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U.S. Nuclear Power Plant Operating Cost and Experience Summaries

Oak Ridge National Laboratory

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, DC 20555-0001

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U.S. Nuclear Power Plant Operating Cost and Experience Summaries

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Abstract

The *U.S. Nuclear Power Plant Operating Cost and Experience Summaries* (NUREG/CR-6577, Supp. 1) report has been prepared to provide historical operating cost and experience information on U.S. commercial nuclear power plants. Costs incurred after initial construction are characterized as annual production costs, which represent fuel and plant operating and maintenance expenses, and capital expenditures related to facility additions/modifications, which are included in the plant capital asset base. As discussed in the report, annual data for these two cost categories were obtained from publicly available reports and must be accepted as having different degrees of accuracy and completeness. Treatment of inconclusive and incomplete data is discussed.

As an aid to understanding the fluctuations in the cost histories, operations summaries for each nuclear unit are provided. The intent of these summaries is to identify important operating events; refueling, major maintenance, and other significant outages; operating milestones; and significant licensing or enforcement actions. Information used in the summaries is condensed from operating reports submitted by the licensees, the Nuclear Regulatory Commission (NRC) database for enforcement actions, and outage reports.

Contents

Acronyms

ABB	Asea Brown Boveri
ac	alternating current
ADS	automatic depressurization system
AFW	auxiliary feedwater
AIT	Augmented Inspection Team
ANO	Arkansas Nuclear One
APRM	average power range monitor
ASP	Accident Sequence Precursor
BWR	boiling water reactor
BWST	borated water storage tank
CEA	control element assembly
CRD	control rod drive
CS	core spray
CVCS	chemical and volume control system
CW	circulating water
dc	direct current
DG	diesel generator
ECCS	emergency core cooling system
EDG	emergency diesel generator
EFW	emergency feedwater
EHC	electrohydraulic control
EIA	Energy Information Administration
ESF	engineered safety feature
FA	fuel assembly
FERC	Federal Energy Regulatory Commission
FP	fire protection
FSAR	Final Safety Analysis Report
FW	feedwater
GE	General Electric Company
HEPA	high efficiency particulate absolute
HHSI	high head safety injection
HPCI	high pressure coolant injection
HPCS	high pressure core spray
HPI	high pressure injection
HPSI	high pressure safety injection
HX	heat exchanger
I&C	instrumentation and control
INEEL	Idaho National Engineering and Environmental Laboratory
IPE	individual plant examination
LBLOCA	large-break loss-of-coolant accident
LCO	limiting condition for operation
LER	licensee event report
LOCA	loss-of-coolant accident
LOSP	loss of off-site power
LPCS	low pressure core spray
LPSI	low pressure safety injection
LWR	light water reactor
MDC	maximum dependable capacity
MFW	main feedwater
MOV	motor-operated valve
MS	main steam
MSIV	main steam isolation valve
MSL	main steam line
MSR	moisture separator reheater
MSVR	main steam valve room
MVA	megavolt ampere
MWe	megawatt (electric)
NPSH	net positive suction head
NRC	Nuclear Regulatory Commission
ORNL	Oak Ridge National Laboratory
PORV	power-operated relief valve
psig	pounds per square inch gauge
PVC	polyvinyl chloride
PWR	pressurized water reactor
QA	quality assurance
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RO	reactor operator
RPS	reactor protection system
RPV	reactor pressure vessel
RRCS	reactor recirculation cooling system
RV	reactor vessel
RWCU	reactor water cleanup (system)
RWST	reactor water storage tank
SBGT	standby gas treatment
SBLC	standby liquid control
SBLOCA	small-break loss-of-coolant accident
SCSS	Sequence Coding and Search System
SG	steam generator
SGTR	steam generator tube rupture
SGTS	standby gas treatment system
SI	safety injection
SRO	senior reactor operator
SRV	safety relief valve
SW	service water
TDAFW	turbine-driven auxiliary feedwater
TS	Technical Specification
UE	Unusual Event
UPS	uninterruptible power supply
USQ	unreviewed safety question
W	Westinghouse

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The authors wish to thank Debbie Queener for development of the database application for collection of the operating experience information and preparation of the database report formats. The authors also wish to thank Linda Dockery for her support in compiling the database reports and organizing this summary document in NUREG format. In addition, the authors express their appreciation to Robert Wood, Technical Monitor, Division of Regulatory Improvement Programs, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, for his insight and guidance.

Glossary

Nameplate rate	The nameplate power designation [gross megawatt (electrical) (MWe)] of the generator in megavolt amperes (MVA) multiplied by the nameplate rating power factor of the generator. Note: The nameplate rating of the generator may not be indicative of the maximum or dependable capacity, because other items of equipment of lesser rating (e.g., the turbine) may limit unit output.
MDC	Maximum dependable capacity (MWe)
MDC net (MWe)	MDC gross output less the normal station service loads (MWe)
Cumulative availability factor	$\frac{\text{Unit available hours} \times 100}{\text{lifetime period hours}}$
Cumulative capacity factor (MDC Net)	$\frac{\text{Net electrical energy generated} \times 100}{\text{lifetime hours} \times \text{MDC net}}$
Cumulative forced outage rate	$\frac{\text{Cumulative forced outage hours} \times 100}{\text{Cumulative unit service hours + forced outage hours}}$
Appendix R (of 10 CFR 50)	NRC's Fire Protection (FP) Regulations
Production cost	Costs for operations and maintenance (O&M) and fuel expense.
Capital additions cost	Costs for major replacement items, such as a steam generator or turbine, or costs for refurbishment of equipment, such as replacement of blades in a turbine. The economic basis for these costs are detailed in the *Introduction* (pages 1–2).

Introduction

Compiled by the Oak Ridge National Laboratory (ORNL), this report presents results of an analysis of historical operating cost and experience information on U.S. commercial nuclear power plants. The work was sponsored by the NRC's Office of Nuclear Reactor Regulation's Division of Regulatory Improvement Programs and provides a supplement to the operating cost and experience information prepared for and submitted to the NRC in October 1997 and published in February 1998 (NUREG/CR-6577).

This report summarizes costs and operating experience for all operational U.S. nuclear plants during 1997–1999. Also included are tabular data for 12 nuclear units that have ceased operations. Historical operations and cost data for units not included in this report can be found in the 1998 publication of this report. The U.S. operational nuclear plants detailed in this report are shown in Table 1, which contains unit summary information through December 1999. Table 2 provides summary details for units that have been permanently shut down or decommissioned. In the cost and experience section of this report, graphs of historical annual production costs (i.e., operations, maintenance, and fuel costs) and capital additions costs are presented in 1999 dollars followed by a unit-by-unit operating experience summary. In the majority of cases, cost data are only available for a total plant (rather than unit) basis. In a few cases where each unit has a substantially different ownership arrangement, cost data are available on a unit-by-unit basis. Where possible, unit-by-unit cost histories have been provided.

The sources of cost data for the plots are the Federal Energy Regulatory Commission (FERC) Form 1 for private utility companies and the Energy Information Administration (EIA) Form 412 for public utilities. Annual data submissions are required by the utilities; these were obtained from computerized databases from the Utility Data Institute. There are cases where data for all years were not available. The missing data are noted by a discontinuous line on the graphs. Those plants with incomplete cost histories include:

Cooper—1999
Hope Creek—1996
Limerick—1997
Pilgrim—1999
Three Mile Island—1999

Note that capital additions costs reported in the utility filings are based on the current total capitalized value for the plant. The change in the capital value reported from one year to the next is the only source of publicly available data that can be analyzed to determine capital additions. There are, however, limits to the accuracy of this approach. Reports of total capital value include all adjustments to the capital base, including any decommissioning or capital write-offs. As such, the annual capital additions represent net values of both additions and reductions in the capital asset base. As a result, the change in capital value for some years is a negative value. For the purposes of this report, years with negative capital change are shown as zero capital additions cost. Because of this net reporting, capital additions are not possible to discern in a year in which a new unit is placed into service at a multiunit site that is reported on a total plant basis. Finally, some utilities have sold part of their capital asset base to others in a sale/lease arrangement. In several cases, the reduced capital asset value that is reported precludes determining a true capital additions cost. In each of these scenarios, the capital additions cost has been shown on the charts as a zero value.

The nuclear power plant operating experience summaries contained in this document were prepared from several sources. Plant outage data were extracted from the monthly operating reports compiled by the Idaho National Engineering and Environmental Laboratory (INEEL) for the period from January 1997 through December 1999. NRC-imposed fines or civil penalties were obtained from the NRC database for enforcement actions. Significant events were extracted from NRC Daily Events reported in compliance with 10 CFR 50.72, and operational events were taken from the NRC Sequence Coding and Search System (SCSS) licensee event reports (LERs) and ORNL's Accident Sequence Precursor (ASP) database. The intent of these summaries is to identify important operating events, major refueling and maintenance outages, operating milestones, and significant licensing or enforcement actions. A significant outage is defined as an outage that represents approximately one percent annual availability factor lost. Note that if the month that an event began is the same as the month it ended, the date is only listed one time. Events identified for analysis typically included the following:

- unexpected core damage initiators loss-of-offsite power (LOSP), steam generator tube rupture (SGTR), and small-break loss-of-coolant accidents (LOCA);
- all events in which a reactor trip was demanded and a safety-related component failed;
- all support system failures, including failures in cooling water systems, instrument air, instrumentation and control, and electric power systems;
- any event in which two or more failures occurred;
- any event or operating condition that was not predicted or that proceeded differently from the plant design basis; and
- any event that, based on the reviewers' experience, could have resulted in or significantly affected a chain of events leading to potential severe core damage.

Events determined to be significant were summarized in this report.

Comments on the operating cost and experience information in this report should be submitted to Mr. Robert Wood, Office of Nuclear Reactor Regulation, U.S. NRC, Washington, D.C. 20555.

Table 1. Operational units summary

Docket No.	Plant name	Nameplate rating (MWe)	MDC net (MWe)	Cumulative availability factor	Cumulative capacity factor (MDC net)	Cumulative forced outage rate	Construction permit date	Operating license date	Commercial operation date	License expiration date
313	Arkansas Nuclear One 1	903	836	74.9	68.7	8.9	12/6/68	5/21/74	12/19/74	5/20/14
368	Arkansas Nuclear One 2	943	858	77.9	77.4	8.6	12/6/72	9/1/78	3/26/80	7/17/18
334	Beaver Valley 1	923	810	63.9	59.4	17.4	6/26/70	7/2/76	10/1/76	1/29/16
412	Beaver Valley 2	923	820	81.0	74.8	12.0	5/3/74	8/14/87	11/17/87	5/27/27
456	Braidwood 1	1175	1120	79.0	75.2	5.7	12/31/75	7/2/87	7/29/88	10/17/26
457	Braidwood 2	1175	1120	84.6	80.5	3.7	12/31/75	5/20/88	10/17/88	12/18/27
259	Browns Ferry 1	1152	1065	N/A	N/A	N/A	5/10/67	12/20/75	8/1/74	12/20/13
260	Browns Ferry 2	1152	1065	71.1	63.7	12.7	5/10/67	8/2/74	3/1/75	6/28/14
296	Browns Ferry 3	1152	1065	68.3	63.8	13.9	7/31/68	8/18/76	3/1/77	7/2/16
325	Brunswick 1	867	767	63.6	58.2	11.5	2/7/70	11/12/76	3/18/77	9/8/16
324	Brunswick 2	867	754	64.0	56.1	9.3	2/7/70	12/27/74	11/3/75	12/27/14
454	Byron 1	1175	1105	80.7	75.0	2.1	12/31/75	2/14/85	9/16/85	10/31/24
455	Byron 2	1175	1105	87.3	80.3	1.9	12/31/75	1/30/87	8/21/87	11/6/26
483	Callaway	1236	1125	87.5	85.1	2.1	4/16/76	10/18/84	12/19/84	10/18/24
317	Calvert Cliffs 1	918	835	71.4	71.3	7.8	7/7/69	7/31/74	5/8/75	7/31/14
318	Calvert Cliffs 2	911	840	74.8	73.2	4.9	7/7/69	11/30/76	4/1/77	8/31/16
413	Catawba 1	1305	1129	78.0	77.0	6.8	8/7/75	1/17/85	6/29/85	12/6/24
414	Catawba 2	1305	1129	82.7	78.0	8.0	8/7/75	5/15/86	8/19/86	2/24/26
461	Clinton	985	930	62.3	54.1	8.4	2/24/76	4/17/87	11/24/87	9/29/26
445	Comanche Peak 1	1161	1150	83.1	77.7	3.3	12/19/74	4/17/90	8/13/90	2/8/30
446	Comanche Peak 2	1161	1150	83.7	79.5	4.0	12/19/74	4/6/93	8/3/93	2/2/33
315	(D.C.) Cook 1	1152	1000	72.7	62.8	16.4	3/25/69	10/25/74	8/28/75	10/25/14
316	(D.C.) Cook 2	1133	1060	66.0	55.9	23.9	3/25/69	12/23/77	7/1/78	12/23/17

Table 1 (continued)

Docket No.	Plant name	Nameplate rating (MWe)	MDC net (MWe)	Cumulative availability factor	Cumulative capacity factor (MDC net)	Cumulative forced outage rate	Construction permit date	Operating license date	Commercial operation date	License expiration date
298	Cooper	836	764	74.5	65.8	7.2	6/4/68	1/18/74	7/1/74	1/18/14
302	Crystal River 3	890	818	63.4	61.3	20.3	9/25/68	1/28/77	3/13/77	12/3/16
346	Davis-Besse	925	873	67.0	63.3	15.2	3/24/71	4/22/77	7/31/78	4/22/17
275	Diablo Canyon 1	1137	1073	84.8	81.8	3.0	4/23/68	11/2/84	5/7/85	9/22/21
323	Diablo Canyon 2	1164	1087	85.6	83.3	3.5	12/9/70	8/26/85	3/13/86	4/26/25
237	Dresden 2	840	772	69.5	58.7	13.2	1/10/66	2/20/91	6/9/70	1/10/06
249	Dresden 3	840	773	67.4	57.6	13.8	10/14/66	3/2/71	11/16/71	1/12/11
331	Duane Arnold	566	520	75.1	66.1	9.1	6/22/70	2/22/74	2/1/75	2/21/14
348	(Joseph M.) Farley 1	860	812	80.1	74.9	5.1	8/16/72	6/25/77	12/1/77	6/25/17
364	(Joseph M.) Farley 2	860	822	85.7	79.5	3.2	8/16/72	3/31/81	7/30/81	3/31/21
341	Fermi 2	1179	1085	66.4	62.3	19.5	9/26/72	7/15/85	1/23/88	3/20/25
333	(James A.) Fitzpatrick	883	762	70.1	63.9	10.8	5/20/70	10/17/74	7/28/75	10/17/14
285	Fort Calhoun 1	502	478	78.2	70.7	3.8	6/7/68	8/9/73	9/26/73	8/9/13
244	Ginna (Robert E.)	517	470	79.4	75.3	5.1	4/25/66	12/10/84	7/1/70	9/18/09
416	Grand Gulf 1	1373	1179	80.6	75.9	5.7	9/4/74	11/1/84	7/1/85	6/16/22
400	(Shearon) Harris 1	951	860	83.5	82.2	3.1	1/27/78	1/12/87	5/2/87	10/14/26
321	(Edwin I.) Hatch 1	850	805	75.4	64.7	8.9	9/30/69	10/13/74	12/31/75	8/6/14
366	(Edwin I.) Hatch 2	850	809	77.1	65.5	5.9	12/27/72	6/13/78	9/5/79	6/13/18
354	Hope Creek 1	1170	1031	82.4	81.7	4.0	11/4/74	7/25/86	12/20/86	4/11/26
247	Indian Point 2	1310	951	68.1	62.2	11.4	10/14/66	9/28/73	8/1/74	9/28/13
286	Indian Point 3	1013	965	55.5	52.2	26.2	8/13/69	4/5/76	8/30/76	12/15/15
305	Kewaunee	560	511	83.4	82.1	1.7	8/6/68	12/21/73	6/16/74	12/21/13
373	La Salle County 1	1146	1036	60.8	58.5	13.1	9/10/73	8/13/82	1/1/84	5/17/22
374	La Salle County 2	1146	1036	63.7	58.4	19.3	9/10/73	3/23/84	10/19/84	12/26/23
352	Limerick 1	1160	1105	82.8	74.7	4.0	6/19/74	8/8/85	2/1/86	10/26/24

Table 1 (continued)

Docket No.	Plant name	Nameplate rating (MWe)	MDC net (MWe)	Cumulative availability factor	Cumulative capacity factor (MDC net)	Cumulative forced outage rate	Construction permit date	Operating license date	Commercial operation date	License expiration date
353	Limerick 2	1162	1115	90.2	81.9	3.2	6/19/74	8/25/89	1/8/90	6/22/29
369	McGuire 1	1305	1129	72.8	70.6	11.0	2/23/73	7/8/81	12/1/81	6/21/21
370	McGuire 2	1305	1129	77.7	79.3	6.4	2/23/73	5/27/83	3/1/84	3/3/23
336	Millstone 2	909	871	59.5	60.0	19.3	12/11/70	9/30/75	12/26/75	7/31/15
423	Millstone 3	1253	1137	62.1	60.5	28.8	8/9/74	1/31/86	4/23/86	11/25/25
263	Monticello	577	544	80.4	71.3	4.4	6/19/67	1/9/81	6/30/71	9/8/10
220	Nine Mile Point 1	642	565	65.9	65.3	21.9	4/12/65	12/26/74	12/1/69	8/22/09
410	Nine Mile Point 2	1259	1105	73.3	68.5	22.4	6/24/74	7/2/87	3/11/88	10/31/26
338	North Anna 1	994	893	76.5	73.9	7.5	2/19/71	4/1/78	6/6/78	4/1/18
339	North Anna 2	979	897	83.3	80.7	4.7	2/19/71	8/21/80	12/14/80	8/21/20
269	Oconee 1	934	846	75.4	72.9	9.9	11/6/67	2/6/73	7/15/73	2/6/13
270	Oconee 2	934	846	77.8	74.5	9.7	11/6/67	10/6/73	9/9/74	10/6/13
287	Oconee 3	934	846	76.6	75.1	10.0	11/6/67	7/19/74	12/16/74	7/19/14
219	Oyster Creek	550	619	68.4	63.2	9.1	12/15/64	7/2/91	12/1/69	12/15/09
255	Palisades	812	730	57.6	54.4	25.2	3/14/67	2/21/91	12/31/71	3/14/07
528	Palo Verde 1	1403	1221	69.8	69.5	8.6	5/25/76	6/1/85	1/28/86	12/31/24
529	Palo Verde 2	1403	1221	74.0	74.1	3.8	5/25/76	4/24/86	9/19/86	12/9/25
530	Palo Verde 3	1403	1230	79.1	78.8	3.4	5/25/76	11/25/87	1/8/88	3/25/27
277	Peach Bottom 2	1221	1093	66.3	60.2	10.0	1/31/68	12/14/73	7/5/74	8/8/13
278	Peach Bottom 3	1221	1093	66.9	60.2	10.1	1/31/68	7/2/74	12/23/74	7/2/14
440	Perry 1	1250	1166	71.4	72.0	7.9	5/3/77	11/13/86	11/18/87	3/18/26
293	Pilgrim 1	678	670	63.0	56.8	10.5	8/26/68	9/15/72	12/1/72	6/8/12
266	Point Beach 1	524	485	80.8	71.9	4.6	7/19/67	10/5/70	12/21/70	10/5/10
301	Point Beach 2	524	485	83.3	75.5	2.3	7/25/68	3/8/73	10/1/72	3/8/13
282	Prairie Island 1	593	513	85.2	81.0	4.6	6/25/68	4/5/74	12/16/73	8/9/13

Table 1 (continued)

Docket No.	Plant name	Nameplate rating (MWe)	MDC net (MWe)	Cumulative availability factor	Cumulative capacity factor (MDC net)	Cumulative forced outage rate	Construction permit date	Operating license date	Commercial operation date	License expiration date
306	Prairie Island 2	593	512	87.5	83.3	2.9	6/25/68	10/29/74	12/21/74	10/29/14
254	Quad Cities 1	828	769	73.4	64.9	7.3	2/15/67	12/14/72	2/18/73	12/14/12
265	Quad Cities 2	828	769	70.7	62.7	10.5	2/15/67	12/14/72	3/10/73	12/14/12
458	River Bend 1	936	936	73.3	69.6	10.7	3/25/77	11/20/85	6/16/86	8/29/25
261	(H. B.) Robinson 2	739	683	71.5	68.7	12.5	4/13/67	9/23/70	3/7/71	7/31/10
272	Salem 1	1170	1106	55.3	52.5	29.3	9/25/68	12/1/76	6/30/77	8/13/16
311	Salem 2	1170	1106	55.5	52.6	30.0	9/25/68	5/20/81	10/13/81	4/18/20
361	San Onofre 2	1127	1070	76.3	76.8	4.5	10/18/73	9/7/82	8/8/83	10/18/13
362	San Onofre 3	1127	1080	79.0	77.8	3.9	10/18/73	9/16/83	4/1/84	10/18/13
443	Seabrook	1197	1158	56.4	57.8	6.9	7/7/76	3/15/90	8/19/90	10/17/26
327	Sequoyah 1	1221	1117	58.4	59.1	26.5	5/27/70	9/17/80	7/1/81	9/17/20
328	Sequoyah 2	1221	1117	63.7	62.8	25.7	5/27/70	9/15/81	6/1/82	9/15/21
498	South Texas Project 1	1311	1251	70.9	71.6	16.7	12/22/75	3/22/88	8/25/88	8/20/27
499	South Texas Project 2	1311	1251	72.5	72.6	16.2	12/22/75	3/28/89	6/19/89	12/15/28
335	St Lucie 1	850	839	77.3	75.8	4.6	7/1/70	3/1/76	12/21/76	3/1/16
389	St Lucie 2	850	839	84.1	83.1	5.3	5/2/77	6/10/83	8/8/83	4/6/23
395	Summer (Virgil C.)	900	945	81.5	74.1	3.6	3/21/73	11/12/82	1/1/84	8/6/22
280	Surry 1	848	801	71.0	65.4	13.8	6/25/68	5/25/72	12/22/72	5/25/12
281	Surry 2	848	801	69.5	65.5	11.0	6/25/68	1/29/73	5/1/73	1/29/13
387	Susquehanna 1	1165	1090	78.5	74.4	6.6	11/2/73	11/12/82	6/8/83	7/17/22
388	Susquehanna 2	1168	1094	83.6	79.2	4.8	11/2/73	6/27/84	2/12/85	3/23/24
289	Three Mile Island 1	872	786	61.6	63.3	30.2	5/18/68	4/19/74	9/2/74	4/19/14
250	Turkey Point 3	760	693	69.2	65.6	9.2	4/27/67	7/19/72	12/14/72	7/19/12
251	Turkey Point 4	760	693	68.7	65.8	8.6	4/27/67	4/10/73	9/7/73	4/10/13
271	Vermont Yankee	540	510	81.4	77.2	4.5	12/11/67	2/28/73	11/30/72	3/21/12

Table 1 (continued)

Docket No.	Plant name	Nameplate rating (MWe)	MDC net (MWe)	Cumulative availability factor	Cumulative capacity factor (MDC net)	Cumulative forced outage rate	Construction permit date	Operating license date	Commercial operation date	License expiration date
425	Vogtle 1 (Alvin W.)	1215	1162	86.4	84.3	3.7	6/28/74	3/16/87	6/1/87	1/16/27
425	Vogtle 2 (Alvin W.)	1215	1162	89.2	86.6	1.7	6/28/74	3/31/89	5/20/89	2/9/29
397	Washington Nuclear 2	1199	1107	71.9	61.2	9.4	3/19/73	4/13/84	12/13/84	12/20/23
382	Waterford 3	1200	1075	83.7	82.3	4.4	11/14/74	3/16/85	9/24/85	12/18/24
390	Watts Bar 1	1270	1117	88.5	87.0	1.8	1/23/73	2/7/96	5/27/96	11/9/35
482	Wolf Creek 1	1236	1163	82.1	80.5	3.0	5/31/77	6/4/85	9/3/85	3/11/25

N/A= not available

Note: See *Glossary* (page xi) for definitions of "cumulative capacity factor" and "cumulative availability factor."

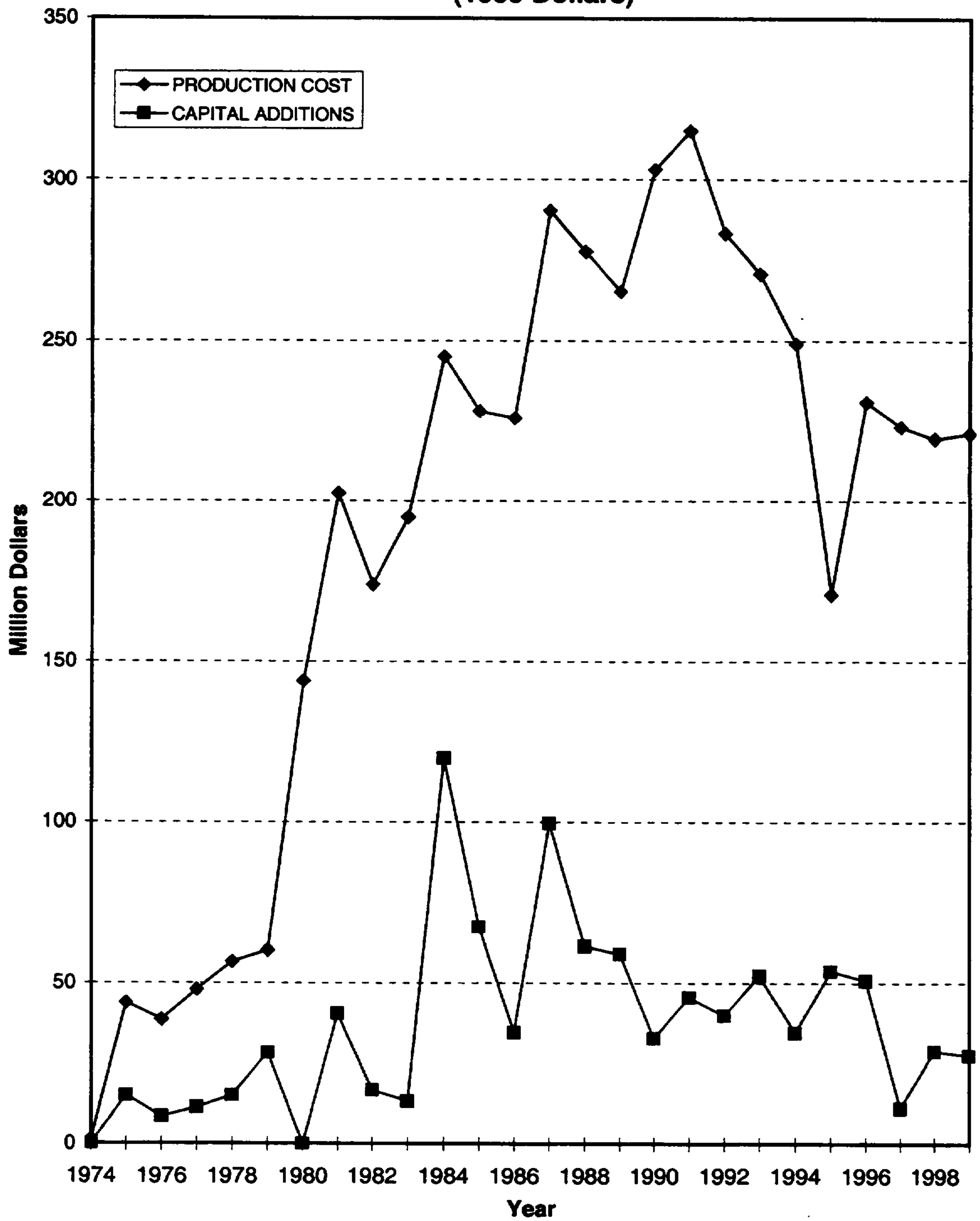
Table 2. Permanently shutdown units

Docket No.	Plant name	Nameplate rating (MWe)	MDC net (MWe)	Cumulative availability factor	Cumulative capacity factor (MDC net)	Cumulative forced outage rate	Construction permit date	Operating license date	Commercial operation date	License expiration date
155	Big Rock Point	75	67	71.3	62.1	8.6	5/31/60	8/30/62	3/29/63	5/3/00
213	Haddam Neck	600	560	76.8	72.8	6.3	5/26/64	12/27/74	1/1/68	6/29/07
309	Maine Yankee	920	860	73.1	67.8	9.1	10/21/68	6/29/73	12/28/72	10/21/08
245	Millstone 1	662	641	69.1	65.4	20.7	5/19/66	10/31/86	3/1/71	10/6/10
312	Rancho Seco	963	873	47.4	37.5	42.7	10/11/68	8/16/74	4/17/75	Decommissioned
206	San Onofre 1	456	436	57.7	52.4	17.9	3/2/64	3/27/67	1/1/68	Decommissioned
320	Three Mile Island 2	871	808	0.0	0.0	0.0	11/4/69	2/8/78	12/30/78	Decommissioned
344	Trojan	1216	1095	61.2	54.2	13.7	2/8/71	11/21/75	5/20/76	Decommissioned
29	Yankee-Rowe	185	167	77.7	73.7	4.9	11/4/57	6/23/61	7/1/61	Decommissioned
295	Zion 1	1085	1040	63.0	52.1	15.8	12/26/68	10/19/73	12/31/73	4/6/13
304	Zion 2	1085	1040	65.0	53.8	13.2	12/26/68	11/14/73	9/17/74	4/14/13

U. S. NUCLEAR POWER PLANT
COST AND EXPERIENCE SUMMARIES

ARKANSAS NUCLEAR ONE
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**ARKANSAS NUCLEAR ONE 1**	Nameplate Rating (MWe):	**903**
Location:	**Pope County, Arkansas**	MDC Net MWe:	**836**
Operator:	**Energy Operations Inc.**	Cumul. Avail. Factor:	**74.9**
Type:	**Babcock & Wilcox PWR**	Cumul. Cap. Factor (MDC Net):	**68.7**
Construction Permit:	**12/6/68**	Cumul. Forced Outage Rate:	**8.9**
Operating License:	**5/21/74**	3-Year Avg. Cap. Factor (MDC Net):	**91.9**
Commercial Oper. Date:	**12/19/74**	License Expiration:	**5/20/14**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
May 1997		The NRC proposed and the licensee paid a $50,000 fine based on a Severity Level III violation. The licensee failed to maintain an adequate lube oil collection system for the reactor coolant pumps (RCPs), which resulted in oil accumulation on fibrous insulation. This accumulation created the potential for a fire. In two other instances, the licensee also failed to take prompt action to identify and correct conditions that could have resulted in a fire.
Jan 1998		The unit was taken off-line and shut down for 8 d when an excessive amount of debris overwhelmed the intake structure and caused damage to the traveling screens. The screens were repaired, and additional debris grates were installed in the intake bay further upstream of the intake structure.
Mar 1998	May 1998	The unit was taken off-line and shut down for 44 d for the 14th maintenance and refueling outage.
Dec 1998		The reactor at Arkansas Nuclear One, Unit 1 (ANO1) was tripped twice in 4 d. Each time a heavy fish (shad) run in the intake bay caused the intake screens to the plant to become clogged. Historically, ANO has experienced shad runs at this time of year. The plant was at 100% power on December 25 when the first shad run began, followed by a plant trip. Operations personnel were expecting this shad run based on the current lake conditions. After recovering from the trip, a startup was begun, and the plant was at 13% power on December 28 when it experienced its second shad run. The circulating water (CW) pumps were cycled in an effort to keep the intake traveling screens clean. However, after about 30 min, only one CW pump was running, and a plant shutdown commenced. At 8% power, the screen wash differential pressure increased above allowable limits, and the plant was tripped. Although both ANO1 and ANO2 share a common intake structure, Unit 2 was not affected by either event and remained at 100% power. Unit 2 requires less CW flow than Unit 1 because Unit 2 has a cooling tower and the shad run was more concentrated on the Unit 1 side of the intake structure.

Dec 1998	Jan 1999	After modifications were made to repair the traveling screens and improve their performance, the unit was placed back on-line. Another significant fish intrusion occurred that forced the unit to be taken off-line due to degrading CW conditions. Nets are being installed at the intake mouth to deter future intrusion.
Sep 1999	Oct 1999	During the planned shutdown for the 15th maintenance and refueling outage, a RCP experienced reverse rotation when it was secured. The plant abnormal operating procedures require the operators to secure the other RCPs. As a result of the loss of all the RCPs, the emergency feedwater (EFW) system automatically started, and natural circulation was initiated. The unit was shut down for 30 d for this outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

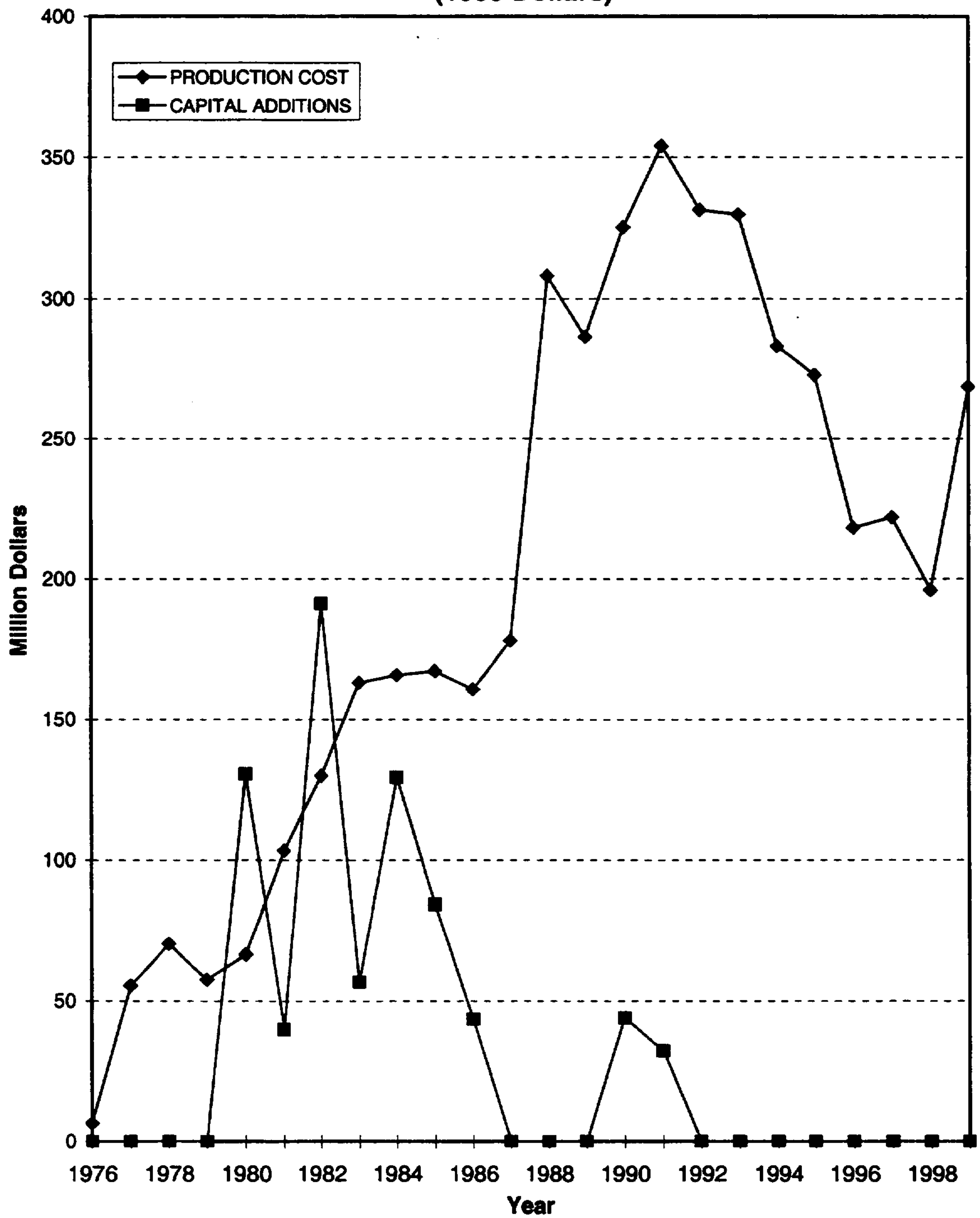
Unit:	**ARKANSAS NUCLEAR ONE 2**	Nameplate Rating (MWe):	**943**
Location:	**Pope County, Arkansas**	MDC Net MWe:	**858**
Operator:	**Entergy Operations Inc.**	Cumul. Avail. Factor:	**77.9**
Type:	**Combustion Engineering PWR**	Cumul. Cap. Factor (MDC Net):	**77.4**
Construction Permit:	**12/6/72**	Cumul. Forced Outage Rate:	**8.6**
Operating License:	**9/1/78**	3-Year Avg. Cap. Factor (MDC Net):	**89.0**
Commercial Oper. Date:	**3/26/80**	License Expiration:	**7/17/18**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
May 1997	Jun 1997	The unit was taken off-line and shut down for 31 d for the 12th refueling and maintenance outage.
Feb 1998	Mar 1998	The unit was taken off-line and shut down for 25 d for a planned steam generator (SG) tube inspection outage.
May 1998		The plant was proceeding with a planned shut down from 100% power due to a massive tube leak in the main condenser. While in hot standby, the EFW system was automatically actuated and ran for 30 min.
Jan 1999	Feb 1999	The unit was taken off-line and shut down for 48 d for the 13th refueling and maintenance outage.
Feb 1999		On the 25th day of the refueling outage, the operators were draining the canal to the refueling water tank using two low-pressure safety injection (LPSI) pumps to prepare for reactor head reassembly. When water level in the vessel was at 105 in., the operators noticed a rapid level decrease. The operators stopped one of the LPSI pumps and began closing the refueling water tank isolation valve. The water level dropped almost 50 in. before stopping at 56 in., which is below the reduced-inventory operations entry level of 65 in. The level was restored within 7 min.
Nov 1999		The unit was taken off-line and shut down for 17 d for a planned midcycle SG inspection outage.

BEAVER VALLEY
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**BEAVER VALLEY 1**	Nameplate Rating (MWe):	**923**
Location:	**Beaver County, Pennsylvania**	MDC Net MWe:	**810**
Operator:	**FirstEnergy Nuclear Operating Co.**	Cumul. Avail. Factor:	**63.9**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**59.4**
Construction Permit:	**6/26/70**	Cumul. Forced Outage Rate:	**17.4**
Operating License:	**7/2/76**	3-Year Avg. Cap. Factor (MDC Net):	**60.8**
Commercial Oper. Date:	**10/1/76**	License Expiration:	**1/29/16**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	Apr 1997	Both Beaver Valley Units 1 and 2 were operating at 100% power on March 19, 1997, when each unit tripped due to a load rejection. Electrical fault protection signals from a 345-kV bus in the onsite switchyard tripped both main generators and opened all four generator output breakers. Emergency diesel generator (EDG) 1-1 automatically started but did not load onto its respective bus; EDG 1-2 did not start and was declared inoperable. The "B" auxiliary feedwater (AFW) header flow rate for the "B" SG on Unit 2 was declared inoperable. Unit 1 generator output breakers opened unexpectedly when a bus backup timer relay in the 345-kV distribution system timed out after a phase-to-ground fault on a transmission line in the Ohio Edison System. Subsequent to the reactor trip, the unit was cooled down to cold shutdown conditions to repair a secondary-side leak at both the "A" and "C" SG handhole flanges. The unit remained in cold shutdown to repair a body-to-bonnet flange joint leak on the "A" reactor coolant loop cold-leg isolation valve. The unit was off-line and shut down for 25 d for the forced maintenance outage.
Apr 1997		The NRC proposed and the licensee paid a $100,000 fine for two Severity Level III violations. The first violation was for deficiencies associated with inadequate control of leak sealant repairs on the Unit 2 reactor head vent system. The second violation was for failing to correct an adverse condition to quality at Unit 1, which involved reactor operation with two of three pressurizer power-operated relief valve (PORV) block valves shut for 13 years.
Jun 1997	Jul 1997	The unit was taken off-line and shut down for 34 d for a forced outage to resolve seismic qualification concerns with the main feedwater (MFW) flow transmitters. The unit remained shut down to complete modifications to several pipe supports on the chemical and volume control system (CVCS) normal and excess letdown lines.

Sep 1997	Jan 1998	The unit was taken off-line and shut down for 115 d for the 12th refueling and maintenance outage. The refueling and maintenance outage was originally scheduled for 45 d, but the outage was extended to evaluate and to correct design deficiencies with the original plant piping supports in small-bore pipes having a diameter of 2 in. or less in a variety of systems in the plant. The unit remained shut down and in the cooldown mode to inspect, evaluate, and replace 7300/7100 process rack components due to potential configuration control issues related to their quality assurance (QA) Category 2 evaluation.
Dec 1997		On December 8, the Beaver Valley licensee determined that the high-head safety injection (HHSI) systems at Beaver Valley 1 and 2 were susceptible to failure due to accumulation of hydrogen in the HHSI pump suction lines. In August 1997, Unit 2 HHSI pump "C" was determined to be gas bound. During a subsequent surveillance test on September 12, the pump failed to meet its required performance criteria and was removed from service until October 4. Both the rotating assembly and the casing were replaced; the pump shaft was found to be cracked. Apparently abnormal impact loading was caused by ingestion of gas voids that accumulated in the suction piping during pump starts. The hydrogen gas was stripped from the solution by the miniflow recirculation line flow-restricting orifice.
Jan 1998	Aug 1998	The unit was taken off-line and shut down for 196 d for a forced outage. The unit was originally removed from service to test several valves required to service safety-related equipment in accordance with plant technical specifications (TS). However, the unit remained shut down in mode 5, and the reactor coolant system (RCS) was depressurized to permit modifications to the nitrogen supply subsystem for the PORVs. On August 11, during an attempted startup, the plant experienced an automatic reactor trip due to a low "A" SG level coincident with a steam flow greater than feed flow.
Feb 1998		The NRC proposed and the licensee paid a $55,000 fine for failing to prevent repeated occurrences of gas binding of an HHSI pump.
Apr 1998		The plant was in cold shut down on April 27, when a gas void was discovered between the low-head safety injection (SI) pump and the charging/HHSI pump suction.
Feb 1999		The unit was taken off-line and shut down for 8 d for a forced maintenance outage. Startup from the forced outage was delayed when four condenser steam dump valves failed to open due to wear in their balance chambers.
Apr 1999		The unit was taken off-line and shut down for 25 d for a planned outage to complete required surveillance testing in accordance with the TS. The planned 16-d surveillance outage was extended because of the required repair of a reactor plant component cooling water system leak. The outage was further extended to cleanup and test the main unit generator seal oil system prior to startup.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**BEAVER VALLEY 2**	Nameplate Rating (MWe):	**923**
Location:	**Beaver County, Pennsylvania**	MDC Net MWe:	**820**
Operator:	**FirstEnergy Nuclear Operating Co.**	Cumul. Avail. Factor:	**81.0**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**74.8**
Construction Permit:	**5/3/74**	Cumul. Forced Outage Rate:	**12.0**
Operating License:	**8/14/87**	3-Year Avg. Cap. Factor (MDC Net):	**63.4**
Commercial Oper. Date:	**11/17/87**	License Expiration:	**5/27/27**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jan 1997		The unit was taken off-line and shut down for 5 d to investigate a reactor trip caused by a turbine generator trip, which was initiated by spurious operation of a main transformer ground protection relay.
Mar 1997		Unit 2 generator output breakers opened unexpectedly when a bus backup timer relay in the 345 kV distribution system timed out after a phase-to-ground fault on a transmission line in the Ohio Edison System. Subsequent to the reactor trip, the unit was cooled down to cold shutdown conditions to repair and modify the AFW to SG-nozzle check valves. The unit was off-line and shut down for 10 d for this forced maintenance outage.
Apr 1997		The NRC proposed and the licensee paid a $100,000 fine for two Severity Level III violations. The first violation was for deficiencies associated with inadequate control of leak sealant repairs on the Unit 2 reactor head vent system. The second violation was for failing to correct an adverse condition to quality at Unit 1, which involved reactor operation with two of three pressurizer PORV block valves shut for 13 years.
Jul 1997	Jul 1997	The unit was taken off-line, shut down and cooled down for forced maintenance outage for 13 d to repair the seals on both the "A" and "C" RCPs. The seal leakage was due to particulate material deposited on the seals. The seals were replaced.
Dec 1997	Sep 1998	The unit was taken off-line and shut down for 284 d for forced maintenance outage. Initially, the unit was shut down to make modifications to the control room emergency pressurization system because of vulnerabilities in meeting some single active failure design criteria. The unit remained shut down to replace and test three potentially degraded cells on battery 2-1. The unit remained shut down to resolve several TS compliance issues; to permit repairs to leaking PORVs; and to complete modifications, repair, and testing of Atwood & Morrill weighted-arm check valves.

