relays
4	9/11/82	1,661.4	S	Refueling outage scheduled from 9/11/82 to 11/14/82.	C	1	Reactor (RC)	Fuel elements



DESIGN ELEC. RATING - 660 MAX. DEPEND. CAP. - 654 (100%) MILLSTONE 1

MILLSTONE 2

I. Summary

Description	Performance	Outages
Location: Waterford, Connecticut	Net electrical energy generated (MWh): 5,009,081	Total No.: 12
Docket No.: 50-336	Unit availability factor (%): 70.6	Forced: 11
Reactor type: PWR	Unit capacity factor (%) (using MDC): 66.2	Scheduled: 1
Maximum dependable capacity [MW(e)-net]: 864	Unit capacity factor (%) [using design MW(e)]: 65.7	Total hours: 2,575[a] (29.4%)
Commercial operation: 12/26/75		Forced: 793 (9.0%)
Years operating experience: 7.1		Scheduled: 1,782[a] (20.3%)

II. Highlights

Millstone 2 began the year in a continuation of a refueling and maintenance outage that had begun in early December 1981. The reactor came back on line in mid-March and then ran without extended outages until mid-July, when an operational error while performing turbine surveillance caused a trip that was extended to a total of five days to perform other maintenance tasks. Then, on July 22, a 13-day outage resulted from a primary system leak, which turned out to be due to a leaking PORV (power-operated relief valve) on the pressurizer. A five-day outage at the end of October resulted from instrument electrical problems caused by fuse replacement in the engineering safety analysis system.

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[a]Includes 1763 h in 1982 from continuation of 12/15/81 outage.

Details of plant outages for Millstone 2

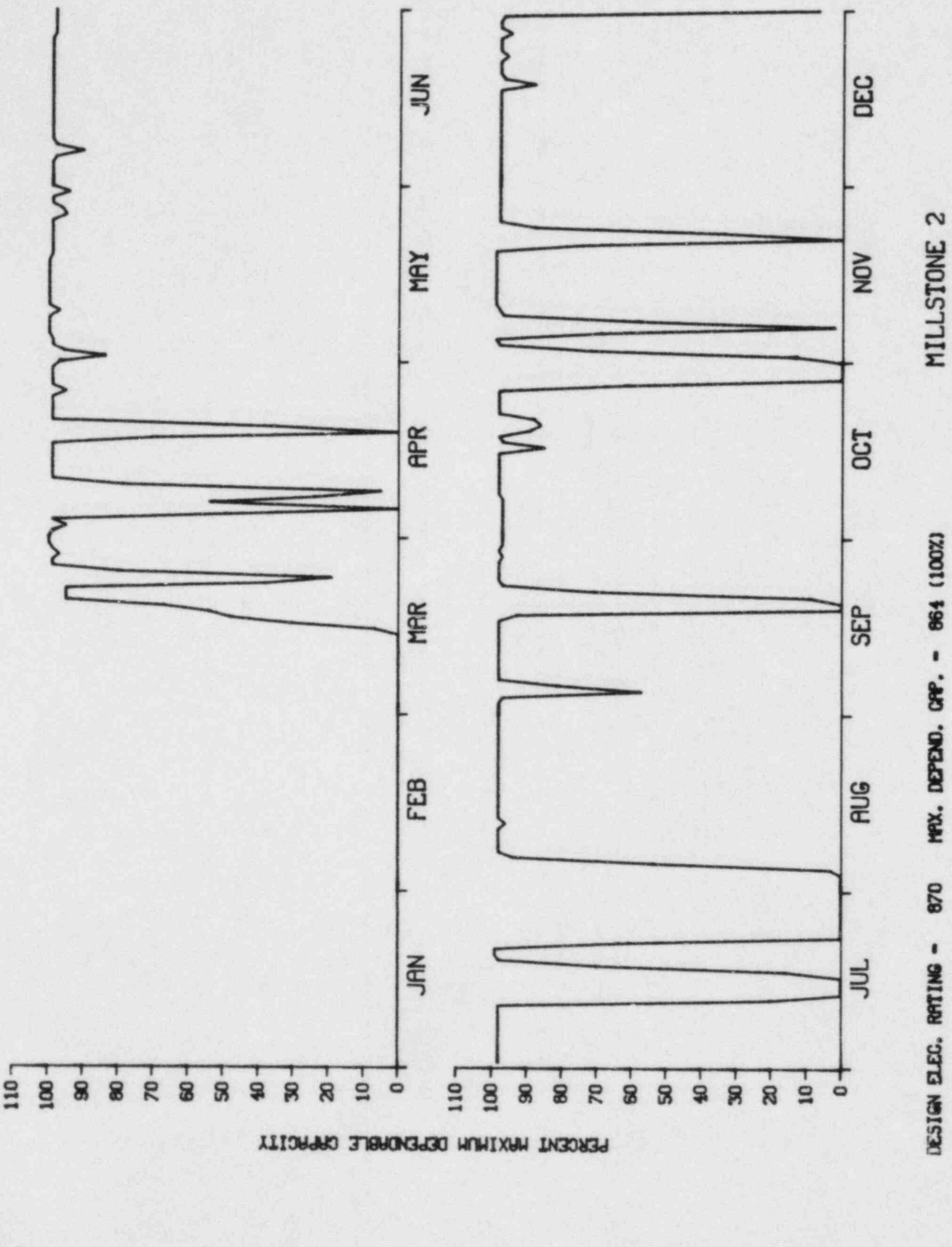
No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	12/05/81	1,763.0	S	Completion of refueling and maintenance outage.	C	4	Reactor (RC)	Fuel elements
2	3/23/82	24.0	F	Reactor protection system trip (TM/LP) from noise-induced signals. Noise problem was corrected and power operation resumed via normal operating procedures.	H	3	Instrumentation and controls (IA)	Instrumentation and controls
3	4/04/82	27.7	F	Tripped from 100% power due to seaweed clogging the water intake screens. Cleared seaweed from screens and commenced startup via normal operation procedures. On recovery from scram, tripped on startup from a trip circuit breaker being open despite a closed signal. Repaired TCB closure mechanism and resumed startup procedures.	A	3	Steam and power conversion (HF)	Filters
4	4/05/82	7.1	F	Tripped on steam generator low level from 15% power following recovery from 4/4/82 trip.	H	3	Instrumentation and controls (IA)	Instrumentation and controls
5	4/07/82	34.0	F	Initiated manual shutdown from 100% power due to partially failed manway gasket on 3B feedwater heater. Removed and replaced all such gaskets on all feedwater heaters containing similar gasket material and commenced normal startup operations.	A	1	Steam and power conversion (HB)	Heat exchangers
6	4/17/82	37.8	F	Trip from 100% power on loss of instrument air. Air leak was repaired and normal startup operations were commenced.	A	3	Auxiliary process (PA)	Blowers

Details of plant outages for Millstone 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
7	7/12/82	121.5	F	Tripped from 100% power due to operational error while performing turbine thrust bearing surveillance. While shut down, performed various maintenance activities and commenced routine startup procedure on July 16, 1982.	G	3	Steam and power conversion (HA)	Turbines
8	7/22/82	306.5	F	Manually shut down reactor from 100% power to cold shutdown due to unidentified reactor coolant system leakage in excess of 1-gpm Tech. Spec. LCO limit. Subsequently identified 2-RC 403 (pressurizer power operated block valve) as source of leakage. Repaired 2-RC 403.	A	1	Reactor coolant (CI)	Valves
9	9/17/82	61.3	F	Reactor trip from 100% due to high reactor coolant system pressure induced by turbine control valve closure due to failure in the turbine throttle pressure detector.	A	3	Steam and power conversion (HA)	Instrumentation and controls
10	10/27/82	115.5	F	While replacing fuses in the engineering safety analysis system actuation cabinet 24-V power supply, undervoltage actuation module fired, causing loss of normal power on one 4160 vital bus. This resulted in instrument de-energization causing a turbine trip.	A	3	Instrumentation and controls (IB)	Instrumentation and controls
11	11/05/82	24.9	F	Tripped from 100% power on a thermal margin low pressure trip signal as a result of an instrument noise spike. Resumed normal startup procedures on 11/06/82.	A	3	Instrumentation and controls (IA)	Instrumentation and controls

Details of plant outages for Millstone 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
12	11/20/82	32.4	F	Tripped from 100% power due to feed reg. valve closure resulting from an instruments noise spike. Resumed normal startup procedures on 11/21/82.	A	3	Reactor coolant (CH)	Valves
13	12/31/82	18.8	S	Went to hot shutdown, mode 2, condition to repair secondary side steam leaks.	B	2	Steam and power conversion (HJ)	Pipes and/or fittings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DESIGN ELEC. RATING - 870 MAX. DEPEND. CAP. - 864 (100%)
MILLSTONE 2

MONTICELLO

I. Summary

Description	Performance	Outages
Location: Monticello, Minnesota	Net electrical energy generated (MWh): 2,420,820	Total No.: 8
Docket No.: 50-263	Unit availability factor (%): 63.3	Forced: 2
Reactor type: BWR	Unit capacity factor (%) (using MDC): 52.6	Scheduled: 6
Maximum dependable capacity [MW(e)-net]: 536	Unit capacity factor (%) [using design MW(e)]: 50.7	Total hours: 3,214[a] (36.7%)
Commercial operation: 6/30/71		Forced: 97 (1.1%)
Years operating experience: 11.8		Scheduled: 3,116[a] (35.6%)

II. Highlights

Monticello began the year 1982 in an outage for maintenance, which had begun the previous October. When the unit came back on line in mid-January, it operated without major outages until it began refueling at the beginning of September. From mid-April on, the operating power level declined gradually and steadily as the fuel was approaching the depletion point and available reactivity was no longer sufficient to operate at full power. The refueling outage lasted for fourteen and a half weeks until mid-December. The last two weeks of December were marked by a total of ten days of outage, in two separate intervals, caused by the need to align and repair turbine bearings.

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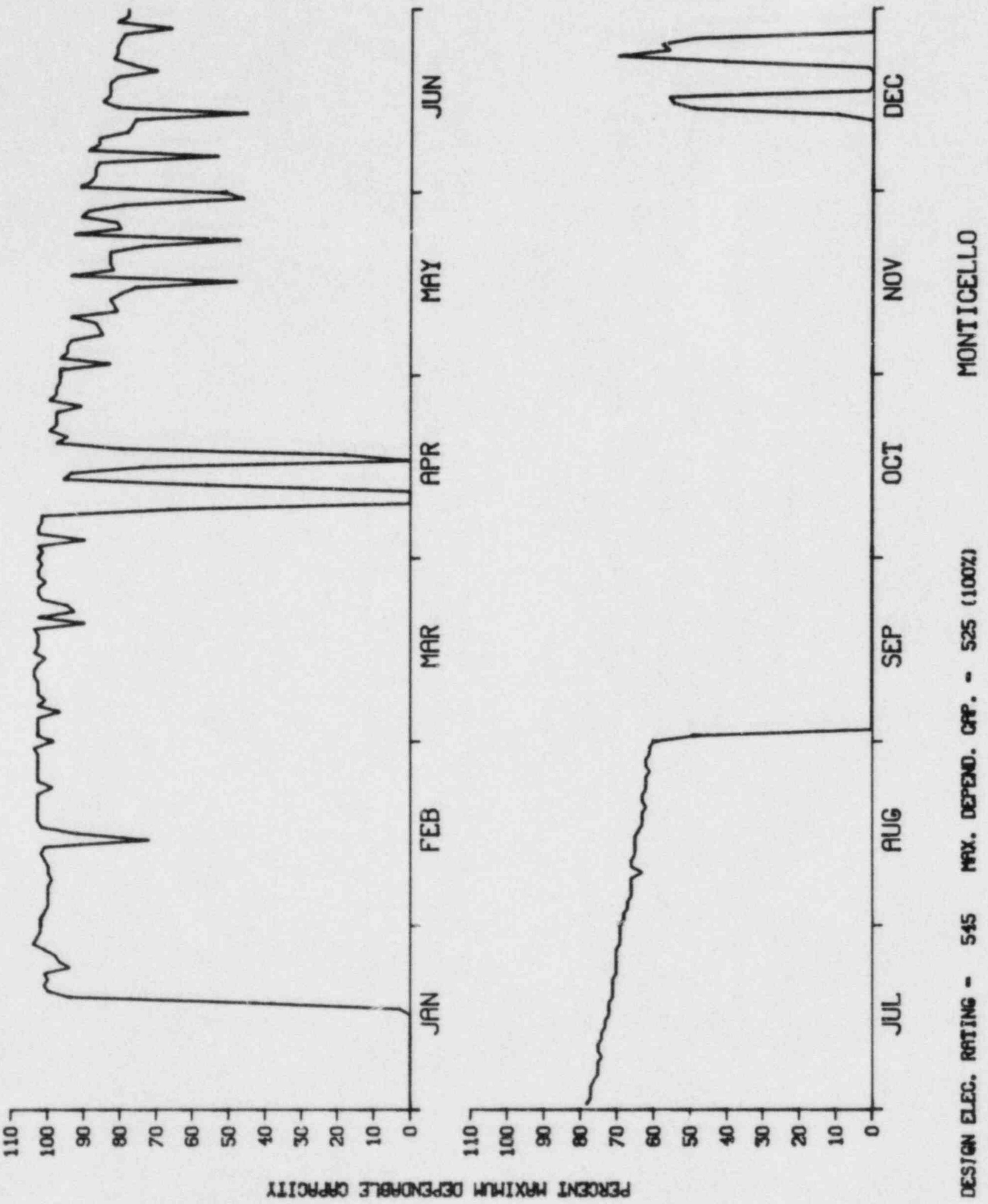
[a]Includes 382 h in 1982 from continuation of 10/23/81 outage.

Details of plant outages for Monticello

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	10/23/81	381.7	S	Continuation of 1981 fall maintenance outage.	B	4	System code not applicable (ZZ)	Codes not applicable
2	1/17/82	1.2	S	Generator off-line for turbine overspeed test.	B	1	Steam and power conversion (HA)	Turbines
3	1/17/82	17.4	F	Generator off-line for inspection of No. 9 bearing.	H	1	Steam and power conversion (HA)	Turbines
4	4/08/82	80.0	F	Reactor scram after loss of generator excitation due to field flashing circuitry problems.	A	3	Steam and power conversion (HA)	Generators
5	4/15/82	39.3	S	Scheduled orderly shutdown to repair leaking safety/relief valve.	A	1	Reactor coolant (CC)	Valves
6	9/01/82	2,458.7	S	Start of 1982 refueling outage.	C	2	Reactor (RC)	Fuel elements
7	12/13/82	1.2	S	Turbine overspeed test.	B	9	Steam and power conversion (HA)	Turbines
8	12/17/82	112.3	S	Turbine bearing repair and alignment.	B	2	Steam and power conversion (HA)	Turbines
9	12/26/82	121.7	S	Turbine bearing repair and alignment.	B	2	Steam and power conversion (HA)	Turbines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DESIGN ELEC. RATING - 545 MAX. DEPEND. CAP. - 525 (100%)
MONTICELLO

NINE MILE POINT 1

I. Summary

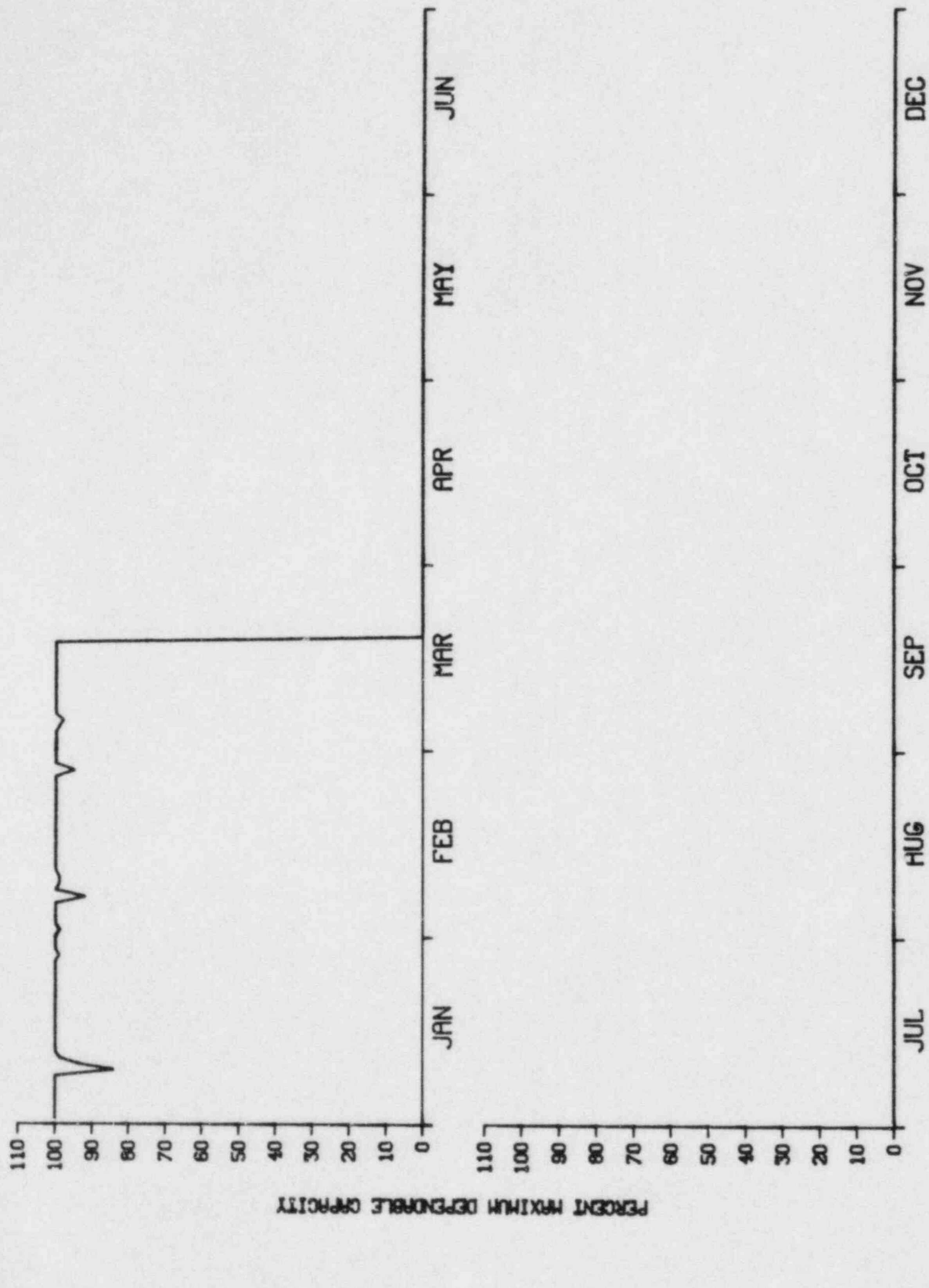
Description	Performance	Outages
Location: Scriba, New York	Net electrical energy generated (MWh): 1,134,758	Total No.: 2
Docket No.: 50-220	Unit availability factor (%): 21.4	Forced: 1
Reactor type: BWR	Unit capacity factor (%) (using MDC): 21.2	Scheduled: 1
Maximum dependable capacity [MW(e)-net]: 610	Unit capacity factor (%) [using design MW(e)]: 20.9	Total hours: 6,888 (78.6%)
Commercial operation: 12/01/69		Forced: 6,754 (77.1%)
Years operating experience: 13.2		Scheduled: 134 (1.5%)

II. Highlights

Nine Mile Point operated without any outages until March 19, when it was taken down to replace the seals on the recirculation pumps. Prior to startup, a crack was discovered in the recirculation piping where the piping joins the safe ends attaching to the reactor vessel. It was decided, based on a finding of intergranular stress corrosion as the source of the safe-end cracks, to replace all the recirculation piping. This outage lasted all the remainder of the year and well into 1983.

Details of plant outages for Nine Mile Point 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	3/19/82	133.5	S	Scheduled maintenance outage to replace recirc. pump seals.	B	1	Steam and power conversion (HF)	Pumps
2	3/23/82	6,754.0	F	Crack found in recirc. piping during vessel hydro prior to start up.	A	9	Steam and power conversion (HF)	Pipes and/or fittings



NINE MILE POINT 1

DESIGN ELEC. RATING - 620 MAX. DEPEND. CAP. - 610 (100%)

NORTH ANNA 1

I. Summary

Description	Performance	Outages
Location: Mineral, Virginia	Net electrical energy generated (MWh): 2,397,857	Total No.: 11
Docket No.: 50-338	Unit availability factor (%): 34.6	Forced: 9
Reactor type: PWR	Unit capacity factor (%) (using MDC): 31.6	Scheduled: 2
Maximum dependable capacity [MW(e)-net]: 850	Unit capacity factor (%) [using design MW(e)]: 30.2	Total hours: 5,730 (65.4%)
Commercial operation: 6/06/78		Forced: 895 (10.2%)
Years operating experience: 4.7		Scheduled: 4,835 (55.2%)

II. Highlights

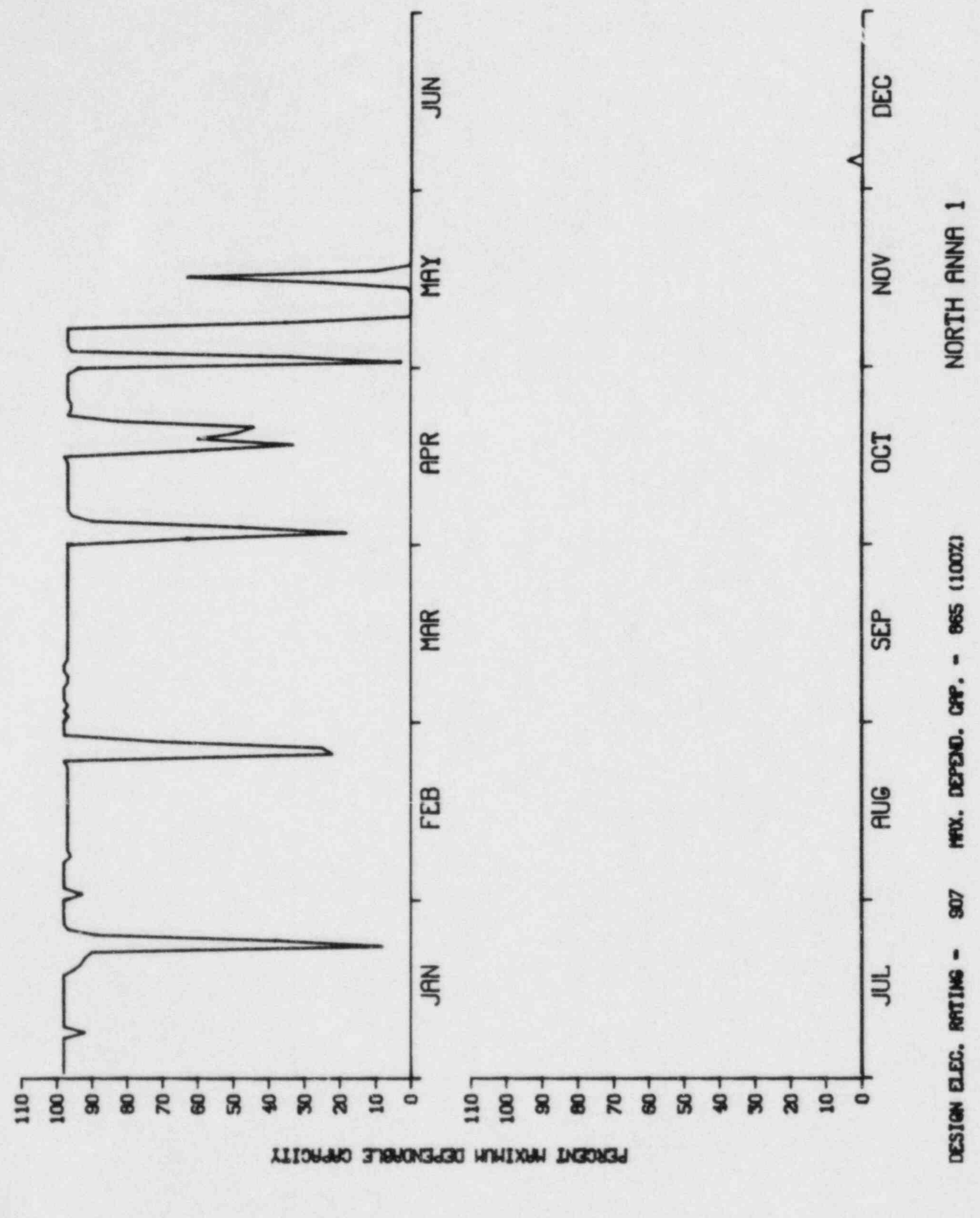
North Anna 1 operated with only minor interruptions of full-power operation from the start of 1982 until May 8, when a six-day outage was begun to perform maintenance inside the containment on a steam generator manway and a number of valves. Two days after restarting, the unit was again shut down, this time for what proved to be a 28-week refueling and maintenance outage which included replacing control rod guide tube hold-down bolts, replacing thermal sleeves, and repairing the main generator. On December 4 the refueling and maintenance outage was completed, but before the unit reached more than a few percent of full power, one of the main transformers failed, shutting the unit down past the end of the year.

Details of plant outages for North Anna 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/23/82	13.4	F	Ramped unit down and removed from service to isolate 5B and 6B feed-water heater.	B	1	Instrumentation and controls (IA)	Instrumentation and controls
2	2/23/82	20.4	F	Ramped unit down to 35% power and manually tripped the turbine/reactor due to tube rupture in gland steam condenser. The tube was plugged prior to returning unit to service.	A	1	Steam and power conversion (HC)	Heat exchangers
3	4/01/82	13.5	F	Reactor trip due to voltage spike on N-41 with N-44 in trip.	G	3	Instrumentation and controls (IA)	Instrumentation and controls
4	4/16/82	8.5	F	Manual reactor trip due to loss of circulating water pumps.	G	2	Steam and power conversion (HF)	Pumps
5	4/19/82	4.8	F	Reactor trip due to voltage spike while adjusting N-43 with N-44 in trip.	A	3	Instrumentation and controls (IA)	Instrumentation and controls
6	5/01/82	30.3	F	Normal rampdown to repair 5B feed-water heater, followed by a reactor trip while adjusting the trip set points of power range nuclear instruments.	A	1	Instrumentation and controls (IA)	Instrumentation and controls
7	5/08/82	154.7	F	Normal rampdown and reactor shutdown. Perform maintenance in containment on SG "C" manway and various valves.	A	1	Steam and power conversion (HB)	Heat exchangers
8	5/17/82	100.0	S	Normal rampdown and reactor shutdown due to noise in "A" steam generator.	C	1	Steam and power conversion (HB)	Heat exchangers
9	5/17/82	4,734.9	S	Refueling.	C	9	Reactor (RC)	Fuel elements

Details of plant outages for North Anna 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
10	12/04/82	13.9	F	The cause of the reactor trip was a malfunction of turbine EHC system which also was the cause of the safety injection that followed the trip.	A	3	Engineered safety features (SF)	Instrumentation and controls
11	12/05/82	635.4	F	The cause of the reactor trip was the failure of the "B" phase main transformer. The safety injection which followed was due to two steam flow channels and the nuclear power range instrument that controls the feed regulation bypass valves in auto, all being in the trip position.	A	3	Electric power (EA)	Transformers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DESIGN ELEC. RATING - 907 MAX. DEPEND. CAP. - 865 (100%)
NORTH ANNA 1

NORTH ANNA 2

I. Summary

Description	Performance	Outages
Location: Mineral, Virginia	Net electrical energy generated (MWh): 4,047,202	Total No.: 14
Docket No.: 50-339	Unit availability factor (%): 57.0	Forced: 12
Reactor type: PWR	Unit capacity factor (%) (using MDC): 51.9	Scheduled: 2
Maximum dependable capacity [MW(e)-net]: 898	Unit capacity factor (%) [using design MW(e)]: 50.9	Total hours: 3,768 (43.0%)
Commercial operation: 12/14/80		Forced: 1,447 (16.5%)
Years operating experience: 2.3		Scheduled: 2,320 (26.5%)

II. Highlights

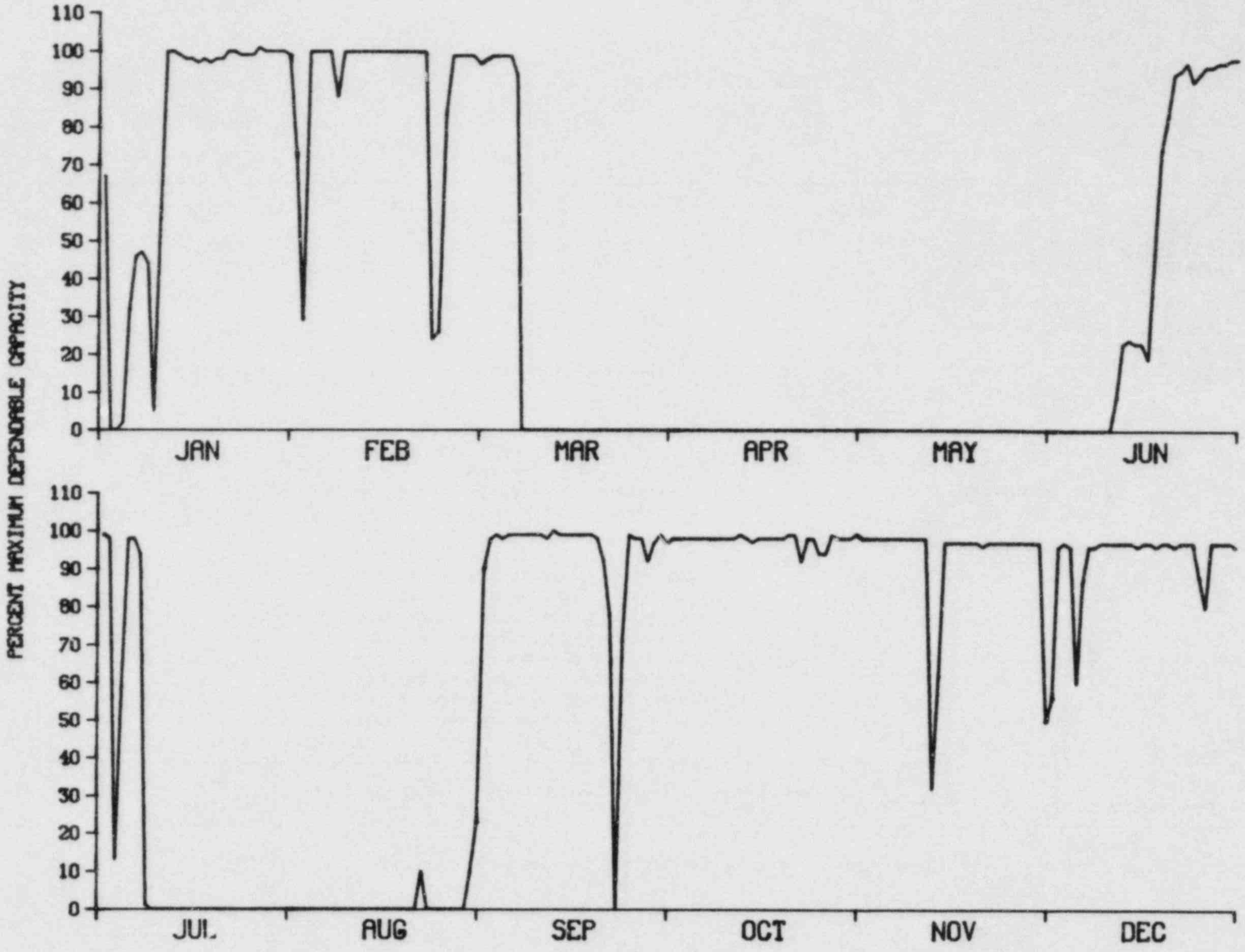
North Anna 2 underwent a number of outages in January of 1982, none of long duration, due to repeated turbine balancing activities. Then, on March 7, the unit started a 14-week refueling and maintenance outage that ended in mid-June. However, in early July the reactor was shut down for an additional six and a half weeks to investigate noise in one of the steam generators and to do ultrasound testing on the thermal sleeves in the reactor cooling system. The noise was found to be due to a loose tube lane blocking device split plate, which had not been tightly inserted during previous maintenance. Immediately after restarting from this outage, and before full power was reached, a failure in one of the main transformers caused an addtional seven and a half days of down time. The remainder of the year was essentially free of major outages.