Feb 1998		The NRC proposed and the licensee paid a $55,000 fine for failing to prevent repeated occurrences of gas binding of an HHSI pump.
Feb 1999	Apr 1999	The unit was taken off-line and shut down for 44 d for the seventh planned refueling and maintenance outage.
Mar 1999		The plant was at cold shutdown on March 29 when the unit experienced a partial LOSP to a 4160-V bus. EDG 2-1 automatically started and reenergized the bus. The unit station service transformer supply breaker to the bus had tripped open.
Jul 1999		Beaver Valley Unit 2 was operating at 94% power on July 16, when the emergency 4-kV bus-tie breaker from off-site power opened due to a detected ground overcurrent condition during the performance of postmaintenance surveillance test on EDG 2-2. When the breaker opened, degraded EDG performance was observed on the associated 4-kV emergency bus. In response to the degraded EDG performance, operating personnel subsequently opened the EDG output breaker to prevent damage to the "B" train safeguards equipment. This action effectively deenergized the 4-kV bus and lead to a total loss of "B" train emergency alternating current (ac) power. At the time of the event, EDG 2-2 was inoperable as a result of degraded flow through the EDG's heat exchanger (HX), which was caused by macrobiological fouling. Redundant train "A" equipment was placed in service as needed, to maintain the Beaver Valley Unit 2 in a stable condition. The loss of train "B" ac power and the subsequent loss of battery chargers 2-2 and 2-4 resulted in a TS violation and required a plant shutdown. Later, EDG 2-2 inadvertently automatically actuated when an operator transferred EDG control from REMOTE to LOCAL. The loss of the emergency bus resulted in the loss of RCP seal injection flow and the loss of RCP thermal barrier cooling flow to two of the RCPs for about 3 min. The unit was taken off-line and shut down for 6 d for a forced outage to investigate the inoperability of the 2-2 EDG following a loss of the emergency 4 kV bus, "DF." The cause for failure was attributed to a faulty control relay in the voltage regulator on the 2-2 EDG, which was replaced. The plant remained shut down to complete the cleaning of the service water (SW) system side of the 2-1 EDG HX, which was fouled by an accumulation of dead Zebra mussels following a clamicide (toxic kill) injection.
Oct 1999	Nov 1999	The unit was taken off-line and shut down for 12 d for forced outage to repair a leaking pressurizer code safety valve and two PORVs.

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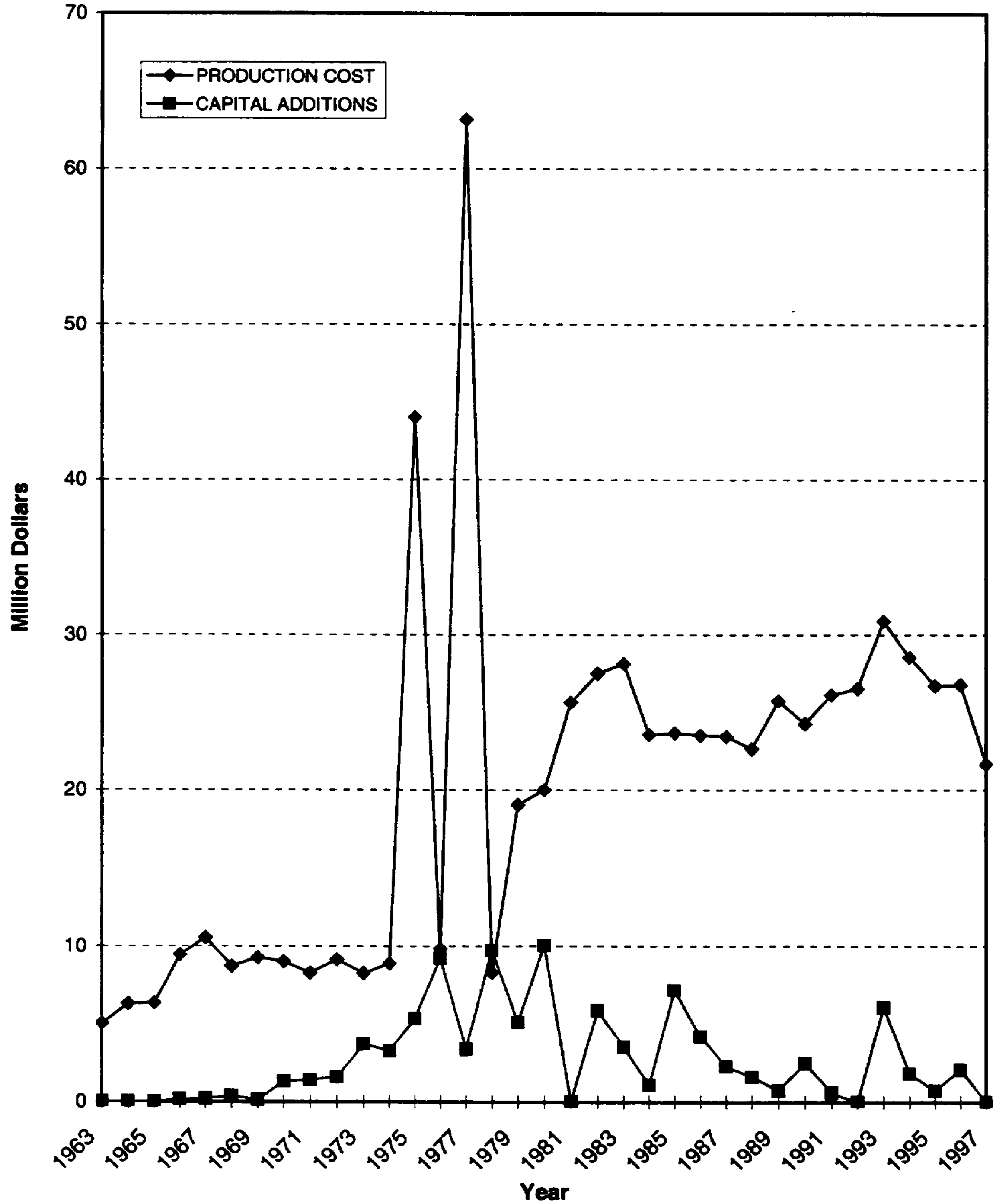
BIG ROCK POINT

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

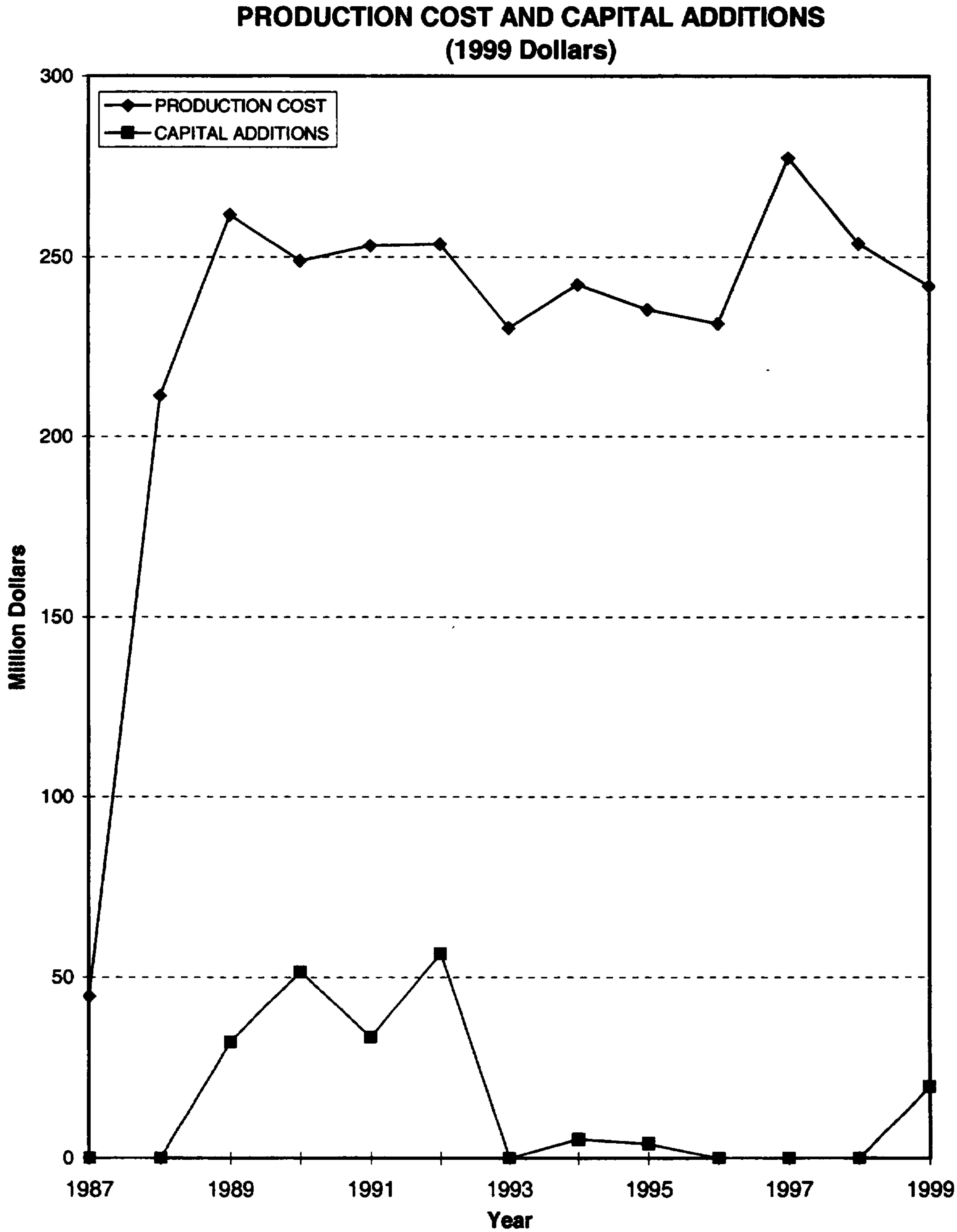
Unit Data Summary (Through December 1999)

Unit:	**BIG ROCK POINT**	Nameplate Rating (MWe):	**75**
Location:	**Charlevoix, MI**	MDC Net MWe:	**67**
Operator:	**Consumers Energy**	Cumul. Avail. Factor:	**71.3**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**62.1**
Construction Permit:	**5/31/60**	Cumul. Forced Outage Rate:	**8.6**
Operating License:	**8/30/62**	3-Year Avg. Cap. Factor (MDC Net):	
Commercial Oper. Date:	**3/29/63**	License Expiration:	**5/3/00**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	May 1997	The unit was taken off-line and shut down for 64 d for a scheduled outage that was extended into a forced outage to investigate and repair leakage from valves in the postincident system.
Aug 1997	Sep 1997	The unit was taken off-line and permanently shut down for decommissioning.
Jul 1998		The plant is in the process of being decommissioned. While emptying the sodium pentaborate tank, it was discovered that the discharge tube to the primary system was severed. Engineering analysis by the licensee determined that the failure occurred sometime between 1979 and 1984. Further, the licensee examined their individual plant examination (IPE) and calculated the effect the failure of the system had on the core damage frequency. The licensee determined, "... the previously evaluated core damage frequency would be expected to increase approximately 4%."
Feb 1999		The site lost power from its substation, which caused a LOSP. The EDG was started and loaded. Off-site power was restored about 3-1/2 h later.

BRAIDWOOD
(Units 1 and 2)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**BRAIDWOOD 1**	Nameplate Rating (MWe):	**1175**
Location:	**Will County, Illinois**	MDC Net MWe:	**1120**
Operator:	**Commonwealth Edison Co.**	Cumul. Avail. Factor:	**79.0**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**75.2**
Construction Permit:	**12/31/75**	Cumul. Forced Outage Rate:	**5.7**
Operating License:	**7/2/87**	3-Year Avg. Cap. Factor (MDC Net):	**86.9**
Commercial Oper. Date:	**7/29/88**	License Expiration:	**10/17/26**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	May 1997	The unit was taken off-line and shut down for 59 d for the sixth refueling and maintenance outage.
Oct 1997		The NRC proposed and the licensee paid a $55,000 fine for violating plant TS surveillance requirements.
Sep 1998	Nov 1998	The unit was taken off-line and shut down for 71 d for the seventh refueling and maintenance outage.
Sep 1998		An unusual event (UE) was declared when a lightning strike during a severe thunderstorm caused an LOSP in the switchyard. The plant was in cold shutdown as part of a refueling outage. The LOSP lasted for about 9 h after a steel 5/16-in. wire-braided cable was blown by 55-mph winds into the startup auxiliary transformer which shorted to ground. This hoist cable for a crane had been tied to an outside movable platform prior to the storm. About 140 ft of the cable was lost.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**BRAIDWOOD 2**	Nameplate Rating (MWe):	**1175**
Location:	**Will County, Illinois**	MDC Net MWe:	**1120**
Operator:	**Commonwealth Edison Co.**	Cumul. Avail. Factor:	**84.6**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**80.5**
Construction Permit:	**12/31/75**	Cumul. Forced Outage Rate:	**3.7**
Operating License:	**5/20/88**	3-Year Avg. Cap. Factor (MDC Net):	**91.6**
Commercial Oper. Date:	**10/17/88**	License Expiration:	**12/18/27**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Sep 1997	Nov 1997	The unit was taken off-line and shut down for 50 d for the sixth refueling and maintenance outage.
		The NRC proposed and the licensee paid a $55,000 fine for violating TS surveillance requirements.
Jan 1998	Feb 1998	The unit was taken off-line and shut down for 9 d following a maintenance error. After troubleshooting, an electric circuit card was replaced in the electrohydraulic control (EHC) system for the main turbine.
Apr 1999	May 1999	The unit was taken off-line and shut down for 26 d for the seventh refueling and maintenance outage.

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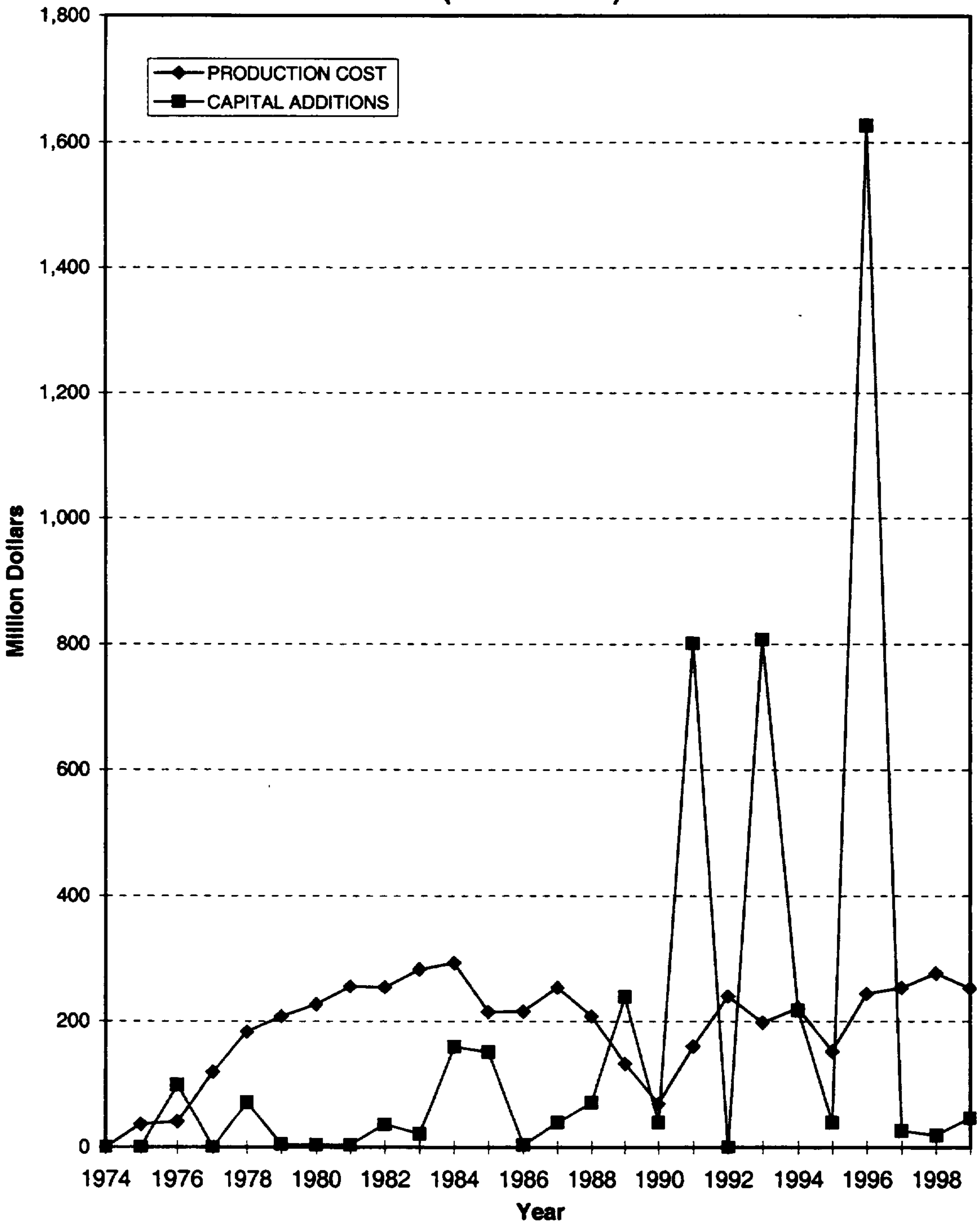
BROWNS FERRY
(Units 1, 2, and 3)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**BROWNS FERRY 2**	Nameplate Rating (MWe):	**1152**
Location:	**Limestone County, Alabama**	MDC Net MWe:	**1065**
Operator:	**Tennessee Valley Authority**	Cumul. Avail. Factor:	**71.1**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**63.7**
Construction Permit:	**5/10/67**	Cumul. Forced Outage Rate:	**12.7**
Operating License:	**8/2/74**	3-Year Avg. Cap. Factor (MDC Net):	**92.4**
Commercial Oper. Date:	**3/1/75**	License Expiration:	**6/28/14**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Sep 1997	Oct 1997	The unit was taken off-line and shut down for 22 d for the seventh refueling and maintenance outage.
Apr 1999	May 1999	The unit was taken off-line and shut down for 27 d for the eighth refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**BROWNS FERRY 3**	Nameplate Rating (MWe):	**1152**
Location:	**Limestone County, Alabama**	MDC Net MWe:	**1065**
Operator:	**Tennessee Valley Authority**	Cumul. Avail. Factor:	**68.3**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**63.8**
Construction Permit:	**7/31/68**	Cumul. Forced Outage Rate:	**13.9**
Operating License:	**8/18/76**	3-Year Avg. Cap. Factor (MDC Net):	**90.4**
Commercial Oper. Date:	**3/1/77**	License Expiration:	**7/2/16**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997	Mar 1997	The unit was taken off-line and shut down for 19 d for a fifth refueling and maintenance outage.
Mar 1997		The plant was shut down, the reactor vessel head had been removed, and the reactor core had been reloaded following a refueling outage. The fuel pool was connected to the reactor cavity, and decay heat was being removed by fuel pool cooling. Browns Ferry receives off-site power from Athens and Trinity located in northern Alabama. The power lines connecting the site to the power sources are called Athens off-site power and Trinity off-site power, respectively. Both Athens and Trinity off-site power sources (161 kV) were lost; however, Browns Ferry Unit 2 was unaffected. A UE was declared. Three of the four EDGs for Unit 3 automatically started and loaded onto their respective buses. The fourth EDG was out of service for preventative maintenance. Off-site power was restored about 1 h later.
Apr 1998		The unit was scrammed, taken off-line, and shut down for 12 d when both recirculation pumps experienced a runback to minimum speed caused by a loss of power to critical circuits. This event caused a reduction in core flow, which resulted in the plant entering a potential instability region on the power-to-flow map.
Sep 1998	Oct 1998	The unit was taken off-line and shut down for 25 d for the sixth refueling and maintenance outage.

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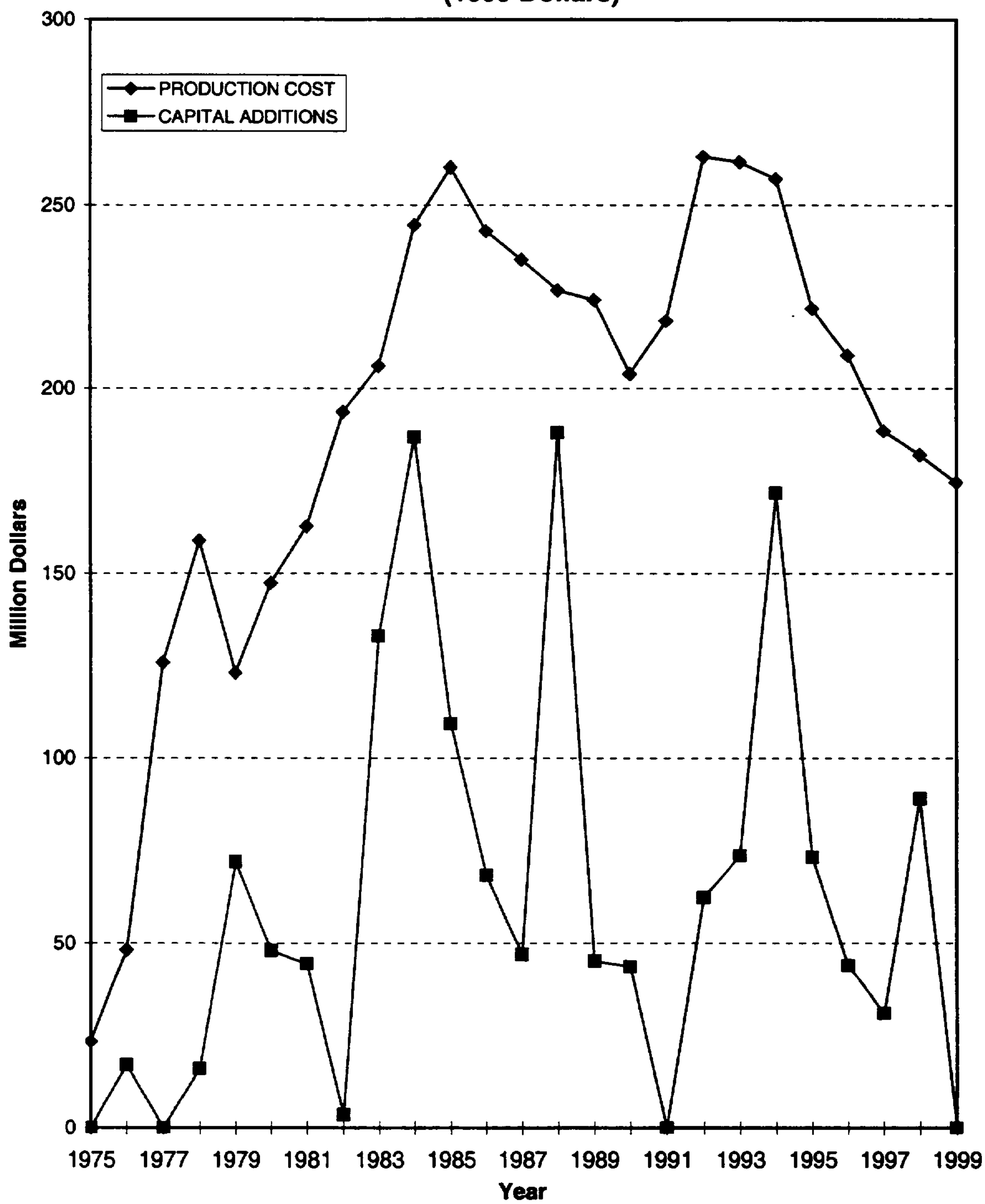
BRUNSWICK
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**BRUNSWICK 1**	Nameplate Rating (MWe):	**867**
Location:	**Brunswick County, North Carolina**	MDC Net MWe:	**767**
Operator:	**Carolina Power & Light Co.**	Cumul. Avail. Factor:	**63.6**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**58.2**
Construction Permit:	**2/7/70**	Cumul. Forced Outage Rate:	**11.5**
Operating License:	**11/12/76**	3-Year Avg. Cap. Factor (MDC Net):	**96.0**
Commercial Oper. Date:	**3/18/77**	License Expiration:	**9/8/16**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jun 1997		During TS surveillance of EDG No. 2, there was a momentary loss of emergency bus E2. EDG No. 2 automatically started and loaded onto the bus. About 5 h later, during more testing, the diesel developed a nonisolable fuel oil line leak that required tripping the EDG, and, again, bus E2 was lost. EDG No. 2 was finally declared operable the next day.
Nov 1997		The unit was taken off-line and shut down for 8-1/2 d to replace failed fuel bundles.
Apr 1998	May 1998	The unit was taken off-line and shut down for 33 d for the tenth refueling and maintenance outage.
Aug 1998		The unit was taken off-line and shut down for 6 d due to Hurricane Bonnie.
Aug 1999		The licensee declared a UE when the National Weather Service issued a hurricane warning for the area for Hurricane Dennis. Both units were shut down. The licensee also reported that all five of its emergency sirens in Hanford County were inoperable as well as two in Brunswick County.
Sep 1999		The unit was taken off-line and shut down for 5 d in preparation for Hurricane Floyd.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**BRUNSWICK 2**	Nameplate Rating (MWe):	**867**
Location:	**Brunswick County, North Carolina**	MDC Net MWe:	**754**
Operator:	**Carolina Power & Light Co.**	Cumul. Avail. Factor:	**64.0**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**56.1**
Construction Permit:	**2/7/70**	Cumul. Forced Outage Rate:	**9.3**
Operating License:	**12/27/74**	3-Year Avg. Cap. Factor (MDC Net):	**91.8**
Commercial Oper. Date:	**11/3/75**	License Expiration:	**12/27/14**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Sep 1997	Oct 1997	The unit was taken off-line and shut down for 40 d for the 12th refueling and maintenance outage.
Jun 1998		The unit was taken off-line and shut down for 5 d to replace the drywell cooling fan motors.
Aug 1998		The unit was taken off-line and shut down for 5 d due to Hurricane Bonnie.
Mar 1999	Apr 1999	The unit was taken off-line and shut down for 40 d for the 13th refueling and maintenance outage.
Sep 1999		The unit was taken off-line and shut down for 7 d due to Hurricane Floyd.

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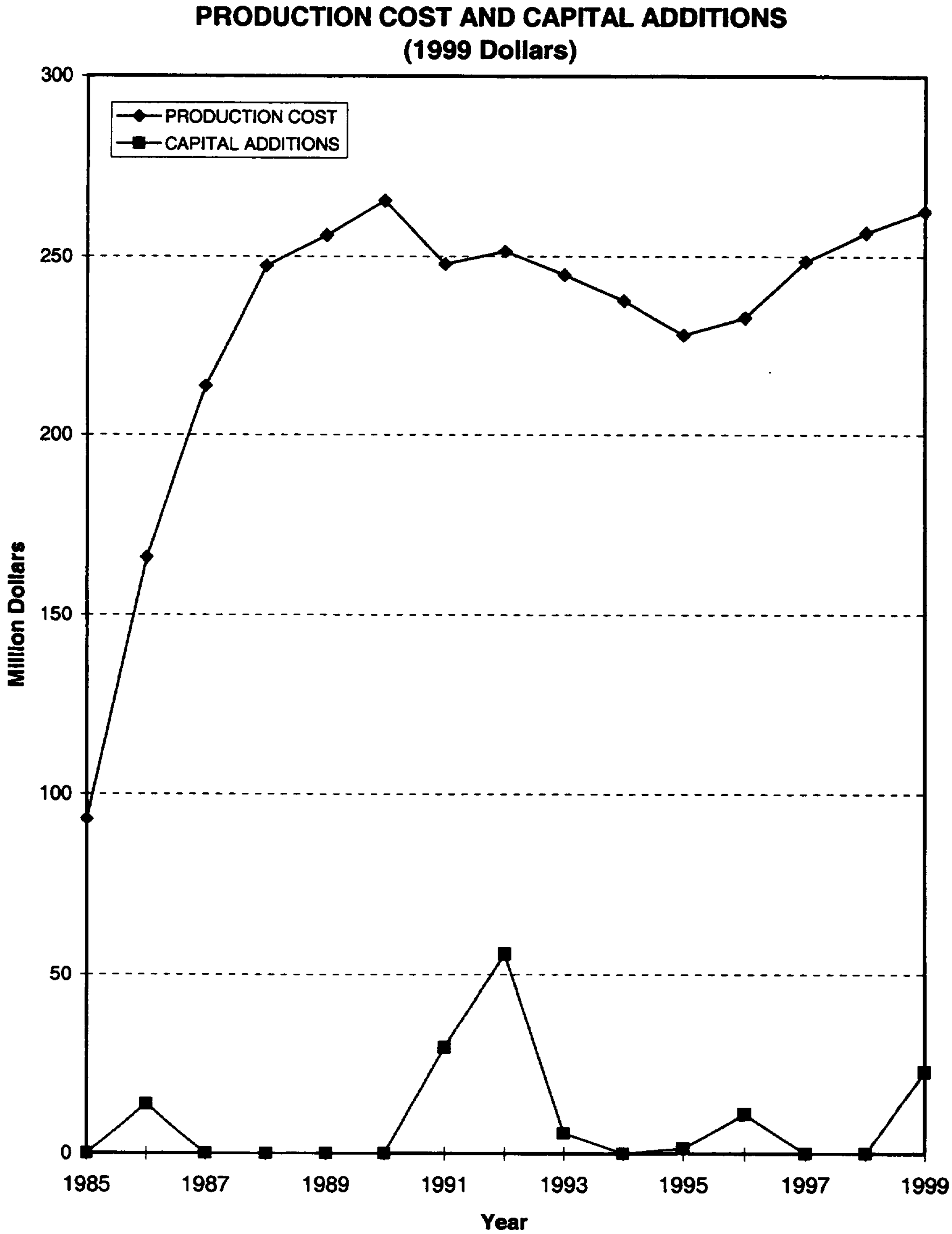
BYRON
(Units 1 and 2)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**BYRON 1**	Nameplate Rating (MWe):	**1175**
Location:	**Ogle County, Illinois**	MDC Net MWe:	**1105**
Operator:	**Commonwealth Edison Co.**	Cumul. Avail. Factor:	**80.7**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**75.0**
Construction Permit:	**12/31/75**	Cumul. Forced Outage Rate:	**2.1**
Operating License:	**2/14/85**	3-Year Avg. Cap. Factor (MDC Net):	**82.1**
Commercial Oper. Date:	**9/16/85**	License Expiration:	**10/31/24**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997	Mar 1997	The unit was taken off-line and shut down for 19 d for a forced outage to repair cooling coils in the reactor containment fan cooler.
Mar 1997		The NRC proposed and the licensee paid a $100,000 fine based on two Severity Level III violations. There were a total of four violations related to the identification of excessive silt accumulation in the essential SW system cooling tower basins and the river screen house intake channel. The first Severity Level III violation was failing to (1) translate design configuration information into volumetric requirements for the essential SW cooling tower makeup calculation and (2) develop appropriate acceptance criteria for surveillance procedures to assure essential SW operability. The second Severity Level III violation was failing to take appropriate corrective actions on two separate occasions to remedy silt accumulation and degraded essential SW trash racks.
Oct 1997		The unit was taken off-line and shut down for 5 d for a forced outage to repair excessive valve leakage.
Nov 1997		The NRC proposed and the licensee paid a $55,000 fine for violating plant TS surveillance requirements.
Nov 1997	Mar 1998	The unit was taken off-line and shut down for 122 d for the eighth planned refueling and maintenance outage.
Aug 1998		The plant was operating at 100% power on August 4 when power was lost to the Unit 1 station auxiliary transformers. The emergency buses were deenergized and repowered by the unit EDGs. Nonvital loads (6.9 kV) fast transferred to the unit auxiliary transformer without tripping. This included the RCPs, thus allowing Unit 1 to continue at power without tripping on loss of load.
Sep 1998		The 1A EDG failed its monthly TS surveillance test on September 12 when it tripped on low lube oil pressure caused by filter material clogging the oil strainers. Also, a lube oil relief valve lifted 9 d before the failed test. Further, due to the flow

		mechanism involved in loading the oil strainers, the low lube oil pressure condition could have existed as far back as the last TS surveillance test on August 19, 1998. This implied that the EDG could have been unavailable for almost 30 d. Furthermore, since this condition resulted from standard maintenance practices used on the EDGs, there could be common-cause failure mechanisms evident from this event.
Mar 1999	Apr 1999	The unit was taken off-line and shut down for 29 d for the ninth planned refueling and maintenance outage.
May 1999		The unit was taken off-line and shut down for 5 d for a forced outage to investigate a human performance error.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

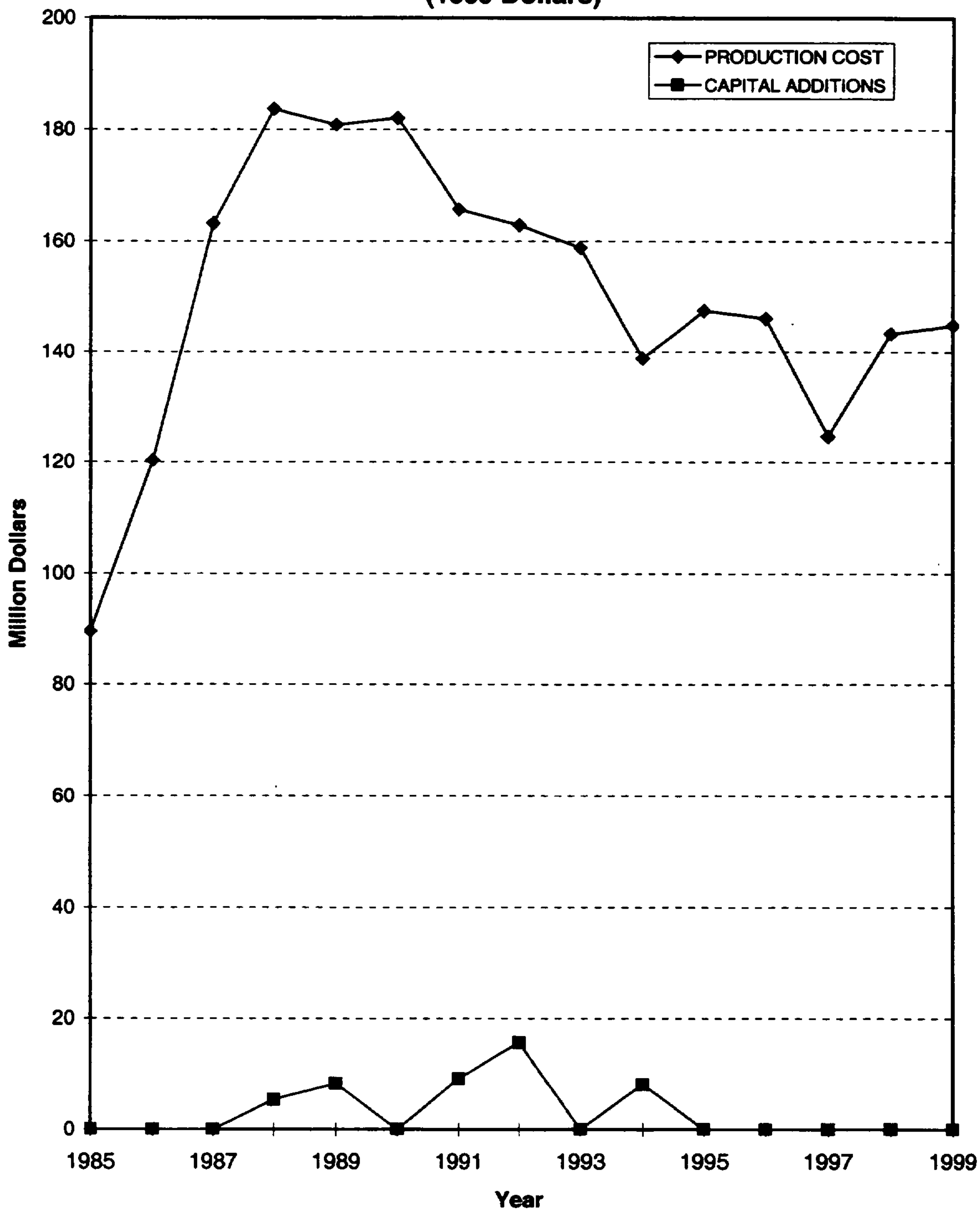
Unit:	**BYRON 2**	Nameplate Rating (MWe):	**1175**
Location:	**Ogle County, Illinois**	MDC Net MWe:	**1105**
Operator:	**Commonwealth Edison Co.**	Cumul. Avail. Factor:	**87.3**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**80.3**
Construction Permit:	**12/31/75**	Cumul. Forced Outage Rate:	**1.9**
Operating License:	**1/30/87**	3-Year Avg. Cap. Factor (MDC Net):	**92.5**
Commercial Oper. Date:	**8/21/87**	License Expiration:	**11/6/26**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997		The unit was taken off-line and shut down for 6 d to repair handhold leaks on the SGs. The NRC proposed and the licensee paid a $100,000 fine based on two Severity Level III violations. There were a total of four violations related to the identification of excessive silt accumulation in the essential SW system cooling tower basins and the river screen house intake channel. The first Severity Level III violation was failing to (1) translate design configuration information into volumetric requirements for the essential SW cooling tower makeup calculation and (2) develop appropriate acceptance criteria for surveillance procedures to assure essential SW operability. The second Severity Level III violation was failing to take appropriate corrective actions on two separate occasions to remedy silt accumulation and degraded essential SW trash racks.
Oct 1997		The unit was taken off-line and shut down for 10 d for a forced outage to replace the extraction steam bellows that had deteriorated.
Nov 1997		The NRC proposed and the licensee paid a $55,000 fine for violating plant TS surveillance requirements.
Apr 1998	May 1998	The unit was taken off-line and shut down for 38 d for the seventh refueling and maintenance outage.
Oct 1999	Nov 1999	The unit was taken off-line and shut down for 24 d for the eighth refueling and maintenance outage.