Details of plant outages for North Anna 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/01/82	69.3	F	Ramped unit down and removed unit from service due to exessive primary leakage. Balance move on turbine.	A	1	Reactor coolant (CF)	Valves
2	1/04/82	7.8	F	Ramped unit down and removed unit from service to balance turbine.	A	1	Reactor coolant (CF)	Valves
3	1/08/82	13.7	S	Ramped unit down and removed unit from service to balance turbine.	B	1	Reactor coolant (CF)	Valves
4	1/09/82	8.3	F	Ramped unit down and removed unit from service to balance turbine.	A	1	Reactor coolant (CF)	Valves
5	1/10/82	4.8	F	Manual turbine trip/reactor trip due to loss of power to "C" station service bus when transferring to station service.	A	1	Reactor coolant (CB)	Circuit closers/ interrupters
6	2/21/82	19.7	F	Reactor trip on nuclear power high negative rate. Dropped rod while trouble shooting rod urgent failure alarm.	A	3	Instrumentation and controls (IA)	Instrumentation and controls
7	3/07/82	2,306.6	S	Scheduled refueling outage.	C	1	Reactor (RC)	Fuel elements
8	6/11/82	4.7	F	Normal rampdown to generator off line to perform turbine overspeed test.	B	1	Steam and power conversion (HA)	Codes not applicable
9	6/16/82	3.8	F	Normal rampdown to generator off line to balance the turbine.	B	1	Steam and power conversion (HA)	Turbines

Details of plant outages for North Anna 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
10	7/03/82	12.9	F	Normal rampdown to 30% power for testing and evaluation of "loose parts" alarm on "A" SG, followed by continued normal rampdown from 30% power to generator off line for further testing and evaluation of the "loose parts" alarm on "A" SG. Additional "loose parts" monitoring pickups were installed during the time unit was off line.	H	1	Instrumentation and controls (IF)	Heat exchangers
11	7/08/82	1,086.8	F	Normal rampdown from 100% power to generator off line to investigate the noise monitored in "A" SG. During this time it was decided to "UT" the thermal sleeves installed in the RCS.	B	1	Steam and power conversion (HJ)	Heat exchangers
12	8/22/82	185.1	F	"B" phase main transformer failure.	A	3	Electric power	Transformers
13	9/21/82	29.8	F	Repair of steam generator FW PP recirc. valve S-FW-250C.	A	1	Steam and power conversion (HH)	Valves
14	11/12/82	14.4	F	The cause of the reactor trip was determined to be a spurious actuation of "A" reactor trip breaker.	H	3	Instrumentation and controls (IA)	Circuit closers/ interrupters



DESIGN ELEC. RATING - 907 MAX. DEPEND. CAP. - 890 (100%) NORTH ANNA 2

OCONEE 1

I. Summary

Description	Performance	Outages
Location: Sececa, South Carolina	Net electrical energy generated (MWh): 5,152,750	Total No.: 22
Docket No.: 50-269	Unit availability factor (%): 72.4	Forced: 21
Reactor type: PWR	Unit capacity factor (%) (using MDC): 68.4	Scheduled: 1
Maximum dependable capacity [MW(e)-net]: 860	Unit capacity factor (%) [using design MW(e)]: 66.3	Total hours: 2,420 (27.6%)
Commercial operation: 7/15/73		Forced: 2,217 (25.3%)
Years operating experience: 9.7		Scheduled: 203 (2.3%)

II. Highlights

Oconee 1 underwent a number of relatively extended shutdowns during 1982. The first of these began on January 6 and lasted for 24 days. The first 11 days were due to high turbine vibration, requiring rebalance of the turbine, plus repair of a hydrogen leak on the electric generator; the last 13 days were due to the need to repair leaks in a high-pressure feedwater heater. A 17-day outage in February was caused by a steam generator tube leak, requiring plugging of the leaking tube. A similar problem in the other steam generator resulted in an 18-day shutdown in March. In mid-May a control rod dropped during rod motion testing due to a failed rod stator, and the resulting 24-day outage was also used to repair feedwater heater leaks and perform other maintenance and inspections. The reactor then operated without major outages until October 22, when required adjustments on the code pressurizer relief valves were made during an eight-and-a-half-day shutdown.

Details of plant outages for Oconee 1

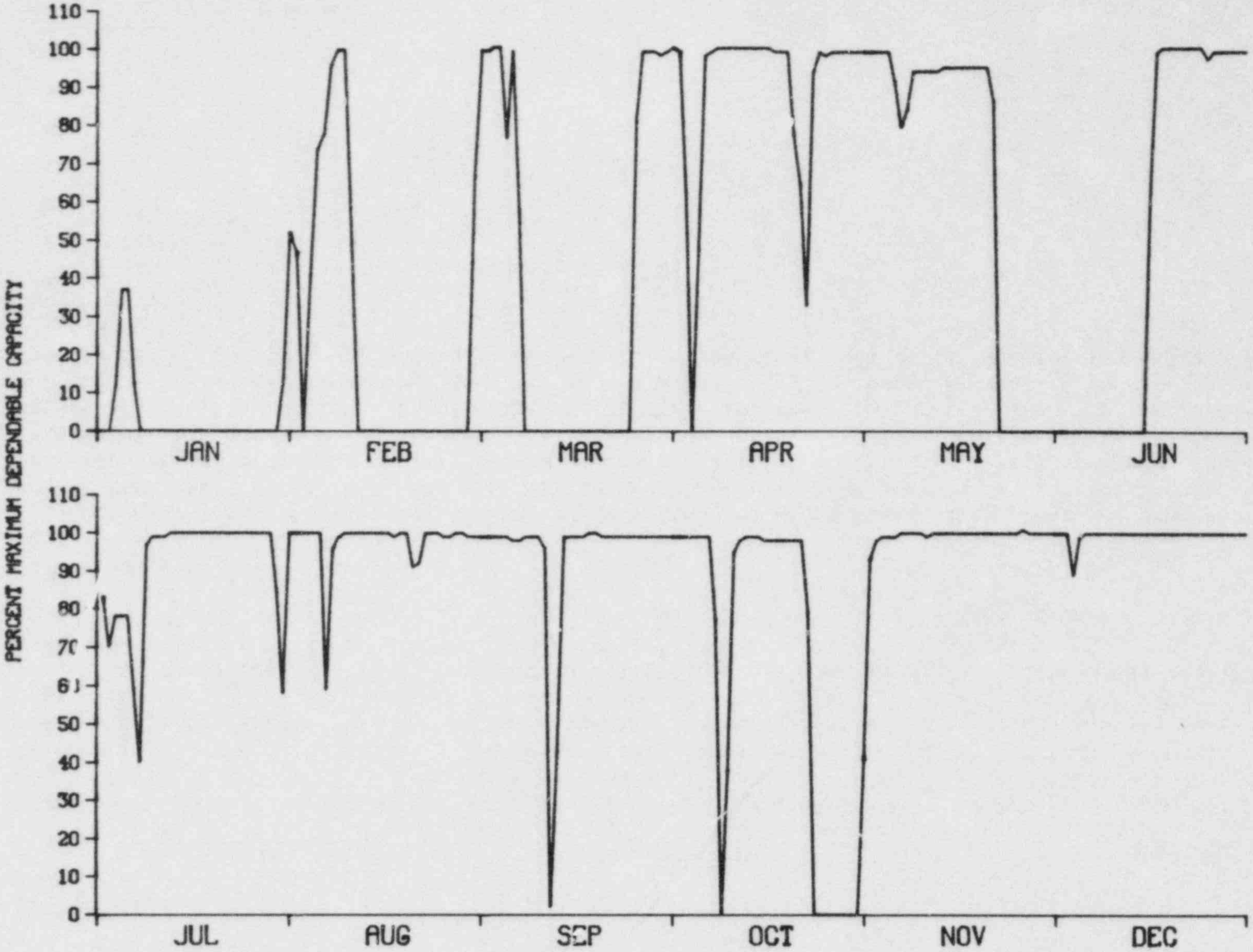
No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/01/82	12.0	F	Moisture separator reheater drain tank high level tripped turbine/reactor.	A	3	Steam and power conversion (HC)	Turbines
2	1/01/82	6.2	F	Moisture separator reheater drain tank high level tripped turbine/reactor.	A	3	Steam and power conversion (HC)	Turbines
3	1/01/82	16.6	F	Moisture separator reheater drain tank high level tripped turbine/reactor.	A	3	Steam and power conversion (HC)	Turbines
4	1/02/82	21.0	F	Turbine/reactor trip due to false loss-of-stator-coolant signal.	A	3	Steam and power conversion (HA)	Instrumentation and controls
5	1/06/82	276.7	F	Turbine bearing No. 1 exceeded high vib. limit. Shutdown for balance shot and repair of generator hydrogen leak.	A	1	Steam and power conversion (HA)	Turbines
6	1/17/82	294.5	F	Outage extended due to leaks in the high-pressure feedwater heaters 1A1 and 1A2.	A	9	Reactor coolant (CH)	Heat exchangers
7	1/30/82	4.1	F	Removed unit from service for turbine balance shot. Reactor remained critical.	A	1	Steam and power conversion (HA)	Turbines
8	2/01/82	31.8	F	Turbine off for a balance shot. Reactor remained critical.	A	1	Steam and power conversion (HA)	Turbines
9	2/09/82	417.6	F	Removed unit from service to repair tube leak in the 1A steam generator.	A	1	Reactor coolant (CB)	Heat exchangers
10	3/06/82	432.2	F	1B steam generator tube leak repair.	A	1	Reactor coolant (CB)	Heat exchangers

Details of plant outages for Oconee 1 (continued)

No.	Date	Duration (n)	Type	Description	Cause	Shutdown method	System involved	Component involved
11	3/24/82	3.2	F	Reactor tripped on high reactor coolant system pressure due to a feedwater control problem, causing a swing in flow.	A	3	Reactor coolant (CB)	Instrumentation and controls
12	4/02/82	36.3	F	Reactor tripped when a control problem allowed the group No. 6 rods to drop into core.	A	3	Reactor (RB)	Conrol rod drive mechanisms
13	4/20/82	9.7	F	Unit was removed from service and reactor at hot shutdown to add oil to the 1A1 RCP motor lower oil pot.	A	1	Reactor coolant (CB)	Motors
14	5/21/82	572.9	F	During conrod movement test, No. 8 rod on group 1 dropped due to shorted stator, causing a reactor/turbine trip. During outage also cleaned/inspected CRD stators, repaired feedwater heater leaks and pressurizer relief valve RC-66, and inspected reactor bldg. secondary shielding wall tendons.	A	3	Reactor (RB)	Conrol rod drive
15	7/06/82	7.6	F	Unit off and reactor at hot shutdown to weld patch on "C" bleed line.	B	1	Steam and power conversion (HE)	Turbines
16	7/29/82	9.2	F	Reactor/turbine trip caused by lightning.	A	3	System code not applicable (ZZ)	Codes not applicable
17	8/06/82	3.2	F	Reactor trip due to CRD group 6 drop when power from auxiliary power supply was lost.	H	3	Electric power (EB)	Circuit closers/ interrupters
18	9/10/82	11.6	F	Low EHC pressure trip. Pressure switch activating above set point.	H	3	Steam and power conversion (HA)	Instrumentation and controls

Details of plant outages for Oconee 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
19	9/11/82	6.3	F	Reactor trip due to a feedwater transient resulting from an operator error.	G	3	Reactor coolant (CH)	Codes not applicable
20	9/11/82	9.7	F	Turbine trip on loss of stator cooling. Loss of power to stator cooling pump caused by faulty breaker in load center feeding the pump.	A	3	Steam and power conversion (HA)	Circuit closers/ interrupters
21	10/07/82	34.1	F	Reactor shutdown to add oil to "1A1" RCP.	H	1	Reactor coolant (CB)	Pumps
22	10/22/82	203.5	S	Unit shutdown to adjust internal ring settings of pressurizer code relief valves.	B	1	Reactor coolant (CB)	Valves



DESIGN ELEC. RATING - 887 MAX. DEPEND. CAP. - 860 (100%) OCONEE 1

OCONEE 2

I. Summary

Description	Performance	Outages
Location: Seneca, South Carolina	Net electrical energy generated (MWh): 3,737,387	Total No.: 14
Docket No.: 50-270		Forced: 11
Reactor type: PWR	Unit availability factor (%): 52.3	Scheduled: 3
Maximum dependable capacity [MW(e)-net]: 860	Unit capacity factor (%) (using MDC): 45.6	Total hours: 4,179[a] (47.7%)
		Forced: 1,022 (11.7%)
Commercial operation: 9/09/74	Unit capacity factor (%) [using design MW(e)]: 44.2	Scheduled: 3,157[a] (36.0%)
Years operating experience: 9.1		

II. Highlights

Oconee 2 began the year in an extended refueling and maintenance outage that had started the very end of December 1981 and was used also for ten-year in-service inspection and for replacement of the core support assembly bolts. This outage lasted for a total of 17 weeks, until mid-May. The last 18 days of this outage were occupied with replacing secondary shielding-wall tendons. In late June a severe leak in the turbine extraction piping required two weeks to repair. Then, in the last week of August, it was necessary to shut down for 11 and a half days to replace a leaking code relief valve. In mid-October, adjustments had to be made to the pressurizer code relief valves, requiring a six-day outage.

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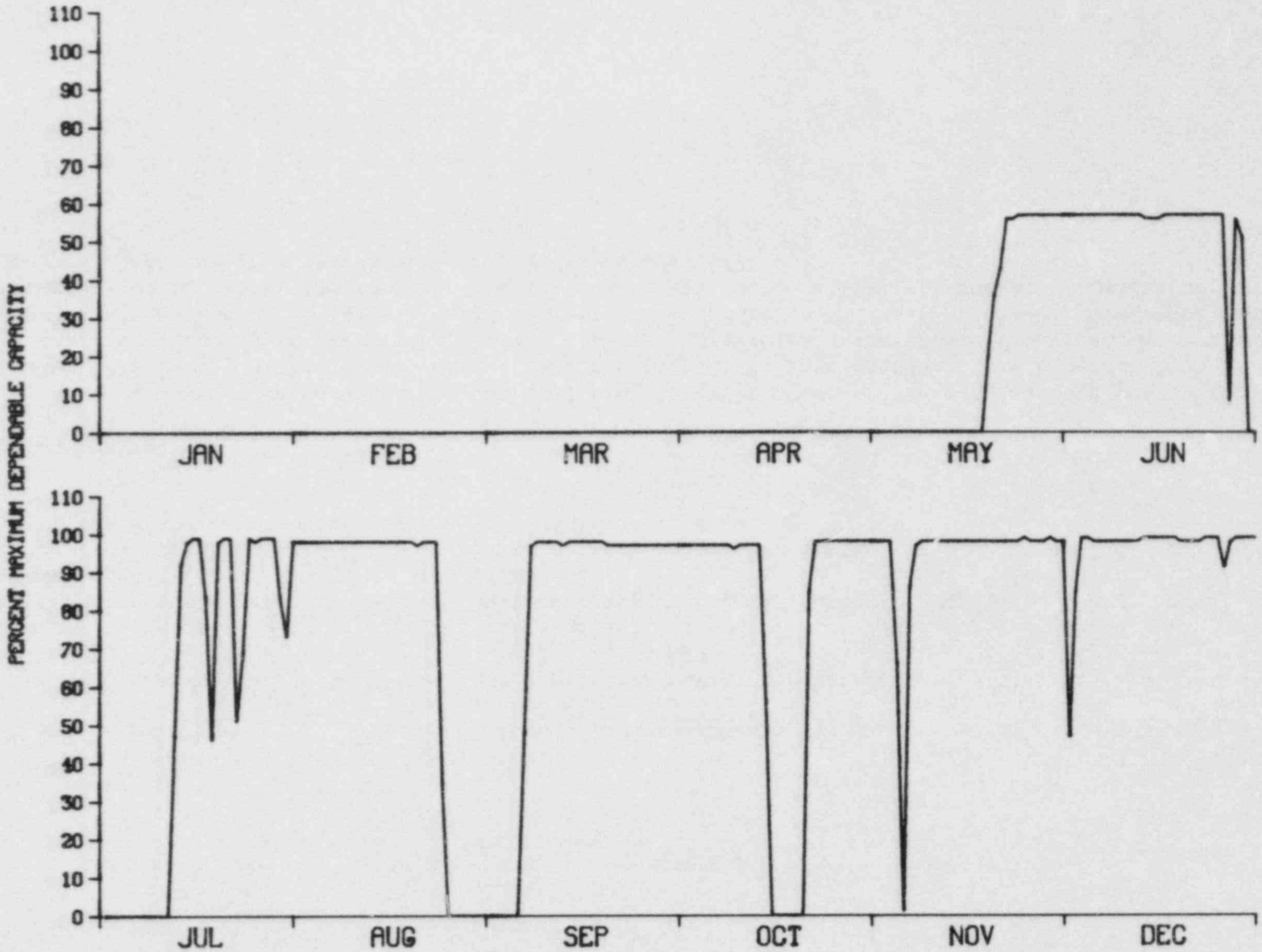
[a]Includes 1,554 h in 1982 from continuation of 12/28/81 outage.

Details of plant outages for Oconee 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	12/28/81	1,554.0	S	Scheduled refueling outage in combination with 10-year ISI. This outage runs in parallel with the core support bolt replacement outage and NRC NSMS. The hours cited are for the refueling portion only.	C	4	Reactor (RC)	Fuel elements
2	12/28/81	1,272.0	S	Core support assembly bolt replacement. This outage runs in combination with the refueling outage of the same date. The hours cited are for the bolt replacement portion of the outage only.	B	4	Reactor coolant (CA)	Vessels, pressure
3	4/28/82	435.5	F	Containment secondary shielding wall tendon replacement.	A	9	System code not applicable (ZZ)	Codes not applicable
4	5/16/82	54.5	S	Zero power physics testing.	B	9	System code not applicable (ZZ)	Codes not applicable
5	5/19/82	2.8	F	Turbine/reactor trip at 20% power due to failure to reset contact buffers in RPS cabinets after overspeed of turbine.	G	3	Steam and power conversion (HA)	Turbines
6	6/26/82	20.0	F	Low turbine control oil pressure resulted in turbine/reactor trip.	A	3	Steam and power conversion (HA)	Turbines
7	6/28/82	323.6	F	Reactor/turbine was tripped manually following a severe leak in the turbine extraction piping.	A	2	Steam and power conversion (HA)	Turbines
8	7/17/82	9.7	F	Unit off to repair a control (EHC) oil leak on the turbine front standard. Reactor remained critical.	A	1	Steam and power conversion (HA)	Turbines

Details of plant outages for Oconee 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
9	7/22/82	5.6	F	Turbine/reactor trip due to turbine control oil (EHC) pressure switch.	A	3	Steam and power conversion (HA)	Instrumentation and controls
10	7/29/82	6.2	F	Reactor/turbine trip caused by lightning.	H	3	System code not applicable (ZZ)	Codes not applicable
11	8/24/82	29.8	F	Spurious turbine trip while work was under way on hydraulic controls.	H	3	Steam and power conversion (HA)	Instrumentation and controls
12	8/25/82	276.7	S	Began outage to replace leaking code relief valves.	B	9	Reactor coolant (CB)	Valves
13	10/14/82	151.5	F	Unit shutdown to adjust internal ring settings of pressurizer code relief valves.	B	1	Reactor coolant (CB)	Valves
14	11/04/82	28.0	F	Reactor trip on high pressure due to defective vacuum switch on 2A FWPT.	A	3	Reactor coolant (CH)	Instrumentation and controls
15	12/01/82	9.0	F	Feedwater flow transmitter failed; unit trip then resulted from flux/flow imbalance.	A	3	Reactor coolant (CH)	Instrumentation and controls



DESIGN ELEC. RATING - 887 MAX. DEPEND. CAP. - 860 (100%)

OCONEE 2

OCONEE 3

I. Summary

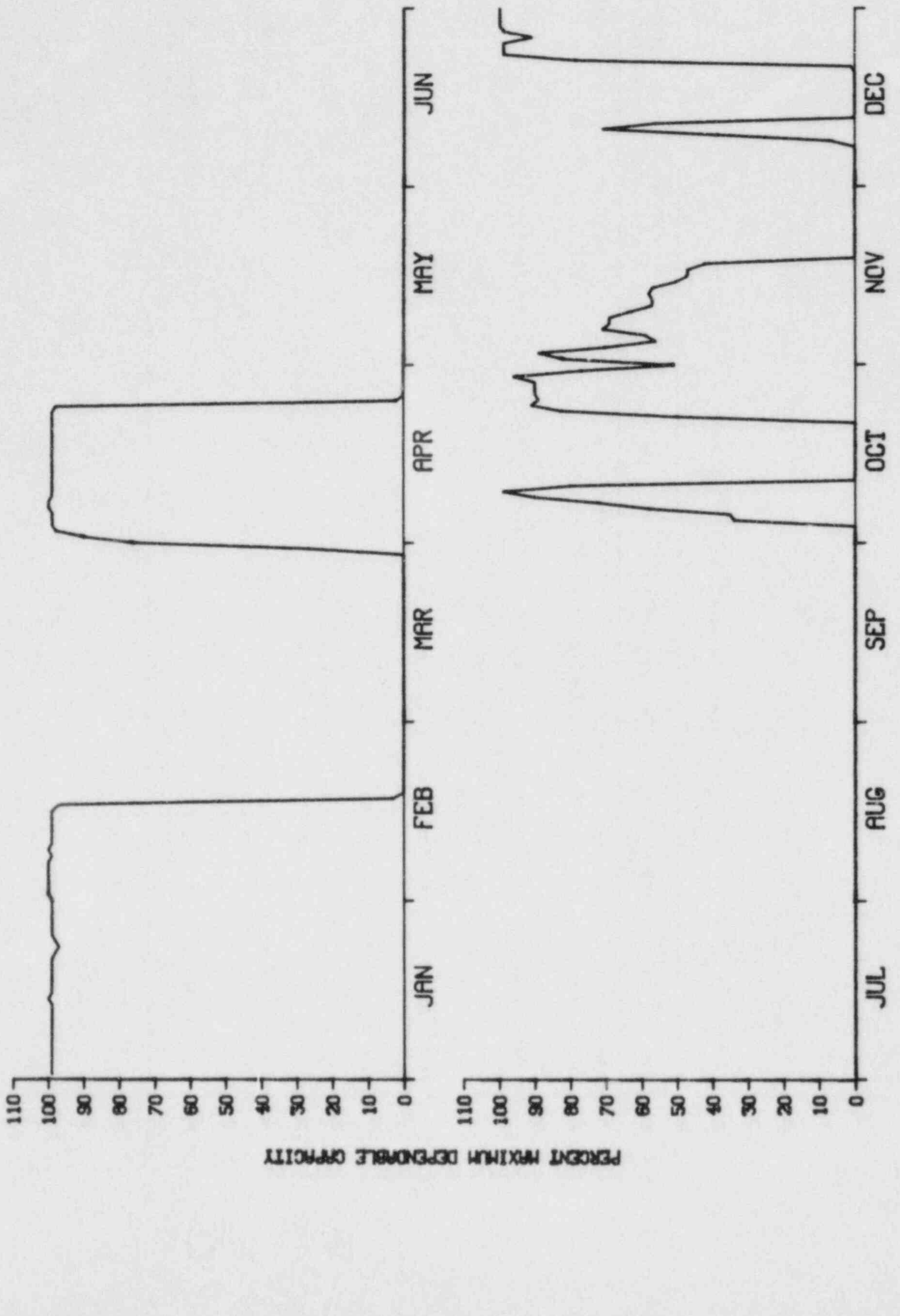
Description	Performance	Outages
Location: Seneca, South Carolina	Net electrical energy generated (MWh): 2,116,625	Total No.: 6
Docket No.: 50-287	Unit availability factor (%): 32.3	Forced: 5
Reactor type: PWR	Unit capacity factor (%) (using MDC): 28.1	Scheduled: 1
Maximum dependable capacity [MW(e)-net]: 860	Unit capacity factor (%) [using design MW(e)]: 27.2	Total hours: 5,933 (67.7%)
Commercial operation: 12/16/74		Forced: 2,029 (23.1%)
Years operating experience: 8.3		Scheduled: 3,904 (44.6%)

II. Highlights

Oconee 3 was down more than it was operating in 1982. Most of the outages were due to steam generator tube leaks, although the longest single outage, a 23-week shutdown that extended from late April to early October was for refueling and the ten-year in-service inspection. Tube leak investigation and repair outages accounted for six weeks in February and March, 11 days in October, three more weeks in November and December, and another 10 days in late December. All in all the steam generator tube leak problems kept the unit shut down for 12 weeks during 1982.

Details of plant outages for Oconee 3

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	2/16/82	1,012.9	F	Unit removed from service to repair a tube leak in the 3A steam generator.	A	1	Reactor coolant (CB)	Heat exchangers
2	4/24/82	3,904.1	S	Scheduled refueling/10 yr. ISI/NRC NSMs. Steam generator auxiliary feed ring inspection is also in progress.	C	1	Reactor (RC)	Fuel elements
3	10/10/82	267.1	F	Unit shutdown to attempt to locate steam generator tube leak. Work also completed on pressurizer code relief.	A	1	Reactor coolant (CB)	Heat exchangers
4	11/17/82	498.6	F	Unit shutdown to repair steam generator tube leaks.	A	1	Reactor coolant (CB)	Heat exchangers
5	12/09/82	9.8	F	Failure of level control switch caused unit trip on high moisture separator reheat level.	A	3	Reactor coolant (CC)	Instrumentation and controls
6	12/11/82	240.2	F	Unit shutdown to repair steam generator tube leak.	A	1	Reactor coolant (CB)	Heat exchangers


PERCENT MAXIMUM DEPENDABLE CAPACITY
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DESIGN ELEC. RATING - 887 MAX. DEPEND. CAP. - 860 (100%)
OCONEE 3

OYSTER CREEK 1

I. Summary

Description	Performance	Outages
Location: Tows River, New Jersey	Net electrical energy generated (MWh): 2,013,090	Total No.: 5
Docket No.: 50-219	Unit availability factor (%): 62.5	Forced: 5
Reactor type: BWR	Unit capacity factor (%) (using MDC): 37.1	Scheduled: 0
Maximum dependable capacity [MW(e)-net]: 620	Unit capacity factor (%) [using design MW(e)]: 35.4	Total hours: 3,284[a] (37.5%)
Commercial operation: 12/23/69		Forced: 3,284[a] (37.5%)
Years operating experience: 13.3		Scheduled: 0 (0%)

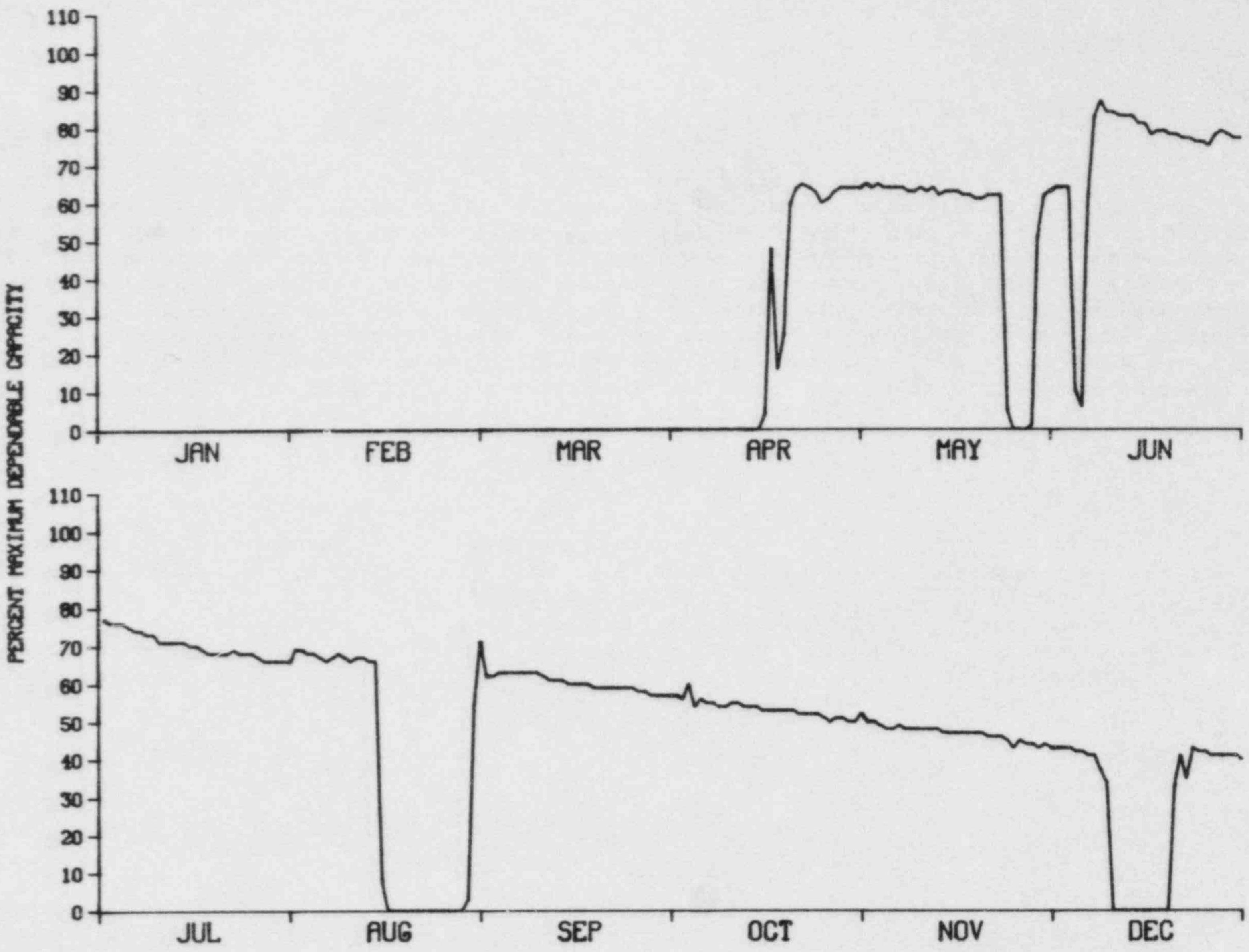
II. Highlights

During the first 15 weeks of 1982, Oyster Creek was down in a continuation of an outage that started on December 9, 1981, for repair of isolation valves on the isolation condenser and was then extended for other maintenance, including repair of an air cooler on a diesel generator and a control-rod-drive hydraulic pump. In April and May the plant operated at reduced power (65%) due to the unavailability of one of the three condensate pumps. On May 23 a leak on a reheater manway cover caused a five-day outage. In early June the third condensate pump was again available, so that power could be increased to full level. However, decreasing core reactivity availability started the power on a gradual downward slope which extended the rest of the year and limited operating power to about 40% of full power by year's end. In mid-August the plant was shut down for 15 days for inspection and repair of the containment spray system heat exchangers, and in mid-December a worn reactor recirculation pump seal caused increasing leakage and forced a 10-day outage for repairs.

[a]Includes 2,513 h in 1982 from continuation of 12/09/81 outage.

Details of plant outages for Oyster Creek 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	12/09/81	2,513.4	F	Shutdown to investigate and correct isolation condenser isolation valve operability concerns.	B	4	Reactor coolant (CF)	Valves
2	4/17/82	25.0	F	The off gas system absolute filter became saturated causing a condenser low vacuum scram.	G	3	System code not applicable (ZZ)	Codes not applicable
3	5/23/82	111.8	F	Complete maintenance on second stage steam reheater manway.	B	1	System code not applicable (ZZ)	Codes not applicable
4	6/04/82	37.7	F	Turbine trip greater than 40% power. Turbine trip caused by high reactor water level when feedwater pumps went to runout while filling the reactor cleanup system.	H	3	System code not applicable (ZZ)	Codes not applicable
5	8/15/82	353.6	F	Plant shutdown for inspection/repairs on the containment spray system heat exchangers.	H	1	Engineered safety features (SB)	Heat exchangers
6	12/10/82	242.7	F	Manual shutdown caused by increasing trend in dry-well unidentified leak rate due to a worn reactor recirculation pump seal.	A	1	Reactor coolant (CB)	Pumps



DESIGN ELEC. RATING - 650 MAX. DEPEND. CAP. - 620 (100%) OYSTER CREEK 1

PALISADES

I. Summary

Description

Location: South Haven, Michigan
Docket No.: 50-255
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 635
Commercial operation: 12/31/71
Years operating experience: 11.0

Performance

Net electrical energy generated (MWh): 3,345,123
Unit availability factor (%): 54.7
Unit capacity factor (%) (using MDC): 60.1
Unit capacity factor (%) [using design MW(e)]: 47.4

Outages

Total No.: 15
Forced: 15
Scheduled: 0
Total hours: 3,970[a] (45.3%)
Forced: 3,970[a] (45.3%)
Scheduled: 0 (0%)

II. Highlights

Palisades was down for a variety of reasons during substantial periods in 1982, totaling almost half the year. In late January more than five days were lost when the reactor tripped during transfer from station power to startup power, and then it had to remain down because of excessive sodium in the steam generators due to caustic NaOH from a blowdown demineralizer backflush in which valves leaked. A failure of one of the two cooling pumps caused a 28-day outage that began in early February. In late March a steam generator tube leak forced a shutdown that lasted seven weeks. In May, just after restarting from the last outage, the plant shut down for another 12 days to replace a damaged exciter on the main generator. In July the plant had to shut down again for 51 days when the second cooling tower pump failed due to a bearing failure. When the plant then came back on line in early September, it remained in operation with only minor outages the rest of the year.