CALLAWAY

PRODUCTION COST AND CAPITAL ADDITIONS (1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

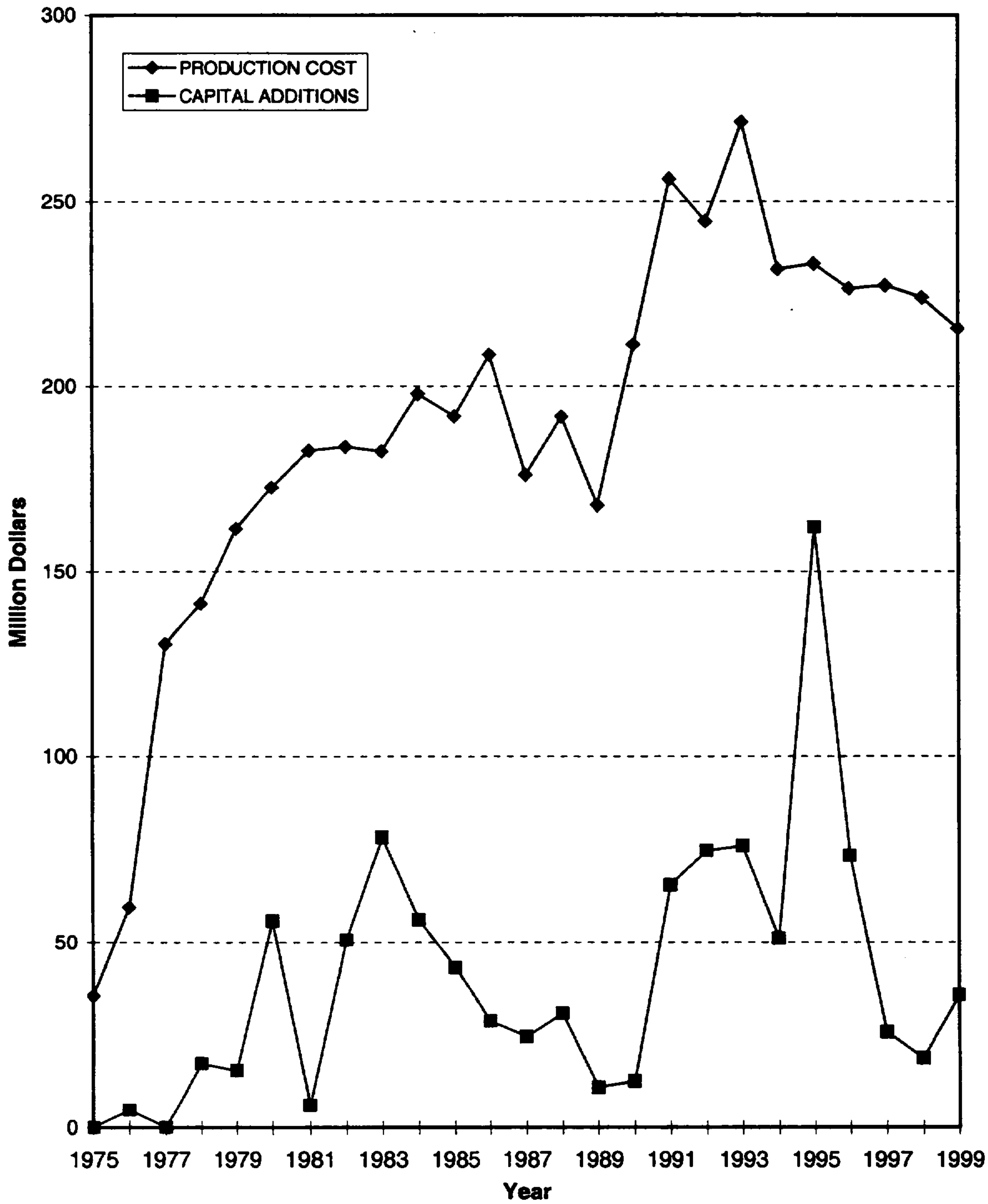
Unit:	**CALLAWAY**	Nameplate Rating (MWe):	**1236**
Location:	**Callaway County, Missouri**	MDC Net MWe:	**1125**
Operator:	**AmerenUE**	Cumul. Avail. Factor:	**87.5**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**85.1**
Construction Permit:	**4/16/76**	Cumul. Forced Outage Rate:	**2.1**
Operating License:	**10/18/84**	3-Year Avg. Cap. Factor (MDC Net):	**86.2**
Commercial Oper. Date:	**12/19/84**	License Expiration:	**10/18/24**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Apr 1998	May 1998	The unit was taken off-line and shut down for 31 d for the ninth refueling and maintenance outage.
Aug 1999		The unit was taken off-line and shut down for 8 d to repair a steam line separation. On August 11, the Callaway plant experienced a rupture of a reheater drain tank line. As a result, the plant operators initiated a manual reactor trip. Because the plant was shut down, off-site power was required to supply the plant equipment loads. During this period, the grid conditions were such that a substantial power flow was occurring from north to south through the local Callaway grid. The licensee stated that the deregulated wholesale market contributed to conditions in which higher grid power flows are likely to occur. The licensee stated that these large flows were observed at this time. This power flow, coupled with a high local demand and the loss of the Callaway generator, resulted in switchyard voltage at the site dropping below the minimum requirements for 12 h. Although off-site power remained available during the reactor trip transient, the posttrip analysis indicated that if additional on-site loads had been in operation at the time of the event, the 4.16-kV distribution voltage may have decreased below the set point of the second-level undervoltage relays, separating the loads from off-site power. However, both EDGs were operable and would have started if a sustained low-voltage condition occurred on the emergency busses. When the unit is on-line, local voltage is controlled by the generator output; therefore, this problem would only apply when the generator is not supplying the grid.
Oct 1999	Nov 1999	The unit was taken off-line and shut down for 35 d for the tenth refueling and maintenance outage.

CALVERT CLIFFS
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**CALVERT CLIFFS 1**	Nameplate Rating (MWe):	**918**
Location:	**Calvert County, Maryland**	MDC Net MWe:	**835**
Operator:	**Baltimore Gas & Electric Co.**	Cumul. Avail. Factor:	**71.4**
Type:	**Combustion Engineering PWR**	Cumul. Cap. Factor (MDC Net):	**71.3**
Construction Permit:	**7/7/69**	Cumul. Forced Outage Rate:	**7.8**
Operating License:	**7/31/74**	3-Year Avg. Cap. Factor (MDC Net):	**92.4**
Commercial Oper. Date:	**5/8/75**	License Expiration:	**7/31/14***

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Sep 1997		The NRC proposed and the licensee paid a $176,000 fine for a programmatic breakdown in radiation protection during plant operations.
Sep 1997		The unit was taken off-line and shut down for 8 d for a planned outage to replace a degraded RCP seal and to investigate the cause for the degradation.
Dec 1997		The licensee reported on December 10 that the EDG may have been inoperable for 338 h. During this period of unavailability, the other train of emergency power was also unavailable for some periods of time.
Mar 1998		On March 25, Calvert Cliffs Unit 1 No. 1B EDG failed to start during performance of a routine TS surveillance test. A piece of nylon in the EDG's governor shutdown solenoid valve prevented the governor from operating properly. The licensee estimated that this occurred on March 22.
Apr 1998	Jun 1998	The unit was taken off-line and shut down for 66 d for the 13th planned refueling and maintenance outage.
Apr 1998		Calvert Cliffs Unit 1 was at hot shutdown on April 4 when 8 of 13 main safety valves failed to lift within the required set point band set forth in plant TS. A diver working in the Unit 1 intake bay died from an apparent heart attack while lowering the barrier in the bay so the cavity could be pumped down for work on the CW pump. An instrumentation and controls (I&C) technician exceeded his stay time in a radiation field while working on in-core nuclear instrumentation. Calvert Cliffs Unit 1 was in cold shutdown on April 14, when the licensee observed an accumulation of boric acid on the pressurizer at the pressurizer heater penetration. This indicates a leak in the penetration welds and a RCS pressure boundary leak.

Oct 1998		The NRC proposed and the licensee paid a $55,000 fine for failing to properly implement radiological control procedures.
May 1999		The unit was taken off-line and shut down for 8 d for a planned outage to repair a cavity cooling fan motor and a moisture separator drain tank.
Jul 1999		Calvert Cliffs Unit 1 was operating at 100% power on July 24 when it experienced a loss of a unit transformer due to an apparent lightning strike. The loss of the transformer caused a turbine trip, which caused a reactor trip.
Jul 1999	Aug 1999	The unit was taken off-line and shut down for 10 d for a forced outage. The reactor tripped after a close-proximity lightning strike to a main transformer caused protective devices to open the main generator output breakers, which resulted in a loss of load.

*License has been extended in 2000. As of December 1999, extension of this license had not been grated.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

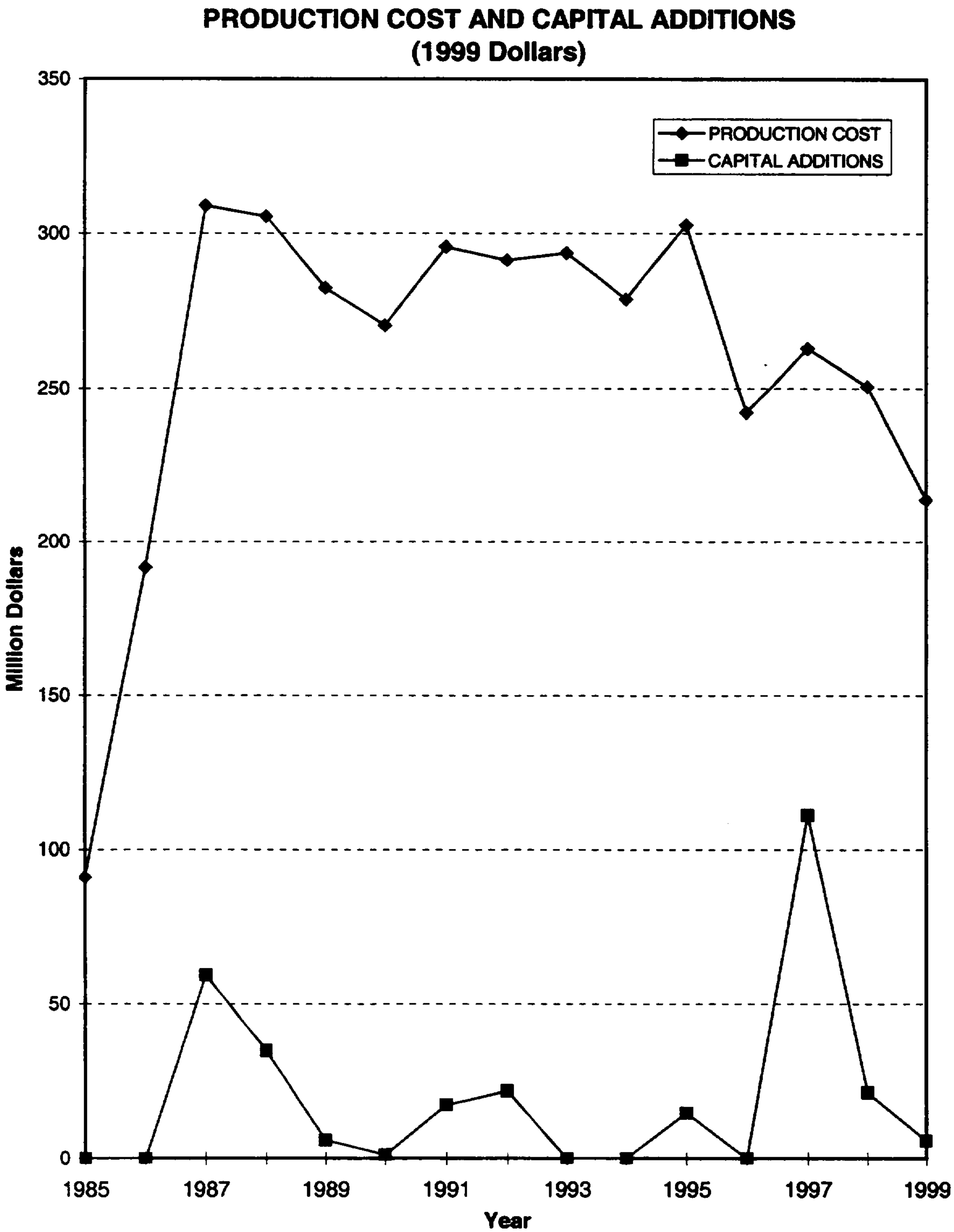
Unit:	**CALVERT CLIFFS 2**	Nameplate Rating (MWe):	**911**
Location:	**Calvert County, Maryland**	MDC Net MWe:	**840**
Operator:	**Baltimore Gas & Electric Co.**	Cumul. Avail. Factor:	**74.8**
Type:	**Combustion Engineering PWR**	Cumul. Cap. Factor (MDC Net):	**73.2**
Construction Permit:	**7/7/69**	Cumul. Forced Outage Rate:	**4.9**
Operating License:	**11/30/76**	3-Year Avg. Cap. Factor (MDC Net):	**88.5**
Commercial Oper. Date:	**4/1/77**	License Expiration:	**8/31/16***

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	May 1997	The unit was taken off-line and shut down for 69 d for a tenth refueling and maintenance outage.
Sep 1997		The NRC proposed and the licensee paid a $176,000 fine for a programmatic breakdown in radiation protection during plant operations.
Jan 1998		On January 12, it was discovered that the Unit 2 EDG had been inoperable for 15 d. The 2B EDG was returned to service on January 13. Calvert Cliffs now has two EDGs per unit plus a nonsafety-related blackout EDG available.
Jul 1998	Aug 1998	The unit was manually tripped from 100% power and shut down for 15 d due to a steam leak from a 2-in. vent line on a moisture separator reheater (MSR).
Aug 1998		Three of the five available reactor vessel water level sensors were found failed. This violated the TS requirement for minimum number of operable sensors for a given channel. Alternate methods for monitoring the RCS and core voiding, using pressurizer level, RCS subcooling, hot-leg and cold-leg temperatures, and core exit thermocouple instrumentation were incorporated.
Oct 1998		The NRC proposed and the licensee paid a $55,000 fine for failing to properly implement radiological control procedures.
Mar 1999	May 1999	The unit was taken off-line and shut down for 57 d for the 11th refueling and maintenance outage.

*License has been extended in 2000. As of December 1999, extension of this license had not been grated.

CATAWBA
(Units 1 and 2)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**CATAWBA 1**	Nameplate Rating (MWe):	**1305**
Location:	**York County, South Carolina**	MDC Net MWe:	**1129**
Operator:	**Duke Power**	Cumul. Avail. Factor:	**78.0**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**77.0**
Construction Permit:	**8/7/75**	Cumul. Forced Outage Rate:	**6.8**
Operating License:	**1/17/85**	3-Year Avg. Cap. Factor (MDC Net):	**91.5**
Commercial Oper. Date:	**6/29/85**	License Expiration:	**12/6/24**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Nov 1997	Jan 1998	The unit was taken off-line and shut down for 36 d for the tenth planned refueling and maintenance outage.
May 1998		When condensate flow was reduced as part of a power reduction on May 7, condensate recirculation control valve 1CM-127 opened, allowing heated water to flow to the upper surge tanks. These tanks provide one of the condensate (nonsafety) grade suction supplies to the AFW. The LER noted that the upper surge tanks' temperature exceeded the maximum analyzed temperature for about 3 h. Based on an evaluation performed by the licensee, no events were identified that rely on the AFW for accident mitigation and recovery that would be expected to experience a safety-significant increase in consequences. The NRC sent an Augmented Inspection Team (AIT) to investigate the event. AFW was available throughout the entire 3-h time that the upper surge tanks experienced high temperatures.
Aug 1998		On August 5, the licensee reported ice condenser problems. The licensee provided extensive documentation to show that the extent of the ice condenser damage would not impact the ability of the ice condenser to remove latent heat following a LOCA event. Some structural damage was documented; however, the likelihood of this preventing the flow of air and steam through the flow channels was estimated to be very low. Although the ice condenser remained functional, it was technically inoperable; therefore, plant TS were violated. The unit was taken off-line and shut down for 24-1/2 d for a forced outage to repair excessive flow channel blockage in the ice condenser.
Apr 1999	May 1999	The unit was taken off-line and shut down for 32 d for the 11th planned refueling and maintenance outage.

Jun 1999

On June 8, the 1B centrifugal charging pump failed. Then, on June 11, with Catawba Unit 1 operating at 100% power, the emergency core cooling system (ECCS) operating requirement TS were violated when repairs to the 1B centrifugal charging pump were not completed within the 72-h allowable outage time. The licensee had foreseen that the pump repair could not be completed within 72 h and filed for and received a Notice of Enforcement Discretion from the NRC. The enforcement discretion extended the allowable outage time to 7 d. During the early stages of work on the pump, on June 10, the doors to the pump room were propped open to allow installation of a temporary ventilation duct. This resulted in operation prohibited by TS for the auxiliary building filtered ventilation exhaust system because the open doors were a breach of the ventilation system pressure boundary.

Nov 1999

On November 19, EDG 1B was declared inoperable for maintenance activities. Following the maintenance, the 1B EDG failed its operational tests. After extensive troubleshooting, along with an approved 48-h Notice of Enforcement Discretion from the NRC, the licensee finally identified a governor problem. The EDG governor was replaced. Previously, the 1B EDG was tested bimonthly as a result of related problems in an earlier test. Therefore, the EDG was possibly unavailable for its safety function for up to 13 d while the plant remained in power operations.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**CATAWBA 2**	Nameplate Rating (MWe):	**1305**
Location:	**York County, South Carolina**	MDC Net MWe:	**1129**
Operator:	**Duke Power**	Cumul. Avail. Factor:	**82.7**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**78.0**
Construction Permit:	**8/7/75**	Cumul. Forced Outage Rate:	**8.0**
Operating License:	**5/15/86**	3-Year Avg. Cap. Factor (MDC Net):	**88.0**
Commercial Oper. Date:	**8/19/86**	License Expiration:	**2/24/26**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	May 1997	The unit was taken off-line and shut down for 42 d for the eighth planned refueling and maintenance outage.
Sep 1998	Oct 1998	The unit was taken off-line and shut down for 42 d for the ninth planned refueling and maintenance outage. The outage was extended 4 days to repair the main turbine generator.
Sep 1998		The plant was in cold shutdown on September 6 at the start of a refueling outage when power was lost to a 4160-V essential bus. Plant personnel were in the process of removing an EDG from service to perform outage-related maintenance, and they opened the wrong potential transformer drawer. A motor-driven AFW pump automatically started, the control room ventilation system automatically started, and a PORV lifted.
Jan 1999		On January 15 Catawba Unit 2 was operating at 100% power when a relay failure occurred and resulted in the degradation of the AFW system. The turbine-driven AFW Pump Train "A" controls were degraded, and the "2A" Train of motor-driven AFW was inoperable. A similar event also occurred on January 29, again with Catawba Unit 2 operating at 100% power. In the second event, the same relay failed again. The cause of both events was determined to be a shorted relay coil. The relay coil was replaced after the first event, and after the second event the entire relay was replaced.
May 1999	June 1999	The unit was taken off-line and shut down for 41-1/2 d for a forced outage to repair a main generator ground fault, which caused a turbine runback and full load rejection.

May 1999		Catawba Unit 2 was at 8% power on May 4 when all three Unit 2 AFW pumps were declared inoperable as a result of flow restrictions caused by corrosion that was detected in the assured (backup) supply piping from the nuclear SW system. The nuclear SW system is the last-resort supply of water for the AFW system. The corrosion was also determined to exist on Catawba Unit 1, which was in a refueling outage at the time. The licensee performed an engineering analysis and an evaluation, which showed that sufficient flow capacity existed to support two AFW pumps. The nuclear SW supply to the turbine-driven AFW pump was isolated. Unit 2 was then shut down per TS. Subsequent corrective actions included cleaning the affected piping for both units and flow testing the piping.
Dec 1999	Jan 2000	The unit was taken off-line and shut down for 5 d for a forced outage to investigate a spurious main turbine trip signal caused by a turbine emergency trip solenoid problem.

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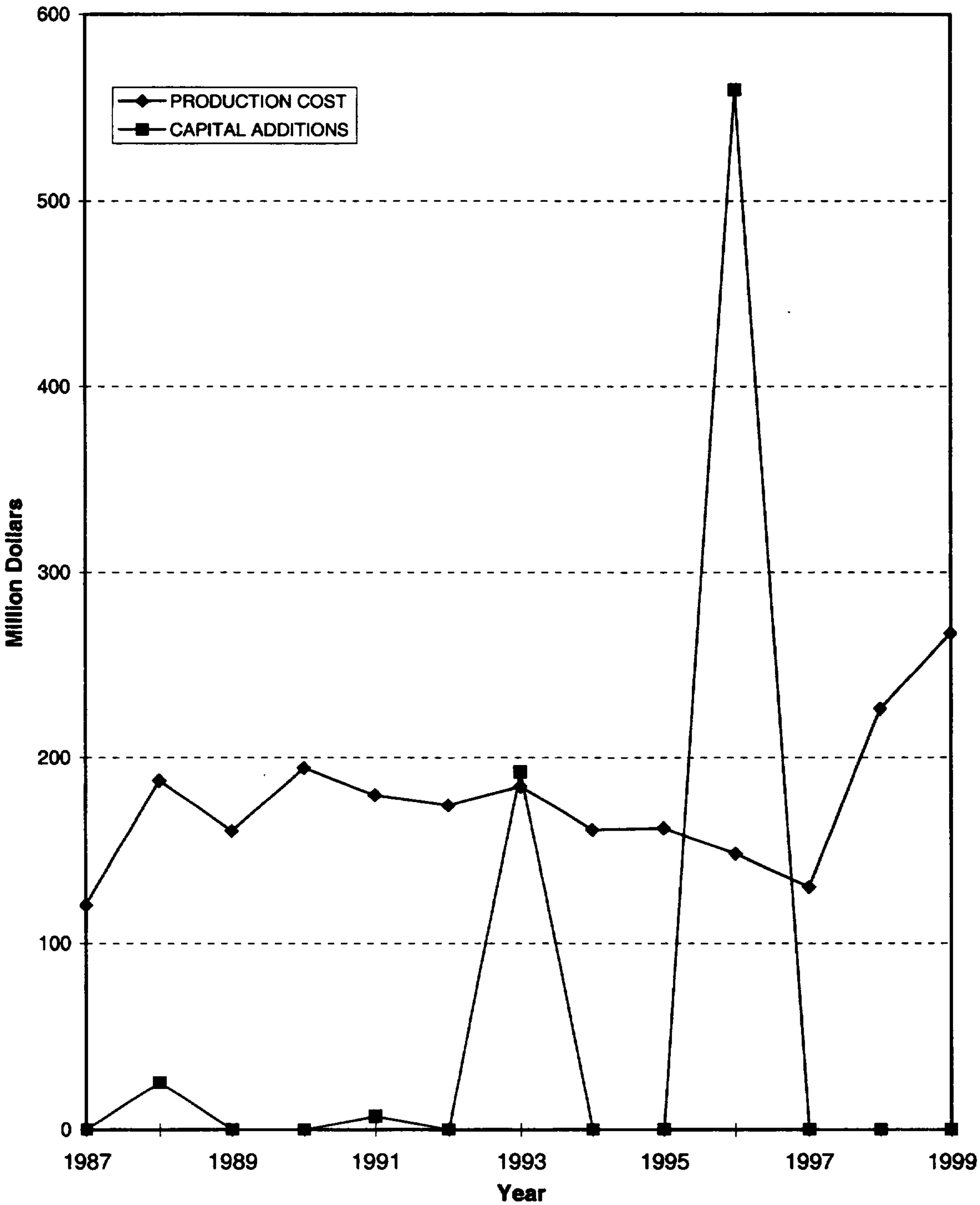
CLINTON

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**CLINTON**	Nameplate Rating (MWe):	**985**
Location:	**Dewitt County, Illinois**	MDC Net MWe:	**930**
Operator:	**AmerGen Energy Co.**	Cumul. Avail. Factor:	**62.3**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**54.1**
Construction Permit:	**2/24/76**	Cumul. Forced Outage Rate:	**8.4**
Operating License:	**4/17/87**	3-Year Avg. Cap. Factor (MDC Net):	**19.2**
Commercial Oper. Date:	**11/24/87**	License Expiration:	**9/29/26**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Oct 1996	May 1999	The unit was taken off-line and shut down for a sixth planned refueling and maintenance outage; however, the plant remained off-line and shut down for 955 d to respond to NRC concerns. The plant was started up on May 25.
Jul 1997		The NRC proposed and the licensee paid a $450,000 fine for numerous procedure problems, a nonconservative decision, multiple TS surveillance problems, and for management ineffectiveness.
Aug 1997		On August 23, the licensee reported that two safety-related, 4-kV, Westinghouse (W) breakers failed to open when they were tested. The NRC assigned an AIT to investigate and to study the two failures. The LER cites the two failures and three more breakers that met the minimum conditions for failure. In all, 75 breakers were affected, and the AIT concluded that common cause failures were also responsible.
		The NRC proposed and the licensee paid a $110,000 fine for failing to correct hardened grease or lubrication problems in circuit breakers.
Sep 1997		On September 29, the licensee reported that the battery charger for Division I failed while performing its safety function and the other division's battery charger was in a degraded condition. The LER indicates that this condition was in effect since the original installation.
Feb 1998		The licensee declared an alert under its emergency plan after shutdown cooling was lost for almost 3 h on February 13.
Jun 1998		The licensee declared a UE on June 29 when three of four off-site power sources were lost. Severe thunderstorms, tornadoes, and high winds deenergized two off-site 345-kV power lines and one 138-kV power line. The plant was in cold shutdown at the time of the event.

Oct 1998	The licensee reported on October 2 that a design modification completed in July 1997 opened a valve that was interlocked to another valve that subsequently needed testing; however, the second valve could not be opened due to the interlock. The LER indicates that, "Had the plant been in a mode that required suppression pool cooling to be operable, local action by operators would have been required to manually open 1E12-F024B to place the residual heat removal (RHR) system "B" train in suppression pool cooling." This "... would have required either operating 1E12-F024B manually or closing the circuit breaker for 1E12-F006B."
Jan 1999	The licensee declared a UE on January 6 when the plant lost off-site power to its emergency buses. A 138-kV off-site power line was lost while it was supplying power to the emergency reserve auxiliary transformer. The reserve auxiliary transformer was out of service at the same time; consequently, all three EDGs automatically started and loaded onto their respective buses. Shutdown cooling was lost, but the reactor water cleanup (RWCU) system was used to maintain RCS temperature. The licensee estimated that it would take 72 h for boiling to occur in the reactor pressure vessel (RPV) if shutdown cooling were completely lost.

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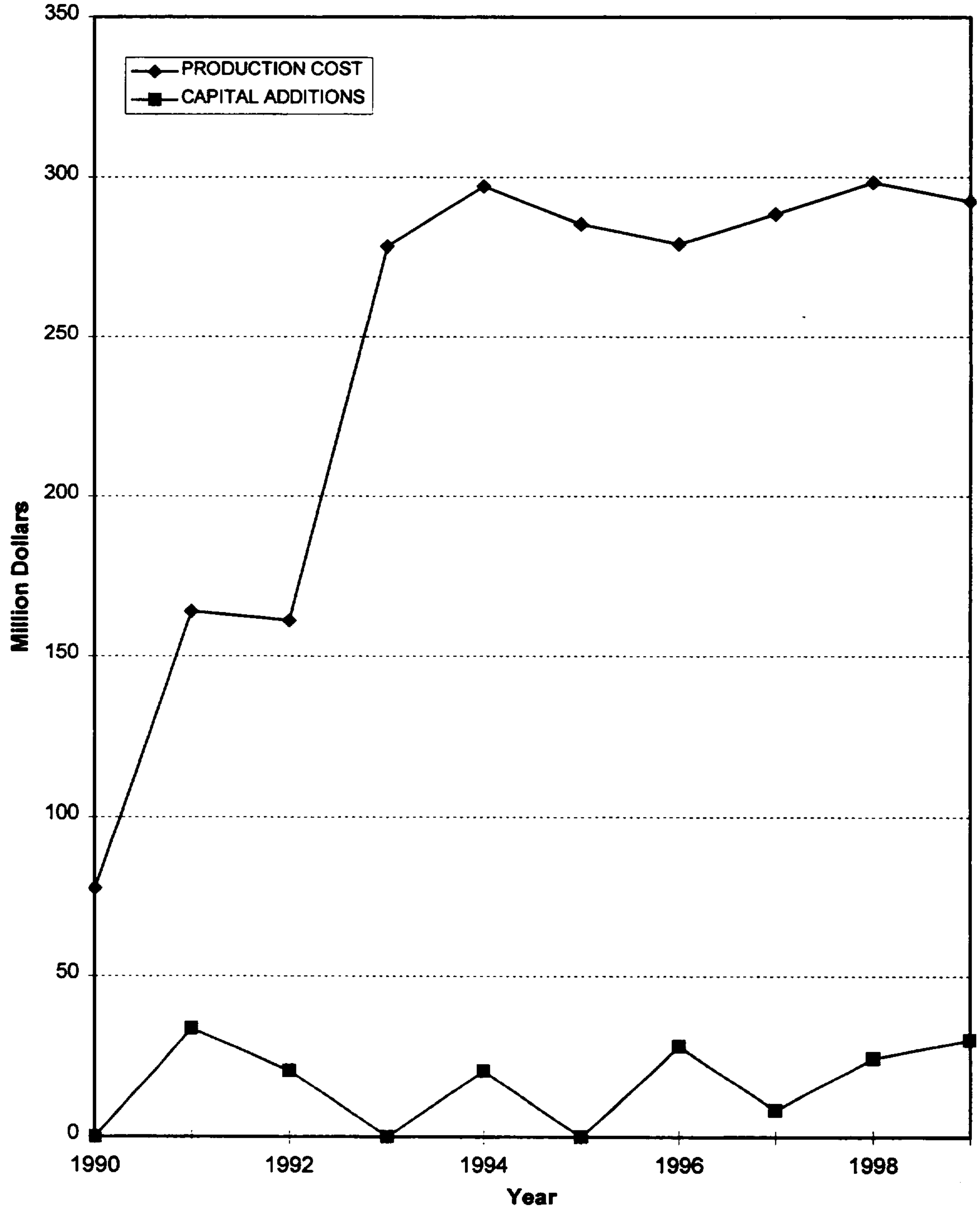
COMANCHE PEAK
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**COMANCHE PEAK 1**	Nameplate Rating (MWe):	**1161**
Location:	**Somervell County, Texas**	MDC Net MWe:	**1150**
Operator:	**TXU Electric and Gas**	Cumul. Avail. Factor:	**83.1**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**77.7**
Construction Permit:	**12/19/74**	Cumul. Forced Outage Rate:	**3.3**
Operating License:	**4/17/90**	3-Year Avg. Cap. Factor (MDC Net):	**88.0**
Commercial Oper. Date:	**8/13/90**	License Expiration:	**2/8/30**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1998	Apr 1998	The unit was taken off-line and shut down for 38 d for the sixth refueling and maintenance outage.
Sep 1999	Oct 1999	The unit was taken off-line and shut down for 35 d for the seventh refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**COMANCHE PEAK 2**	Nameplate Rating (MWe):	**1161**
Location:	**Somervell County, Texas**	MDC Net MWe:	**1150**
Operator:	**TXU Electric and Gas**	Cumul. Avail. Factor:	**83.7**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**79.5**
Construction Permit:	**12/19/74**	Cumul. Forced Outage Rate:	**4.0**
Operating License:	**4/6/93**	3-Year Avg. Cap. Factor (MDC Net):	**86.6**
Commercial Oper. Date:	**8/3/93**	License Expiration:	**2/2/33**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jan 1997		The unit was taken off-line and shut down for 4 d for a planned maintenance outage to repair an oil leak on the capacitance coupled transformer.
Oct 1997	Dec 1997	The unit was taken off-line and shut down for 46 d for the third refueling and maintenance outage.
Mar 1999	Apr 1999	The unit was taken off-line and shut down for 34 d for the fourth refueling and maintenance outage.

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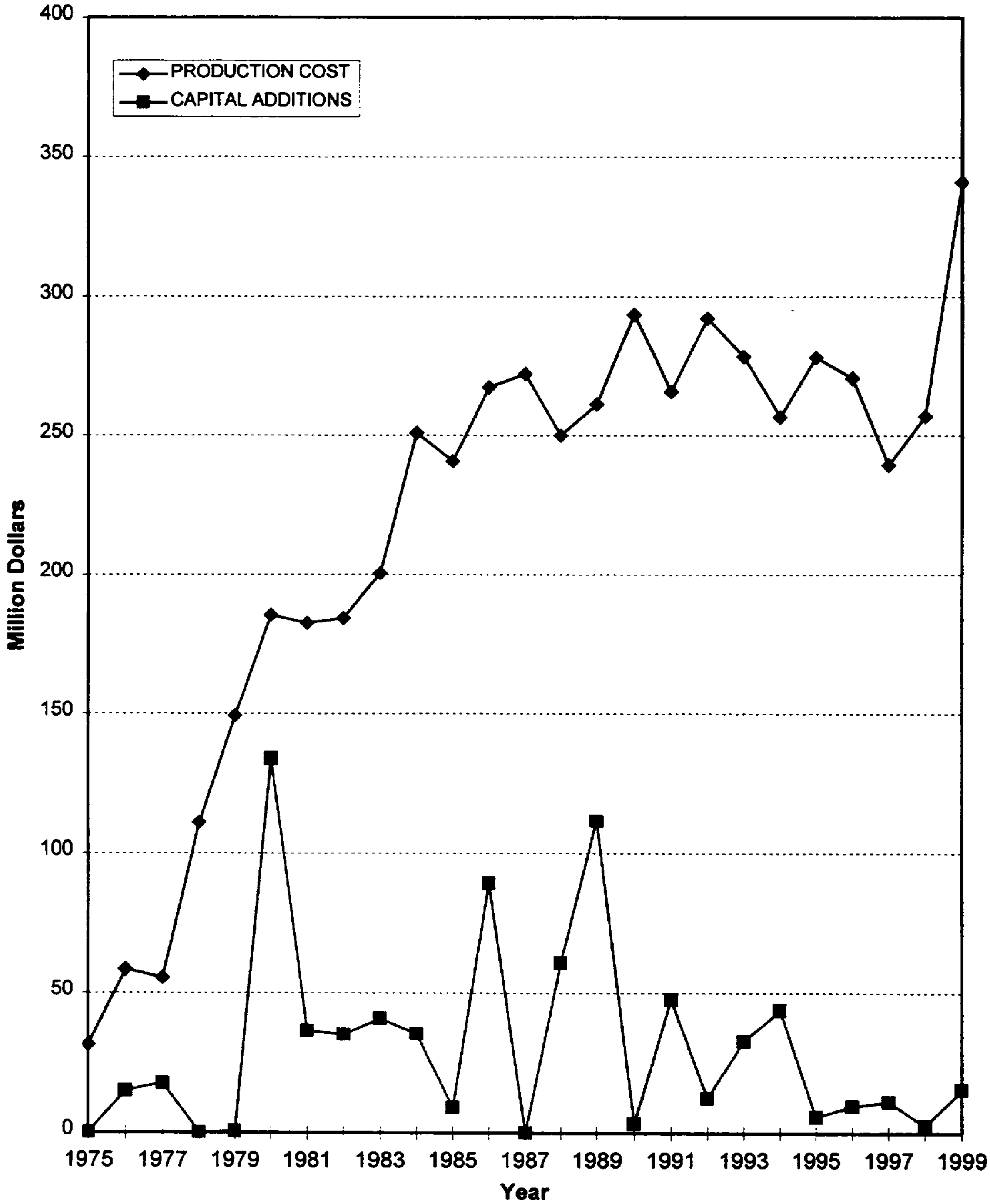
D. C. COOK
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**D. C. COOK 1**	Nameplate Rating (MWe):	**1152**
Location:	**Berrien County, Michigan**	MDC Net MWe:	**1000**
Operator:	**Indiana Michigan Power Co.**	Cumul. Avail. Factor:	**72.7**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**62.8**
Construction Permit:	**3/25/69**	Cumul. Forced Outage Rate:	**16.4**
Operating License:	**10/25/74**	3-Year Avg. Cap. Factor (MDC Net):	**17.3**
Commercial Oper. Date:	**8/28/75**	License Expiration:	**10/25/14**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	Apr 1997	The unit was taken off-line and shut down for 57 d for the 15th planned refueling and maintenance outage.
Aug 1997		The licensee reported net positive suction head (NPSH) problems with the RHR pumps under certain accident conditions. However, on August 22, the licensee indicated that under worst-case conditions, adequate NPSH would be maintained for the RHR pumps in the recirculation mode. Vortexing could occur if the water level in the active recirculation sump dropped below the 602-ft, 10-in. level under maximum flow conditions. In the worst-case accident conditions, safety analysis indicated that the level could be as low as 602 ft, 2 in.
Sep 1997	Dec 1999	The unit was taken off-line, shut down, and defueled on September 8 to resolve design basis questions discovered during a NRC architect and engineering inspection. The plant remained shut down for the remainder of this reporting period (845 d).
Sep 1997		The plant was in cold shutdown on September 17 when the licensee reported that fibrous material was present in both Cook Unit 1 and Unit 2 containments in enough quantity to potentially cause excessive blockage of the containment sump screen during the recirculation phase of a LOCA. In 1985, 1986, and 1995 "Fiberfax" refractory insulation materials in bulk, blanket, or board form were used as damming material when installing fire stops in cable trays. The material was never removed and was present in 12 cable trays in Unit 1 and 15 cable trays in Unit 2. Earlier, on September 5, the licensee reported five 3/4-in. holes left unprotected by a 1/4-in. particulate screen in the containment sump when the position of the screen was changed. This could allow particles up to 3/4 in. in size to enter the ECCS suction piping. It was possible, following a LOCA, that a trip of the running RHR pump during switchover to recirculation mode could cause a failure of all medium- and high-head injection pumps. There is a 15-min window while switching to recirculation mode where a failure of the west RHR pump could fail all charging and SI pumps because of a loss of suction. In February 1998 additional fibrous material was discovered in the ice condenser area of both units.

The fibrous material, which was a piece roughly 10 ft by 10 ft, represents approximately 15 ft^3 of additional material for each containment.

Nov 1997 An NRC events assessment panel determined on November 4 that design problems at the Cook plant that caused the shut down constituted a significant event. The event relates to multiple deficiencies found at the plant that affect ECCS and containment heat removal systems.

Jan 1998 On January 22, with Units 1 and 2 in cold shutdown, personnel discovered screw heads in the ice melt system trash filter in the ice condenser. The screws were apparently from the Unit 1 ice condenser's ice basket coupling rings, and a decision was made to inspect a sample of baskets in both units. The inspection identified baskets that were missing more than the maximum allowable number of screws per coupling ring at the bottom rim of the basket. This was determined to constitute an unanalyzed condition. The licensee decided to melt out each unit's ice condenser to address a variety of issues, including missing or damaged ice basket coupling screws. The licensee found two Unit 1 ice baskets with an excessive number of screws missing or damaged. NRC inspectors also observed blocked ice bed flow passages in the ice condenser. Subsequent inspections indicated that both units had up to 20% of the flow passage blocked. The reactor vendor, W, performed an engineering analysis for the safety significance of this event. W determined that the potential for 60 ice baskets to be unpinned in Modes 3 and 4 was minimal. However, the safety significance of a basket ejection during a postulated accident was only partially evaluated by W. It was determined that if unobstructed baskets are not secured at the bottom rim, they could eject 13 ft, 5 in. into the upper plenum area of the ice condenser due to postulated accident blowdown forces. The upward displacement would not be enough to open steam bypass flow routes around the ice bed during the initial dynamic phase of the accident blowdown, and the ice would remain in the upper portion of the ice condenser for heat removal during the long-term decay heat phase of the LOCA.

Mar 1998 The licensee decided on March 13 to melt the 2.59 million lb of ice in the Unit 1 ice condenser. The ice condenser system consists of 1944 baskets, each 45 ft high and approximately 1 ft in diameter. This decision was made after debris was found in the ice melted from 110 baskets. Additionally, the software code that was used to determine the radial row average ice weight underestimated weights of less than 800 lb. Lower portions of some ice baskets were devoid of ice. The trash, which had been frozen into the ice, could have caused plugging of the containment sump screens when the ice melted following a LOCA. It was determined that the 1/4-in. particulate retention requirement for the containment recirculation sump was not properly established in 1979 following sump modifications. One of the modifications involved moving a 1/4-in. retention element from inside the recirculation sump to the entrance of the sump. When the element was moved, the 1/4-in. retention requirement was not fully addressed, and pathways exceeding the 1/4-in. retention requirement were inadvertently established. The containment sump connects to the recirculation sump via an 8-in. drain line.

Aug 1998 Both Units 1 and 2 at the D. C. Cook plant were in cold shutdown on August 31 when a station service transformer was lost. Safety and nonsafety-related buses "C" and "D" for both units were deenergized as a result, and the "CD" diesel generators (DGs) automatically started and loaded, reenergizing the safety-related loads.

Mar 1999

The NRC proposed and the licensee paid a $500,000 fine based on violations in four areas: (1) the performance of surveillance tests, (2) the implementation of the corrective action program, (3) the control of the facility design basis, and (4) the conduct of safety evaluations.

On March 27, during development of an ECCS thermal-hydraulic flow analysis model, plant engineering concluded from preliminary hydraulic flow analysis results that the Unit 1 SI and centrifugal charging throttle valves could potentially experience cavitation during a LOCA. During a LOCA, large differential pressures created across the SI and centrifugal charging throttle valves would result in cavitation and possible mechanical erosion of the valves and downstream piping. During post-LOCA conditions, throttle valve erosion could lead to a pump runout condition and subsequent failure of the ECCS pumps. Radiography performed to determine valve position showed the valves to be less open than predicted by the hydraulic analysis. This condition could result in LOCA-generated debris becoming lodged in the throttle valve and result in reduced flow to the reactor core. Similar conditions exist for the Unit 2 SI and centrifugal charging throttle valves. Inspection by the licensee indicated that five of the six Unit 1 throttle valves were found to be less than 44% open.

Apr 1999

The licensee reported on April 7 that the EDGs air supply used for starting may have excessive leakage. The EDGs are supplied air by nonsafety-related air compressors. Each EDG has a 285-ft^3 receiver, kept at a minimum pressure of 220 pounds per square inch gauge (psig), This is sized to allow at least two EDG start attempts. The air receivers are cross-connected to allow the opposite EDG air system to start both EDGs if necessary. The air receivers also supply the control air for the EDG. If nonsafety-related air compressors should fail, system leakage could reduce control air below the 60 psig required to maintain the throttle control fully retracted and the EDG could trip.

May 1999

The licensee reported on May 27 that the auxiliary building ventilation may not be adequate to provide sufficient cooling during a design basis event. Impacted systems include component cooling water, spray, RHR, charging and SI. It is likely that the cooling would be adequate for an extended period of time.

Jun 1999

The licensee reported on June 9, during performance of preliminary electrical load flow analyses, that the TS 4160-V ac electrical bus degraded-voltage lower allowable limit may be too low to ensure adequate voltage for some of the 600-V ac and 120-V ac safety-related loads during a design basis accident. Additional reviews determined that the degraded-voltage relay set point is not related to ensuring adequate voltage to safety-related equipment during a design basis accident. However, a postulated sustained worst-case off-site degraded grid voltage condition, above the relay set point, could have resulted in some electrical equipment terminal voltages below those required for starting or continuous operation during a design basis accident.

Oct 1999

On October 22, the licensee reported that several locations in the plant should be considered unprotected from the effects of a postulated nearby high-energy line break event, which had previously been analyzed as protected from or not susceptible to the effects of a such a break event. However, recent evaluations identified certain areas with equipment that was either not qualified for the harsh environment that would result from a high-energy line break or would have been damaged by the jet impingement from a crack in high-energy piping near the equipment. The equipment potentially affected includes the AFW pumps, safety- and nonsafety-related 6700-V ac and lower voltage switchgear, EDGs, component cooling water pumps, Unit 2 turbine-driven AFW pump battery train, and cabling and conduit inside containment.

Dec 1999

The licensee reported on December 30 that a preliminary calculation review determined that the valves which provide a suction path from the containment sump to the ECCS pumps and the valves which align RHR to the upper containment spray header were susceptible to pressure locking/thermal binding following a LOCA. Both D. C. Cook Units 1 and 2 were in a refueling outage at the time of the report.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**D. C. COOK 2**	Nameplate Rating (MWe):	**1133**
Location:	**Berrien County, Michigan**	MDC Net MWe:	**1060**
Operator:	**Indiana Michigan Power Co.**	Cumul. Avail. Factor:	**66.0**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**55.9**
Construction Permit:	**3/25/69**	Cumul. Forced Outage Rate:	**23.9**
Operating License:	**12/23/77**	3-Year Avg. Cap. Factor (MDC Net):	**21.1**
Commercial Oper. Date:	**7/1/78**	License Expiration:	**12/23/17**

Unit Data Summary (Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997		The unit was taken off-line and shut down for 7 d to investigate why a reactor protection actuation was received as a result of a steam flow/feed flow mismatch, coincident with low SG level in the No. 1 SG. A feedwater (FW) controller failure caused the FW regulating valve to close resulting in the trip.
May 1997		The unit was taken off-line and shut down for 6-1/2 d for a planned maintenance outage on the "AB" EDG that required a shutdown of the unit per TS.
Sep 1997	Dec 1999	The unit was taken off-line, shut down, and defueled on September 8 to resolve design basis questions discovered during an NRC architect and engineering inspection. The plant remained shut down for the remainder of this reporting period (845 d).
Jul 1998		On July 15, with Unit 1 and Unit 2 in cold shutdown, it was determined that the potential existed for a postulated critical crack in a Unit 2 main steam line (MSL) to degrade the ability of adjacent component cooling water pumps to perform their design function. The component cooling water pumps for both units are adjacent to one another in a semienclosed area in the auxiliary building. Adjacent to the pumps is a pipe chase enclosing two Unit 2 MSLs and a MFW line, which can be accessed through any one of three doors. Although the pipe chase walls provide a qualified high-energy line break barrier, no calculation could be found to show that the doors would withstand the energy released from a postulated critical crack. The licensee determined that this constituted an unanalyzed condition.
Mar 1999		The NRC proposed and the licensee paid a $500,000 fine based on violations in four areas: (1) the performance of surveillance tests, (2) the implementation of the corrective action program, (3) the control of the facility design basis, and (4) the conduct of safety evaluations.

Dec 1999	The licensee reported on December 30 that a preliminary calculation review determined that the valves which provide a suction path from the containment sump to the ECCS pumps and the valves which align RHR to the upper containment spray header were susceptible to pressure locking/thermal binding following a LOCA. Both D. C. Cook Units 1 and 2 were in a refueling outage at the time of the report.

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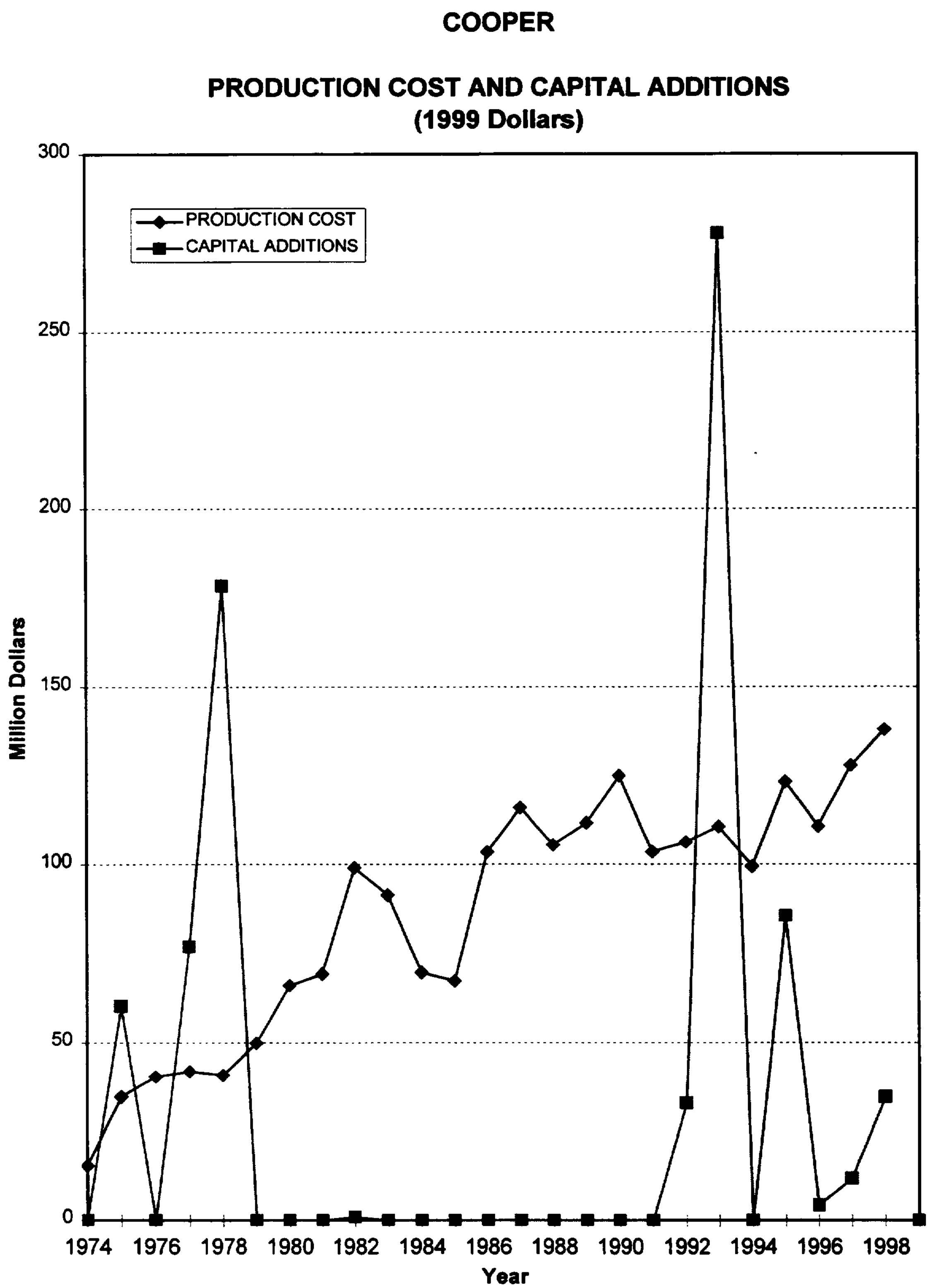
COOPER
PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)
PRODUCTION COST
CAPITAL ADDITIONS
Million Dollars
300
250
200
150
100
50
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1974
1976
1978
1980
1982
1984
1986
1988
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1992
1994
1996
1998
Year

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

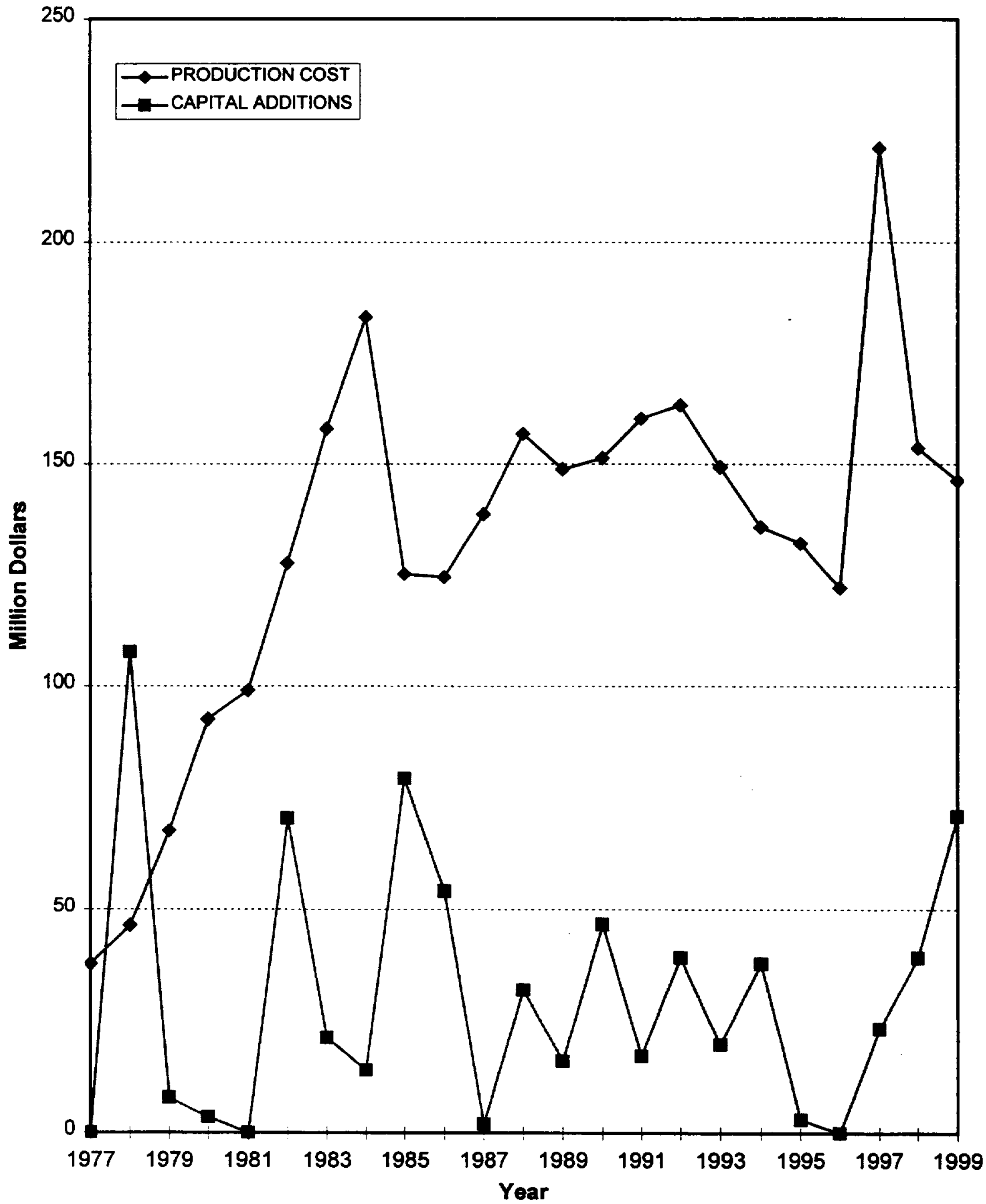
Unit:	**COOPER**	Nameplate Rating (MWe):	**836**
Location:	**Nemaha County, Nebraska**	MDC Net MWe:	**764**
Operator:	**Nebraska Public Power District**	Cumul. Avail. Factor:	**74.5**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**65.8**
Construction Permit:	**6/4/68**	Cumul. Forced Outage Rate:	**7.2**
Operating License:	**1/18/74**	3-Year Avg. Cap. Factor (MDC Net):	**83.9**
Commercial Oper. Date:	**7/1/74**	License Expiration:	**1/18/14**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	May 1997	The unit was taken off-line and shut down for 54 d for the 17th refueling and maintenance outage.
Jul 1997	Aug 1997	The unit was taken off-line and shut down for 5-1/2 d to repair a torus-to-drywell vacuum breaker that failed its TS surveillance test.
Dec 1997		The NRC proposed and the licensee paid a $110,000 fine based on corrective action program deficiencies.
Feb 1998	Mar 1998	The unit was taken off-line and shut down for 14 d for a scheduled midcycle shutdown to perform planned maintenance on safety relief valves (SRVs).
Oct 1998	Dec 1998	The unit was taken off-line and shut down for 78 d for the 18th refueling and maintenance outage.
Sep 1999		The unit was taken off-line and shut down for 8 d for a forced outage when both trains of the standby gas treatment (SBGT) system were declared inoperable.
Sep 1999		The unit was taken off-line and shut down when both trains of the SBGT system were declared inoperable after an explosion in the off-gas system. Indications were that the explosion took place in the Zulu sump, damaging the sump and affecting the Zulu sump pumps. Following a rapid shutdown of the unit, the licensee declared a UE because of the explosion. When the off-gas system was completely vented and free of hydrogen, the licensee terminated the UE.

CRYSTAL RIVER 3

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

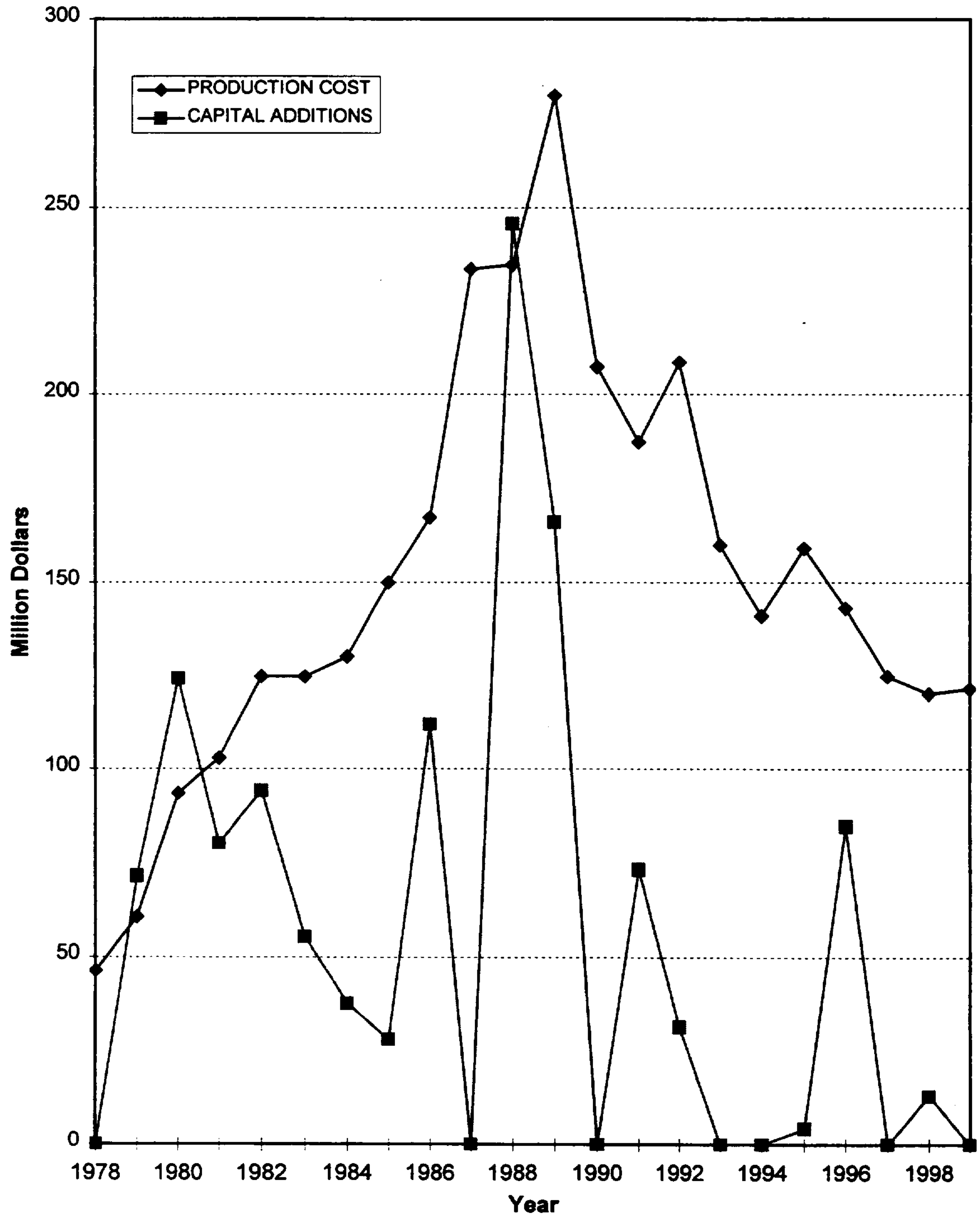
Unit:	**CRYSTAL RIVER 3**	Nameplate Rating (MWe):	**890**
Location:	**Citrus County, Florida**	MDC Net MWe	**818**
Operator:	**Florida Power Corp.**	Cumul. Avail. Factor:	**63.4**
Type:	**Babcock & Wilcox PWR**	Cumul. Cap. Factor (MDC Net):	**61.3**
Construction Permit:	**9/25/68**	Cumul. Forced Outage Rate:	**20.3**
Operating License:	**1/28/77**	3-Year Avg. Cap. Factor (MDC Net):	**59.8**
Commercial Oper. Date:	**3/13/77**	License Expiration:	**12/3/16**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Sep 1996	Jan 1998	The unit was taken off-line and shut down for a planned maintenance outage; however, the plant remained off-line and in cold shutdown for 1 year and 5 months (514 d) in response to NRC regulatory concerns. The plant was started up on January 31.
Mar 1997		The NRC proposed and the licensee paid a $50,000 fine for multiple violations related to the implementation of the licensee's physical security plan. Specifically, the following six violations were identified: (1) failing to maintain adequate implementing procedures, (2) failing to properly respond to a protected area alarm, (3) failing to be able to assess more than one protected area alarm at a time, (4) failing to maintain a physical barrier to the protected area, (5) failing to appropriately control and safeguards weapons stored in the guard force armory, and (6) failing to properly submit security plan changes to the NRC as required by 10 CFR 50.54(p).
Oct 1999	Nov 1999	The unit was taken off-line and shut down for 42 d for the 11th refueling and maintenance outage.

DAVIS-BESSE

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**DAVIS-BESSE**	Nameplate Rating (MWe):	**925**
Location:	**Ottawa County, Ohio**	MDC Net MWe:	**873**
Operator:	**FirstEnergy Nuclear Operating Co.**	Cumul. Avail. Factor:	**67.0**
Type:	**Babcock & Wilcox PWR**	Cumul. Cap. Factor (MDC Net):	**63.3**
Construction Permit:	**3/24/71**	Cumul. Forced Outage Rate:	**15.2**
Operating License:	**4/22/77**	3-Year Avg. Cap. Factor (MDC Net):	**90.2**
Commercial Oper. Date:	**7/31/78**	License Expiration:	**4/22/17**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
May 1997		The unit was taken off-line and shut down for 24 d for a forced outage to investigate a plant trip. The trip occurred after receiving a fire alarm on the main transformer, which actuated the deluge FP system. The fire alarm was caused by a temperature switch falsely indicating a high-temperature condition.
May 1997		Davis-Besse was operating at 100% power on May 4 when the main transformer deluge system actuated for unknown reasons. The actuation started the electrically driven fire pump, which sprayed water on the transformer for 2 to 3 min. This caused a differential ground on the main transformer, which resulted in a main generator lockout and subsequent turbine trip. The turbine trip caused a reactor trip.
Apr 1998		On April 10 while shutting down the reactor to begin its 11th refueling outage and Davis-Besse was still at 27% power, both makeup filters became plugged by resin that was released from a purification demineralizer placed in service to remove lithium from the RCS. The plugged filter caused letdown pressure to increase above a relief valve set point. The relief valve lifted, and 80 gal of water were relieved to the reactor coolant drain tank. Increased makeup flow to the RPV from seal injection flow to the RCPs and bypass flow around a closed isolation valve caused the pressurizer level to increase also.
Apr 1998	May 1998	The unit was taken off-line and shut down for 42 d for the 11th refueling and maintenance outage. The outage was extended 5 d to investigate filter fouling.
Jun 1998	Jul 1998	The unit was taken off-line and shut down for 12 d for a forced outage after an automatic reactor trip, which resulted from lightning strikes and a tornado touching down in the switchyard.
Jun 1998		Davis-Besse was operating at 99% power on June 24 when lightning strikes were seen in the plant switchyard. Both EDGs were started as a precaution. A lightning strike caused a LOSP, followed by a turbine and reactor trip. A tornado touched down in the switchyard and caused damage to the switchyard, the cooling tower,

		and the turbine building. The licensee declared an alert. AFW pumps automatically started, and supplied EFW to the once-through SGs. The temperature of the No. 2 EDG room reached 2° above its maximum limit while the outside air temperature was 97°F. The EDG was declared inoperable. Eleven transmission towers near the plant were damaged by the tornado.
Sep 1998		On September 9, Davis-Besse plant personnel observed a buildup of boric acid crystals on the outside of the pressurizer spray valve, No. RD-2. Upon closer inspection, the licensee discovered that the nuts on two of the eight body-to-bonnet bolts were missing. The missing nuts were replaced. The licensee determined that under certain design conditions, the valve would not have met plant design criteria for RCS pressure boundary. This valve had been replaced during the last refueling outage approximately 3-1/2 months earlier.
Oct 1998		The unit was taken off-line and shut down for 4 d for a forced outage to investigate the loss of an essential 4160-V bus, repair a failed rupture disk that caused a leak in the component cooling water system, and to initiate a modification for additional overpressure protection.
Oct 1998		On October 14, two electrical busses at Davis-Besse experienced a lockout. The lockout caused the loss of a condensate pump and several other plant loads powered by these busses. Operators reduced thermal power to 87%. Component cooling water pump 1-2 tripped. When the other component cooling water pump, No. 1-1, automatically started, a system leak developed that was determined to be located inside the containment. As a result, the plant operators tripped the reactor. In addition, AFW Pump 1-1 was out of service for testing prior to the lockout event.
Apr 1999	May 1999	The unit was taken off-line and shut down for 17 d for a scheduled midcycle refueling outage.
Oct 1999		On October 2, the No. 2 component cooling water pump tripped when its motor supply breaker tripped because of a phase-to-ground fault on a power cable. The fault was traced to a 5-kV cable in an underground conduit. The cable had been in service for 23 years. The cable showed severe corrosion on the bare copper ground conductor and cracking of the outer neoprene jacket. It appears that groundwater seeped into the conduit over a period of time.

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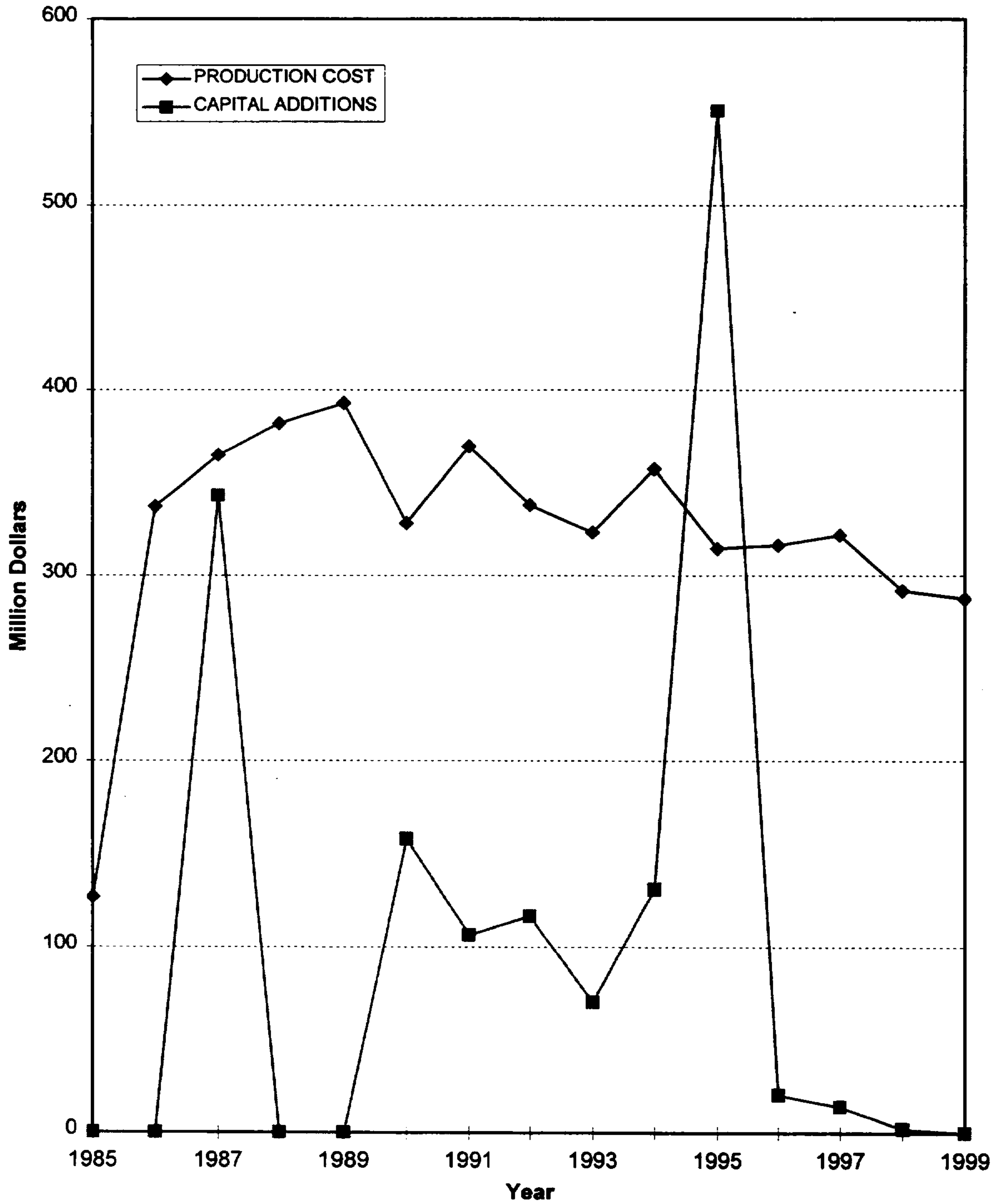
DIABLO CANYON
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**DIABLO CANYON 1**	Nameplate Rating (MWe):	**1137**
Location:	**San Luis Obispo County, California**	MDC Net MWe:	**1073**
Operator:	**Pacific Gas & Electric Co.**	Cumul. Avail. Factor:	**84.8**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**81.8**
Construction Permit:	**4/23/68**	Cumul. Forced Outage Rate:	**3.0**
Operating License:	**11/2/84**	3-Year Avg. Cap. Factor (MDC Net):	**90.0**
Commercial Oper. Date:	**5/7/85**	License Expiration:	**9/22/21**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Apr 1997	Jun 1997	The unit was taken off-line and shut down for 44 d for the eighth refueling and maintenance outage.
Aug 1997		On August 5, a single engine aircraft hit two 500-kV lines near Hesperia, California. Although the lines were not downed, Southern California Edison cut power to the lines. The resulting grid disturbance affected three facilities: Diablo Canyon, Palo Verde, and San Onofre. All three sites experienced increased frequency ranging from 60.3 to 63 Hz. The grid instability lasted approximately 15 min. Diablo Canyon only experienced a momentary increase in generator frequency of 63 Hz with no other effect on the units.
Nov 1998		Ultrasonic testing identified a gas void of 16.7 gal (2.2 ft^3) in the ECCS cross-tie piping in Unit 2 on March 27, 1998. The licensee determined that the gas voids in the piping could have impacted the operability of both SI pumps or both centrifugal charging pumps during the recirculation mode following a LOCA.
Dec 1998		The unit was taken off-line and shut down for 8 d for forced outage to repair both a crack in a weld on the lube oil cooler and an RCS leak on the thermowell for RCP 1-3.
Feb 1999	Mar 1999	The unit was taken off-line and shut down for 35 d for the ninth refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**DIABLO CANYON 2**	Nameplate Rating (MWe):	**1164**
Location:	**San Luis Obispo County, California**	MDC Net MWe:	**1087**
Operator:	**Pacific Gas & Electric Co.**	Cumul. Avail. Factor:	**85.6**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**83.3**
Construction Permit:	**12/9/70**	Cumul. Forced Outage Rate:	**3.5**
Operating License:	**8/26/85**	3-Year Avg. Cap. Factor (MDC Net):	**89.2**
Commercial Oper. Date:	**3/13/86**	License Expiration:	**4/26/25**

Unit Data Summary (Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	Apr 1997	The unit was taken off-line and shut down for 6 d for a forced outage to investigate why the reactor tripped on two-out-of-three coincident SG 2.2 low-low level due to loss of speed control on MFW pump 2-2.
Aug 1997		On August 5, a single engine aircraft hit two 500-kV lines near Hesperia, California. Although the lines were not downed, Southern California Edison cut power to the lines. The resulting grid disturbance affected three facilities: Diablo Canyon, Palo Verde, and San Onofre. All three sites experienced increased frequency ranging from 60.3 to 63 Hz. The grid instability lasted approximately 15 min. Diablo Canyon only experienced a momentary increase in generator frequency of 63 Hz with no other effect on the units.
Oct 1997		The plant was at 100% power when a maintenance crew removing scaffolding somehow caused a main steam (MS) isolation valve (MSIV) to close. This caused a reactor trip. Subsequent to the trip the "sensed" MSL pressure dropped below a set point; as a result, that low-sensed MSL pressure activated an SI signal. All three AFW pumps started and injected into the vessel for approximately 16 min. A UE was declared based on the reactor trip and SI. The AFW injection caused a PORV to lift seven times.
Feb 1998	Mar 1998	The unit was taken off-line and shut down for 42 d for the eighth refueling and maintenance outage.
Dec 1998		The unit was taken off-line and shut down for 5-1/2 d for a forced outage when the reactor was manually tripped due to heavy debris loading of the main CW system.
Sep 1999	Oct 1999	The unit was taken off-line and shut down for 32 d for the ninth refueling and maintenance outage.

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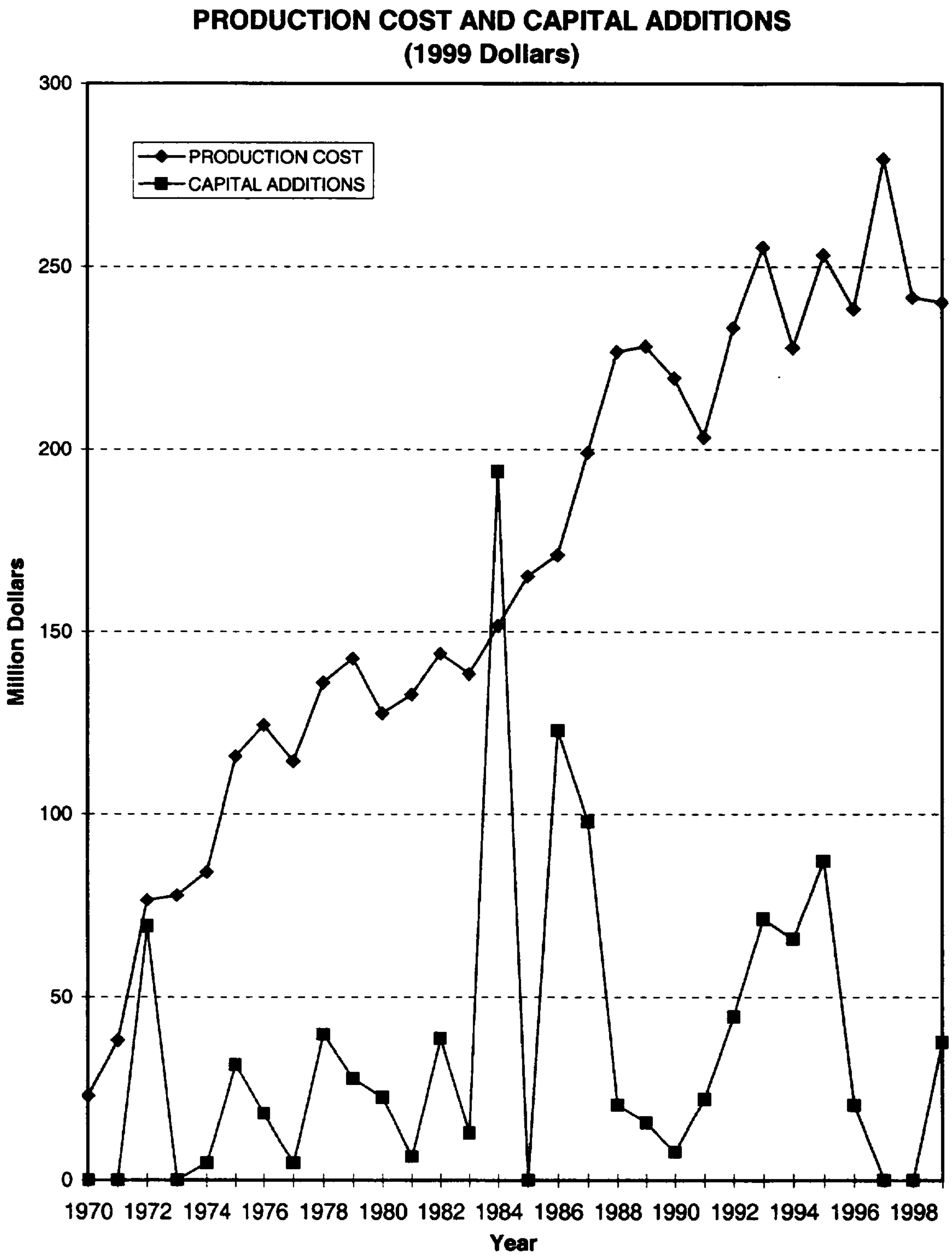
DRESDEN
(Units 2 and 3*)



*1970–1084 includes Unit 1 costs.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**DRESDEN 2**	Nameplate Rating (MWe):	**840**
Location:	**Grundy County, Illinois**	MDC Net MWe:	**772**
Operator:	**Commonwealth Edison Co.**	Cumul. Avail. Factor:	**69.5**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**58.7**
Construction Permit:	**1/10/66**	Cumul. Forced Outage Rate:	**13.2**
Operating License:	**2/20/91**	3-Year Avg. Cap. Factor (MDC Net):	**86.0**
Commercial Oper. Date:	**6/9/70**	License Expiration:	**1/10/06**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Apr 1997	May 1997	The unit was taken off-line and shut down for 29 d for a forced outage to repair the auxiliary contact assembly in Merlin Gerin electrical breakers.
May 1997		The unit was taken off-line and shut down for 5 d to repair an MSIV packing leak.
Jul 1997	Aug 1997	The unit was taken off-line and shut down for 4 d due to a reactor scram caused by a reactor vessel (RV) level transient.
Dec 1997		The unit was taken off-line and shut down for 4 d to investigate a spurious half scram that was received during an instrument surveillances.
Jan 1998		The unit was taken off-line and shut down for 4 d to investigate the cause for a scram while conducting TS instrument surveillances.
Mar 1998	Apr 1998	The unit was taken off-line and shut down for 42 d for the 15th refueling and maintenance outage.
Oct 1999		The unit was taken off-line and shut down for 27 d for the 16th refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**DRESDEN 3**	Nameplate Rating (MWe):	**840**
Location:	**Grundy County, Illinois**	MDC Net MWe:	**773**
Operator:	**Commonwealth Edison Co.**	Cumul. Avail. Factor:	**67.4**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**57.6**
Construction Permit:	**10/14/66**	Cumul. Forced Outage Rate:	**13.8**
Operating License:	**3/2/71**	3-Year Avg. Cap. Factor (MDC Net):	**80.7**
Commercial Oper. Date:	**11/16/71**	License Expiration:	**1/12/11**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	Jun 1997	The unit was taken off-line and shut down for 83 d for the 14th refueling and maintenance outage.
Nov 1997		The unit was taken off-line and shut down for 5 d for a forced outage to repair a failed weld joint on the "B" loop of the recirculation system.
Apr 1998		The unit was taken off-line and shut down for 6 d to investigate the cause for a reactor scram.
May 1998		The unit was taken off-line and shut down for 14 d to replace the main power transformer.
May 1998		The unit was taken off-line and shut down for 5 d for a forced outage because of a reactor scram caused by a cross-around relief valve failing open.
Jan 1999	Feb 1999	The unit was taken off-line and shut down for 27 d for the 15th refueling and maintenance outage.

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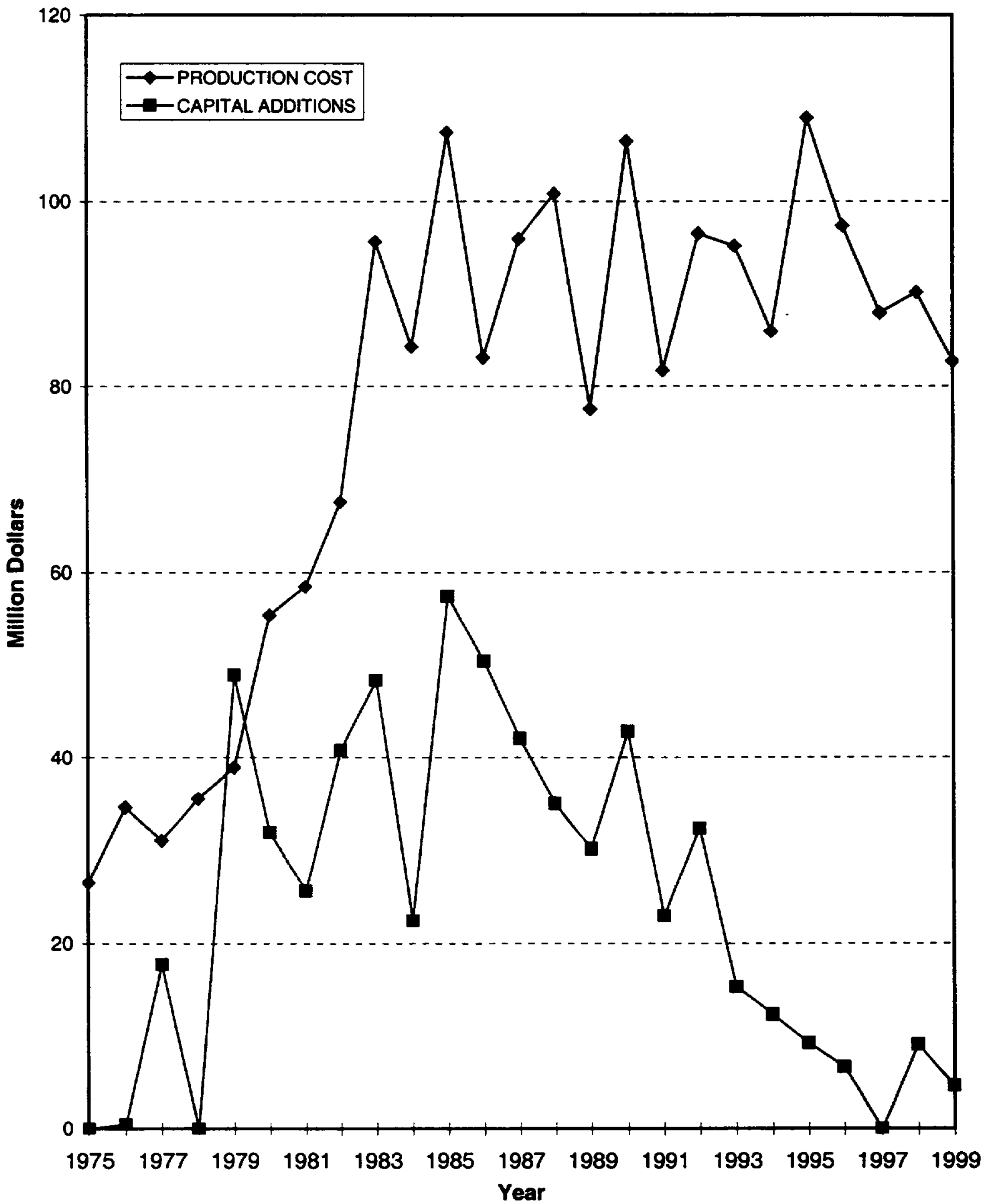
DUANE ARNOLD

PRODUCTION COST AND CAPITAL ADDITIONS (1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

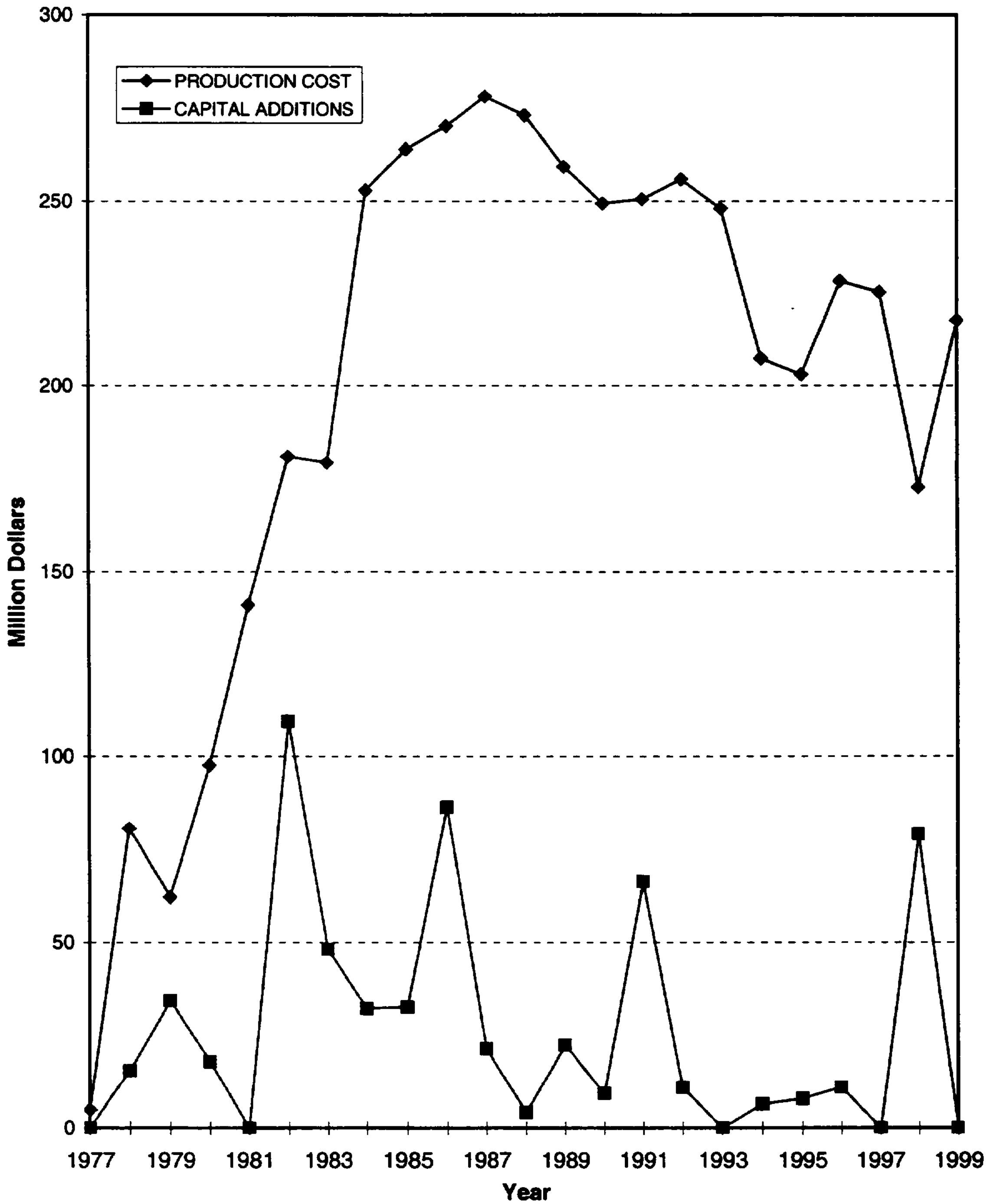
Unit:	**DUANE ARNOLD**	Nameplate Rating (MWe):	**566**
Location:	**Linn County, Iowa**	MDC Net MWe:	**520**
Operator:	**IES Utilities, Inc.**	Cumul. Avail. Factor:	**75.1**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**66.1**
Construction Permit:	**6/22/70**	Cumul. Forced Outage Rate:	**9.1**
Operating License:	**2/22/74**	3-Year Avg. Cap. Factor (MDC Net):	**85.2**
Commercial Oper. Date:	**2/1/75**	License Expiration:	**2/21/14**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jan 1997		The unit was taken off-line and shut down for 6 d to repair a body-to-bonnet leak on an RHR valve.
Mar 1997		The unit was taken off-line and shut down for 6 d to repair a weld on the "3B" drywell cooler.
Aug 1997		The unit was taken off-line and shut down for 6 d for a scheduled outage to repair a main condenser tube leak.
Sep 1997		The unit was taken off-line and shut down for 5 d to repair a weld joint on the MSL.
Apr 1998	May 1998	The unit was taken off-line and shut down for 49 d for the 15th refueling and maintenance outage.
Dec 1998		The unit was taken off-line and shut down for 5 d to repair a feedwater (FW) heater bypass piping leak.
Apr 1999		The unit was taken off-line and shut down for 14 d for a forced outage to investigate and repair a main generator ground fault.
Jun 1999		The unit was taken off-line and shut down for 9 d to repair a drywell electrical penetration.
Oct 1999	Dec 1999	The unit was taken off-line and shut down for 40 d for the 16th refueling and maintenance outage.