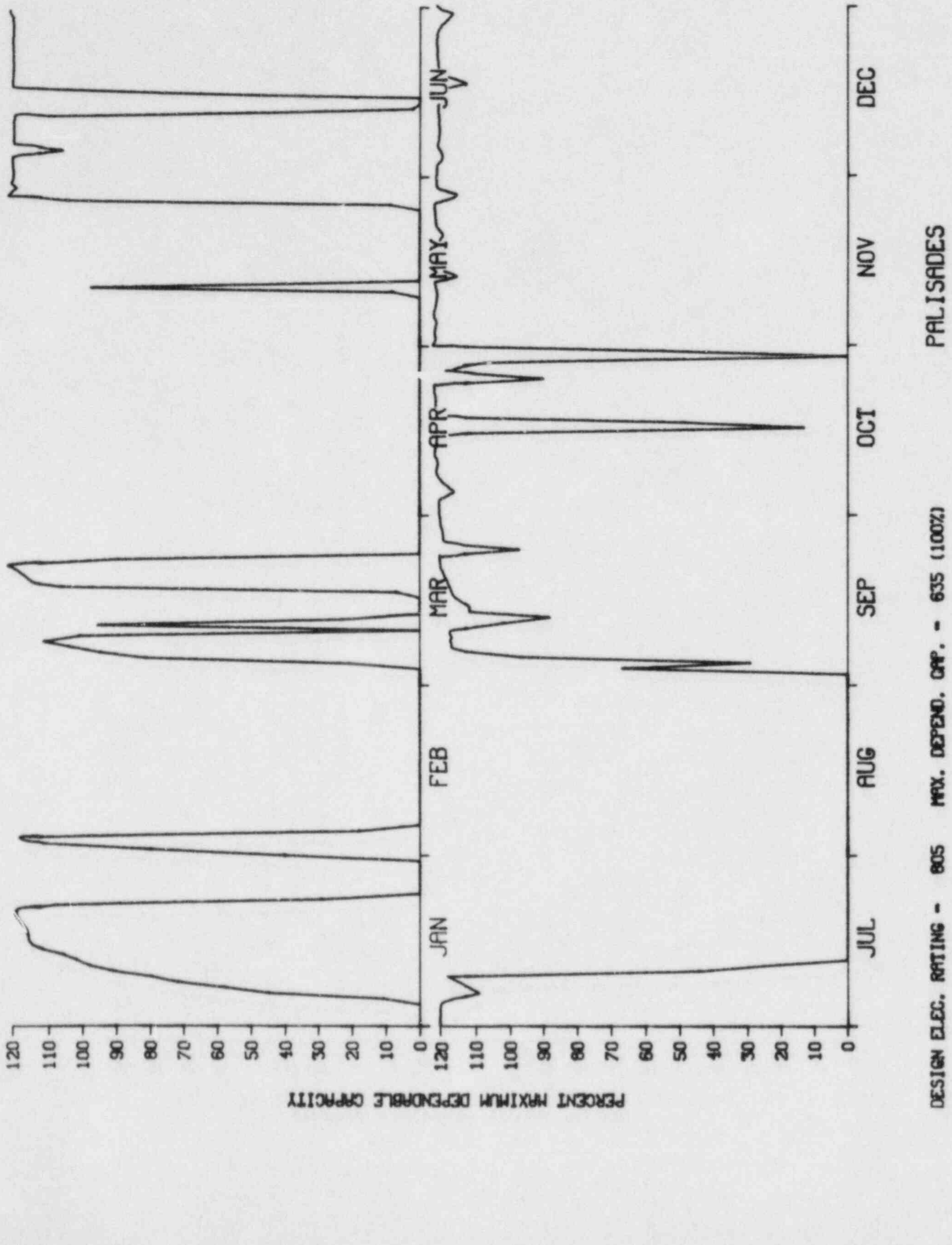
[a]Includes 30 h in 1982 from continuation of 12/31/81 outage.

Details of plant outages for Palisades

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	12/31/81	30.1	F	Turbine control problems.	A	4	Steam and power conversion (HA)	Instrumentation and controls
2	1/02/82	29.8	F	Turbine control problems.	A	3	Steam and power conversion (HA)	Instrumentation and controls
3	1/03/82	33.0	F	Loss of condenser vacuum.	A	3	Reactor coolant (CH)	Other components
4	1/24/82	148.0	F	Steam generator chemistry.	F	3	Reactor coolant (CC)	Codes not applicable
5	1/30/82	10.9	F	Feedwater turbine throttle and trip valve not fully open.	G	2	Reactor coolant (CH)	Valves
6	2/04/82	677.3	F	Cooling tower pump trip.	A	3	Steam and power conversion (HH)	Pumps
7	3/09/82	19.5	F	EH turbine generator control.	A	2	Steam and power conversion (HA)	Instrumentation and controls
8	3/12/82	129.7	F	Iso-phase bus fire.	A	2	Electric power (EB)	Electrical conductors
9	3/23/82	1,141.0	F	Steam generator tube leakage.	A	1	Steam and power conversion (HB)	Heat exchangers
10	5/12/82	349.7	F	Failure of No. 9 bearing and permanent magnet generator.	A	3	Electric power (EG)	Generators
11	6/12/82	40.4	F	Primary coolant pump low oil level.	B	1	Reactor coolant (CB)	Pumps
12	6/14/82	21.0	F	Turbine auto stop oil relief valve problem (reactor was not shut down).	A	9	Steam and power conversion (HA)	Valves
13	7/11/82	1,273.0	F	Cooling tower pump bearing failure.	A	2	Auxiliary water (WE)	Pumps

Details of plant outages for Palisades (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
14	9/04/82	9.2	F	Operating EH pump valved out.	G	3	Instrumentation and controls (IE)	Pumps
15	10/16/82	26.3	F	Failed steam generator level instrument.	A	3	Instrumentation and controls (ID)	Instrumentation and controls
16	10/28/82	31.6	F	Low suction pressure to main feed pump.	G	1	Reactor coolant (CB)	Codes not applicable


PERCENT MAXIMUM DEPENDABLE CAPACITY
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PALISADES
DESIGN ELEC. RATING - 805 MAX. DEPEND. CAP. - 635 (100%)

PEACH BOTTOM 2

I. Summary

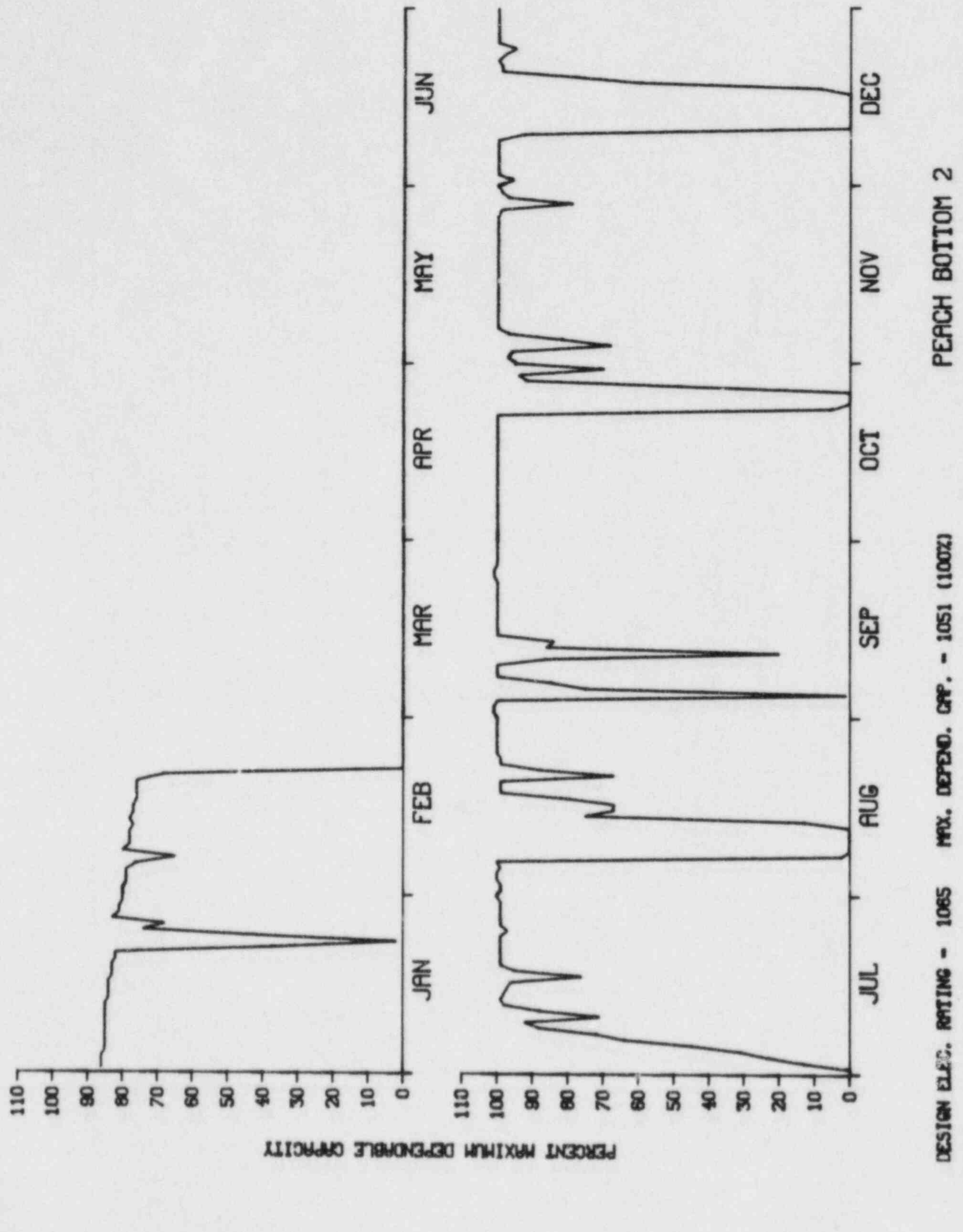
Description	Performance	Outages
Location: Peach Bottom, Pennsylvania	Net electrical energy generated (MWh): 4,794,414	Total No.: 8
Docket No.: 50-277	Unit availability factor (%): 58.1	Forced: 5
Reactor type: BWR	Unit capacity factor (%) (using MDC): 52.1	Scheduled: 3
Maximum dependable capacity [MW(e)-net]: 1,051	Unit capacity factor (%) [using design MW(e)]: 51.4	Total hours: 3,669 (41.9%)
Commercial operation: 7/15/74		Forced: 165 (1.9%)
Years operating experience: 8.9		Scheduled: 3,503 (40.0%)

II. Highlights

Peach Bottom 2 began the year with gradually declining power level as the available reactivity decreased with increasing fuel burnup. Finally, on February 19, the unit began a refueling and maintenance outage that lasted 19 weeks until the start of July. Thereafter there were only two extended outages during the remainder of the year: a six-day shutdown in August to change out recirculation pump seals and a mid-December shutdown for seven days to repair a main steam relief valve.

Details of plant outages for Peach Bottom 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/22/82	32.8	F	Accidental bumping of vibration switch on "2C" reactor feedpump turbine that tripped turbine, resulting in low reactor level, causing automatic scram.	G	3	Reactor coolant (CH)	Instrumentation and controls
2	2/19/82	3,173.4	S	Shutdown for refuel outage.	C	1	Reactor (RC)	Fuel elements
3	8/06/82	154.5	S	Shutdown for replacement of the "2A" and "2B" recirculation pump seals.	B	1	Reactor coolant (CB)	Pumps
4	9/03/82	20.9	F	Shutdown taken to repair a "2A" moisture separator drain tank leak.	B	1	Steam and power conversion (HC)	Heat exchangers
5	9/10/82	15.7	F	Shutdown taken after the outer service air valve to the dry well was found open.	G	1	Engineered safety features (SA)	Valves
6	10/23/82	36.0	F	Continued shutdown after a low oil level alarm was received on the the "2A" recirculation pump.	B	1	Reactor coolant (CB)	Pumps
7	10/24/82	60.0	F	Continuation of the outage because during the return to service (at approx. 800 psi), the "J" main steam line relief valve opened, causing a reactor scram on low level.	A	3	Reactor coolant (CC)	Valves
8	12/09/82	175.3	S	Shutdown for repair of 71 "K" main steam relief valve.	B	1	Reactor coolant (CC)	Valves


PERCENT MAXIMUM DEPENDABLE CAPACITY
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DESIGN ELEC. RATING - 1065   MAX. DEPEND. CAP. - 1051 (100%)
PEACH BOTTOM 2

PEACH BOTTOM 3

I. Summary

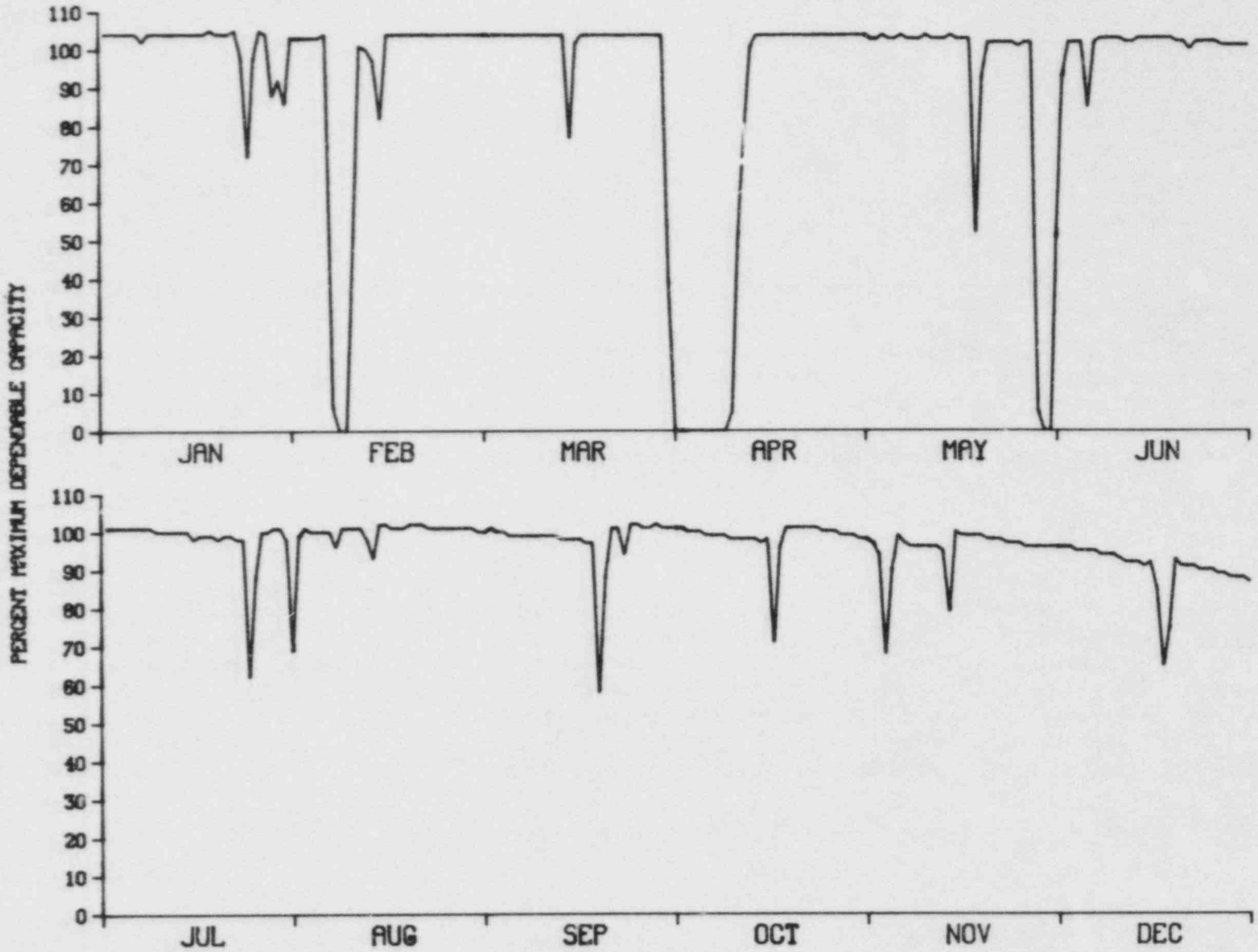
Description	Performance	Outages
Location: Peach Bottom Pennsylvania	Net electrical energy generated (MWh): 8,532,319	Total No.: 3
Docket No.: 50-278	Unit availability factor (%): 95.6	Forced: 3
Reactor type: BWR	Unit capacity factor (%) (using MDC): 94.1	Scheduled: 0
Maximum dependable capacity [MW(e)-net]: 1,035	Unit capacity factor (%) [using design MW(e)]: 91.5	Total hours: 386 (4.4%)
Commercial operation: 12/23/74		Forced: 386 (4.4%)
Years operating experience: 8.3		Scheduled: 0 (0%)

II. Highlights

In 1982 Peach Bottom 3 achieved the highest energy production among all U.S. power reactors and the second-highest availability factor for the BWRs. It reached this enviable record by having only one substantial outage during the year, a ten-day outage in March caused by vibration of the generator exciter housing. During that period a recirculation pump shaft seal was also replaced. Late in the year the maximum power began to drift downward as available reactivity declined due to fuel depletion.

Details of plant outages for Peach Bottom 3

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	2/06/82	74.9	F	Scram caused by failure of transmission line, resulting in tripping of No. 1 transformer.	A	3	Electric power (EA)	Other components
2	3/30/82	242.0	F	Shutdown prompted by increasing vibration on the main generator exciter housing.	A	1	Steam and power conversion (HA)	Generators
3	5/28/82	69.1	F	Shutdown due to apparent high primary containment leakage.	A	1	Engineered safety features (SA)	Valves



DESIGN ELEC. RATING - 1065 MAX. DEPEND. CAP. - 1035 (100%)

PEACH BOTTOM 3

PILGRIM 1

I. Summary

Description	Performance	Outages
Location: Plymouth, Massachusetts	Net electrical energy generated (MWh): 3,287,027	Total No.: 11
Docket No.: 50-293	Unit availability factor (%): 63.9	Forced: 9
Reactor type: BWR	Unit capacity factor (%) (using MDC): 56.0	Scheduled: 2
Maximum dependable capacity [MW(e)-net]: 670	Unit capacity factor (%) [using design MW(e)]: 57.3	Total hours: 3,159[a] (36.1%)
Commercial operation: 12/01/72		Forced: 400 (4.6%)
Years operating experience: 10.5		Scheduled: 2,758[a] (31.5%)

II. Highlights

Pilgrim 1 was in a refueling and modification outage at the start of 1982. This outage, which had begun in late September 1981, lasted until mid-April. Thereafter there were only a small number of extended shutdowns, the largest of these being a 15-day outage in mid-October for repair of a main steam isolation valve. At two separate times during the year, in May/June and in September, the plant operated at reduced power because only two of three condensate pumps were available.

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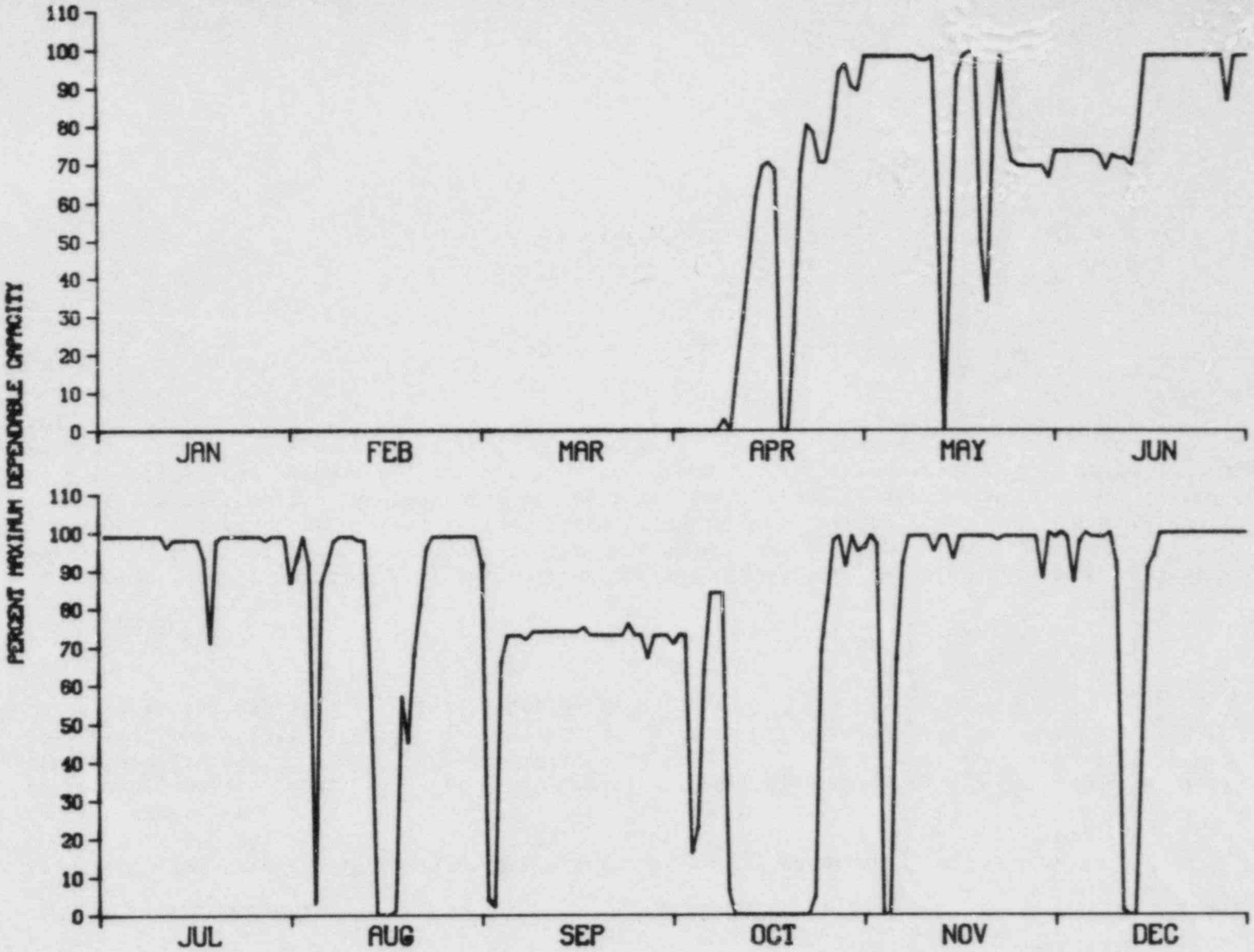
[a]Includes 2,333 h in 1982 from continuation of 9/26/81 outage.

Details of plant outages for Pilgrim 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	9/26/81	2,332.6	S	Refueling/modification outage.	C	4	Reactor (RC)	Fuel elements
2	4/08/82	36.8	F	Turbine testing caused high reactor pressure.	B	3	Steam and power conversion (HA)	Other components
3	4/16/82	60.6	F	Hydrogen seal oil leak. Reactor taken to reduced pressure, then standby for repairs.	A	1	Steam and power conversion (HA)	Other components
4	5/12/82	40.7	F	Reactor scram caused by defective ATWS trip unit found during ATWS high risk test. Trip unit repaired.	A	3	Instrumentation and controls (IA)	Instrumentation and controls
5	5/19/82	23.4	F	Reactor scram due to APRM high flux when turbine ran back, caused by failed temperature sensing unit for stator cooling.	A	3	Steam and power conversion (HA)	Instrumentation and controls
6	8/03/82	23.2	F	Main steam line high rad. scram due to air intrusion.	H	3	Reactor coolant (CD)	Codes not applicable
7	8/13/82	104.9	F	Scram when staging struck main steam line instrument rack.	H	3	Reactor coolant (CD)	Codes not applicable
8	9/01/82	43.3	F	Scram due to low vacuum in main condenser during backwash.	A	3	Steam and power conversion (HC)	Heat exchangers
9	10/03/82	8.9	F	Turbine control valve adjustment.	B	1	Steam and power conversion (HA)	Codes not applicable
10	10/09/82	352.3	S	Repair of "D" inboard MSIV.	B	2	Steam and power conversion (HB)	Valves

Details of plant outages for Pilgrim 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
11	11/02/82	58.6	F	Incorrect setting on safety valve required dry-well entry to effect fix.	H	1	Steam and power conversion (HB)	Valves
12	12/11/82	73.4	S	Repairs made to fourth point heater expansion joints.	A	1	Steam and power conversion (HH)	Heat exchangers



DESIGN ELEC. RATING - 655 MAX. DEPEND. CAP. - 670 (100%) PILGRIM 1

POINT BEACH 1

I. Summary

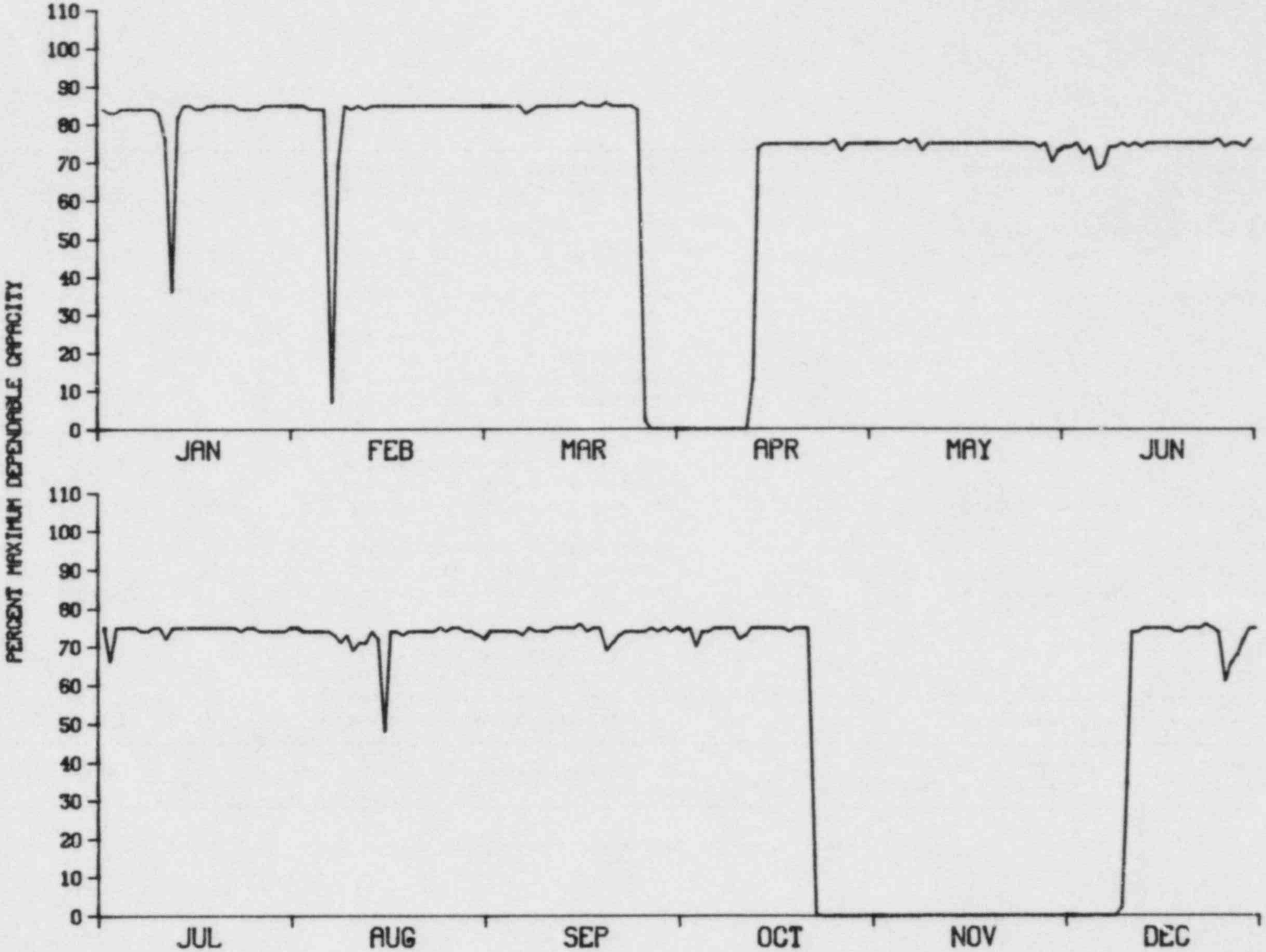
Description	Performance	Outages
Location: Two Creeks, Wisconsin	Net electrical energy generated (MWh): 2,701,830	Total No.: 6
Docket No.: 50-266		Forced: 2
Reactor type: PWR	Unit availability factor (%): 81.8	Scheduled: 4
Maximum dependable capacity [MW(e)-net]: 495	Unit capacity factor (%) (using MDC): 62.3	Total hours: 1,624 (18.5%)
		Forced: 15 (0.2%)
Commercial operation: 12/21/70	Unit capacity factor (%) [using design MW(e)]: 62.1	Scheduled: 1,609 (18.4%)
Years operating experience: 12.2		

II. Highlights

Point Beach 1 operated very reliably during 1982, with only two significant outages during the year. The first of these took place in late March and lasted 17 and a half days; it was due to the need for steam generator inspection, in the course of which four leaking plugs were detected and repaired. From that outage on for the remainder of the year, Point Beach 1 operated with power limited to 78% of full power for the purpose of lowering T_{ave} for steam generator conservation. A refueling outage begun in late October was accomplished in just under seven weeks. No other significant outages occurred during the year.

Details of plant outages for Point Beach 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/11/82	12.8	F	Due to a steam pressure sensing line freeze-up, a 2/3 coincidence signal caused a unit trip on a safety injection signal from a low steam line pressure indication.	A	3	Instrumentation and controls (IB)	Heaters, electric
2	2/06/82	19.7	S	The unit was shut down to repair a gasket leak on the "B" loop cold leg RTD manifold orifice flange.	B	1	Reactor coolant (CX)	Pipes and/or fittings
3	3/26/82	422.0	S	The unit was taken off line for a scheduled SG tube inspection. A hydrostatic test of both SGs revealed three leaking plugs in SG "B" and one leaking plug in SG "A." The unit was returned to service following the successful completion of SG inspections and repairs.	B	1	Reactor coolant (CC)	Heat exchangers
4	10/22/82	1,166.7	S	Began seven-week refueling outage.	C	1	Reactor (RC)	Fuel elements
5	12/09/82	2.1	F	Reactor trip from 20 MWe due to a low-low trip signal.	G	3	Steam and power conversion (HB)	Codes not applicable
6	12/10/82	0.6	S	Unit removed from service for off-line turbine testing.	B	9	System code not applicable (ZZ)	Codes not applicable



DESIGN ELEC. RATING - 497 MAX. DEPEND. CAP. - 495 (100%) POINT BEACH 1

POINT BEACH 2

I. Summary

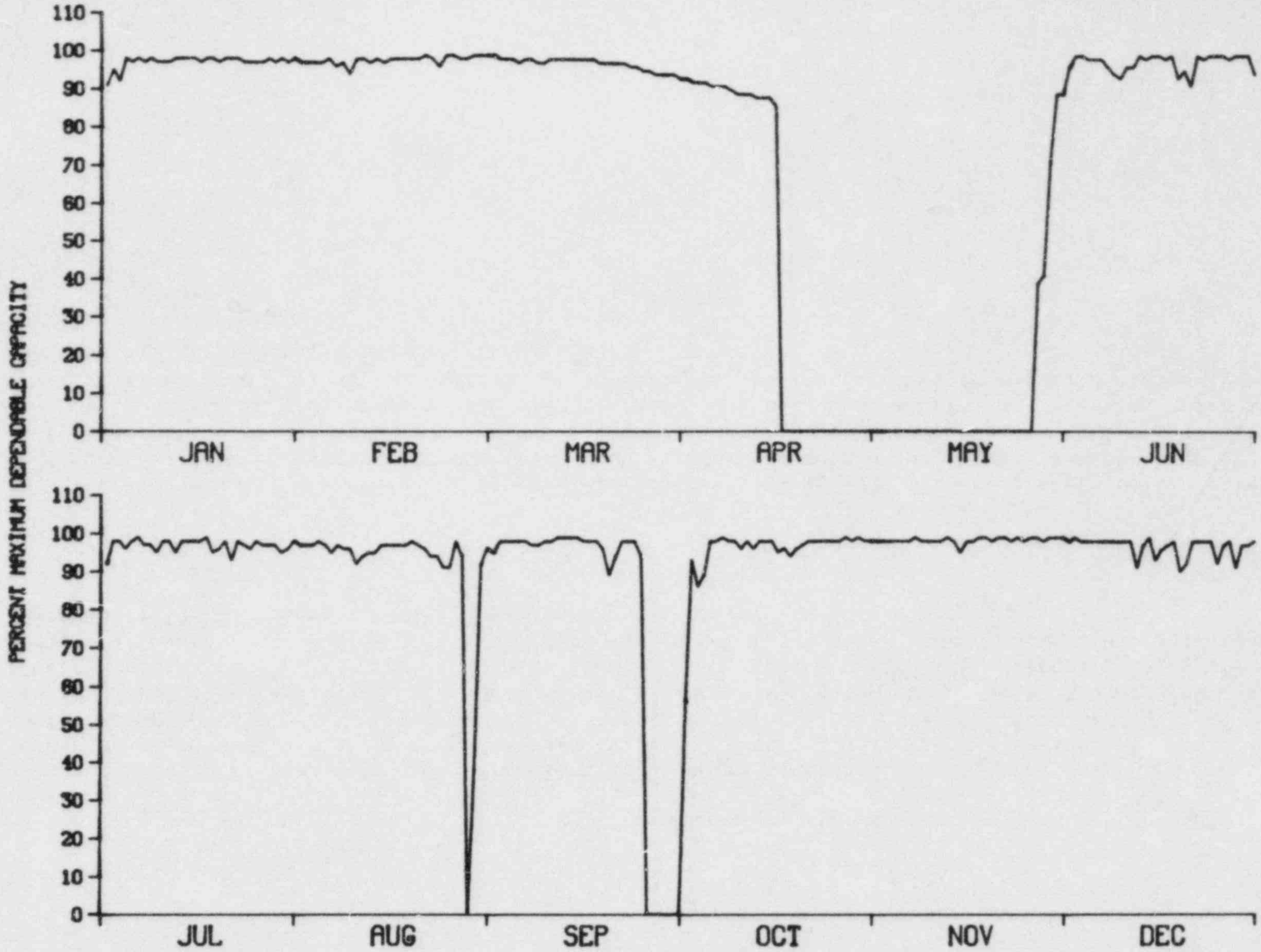
Description	Performance	Outages
Location: Two Creeks, Wisconsin	Net electrical energy generated (MWh): 3,605,501	Total No.: 5
Docket No.: 50-301	Unit availability factor (%): 86.8	Forced: 1
Reactor type: PWR	Unit capacity factor (%) (using MDC): 83.1	Scheduled: 4
Maximum dependable capacity [MW(e)-net]: 495	Unit capacity factor (%) [using design MW(e)]: 82.8	Total hours: 1,163 (13.3%)
Commercial operation: 10/01/72		Forced: 4 (0%)
Years operating experience: 10.4		Scheduled: 1,160 (13.2%)

II. Highlights

Like its sister unit Point Beach 1, Point Beach 2 had an excellent operating year in 1982, with only two relatively brief outages of significant duration. After slowly drifting downward in power production during March and early April due to fuel depletion, the unit shut down on April 16 for its eighth refueling outage. This was completed in less than five weeks, a remarkably brief shutdown for refueling. Only one other significant outage took place during the year, a six-day outage in September to replace a reactor coolant pump seal.