JOSEPH M. FARLEY
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**JOSEPH M. FARLEY 1**	Nameplate Rating (MWe):	**860**
Location:	**Houston County, Alabama**	MDC Net MWe:	**812**
Operator:	**Southern Nuclear Operating Co.**	Cumul. Avail. Factor:	**80.1**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**74.9**
Construction Permit:	**8/16/72**	Cumul. Forced Outage Rate:	**5.1**
Operating License:	**6/25/77**	3-Year Avg. Cap. Factor (MDC Net):	**81.8**
Commercial Oper. Date:	**12/1/77**	License Expiration:	**6/25/17**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	Jun 1997	The unit was taken off-line and shut down for 82 days for the 14th refueling and maintenance outage.
Apr 1997		On April 17, operators reported some of the self-expanding cork seal was missing from the gap between the main steam valve room (MSVR) and containment building and questioned its ability to prevent flooding between the rooms. These seals are required to function as watertight barriers to contain flood volume in the MSVR. The current MFW line break analysis assumes only one motor-driven AFW pump and the turbine-driven auxiliary feedwater (AFW) pump is available. With sections of this seal missing, a flood could render TDAFW pump unavailable. Similar conditions were previously reported on June 22, 1996, and December 10, 1996, and design reviews were submitted, but the possibility of flooding was not considered. The repair of these seals was given a low priority and became part of the backlog of maintenance deficiencies.
Aug 1998	Sep 1998	The unit was taken off-line and shut down for 18 days for a forced outage to inspect and to plug leaking tubes in SG 1B.
Oct 1998	Dec 1998	The unit was taken off-line and shut down for 73 days for the 15th refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**JOSEPH M. FARLEY 2**	Nameplate Rating (MWe):	**860**
Location:	**Houston County, Alabama**	MDC Net MWe:	**822**
Operator:	**Southern Nuclear Operating Co.**	Cumul. Avail. Factor:	**85.7**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**79.5**
Construction Permit:	**8/16/72**	Cumul. Forced Outage Rate:	**3.2**
Operating License:	**3/31/81**	3-Year Avg. Cap. Factor (MDC Net):	**86.6**
Commercial Oper. Date:	**7/30/81**	License Expiration:	**3/31/21**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1998	May 1998	The unit was taken off-line and shut down for 52 d for the 12th refueling and maintenance outage.
Oct 1999	Dec 1999	The unit was taken off-line and shut down for 60 d for the 13th refueling and maintenance outage.

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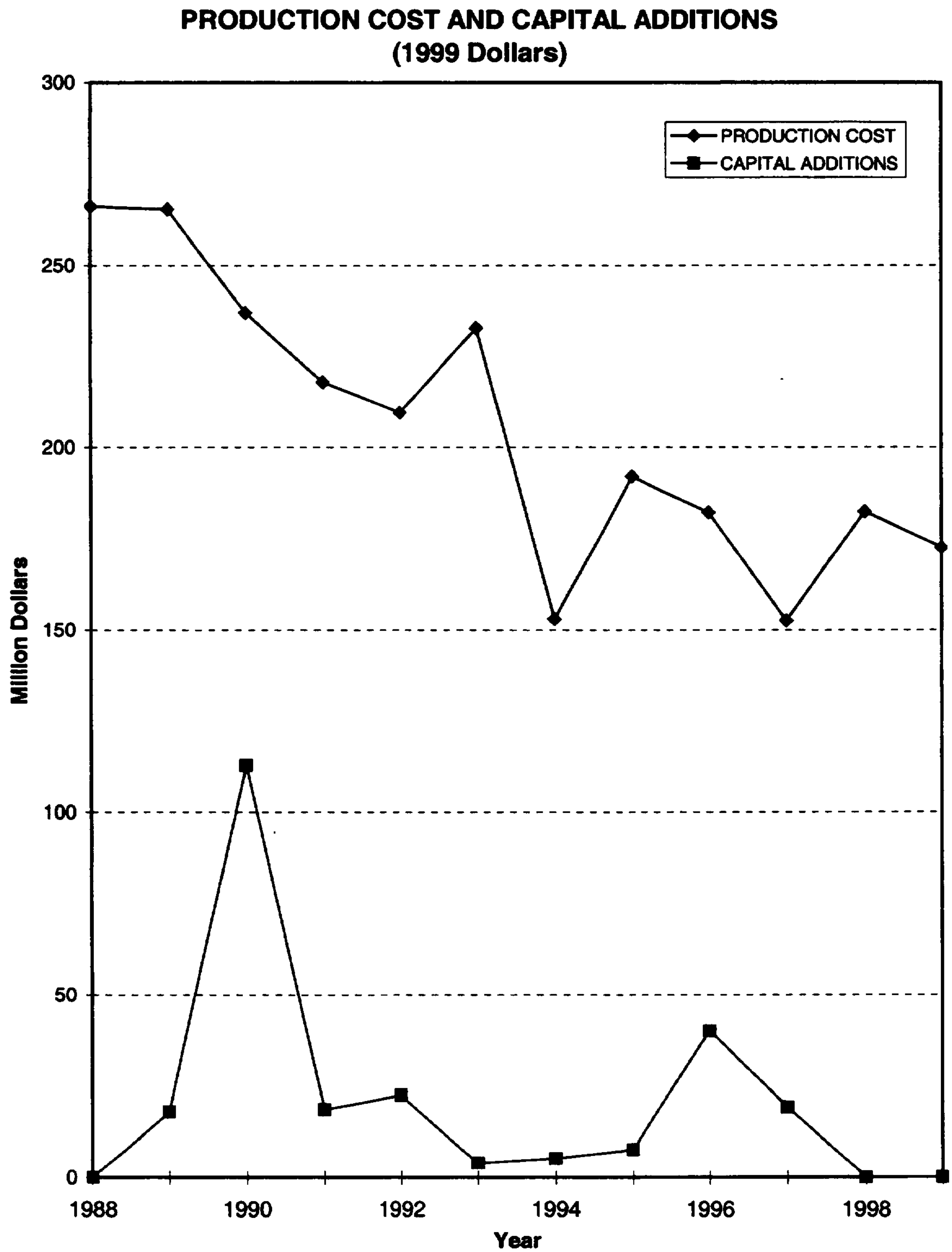
FERMI 2


PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)
PRODUCTION COST
CAPITAL ADDITIONS
Million Dollars
300
250
200
150
100
50
0
1988
1990
1992
1994
1996
1998
Year

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

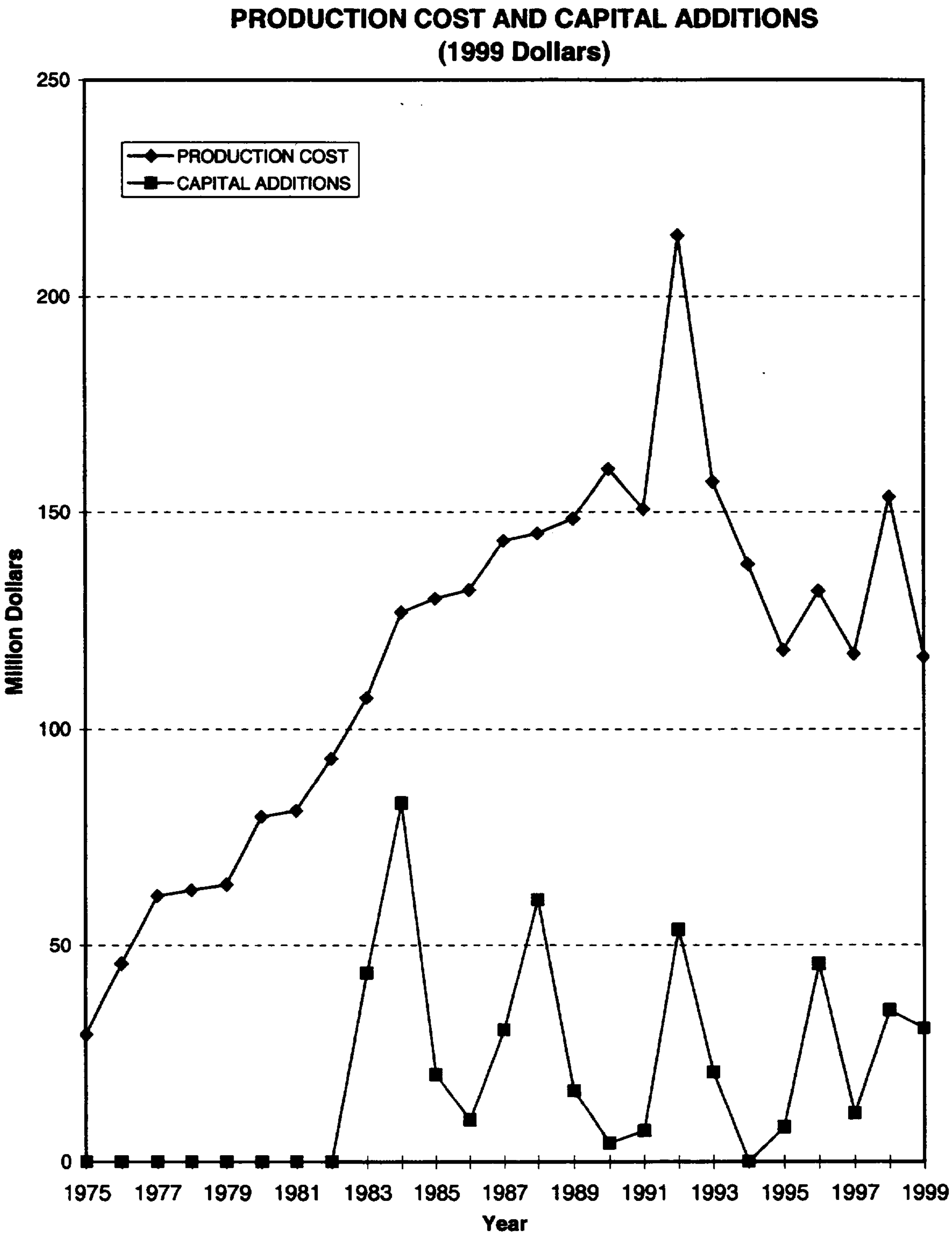
Unit Data Summary (Through December 1999)

Unit:	**FERMI 2**	Nameplate Rating (MWe):	**1179**
Location:	**Monroe County, Michigan**	MDC Net MWe:	**1085**
Operator:	**Detroit Edison Co.**	Cumul. Avail. Factor:	**66.4**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**62.3**
Construction Permit:	**9/26/72**	Cumul. Forced Outage Rate:	**19.5**
Operating License:	**7/15/85**	3-Year Avg. Cap. Factor (MDC Net):	**77.5**
Commercial Oper. Date:	**1/23/88**	License Expiration:	**3/20/25**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jan 1997	May 1997	The unit was taken off-line and shut down for 116 d to repair the off-gas manifold and to inspect and repair the main generator and its output breaker when the breaker failed while attempting to synchronize to the grid.
Oct 1997		The unit was taken off-line and shut down for 16 d to replace two leaking fuel bundles and a reactor recirculation pump seal.
Feb 1998		The unit was taken off-line and shut down for 14 d to investigate a main turbine-generator trip on electrical load rejection, followed by an automatic reactor scram initiated by a reactor protection system (RPS).
Oct 1997		The NRC proposed and the licensee paid a $50,000 fine for multiple corrective action deficiencies.
Feb 1998		The unit was taken off-line and shut down for 14 d to investigate a main turbine-generator trip on electrical load rejection, followed by an automatic reactor scram initiated by a RPS.
Jul 1998		The unit was taken off-line and shut down for 5 d after the operators initiated a manual scram when they observed oscillations in reactor power and associated parameters, caused by unstable flow through the No. 4 turbine control valve.
Sep 1998	Oct 1998	The unit was taken off-line and shut down for 54 d for the sixth refueling and maintenance outage.
Nov 1998		The unit was taken off-line and shut down for 6 d to repair an indicator shaft seal leak on a FW check valve.

JAMES A. FITZPATRICK



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**JAMES A. FITZPATRICK**	Nameplate Rating (MWe):	**883**
Location:	**Oswego County, New York**	MDC Net MWe:	**762**
Operator:	**New York Power Authority**	Cumul. Avail. Factor:	**70.1**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**63.9**
Construction Permit:	**5/20/70**	Cumul. Forced Outage Rate:	**10.8**
Operating License:	**10/17/74**	3-Year Avg. Cap. Factor (MDC Net):	**86.2**
Commercial Oper. Date:	**7/28/75**	License Expiration:	**10/17/14**

Operating History (January 1997 Through December 1999)

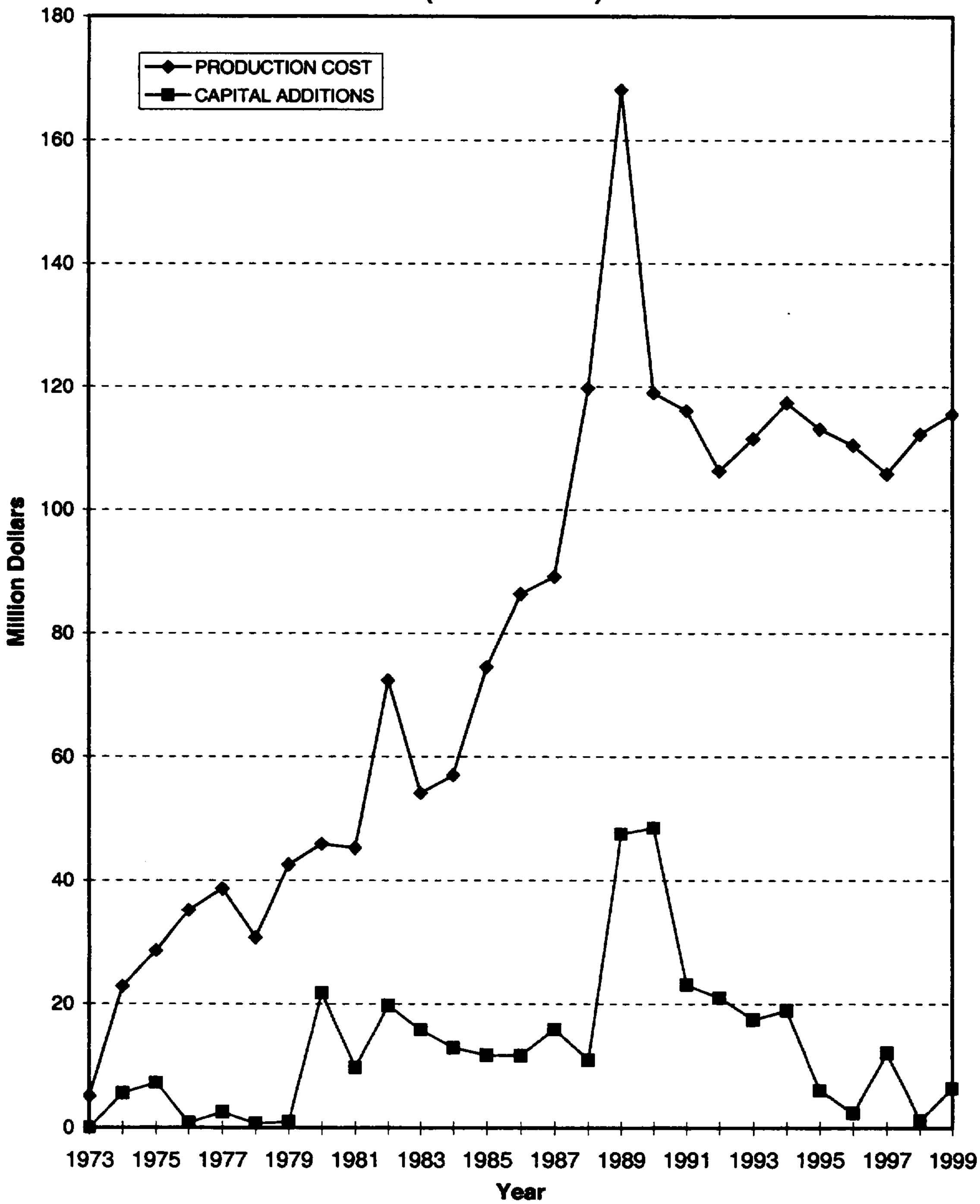
Beginning Date	Ending Date	Comment
Jan 1997		The unit was taken off-line and shut down for 5 d for a forced outage caused by the loss of SW intake due to fish intrusion while two traveling screens were out for maintenance.
Jan 1997		Fitzpatrick was operating at 100% power on January 23 with two of three traveling screens in manual operation mode for maintenance and the third in automatic operation mode. High differential pressure on the screen in the automatic mode caused the operators to reduce power. They were concerned with frazzle ice formation along with debris accumulation on the screen. As a result, the operators (locally) raised the tempering gate. All attempts to move the screens failed, and the shear pins failed on all three traveling screens. Operators scrammed the plant in response to several unsuccessful attempts to restart the screens. Following the scram, about 11 h later, the plant lost shutdown cooling. The high differential pressure across the traveling screens was caused by a large accumulation of 1-1/2 in. stickleback fish. Approximately 1 yd^3 of fish was removed from the screens.
May 1997		When a turbine control valve failed in the open position on May 24, the licensee decided to shut down the plant, and a manual scram was inserted at 70% power. Following the scram and shutdown, a shutdown cooling isolation valve failed to open from the control room and had to be manually opened (locally).
May 1997		The unit was taken off-line and shut down for 6 d for a forced outage to repair the No. 3 turbine control valve. The turbine control valve failed open and could not be closed because the spring pack was broken. The operators manually scrammed the plant.
Sep 1997		The NRC proposed and the licensee paid a $55,000 fine for design control problems.

Dec 1997		The unit was taken off-line and shut down for 7 d for a forced outage to repair SRV pilot valve leakage.
May 1998		The unit was taken off-line and shut down for 10 d for a forced outage to replace a failed power supply.
May 1998		Fitzpatrick was operating at 100% power on May 1 when the operators noticed several control rod drift alarms. The plant was scrammed from 100% power; high-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) both automatically started, but neither system injected into the RPV. The rod drift alarms were caused by a failed power supply in the reactor protection instrumentation system.
Aug 1998		The unit was taken off-line and shut down for 6 d for a forced outage to investigate an automatic trip on low level.
Aug 1998		The unit was taken off-line and shut down for 8 d for a forced outage to repair an outboard MSIV packing leak.
Sep 1998		The NRC proposed and the licensee paid a $55,000 fine for failing to have adequate design measures that would ensure that modifications made to the EDG auxiliaries would perform within the design basis.
Oct 1998	Dec 1998	The unit was taken off-line and shut down for 64 d for the 13th scheduled refueling and maintenance outage.
Jan 1999		Fitzpatrick was at 100% power on January 14 when the plant experienced a fire in its hydrogen storage facility approximately 300 ft west of the plant that lasted for 8 h and 49 min. The licensee declared a UE, and the operators deenergized the 115-kV reserve power switchyard to protect the firefighters, who were fighting the fire near the switchyard. The operators also started and demonstrated operability of the EDGs in accordance with TS. As a safety precaution, the operators left open the tie-breaker that forces-parallel operation with both EDGs (per safety bus) running unloaded. However, this last condition is not listed in the Final Safety Analysis Report (FSAR) and placed the plant outside its design basis. The licensee stated that "... a postevent analysis of this configuration determined that, if the class IE power source(s) had received an automatic initiation signal at this time, protective relay logic would have only allowed one EDG per class IE power source to 'close' on its respective bus." Moreover, "... phase synchronization could not be assured and each EDG would have entered a 'relay race' to determine which EDG on each bus would 'close' first." The licensee stated, "JAF does not have an analysis which demonstrates that a single EDG on a safety bus can supply power to all loads assumed to be required to mitigate the design basis LOCA; therefore, this condition was determined to be outside the design basis of the plant." In its "safety analysis" of this LER, the licensee determined that "... the single operable EDG on each bus was within its design capability to achieve and maintain a safe shutdown without offsite power (no initiation of ECCS loads required)." Further, the licensee indicated that "During this event, the plant was in an unanalyzed condition for approximately a 4-h period."
Jul 1999		The unit was taken off-line and shut down for 5 d for a forced outage to repair a leak on a FW heater drain line.

Oct 1999	The unit was taken off-line and shut down for 11-1/2 d for a forced outage to repair a short in the main generator antimotoring circuit.
Oct 1999	Fitzpatrick was operating at 100% power on October 14 when the plant scrammed and the HPCI turbine tripped on overspeed. Although cause of the HPCI failure was not determined exactly, the licensee replaced the "Remote Servo."
Nov 1999	The unit was taken off-line and shut down for 7 d for a forced outage to repair a broken air line that caused a main turbine trip on high MSR level.
Nov 1999	The plant was operating at 83% power during a power ascension procedure on November 5 when an automatic reactor scram occurred as a result of a main turbine trip. High water levels in the extraction steam system MSR drain tank caused the turbine trip.

FORT CALHOUN 1

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**FORT CALHOUN 1**	Nameplate Rating (MWe):	**502**
Location:	**Washington County, Nebraska**	MDC Net MWe:	**478**
Operator:	**Omaha Public Power District**	Cumul. Avail. Factor:	**78.2**
Type:	**Combustion Engineering PWR**	Cumul. Cap. Factor (MDC Net):	**70.7**
Construction Permit:	**6/7/68**	Cumul. Forced Outage Rate:	**3.8**
Operating License:	**8/9/73**	3-Year Avg. Cap. Factor (MDC Net):	**86.0**
Commercial Oper. Date:	**9/26/73**	License Expiration:	**8/9/13**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Apr 1997		The plant was operating at 100% power on April 21 when there was a major steam line break in the turbine building. The break occurred at the elbow of the 12-in. MS extraction line to the No. 5 heater. The break was characterized as a "fish mouth" break. The operators manually tripped the reactor and declared a UE. As a result of the rupture, asbestos particles in the turbine building were released to the atmosphere via the roof fans, and some were carried to the river via the FP water by the turbine building sump pumps.
Apr 1997	May 1997	The unit was taken off-line and shut down for 21 d for a forced outage to replace a ruptured steam line. The ruptured line was in a section of the high-pressure turbine fourth-stage extraction steam line. The line ruptured at a large-radius (sweep) elbow.
Aug 1997		The NRC proposed and the licensee paid a $55,000 fine for 10 CFR 50, Appendix R violations.
Nov 1997		The NRC proposed and the licensee paid a $110,000 fine for an inoperable containment spray system caused by personnel error during a surveillance test.
Mar 1998	Jun 1998	The unit was taken off-line and shut down for 65 d for the 17th scheduled refueling and maintenance outage.
May 1998		The plant was in cold shut down on May 20 with a plant heatup and startup in progress when security reported to the control room that a transformer had exploded. The explosion caused a loss of the off-site 161-kV power supply and subsequent LOSP. Shutdown cooling was interrupted for several seconds, and the licensee estimated the time to boiling in the RPV was about 2 h; however, no RCS heatup was observed during those few seconds. Both EDGs automatically started and loaded their respective buses. The transformer's automatic FP deluge system inadvertently actuated; the malfunction caused arcs between phases and grounded the transformer.

Jan 1999		The plant was operating at 100% power on January 21 when an incoming off-site 161-kV power line was deenergized. All plant 4160-V buses fast transferred to the alternate on-site 22-kV power source. The plant continued to operate at power.
Oct 1999	Nov 1999	The unit was taken off-line and shut down for 41 d for the 18th scheduled refueling and maintenance outage.

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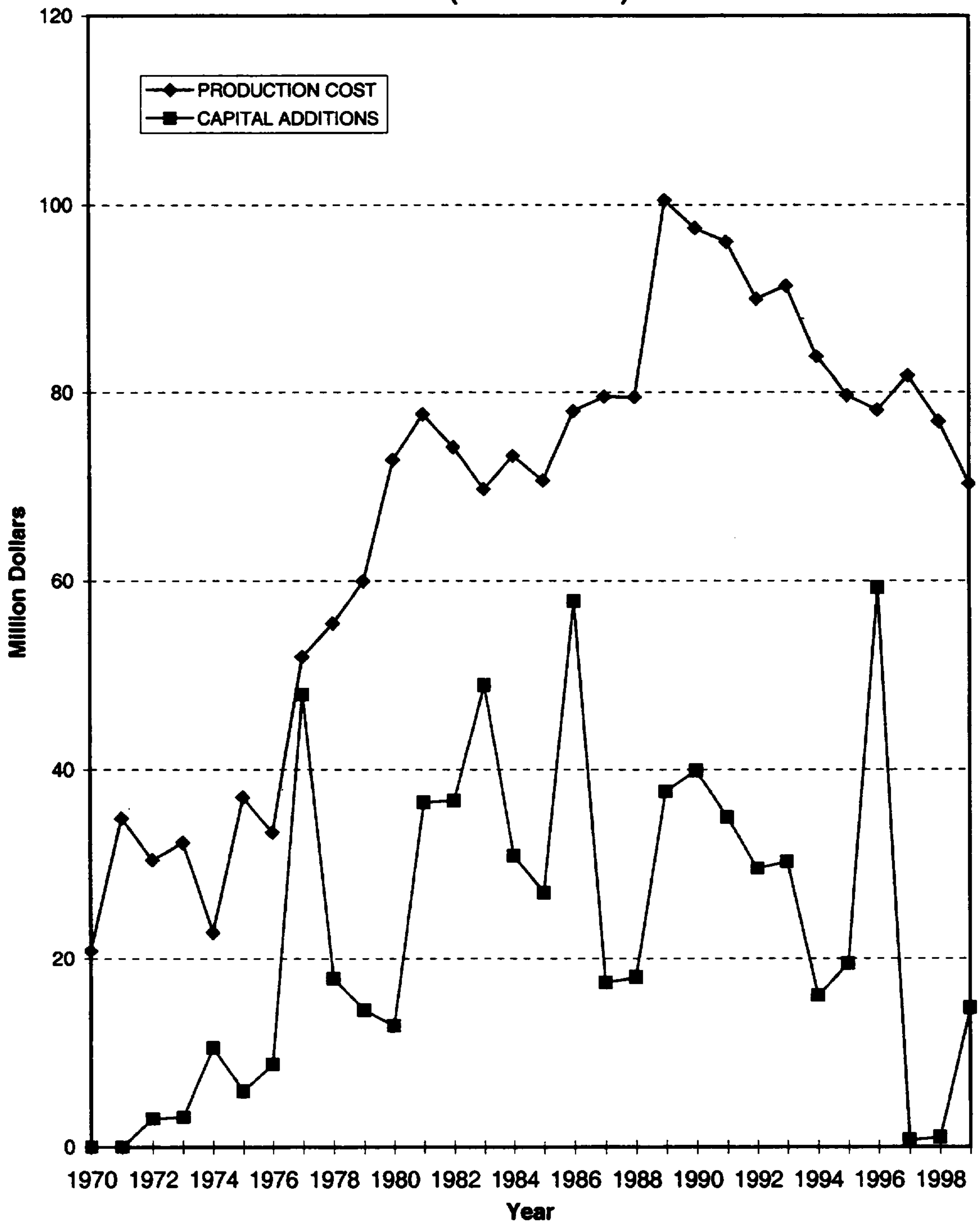
ROBERT E. GINNA

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

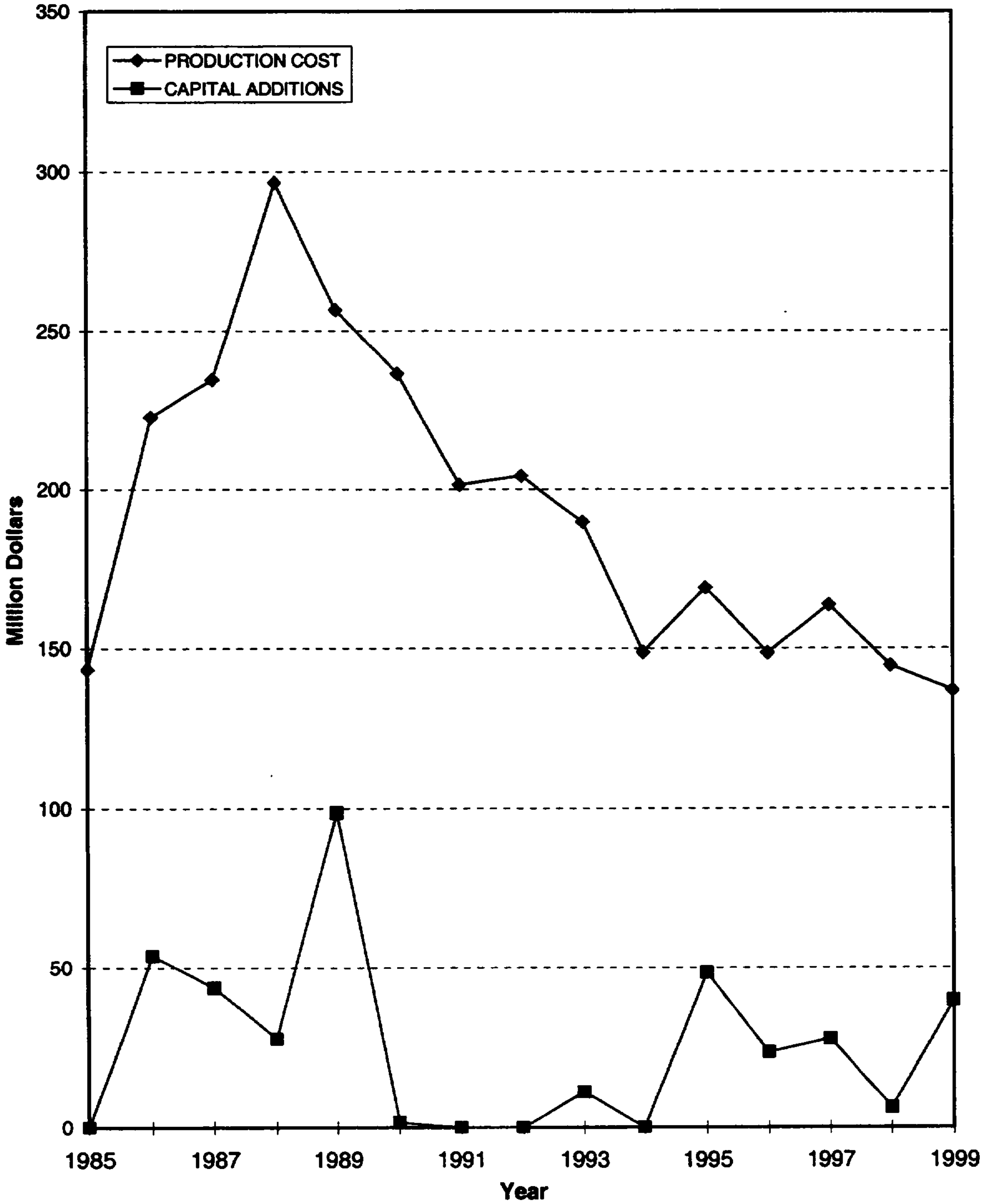
Unit:	**ROBERT E. GINNA**	Nameplate Rating (MWe):	**517**
Location:	**Wayne County, New York**	MDC Net MWe:	**470**
Operator:	**Rochester Gas & Electric Corp.**	Cumul. Avail. Factor:	**79.4**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**75.3**
Construction Permit:	**4/25/66**	Cumul. Forced Outage Rate:	**5.1**
Operating License:	**12/10/84**	3-Year Avg. Cap. Factor (MDC Net):	**93.0**
Commercial Oper. Date:	**7/1/70**	License Expiration:	**9/18/09**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jul 1997		The site had a partial LOSP and an automatic start of an EDG. Power was restored about 1/2 h later.
Sep 1997		The NRC proposed and the licensee paid a $55,000 fine for failing to protect against a land-vehicle bomb.
Oct 1997	Nov 1997	The unit was taken off-line and shut down for 31 d for a scheduled refueling and maintenance outage.
Jul 1998		The licensee filed a 10 CFR 21 report with the NRC regarding W-type DB-75 circuit breakers. There are six installed breakers of this type in the plant with one breaker missing its tripper bar tabs. The licensee indicated that "This deficiency represents a substantial safety hazard." However, this is only a potential failure and "The missing tripper bar tab would not immediately fail the circuit breaker upon removal."
Nov 1998		The site had a partial LOSP and an automatic start of an EDG.
Mar 1999	Apr 1999	The unit was taken off-line and shut down for 52-1/2 d for a scheduled refueling and maintenance outage.

GRAND GULF 1

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

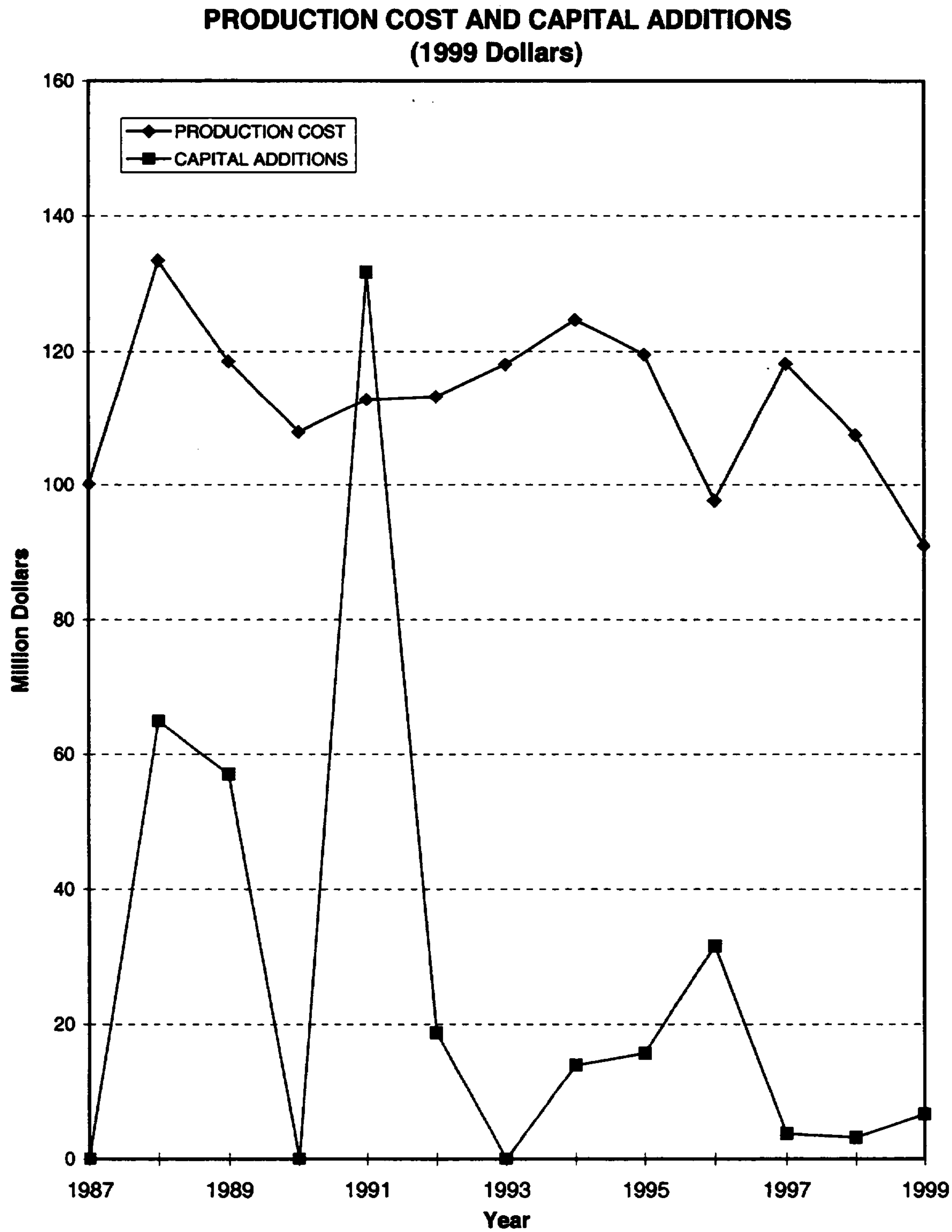
Unit Data Summary (Through December 1999)

Unit:	**GRAND GULF 1**	Nameplate Rating (MWe):	**1373**
Location:	**Claiborne County, Mississippi**	MDC Net MWe:	**1179**
Operator:	**Energy Operations Inc.**	Cumul. Avail. Factor:	**80.6**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**75.9**
Construction Permit:	**9/4/74**	Cumul. Forced Outage Rate:	**5.7**
Operating License:	**11/1/84**	3-Year Avg. Cap. Factor (MDC Net):	**90.1**
Commercial Oper. Date:	**7/1/85**	License Expiration:	**6/16/22**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Apr 1998	May 1998	The unit was taken off-line and shut down for 41 d for the ninth refueling and maintenance outage.
Jan 1999		The unit was taken off-line and shut down for 17 d for a forced outage to inspect and to replace, as necessary, the plant's current transformers after the discovery of melted epoxy compound (used to encapsulate low-voltage current transformers) on the base of the Division I DG feeder breaker.
Feb 1999	Mar 1999	The unit was taken off-line and shut down for 8 d for a forced outage following the failure of the "A" main condenser expansion joint. During the subsequent inspection, the "C" expansion joint was found to have air bubbles in the vulcanized rubber joint. Both expansion joints were replaced.
Sep 1999		The high-pressure core spray (HPCS) EDG was being load tested for 24 h at 110% load when a loud noise was heard. It was followed by a load dip and subsequent high-temperature alarms with sparks being observed coming from the east end-bearing. The EDG was tripped, and during the coastdown the shaft seized at about 15–20 rpm. The EDG had run for about 20 min at 110% load when the bearing failure occurred. The oil level in the reservoir had been decreased to avoid complications from frothing. The EDG was run six times, for a total run time of 8 h, from July 9 through September 9. In addition, the Division I and II EDGs were also inoperable on several occasions (for as long as 24 h) during this time.
Oct 1999	Dec 1999	The unit was taken off-line and shut down for 49 d for the tenth refueling and maintenance outage.

SHEARON HARRIS 1



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

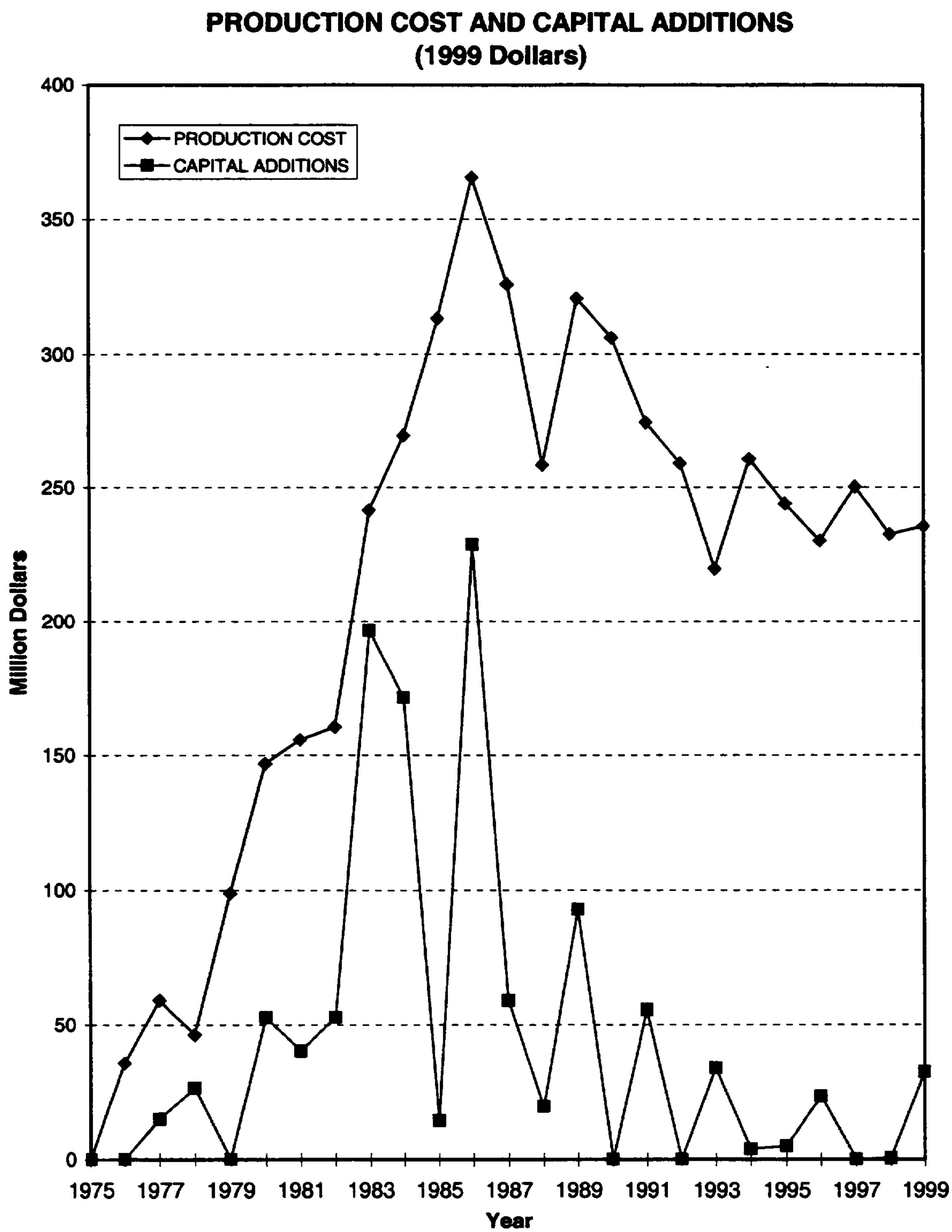
Unit Data Summary (Through December 1999)

Unit:	**SHEARON HARRIS 1**	Nameplate Rating (MWe):	**951**
Location:	**Wake & Chapham County, North Carolina**	MDC Net MWe:	**860**
Operator:	**Carolina Power & Light Co.**	Cumul. Avail. Factor:	**83.5**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**82.2**
Construction Permit:	**1/27/78**	Cumul. Forced Outage Rate:	**3.1**
Operating License:	**1/12/87**	3-Year Avg. Cap. Factor (MDC Net):	**87.9**
Commercial Oper. Date:	**5/2/87**	License Expiration:	**10/14/26**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Apr 1997	Jun 1997	The unit was taken off-line and shut down for 64 d for the seventh refueling and maintenance outage.
Jul 1997		The unit was taken off-line and shut down for 7 d for a forced outage to investigate a plant trip caused by a problem with the main generator exciter rotor.
Dec 1997		While attempting to initiate SG blowdown on the "C" SG, a water hammer event occurred when the outside-containment isolation valve was opened. A socket weld cracked on a valve in a 2-in. line attached to the 6-in. blowdown line. One piping snubber was replaced, also, along with repairs made to some pipe hangers.
Apr 1998		The NRC proposed and the licensee paid a $55,000 fine for allowing two unauthorized individuals access to the protected area.
Oct 1998	Nov 1998	The unit was taken off-line and shut down for 36 d for the eighth refueling and maintenance outage.
Mar 1999		The unit was taken off-line and shut down for 7 d for a forced outage to investigate why the plant received an automatic turbine/reactor trip from the high-SG level in the "C" SG.