Details of plant outages for Point Beach 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	4/16/82	975.3	S	Unit 2 was shut down for its eighth refueling outage. Major work items scheduled to be performed this outage included containment integrated leakage rate testing, eddy current inspection of the steam generator tubes, various section XI material testing, "A" reactor coolant pump motor replacement, replacement of various safety-grade pressure transmitters, and TMI work packages. The unit was scheduled to return to service on 5/29/82.	C	1	Reactor (RC)	Fuel elements
2	5/27/82	0.6	S	Unit removed from service for off-line turbine testing.	B	9	System code not applicable (ZZ)	Codes not applicable
3	5/28/82	3.5	F	Spurious safety injection signal caused by loose terminal connection discovered while isolating 125-V dc bus ground fault.	B	3	System code not applicable (ZZ)	Codes not applicable
4	8/28/82	33.6	S	Shutdown resulted from replacement of isolation valve 2-560A of reactor coolant system's RTD manifold from what is believed to be a plug-stem separation.	A	1	Reactor coolant (CB)	Valves
5	9/25/82	150.4	S	No. 2 seal on "B" reactor coolant pump exhibited signs of increased degradation and was replaced.	B	1	Reactor coolant (CB)	Pumps



DESIGN ELEC. RATING - 497 MAX. DEPEND. CAP. - 495 (100%)

POINT BEACH 2

PRAIRIE ISLAND 1

I. Summary

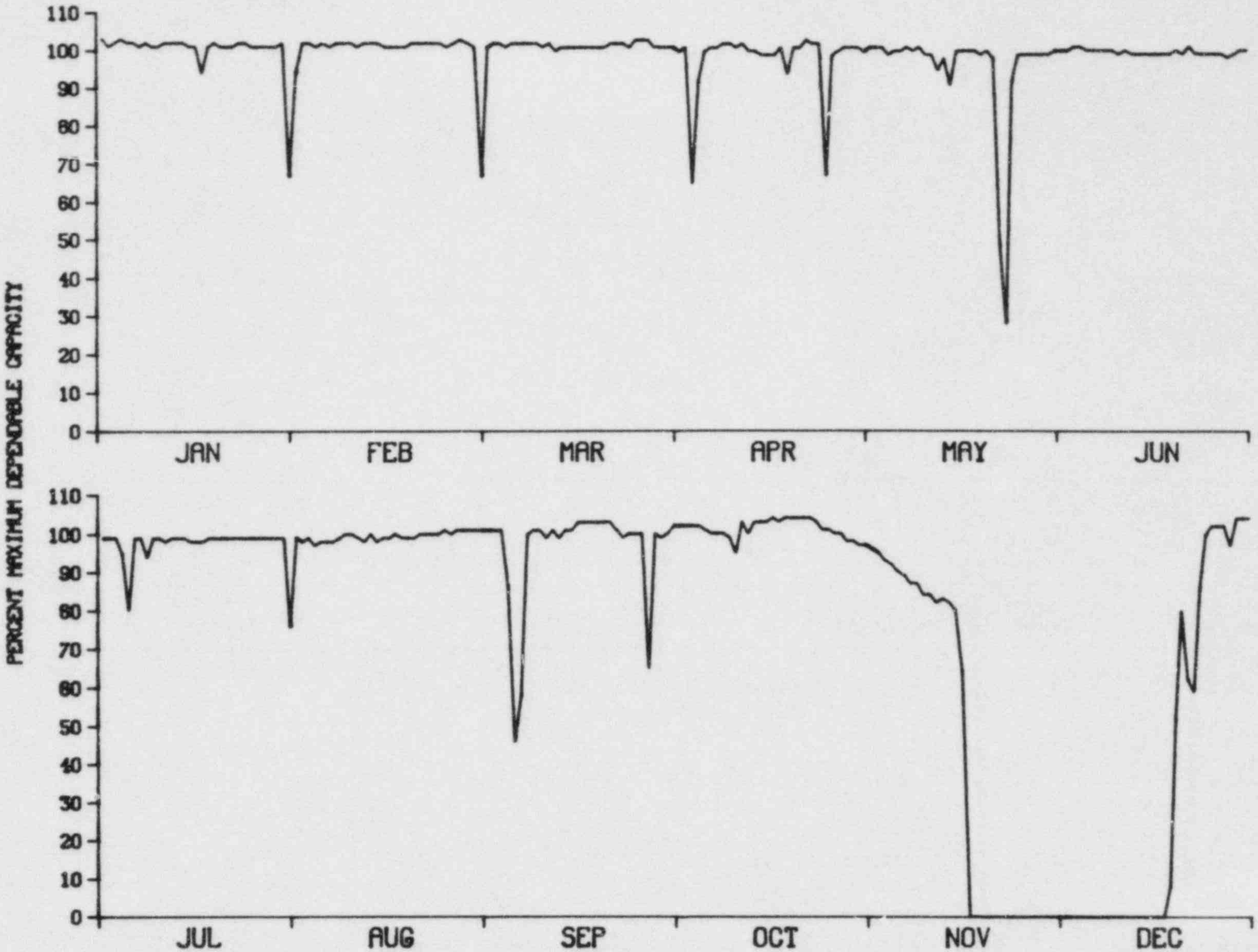
Description	Performance	Outages
Location: Goodhue, Minnesota	Net electrical energy generated (MWh): 3,918,177	Total No.: 2
Docket No.: 50-282	Unit availability factor (%): 90.9	Forced: 1
Reactor type: PWR	Unit capacity factor (%) (using MDC): 88.9	Scheduled: 1
Maximum dependable capacity [MW(e)-net]: 503	Unit capacity factor (%) [using design MW(e)]: 84.4	Total hours: 798 (9.1%)
Commercial operation: 12/16/73		Forced: 16 (0.2%)
Years operating experience: 9.1		Scheduled: 782 (8.9%)

II. Highlights

Prairie Island 1 was among the top nuclear power plants in 1982 with respect to unit availability, achieving a factor of better than 90%, even with a refueling outage, which was in fact the only significant interruption of operation during 1982 and which lasted just over four and a half weeks. This shutdown, which begin in mid-November, had been preceded by a period of several weeks during which the power level declined gradually as the reactivity available became insufficient to maintain maximum power as the result of fuel depletion.

Details of plant outages for Prairie Island 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	9/05/82	16.2	F	Broken air line on feed reg. valve.	A	3	Steam and power conversion (HH)	Pipes and/or fittings
2	11/15/82	781.8	S	Refueling outage commences.	C	2	Reactor (RC)	Fuel elements



DESIGN ELEC. RATING - 530 MAX. DEPEND. CAP. - 503 (100%) PRAIRIE ISLAND 1

PRAIRIE ISLAND 2

I. Summary

Description

Location: Goodhue, Minnesota
Docket No.: 50-306
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 500
Commercial operation: 12/21/74
Years operating experience: 8.0

Performance

Net electrical energy generated (MWh): 3,857,949
Unit availability factor (%): 89.6
Unit capacity factor (%) (using MDC): 88.1
Unit capacity factor (%) [using design MW(e)]: 83.1

Outages

Total No.: 7
- Forced: 6
- Scheduled: 1

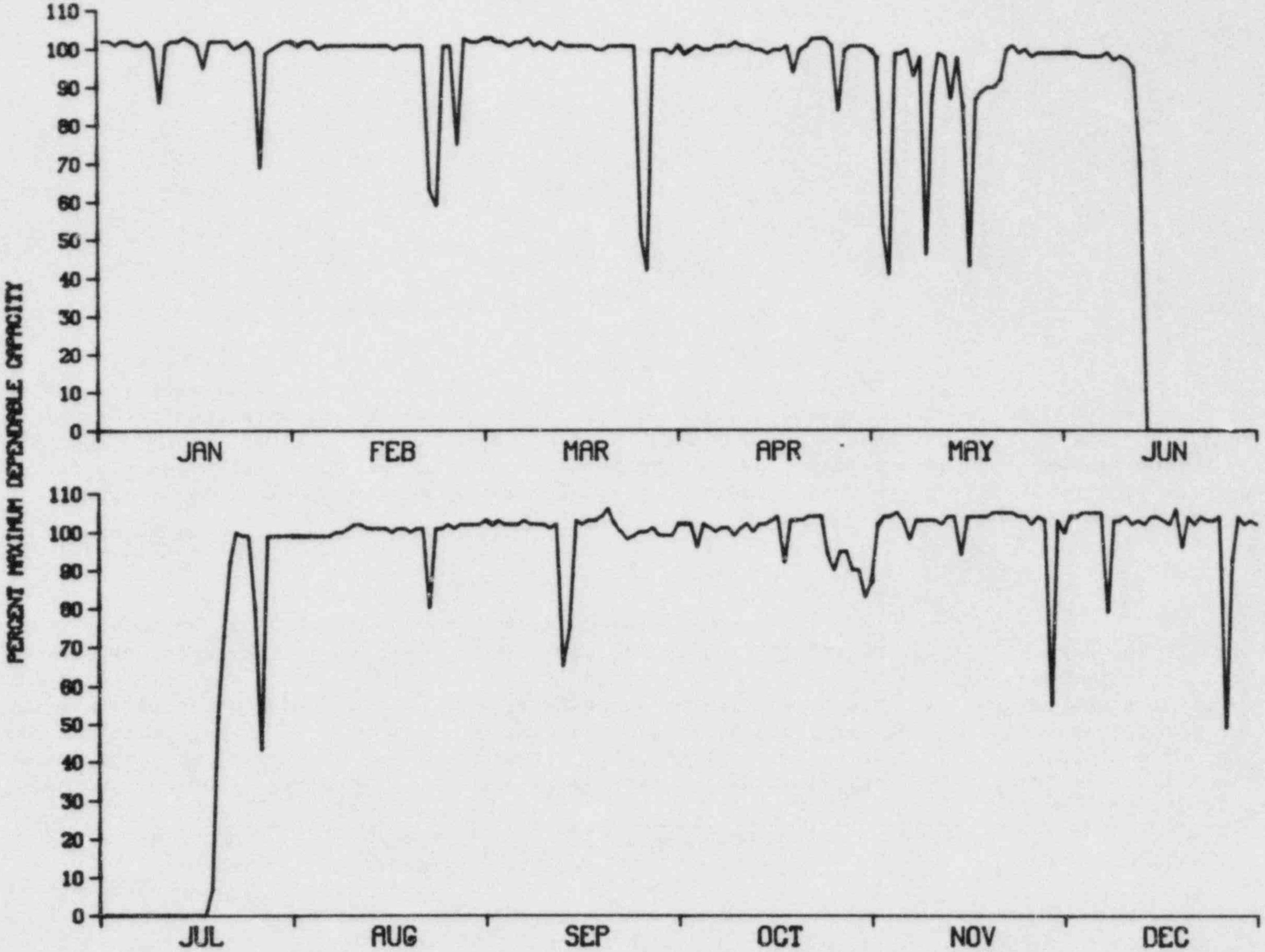
Total hours: 911 (10.4%)
- Forced: 55 (0.6%)
- Scheduled: 856 (9.8%)

II. Highlights

Prairie Island 2 achieved an excellent operating record during 1982 which was almost an exact duplicate of that of its sister reactor, Prairie Island 1. The only significant shutdown during the entire year was a refueling outage starting in mid-June which was accomplished in just over five weeks.

Details of plant outages for Prairie Island 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/26/82	5.1	F	Error on protection logic test.	B	3	System code not applicable (ZZ)	Codes not applicable
2	2/24/82	4.4	F	Error on surveillance test.	G	3	System code not applicable (ZZ)	Codes not applicable
3	3/25/82	9.1	F	Error on surveillance test. Power was limited to <50% for a day due to flux difference limitations.	G	3	System code not applicable (ZZ)	Codes not applicable
4	5/02/82	20.2	F	Control rod urgent failure alarm.	A	2	Instrumentation and controls (IA)	Codes not applicable
5	6/12/82	856.0	S	Refueling commenced.	C	2	Reactor (RC)	Fuel elements
6	9/12/82	12.8	F	Lightning strike on substation.	H	3	Electric power (EA)	Circuit closers/ interrupters
7	12/07/82	3.4	F	Opened wrong breaker.	G	3	System code not applicable (ZZ)	Circuit closers/ interrupters



DESIGN ELEC. RATING - 530 MAX. DEPEND. CAP. - 500 (100%) PRAIRIE ISLAND 2

QUAD CITIES 1

I. Summary

Description	Performance	Outages
Location: Cordova, Illinois	Net electrical energy generated (MWh): 3,224,824	Total No.: 12
Docket No.: 50-254	Unit availability factor (%): 68.0	Forced: 9
Reactor type: BWR	Unit capacity factor (%) (using MDC): 48.2	Scheduled: 3
Maximum dependable capacity [MW(e)-net]: 769	Unit capacity factor (%) [using design MW(e)]: 46.9	Total hours: 2,804 (32.0%)
Commercial operation: 2/18/73		Forced: 115 (1.3%)
Years operating experience: 10.7		Scheduled: 2,689 (30.7%)

II. Highlights

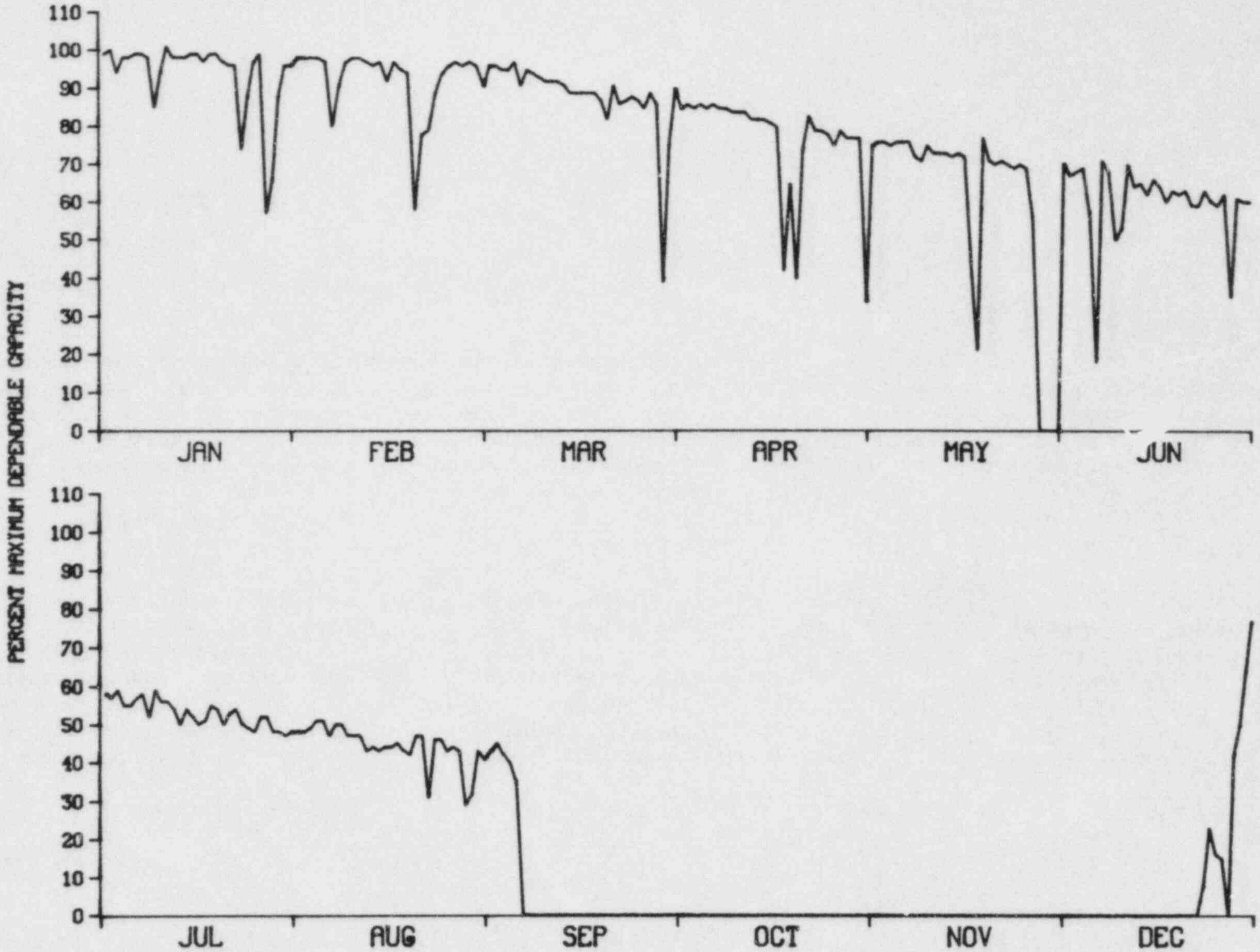
Quad Cities 1 experienced only one significant outage during all of 1982, and this was its end-of-cycle-6 refueling outage which began on September 6 and lasted for about 15 weeks, ending late in December. Declining reactivity caused dropping reactor power during much of the year, starting in February and extending to the refueling outage, by which time the power had dropped to less than 50% of nominal full power.

Details of plant outages for Quad Cities 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/27/82	8.1	F	Reactor scram on spurious scram signal.	H	3	Instrumentation and controls (IA)	Codes not applicable
2	2/18/82	8.0	F	Unit scram on reactor high pressure due to construction personnel working around an instrument rack shaking instrument.	H	3	Instrumentation and controls (IA)	Instrumentation and controls
3	3/29/82	9.2	F	Reactor scram on condenser low vacuum due to loop seal blowing through.	A	3	Steam and power conversion (HJ)	Other components
4	4/17/82	10.3	F	Reactor scram on low condenser vacuum due to condensate demineralizer valve failure.	A	3	Steam and power conversion (HG)	Valves
5	4/19/82	8.7	F	Reactor scram on high main steam line flow, when crafts hit instrument rack with hammer causing spurious trip signal.	H	3	System code not applicable (ZZ)	Codes not applicable
6	4/30/82	9.5	F	Reactor scram on reactor low water level caused by "B" reactor feed pump discharge valve going closed.	A	3	Reactor coolant (CH)	Valve operators
7	5/17/82	21.6	F	Unit shutdown to repair crack in feedwater low flow valve drain line.	A	3	Reactor coolant (CH)	Pipes and/or fittings
8	5/27/82	85.7	S	Unit shutdown to repair generator slip rings.	A	2	Electric power (EB)	Generators
9	6/06/82	13.1	F	Unit in hot standby to complete work on control valve.	A	1	Steam and power conversion (HB)	Valves
10	9/06/82	2,578.7	S	Unit shutdown for end-of-cycle-six refueling outage.	C	2	Reactor (RC)	Fuel elements

Details of plant outages for Quad Cities 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
11	12/22/82	24.5	S	Turbine generator tripped while reactor maintained thermal power to deteriorate a rubber shoe cover in the reactor vessel.	B	9	Reactor coolant (CA)	Codes not applicable
12	12/26/82	26.6	F	Unit was shut down to perform maintenance on traversing in-core probes.	B	2	Instrumentation and controls (IF)	Instrumentation and controls



DESIGN ELEC. RATING - 769 MAX. DEPEND. CAP. - 769 (100%)

QUAD CITIES 1

QUAD CITIES 2

I. Summary

Description

Location: Cordova, Illinois
Docket No.: 50-265
Reactor type: BWR
Maximum dependable capacity [MW(e)-net]: 769
Commercial operation: 3/10/73
Years operating experience: [illegible].6

Performance

Net electrical energy generated (MWh): 5,058,983
Unit availability factor (%): 83.9
Unit capacity factor (%) (using MDC): 75.1
Unit capacity factor (%) [using design MW(e)]: 73.2

Outages

Total No.: 10
Forced: 8
Scheduled: 2
Total hours: 1,413 (16.1%)
Forced: 1,257 (14.3%)
Scheduled: 156 (1.8%)

II. Highlights

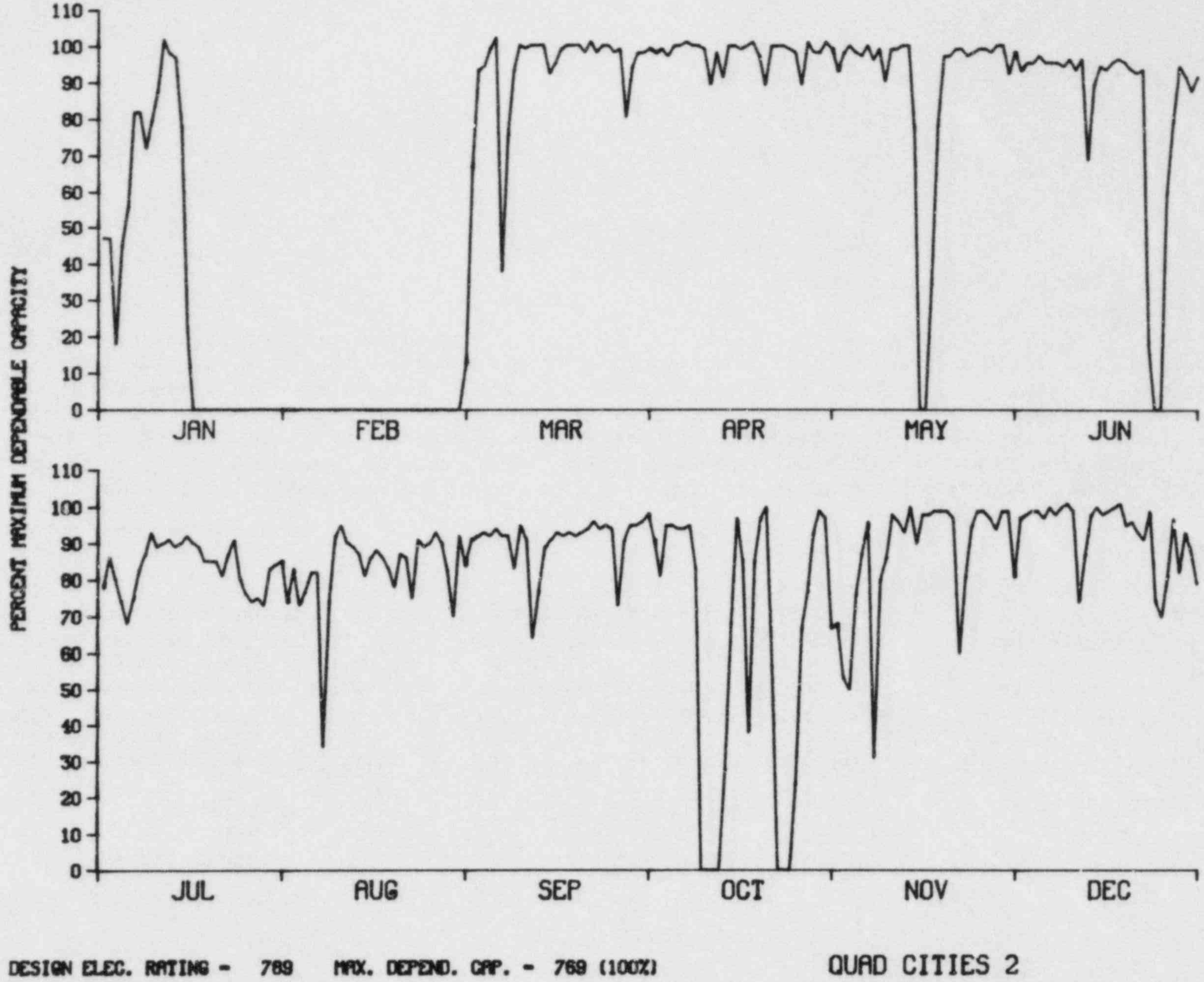
Quad Cities 2 had only one outage of substantial length in 1982, a 44-day shutdown due to a crack in a reactor water cleanup line, which began in mid-January. Two shorter outages in October, totaling eight days, were caused by various maintenance needs, including repair of a recirculating pump discharge valve stem. During much of the summer, the power level was less than maximum due in part to reduced demand and in part to high coolant water temperature.

Details of plant outages for Quad Cities 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/03/82	12.7	F	Reactor scram on low water level due to the "B" feedwater regulation valve failing closed.	A	3	Reactor coolant (CH)	Valves
2	1/15/82	1,056.4	F	Unit shutdown to repair crack in reactor water clean-up line.	A	2	Reactor coolant (CG)	Pipes and/or fittings
3	3/06/82	11.1	F	Reactor scram on vessel high water level due to "B" feedwater regulating valve failing in the open position.	A	3	Reactor coolant (CH)	Valve operators
4	5/15/82	55.3	S	Unit shutdown to repair tube leaks in the main condenser.	B	2	Steam and power conversion (HC)	Heat exchangers
5	6/22/82	65.6	F	Reactor scram on low water level due to loss of power to reactor feed pump when the wrong fuses were removed from the switchgear.	G	3	Reactor coolant (CH)	Circuit closers/ interrupters
6	10/08/82	100.3	S	Scheduled shutdown for weekend maintenance outage and battery discharge test.	B	2	System code not applicable (ZZ)	Codes not applicable
7	10/17/82	9.3	F	Reactor scram on average power range monitor high-high signal due to increase in feedwater flow caused by condensate demineralizer valve problems.	A	3	Steam and power conversion (HG)	Demineralizers
8	10/21/82	19.2	F	Scheduled maintenance outage to repair 33A vacuum breaker.	B	1	Engineered safety features (SD)	Valves

Details of plant outages for Quad Cities 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
9	10/22/82	71.7	F	Outage continued to repair 5A recirc. pump discharge valve stem.	B	9	Reactor coolant (CB)	Valves
10	11/07/82	11.4	F	Reactor scram on average power range monitor high-high signal due to control valve closure during weekly turbine test.	A	3	Steam and power conversion (HA)	Relays


PERCENT MAXIMUM DEPENDABLE CAPACITY
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DESIGN ELEC. RATING - 769 MAX. DEPEND. CAP. - 769 (100%)
QUAD CITIES 2

RANCHO SECO

I. Summary

Description	Performance	Outages
Location: Sacramento, California	Net electrical energy generated (MWh): 3,366,508	Total No.: 13
Docket No.: 50-312	Unit availability factor (%): 53.3	Forced: 11
Reactor type: PWR	Unit capacity factor (%) (using MDC): 44.0	Scheduled: 2
Maximum dependable capacity [MW(e)-net]: 873	Unit capacity factor (%) [using design MW(e)]: 41.9	Total hours: 4,066 (46.4%)
Commercial operation: 4/17/75		Forced: 687 (7.8%)
Years operating experience: 8.2		Scheduled: 3,379 (38.6%)

II. Highlights

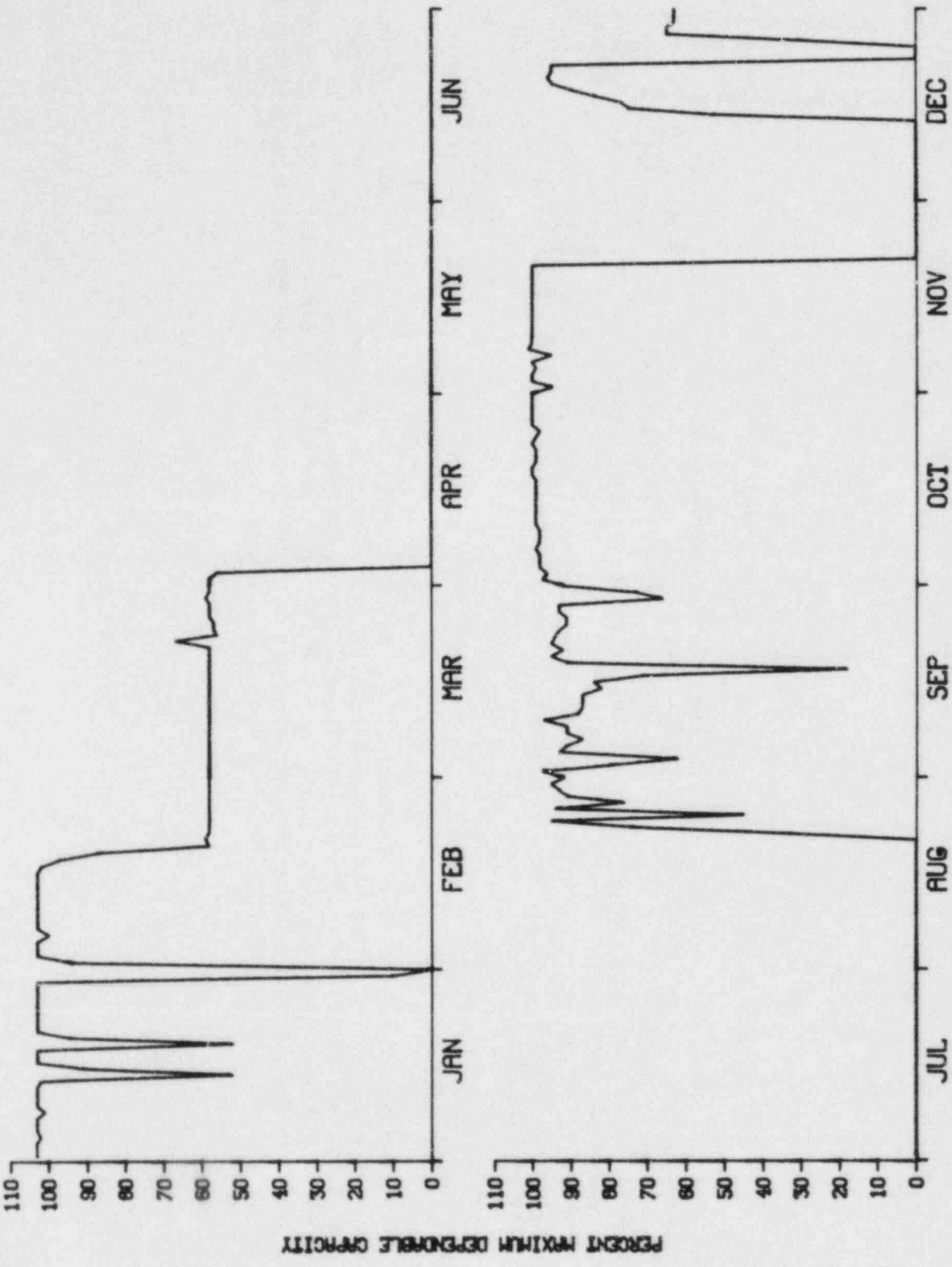
Rancho Seco dropped its power level to 60% on February 16 because of reduced demand. Then, on April 3, the unit was shut down to inspect the high-pressure injection nozzles and to repair the auxiliary feedwater spargers in the once-through steam generator, which had collapsed. One nozzle was found cracked and was repaired. This outage lasted until late August, a total of 20 weeks. In mid-November a 23-day outage was required for repair of a steam generator by plugging two tubes. In late December violent weather caused offsite power frequency fluctuations that resulted in a three-and-a-half-day outage to repair electric equipment.

Details of plant outages for Rancho Seco

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/14/82	7.7	F	Testing in switchyard isolated unit from grid, resulting in a load rejection trip.	G	3	System code not applicable (ZZ)	Codes not applicable
2	1/19/82	6.5	F	Inverter trip caused trip of RPS channels, resulting in a high RC pressure trip.	A	3	Electric power (ED)	Other components
3	1/30/82	41.1	S	Snubber inspection.	B	1	System code not applicable (ZZ)	Codes not applicable
4	4/03/82	3,338.1	S	Inspect and repair HPI nozzles and OTSG auxiliary feedwater ring headers.	B	1	Engineered safety features (SF)	Pipes and/or fittings
5	8/20/82	.5	F	Suspected cause: turbine electro-hydraulic control system malfunction; no corrective action at this time.	A	3	Steam and power conversion (HA)	Mechanical function units
6	8/21/82	2.0	F	Suspected cause: turbine electro-hydraulic control system malfunction; no corrective action at this time.	B	1	Steam and power conversion (HA)	Mechanical function units
7	8/25/82	9.0	F	Suspected cause: turbine electro-hydraulic control system malfunction; no corrective action at this time.	B	3	Steam and power conversion (HA)	Mechanical function units
8	8/27/82	6.5	F	Defective auto stop control pressure valve in turbine electro-hydraulic control system; valve replaced.	B	1	Steam and power conversion (HA)	Mechanical function units
9	9/02/82	3.0	F	Auto-stop oil pressure, checking for leak.	A	1	Steam and power conversion (HA)	Valves

Details of plant outages for Ranco Seco (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
10	9/16/82	12.6	F	Feed pump miniflow line rupture; line replaced.	A	3	Reactor coolant (CH)	Pipes and/or fittings
11	9/28/82	8.1	F	Auto-stop oil pressure; replaced back-pressure regulator.	A	1	Steam and power conversion (HA)	Valves
12	11/21/82	549.0	F	OTSG tube leak. Tubes plugged.	A	1	Reactor coolant (CI)	Heat exchangers
13	12/22/82	82.0	F	Offsite power failure.	A	3	Electric power (EA)	Codes not applicable



DESIGN ELEC. RATING - 918 MAX. DEPEND. CAP. - 873 (100%)

RANCHO SECO

ROBINSON 2

I. Summary

Description

Location: Huntsville, South Carolina
Docket No.: 50-261
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 665
Commercial operation: 3/07/71
Years operating experience: 12.3

Performance

Net electrical energy generated (MWh): 2,251,851
Unit availability factor (%): 48.9
Unit capacity factor (%) (using MDC): 38.7
Unit capacity factor (%) [using design MW(e)]: 36.7

Outages

Total No.: 13
Forced: 9
Scheduled: 4
Total hours: 4,480 (51.1%)
Forced: 346 (3.9%)
Scheduled: 4,134 (47.2%)

II. Highlights

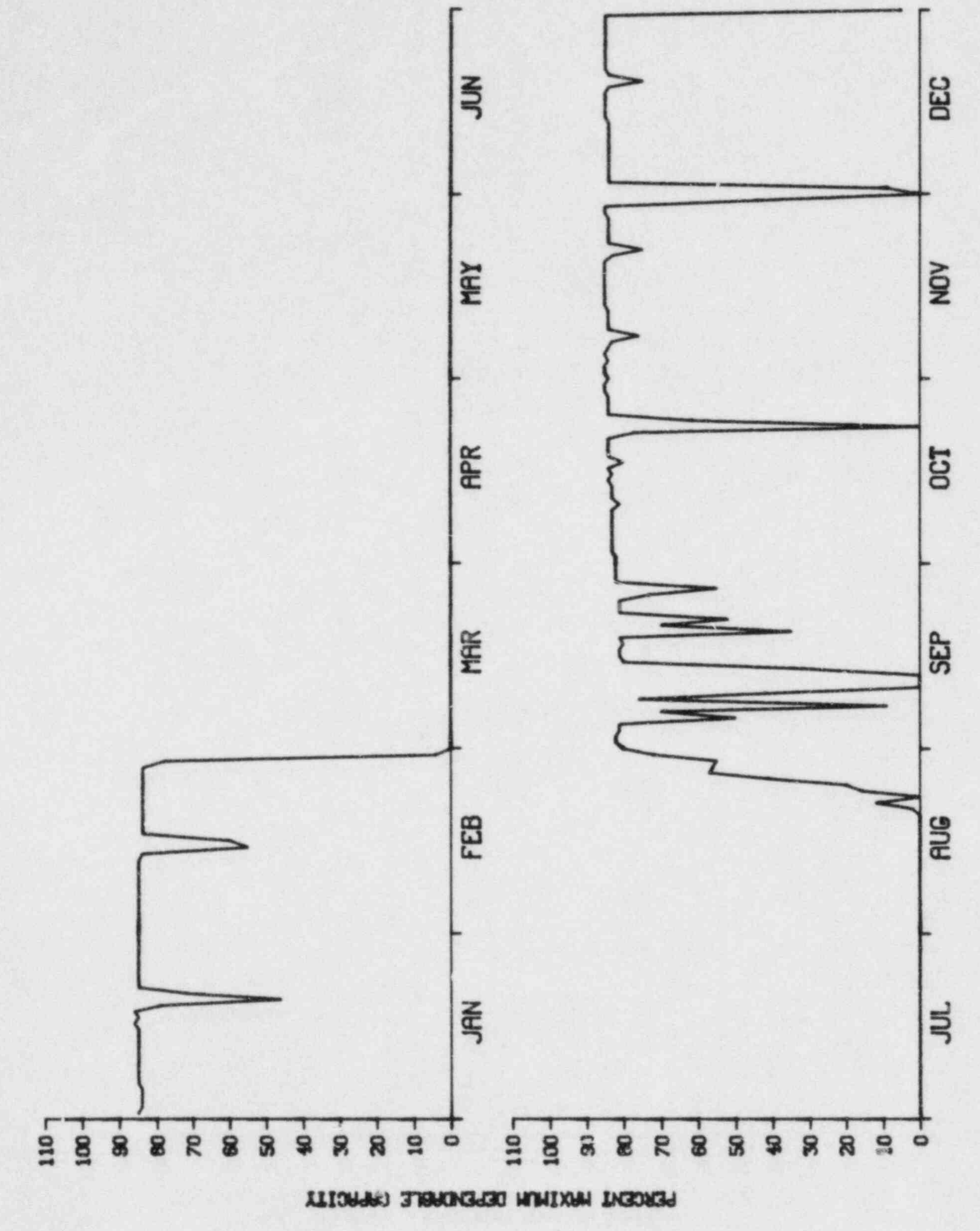
After beginning the year at somewhat reduced power due to a steam generator problem, Robinson 2 entered an extended refueling and in-service inspection outage on February 26, 1982. This outage lasted almost six months (24 weeks) until late August. Thereafter the plant operated with very few interruptions but with an internal restriction to 535 MW(e) net. The only multiday outage after the return to power from the refueling/inspection outage was a four-day shutdown in mid-September to repair a faulty dry-well level switch whose failure had caused the outage.

Details of plant outages for Robinson 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	2/26/82	4,071.7	S	Shutdown for maintenance/refueling outage.	C	3	Reactor (RC)	Fuel elements
2	8/15/82	131.6	F	While bringing the unit off line due to faulty MW indication, the unit tripped, caused by low level SG, resulting in low level trip.	B	3	Steam and power conversion (HB)	Heat exchangers
3	8/21/82	6.0	F	High level SG caused by trip due to feed water reg. valve malfunction.	A	3	Steam and power conversion (HH)	Valves
4	8/21/82	8.0	F	High level SG caused by trip due to feed water reg. valve malfunction.	A	3	Steam and power conversion (HH)	Valves
5	8/22/82	32.3	S	Required turbine overspeed trip test following refueling/ maintenance outage.	B	1	Steam and power conversion (HA)	Turbines
6	8/25/82	0.2	S	Required turbine test. Adjusted overspeed trip.	B	1	Steam and power conversion (HA)	Turbines
7	9/06/82	9.6	F	Solenoid for "C" FWRV failed, causing common fuse for all three FWRVs to blow; FWRVs closed, causing reactor trip from low steam generator water level. Solenoid for "C" FWRV was replaced along with all three fuses.	A	3	Steam and power conversion (HH)	Instrumentation and controls
8	9/07/82	18.7	F	Relief valve failure caused by operator error. Repaired valve and counseled operator.	G		Auxiliary process (PC)	Valves
9	9/13/82	92.6	F	Faulty hot-well level switch, caussing "B" cond. and FW pumps to trip, resulting in low level in "C" SG. Hot-well level switch replaced.	A	3	Steam and power conversion (HH)	Instrumentation and controls

Details of plant outages for Robinson 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
10	9/21/82	7.5	F	Personnel error while performing a periodic test. Technicians were counseled on importance of following procedures.	G	3	Steam and power conversion (HB)	Instrumentation and controls
11	10/24/82	30.1	S	Unit retired for repair of CVCS letdown relief valve and other maintenance items.	B	1	Auxiliary process (PC)	Valves
12	11/29/82	50.4	F	SG chemistry was unacceptable due to mechanical failure of caustic injection valves. This resulted in in-leakage of sodium hydroxide into the make-up water system and from there to the SGs. The valves were replaced. As the reactor was being manually shut down for outage, an automat trip occurred.	A	3	Auxiliary water (WC)	Valves
13	12/31/82	21.5	F	A faulty fuse holder caused the power solenoid for "C" MSIV to de-energize, closing the MSIV, which caused a low-low level in "C" SG and subsequent unit trip.	A	3	Steam and power conversion (HB)	Instrumentation and controls



ROBINSON 2

DESIGN ELEC. RATING - 700 MAX. DEPEND. CAP. - 665 (100%)

SALEM 1

I. Summary

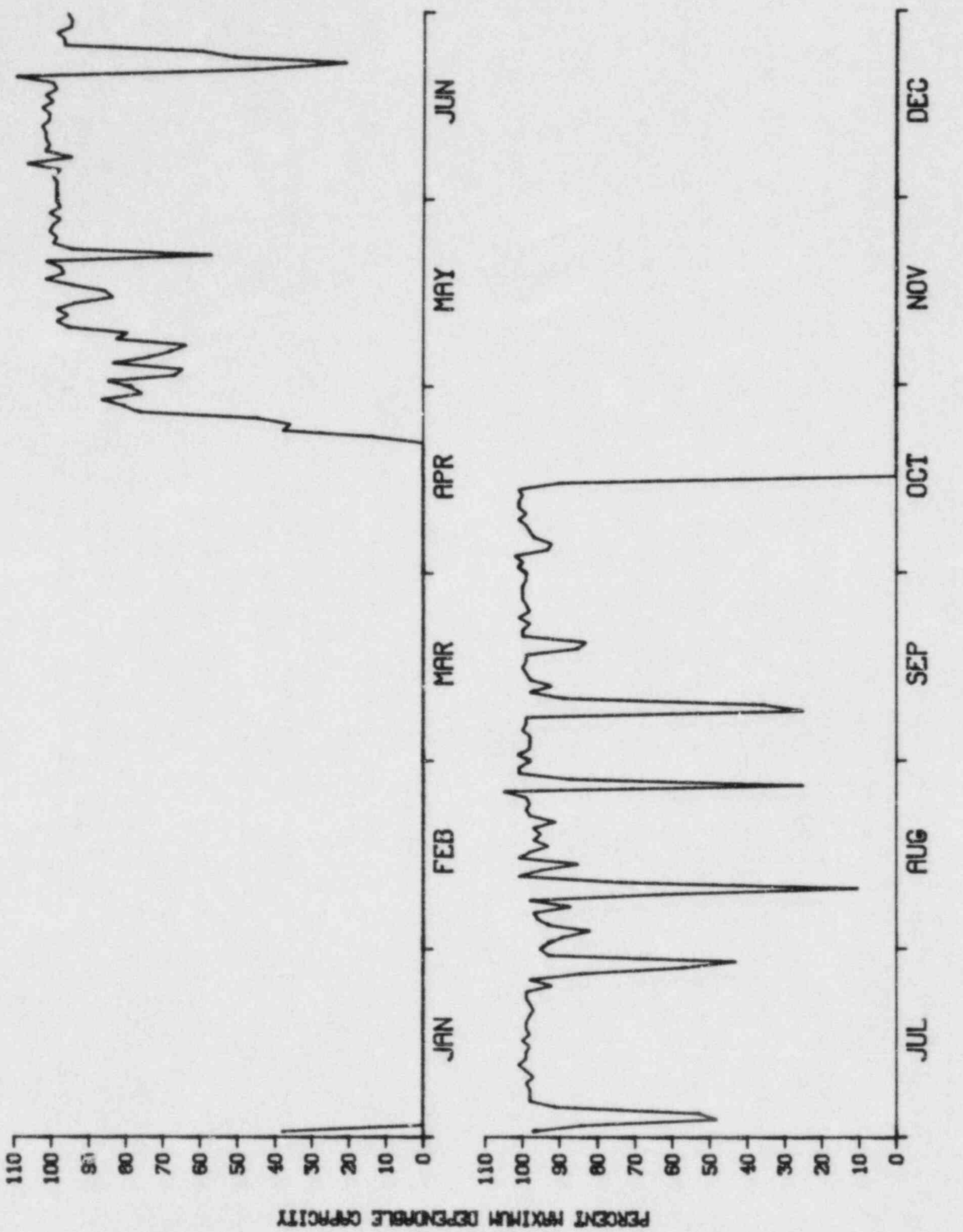
Description	Performance	Outages
Location: Salem, New Jersey	Net electrical energy generated (MWh): 4,094,731	Total No.: 13
Docket No.: 50-272	Unit availability factor (%): 47.9	Forced: 8
Reactor type: PWR	Unit capacity factor (%) (using MDC): 43.3	Scheduled: 5
Maximum dependable capacity [MW(e)-net]: 1,079	Unit capacity factor (%) [using design MW(e)]: 42.9	Total hours: 4,566 (52.1%)
Commercial operation: 6/30/77		Forced: 308 (3.5%)
Years operating experience: 6.0		Scheduled: 4,258 (48.6%)

II. Highlights

On the very first day of 1982 Salem 1 shut down for its annual refueling outage, which was accomplished in ten weeks, with a return to operation the last week of April. From then on the plant operated with only brief shutdowns, although a relatively large number of these, until mid-October, when it shut down again for another "annual" refueling outage which then lasted the entire remainder of the year. Mainly because of its two refueling outages in the same year, less than six months apart, the unit operated less than half the year.

Details of plant outages for Salem 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/01/82	1,732.5	S	Annual refueling outage.	C	1	Reactor (RC)	Fuel elements
2	3/14/82	672.0	S	Replacement of No. 12 component cooling heat exchanger.	B	9	Auxiliary water (WB)	Heat exchangers
3	4/11/82	188.5	F	Replacement of No. 12 component cooling heat exchanger.	B	1	Auxiliary water (WB)	Heat exchangers
4	4/19/82	51.6	F	No. 7 bearing (turbine) high temp.	A	1	Steam and power conversion (HA)	Other components
5	4/22/82	2.8	S	Turbine overspeed test, reactor trip.	B	3	Steam and power conversion (HA)	Turbines
6	6/21/82	19.0	F	No. 11 SG feed pump trip.	A	3	Reactor coolant (CH)	Pumps
7	7/28/82	8.9	F	Operational error.	G	3	Instrumentation and controls (IA)	Instrumentation and controls
8	8/09/82	20.0	F	Nuclear 120-V ac safety system power supplies.	G	2	Electric power (EB)	Generators
9	8/27/82	8.4	F	Pressurizer level instrument and controls, high level.	A	3	Instrumentation and controls (IA)	Instrumentation and controls
10	9/08/82	8.2	F	No. 11 steam generator feed pump tripped trying to balance load between pumps.	A	3	Reactor coolant (CH)	Pumps
11	9/08/82	3.4	F	No. 12 steam generator feed pump low low level.	A	3	Reactor coolant (CH)	Pumps
12	10/15/82	1,706.5	S	Refueling and maintenance commenced.	C	1	Reactor (RC)	Fuel elements
13	12/25/82	144.0	S	Nuclear closed cooling heat exchangers.	B	9	Steam and power conversion (HC)	Heat exchangers



DESIGN ELEC. RATING - 1090 MAX. DEPEND. CAP. - 1079 (100%)

SALEM 1

SALEM 2

I. Summary

Description	Performance	Outages
Location: Salem, New Jersey	Net electrical energy generated (MWh): 7,941,580	Total No.: 13
Docket No.: 50-311	Unit availability factor (%): 97.3	Forced: 13
Reactor type: PWR	Unit capacity factor (%) (using MDC): 82.0	Scheduled: 0
Maximum dependable capacity [MW(e)-net]: 1,149	Unit capacity factor (%) [using design MW(e)]: 81.3	Total hours: 241 (2.7%)
Commercial operation: 10/31/81		Forced: 241 (2.7%)
Years operating experience: 1.6		Scheduled: 0 (0%)

II. Highlights

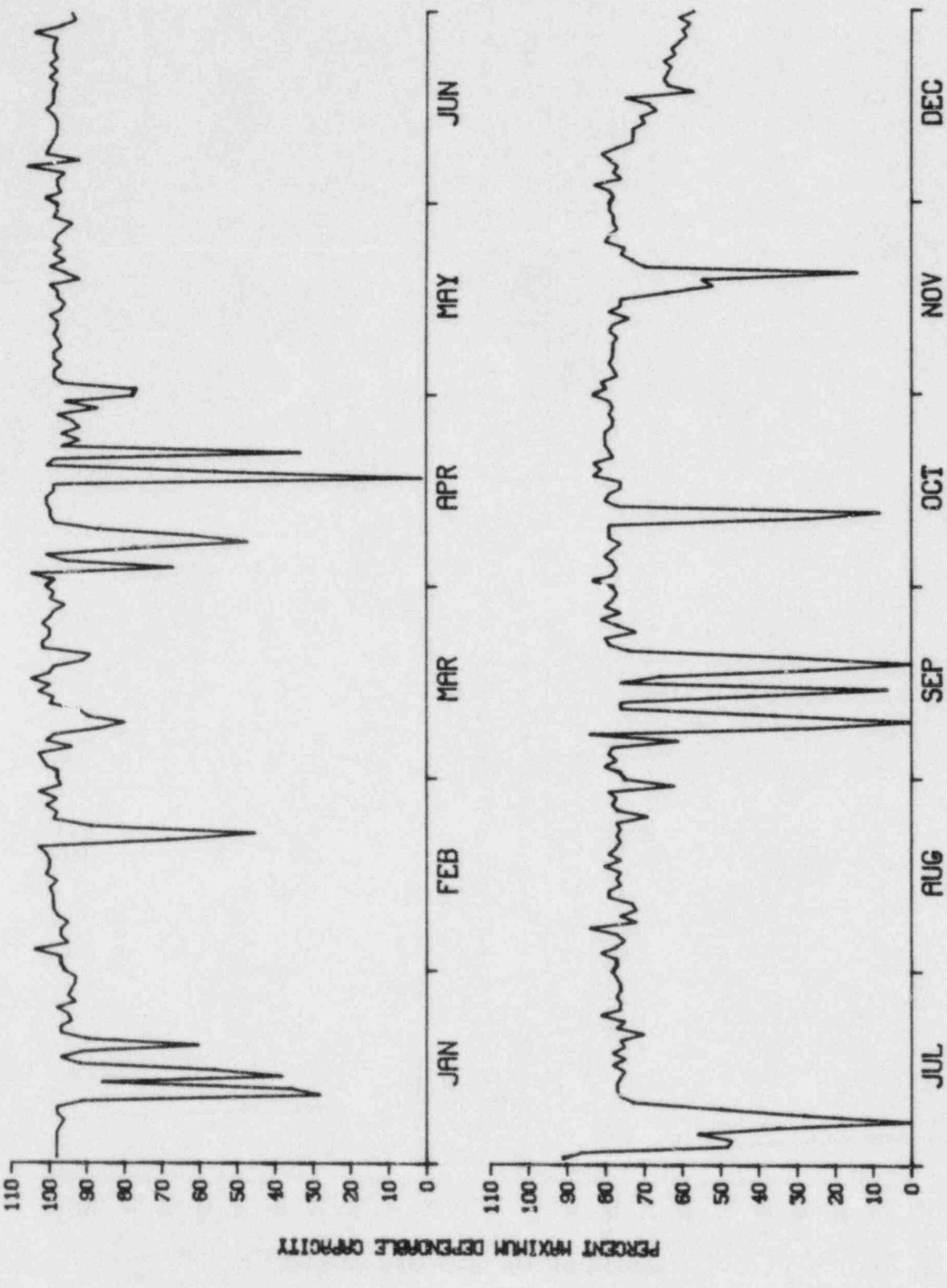
Salem 2 produced the most electricity of any PWR in the United States in 1982 (and was second only to Peach Bottom 3, a BWR, among all the reactors in the country). It also achieved the very highest availability factor among all the reactors in the United States at 97.3%. This highly successful year was achieved by having no refueling outage during the entire 12 months and not a single outage for any reason that lasted as long as two days. There were only five outages that lasted as long as a single day. In December the plant power began to decline as the fuel was depleted and the plant started a coast-down towards refueling in early 1983.

Details of plant outages for Salem 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/11/82	4.3	F	High condenser back pressure due to circulating water screens icing.	A	1	Steam and power conversion (HF)	Filters
2	2/19/82	5.9	F	22 essential controls invertor failed causing steam generator feed pump trip.	A	3	Electric power (ED)	Generators
3	4/17/82	21.4	F	21 SGFP trip caused low-low level in 24 steam generator.	A	3	Reactor coolant (CH)	Pumps
4	4/21/82	3.5	F	21 SGFP overspeed trip.	A	3	Reactor coolant (CH)	Pumps
5	7/06/82	43.5	F	SG feed pump trip on low suction pressure.	A	3	Reactor coolant (CH)	Pumps
6	7/09/82	4.3	F	Main steam isolation valves.	A	3	Other auxiliary (AB)	Valves
7	9/08/82	0.6	F	Nuclear steam generator controls/ No. 23 steam generator high-high level/instrument line blew off No. 23 feed flow transmitter.	A	3	Reactor coolant (CH)	Instrumentation and controls
8	9/08/82	42.5	F	Nuclear containment cooler/filter systems.	A	3	Engineered safety features (SC)	Blowers
9	9/13/82	27.0	F	No. 22 reactor coolant pump high bearing temperature.	A	3	Reactor coolant (CB)	Pumps
10	9/17/82	34.6	F	Nuclear control rod instrumentation.	A	3	Reactor (RC)	Instrumentation and controls
11	9/19/82	6.7	F	Nuclear control rod instrumentation.	A	3	Reactor (RC)	Instrumentation and controls

Details of plant outages for Salem 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
12	10/11/82	32.7	F	Nuclear control rod drive motors.	A	3	Reactor (RB)	Control rods
13	11/19/82	13.5	F	No. 22 SGFP trip, caused low feed flow with low level on No. 24 steam generator.	A	3	Reactor coolant (CH)	Pumps



DESIGN ELEC. RATING - 1115 MAX. DEPEND. CAP. - 1106 (100%)

SALEM 2

SAN ONOFRE 1

I. Summary

Description

Location: San Clemente, California
Docket No.: 50-206
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 436
Commercial operation: 1/01/68
Years operating experience: 15.5

Performance

Net electrical energy generated (MWh): 510,223
Unit availability factor (%): 15.7
Unit capacity factor (%) (using MDC): 13.4
Unit capacity factor (%) [using design MW(e)]: 13.4

Outages

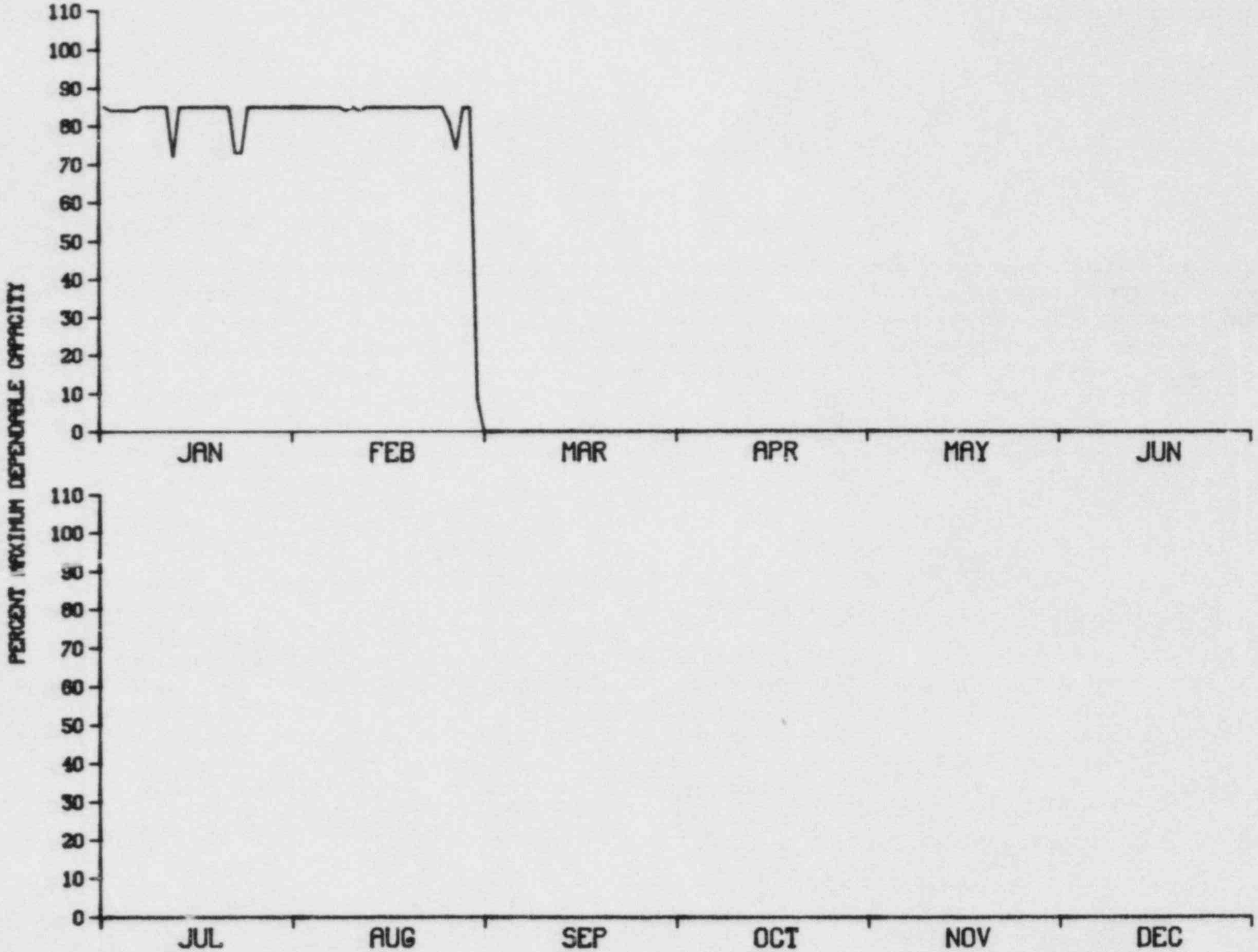
Total No.: 3
Forced: 0
Scheduled: 3
Total hours: 7,405 (84.5%)
Forced: 0 (0%)
Scheduled: 7,405 (84.5%)

II. Highlights

San Onofre 1 operated very well for the first two months of 1982, and then it shut down for the rest of the year. This outage, which occupied 44 weeks in 1982 and was still continuing at year's end, was caused by the need for seismic backfitting and other maintenance work. Initially scheduled for only 12 weeks, this outage was intended to accomplish examination of the steam generator tubes, testing of the safety injection system, making modifications on the diesel generators, and making TMI backfits, as well as seismic upgrading. However, the restart was delayed by questions regarding the acceptability of the seismic backfits, which required resolution by the NRC. It was found that not only did the seismic criteria of this old plant not satisfy current requirements but it was questionable whether they satisfied the requirements in force at the time the plant was built.

Details of plant outages for San Onofre 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/12/82	7.5	S	Condenser cleaning and turbine stop valve testing.	B	5	Steam and power conversion (HC)	Heat exchangers
2	1/22/82	10.1	S	Steam leak on "A" feed reg. valve. Repaired leak.	A	5	Reactor coolant (CH)	Valves
3	2/27/82	7,387.7	S	Extended outage to accomplish seismic backfit and miscellaneous maintenance items.	B	1	Steam and power conversion (HC)	Heat exchangers



DESIGN ELEC. RATING - 436 MAX. DEPEND. CAP. - 436 (100%) SAN ONOFRE 1

SEQUOYAH 1

I. Summary

Description

Location: Chattanooga, Tennessee
Docket No.: 50-327
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 1,128
Commercial operation: 7/01/81
Years operating experience: 2.4

Performance

Net electrical energy generated (MWh): 4,908,979
Unit availability factor (%): 52.8
Unit capacity factor (%) (using MDC): 49.7
Unit capacity factor (%) [using design MW(e)]: 49.0

Outages

Total No.: 12
Forced: 11
Scheduled: 1
Total hours: 4,130 (47.1%)
Forced: 1,446 (16.5%)
Scheduled: 2,684 (30.6%)

II. Highlights

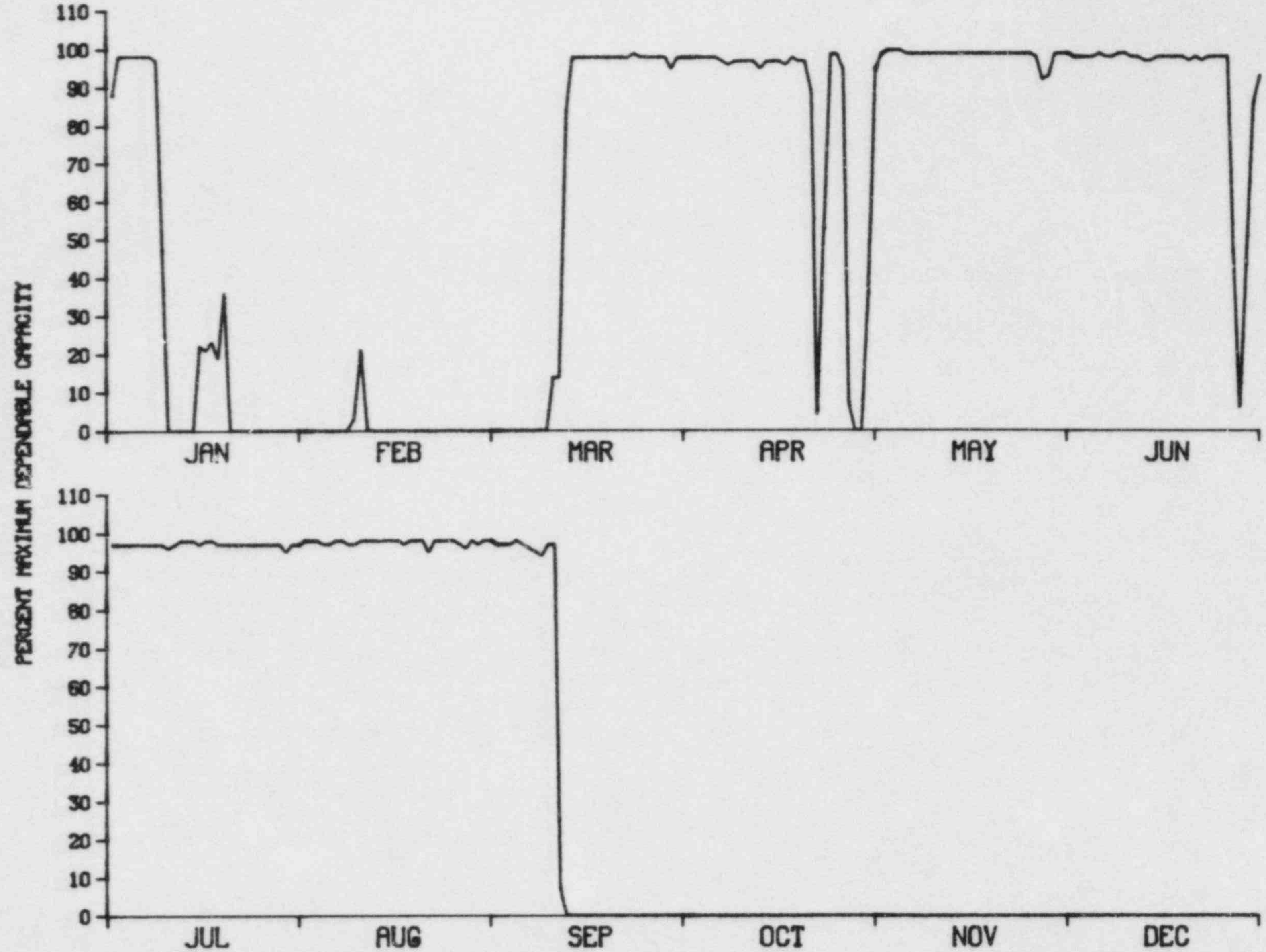
Sequoyah 1 experienced several extended outages in 1982. A five-day shutdown on January 9 was due to an operational error that resulted in unacceptable water chemistry in the secondary coolant system. Then, on January 19, a transformer fault initiated an outage that was extended to perform required ice weighing. This outage lasted for 20 days, ending on February 8. Just two days later, before the plant reached full power, a turbine bearing vibration problem caused a shutdown which was also used to replace one of the main reactor coolant pumps; this pump needed to be replaced because of electrical problems. This outage lasted 28 days, ending in mid-March. The plant then operated at full power with only infrequent minor interruptions until September 11, when a refueling outage began that lasted past the end of the year.