EDWIN I. HATCH
(Units 1 and 2)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**EDWIN I. HATCH 1**	Nameplate Rating (MWe):	**850**
Location:	**Appling County, Georgia**	MDC Net MWe:	**805**
Operator:	**Southern Nuclear Operating Co.**	Cumul. Avail. Factor:	**75.4**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**64.7**
Construction Permit:	**9/30/69**	Cumul. Forced Outage Rate:	**8.9**
Operating License:	**10/13/74**	3-Year Avg. Cap. Factor (MDC Net):	**88.7**
Commercial Oper. Date:	**12/31/75**	License Expiration:	**8/6/14**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jan 1997	Feb 1997	The unit was taken off-line and shut down for 5 d to repair a drywell leak.
Oct 1997	Nov 1997	The unit was taken off-line and shut down for 42 d for the 17th refueling and maintenance outage.
Mar 1999	Apr 1999	The unit was taken off-line and shut down for 59 d for the 18th refueling and maintenance outage.
Jun 1999		The unit was taken off-line and shut down for 4 d to repair a steam leak in a MSR drain line.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**EDWIN I. HATCH 2**	Nameplate Rating (MWe):	**850**
Location:	**Appling County, Georgia**	MDC Net MWe:	**809**
Operator:	**Southern Nuclear Operating Co.**	Cumul. Avail. Factor:	**77.1**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**65.5**
Construction Permit:	**12/27/72**	Cumul. Forced Outage Rate:	**5.9**
Operating License:	**6/13/78**	3-Year Avg. Cap. Factor (MDC Net):	**86.6**
Commercial Oper. Date:	**9/5/79**	License Expiration:	**6/13/18**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	Apr 1997	The unit was taken off-line and shut down for 36 d for the 13th refueling and maintenance outage.
Sep 1997		The unit was taken off-line and shut down for 4-1/2 d for a forced outage when the limit switches on the inboard MSIVs failed to reset during a quarterly TS surveillance.
Nov 1997		The unit was taken off-line and shut down for 6 d for a forced outage to repair a broken hinge pin on a discharge check valve in the reactor recirculation system.
Sep 1998	Nov 1998	The unit was taken off-line and shut down for 63 d for the 14th refueling and maintenance outage.
Jan 1999	Feb 1999	The unit was taken off-line and shut down for a 6-day scheduled outage to repair electrical grounds on the "C" and "K" SRVs.
May 1999		The unit was taken off-line and shut down for 5-1/2 d for a forced outage to repair the isophase bus duct cooling fan on the main generator, which caused a reactor scram when it failed.
Jun 1999		The unit was taken off-line and shut down for 8 d for a forced outage to investigate why the main condenser became unable to reject heat at a rate sufficient to accommodate full-power steam flow.
Jun 1999		A faulty steam jet air ejector caused a loss of vacuum on the main condenser, and the operators manually scrammed the reactor from 41% power. The trip was complicated when two 4160-V safety-related buses failed to transfer to their alternate sources as expected, both reactor recirculation system pumps tripped, and a ground fault on a 600-V bus caused several breakers to trip open. After the trip, when vacuum decreased enough, the MSIVs automatically closed as expected; however, one MSIV failed to close.

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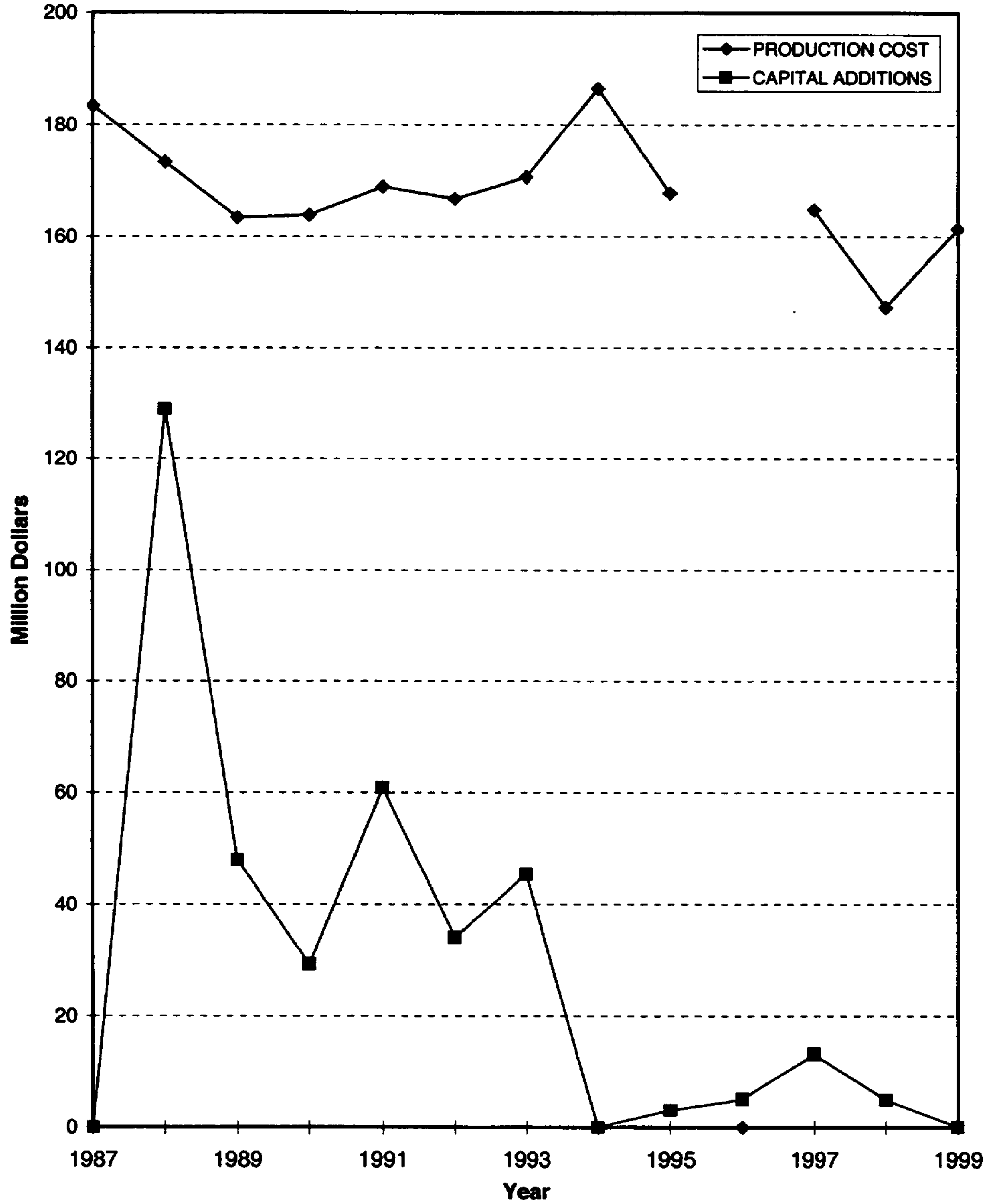
HOPE CREEK 1

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

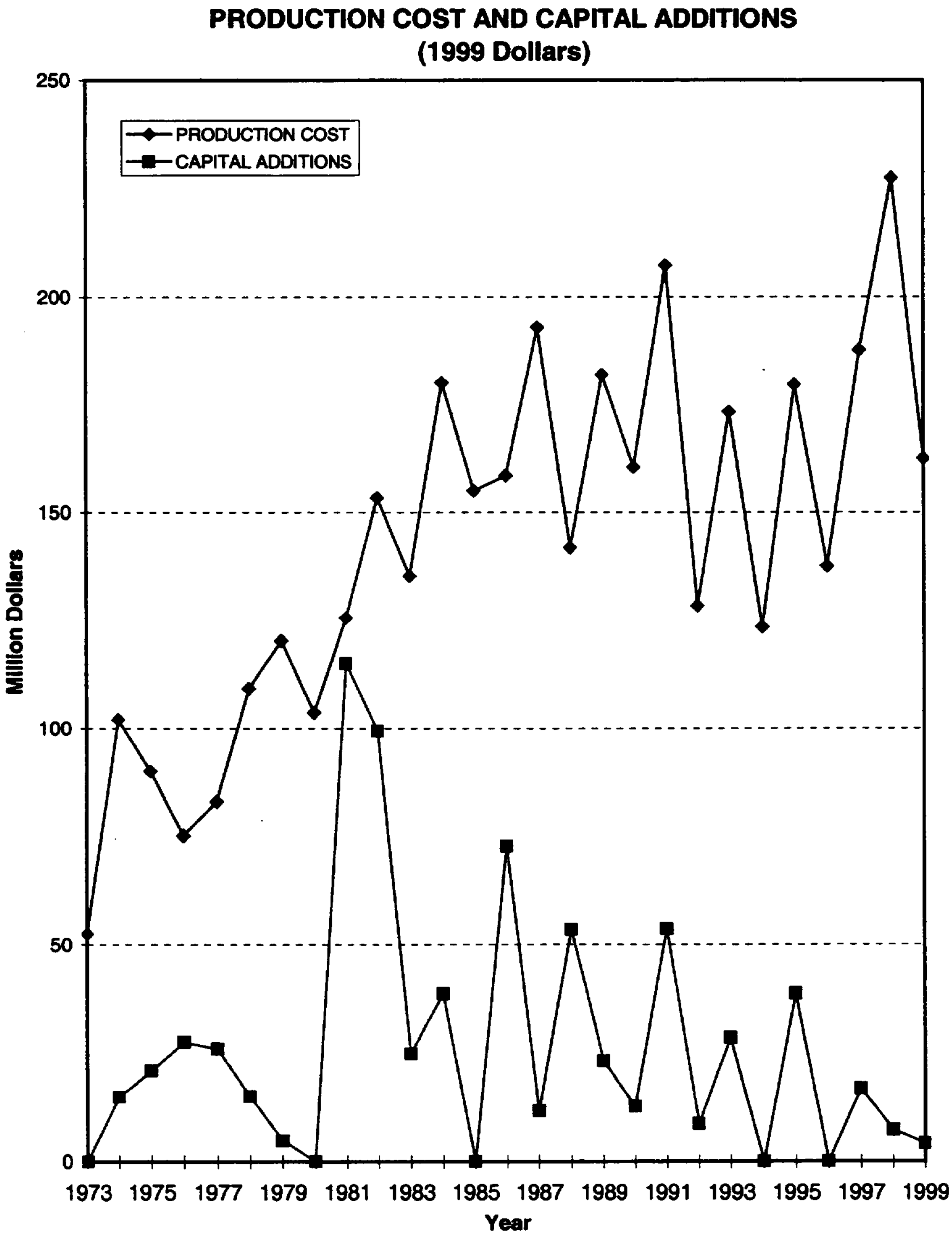
Unit Data Summary (Through December 1999)

Unit:	**HOPE CREEK 1**	Nameplate Rating (MWe):	**1170**
Location:	**Salem County, New Jersey**	MDC Net MWe:	**1031**
Operator:	**Public Service Electric & Gas Co.**	Cumul. Avail. Factor:	**82.4**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**81.7**
Construction Permit:	**11/4/74**	Cumul. Forced Outage Rate:	**4.0**
Operating License:	**7/25/86**	3-Year Avg. Cap. Factor (MDC Net):	**84.2**
Commercial Oper. Date:	**12/20/86**	License Expiration:	**4/11/26**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Sep 1997		The plant was operating at 76% power on September 10 when a main transformer trouble alarm was received in the control room. When the operators investigated, they discovered that none of the fans or oil pumps on the "A" main phase transformer were operating. The plant was tripped after power was reduced to 38%.
Sep 1997	Dec 1997	The unit was taken off-line and shut down for 91 d for the seventh scheduled refueling and maintenance outage.
Dec 1997		On December 5, RCIC failed a TS surveillance test when the operators were unable to control speed and flow for the system. The turbine had to be tripped remotely by the operators in the control room. The failure was traced back to March 1997 when the governor valve stem was last installed. Subsequently, HPCI also failed its TS surveillance test, tripped on start, reset, and then made unacceptable noises and was taken out of service. The plant was shut down and cooled down.
Apr 1998		The NRC proposed and the licensee paid a $55,000 fine for violating control rod drive (CRD) operating procedures during the shutdown margin demonstration.
Nov 1998		The unit was taken off-line and shut down for 9 d for a forced outage to repair a dump valve that had failed in the moisture separator drain tank.
Feb 1999	Mar 1999	The unit was taken off-line and shut down for 47 d for the eighth scheduled refueling and maintenance outage.
Aug 1999	Sep 1999	The unit was taken off-line and shut down for 4 d for a forced outage to repair a reactor recirculation system pump seal.

INDIAN POINT 2



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**INDIAN POINT 2**	Nameplate Rating (MWe):	**1310**
Location:	**Westchester County, New York**	MDC Net MWe:	**951**
Operator:	**Consolidated Edison Co. of NY**	Cumul. Avail. Factor:	**68.1**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**62.23**
Construction Permit:	**10/14/66**	Cumul. Forced Outage Rate:	**11.4**
Operating License:	**9/28/73**	3-Year Avg. Cap. Factor (MDC Net):	**52.8**
Commercial Oper. Date:	**8/1/74**	License Expiration:	**9/28/13**

Operating History (January 1997 Through December 1999)

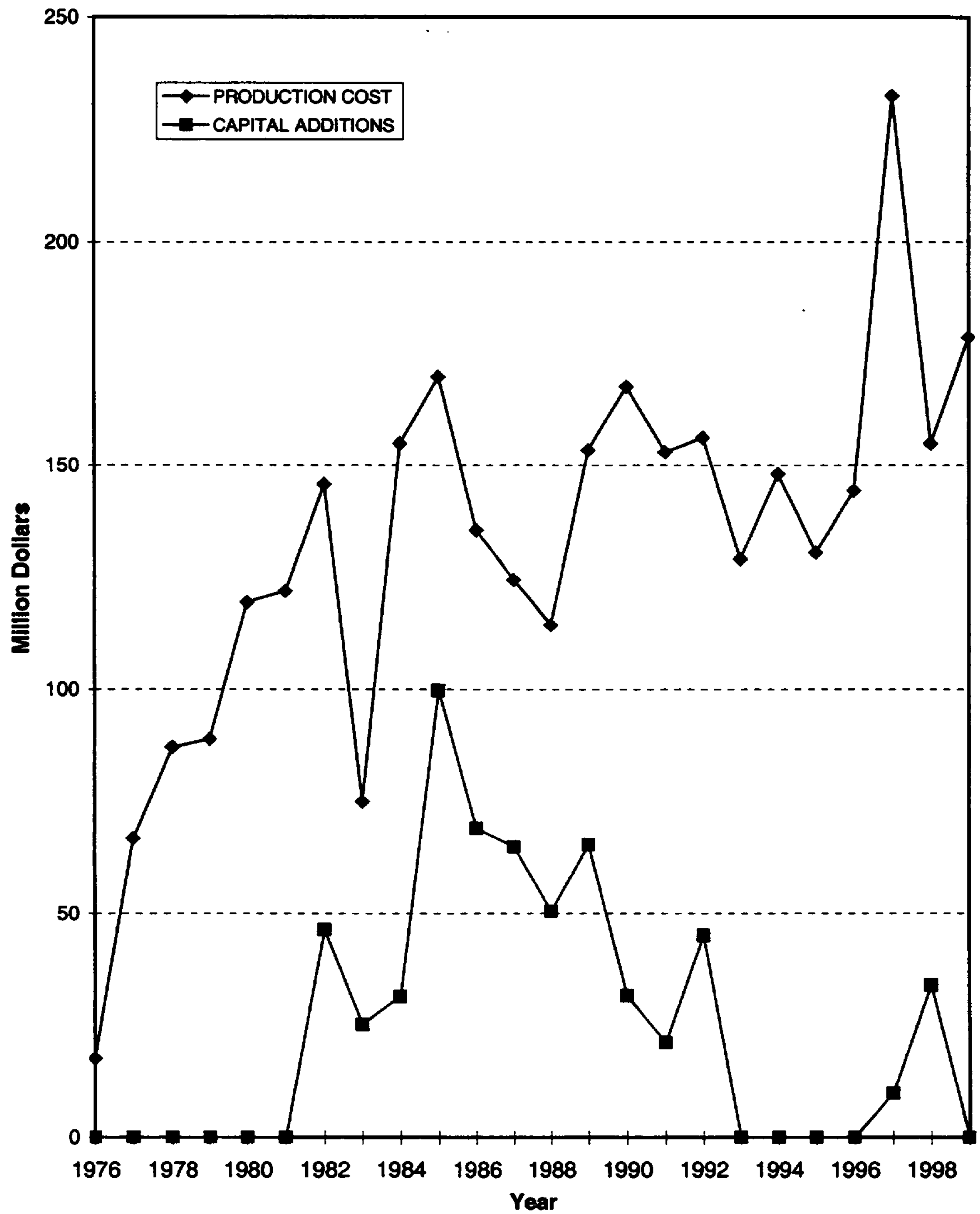
Beginning Date	Ending Date	Comment
Jan 1997		Indian Point Unit 2 was operating at full power on January 26 when the licensee discovered that a FW regulating valve would not close. While decreasing power to repair the valve, the licensee discovered that two other FW regulating valves were stuck open. The turbine was manually tripped when the plant was at 14% power, and that resulted in an automatic reactor trip. Following the shutdown, the remaining FW regulating valve was also discovered to be stuck open. Disassembly of the four valves revealed evidence of severe galling and scoring on the cages and valve plugs. Abrasive grit used on the high-pressure turbine during the 1995 refueling outage was probably the foreign material that caused the valve failures.
Jan 1997	Mar 1997	The unit was taken off-line and shut down for 48 d for a forced outage to investigate MFW regulating valve problems.
May 1997		On May 1, the main generator at Indian Point Unit 2 was taken off-line for the 1997 refueling outage. During a TS surveillance test, one main steam safety valve on SG 23 stuck open, Because of the increasing differential pressure between one SG and two others, a SI signal was generated. During the EDG load sequence, an AFW motor-driven pump and a containment fan cooler unit failed to start. In accordance with emergency operating procedures, the operators manually started both pumps. The main steam safety valve remained open for 5 min and 34 s. During the event, the PORVs opened five times at approximately 90-s intervals until the SI signal was reset and pressurizer spray was established. The RCS cooldown was terminated when the main steam safety valve closed.
May 1997	Jul 1997	The unit was taken off-line and shut down for 71 d for the 13th scheduled refueling and maintenance outage.

Jun 1997		The NRC proposed and the licensee paid a $205,000 fine for noncompliance issues involving hot shorts and loss of instrumentation, inadequate corrective actions, a feedwater regulating valve failing open because of sandblasting grit, and failing to identify the actuation of fire dampers.
Jul 1997		Indian Point Unit 2 was operating at 100% power on July 26 when a problem on a 345-kV transformer cleared three breakers on the off-site power ring bus. The turbine tripped and caused a reactor trip and the loss of all RCPs, which placed the plant in natural circulation conditions for 40 min before forced coolant flow was re-established. A fault in a protective directional relay in the unit auxiliary transformer was the reason the main generator shed its loads. The load shedding from the main generator caused an increase in turbine speed, and the overspeed caused an increase in frequency to the internal loads fed by the generator. This prevented an automatic transfer of the 6.9-kV buses to the station auxiliary transformer that feeds 6.9-kV safety-related buses. This also deenergized two 480-V buses.
Aug 1997		The unit was taken off-line and shut down for 10 d for a forced outage to recalibrate the set points on the pressurizer SRVs.
Oct 1997	Sep 1998	The unit was taken off-line and shut down for 326 d. Originally, the unit was removed from service to investigate problems with 480-V DB-50 electrical breakers. The plant was returned to service on September 5.
Nov 1997		The NRC proposed and the licensee paid a $110,000 fine for an inoperable reactor recirculation pump.
Jul 1998		The NRC proposed and the licensee paid a $110,000 fine for violations regarding inaccurate information, DB-50 electrical breakers, plant TS surveillance testing, and containment atmospheric control.
Aug 1998		Indian Point Unit 2 was in hot shutdown on August 11 when an AFW pump failed to start as expected during a TS surveillance test. The motor supply circuit breaker, W Model DB-50, failed to close when the operator turned the control switch. The licensee filed a 10 CFR Part 21 notification with the NRC regarding the breaker.
Sep 1998		The unit was taken off-line and shut down for 5 d for a forced outage. The unit was shut down to replace the high-efficiency particulate absolute (HEPA) filters on various fan cooler units. Indian Point Unit 2 was at 100% power on September 25 when the W Model DB-75 output circuit breaker for the EDG failed to close. The operators attempted to close the breaker twice without success. The remaining DB-75 circuit breakers were inspected, and one other breaker exhibited similar behavior. The licensee filed a 10 CFR Part 21 notification with the NRC regarding these malfunctions.
Nov 1998		Indian Point Unit 2 was at 99% power on November 19 when the emergency assessment capability was lost on four control room panels. In addition, the licensee determined that both low-level alarms were inoperable in the refueling water storage tank.

Aug 1999		Indian Point Unit 2 was operating at 100% power on August 31 when an automatic reactor and turbine trip occurred due to an overtemperature differential temperature signal. When the I&C group at the plant was replacing a defective bistable for the pressurizer low-pressure trip bistable for protection channel 3, the overtemperature delta-temperature channel trip for protection channel 3 was placed in the trip position. A spurious electrical spike occurred on the overtemperature delta-temperature protection channel 4. This completed the "two out of four" reactor trip logic and caused an overtemperature delta-temperature reactor trip. After the reactor tripped, a sustained undervoltage condition on a 480-V ac bus caused the station blackout logic matrix to generate a blackout signal, stripping the 480-V ac buses and reloading them onto the EDGs. One bus loaded onto its EDG and then tripped off due to an overcurrent trip on the EDG output breaker. A battery charger powered from the bus supported the dc loads on the bus for approximately 7.4 h. During that period of time, power was not restored to the battery charger. Subsequently, an instrument bus was also lost when the voltage on the dc bus became too low for an inverter to provide ac power to the instrument bus. The licensee declared a Notification of UE. The NRC assigned an AIT to investigate the circumstances surrounding the event. Later, it was determined that the licensee should have also declared a UE for the reactor trip.
Aug 1999	Oct 1999	The unit was taken off-line and shut down for 46 d for a forced outage to investigate the reactor trip.

INDIAN POINT 3

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

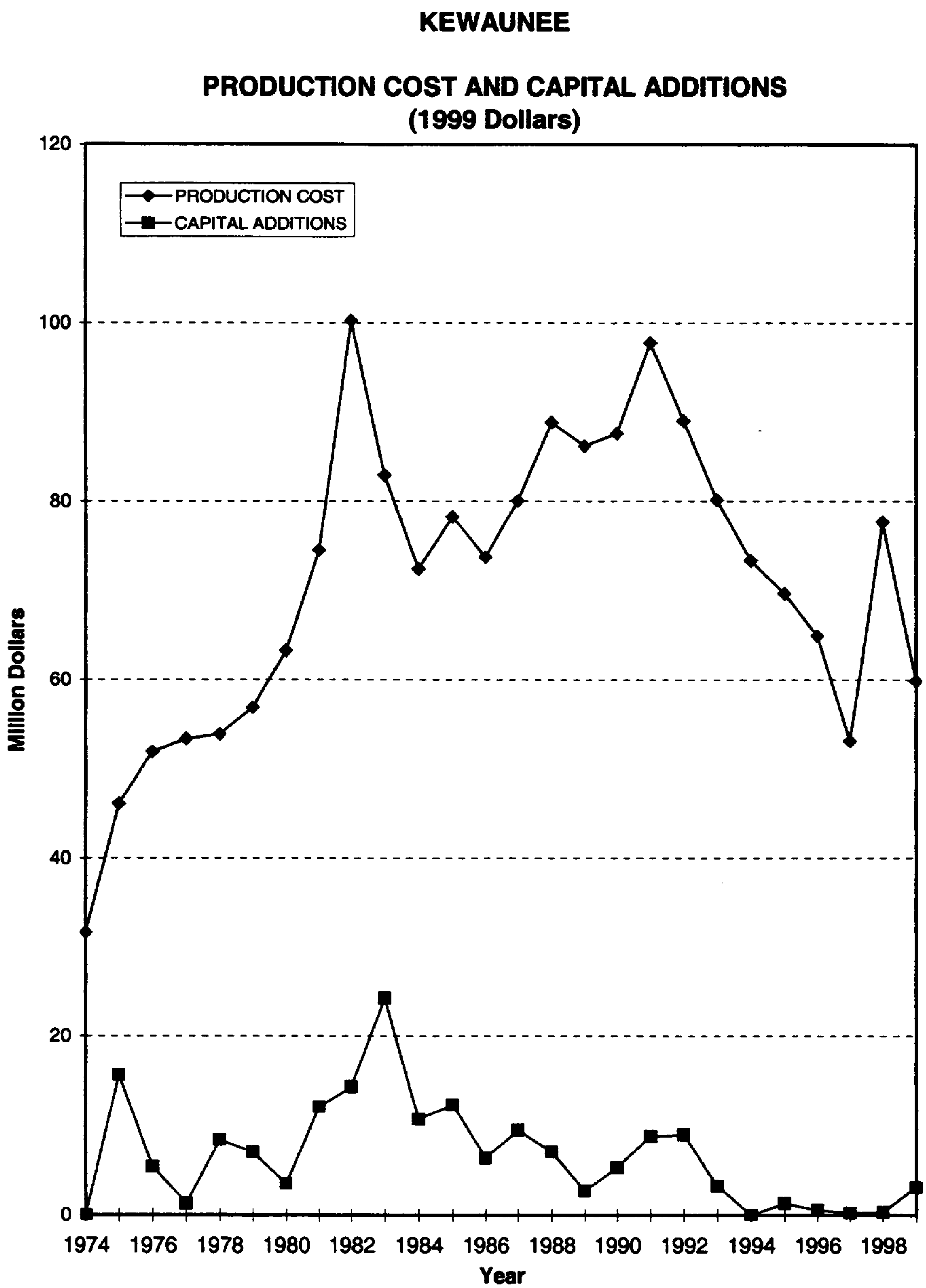
Unit:	**INDIAN POINT 3**	Nameplate Rating (MWe):	**1013**
Location:	**Westchester County, New York**	MDC Net MWe:	**965**
Operator:	**New York Power Authority**	Cumul. Avail. Factor:	**55.5**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**52.2**
Construction Permit:	**8/13/69**	Cumul. Forced Outage Rate:	**26.2**
Operating License:	**4/5/76**	3-Year Avg. Cap. Factor (MDC Net):	**76.0**
Commercial Oper. Date:	**8/30/76**	License Expiration:	**12/15/15**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jan 1997	Feb 1997	The unit was taken off-line and shut down for 32 d for a forced outage. The unit was removed from service because of a high water level in No. 31C FW heater coincident with two other FW heaters, 31 and 32B, being bypassed.
May 1997	Sep 1997	The unit was taken off-line and shut down for 118 d for the ninth scheduled refueling and maintenance outage.
Jun 1997		Indian Point Unit 3 was in a refueling outage on June 6 when Indian Point Unit 2 (another utility) maintenance personnel (another utility) applied a large ground by mistake while switching loads in the switchyard. Both plants share the same switchyard, and the ground caused the loss of the Indian Point Unit 3 station auxiliary transformer. The loss of the transformer caused a LOSP to Indian Point Unit 3. Indian Point Unit 3 had been shut down since May 14, 1997, for the refueling outage and had one EDG out of service for maintenance. The RPV head was removed, the RCS temperature was 125°F, and 119 fuel assemblies had been off-loaded with 74 assemblies remaining in the core. The licensee declared a UE. Off-site power was available (but not used) from one of two 13.8-kV feeder lines. Off-site power was restored approximately 43 min after initial loss, and RCS temperature had increased 2.8°F. When the LOSP occurred, two EDGs started, but the safeguard loads would not load either automatically or manually onto one of the EDGs because of a potential fuse failure. The other EDG loaded and operated as expected. Approximately 40 h later, an automatic start of an EDG occurred because the normal feeder breaker to a safeguards bus tripped open; this time, however, the EDG reenergized the bus, and all loads sequenced back on the bus as expected. On the same day, event 97-010 occurred which involved a loss of ventilation for the 32 EDG and made this EDG technically inoperable. The licensee points out that the 32 EDG would have operated for an unspecified period of time until the room temperature became too high. There were common-cause implications for the other 2 EDGs in this event. The 31 EDG continued to be inoperable because of maintenance. During this period, 31 EDG was unavailable, and 32 EDG was less reliable.

Sep 1997		The licensee reported on September 11 that inadequate emergency operating procedures could allow two motor-driven HHSI pumps to operate without flow during the transfer to hot-leg recirculation following a postulated LOCA. Containment isolation valves on the discharge header for the HHSI pumps were repositioned to the closed position in accordance with emergency operating procedures when the HHSI system is not in operation. Another procedure used for realigning the plant for hot-leg recirculation did not account for this prior repositioning. Thus, two of three high-pressure injection (HPI) pumps could be lost when switching to hot leg recirculation if operators followed the procedure without considering valve alignment.
Sep 1997		The unit was taken off-line and shut down for 5 d for a forced outage to investigate an automatic reactor scram while performing a TS surveillance test.
Dec 1997		The unit was taken off-line and shut down for 11-1/2 d for a forced outage. The plant was shut down for an inoperable 480-V bus. The bus was declared inoperable when an RHR pump circuit breaker failed to open following the performance of a TS surveillance test.
Dec 1997		Indian Point Unit 3 was operating at 100% power on December 18 when a 480-V RHR pump motor circuit breaker stuck closed during its TS surveillance testing. The pump motor circuit breaker, model DS 416, would not open from the control room or locally. The associated 480-V bus was declared inoperable, and the unit was shut down. The RHR breaker opened without operator interaction about 2-1/2 h after the initial failure to open. Further testing revealed another breaker exhibiting the same behavior. The licensee determined that 16 of these breakers were suspected of having had deficient maintenance performed on them by the same contractor. As a result, the licensee declared all three EDGs inoperable.
May 1998		Indian Point Unit 3 was operating at 100% power on May 28 when the normal supply breaker to a safety-related 480-V bus tripped open. This event began when a contract worker bumped into a control switch on an EDG control panel for the supply breaker that tripped open. As a result, a partial LOSP was initiated, a non-SI signal was generated, and an EDG automatically started with the requisite load shedding and sequencing back on the required loads. During the subsequent recovery from the trip, the isolation valve for the cooling water return flow from the thermal barrier heat exchanger for the RCPs closed. RCP seal cooling was lost for about 1 min. Further, the supply breaker to the bus that provided power to the EDG auxiliaries tripped open, which caused the loss of EDG room ventilation fans, the engine crank exhauster, and fuel oil temperature alarms. The loss of bus was discovered when the operators investigated high-temperature alarms and discovered the exhaust fans were not running in the EDG room.
Nov 1998	Dec 1998	The unit was taken off-line and shut down for 15 d for a scheduled outage. The unit was shut down because of violations of TS surveillance requirements that resulted from inadequate leak rate testing of containment isolation valves.
Sep 1999	Oct 1999	The unit was taken off-line and shut down for 41 d for the tenth scheduled refueling and maintenance outage.

Oct 1999	Indian Point Unit 3 was in cold shutdown on October 12 when the plant had an inadvertent SI actuation signal and a subsequent automatic start of an EDG.


KEWAUNEE
PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)
PRODUCTION COST
CAPITAL ADDITIONS
Million Dollars
0
20
40
60
80
100
120
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
Year

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

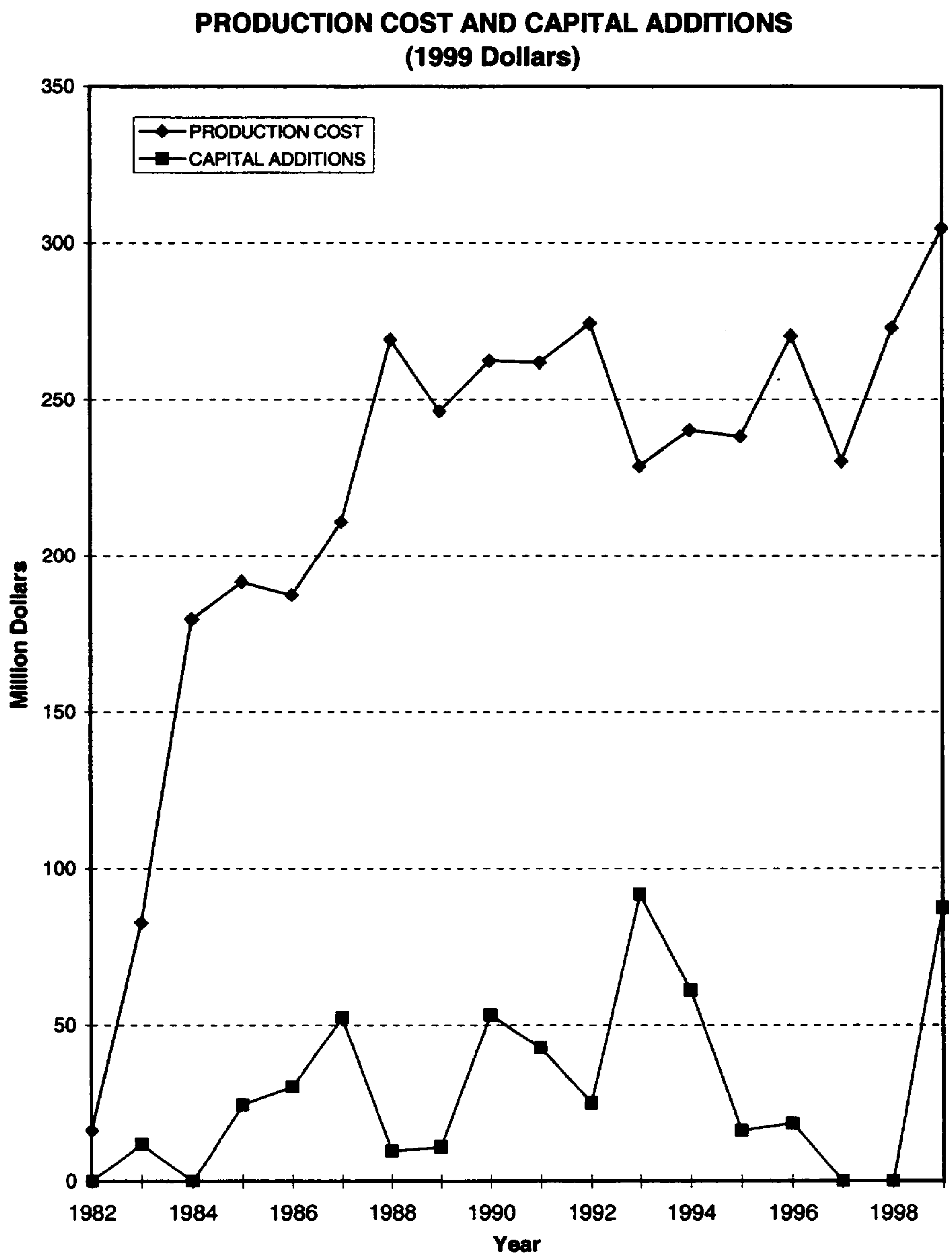
Unit Data Summary (Through December 1999)

Unit:	**KEWAUNEE**	Nameplate Rating (MWe):	**560**
Location:	**Kewaunee County, Wisconsin**	MDC Net MWe:	**511**
Operator:	**Wisconsin Public Service Corp.**	Cumul. Avail. Factor:	**83.4**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**82.1**
Construction Permit:	**8/6/68**	Cumul. Forced Outage Rate:	**1.7**
Operating License:	**12/21/73**	3-Year Avg. Cap. Factor (MDC Net):	**78.1**
Commercial Oper. Date:	**6/16/74**	License Expiration:	**12/21/13**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Aug 1997		The NRC proposed and the licensee paid a $50,000 fine based on inadequate TS surveillance testing of the RHR and AFW pumps.
Feb 1998		The unit was taken off-line and shut down for 7 d for scheduled outage to repair RCP No. 2 seal.
Oct 1998	Nov 1998	The unit was taken off-line and shut down for 41 d for the 22nd refueling and maintenance outage.

LA SALLE COUNTY
(Units 1 and 2)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**LA SALLE COUNTY 1**	Nameplate Rating (MWe):	**1146**
Location:	**La Salle County, Illinois**	MDC Net MWe:	**1036**
Operator:	**Commonwealth Edison Co.**	Cumul. Avail. Factor:	**60.8**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**58.5**
Construction Permit:	**9/10/73**	Cumul. Forced Outage Rate:	**13.1**
Operating License:	**8/13/82**	3-Year Avg. Cap. Factor (MDC Net):	**41.7**
Commercial Oper. Date:	**1/1/84**	License Expiration:	**5/17/22**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Sep 1996	Aug 1998	The unit was taken off-line and shut down for 686 d from September 22, 1996, until August 8, 1998. The plant was originally shut down to repair a main turbine control valve; however, the outage was extended due to regulatory concerns.
Feb 1997		The NRC proposed and the licensee paid a $650,000 fine for injecting foam material into the SW system and clogging the system.
Dec 1998		The unit was taken off-line and shut down for 7 d for a planned maintenance outage.
Oct 1999	Nov 1999	The unit was taken off-line and shut down for 30 d for the eighth refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**LA SALLE COUNTY 2**	Nameplate Rating (MWe):	**1146**
Location:	**LaSalle County, Illinois**	MDC Net MWe:	**1036**
Operator:	**Commonwealth Edison Co.**	Cumul. Avail. Factor:	**63.7**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**58.4**
Construction Permit:	**9/10/73**	Cumul. Forced Outage Rate:	**19.3**
Operating License:	**3/23/84**	3-Year Avg. Cap. Factor (MDC Net):	**24.4**
Commercial Oper. Date:	**10/19/84**	License Expiration:	**12/26/23**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Sep 1996	Apr 1999	The unit was taken off-line and shut down for 933 d from September 20, 1996, until April 10, 1999. The plant was originally shut down for a scheduled refueling and maintenance outage; however, the outage was extended due to regulatory concerns.
Feb 1997		The NRC proposed and the licensee paid a $650,000 fine for injecting foam material into the SW system and clogging the system.

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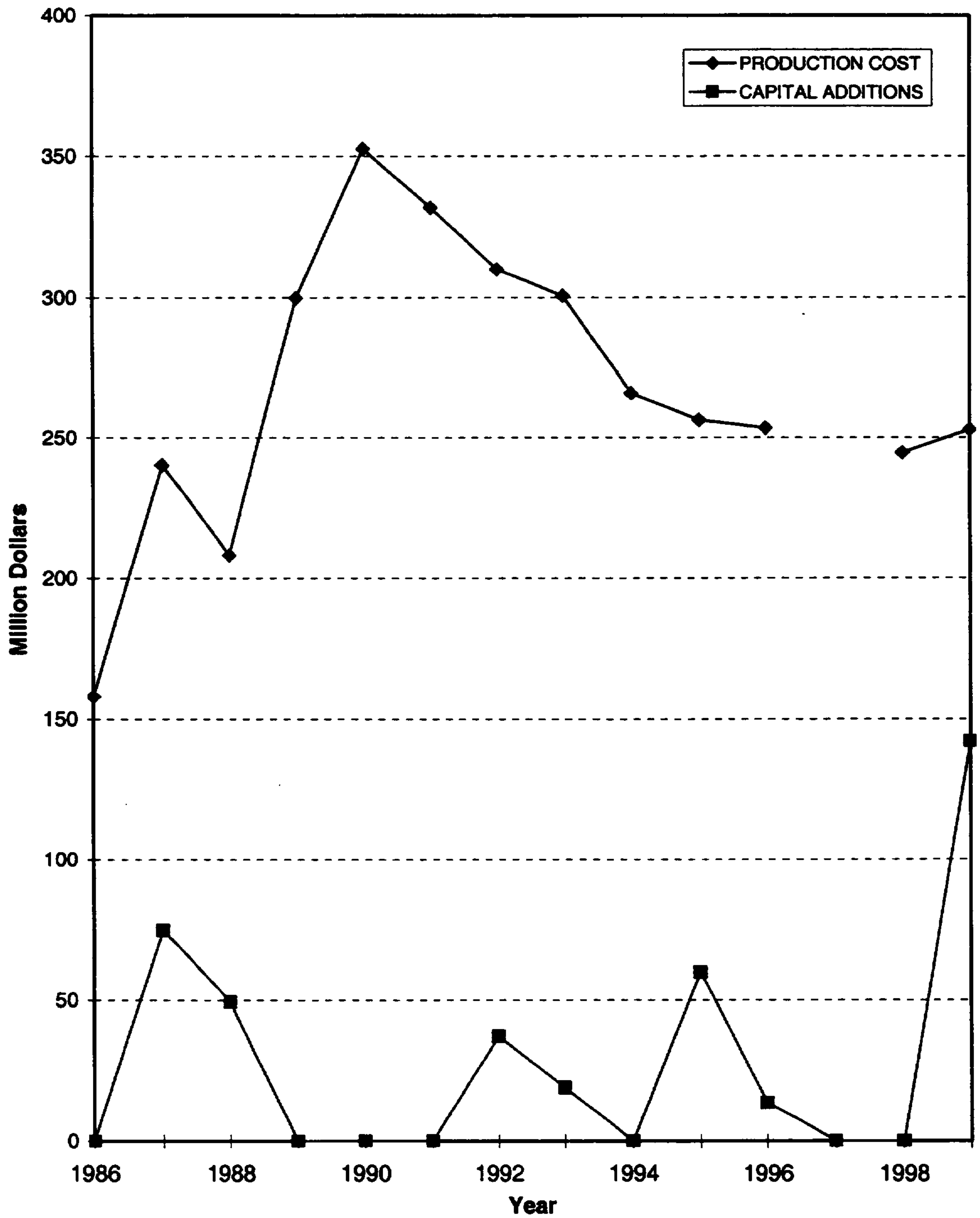
LIMERICK
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**LIMERICK 1**	Nameplate Rating (MWe):	**1160**
Location:	**Montgomery County, Pennsylvania**	MDC Net MWe:	**1105**
Operator:	**PECO Energy Co.**	Cumul. Avail. Factor:	**82.8**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**74.7**
Construction Permit:	**6/19/74**	Cumul. Forced Outage Rate:	**4.0**
Operating License:	**8/8/85**	3-Year Avg. Cap. Factor (MDC Net):	**89.5**
Commercial Oper. Date:	**2/1/86**	License Expiration:	**10/26/24**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jun 1997		The unit was taken off-line and shut down for 6 d for a scheduled maintenance outage to repair an SRV.
Sep 1997		The NRC proposed and the licensee paid an $80,000 fine for falsifying the cooling water sample and FP surveillance records from the reactor enclosure.
Jan 1998	Feb 1998	The unit was taken off-line and shut down for 6 d for a forced maintenance outage to repair the HPCI turbine exhaust valve.
Apr 1998	May 1998	The unit was taken off-line and shut down for 48 d for the seventh scheduled refueling and maintenance outage.
Aug 1998		The NRC proposed and the licensee paid a $55,000 fine for corrective action violations.
Dec 1998		The unit was taken off-line and shut down for 12 d for a scheduled maintenance outage to repair damaged fuel.
Jan 1999		The unit was taken off-line and shut down for 5 d for a forced outage to investigate a loss of FW incident that caused a reactor scram.
Apr 1999		The plant was operating at 100% power on April 20 when the deep-bed demineralizer outlet valves on the condensate system failed to close for some unknown reason. The licensee speculated that a computer malfunction was responsible. The closure of these valves caused a loss of MFW and a subsequent reactor scram from 100% power. Following the scram: one control rod had a slow insert time, no SRVs lifted, and HPCI and RCIC automatically initiated and injected into the RPV. HPCI was secured, and RCIC was used to maintain RPV level; there was a trip of the reactor recirculation system pumps when a breaker failed to open because the loads had been removed. The MSIVs were closed sometime later.

Jun 1999	The plant was operating at 100% power on June 11 when an equipment operator made a mistake during turbine valve testing and caused a scram. The licensee also reported that HPCI was unavailable for 2 months from April 24 until June 25. Moreover, "... HPCI would not start and was therefore unable to perform its function."

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**LIMERICK 2**	Nameplate Rating (MWe):	**1162**
Location:	**Montgomery County, Pennsylvania**	MDC Net MWe:	**1115**
Operator:	**PECO Energy Co.**	Cumul. Avail. Factor:	**90.2**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**81.9**
Construction Permit:	**6/19/74**	Cumul. Forced Outage Rate:	**3.2**
Operating License:	**8/25/89**	3-Year Avg. Cap. Factor (MDC Net):	**88.3**
Commercial Oper. Date:	**1/8/90**	License Expiration:	**6/22/29**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997		The unit was taken off-line and shut down for 27 d for the fourth scheduled refueling and maintenance outage.
Mar 1997	Apr 1997	The unit was taken off-line and shut down for 4 d for a scheduled maintenance outage to repair the main turbine generator alterex, a part of the generator exciter as a subcomponent of the turbine generator.
May 1997		The unit was taken off-line and shut down for 5 d for a scheduled maintenance outage to repair the main turbine alterex.
Sep 1997		The NRC proposed and the licensee paid an $80,000 fine for falsifying the cooling water sample and FP surveillance records from the reactor enclosure.
Oct 1997		An alert was declared because a piece of ECCS equipment was inoperable due to a fire. During a load test, flames were observed shooting out of the exhaust stack for No. D21 EDG. The fire lasted 10 to 15 min. The cause of the fire was unburned fuel oil from the failed No. 1 lower piston that mixed with exhaust from the other cylinders.
May 1998	Jun 1998	The unit was taken off-line and shut down for 17 d for a scheduled maintenance outage.
Jun 1998		The plant was in cold shutdown for a maintenance shutdown. The plant had an inadvertent standby liquid control (SBLC) actuation and, subsequently, injected approximately 320 gal of sodium pentaborate solution into the RPV. Postmaintenance testing on an SRV solenoid induced electromagnetic interference on the redundant reactivity control system and actuated SBLC. "... the interference was not previously observed because testing of these SRV solenoids is usually done during refueling outages when the reactor recirculation cooling system (RRCS) is disabled."

Aug 1998		The NRC proposed and the licensee paid a $55,000 fine for corrective action violations.
Apr 1999	May 1999	The unit was taken off-line and shut down for 39 d for the fifth scheduled refueling and maintenance outage.

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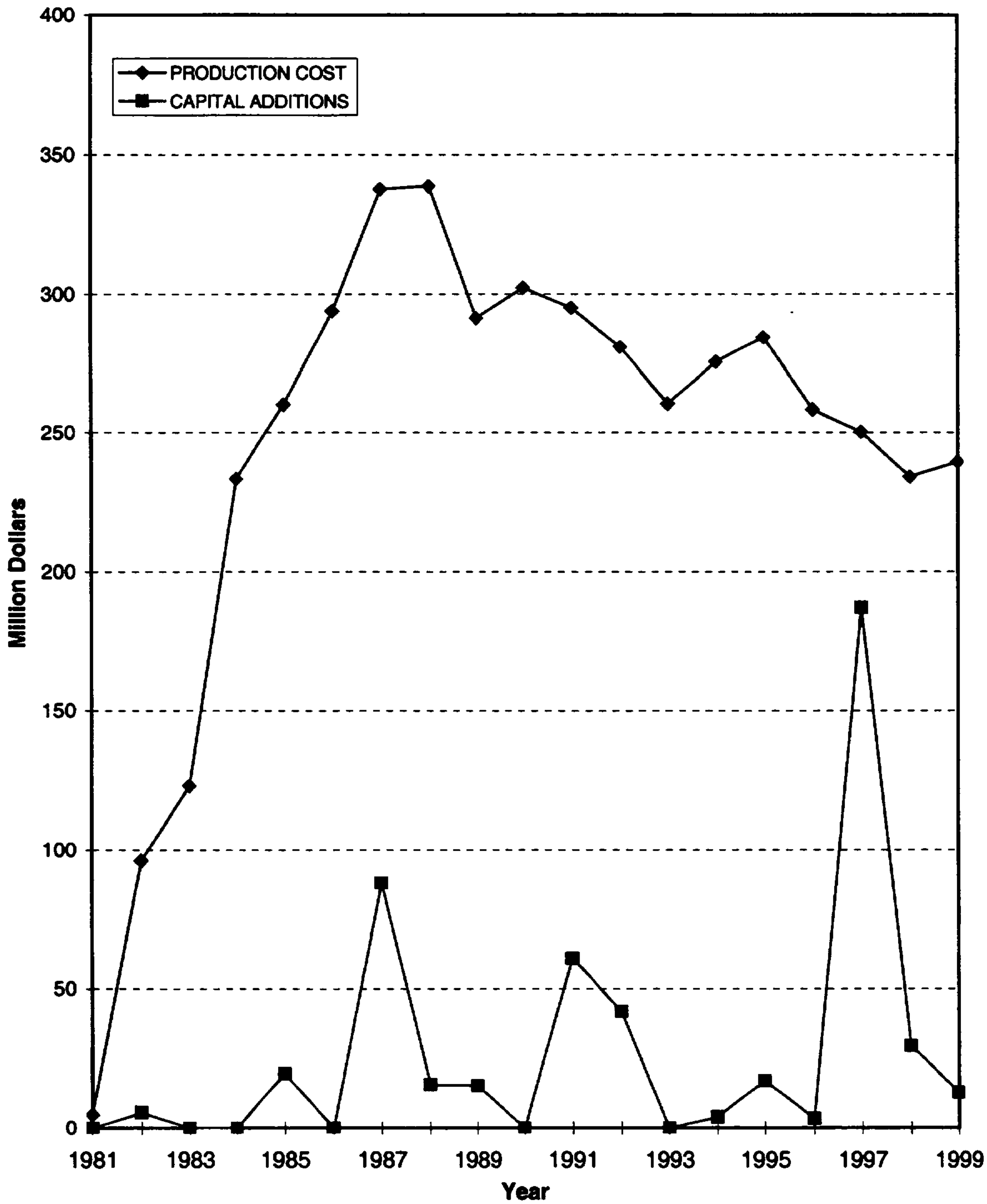
McGUIRE
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**McGUIRE 1**	Nameplate Rating (MWe):	**1305**
Location:	**Mecklenburg County, North Carolina**	MDC Net MWe:	**1129**
Operator:	**Duke Power Co.**	Cumul. Avail. Factor:	**72.8**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**70.6**
Construction Permit:	**2/23/73**	Cumul. Forced Outage Rate:	**11.0**
Operating License:	**7/8/81**	3-Year Avg. Cap. Factor (MDC Net):	**83.8**
Commercial Oper. Date:	**12/1/81**	License Expiration:	**6/12/21**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997	May 1997	The unit was taken off-line and shut down for 94 d for the 11th scheduled refueling and maintenance outage. The SGs were also replaced.
May 1998	Jul 1998	The unit was taken off-line and shut down for 34 d for the 12th scheduled refueling and maintenance outage.
Jun 1998		A UE was declared when Unit 1 lost off-site power after an explosion of a switchyard breaker. Unit 1 was shut down and in a refueling outage since May 28, 1998, with one of two off-site power sources available. Unit 2 was at 100% power and was supplying power to the Unit 1 emergency buses. Unit 2 had one of two EDGs out of service during the Unit 1 LOSP. A current transformer in the second off-site power supply path failed, and Unit 1 nonessential buses lost power. The essential buses remained powered by Unit 2, and decay heat removal was never interrupted. The off-site power supply path was restored within 52 min.
Sep 1999	Oct 1999	The unit was taken off-line and shut down for 42 d for the 13th scheduled refueling and maintenance outage.
Oct 1999	Nov 1999	The unit was taken off-line and shut down for 6-1/2 d for a forced outage to replace a split pin in a CRD mechanism.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**McGUIRE 2**	Nameplate Rating (MWe):	**1305**
Location:	**Mecklenburg County, North Carolina**	MDC Net MWe:	**1129**
Operator:	**Duke Power Co.**	Cumul. Avail. Factor:	**77.7**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**79.3**
Construction Permit:	**2/23/73**	Cumul. Forced Outage Rate:	**6.4**
Operating License:	**5/27/83**	3-Year Avg. Cap. Factor (MDC Net):	**86.5**
Commercial Oper. Date:	**3/1/84**	License Expiration:	**3/3/23**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jun 1997		The unit was taken off-line and shut down for 15 d to repair a SG tube leak.
Jul 1997		The unit was taken off-line and shut down for 11 d following a reactor and turbine trip caused by an RCP trip.
Oct 1997	Dec 1997	The unit was taken off-line and shut down for 77 d for the 11th refueling and maintenance outage.
Mar 1999	Apr 1999	The unit was taken off-line and shut down for 33 d for the 12th refueling and maintenance outage.

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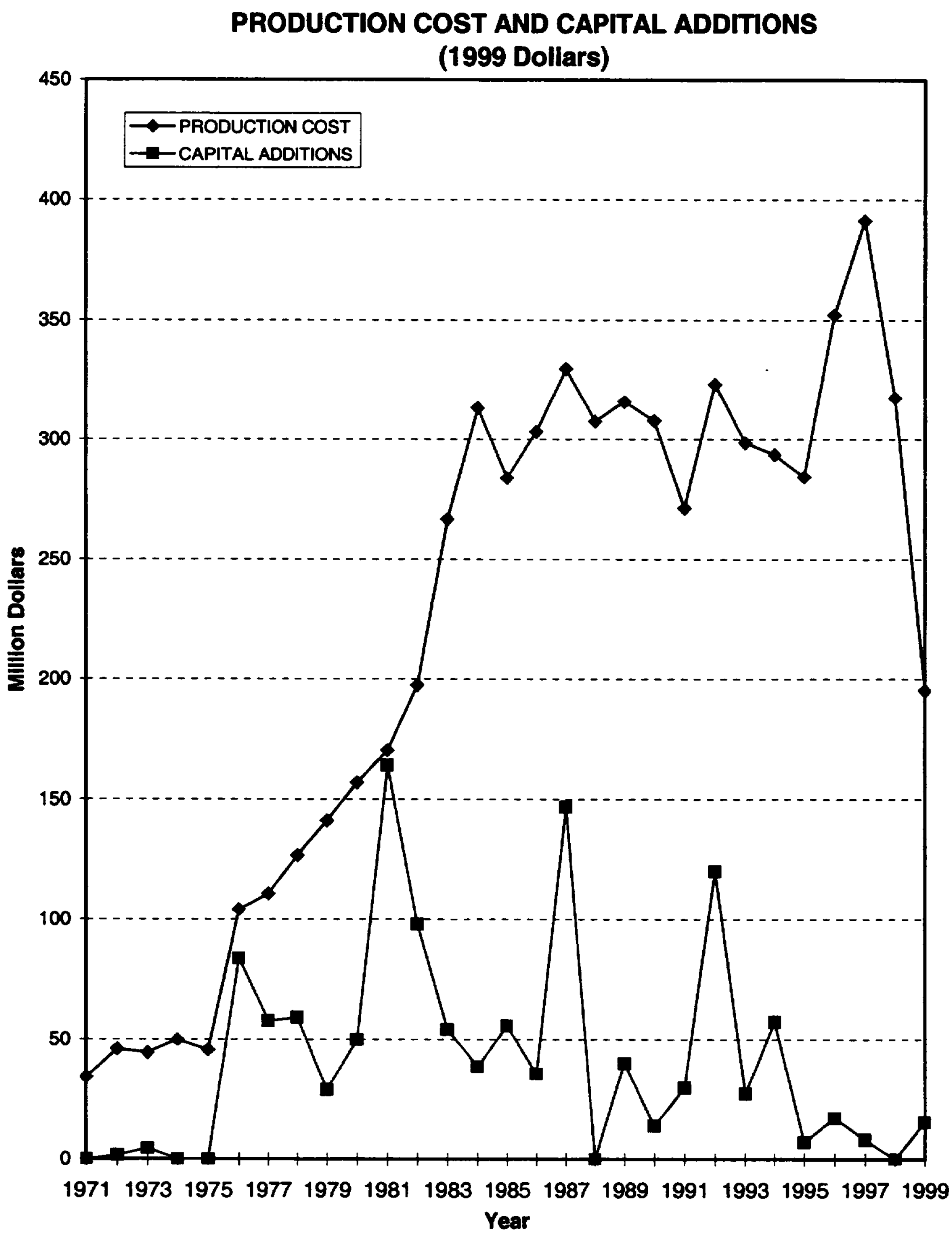
MILLSTONE 1 & 2*



*Includes Unit 1 data through 1998.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**MILLSTONE 2**	Nameplate Rating (MWe):	**909**
Location:	**New London County, Connecticut**	MDC Net MWe:	**871**
Operator:	**Northeast Nuclear Energy Co.**	Cumul. Avail. Factor:	**59.5**
Type:	**Combustion Engineering PWR**	Cumul. Cap. Factor (MDC Net):	**60.0**
Construction Permit:	**12/11/70**	Cumul. Forced Outage Rate:	**19.3**
Operating License:	**9/30/75**	3-Year Avg. Cap. Factor (MDC Net):	**19.2**
Commercial Oper. Date:	**12/26/75**	License Expiration:	**7/31/15**

Operating History (January 1997 Through December 1999)

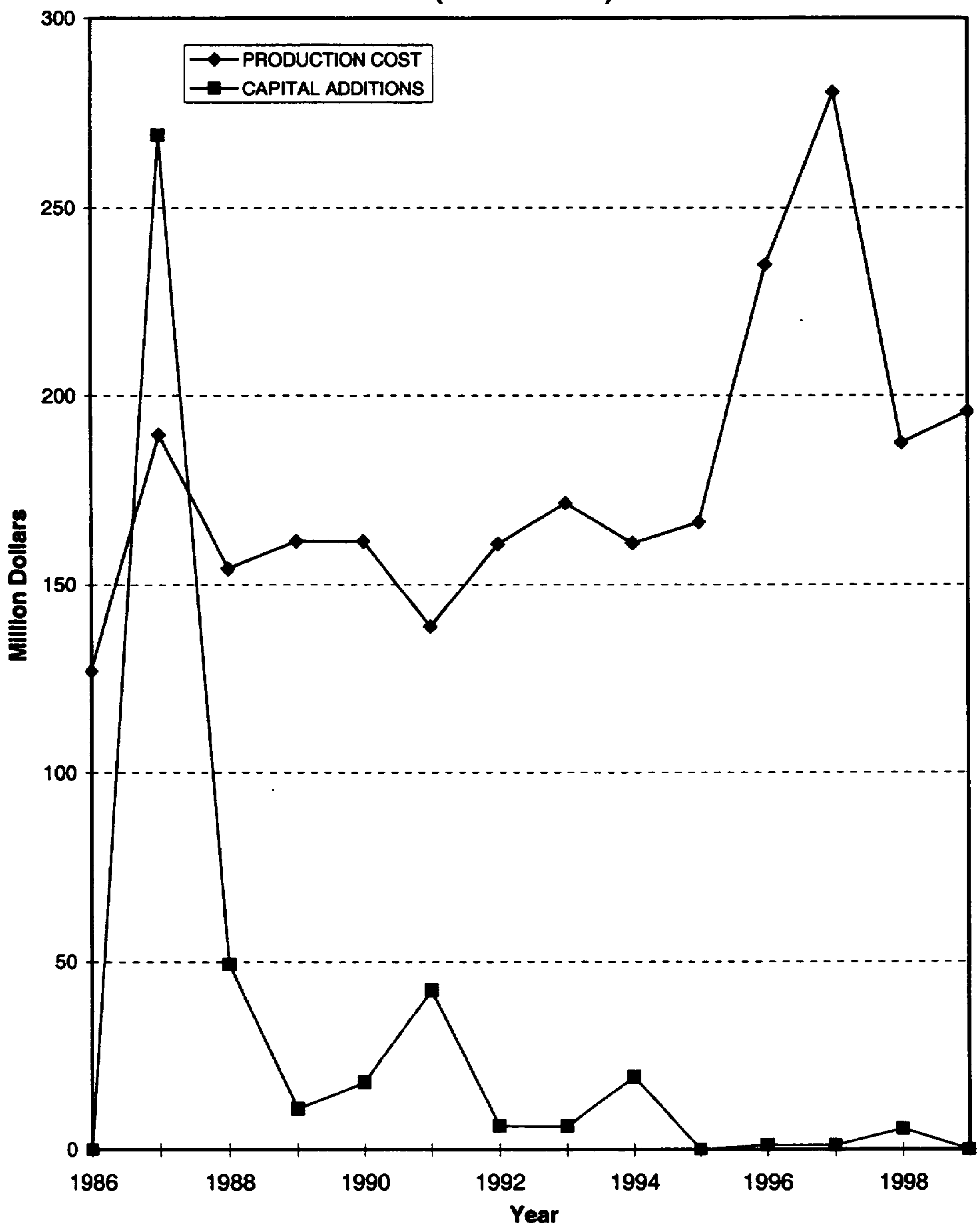
Beginning Date	Ending Date	Comment
Feb 1996	May 1999	The unit was taken off-line and shut down for 1173 d from February 20 until May 8. The plant was originally shut down in November 1995 for the 15th scheduled refueling and maintenance outage; however, the outage was extended due to regulatory concerns. The NRC issued a confirmatory order requiring independent corrective action verification, third-party review of the station employee concerns program, and design basis verification for response to a 10 CFR 50.54(f) violation.
Apr 1997		On April 15, the licensee determined that the potential existed for waterhammer and two-phase flow to occur in the piping for the containment air recirculation system cooler and could cause the piping to fail. It was also determined that 9 of a total of 89 containment penetrations were susceptible to thermally induced overpressurization.
Jun 1997		The plant was at cold shutdown on June 12 when the licensee, during a TS review of the high-pressure safety-injection (HPSI) pump, determined that the HPSI system flow to the core might be less than the flow assumed in the FSAR analysis. This was based on a calculation that there is greater flow from a cold-leg break than what was assumed previously, there were flow measurement inaccuracies that had not been accounted for, and plant operation may have been in a speculative region of the pump flow curve. The worst case occurs when the pumps are operating between 1100 psig and shutoff head.
Jul 1997		The NRC proposed and the licensee paid a $55,000 fine for security violations.

Aug 1997	On August 2, oil was found to be leaking from a cracked weld in the A EDG lube oil system piping. Subsequent investigation revealed that the failed weld was a partial penetration weld, rather than the full penetration weld specified by design. Additional partial penetration welds were found on the A EDG. An evaluation of the B EDG was performed. Partial penetration welds were found in its lube oil piping as well, but no leaks were found. A report was filed on August 30 indicating that the A EDG had been inoperable. The B EDG was conservatively identified as having failed as well. The LER for this event indicates that, while there was an increased chance of vibration-induced fatigue failures in other partial penetration welds, stresses on the partial penetration welds were within code allowable values. Therefore, coincident failure of the B EDG due to weld cracking was not judged to be credible.
Oct 1997	On October 29, the licensee identified a scenario in which the sump recirculation valves would fail open following a design basis accident. At the time of the report, the plant was shut down for refueling. In 1995 Northeast Utilities determined that the containment sump isolation valves at Millstone 2 were subject to thermally induced pressure locking if water trapped in the valve bonnets was heated by water in the containment sump piping before the valves were opened for sump recirculation after a LOCA. Northeast Utilities subsequently determined that the containment sump valves were also vulnerable to pressure locking caused by variations in containment pressure. The valve bonnets could be pressurized to the maximum containment pressure that would exist following an accident. In combination with the low pressure that would exist on the outer disk surfaces when sump recirculation was required, this could result in a higher differential pressure across the valve disk than what was assumed when sizing the valve actuator and could prevent the valves from opening. The plant was in a refueling outage on November 26, 1997, when a piece of polyvinyl chloride (PVC) coating peeled from the inside lining of the SW piping and became lodged in an EDG strainer. The piece of PVC measured approximately 6 in. by 10 in. The licensee also indicated that the component cooling water HXs in the reactor building were susceptible to this phenomenon.
Dec 1997	The NRC proposed and the licensee paid a $2,100,000 fine for three Severity Level II violations and one Severity Level III violation.
Apr 1998	The NRC proposed and the licensee paid a $55,000 fine for a design problem that had the potential to inject air into the charging and SI pumps.
May 1998	On May 19, the licensee reported that the MFW pump discharge valves and the MFW block valves may not fully close against the system maximum differential pressure. Inspection of wear marks on the disc seating surfaces indicates that the valves may have failed to achieve closure adequate to ensure flow shutoff. If a MSL break were to occur, a MSL isolation signal would close these valves and the FW regulating valves. However, if the FW regulating valves failed to close completely, a faulted SG might not be isolated as required. This could result in higher containment pressures than previously determined in safety analyses.
Mar 1999	The NRC proposed and the licensee paid an $88,000 fine for discriminating against two contractor employees.

May 1999	The unit was taken off-line and shut down for 4 d for a forced outage to investigate a reactor trip and repair a steam leak in the turbine building and adjust the FW heater level control system.
Sep 1999	The unit was taken off-line and shut down for 7 d for a forced outage to investigate why a control rod became misaligned from remainder of rods in the group. The malfunction was a short circuit caused by abrasion of cable insulation.

MILLSTONE 3

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**MILLSTONE 3**	Nameplate Rating (MWe):	**1253**
Location:	**New London County**	MDC Net MWe:	**1137**
Operator:	**Northeast Nuclear Energy Co.**	Cumul. Avail. Factor:	**62.1**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**60.5**
Construction Permit:	**8/9/74**	Cumul. Forced Outage Rate:	**28.8**
Operating License:	**1/31/86**	3-Year Avg. Cap. Factor (MDC Net):	**38.6**
Commercial Oper. Date:	**4/23/86**	License Expiration:	**11/25/25**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1996	Jul 1998	The unit was taken off-line and shut down for 823 d from March 30, 1996, until July 2, 1998. The plant was originally shut down for a maintenance outage; however, the outage was extended due to regulatory concerns. The NRC issued a confirmatory order requiring independent corrective action verification, third party review of the station employee concerns program, and design basis verification for response to a 10 CFR 50.54(f) violation.
Jul 1997		The NRC proposed and the licensee paid a $55,000 fine for security violations.
Dec 1997		The NRC proposed and the licensee paid a $2,100,000 fine for three Severity Level II violations and one Severity Level III violation.
Feb 1998		The plant was in cold shut down on February 18 when it was postulated that the RHR pump recirculation valve could cycle open and close until it failed if a LOCA occurred that stabilized with RCS pressure just below RHR pump discharge pressure. During testing the valve closed on a pump start due to a pressure spike, which makes the valve cycle unexpectedly. If the valve failed closed, minimum flow might not be adequate to keep the RHR pump cool, and pump failure could result. The licensee indicated that the reduced flow would still be adequate to provide sufficient cooling to the RHR pump.
Apr 1998		The NRC proposed and the licensee paid a $55,000 fine for a design problem that had the potential to inject air into the charging and SI pumps.
Aug 1998		The unit was taken off-line and shut down for 8 d for a forced outage to repair an AFW valve.
Dec 1998		The unit was taken off-line and shut down for 20-1/2 d for a forced outage to investigate a reactor trip caused by MSIV "A" closing during a routine performance valve stroke testing. The valve closed due to a crack in the solenoid valve disc.

Mar 1999		The NRC proposed and the licensee paid an $88,000 fine for discriminating against two contractor employees.
May 1999	Jun 1999	The unit was taken off-line and shut down for 60 d for the scheduled sixth refueling and maintenance outage.

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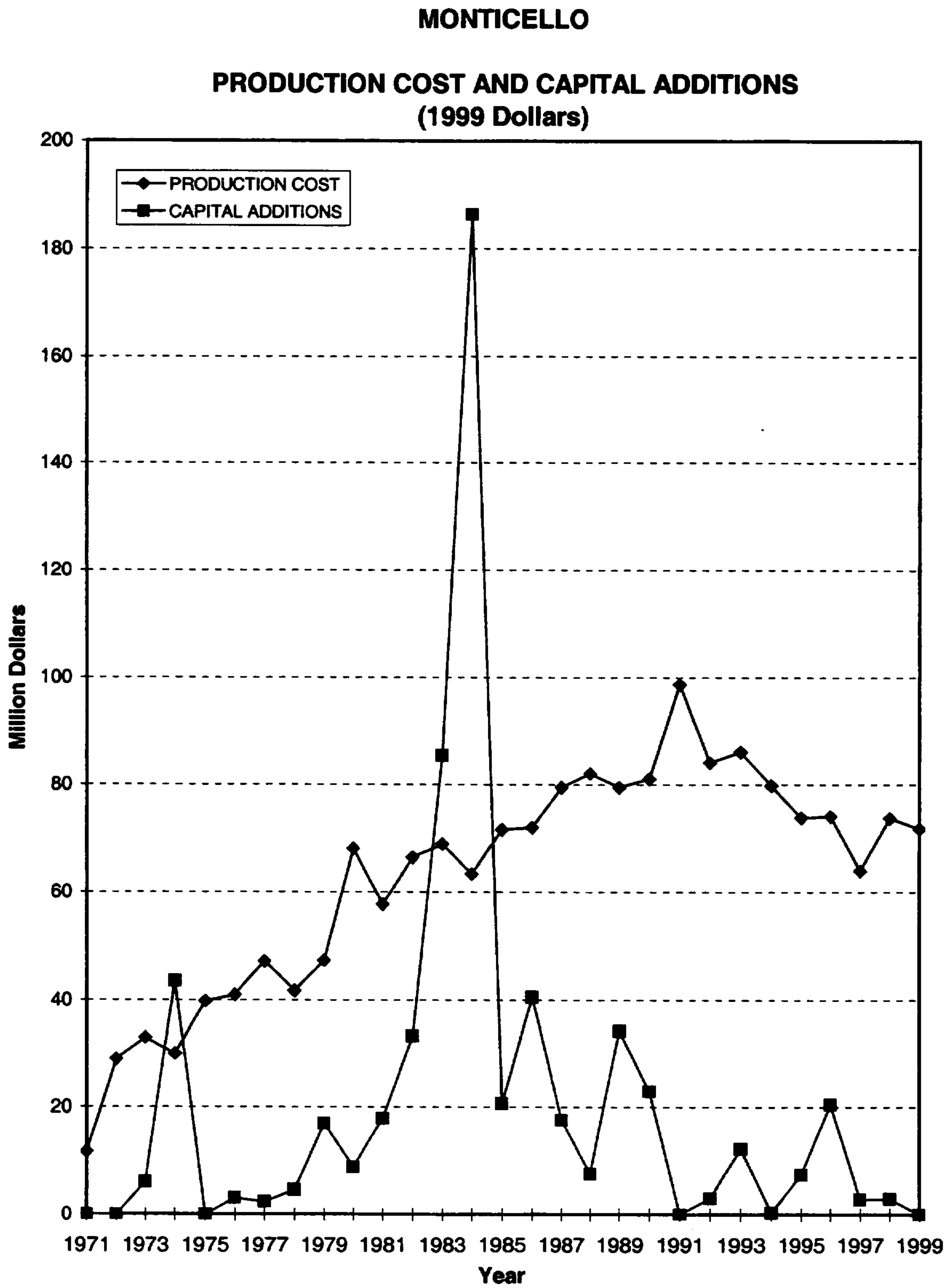
MONTICELLO
PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)
PRODUCTION COST
CAPITAL ADDITIONS
Million Dollars
0
20
40
60
80
100
120
140
160
180
200
1971
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
Year

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**MONTICELLO**	Nameplate Rating (MWe):	**577**
Location:	**Wright County, Minnesota**	MDC Net MWe:	**544**
Operator:	**Northern States Power Co.**	Cumul. Avail. Factor:	**80.4**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**71.3**
Construction Permit:	**6/19/67**	Cumul. Forced Outage Rate:	**4.4**
Operating License:	**1/9/81**	3-Year Avg. Cap. Factor (MDC Net):	**83.0**
Commercial Oper. Date:	**6/30/71**	License Expiration:	**9/8/10**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
May 1997	Jul 1997	The unit was taken off-line and shut down for 83 d for a scheduled outage to install new suction strainers for the ECCS.
May 1997		The unit was taken off-line and shut down to replace the strainers on the suction lines from the pressure suppression pool (torus) to various ECCSs.
Nov 1997		The unit was taken off-line and shut down for 5 d for a forced outage to investigate a manual reactor scram.
Mar 1998		The unit was taken off-line and shut down for 37 d for a scheduled refueling and maintenance outage.
Sep 1998		The unit was taken off-line and shut down for 7 d for a forced outage to investigate a reactor trip caused by a loss of condenser vacuum, which resulted from off-gas recombiner problems.
Apr 1999		The unit was taken off-line and shut down for 8 d for a forced outage to investigate a reactor scram on low water level after the failure of a power supply in the digital FW control system.
Apr 1999		The plant scrammed from 100% power on low reactor water level on April 22. Following the scram, HPCI was declared inoperable because of water entering the MSLs.
May 1999		The unit was taken off-line and shut down for 19-1/2 d for a forced outage to investigate a reactor manual scram in response to problems with the off-gas system.

May 1999

The plant was manually scrammed on May 8 after the "B" air ejector suction valves closed and caused a loss of main condenser vacuum. There were numerous operator errors both before and after the scram. For example, "Procedures directed the operators to isolate steam loads and repressurize the lines by opening the MSL drains. The operators did not initially isolate two of the steam loads identified by the procedure." The operators also failed to take the mode switch out of the RUN position following the scram (also a procedure and training violation).

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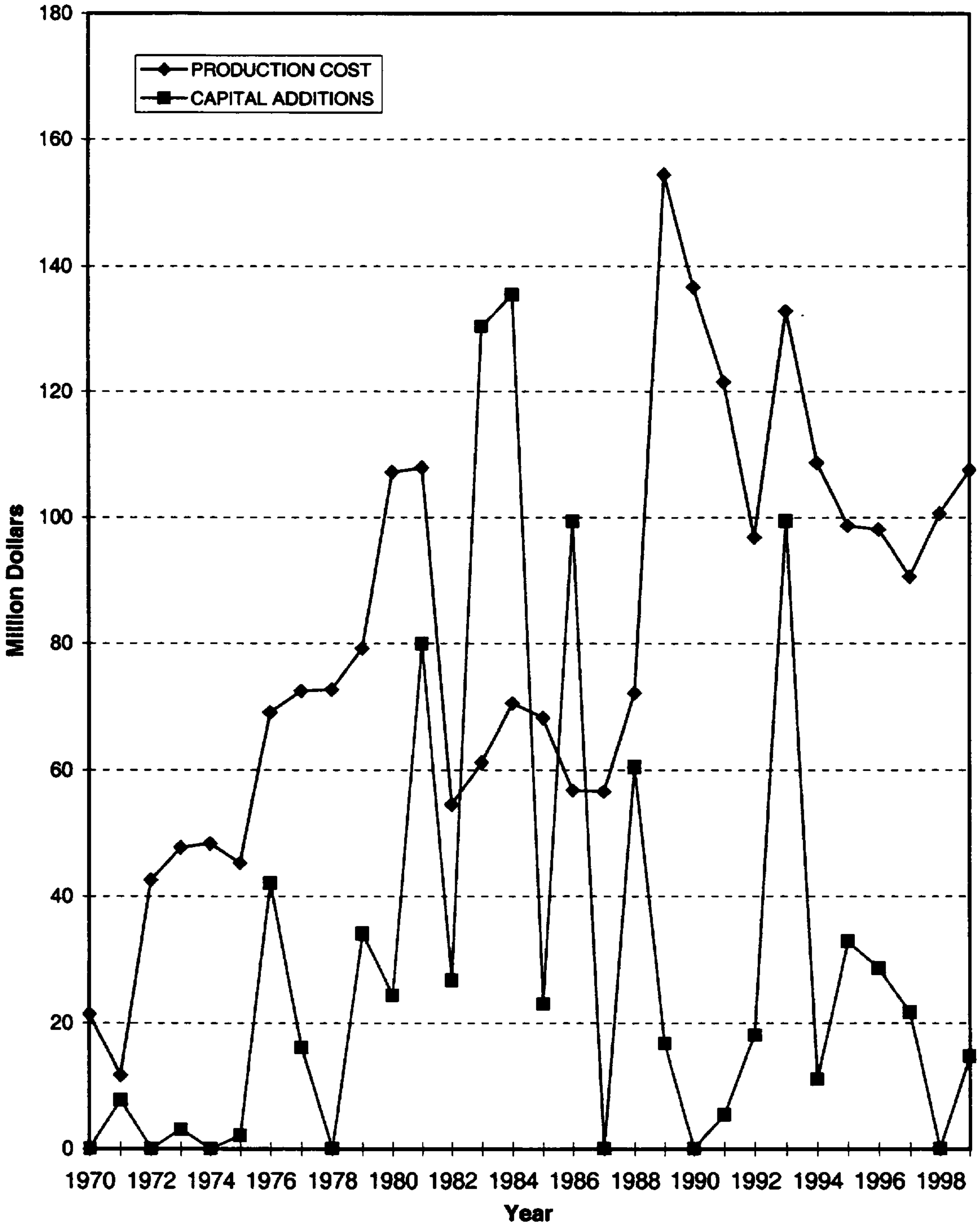
NINE MILE POINT 1

PRODUCTION COST AND CAPITAL ADDITIONS (1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**NINE MILE POINT 1**	Nameplate Rating (MWe):	**642**
Location:	**Oswego County, New York**	MDC Net MWe:	**565**
Operator:	**Niagara Mohawk Power Corp.**	Cumul. Avail. Factor:	**65.9**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**65.3**
Construction Permit:	**4/12/65**	Cumul. Forced Outage Rate:	**21.9**
Operating License:	**12/26/74**	3-Year Avg. Cap. Factor (MDC Net):	**74.8**
Commercial Oper. Date:	**12/1/69**	License Expiration:	**8/22/09**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	May 1997	The unit was taken off-line and shut down for 67 d for a scheduled refueling and maintenance outage.
May 1997		The NRC proposed and the licensee paid a $200,000 fine for three Severity Level III violations. The violations involved inadequate design controls and deficient and incomplete corrective actions associated with an overfill event in the RPV.
May 1997		The unit was taken off-line and shut down for 4 d for a forced outage to make repairs to the RWCU system.
Jun 1997		The unit was taken off-line and shut down for 7 d for a forced outage to repair a isolation valve in the drywell inboard floor drain.
Sep 1997	Dec 1997	The unit was taken off-line and shut down for 86 d for a scheduled maintenance outage. The unit was shut down for repairs to the emergency condensers because of tube leaks; the licensee made the decision to replace the tube bundles for all four emergency condenser vessels.
Dec 1997		The NRC proposed and the licensee paid a $50,000 fine for baseline inspection violations of the maintenance rule.
Feb 1998		The NRC proposed and the licensee paid a $55,000 fine for various violations, which represent a breakdown of the licensee's radwaste and transportation program.
Apr 1998	May 1998	The unit was taken off-line and shut down for 28 d for a scheduled maintenance outage. The unit was removed from service due to inoperability of the control room emergency ventilation system; all necessary modifications were made prior to startup.
Apr 1999	Jun 1999	The unit was taken off-line and shut down for 66 d for a scheduled refueling and maintenance outage.

Apr 1999	Jun 1999	The unit was removed from service due to inoperability of the control room emergency ventilation system. Necessary modifications were made prior to startup.
Jul 1999	Aug 1999	The unit was taken off-line and shut down for 13-1/2 d for a forced outage to investigate why the reactor scrammed on an average power range monitor (APRM) high–high neutron flux.
Jul 1999		On July 23, the plant scrammed from 100% power during postmaintenance testing of the turbine mechanical pressure regulator. There were some minor complications following the scram. For example, water entered the bottom of the emergency condenser, and the operators failed to follow procedures that required them to move the mode switch from "REFUEL" back to "SHUTDOWN." Also, two MFW pumps tripped on low suction pressure that resulted from the high flow generated by the turbine-geared MFW pump as the main turbine coasted down. Additionally, a manual reactor scram was ordered just prior to the automatic reactor trip signal that actually tripped the reactor.
Oct 1999		The unit was taken off-line and shut down for 28 d for a scheduled maintenance outage that was extended to a forced outage for pump seal maintenance in the recirculation system.

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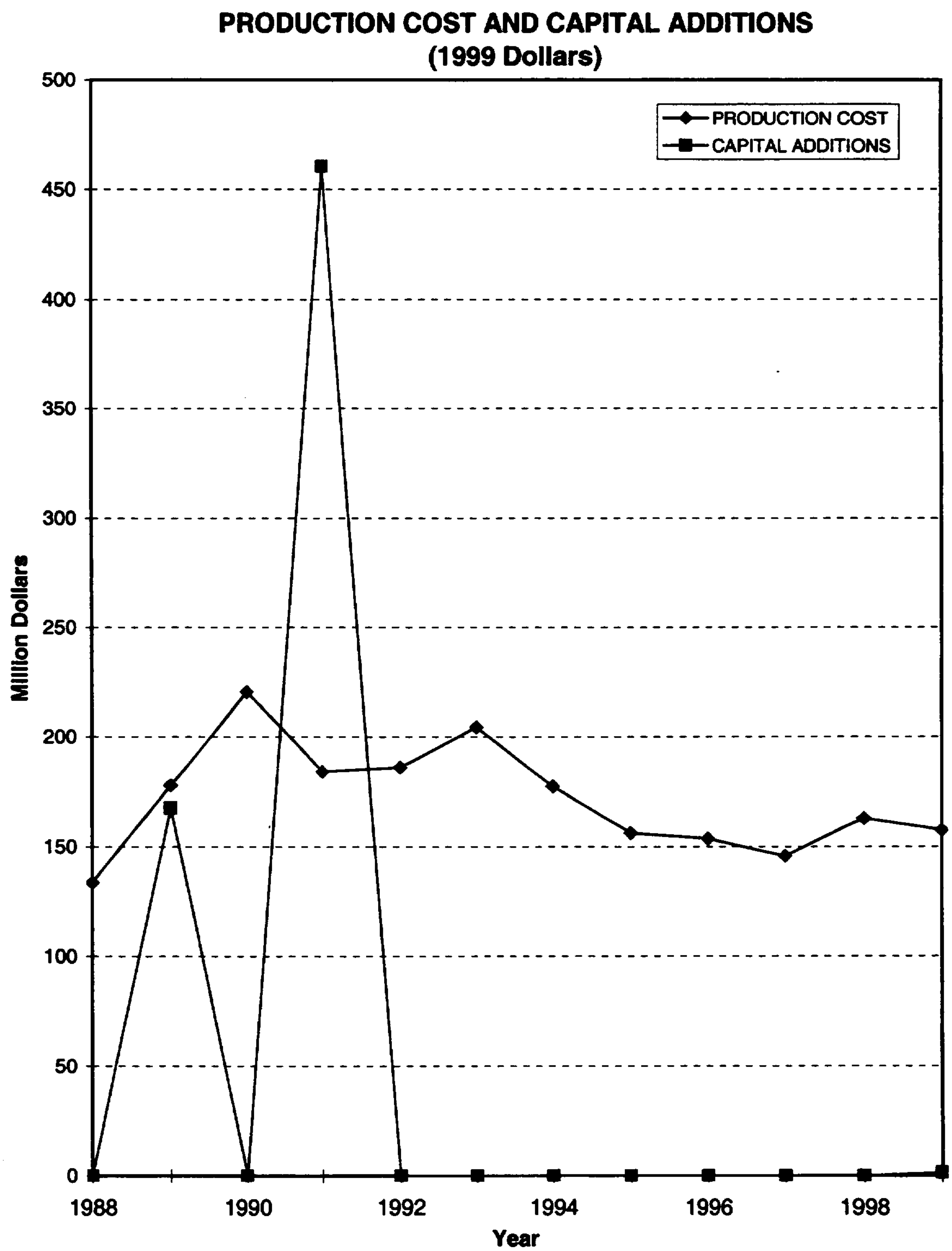
NINE MILE POINT 2



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**NINE MILE POINT 2**	Nameplate Rating (MWe):	**1259**
Location:	**Oswego County, New York**	MDC Net MWe:	**1105**
Operator:	**Niagara Mohawk Power Corp.**	Cumul. Avail. Factor:	**73.3**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**68.5**
Construction Permit:	**6/24/74**	Cumul. Forced Outage Rate:	**22.4**
Operating License:	**7/2/87**	3-Year Avg. Cap. Factor (MDC Net):	**85.5**
Commercial Oper. Date:	**3/11/88**	License Expiration:	**10/31/26**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
May 1997		The NRC proposed and the licensee paid a $200,000 fine for three Severity Level III violations. The violations involved inadequate design controls and deficient and incomplete corrective actions associated with an overfill event in the RPV.
Jun 1997		The unit was taken off-line and shut down for 7 d for a forced refueling outage to investigate MSR problems.
Aug 1997		The unit was taken off-line and shut down for 6 d for a forced outage to replace a leaking flex hose on control valve body drain for the "B" recirculation flow.
Nov 1997		The unit was taken off-line and shut down for 6 d for a forced outage to make repairs to control valve positioner for the "A" recirculation flow.
Dec 1997		The NRC proposed and the licensee paid a $50,000 fine for baseline inspection violations of the maintenance rule.
Feb 1998		The NRC proposed and the licensee paid a $55,000 fine for various violations, which represent a breakdown of the licensee's radwaste and transportation program.
Mar 1998		The unit was operating at 92% power on March 28 when one off-site 115-kV power line was lost. Several engineered safety feature (ESF) actuations occurred, and as a result, Division 1 and 3 EDGs automatically started and loaded onto their respective buses.
May 1998	Jul 1998	The unit was taken off-line and shut down for 64 d for the sixth scheduled refueling and maintenance outage.
Nov 1998	Dec 1998	The unit was taken off-line and shut down for 8 d for a forced outage to make repairs to the "B" recirculation flow control valve.
Apr 1999	May 1999	The unit was taken off-line and shut down for 10 d for a forced outage to replace a failed main generator protection relay.