Details of plant outages for Sequoyah 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/09/82	122.4	F	Steam generator water chemistry out of specifications. Operational error.	H	1	Steam and power conversion (HB)	Heat exchangers
2	1/19/82	2.7	F	Main feed pumps tripped.	A	3	Steam and power conversion (HB)	Pumps
3	1/19/82	480.1	F	Fault at B-phase transformer, and weighing outage.	A	3	Electric power (EG)	Transformers
4	2/09/82	683.6	F	Turbine 11 bearing excessive vibration. No. 2 reactor coolant pump replacement due to electrical problems.	A	1	Steam and power conversion (HA)	Turbines
5	3/10/82	4.5	F	Low-low steam generator level No. 2 SG due to swings in levels during startup.	A	3	Steam and power conversion (HB)	Heat exchangers
6	3/10/82	7.0	F	Blown fuse at condensate system caused loss of suction to main feed pumps resulting in RX trip.	A	3	Steam and power conversion (HH)	Circuit closers/ interrupters
7	3/11/82	5.9	F	Reactor trip on low-low level steam generator No. 2 due to swings in levels during startup.	A	3	Steam and power conversion (HB)	Heat exchangers
8	3/11/82	3.4	F	Low-low SG level No. 1 steam generator hard to control; swings in levels during startup.	A	3	Steam and power conversion (HB)	Heat exchangers
9	4/21/82	18.6	F	Low-low No. 1 SG level, feedwater controls failed to control in auto; RX tripped 8% power.	A	3	Steam and power conversion (HB)	Instrumentation and controls

Details of plant outages for Sequoyah 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
10	4/26/82	88.8	F	Control rod M/G set problems.	A	3	Instrumentation and controls (IA)	Motors
11	6/26/82	28.7	F	Steam leak on No. 2 main steam check valve.	A	1	Steam and power conversion (HB)	Valves
12	9/11/82	2,684.2	S	Refueling outage.	C	1	Reactor (RC)	Fuel elements



DESIGN ELEC. RATING - 1128   MAX. DEPEND. CAP. - 1128 (100%)   SEQUOYAH 1

SEQUOYAH 2

I. Summary

Description

Location: Chattanooga, Tennessee
Docket No.: 50-328
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 1,128
Commercial operation: 6/01/82
Years operating experience: 1.0

Performance

Net electrical energy generated (MWh): 3,926,291
Unit availability factor (%): 74.1
Unit capacity factor (%) (using MDC): 66.7
Unit capacity factor (%) [using design MW(e)]: 66.0

Outages[a]

Total No.: 8
  Forced: 7
  Scheduled: 1
Total hours: 1,307 (25.4%)
  Forced: 829 (16.1%)
  Scheduled: 478 (9.3%)

II. Highlights

Sequoyah 2 declared commercial operation on June 1, 1982, the only reactor to begin its commercial life in 1982. The plant operated quite reliably without major shutdowns until November 13, when it was taken down for ice weighing, as required by the Technical Specifications. Before the plant could come back on line in early December, a problem in the generator hydrogen cooling system (a damaged fan blade) caused the outage to be extended to December 31, a total of 49 days.

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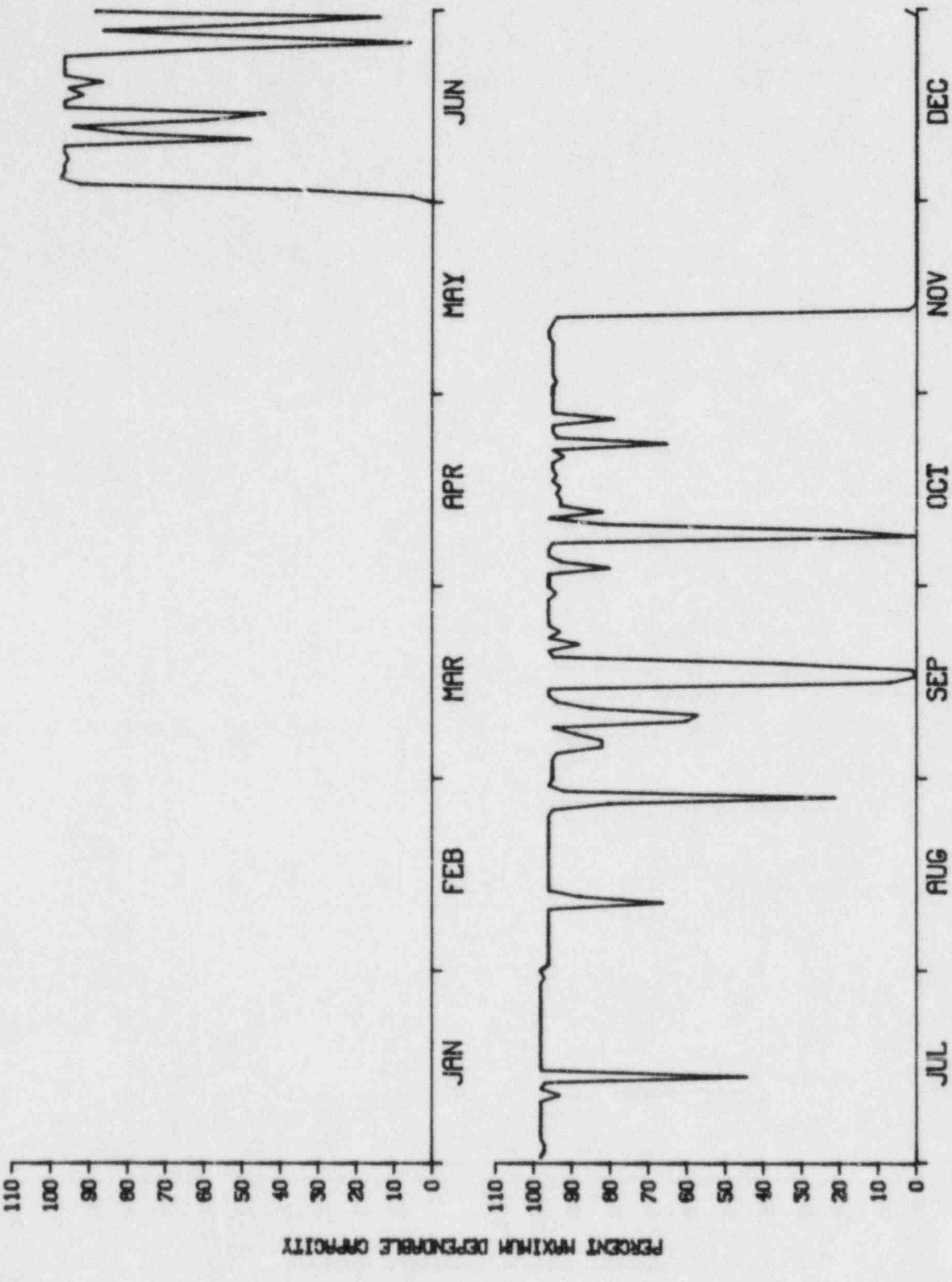
[a]The outages and the percentages computed for them cover only the period of commercial operation in 1982 which began on 6/01/82.

Details of plant outages for Sequoyah 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	6/24/82	26.2	F	Reactor trip low-low No. 1 SG level. Regulator valve drifted closed causing feedwater isolation.	A	3	Steam and power conversion (HH)	Valves
2	6/28/82	7.7	F	Dropped load to repair valve 3-510. Reactor at 25%.	A	1	Steam and power conversion (HH)	Valves
3	6/29/82	3.9	F	Reactor tripped low-low level No. 4 SG after high-high level tripped the turbine.	G	3	Steam and power conversion (HB)	Codes not applicable
4	8/27/82	9.4	F	Water in junction box caused a short in solenoid circuit. Valve 3-48 (loop 2) failed closed; caused unit to trip.	A	3	Steam and power conversion (HH)	Valves
5	9/14/82	65.4	F	Manual shutdown, repair diaphragm on UHI.	B	1	Engineered safety features (SF)	Instrumentation and controls
6	10/07/82	24.3	F	Unit tripped due to a voltage regulator problem on the generator.	A	3	Steam and power conversion (HA)	Instrumentation and controls
7	11/13/82	477.9	S	Ice weighing per Technical Specifications. Manual shutdown.	B	1	Engineered safety features (SB)	Codes not applicable
8	12/03/82	692.2	F	Found damaged fan blades in the hydrogen cooling system.	B	9	Steam and power conversion (HA)	Blowers



SEQUOYAH 2

DESIGN ELEC. RATING - 1148 MAX. DEPEND. CAP. - 1148 (100%)

ST. LUCIE 1

I. Summary

Description

Location: Ft. Pierce, Florida
Docket No.: 50-335
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 777
Commercial operation: 12/21/76
Years operating experience: 6.7

Performance

Net electrical energy generated (MWh): 6,784,644
Unit availability factor (%): 94.0
Unit capacity factor (%) (using MDC): 96.4
Unit capacity factor (%) [using design MW(e)]: 96.4

Outages

Total No.: 10
 Forced: 9
 Scheduled: 1
Total hours: 530 (6.0%)
 Forced: 83 (0.9%)
 Scheduled: 447 (5.1%)

II. Highlights

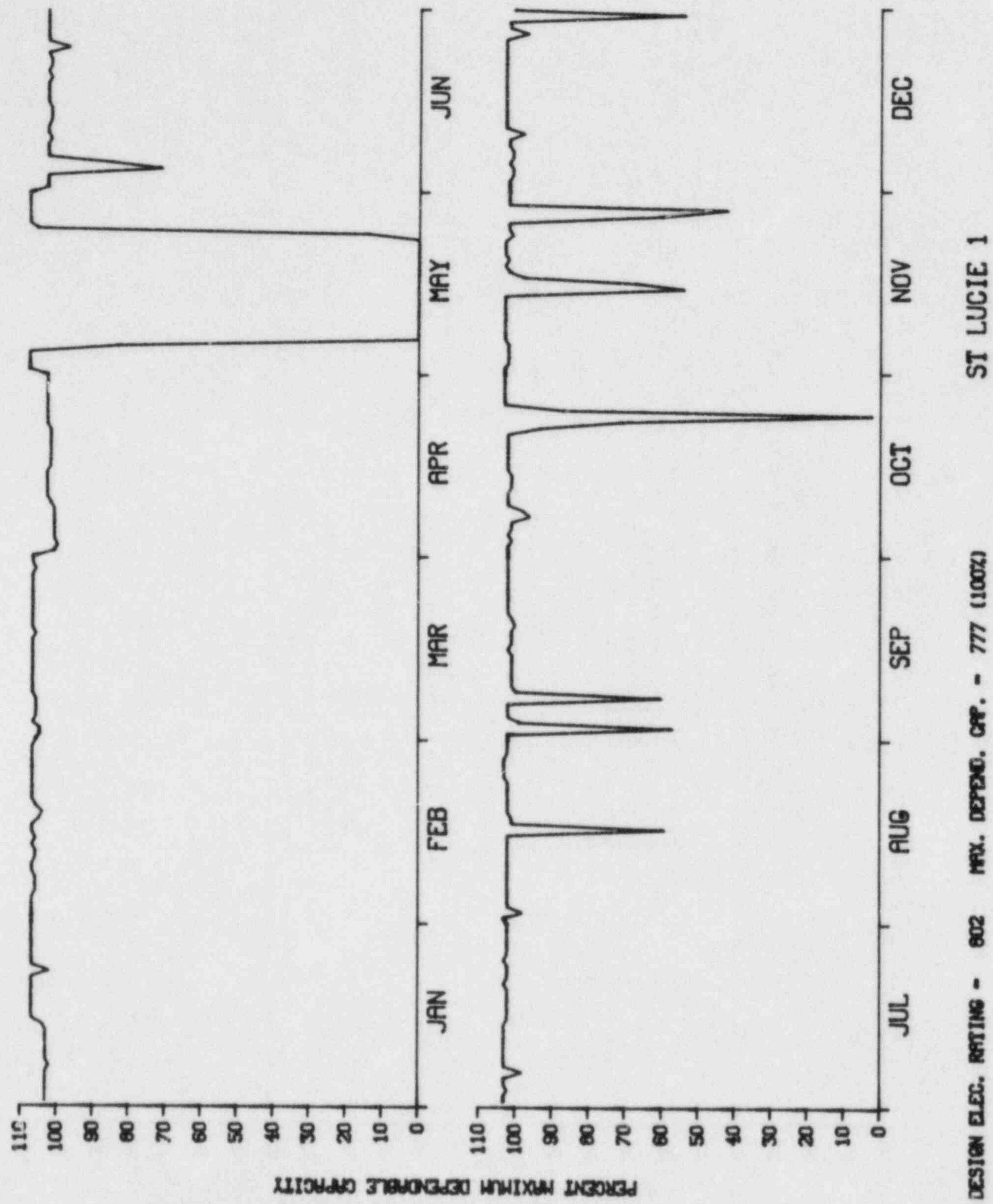
St. Lucie 1 achieved a very high availability factor in 1982, second highest among the PWRs, and produced the third-greatest amount of electric energy of all the U.S. PWRs. The only significant outage during the entire year was an 18-and-a-half-day outage in May for steam generator inspection and maintenance on a coolant pump seal. A one-day outage in October was caused by a condensate pump failure that required installation of a spare pump.

Details of plant outages for St. Lucie 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	5/05/82	446.8	S	Unit removed from service for steam generator inspection. Outage extended for maintenance of reactor coolant pump seal.	B	1	Steam and power conversion (HB)	Heat exchangers
2	6/04/82	5.2	F	The unit was removed from service to repair a generator breaker disconnect switch in the plant switchyard.	A	1	Electric power (EG)	Circuit closers/ interrupters
3	8/16/82	6.2	F	Unit was manually tripped following loss of power to 4.16-kV bus. A load shedding relay in the vital/ nonvital tie breaker had been jarred. The bus was re-energized and the unit returned to power.	H	2	Electric power (EB)	Relays
4	9/02/82	5.7	F	A test plug slipped while testing the generator trip circuitry causing a generator trip followed by a reactor trip. The unit was returned to power.	G	3	Steam and power conversion (HA)	Codes not applicable
5	9/07/82	7.3	F	A generator trip was caused by work on generator motor operators in the switchyard. A reactor trip followed. While returning to power, steam generator low level caused another reactor trip. The unit was then returned to power.	G	3	Steam and power conversion (HA)	Codes not applicable
6	10/23/82	26.8	F	Loss of condensate pump caused unit trip. Unit returned to service on installed spare pump.	A	3	Steam and power conversion (HH)	Pumps

Details of plant outages for St. Lucie 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
7	11/14/82	8.2	F	Unit tripped on low SG pressure following unintentional emergency boration. Unit returned to service.	G	3	Engineered safety features (SF)	Valves
8	11/14/82	2.8	F	Unit tripped during power increase following above event due to low SG level. Unit returned to service.	H	3	Reactor coolant (CH)	Valves
9	11/26/82	17.2	F	Unit tripped during testing of safeguards instrumentation cabinet due to mispositioned switch. The unit was returned to service.	G	3	Instrumentation and controls (IA)	Instrumentation and controls
10	12/30/82	3.4	F	Reactor trip caused by spurious inverter trip in conjunction with trip breaker maintenance. The unit was returned to service.	A	3	Instrumentation and controls (IA)	Generators


PERCENT MAXIMUM DEPENDABLE CAPACITY
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ST LUCIE 1
DESIGN ELEC. RATING - 802 MAX. DEPEND. CAP. - 777 (100%)

SURRY 1

I. Summary

Description	Performance	Outages
Location: Surry, Virginia	Net electrical energy generated (MWh): 5,483,227	Total No.: 21
Docket No.: 50-280	Unit availability factor (%): 88.8	Forced: 19
Reactor type: PWR	Unit capacity factor (%) (using MDC): 80.8	Scheduled: 2
Maximum dependable capacity [MW(e)-net]: 775	Unit capacity factor (%) [using design MW(e)]: 79.4	Total hours: 4,566 (52.1%)
Commercial operation: 12/22/72		Forced: 308 (3.5%)
Years operating experience: 10.5		Scheduled: 4,258 (48.6%)

II. Highlights

Surry 1 operated very well during 1982, with almost 90% availability and no very extensive outages. Only two multiday shutdowns occurred: in February the plant was shut down for 13 days to do maintenance on the secondary system, and another scheduled maintenance outage took place on October 1, which lasted for two weeks.

Details of plant outages for Surry 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/05/82	58.4	F	Fire in ground straps on isolated phase bus ductwork caused by induced current. Unit was shut down and ductwork and ground st[illegible] were replaced prior to startup.	H	1	Electric power (EG)	Electrical conductors
2	2/08/82	319.4	S	Shutdown to perform secondary system maintenance inside the containment. Reactor trip/SI occurred during shutdown due to turbine power swings caused by EHC control system problems. Instrument Dept. investigated EHC problems prior to startup.	B	2	Steam and power conversion (HB)	Codes not applicable
3	2/22/82	9.5	F	The reactor tripped on a [illegible]igh-high SG level signal due to leakage past the main feed flow control valve while feeding the SGs in manual.	H	3	Steam and power conversion (HB)	Valves
4	2/22/82	3.7	F	The reactor tripped on a steam flow's feed flow coincident with a low SG level while feeding SGs in manual.	H	3	Steam and power conversion (HB)	Codes not applicable
5	3/25/82	15.4	F	Instrument technicians performing a periodic test placed instrumentation in "trip," which in coincidence with a switch out of adjustment caused the "A" reactor coolant pump to trip, causing a low flow reactor trip. The switch was adjusted prior to unit startup.	H	3	Steam and power conversion (HH)	Pumps
6	4/13/82	24.8	F	Loss of "A" RCP caused a reactor trip on low flow and a high steam flow—low T_{ave} and SI. The electrical problem was corrected prior to startup.	A	3	Auxiliary water (WB)	Valve operators

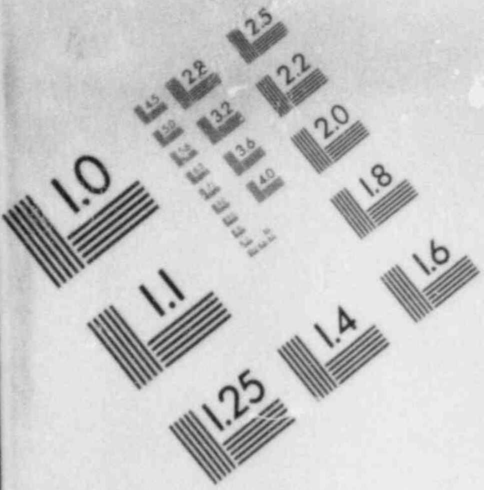
Details of plant outages for Surry 1 (continued)

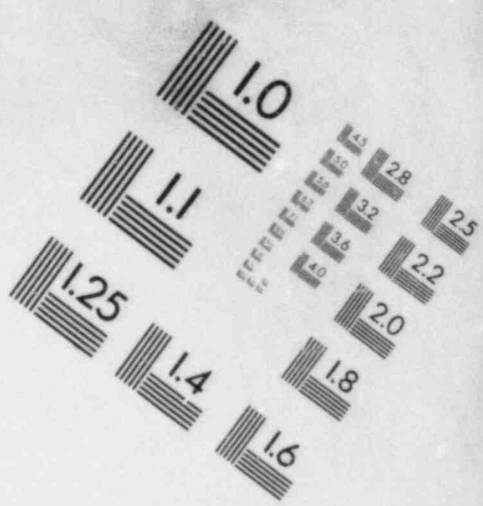
No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
7	4/14/82	7.2	F	The reactor tripped on a header-to-line steam pressure differential signal. The Sl was caused by a spurious vibration-induced header pressure signal.	H	3	Steam and power conversion (HB)	Instrumentation and controls
8	4/15/82	13.7	F	The reactor tripped on a low level in "C" SG coincident with a feed flow—steam flow mismatch. It was later discovered that the feedback arm on the "C" main feed flow control valve was broken.	A	3	Instrumentation and controls (IE)	Instrumentation and controls
9	4/15/82	11.7	F	The reactor tripped on a header-to-line steam pressure differential pressure signal. All associated pressure transmitters and circuitry were checked prior to startup.	H	3	Steam and power conversion (HB)	Instrumentation and controls
10	4/16/82	7.4	F	The reactor tripped on a low—low level in "C" SG. The broken feed-back arm on the main feed flow control valve was discovered and repaired following this trip.	A	3	Steam and power conversion (HB)	Valves
11	4/16/82	17.8	F	The reactor tripped on "C" SG low level coincident with a feed flow—steam flow mismatch signal while feeding the SGs in manual.	G	3	Steam and power conversion (HB)	Codes not applicable
12	4/25/82	8.5	F	The reactor tripped on a low low level in "C" SG when the main feed flow control valve failed closed. The diaphragm on the pneumatic operator was replaced prior to startup.	A	3	Steam and power conversion (HB)	Valves

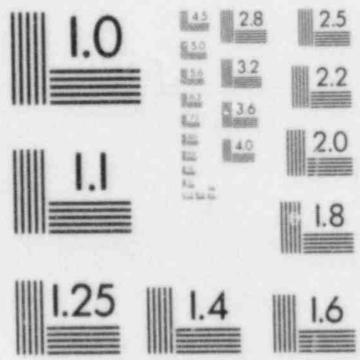
Details of plant outages for Surry 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
13	4/25/82	1.9	F	The reactor tripped on an intermediate range neutron detector high flux signal because the operator failed to block this trip at 10% power. The operator was counseled regarding the failure to block the trip as required.	G	3	Instrumentation and controls (IA)	Codes not applicable
14	7/13/82	18.3	F	"B" reactor trip bypass breaker was not racked in properly prior to Instrument Dept. testing of train "B" reactor trip signals. This caused a reactor trip. Operators have been reinstructed on proper procedures for racking in reactor trip bypass breakers and verifying proper insertion of breaker in cubicle.	G	3	Instrumentation and controls (IA)	Circuit closers/ interrupters
15	8/24/82	16.4	F	Mechanics working near the steam header pressure transmitters with an impact wrench jarred the transmitters, causing a spurious safety injection. All personnel involved have been made aware of the sensitivity of these transmitters to vibration.	G	3	Steam and power conversion (HB)	Instrumentation and controls
16	10/01/82	337.4	S	While reducing power for a scheduled maintenance outage, the reactor tripped on a steam flow—feed flow mismatch coincident with low level in "C" SG. The low level was a result of feed control system problems and was corrected prior to startup.	A	3	Steam and power conversion (HH)	Instrumentation and controls

IMAGE EVALUATION TEST TARGET (MT-3)







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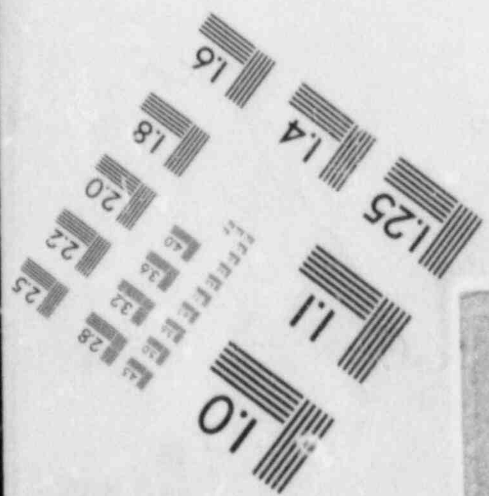
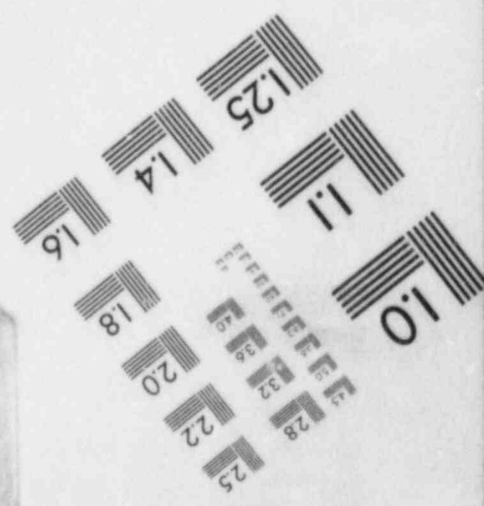
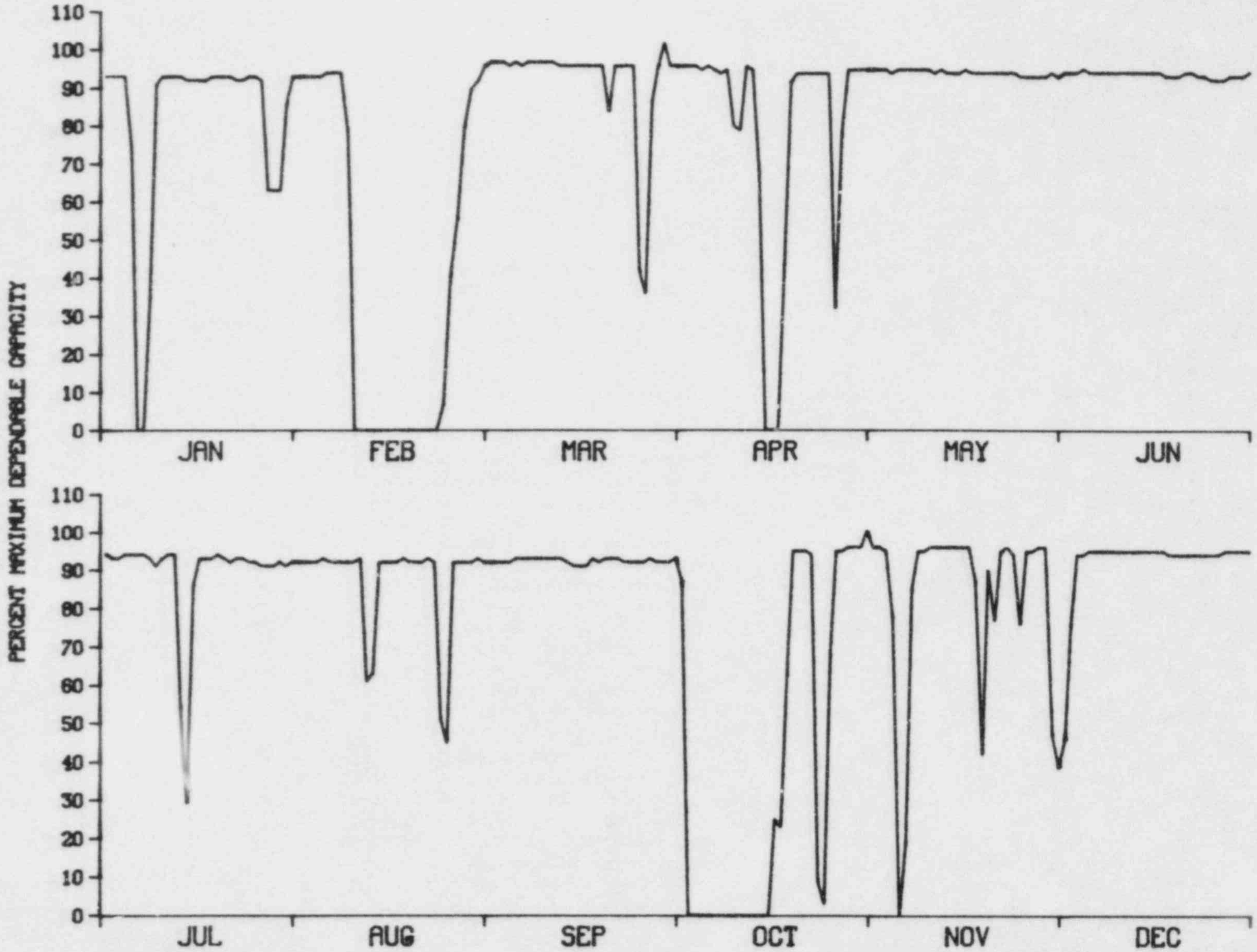




Details of plant outages for Surry 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
17	10/16/82	17.2	F	A faulty power mismatch card in the circuitry for excore detector N-42 resulted in a turbine runback, "B" feed flow control valve failed to respond quickly enough, and the reactor tripped on a high level in "B" steam generator.	A	3	Steam and power conversion (HH)	Valves
18	10/23/82	38.9	F	"B" feed flow control valve failed closed during power reduction, resulting in a "B" SG low level trip. The reactor had been in the process of being shut down for repair of 1-DG-14 when it tripped; 1-DG-14 was repaired, and the feed-back arm on the positioner for "B" feed flow control valve was repaired.	A	3	Steam and power conversion (HH)	Valves
19	11/04/82	41.3	F	Loss of "A" main transformer caused generator trip due to initiation of fire-water spray-down of transformer, causing a ground fault.	A	3	Reactor (RC)	Fuel elements
20	11/18/82	1.5	F	Generator taken off line to remove disconnect G105 from service due to overheating.	A	1	Reactor (RB)	Other components
21	11/29/82	9.7	F	Reactor trip due to "A" reactor coolant pump. Loss of pump was caused by a relay failure (33xB-V590) during performance of PT-8.3A.	A	3	Reactor (RC)	Fuel elements



DESIGN ELEC. RATING - 788 MAX. DEPEND. CAP. - 775 (100%)

SURRY 1

SURRY 2

I. Summary

Description	Performance	Outages
Location: Surry, Virginia	Net electrical energy generated (MWh): 5,492,206	Total No.: 14
Docket No.: 50-281	Unit availability factor (%): 88.3	Forced: 11
Reactor type: PWR	Unit capacity factor (%) (using MDC): 80.9	Scheduled: 3
Maximum dependable capacity [MW(e)-net]: 775	Unit capacity factor (%) [using design MW(e)]: 79.6	Total hours: 1,028 (11.7%)
Commercial operation: 5/01/73		Forced: 194 (2.2%)
Years operating experience: 9.8		Scheduled: 834 (9.5%)

II. Highlights

Surry 2 experienced no major interruptions during 1982. It, like its sister unit Surry 1, also reached almost 90% availability during the year. A six-day maintenance outage took place at the beginning of March, and a four-day outage in April was needed to repack a valve stem that was leaking coolant at about one gallon per minute. A 13-day spring maintenance outage was begun on May 15. The unit was then operated virtually without interruption until another scheduled maintenance shutdown was undertaken in December, which lasted 16 days.

Details of plant outages for Surry 2

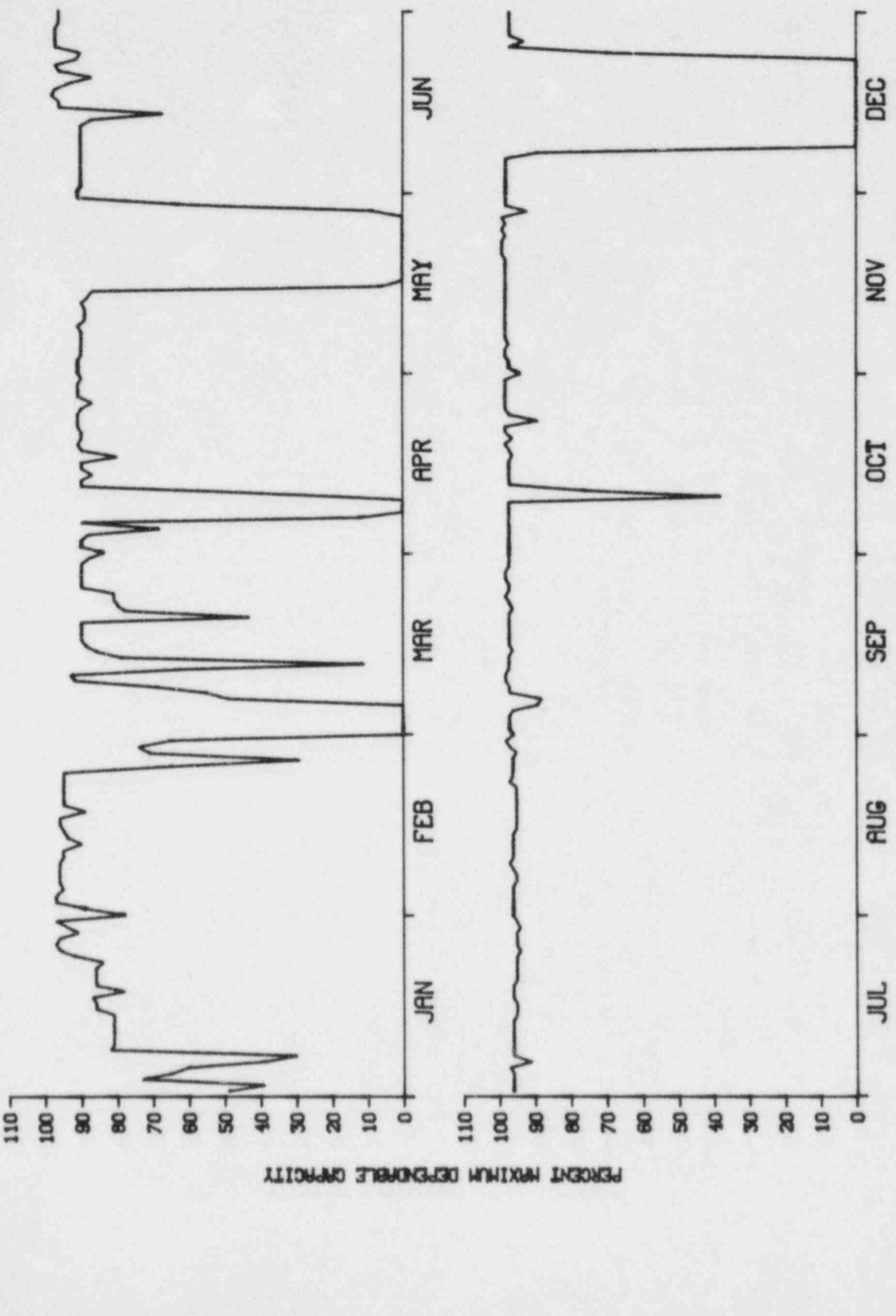
No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/02/82	4.1	F	Unit tripped on "6B" FW heater high-level turbine trip signal. No cause determined. The "5B" and "6B" FW heater were isolated and bypassed. Unit power limited to 90%.	H	3	Steam and power conversion (HH)	Instrumentation and controls
2	1/07/82	9.5	F	Lost EHC system pumps causing a turbine trip—reactor trip. Repaired EHC system leak prior to startup.	H	3	Steam and power conversion (HA)	Pumps
3	2/23/82	4.9	F	The reactor tripped on an over-temperature-overpower delta-T signal following a trip of the high-pressure drains pump. The Instrument Dept. calibrated loop delta-Ts following startup.	H	3	Instrumentation and controls (IA)	Pumps
4	2/24/82	3.6	F	The reactor tripped on a high-high level in "6B" feedwater heater caused by leaking tubes. Leaking tubes were subsequently plugged.	H	3	Steam and power conversion (HH)	Heat exchangers
5	2/24/82	2.0	F	The unit tripped on a low-low level signal on "C" SG while feeding in manual and increasing power.	H	3	Steam and power conversion (HB)	Codes not applicable
6	2/27/82	146.0	S	Shutdown for maintenance.	H	1	Instrumentation and controls (IE)	Instrumentation and controls
7	3/11/82	24.1	F	The unit was shutdown in accordance with 3.3.B due to a loss of recirculation flow to the boron injection tank. The recirculation flow was reestablished prior to startup.	G	3	Engineered safety features (SF)	Codes not applicable

Details of plant outages for Surry 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
8	3/20/82	9.4	F	Loss of EHC pressure due to a relief valve lifting caused all turbine governor valves to drift closed. Operator manually tripped the turbine and reactor; problem was corrected prior to unit startup.	A	2	Engineered safety features (SF)	Codes not applicable
9	4/06/82	100.1	F	Reactor shutdown due to 1-gpm unisolable reactor coolant leakage through valve packing. Valve was repacked prior to unit recovery.	A	1	Reactor coolant (CX)	Valves
10	5/15/82	307.7	S	Turbine trip—reactor trip by "B" SG high-high level while feeding in manual during power reduction for shutdown for scheduled spring maintenance outage.	B	3	Steam and power conversion (HB)	Codes not applicable
11	5/28/82	14.4	F	Turbine trip—reactor trip by "C" SG high-high level while feeding SGs in manual following startup. "C" SG feedwater flow control valve response was sluggish and the valve was exercised several times prior to the next startup.	A	3	Steam and power conversion (HB)	Valves
12	10/10/82	15.8	F	The inverter supplying VBIII failed. This resulted in a turbine runback, reactor trip, and safety injection. The inverter was repaired prior to unit startup.	A	3	Electric power (ED)	Generators
13	12/08/82	380.1	S	Unit taken off the line for maintenance outage.	B	1	Reactor coolant (CC)	Instrumentation and controls

Details of plant outages for Surry 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
14	12/23/82	5.9	F	Reactor tripped during startup while in manual feed control, due to a high level in "C" steam generator.	G	3	Steam and power conversion (HB)	Codes not applicable



DESIGN ELEC. RATING - 788 MAX. DEPEND. CAP. - 775 (100%)

SURRY 2

THREE MILE ISLAND 1

I. Summary

Description

Location: Middletown, Pennsylvania
Docket No.: 50-289
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 776
Commercial operation: 9/02/74
Years operating experience: 8.5

Performance

Net electrical energy generated (MWh): 0
Unit availability factor (%): 0
Unit capacity factor (%) (using MDC): 0
Unit capacity factor (%) [using design MW(e)]: 0

Outages

Total No.: 1
  Forced: 1
  Scheduled: 0
Total hours: 8,760[a] (100%)
  Forced: 8,760[a] (100%)
  Scheduled: 0 (0%)

II. Highlights

Three Mile Island 1, shut down by NRC order since the accident to its sister unit in 1979, remained off line during the entire year. Startup is not anticipated before 1984.

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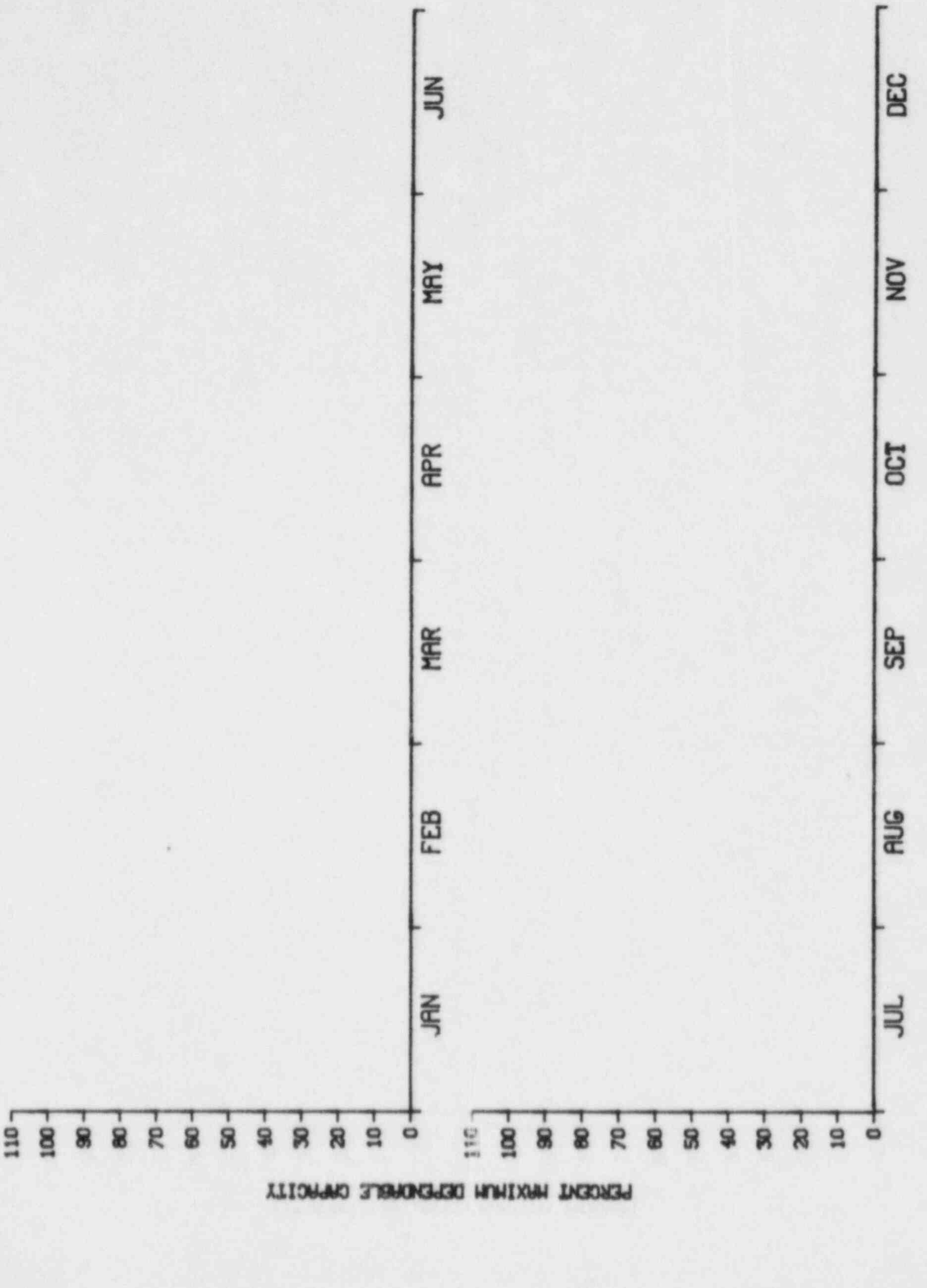
[a]This comprises the entire year in a shutdown which began 2/17/79.

Details of plant outages for Three Mile Island 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	2/17/79	8,760.0	F	Regulatory restraint order continues.	D	4	System code not applicable (ZZ)	Codes not applicable



DESIGN ELEC. RATING - 819 MAX. DEPEND. CAP. - 776 (100%)

THREE MILE ISLAND 1

TROJAN

I. Summary

Description

Location: Prescott, Oregon
Docket No.: 50-344
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 1,080
Commercial operation: 5/20/76
Years operating experience: 7.0

Performance

Net electrical energy generated (MWh): 4,802,041
Unit availability factor (%): 60.8
Unit capacity factor (%) (using MDC): 50.8
Unit capacity factor (%) [using design MW(e)]: 48.5

Outages

Total No.: 11
Forced: 8
Scheduled: 3
Total hours: 4,007 (45.7%)
Forced: 324 (3.7%)
Scheduled: 3,683 (42.0%)

II. Highlights

Trojan was shut down in late March 1982 because its capacity was not needed, due to availability of cheaper hydroelectric power in the utility's system. This outage merged into a refueling outage which began on April 19 and lasted until late August. The combined outage occupied 22 weeks, of which 18 were for refueling and the rest because power was not needed. Two brief outages close together in September, totaling about three days, were due to valve leakage and a faulty pressure switch on a main feedwater pump oil lubrication system. In November the plant was down for 11 and a half days because of problems with pressurizer level and pressure transmitters.

Details of plant outages for Trojan

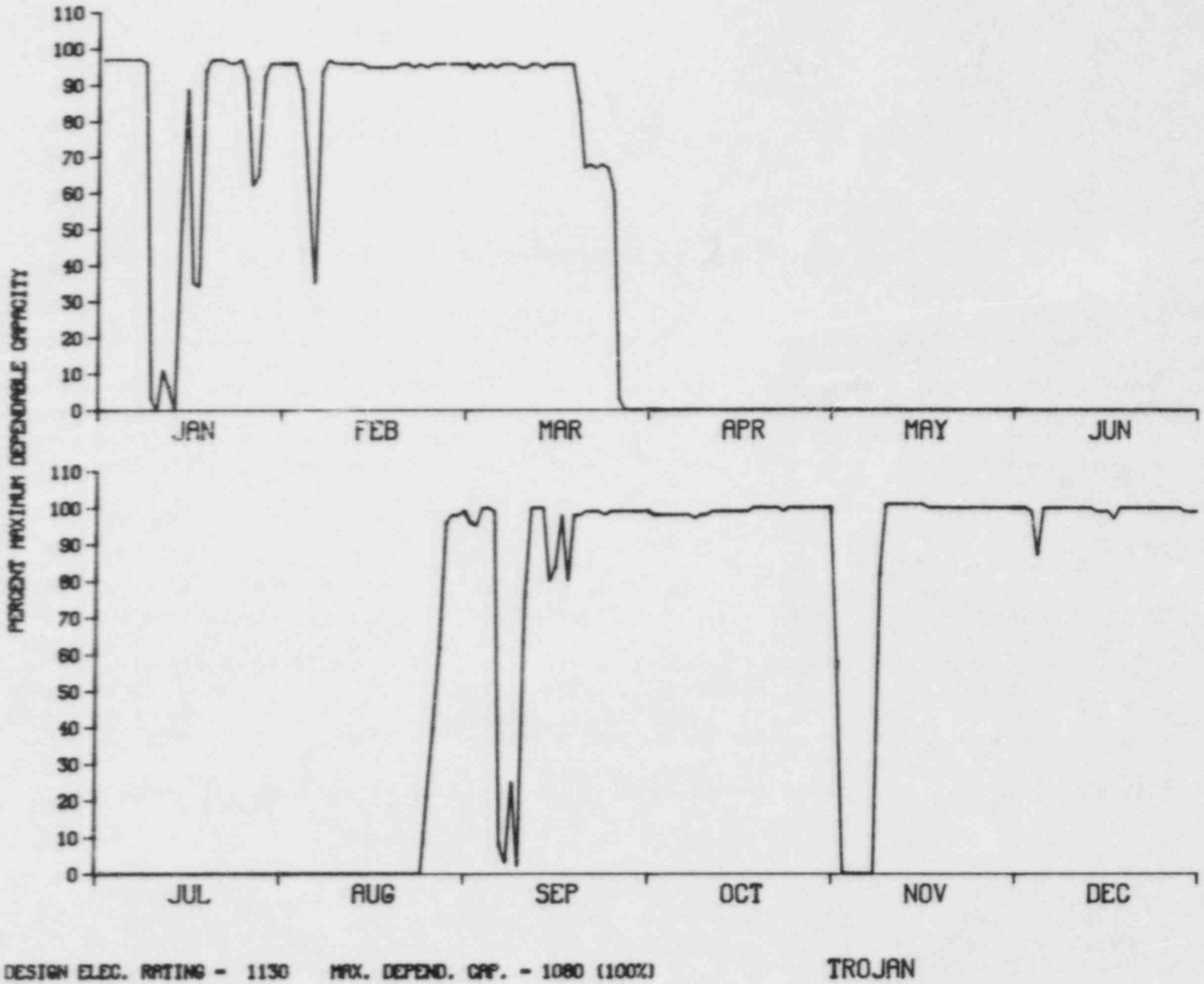
No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/09/82	59.7	F	Elbow failure on 18-in. extraction steam line to 5B FW heater due to moisture erosion. Replaced elbow and investigated other elbows with similar steam flow and moisture content.	A	2	Steam and power conversion (HJ)	Pipes and/or fittings
2	1/12/82	43.0	F	No. 2 inverter to Y22 failed due to faulty transformer and diode. Transformer and diode replaced. Westinghouse investigation continues.	A	2	Electric power (EB)	Generators
3	1/16/82	20.5	F	No. 2 inverter to Y22 failed due to faulty transformer. Caused an SI signal and reactor trip due to the steam dump valves opening and causing actual high steam flow bistable trips concurrent with low steam line pressure.	A	3	Electric power (EB)	Generators
4	2/04/82	12.4	F	The main turbine was taken off line to replace a stator cooling water strainer which had a high differential pressure. The reactor subsequently tripped from 5% power on "A" steam generator low-low level, caused by difficulty in manually controlling level.	B	3	Steam and power conversion (HA)	Filters
5	3/26/82	571.3	S	Favorable hydroelectric conditions allowed the plant to be shut down based upon economic considerations. Abundant hydroelectric power was available in the Northwest and its utilization was more economical than continued plant generation.	F	1	System code not applicable (ZZ)	Codes not applicable

Details of plant outages for Trojan (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
6	4/19/82	3,070.1	S	The 1982 refueling outage.	C	1	Reactor (RC)	Fuel elements
7	9/06/82	41.6	S	Scheduled outage to repair a body-to-bonnet leak on RCS RTD manifold hot leg outlet isolation valve, 8073C. On the power reduction the turbine was manually tripped at 10% power, resulting in a reactor trip.	B	2	Instrumentation and controls (IE)	Valves
8	9/08/82	30.1	F	The reactor was manually tripped at 54% power due to a trip of the south MFP. A faulty pressure switch on the pump lube oil system was replaced. The plant remained off the line to perform maintenance on various secondary system components.	A	1	Steam and power conversion (HH)	Instrumentation and controls
9	9/14/82	3.0	F	The reactor tripped from SG "C" low level with low feedwater flow due to a north main feedwater pump trip. I&C technicians caused a ground on instrument bus Y02 while troubleshootng generator core monitor. Since the north MFP governor is also powered from Y02, the pump subsequently tripped.	G	3	Steam and power conversion (HH)	Codes not applicable
10	9/17/82	2.9	F	The reactor tripped on low-low SG level due to a south main feedwater pump trip. The south MFP trip was caused by a failed proximitor in the thrust bearing wear detector. The proximitor was replaced.	A	3	Steam and power conversion (HH)	Instrumentation and controls

Details of plant outages for Trojan (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
11	11/01/82	152.1	F	The reactor tripped from low pressurizer pressure while I&C technicians were troubleshooting pressurizer level transmitter LT-461. Venting the level transmitter resulted in depressurization of two pressurizer pressure transmitters which share a common tap with LT-461, causing the reactor trip. The vent was promptly shut to prevent further depressurization. I&C testing procedures are being revised to prevent recurrence of this event. The plant remained shut down to perform maintenance on numerous items.	G	3	Reactor coolant (CJ)	Instrumentation and controls


PERCENT MAXIMUM DEPENDABLE CAPACITY
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DESIGN ELEC. RATING - 1130 MAX. DEPEND. CAP. - 1080 (100%)
TROJAN

TURKEY POINT 3

I. Summary

Description

Location: Florida City, Florida
Docket No.: 50-250
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 646
Commercial operation: 12/14/72
Years operating experience: 10.2

Performance

Net electrical energy generated (MWh): 3,765,886
Unit availability factor (%): 64.1
Unit capacity factor (%) (using MDC): 66.5
Unit capacity factor (%) [using design MW(e)]: 62.0

Outages

Total No.: 14
Forced: 12
Scheduled: 2
Total hours: 3,146[a] (35.9%)
Forced: 725 (8.3%)
Scheduled: 2,421[a] (27.6%)

II. Highlights

Turkey Point 3 began the year in a major outage, started the previous June and extending 14 weeks into 1982, for steam generator repair. Once the plant came back on line in mid-April, it ran rather reliably the rest of the year with only a few significant stoppages. A reactor coolant pump oil leak and a snubber repair required three days of down time at the end of May, and a failed reactor coolant pump motor had to be replaced in July, which resulted in a 17-day shutdown starting July 21. The only other significant outage was a one-week shutdown in late November to reweld a small pipe leading from a main steam line to a steam flow transmitter.

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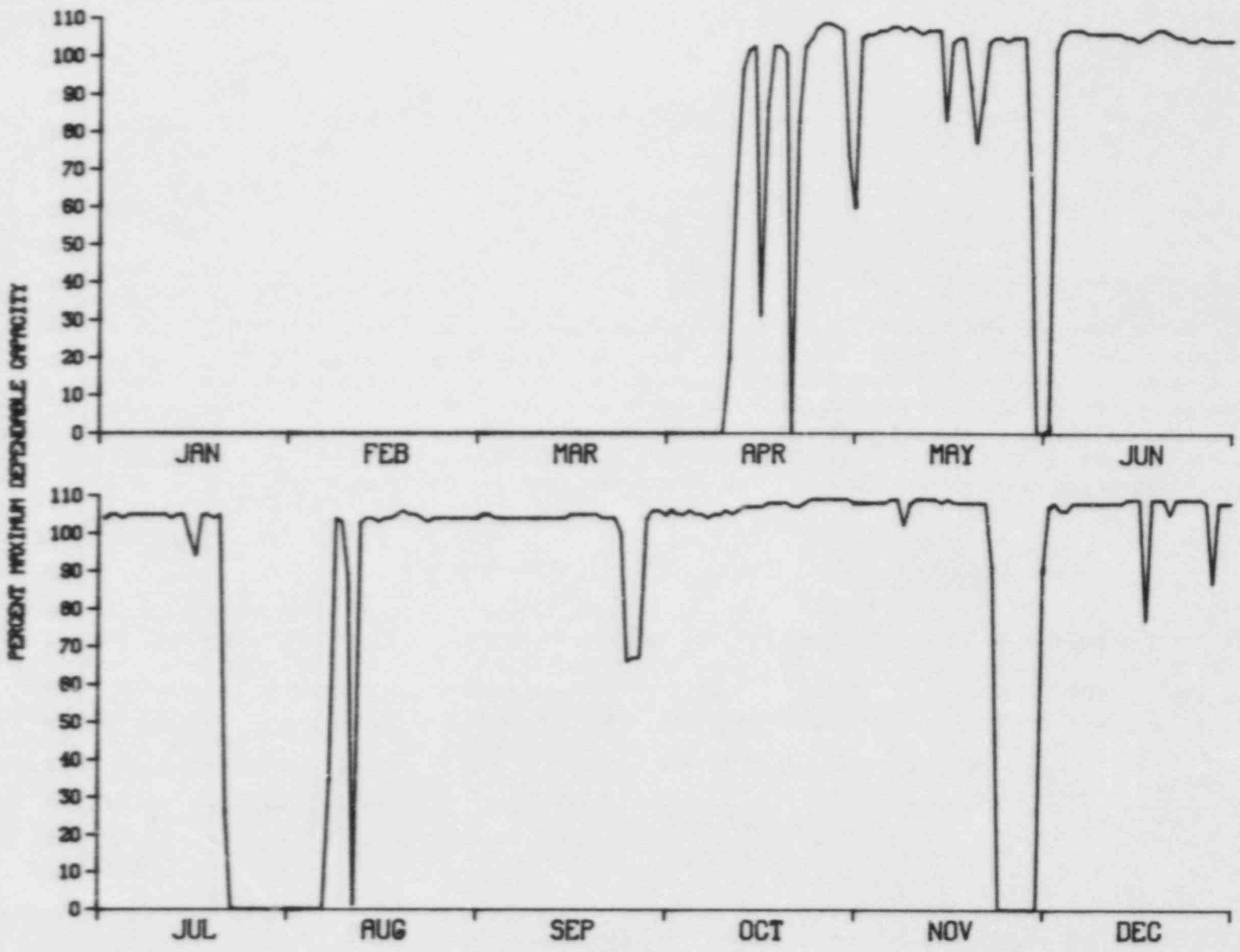
[a]Includes 2,380 h in 1982 from continuation of 6/24/81 outage.

Details of plant outages for Turkey Point 3

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	6/24/81	2,379.6	S	Steam generator repair program.	B	4	Steam and power conversion (HB)	Heat exchangers
2	4/10/82	6.5	F	Reactor trip caused by a spike on one channel of overtemperature delta T instrument while performing maintenance on the other channel.	A	3	Instrumentation and controls (IA)	Instrumentation and controls
3	4/15/82	17.3	S	Unit taken off line for turbine overspeed test, and then shut down following indication of a dropped rod.	B	1	Steam and power conversion (HA)	Turbines
4	4/20/82	21.7	F	Reactor trip due to high steam generator level which was caused by a failure of the controller of the feed regulating valve.	A	3	Steam and power conversion (HH)	Circuit closers/ interrupters
5	4/20/82	5.4	F	See cause for shutdown 4 above. Controller was repaired.	A	3	Steam and power conversion (HH)	Circuit closers/ interrupters
6	4/29/82	10.8	F	Reactor trip caused by low level in the steam generator due to failure of a condensate pump. A second trip occurred while still off line due to a power spike to nuclear instruments.	A	3	Steam and power conversion (HH)	Pumps
7	5/15/82	4.5	F	Reactor trip caused by loss of power to the rods due to problems with the control rod drive MG sets. The problems are still being evaluated.	A	3	Electric power (EB)	Other components
8	5/19/82	2.3	F	Reactor trip caused by an inadvertent opening of the RCP breaker while maintenance was in progress.	A	3	Electric power (EB)	Relays

Details of plant outages for Turkey Point 3 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
9	5/20/82	8.5	F	Reactor trip caused by loss of power to the rods due to problems with the control rod drive MG sets. The problem is still being evaluated.	A	3	Electric power (EB)	Other components
10	5/29/82	71.3	F	Unit removed from service to repair reactor coolant pump oil leak. Outage continued to repair snubber on the SG blowdown drain line.	A	1	Reactor coolant (CB)	Pumps
11	6/01/82	5.5	F	The unit tripped on steam generator low level coincident with a mismatch of steam flow and feed flow. The unit was recovered and brought back on line.	H	3	Instrumentation and controls (IA)	Instrumentation and controls
12	7/21/82	415.4	F	Reactor tripped due to loss of reactor coolant pump which tripped due to instantaneous overcurrent. The reactor coolant pump motor was replaced.	A	3	Reactor coolant (CB)	Motors
13	8/10/82	24.1	S	Unit 3 was removed from service to repair feed [illegible] drain valve and to repair/adjust the turbine control valve. Unit 3 was then returned to full power.	A	1	Reactor coolant (CH)	Valves
14	11/22/82	170.0	F	Unit was removed from service to repair weld on steam line to main steam line flow transmitter. Unit was then returned to service.	A	1	Reactor coolant (CC)	Pipes and/or fittings
15	12/28/82	3.0	F	Reactor was tripped by a spurious signal while performing a nuclear instrumentation periodic test. A module was replaced and the unit returned to power.	H	3	Instrumentation and controls (IA)	Instrumentation and controls



DESIGN ELEC. RATING - 693 MAX. DEPEND. CAP. - 646 (100%)

TURKEY POINT 3

TURKEY POINT 4

I. Summary

Description

Location: Florida City, Florida
Docket No.: 50-251
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 646
Commercial operation: 9/07/73
Years operating experience: 9.5

Performance

Net electrical energy generated (MWh): 3,844,893
Unit availability factor (%): 66.3
Unit capacity factor (%) (using MDC): 67.9
Unit capacity factor (%) [using design MW(e)]: 63.3

Outages

Total No.: 16
Forced: 13
Scheduled: 3
Total hours: 2,948 (33.6%)
Forced: 779 (8.9%)
Scheduled: 2,170 (24.8%)

II. Highlights

Turkey Point 4 had to shut down for six and a half days in early February to balance the exciter on its turbine generator. The unit then operated without major problems until June 5, when it was taken down for nine days to repair a steam generator tube leak and to do maintenance on the secondary cooling loop to reduce several minor leakages. Much of July (19 days) was occupied with resolving steam generator leakage problems found to be due to foreign objects in the secondary side of the system, which were removed. Some preventive tube plugging was also done at that time. The plant then operated smoothly until October 9, when a major steam generator repair program was begun, which lasted the rest of the year and on into 1983.

Details of plant outages for Turkey Point 4

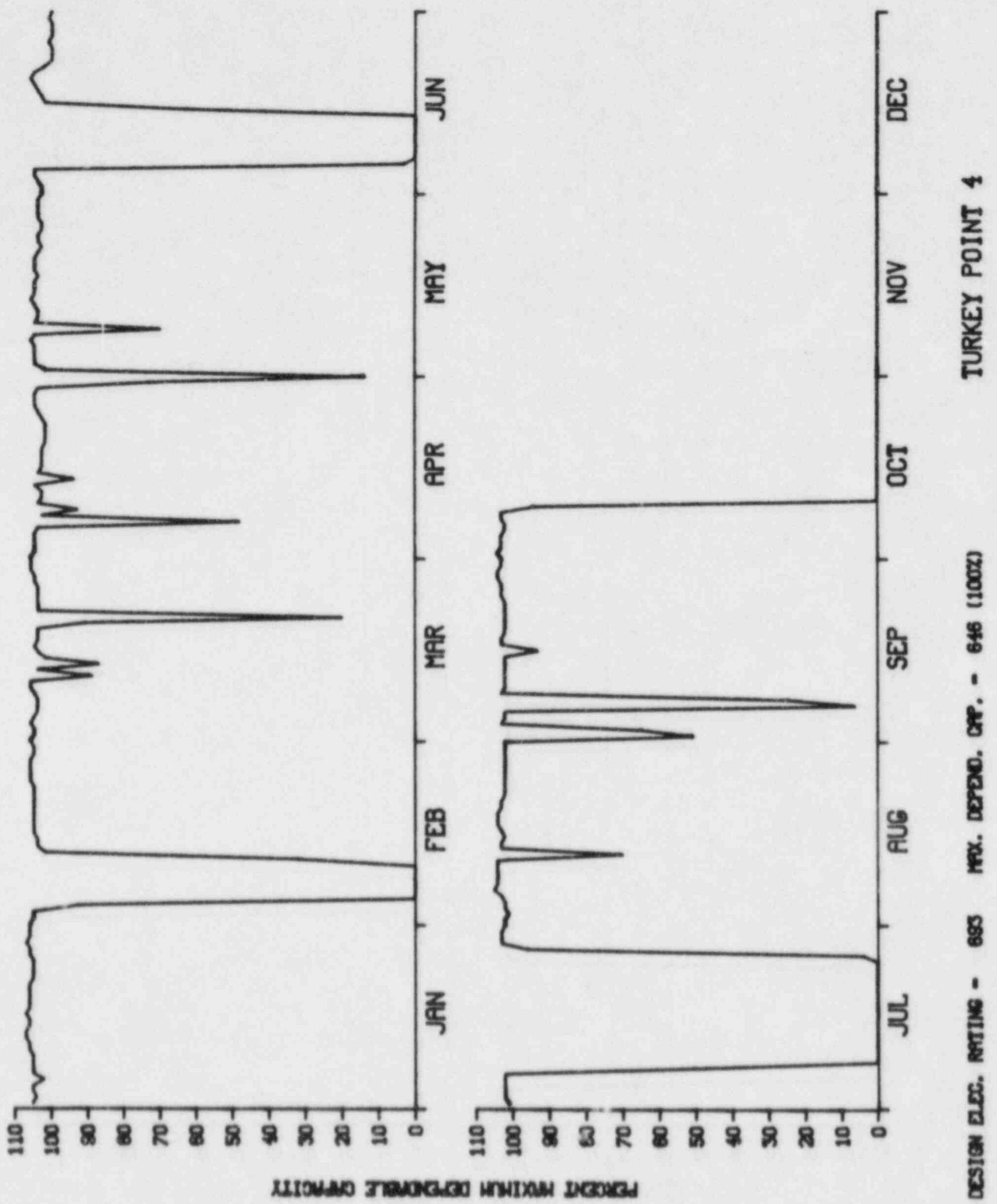
No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	2/03/82	157.6	S	Unit removed from service to balance exciter on turbine generator.	B	1	Steam and power conversion (HA)	Generators
2	3/11/82	2.4	F	Reactor trip caused by turbine trip. Cause of turbine trip unknown. Unit returned to power.	A	3	Steam and power conversion (HA)	Turbines
3	3/13/82	2.8	F	Unit was manually tripped due to loss of rod position indication caused by inverter failure.	A	2	Instrumentation and controls (ID)	Generators
4	3/20/82	19.0	S	Unit taken off line for turbine overspeed test and for Unit 3 safeguards test.	B	1	System code not applicable (ZZ)	Codes not applicable
5	4/06/82	11.8	F	Reactor trip due to turbine runback caused by a ground on a vital instrument bus. The ground was repaired.	A	3	Electric power (EB)	Electrical conductors
6	4/13/82	1.7	F	Reactor trip caused by a spurious signal that occurred during reactor protection system testing.	B	3	Instrumentation and controls (IA)	Instrumentation and controls
7	4/23/82	1.8	F	Reactor trip due to loss of steam generator feed caused by a condensate pump trip. Feedwater was restored and the unit returned to power.	A	3	Steam and power conversion (HH)	Pumps
8	4/29/82	7.1	F	Reactor trip caused by turbine runback that resulted from a loss of instrument power. The instrument was being powered from Unit 3, which had tripped off the line.	A	3	Steam and power conversion (HH)	Pumps

Details of plant outages for Turkey Point 4 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
9	4/30/82	16.7	F	Reactor trip caused by low level in the steam generator due to mechanical failure of feed regulator valve controller.	A	3	Steam and power conversion (HH)	Valves
10	5/08/82	3.1	F	The unit was removed from service to repair a leaking cooling line in the turbine generator exciter.	A	1	Steam and power conversion (HA)	Heat exchangers
11	6/05/82	220.3	F	Unit was removed from service to repair secondary system minor steam leaks and to plug a leaking steam generator tube.	A	1	Steam and power conversion (HB)	Heat exchangers
12	7/07/82	463.6	F	Unit removed from service to investigate primary to secondary leakage. Foreign objects on secondary side found to be the cause. Most of the foreign objects were removed and preventive plugging was completed. The unit was returned to operation.	B	1	Reactor coolant (CC)	Heat exchangers
13	8/12/82	5.8	F	Reactor tripped on high steam generator level due to damage to a feedwater regulator valve control cable. The cable was repaired and the unit was returned to service.	G	3	Reactor coolant (CH)	Valves
14	9/01/82	3.0	F	A procedural error during a surveillance test caused a feedwater regulating valve to close. This resulted in a reactor trip. The unit was returned to power.	G	3	Reactor coolant (CC)	Codes not applicable

Details of plant outages for Turkey Point 4 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
15	9/06/82	38.5	F	The unit was manually tripped after indications showed decreasing RCS pressure. This was caused by a partially open pressurizer spray valve. The valve was repaired and the unit was returned to service.	A	2	Reactor coolant (CA)	Valves
16	10/09/82	1,993.2	S	Steam generator repair program in accordance with paragraph III.h. of the Unit 4 facility operating license DPR 41.	H	1	Steam and power conversion (HB)	Heat exchangers


PERCENT MAXIMUM DEPENDABLE CAPACITY
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DESIGN ELEC. RATING - 693 MAX. DEPEND. CAP. - 646 (100%)
TURKEY POINT 4

VERMONT YANKEE 1

I. Summary

Description

Location: Vernon, Vermont
Docket No.: 50-271
Reactor type: BWR
Maximum dependable capacity [MW(e)-net]: 504
Commercial operation: 11/30/72
Years operating experience: 10.3

Performance

Net electrical energy generated (MWh): 4,174,255
Unit availability factor (%): 96.0
Unit capacity factor (%) (using MDC): 94.5
Unit capacity factor (%) [using design MW(e)]: 92.7

Outages

Total No.: 8
Forced: 6
Scheduled: 2
Total hours: 352 (4.0%)
Forced: 254 (2.9%)
Scheduled: 80 (1.1%)

II. Highlights

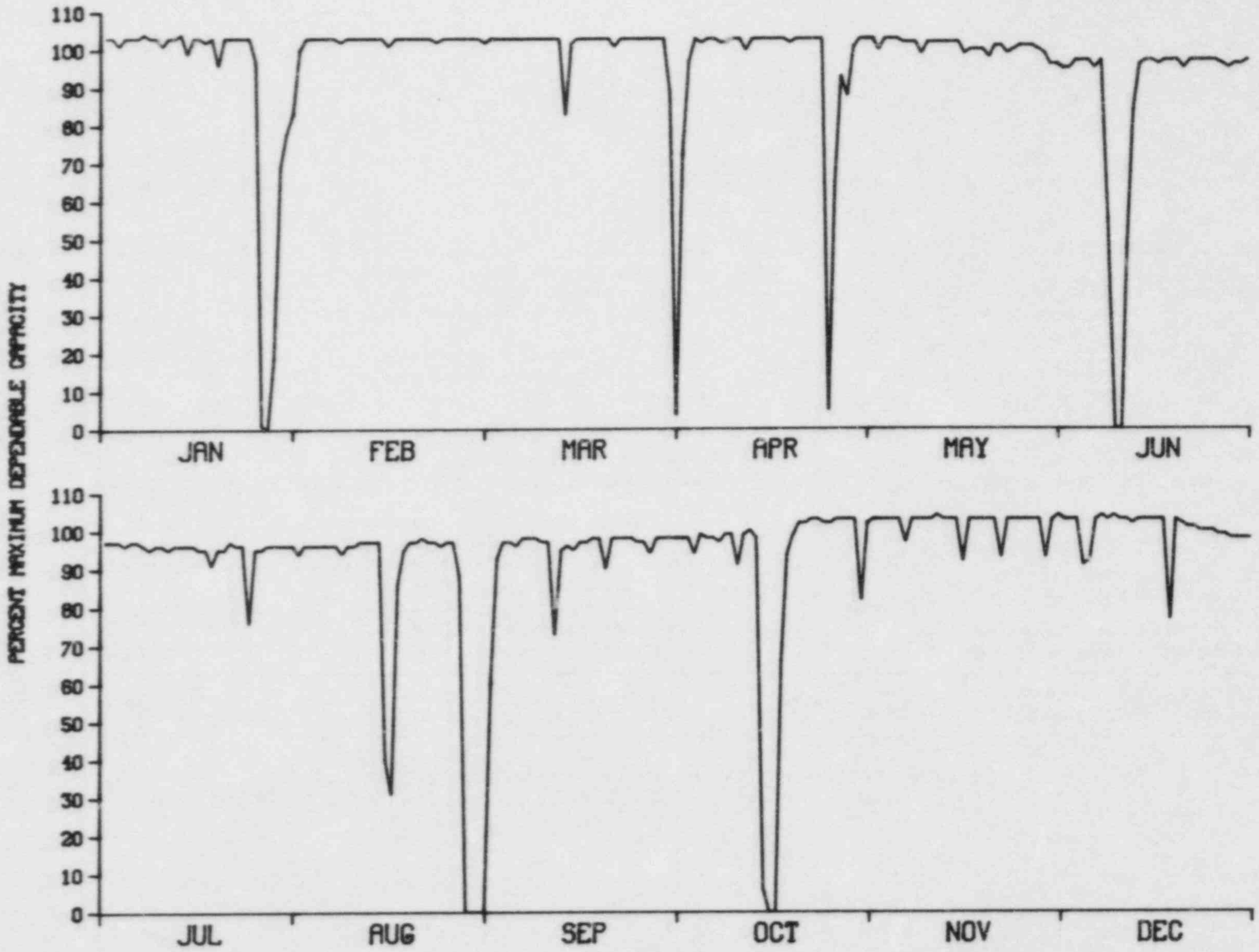
Vermont Yankee operated extremely reliably during 1982, achieving the highest availability among all the American BWR power reactors. It totaled just 14 days off line the entire year. The longest outage was a four-day stoppage at the end of August to replace reactor recirculation pump seals and perform other maintenance. A steam leak repair on reactor moisture separator drain tank piping, which shut the system down for just under three days in October, was the only other significant down time. At the very end of the year the power output was beginning to drop as the plant reactivity approached exhaustion with a refueling outage approaching.

Details of plant outages for Vermont Yankee 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/26/82	57.8	F	Plant shutdown to repair main turbine moisture separator drain line erosion.	A	1	Steam and power conversion (HB)	Pipes and/or fittings
2	3/30/82	24.0	F	Reactor scrammed on high flux in response to a pressure spike that originated in the main turbine control system. An investigation revealed that a turbine control oil system filter was loosened to the extent that unfiltered oil could have been cycled back into the system.	A	3	Steam and power conversion (HB)	Instrumentation and controls
3	4/24/82	22.3	F	Reactor scrammed on low reactor vessel level due to a failure in the feedwater control system. An investigation revealed dirt in the air circuit of the "A" feedwater regulator valve pneumatic current-to-pressure converter. This caused an incorrect valve position signal to be initiated. The converter was replaced.	A	3	Reactor coolant (CH)	Instrumentation and controls
4	6/08/82	59.0	F	Plant manually shutdown to investigate increasing dry-well temperature. The increase was due to the mechanical failure of two of the four dry-well air cooling and recirculation units. The failed parts were repaired/replaced. Analysis of event continuing.	A	2	Other auxiliary (AA)	Blowers

Details of plant outages for Vermont Yankee 1 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
5	8/15/82	22.2	F	Reactor scrammed on high flux in response to a pressure spike that originated in the main turbine control system. The manual pressure regulator was found to be clogged. The system was disassembled, cleaned, and returned to service.	A	3	Steam and power conversion (HB)	Instrumentation and controls
6	8/27/82	96.4	S	Plant shutdown for the replacement of the reactor recirc. pump seals and other maintenance.	B	2	Reactor coolant (CB)	Pumps
7	9/01/82	1.5	S	Plant shutdown for the replacement of the reactor recirc. pump seals and other maintenance.	B	2	Reactor coolant (CB)	Pumps
8	10/14/82	68.3	F	Plant shutdown to repair a steam leak in the main turbine moisture separator drain tank piping.	A	2	Steam and power conversion (HJ)	Pipes and/or fittings



DESIGN ELEC. RATING - 514 MAX. DEPEND. CAP. - 504 (100%) VERMONT YANKEE 1

YANKEE-ROWE

I. Summary

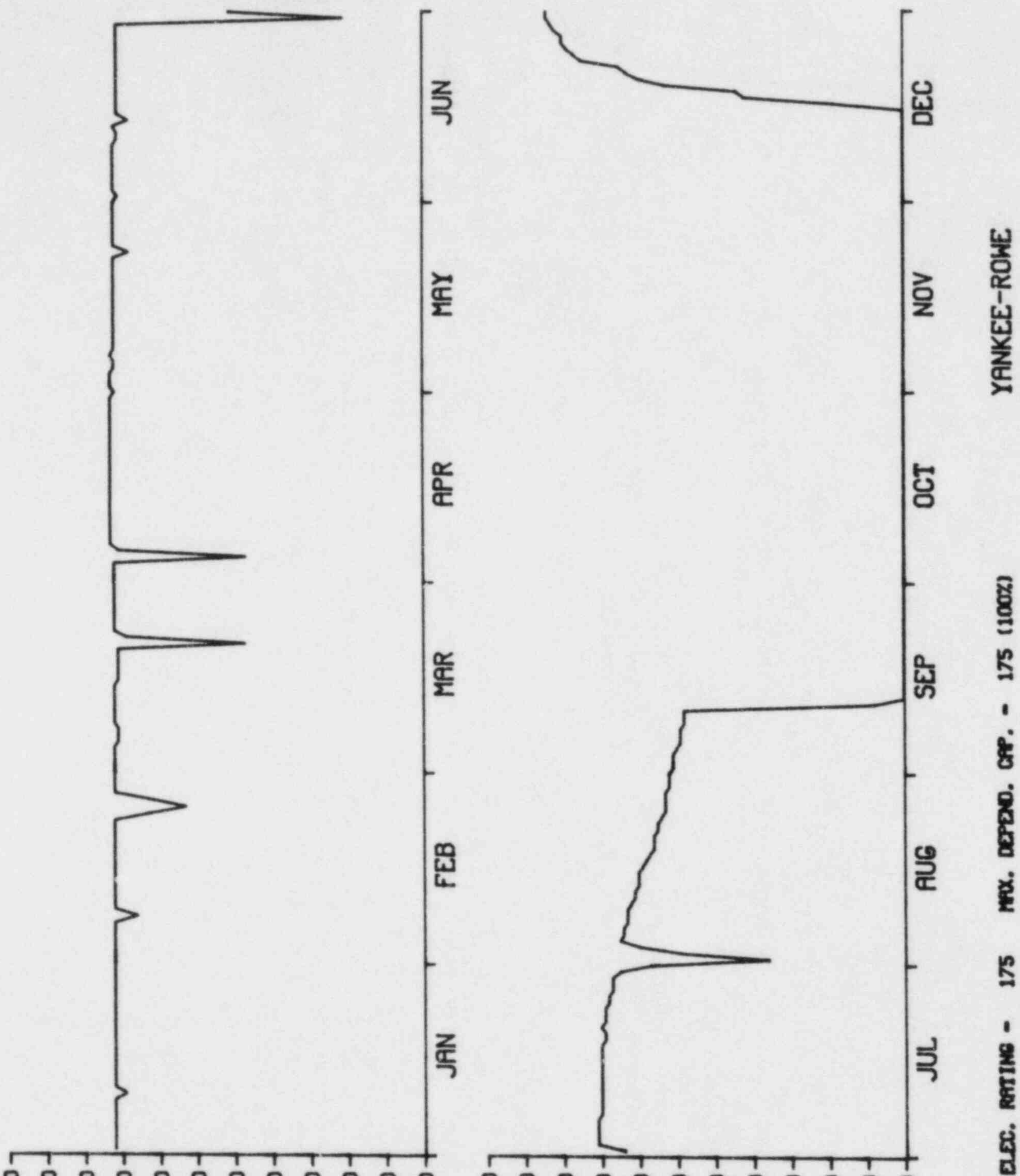
Description	Performance	Outages
Location: Rowe, Massachusetts	Net electrical energy generated (MWh): 882,161	Total No.: 4
Docket No.: 50-029	Unit availability factor (%): 73.4	Forced: 3
Reactor type: PWR	Unit capacity factor (%) (using MDC): 57.5	Scheduled: 1
Maximum dependable capacity [MW(e)-net]: 175	Unit capacity factor (%) [using design MW(e)]: 57.5	Total hours: 2,330 (26.6%)
Commercial operation: 7/01/61		Forced: 27 (0.3%)
Years operating experience: 22.1		Scheduled: 2,303 (26.3%)

II. Highlights

Yankee-Rowe, the oldest running power reactor in the United States, operated extremely reliably during 1982 with a total outage sum of only 27 *hours* during all of 1982, with the exception of a refueling outage that began on September 11 and lasted about 14 weeks, until mid-December. The plant power was restricted to just over 80% of full power all year, awaiting the installation of turbine baffle plates. From mid-July until the refueling outage began, the power level dropped gradually due to reactivity depletion, ending at about 60% at the time of shutdown.

Details of plant outages for Yankee Rowe

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	6/29/82	18.1	F	Shutdown due to turbine trip caused by loss of Z-126 high line during a thunderstorm.	H	3	Steam and power conversion (HA)	Electrical conductors
2	7/31/82	6.4	F	Thunderstorms caused electrical interruption on high lines.	H	3	Steam and power conversion (HA)	Electrical conductors
3	7/31/82	2.8	F	Plant trip caused by electrical disturbance on high lines due to severe thunderstorms.	H	3	Steam and power conversion (HA)	Electrical conductors
4	9/11/82	2,302.6	S	Refueling outage.	C	1	Reactor (RC)	Fuel elements


PERCENT MAXIMUM DEPENDABLE CAPACITY
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DESIGN ELEC. RATING - 175 MAX. DEPEND. CAP. - 175 (100%)
YANKEE-ROWE

ZION 1

I. Summary

Description

Location: Zion, Illinois
Docket No.: 50-295
Reactor type: PWR
Maximum dependable capacity [MW(e)-net]: 1,040
Commercial operation: 12/31/73
Years operating experience: 9.5

Performance

Net electrical energy generated (MWh): 4,695,388
Unit availability factor (%): 59.1
Unit capacity factor (%) (using MDC): 51.5
Unit capacity factor (%) [using design MW(e)]: 51.5

Outages

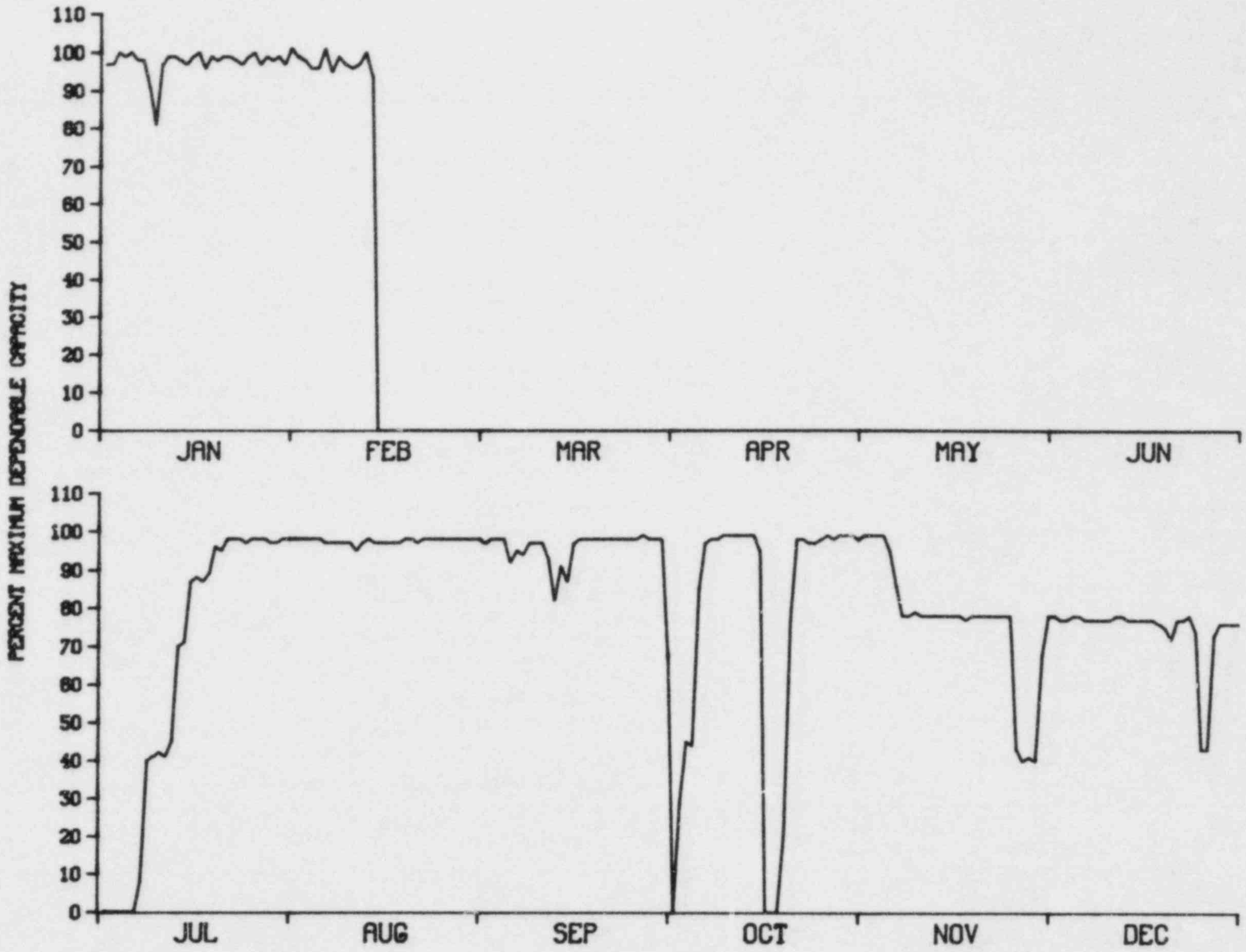
Total No.: 9
Forced: 8
Scheduled: 1
Total hours: 3,586 (40.9%)
Forced: 1,705 (19.5%)
Scheduled: 1,881 (21.5%)

II. Highlights

Zion 1 shut down on February 13 for a seven-day outage to repair steam leaks; then a number of additional outages combined to keep the plant shut down until the first week of July. Eight weeks were due to refueling, and then ten days were added for steam generator repair due to a nozzle cover having been left in the steam generator during the previous repair. This was followed by four and a half weeks due to loose parts in the primary system and then another 16 days because a safety injection pump shaft broke. Thereafter, there were no more long outages, with exception of a three-and-a-half-day shutdown in October because a diesel generator failed while the second was down for maintenance. Power reductions due to low demand marked the operation of the unit at the end of the year.

Details of plant outages for Zion 1

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	2/13/82	168.0	F	Unit shutdown due to steam leaks.	A	1	Steam and power conversion (HB)	Pipes and/or fittings
2	2/20/82	1,881.2	S	Following unit shutdown, cycle VI-VII refueling began.	C	9	Reactor (RC)	Fuel elements
3	5/09/82	252.0	F	Unit remained shutdown to straighten bent tube ends due to reactor coolant system steam generator nozzle cover left in from last outage.	H	9	Reactor coolant (CC)	Heat exchangers
4	5/19/82	752.5	F	Unit remained shutdown for reactor coolant system "a" loop loose parts.	H	9	Reactor coolant (CB)	Pipes and/or fittings
5	6/20/82	392.3	F	Unit remained shutdown because 1A safety injection pump shaft broken.	A	9	Engineered safety features (SF)	Pumps
6	7/06/82	15.7	F	Reactor trip/safety injection while performing operating surveillance.	G	3	System code not applicable (ZZ)	Codes not applicable
7	7/07/82	5.6	F	Reactor/turbine trip on intermediate range high flux trip from power dropping below set point.	A	3	Instrumentation and controls (IA)	Other components
8	9/30/82	37.0	F	Reactor was manually tripped due to feedwater and rod control system problems.	A	2	Reactor (RB)	Instrumentation and controls
9	10/16/82	81.5	F	Failure of 1B diesel generator with 1 out of service for maintenance.	A	1	Electric power (EE)	Engines, internal combustion



DESIGN ELEC. RATING - 1040 MAX. DEPEND. CAP. - 1040 (100%) ZION 1

ZION 2

I. Summary

Description	Performance	Outages
Location: Zion, Illinois Docket No.: 50-304 Reactor type: PWR Maximum dependable capacity [MW(e)-net]: 1,040 Commercial operation: 9/17/74 Years operating experience: 9.0	Net electrical energy generated (MWh): 5,158,063 Unit availability factor (%): 69.4 Unit capacity factor (%) (using MDC): 56.6 Unit capacity factor (%) [using design MW(e)]: 56.6	Total No.: 17 Forced: 17 Scheduled: 0 Total hours: 2,680 (30.6%) Forced: 2,680 (30.6%) Scheduled: 0 (0%)

II. Highlights

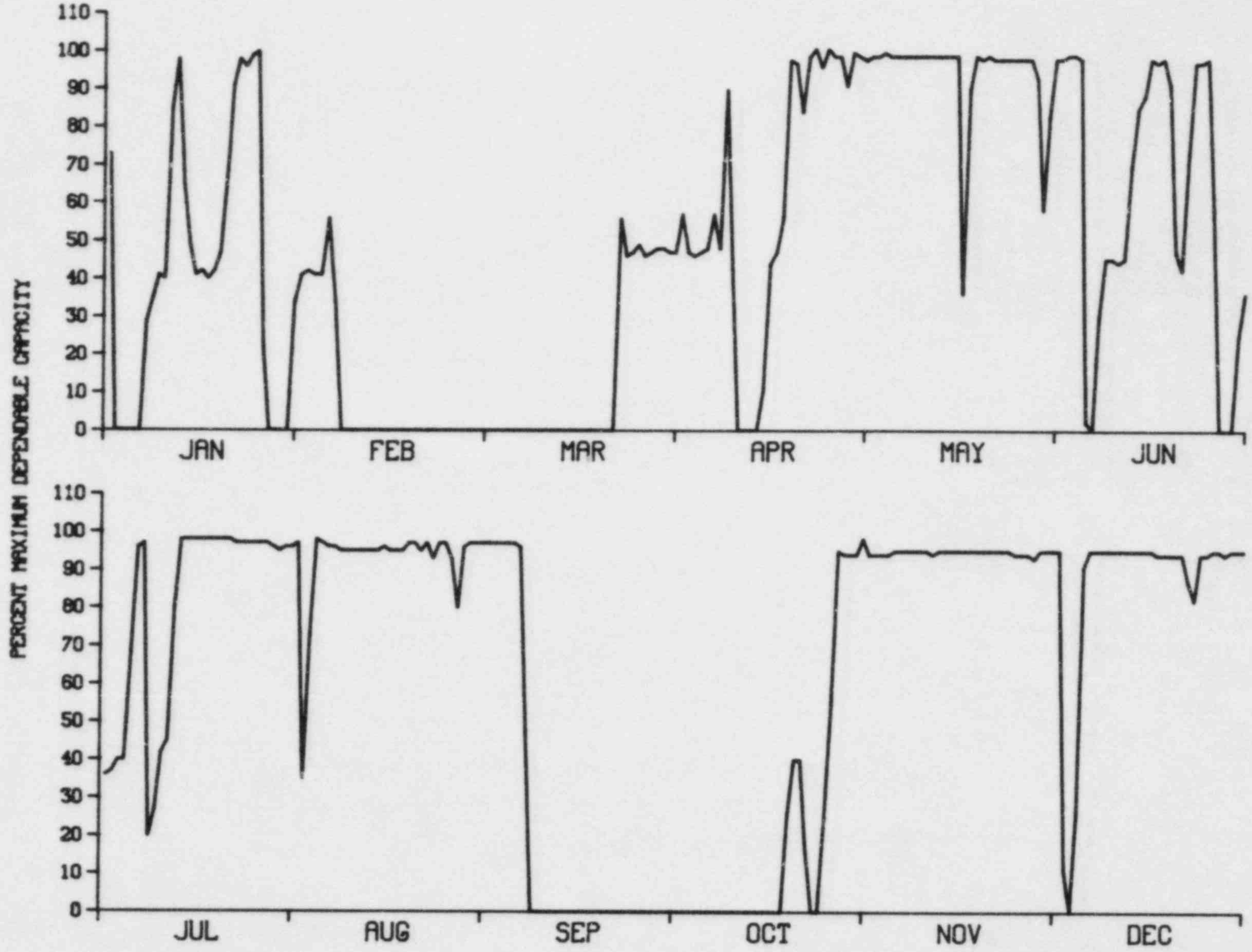
Zion 2 was troubled with a relatively large number of forced outages during 1982, some of rather substantial duration. Following some shorter outages in January the plant was down for 43 days beginning February 6, due to turbine vibration. The turbine continued to cause intermittent problems until, on September 6, a turbine blade repair outage of 40 days' duration was begun. Other problems associated with briefer outages during 1982 included arcing bushings on the main transformer, electro-hydraulic control system problems, and other electric problems.

Details of plant outages for Zion 2

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
1	1/02/82	95.2	F	While bringing the unit down, a manual turbine/reactor trip occurred due to condenser tube leaks.	A	2	Steam and power conversion (HC)	Heat exchangers
2	1/06/82	21.5	F	Reactor trip occurred while opening the MSIV due to steam generator low-low level.	A	9	Steam and power conversion (HB)	Heat exchangers
3	1/26/82	99.7	F	Unit shutdown due to condenser tube leaks.	A	1	Steam and power conversion (HC)	Heat exchangers
4	2/06/82	1,038.6	F	Unit shutdown due to turbine vibration.	A	1	Steam and power conversion (HA)	Turbines
5	4/09/82	122.2	F	Turbine manually tripped due to valve malfunction.	A	2	Steam and power conversion (HA)	Valves
6	5/16/82	5.5	F	Reactor trip from 2D steam generator high level caused by 2C feedwater pump.	A	3	Steam and power conversion (HB)	Pumps
7	6/05/82	52.9	F	Reactor trip from improperly opened drain valve on pressurizer transmitter.	G	3	Instrumentation and controls (IA)	Codes not applicable
8	6/25/82	87.5	F	Reactor trip from generator trip from arcing bushings on main transformer.	A	3	Steam and power conversion (HA)	Other components
9	7/08/82	24.8	F	Turbine/reactor trip. Manually shut down due to loss of vacuum from steam flow-feed flow mismatch.	A	2	Steam and power conversion (HA)	Codes not applicable
10	8/02/82	13.8	F	Reactor trip from 2C feedwater pump control problems.	A	3	Steam and power conversion (HH)	Pumps

Details of plant outages for Zion 2 (continued)

No.	Date	Duration (h)	Type	Description	Cause	Shutdown method	System involved	Component involved
11	9/07/82	964.7	F	Off line for turbine blade repair problems.	A	1	Steam and power conversion (HA)	Turbines
12	10/17/82	8.9	F	Steam flow—feed flow mismatch with low steam generator level while latching.	A	3	Steam and power conversion (HA)	Codes not applicable
13	10/18/82	3.3	F	Shutdown to adjust rod position indicator.	A	1	Reactor (RB)	Conrol rod drive mechanisms
14	10/18/82	22.2	F	Generator trip on reverse power from EHC trouble.	A	3	Steam and power conversion (HA)	Instrumentation and controls
15	10/22/82	69.6	F	Reactor trip—turbine trip on steam generator steam flow—feed flow mismatch with low steam generator level from EHC trouble.	A	3	Steam and power conversion (HB)	Instrumentation and controls
16	12/02/82	42.3	F	Reactor trip due to an electrical disturbance.	H	3	Electric power (EA)	Codes not applicable
17	12/04/82	7.5	F	Turbine trip—reactor trip due to feedwater control problems.	A	3	Steam and power conversion (HH)	Instrumentation and controls



DESIGN ELEC. RATING - 1040 MAX. DEPEND. CAP. - 1040 (100%) ZION 2

Appendix C

ABNORMAL OCCURRENCE CRITERIA

For this report, the following criteria for abnormal occurrence determinations were used. These criteria were promulgated in an NRC policy statement that was published in the *Federal Register*, Vol. 42, pp. 10950–52, February 24, 1977.

Abnormal occurrences are defined as events involving a major reduction in the degree of protection of the public health or safety. Such an event would involve a moderate or more severe impact on the public health or safety and would include but need not be limited to: (1) moderate exposure to, or release of, radioactive material licensed by or otherwise regulated by the NRC; (2) major degradation of essential safety-related equipment; or (3) major deficiencies in design, construction, use of, or in management controls for, licensed facilities or material.

Examples of the types of events that are evaluated in detail using these criteria follow.

For All Licensees

1. Exposure of the whole body of any individual to 25 rems or more of radiation; exposure of the skin of the whole body of any individual to 150 rems or more of radiation; or exposure of the feet, ankles, hands, or forearms of any individual to 375 rems or more of radiation [10 CFR Part 20.403(a) (1)]; or equivalent exposures from internal sources.
2. An exposure to an individual in an unrestricted area such that the whole-body dose received exceeds 0.5 rem in one calendar year [10 CFR Part 20.105(a)].
3. The release of radioactive material to an unrestricted area in concentrations that, if averaged over a period of 24 h, exceed 500 times the regulatory limit of Appendix B, Table II, 10 CFR Part 20 [10 CFR Part 20.403(b)].
4. Radiation or contamination levels in excess of design values on packages, or loss of confinement of radioactive material such as: (a) a radiation dose rate of 1000 mrems/h 3 ft from the surface of a package containing the radioactive material, or (b) release of radioactive material from a package in amounts greater than the regulatory limit [10 CFR Part 71.36(a)].
5. Any loss of licensed material in such quantities and under such circumstances that substantial hazard may result to persons in unrestricted areas.
6. A substantiated case of actual or attempted theft or diversion of licensed material or sabotage of a facility.
7. Any substantiated loss of special nuclear material or any substantiated inventory discrepancy that is judged to be significant relative to normally expected performance and caused by theft or diversion or by substantial breakdown of the accountability system.

8. Any substantiated breakdown of physical security or material control (i.e., access control, containment, or accountability systems) that significantly weakens the protection against theft, diversion, or sabotage.
9. An accidental criticality [10 CFR Part 70.52(a)].
10. A major deficiency in design, construction, or operation having safety implications requiring immediate remedial action.
11. Serious deficiency in management of procedural controls in major areas.
12. Series of events (where individual events are not of major importance), recurring incidents, and incidents with implications for similar facilities (generic incidents) that create major safety concern.

For Commercial Nuclear Power Plants

1. Exceeding a safety limit of license Technical Specifications [10 CFR Part 50.36(c)].
2. Major degradation of fuel integrity, primary coolant pressure boundary, or primary containment boundary.
3. Loss of plant capability to perform essential safety function such that a potential release of radioactivity in excess of 10 CFR Part 100 guidelines could result from a postulated transient or accident (e.g., loss of emergency core-cooling system, loss of control rod system).
4. Discovery of a major condition not specifically considered in the Safety Analysis Report or Technical Specification that requires immediate remedial action.
5. Personnel error or procedural deficiencies that result in loss of plant capability to perform essential safety functions such that a potential release of radioactivity in excess of 10 CFR Part 100 guidelines could result from a postulated transient or accident (e.g., loss of emergency core-cooling system, loss of control rod system).

For Fuel Cycle Licensees

1. A safety limit of license Technical Specifications is exceeded and a plant shutdown is required [10 CFR Part 50.36(c)].
2. A major condition not specifically considered in the Safety Analysis Report or Technical Specifications that requires immediate remedial action.
3. An event that seriously compromises the ability of a confinement system to perform its designated function.

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13. ABSTRACT (200 words or less)

This report is the ninth in a series of reports issued annually that summarizes the operating experience of nuclear power plants in commercial operation in the United States. Power generation statistics, plant outages, reportable occurrences, fuel element performance, and occupational radiation exposure for each plant are presented and discussed, and summary highlights are given. The report includes 1982 data from 72 plants; 24 boiling-water-reactor plants, 47 pressurized-water-reactor plants, and 1 high-temperature gas-cooled reactor plant.

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