Apr 1999		The plant scrammed from 100% power on April 24 due to an unknown electrical transient. Both motor-driven MFW pumps tripped, all three condensate booster pumps tripped, and the reactor recirculation system pumps tripped. During the scram recovery, RCIC failed to come up to speed and was tripped. There was a blown fuse on an uninterruptible power supply (UPS) along with some other complications in the scram recovery. The licensee indicated that the electrical transient was "... determined to be failure of a relay in the generator protection circuit." After the reactor trip, 25 investigations or reports were initiated as a result of the April 24 event.
Jun 1999	Jul 1999	The unit was taken off-line and shut down for 30 d for a forced maintenance outage to repair a failed FW master flow controller. The controller failed when transferring from automatic to manual control.
Jun 1999		The plant was operating at 100% power when the MFW master controller failed, which caused a low reactor water level resulting in a scram. In addition, off-site power line No. 5 failed following the scram. Operators closed all MSIVs, the SBGT system automatically started, and Division 1 and 3 EDGs automatically started. The operators used RCIC to control reactor water level after the scram; however, they noticed oscillations in system flow and declared RCIC inoperable.

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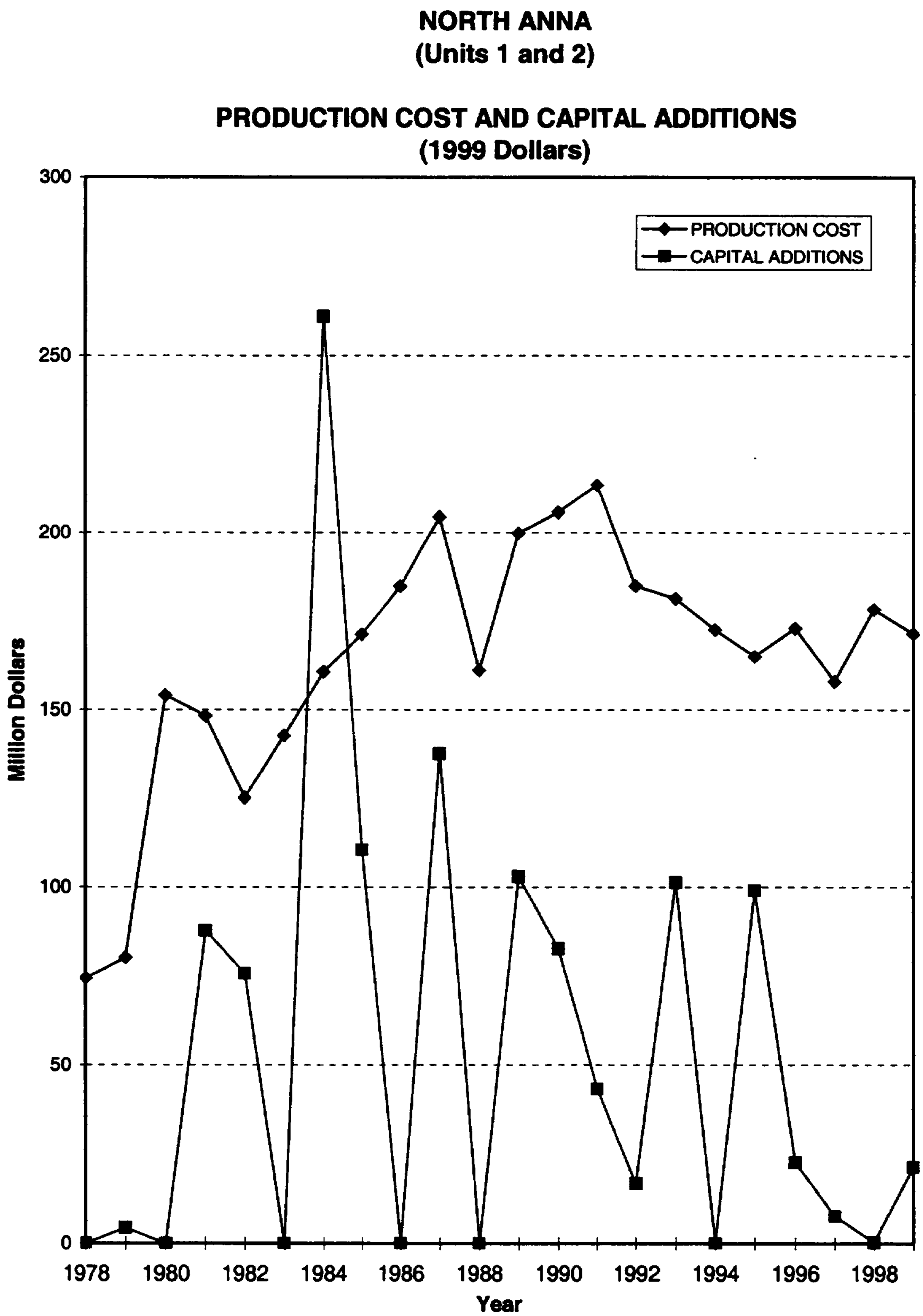
NORTH ANNA
(Units 1 and 2)
PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)
PRODUCTION COST
CAPITAL ADDITIONS
Million Dollars
300
250
200
150
100
50
0
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
Year

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**NORTH ANNA 1**	Nameplate Rating (MWe):	**994**
Location:	**Louisa County, Virginia**	MDC Net MWe:	**893**
Operator:	**Dominion Generation**	Cumul. Avail. Factor:	**76.5**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**73.9**
Construction Permit:	**2/19/71**	Cumul. Forced Outage Rate:	**7.5**
Operating License:	**4/1/78**	3-Year Avg. Cap. Factor (MDC Net):	**95.9**
Commercial Oper. Date:	**6/6/78**	License Expiration:	**4/1/18**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
May 1997	Jun 1997	The unit was taken off-line and shut down for 32 d for the 12th scheduled refueling and maintenance outage.
Sep 1998	Oct 1998	The unit was taken off-line and shut down for 25 d for the 13th scheduled refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**NORTH ANNA 2**	Nameplate Rating (MWe):	**979**
Location:	**Louisa County, Virginia**	MDC Net MWe:	**897**
Operator:	**Dominion Generation**	Cumul. Avail. Factor:	**83.3**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**80.7**
Construction Permit:	**2/19/71**	Cumul. Forced Outage Rate:	**4.7**
Operating License:	**8/21/80**	3-Year Avg. Cap. Factor (MDC Net):	**93.8**
Commercial Oper. Date:	**12/14/80**	License Expiration:	**8/21/20**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Oct 1977		The engine cooling fan for the 1H EDG failed for unknown reasons, and about 24 h later the 1J EDG was declared inoperable for its associated TS surveillance test. This placed the plant in a reportable event status for almost 3 h.
Apr 1998	May 1998	The unit was taken off-line and shut down for 29 d for the 12th refueling and maintenance outage.
Sep 1999	Oct 1999	The unit was taken off-line and shut down for 29 d for the 13th refueling and maintenance outage.

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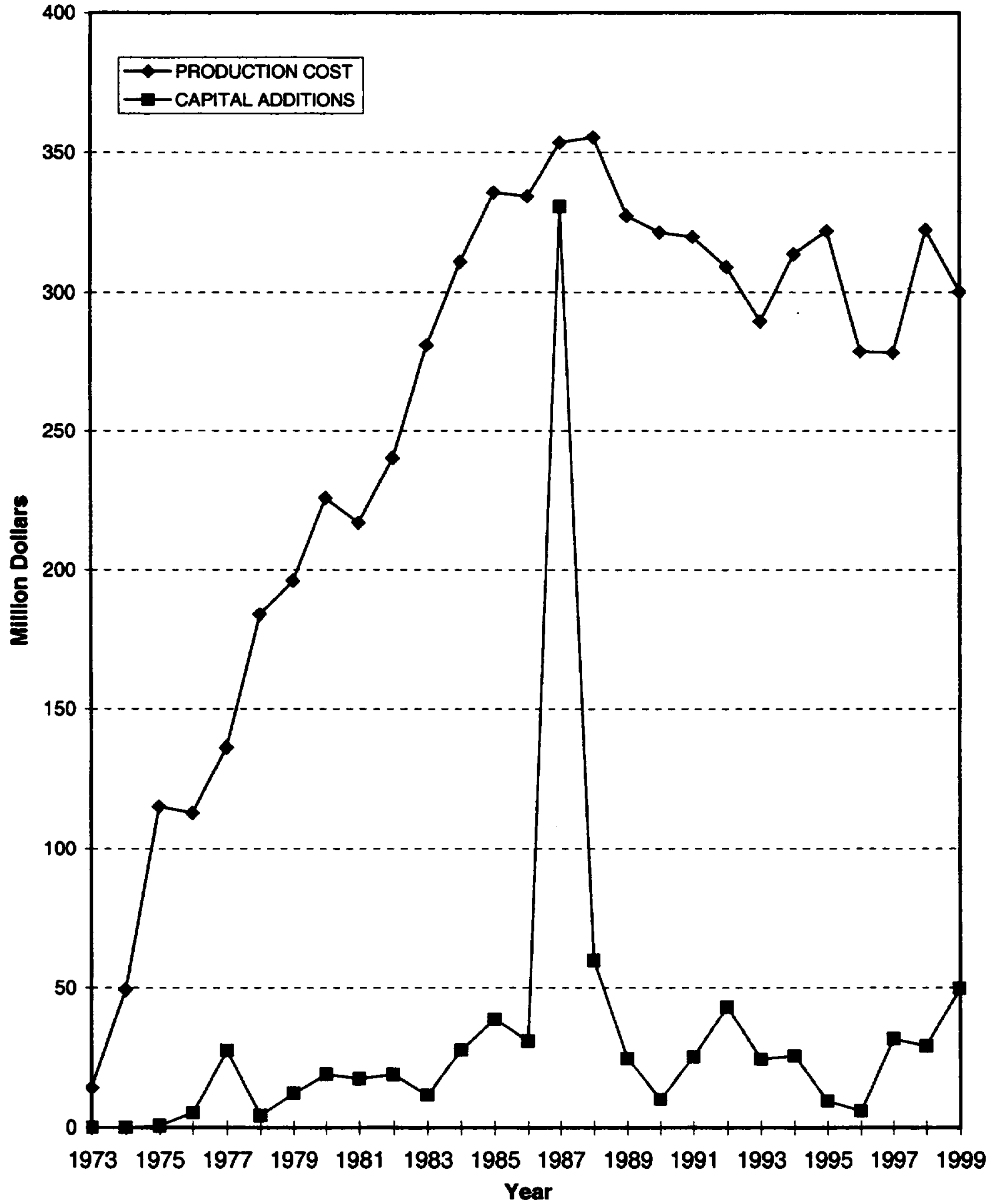
OCONEE
(Units 1, 2, and 3)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**OCONEE 1**	Nameplate Rating (MWe):	**934**
Location:	**Oconee County, South Carolina**	MDC Net MWe:	**846**
Operator:	**Duke Power**	Cumul. Avail. Factor:	**75.4**
Type:	**Babcock & Wilcox PWR**	Cumul. Cap. Factor (MDC Net):	**72.9**
Construction Permit:	**11/6/67**	Cumul. Forced Outage Rate:	**9.9**
Operating License:	**2/6/73**	3-Year Avg. Cap. Factor (MDC Net):	**69.2**
Commercial Oper. Date:	**7/15/73**	License Expiration:	**2/6/13***

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Oct 1996	Feb 1997	The unit was taken off-line and shut down for 127 d for a forced maintenance outage. The original outage was extended to make piping repairs to the MSR drain line.
Mar 1997		The licensee indicated on March 17 that two of three post-LOCA boron dilution paths have been inoperable since their original installation in 1975 due to thermal expansion concerns outlined in U.S. NRC GL 96-06.
Mar 1997	Apr 1997	The unit was taken off-line and shut down for 14 d for a scheduled maintenance outage to repair "1A1" RCP vibration problems.
Jun 1997	Jul 1997	The unit was taken off-line and shut down for 20 d for a scheduled maintenance outage to inspect the HPI flow nozzles.
Sep 1997		The NRC proposed and the licensee paid a $330,000 fine for having cracks in the HPI line and for failure of the HPI pump.
Sep 1997	Nov 1997	The unit was taken off-line and shut down for 84 d for the 17th scheduled refueling and maintenance outage.
Dec 1997	Feb 1998	The unit was taken off-line and shut down for 41 d for a forced maintenance outage to repair a tube leak in SG "1A" and a pressurizer drain line leak.
Feb 1998		On February 12, the licensee discovered that the borated water storage tank (BWST) level instruments was calibrated about 18 in. lower than that assumed in the calculations supporting emergency operating procedures actions. Following the existing emergency operating procedures in effect at that time could result in vortex formation in the suction of the ECCS and building spray pumps before the operators had a chance to swap the suction from the BWST to the reactor building emergency sump.

Aug 1998		The unit was taken off-line and shut down for 17 d for a forced maintenance outage to repair "1A2" RCP high seal flow.
May 1999	Jun 1999	The unit was taken off-line and shut down for 42 d for the 18th scheduled refueling and maintenance outage.

*License has been extended in 2000. As of December 1999, extension of this license had not been granted.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**OCONEE 2**	Nameplate Rating (MWe):	**934**
Location:	**Oconee County, South Carolina**	MDC Net MWe:	**846**
Operator:	**Duke Power**	Cumul. Avail. Factor:	**77.8**
Type:	**Babcock & Wilcox PWR**	Cumul. Cap. Factor (MDC Net):	**74.5**
Construction Permit:	**11/6/67**	Cumul. Forced Outage Rate:	**9.7**
Operating License:	**10/6/73**	3-Year Avg. Cap. Factor (MDC Net):	**80.0**
Commercial Oper. Date:	**9/9/74**	License Expiration:	**10/6/13***

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jan 1997	Feb 1997	The unit was taken off-line and shut down for 19 d for a forced outage to repair a ruptured second-stage reheater drain line.
Apr 1997	May 1997	The unit was taken off-line and shut down for 32 d for a forced outage to investigate RCS leakage and repair a weld leak on a HPI line.
Apr 1997		The plant was shut down on April 22 because unidentified RCS leakage exceeded the TS limit of 1 gpm. The leakage had increased to 12 gpm by the time RCS pressure was sufficiently reduced. A subsequent containment entry identified an unisolable leak in the HPI line safe-end connected to the reactor coolant loop nozzle.
Jul 1997		A grid disturbance caused an overcurrent relay to actuate and, subsequently, lock out the main generator. As a result, the reactor tripped from 100% power. One HPI pump started automatically, and the other HPI pump was manually started by the operators. The Oconee 230-kV switchyard experienced an overcurrent condition when the Jocassee switchyard lost two of its hydro units' field excitation while pumping back from Lake Keowee.
Sep 1997		The unit was taken off-line and shut down for 7 d for a forced outage to repair a leak on a valve in the decay heat removal system.
Sep 1997		The NRC proposed and the licensee paid a $330,000 fine for having cracks in the HPI line and a failure of the HPI pump.
Mar 1998	May 1998	The unit was taken off-line and shut down for 63 d for the 16th scheduled refueling and maintenance outage.
May 1998		The unit was taken off-line and shut down for 5 d for a forced outage to repair a SG tube plug leak.

Sep 1998		The unit was taken off-line and shut down for 6 d for a forced outage to repair an MFW riser line leak.
Feb 1999		The unit was taken off-line and shut down for 6 d for a forced outage to repair a SG riser ring leak.
Jun 1999		The unit was taken off-line and shut down for 4 d for a forced outage to investigate a reactor and a turbine trip that was caused by a high-level alarm in a MSR drain tank.
Nov 1999	Dec 1999	The unit was taken off-line and shut down for 43 d for the 17th scheduled refueling and maintenance outage.

*License has been extended in 2000. As of December 1999, extension of this license had not been granted.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**OCONEE 3**	Nameplate Rating (MWe):	**934**
Location:	**Oconee County, South Carolina**	MDC Net MWe:	**846**
Operator:	**Duke Power**	Cumul. Avail. Factor:	**76.6**
Type:	**Babcock & Wilcox PWR**	Cumul. Cap. Factor (MDC Net):	**75.1**
Construction Permit:	**11/6/67**	Cumul. Forced Outage Rate:	**10.0**
Operating License:	**7/19/74**	3-Year Avg. Cap. Factor (MDC Net):	**80.0**
Commercial Oper. Date:	**12/16/74**	License Expiration:	**7/19/14***

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jan 1997	Mar 1997	The unit was taken off-line and shut down for 42-1/2 d for a scheduled maintenance outage to repair a MSR drain line.
May 1997	Jun 1997	The unit was taken off-line and shut down for 30 d for a forced outage to inspect the HPI flow nozzles.
May 1997		On May 3, the licensee declared a UE because two of three HPI pumps were inoperable. The licensee suspected that the letdown storage tank water level indications were not indicating the proper level. The letdown storage tank supplies water to the suction of the three HPI pumps. An engineering evaluation of the inaccurate level indication determined that the Oconee 3 HPI system would not have been able to perform its intended safety function during power operating conditions from February 22 until May 3 when the unit was shut down. The potential existed for hydrogen to be drawn into the suction of the HPI pumps following a small-break loss-of-coolant accident (SBLOCA). The NRC Events Assessment panel classified this as a Significant Event in its Performance Indicator Program.
Jun 1997	Jul 1997	The unit was taken off-line and shut down for 11 d for a forced outage to test and repair the seal oil system.
Sep 1997		The NRC proposed and the licensee paid a $330,000 fine for having cracks in the HPI line and a failure of the HPI pump.
Sep 1997	Oct 1997	The unit was taken off-line and shut down for 14-1/2 d for a scheduled maintenance outage to repair the "3B" reactor building cooling unit.
Oct 1998	Nov 1998	The unit was taken off-line and shut down for 47 d for the 16th scheduled refueling and maintenance outage.

Nov 1998	The licensee conducted a special test of the Keowee Hydro Station (the on-site emergency power source for Oconee station) on November 19. Keowee Unit 2 was removed from service and modified as part of the test. Both Keowee units were started as part of the postmodification functional test; however, field breakers on Keowee Unit 1 failed, and since Unit 2 was considered inoperable due to the modification, both trains of on-site emergency power were inoperable, and there was an approximately 1 min loss of station power to Oconee Unit 3. Oconee Units 1 and 2 were both at full power, and Oconee Unit 3 was in a refueling outage.
Dec 1998	The unit was taken off-line and shut down for 9 d for a forced outage to conduct a turbine overspeed trip test and investigate a high-sodium concentration in the secondary system.

*License has been extended in 2000. As of December 1999, extension of this license had not been grated.

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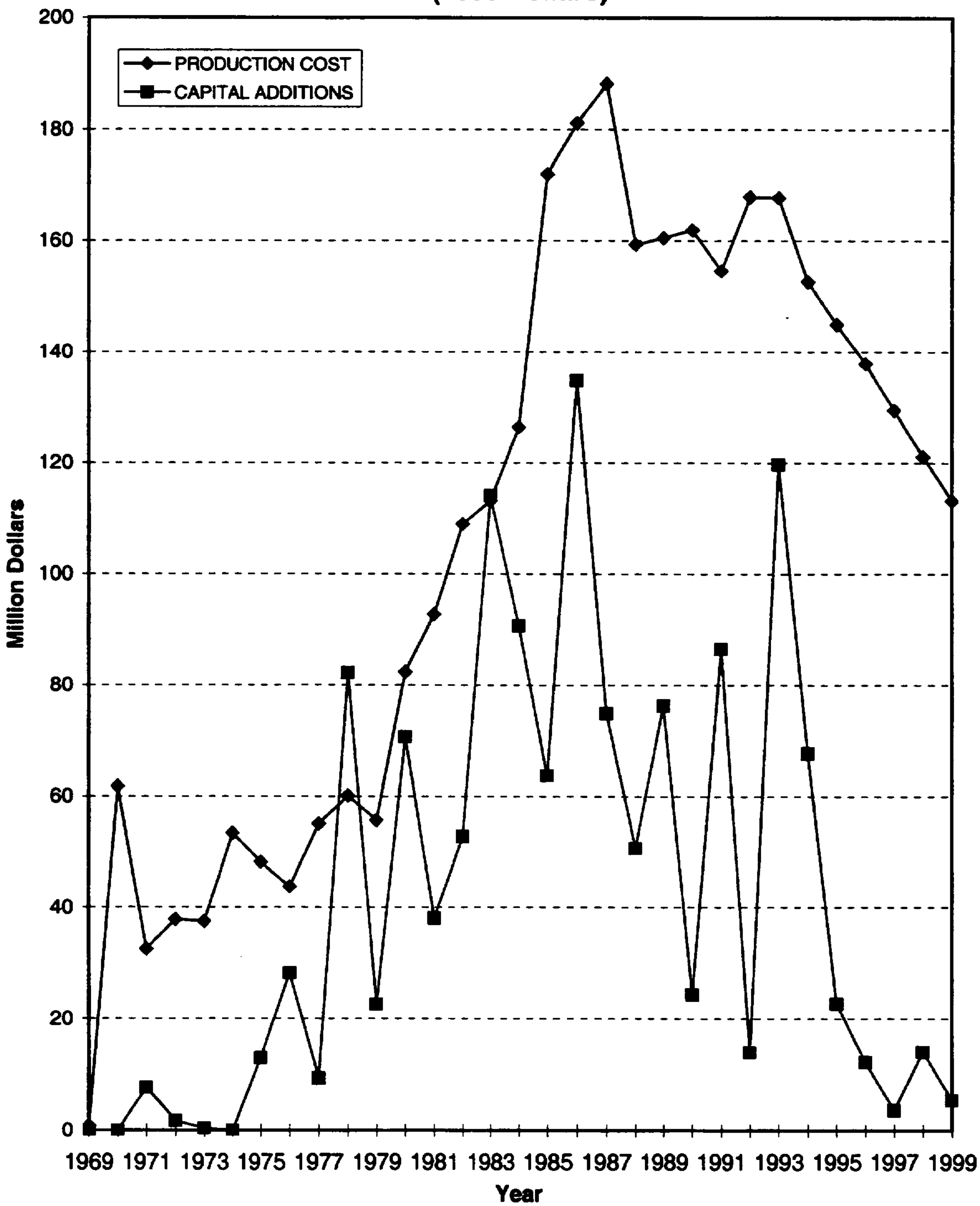
OYSTER CREEK

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

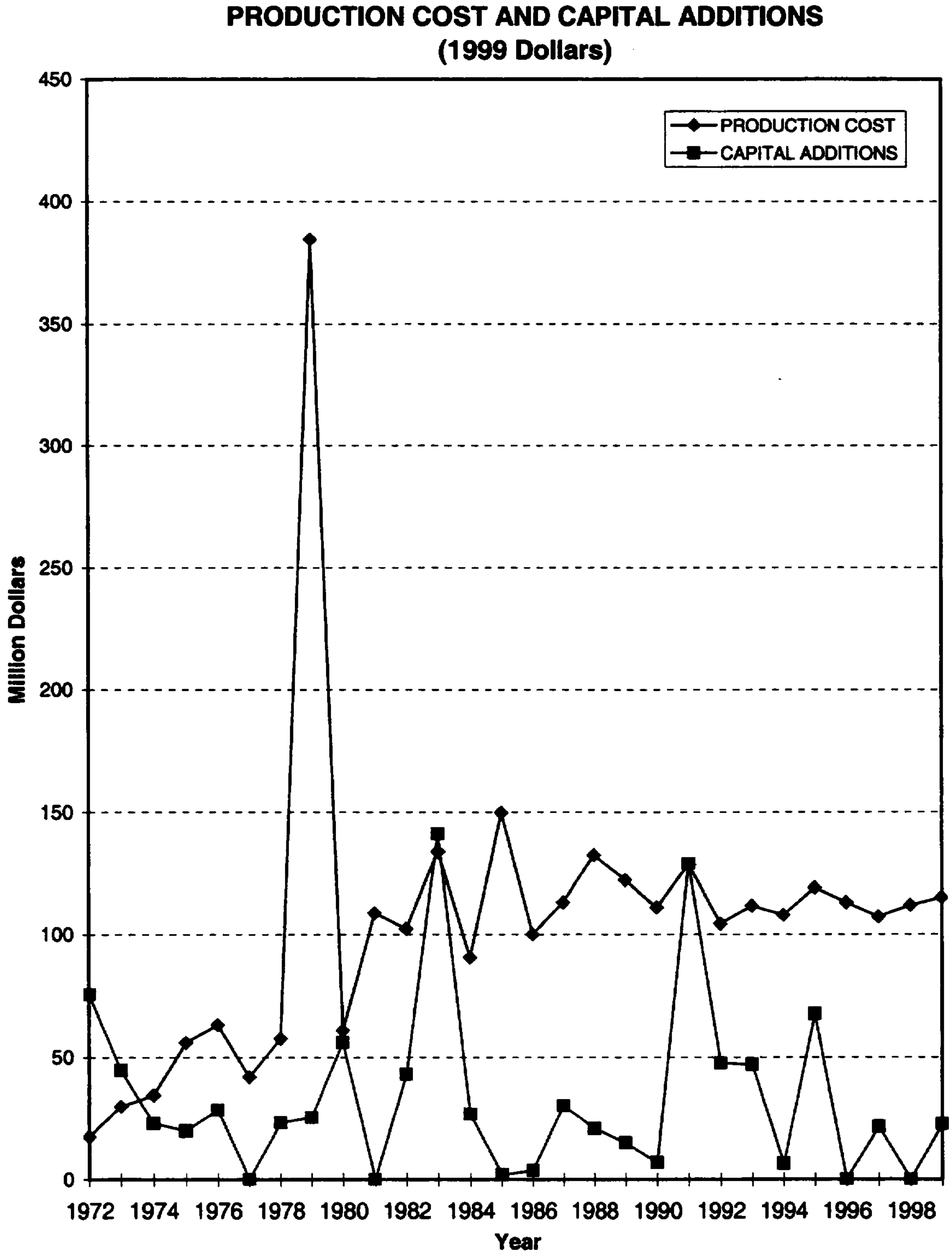
Unit Data Summary (Through December 1999)

Unit:	**OYSTER CREEK**	Nameplate Rating (MWe):	**550**
Location:	**Ocean County, New Jersey**	MDC Net MWe:	**619**
Operator:	**GPU Nuclear Inc.**	Cumul. Avail. Factor:	**68.4**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**63.2**
Construction Permit:	**12/15/64**	Cumul. Forced Outage Rate:	**9.1**
Operating License:	**7/2/91**	3-Year Avg. Cap. Factor (MDC Net):	**90.8**
Commercial Oper. Date:	**12/1/69**	License Expiration:	**12/15/09**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Apr 1997	May 1997	The unit was taken off-line and shut down for 12 d for a forced outage to investigate the failure of a CRD scram time test.
Aug 1997		On August 1, maintenance was being performed on the main generator exciter while the plant was at 100% power. An exciter brush shattered during the procedure, resulting in a field ground and an insulation fire. The reactor was scrammed, the turbine-generator tripped, the carbon dioxide fire suppression system was manually initiated, and the plant 4-kV buses transferred to the plant startup transformers. The 4-kV safety bus voltage degraded and resulted in the buses being stripped of their off-site feeds. As a result, the EDGs started and powered the safety buses. Also, the MSIVs closed on the loss of power, and the CRD pumps failed to automatically start. Further, the standby gas treatment system (SGTS) automatically started during the event.
Aug 1997		The unit was taken off-line and shut down for 12-1/2 d for a forced outage to investigate a reported fire in the generator exciter. The plant was restarted on August 10; but due to an isolation condenser shell temperature that approached saturation conditions, the plant was shut down again.
Mar 1998	Apr 1998	The unit was taken off-line and shut down for 16 d for a forced outage to investigate the steam jet air-ejector system failure and subsequent main condenser vacuum degradation.
Jul 1998		The NRC proposed and the licensee paid a $55,000 fine for inoperable ADS valves and for design errors and apparent qualification concerns that contributed to the inoperability.
Sep 1998	Nov 1998	The unit was taken off-line and shut down for 50 d for the 17th scheduled refueling and maintenance outage.

PALISADES


PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)
PRODUCTION COST
CAPITAL ADDITIONS
Million Dollars
450
400
350
300
250
200
150
100
50
0
1972 1974 1976 1978 1980 1982 1984 1986 1988 1990 1992 1994 1996 1998
Year

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**PALISADES**	Nameplate Rating (MWe):	**812**
Location:	**Van Buren County, Michigan**	MDC Net MWe:	**730**
Operator:	**Consumers Energy**	Cumul. Avail. Factor:	**57.6**
Type:	**Combustion Engineering PWR**	Cumul. Cap. Factor (MDC Net):	**54.4**
Construction Permit:	**3/14/67**	Cumul. Forced Outage Rate:	**25.2**
Operating License:	**2/21/91**	3-Year Avg. Cap. Factor (MDC Net):	**85.1**
Commercial Oper. Date:	**12/31/71**	License Expiration:	**3/14/07**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jan 1997		The unit was taken off-line and shut down for 8 d for a forced maintenance outage to repair a steam leak on an MSIV.
Jan 1997	Feb 1997	The unit was taken off-line and shut down for 16 d for a forced maintenance outage to repair a main generator flex connector.
Sep 1997	Oct 1997	The unit was taken off-line and shut down for 16 d for a forced maintenance outage to repair an RCP seal leakoff-line leak.
Jan 1998		On December 24, 1997, an air leak was identified on the solenoid valve for an evaporator-component cooling water valve. Air to the solenoid valve was isolated, which closed the valve. This is the required safety position of the valve. The closure of the valve isolated return-component cooling water flow from the evaporator, which resulted in pressurizing the radioactive waste evaporators to full-component cooling water system pressure (about 120 psi). On December 26, the licensee determined that the solenoid valve needed to be replaced. Because liquid radioactive waste inventory was low, the operations department was not concerned with leaving the evaporator isolated for up to 2 weeks. Then on December 28, a component cooling water leak of about 100 mL/min was observed at a gasketed flange on the "A" radioactive waste evaporator distillate cooler. The leakage was monitored several times per shift. On December 29, the licensee determined that any further attempts to tighten the flange would probably not reduce the leakage but could cause the leakage to increase. On January 1, 1998, the distillate cooler leak increased to about 200 gpm, this exceeded the makeup capability of the component cooling water system. The leak was enough to empty the component cooling water surge tank and reduce the discharge header pressure to 98 psi. About 15 min later, the operators identified and isolated the component cooling water leak by closing a spent fuel pool cooling valve (from the control room) and an evaporator supply valve (locally). Because the evaporator return valve had been closed on December 24, these actions stopped the leak and allowed the component cooling water system to refill. After refilling, the system was vented many times over the

		next several days to assure that air was removed from the system. Some portions of the system that had been isolated during this event were returned to service.
Apr 1998	Jun 1998	The unit was taken off-line and shut down for 44 d for a scheduled refueling and maintenance outage.
Apr 1998		The NRC proposed and the licensee paid a $55,000 fine for violations involving work control operations.
Dec 1998	Jan 1999	The unit was taken off-line and shut down for 25 d for a forced maintenance outage to repair an RCP oil leak.
May 1999		The unit was taken off-line and shut down for 10-1/2 d for a forced maintenance outage to replace an RCP seal.
Oct 1999	Dec 1999	The unit was taken off-line and shut down for 59 d for a scheduled refueling and maintenance outage.

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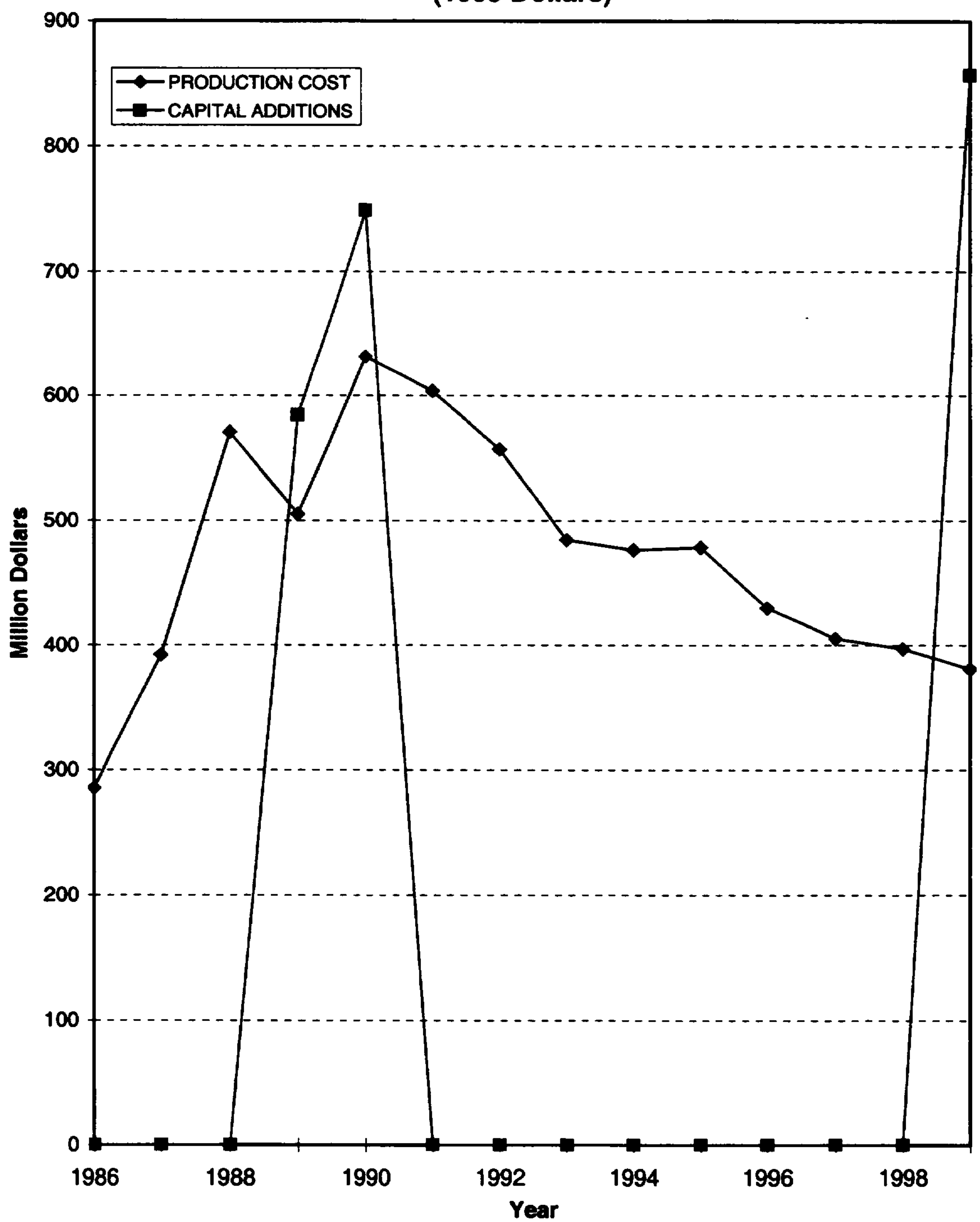
PALO VERDE
(Units 1, 2, and 3)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**PALO VERDE 1**	Nameplate Rating (MWe):	**1403**
Location:	**Maricopa County, Arizona**	MDC Net MWe:	**1221**
Operator:	**Arizona Public Service Co.**	Cumul. Avail. Factor:	**69.8**
Type:	**Combustion Engineering PWR**	Cumul. Cap. Factor (MDC Net):	**69.5**
Construction Permit:	**5/25/76**	Cumul. Forced Outage Rate:	**8.6**
Operating License:	**6/1/85**	3-Year Avg. Cap. Factor (MDC Net):	**91.7**
Commercial Oper. Date:	**1/28/86**	License Expiration:	**12/31/24**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
May 1997		The unit was taken off-line and shut down for 4 d for a forced maintenance outage to investigate why the reactor tripped due to a load shed on the NAN-S01 bus.
Aug 1997		On August 5 a single-engine aircraft hit two 550-kV lines near Hesperia, California. Although the lines were not downed, Southern California Edison cut power to the lines. The resulting grid disturbance affected three facilities: Diablo Canyon, Palo Verde, and San Onofre. All three sites experienced increased frequency ranging from 60.3 to 63 Hz. The grid instability lasted approximately 15 min. Palo Verde experienced a steam bypass on all three units with Unit 1 having a steam bypass valve momentarily open.
Mar 1998	Apr 1998	The unit was taken off-line and shut down for 37 d for the seventh scheduled refueling and maintenance outage.
May 1998		On May 7 it was determined that the Unit 1 "A" train HPSI check valve allowed sufficient backflow such that the "B" train HPSI could not supply minimum flow required. The "A" train check valve was inoperable from October 17, 1996, until April 11, 1998. The Unit 2 "B" train check valve was tested on May 14, and it also demonstrated excessive reverse flow. The failure in both cases was because the check valves had been assembled incorrectly, which represented a common cause failure. There was a vertical misalignment of the disc, which resulted in interference between the disc and valve body and caused incomplete valve closure. The "B" HPSI train pump discharge check valve had a back leakage of 37.5 gpm. It is possible that during a design basis event when the "B" train HPSI system is assumed to fail, the redundant "A" train HPSI system might not meet design basis minimum flow because of back leakage through the "B" train check valve. Because the check valve could potentially divert flow from a redundant ECCS system such as RCIC, a condition also could have existed that could have prevented the fulfillment of a safety function. This led to a fine in January 1999.

Aug 1998		The NRC proposed and the licensee paid a $50,000 fine for falsifying a surveillance test.
Jan 1999		The NRC proposed and the licensee paid a $55,000 fine for the degraded performance capability of the HPSI system under certain accident conditions. Incorrectly assembled check valves would have resulted in flow significantly less than that assumed in the safety analysis from HPSI to the RV.
Oct 1999	Nov 1999	The unit was taken off-line and shut down for 39 d for the eighth scheduled refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**PALO VERDE 2**	Nameplate Rating (MWe):	**1403**
Location:	**Maricopa County, Arizona**	MDC Net MWe:	**1221**
Operator:	**Arizona Public Service Co.**	Cumul. Avail. Factor:	**74.0**
Type:	**Combustion Engineering PWR**	Cumul. Cap. Factor (MDC Net):	**74.1**
Construction Permit:	**5/25/76**	Cumul. Forced Outage Rate:	**3.8**
Operating License:	**4/24/86**	3-Year Avg. Cap. Factor (MDC Net):	**92.5**
Commercial Oper. Date:	**9/19/86**	License Expiration:	**12/9/25**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Aug 1997		On August 5 a single-engine aircraft hit two 550-kV lines near Hesperia, California. Although the lines were not downed, Southern California Edison cut power to the lines. The resulting grid disturbance affected three facilities: Diablo Canyon, Palo Verde, and San Onofre. All three sites experienced increased frequency ranging from 60.3 to 63 Hz. The grid instability lasted approximately 15 min. Palo Verde experienced a steam bypass on all three units with Unit 1 having a steam bypass valve momentarily open.
Sep 1997	Oct 1997	The unit was taken off-line and shut down for 37 d for the seventh refueling and maintenance outage.
Oct 1997		The unit was taken off-line and shut down for 9 d to repair the upper journal and thrust bearing for RCP 2B.
Aug 1998		The NRC proposed and the licensee paid a $50,000 fine for falsifying a surveillance test.
Jan 1999		The NRC proposed and the licensee paid a $55,000 fine for the degraded performance capability of the HPSI system under certain accident conditions. Incorrectly assembled check valves would have resulted in flow significantly less than that assumed in the safety analysis from HPSI to the RV.
Mar 1999	May 1999	The unit was taken off-line and shut down for 36 d for the eighth refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**PALO VERDE 3**	Nameplate Rating (MWe):	**1403**
Location:	**Maricopa County, Arizona**	MDC Net MWe:	**1230**
Operator:	**Arizona Public Service Co.**	Cumul. Avail. Factor:	**79.1**
Type:	**Combustion Engineering PWR**	Cumul. Cap. Factor (MDC Net):	**78.8**
Construction Permit:	**5/25/76**	Cumul. Forced Outage Rate:	**3.4**
Operating License:	**11/25/87**	3-Year Avg. Cap. Factor (MDC Net):	**91.6**
Commercial Oper. Date:	**1/8/88**	License Expiration:	**3/25/27**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997	Mar 1997	The unit was taken off-line and shut down for 38 d for the seventh refueling and maintenance outage.
Aug 1997		On August 5 a single-engine aircraft hit two 550-kV lines near Hesperia, California. Although the lines were not downed, Southern California Edison cut power to the lines. The resulting grid disturbance affected three facilities: Diablo Canyon, Palo Verde, and San Onofre. All three sites experienced increased frequency ranging from 60.3 to 63 Hz. The grid instability lasted approximately 15 min. Palo Verde experienced a steam bypass on all three units with Unit 1 having a steam bypass valve momentarily open.
Aug 1998		The NRC proposed and the licensee paid a $50,000 fine for falsifying a surveillance test.
Sep 1998	Oct 1998	The unit was taken off-line and shut down for 37 d for the eighth refueling and maintenance outage.
Jan 1999		The NRC proposed and the licensee paid a $55,000 fine for the degraded performance capability of the HPSI system under certain accident conditions. Incorrectly assembled check valves would have resulted in flow significantly less than that assumed in the safety analysis from HPSI to the RV.

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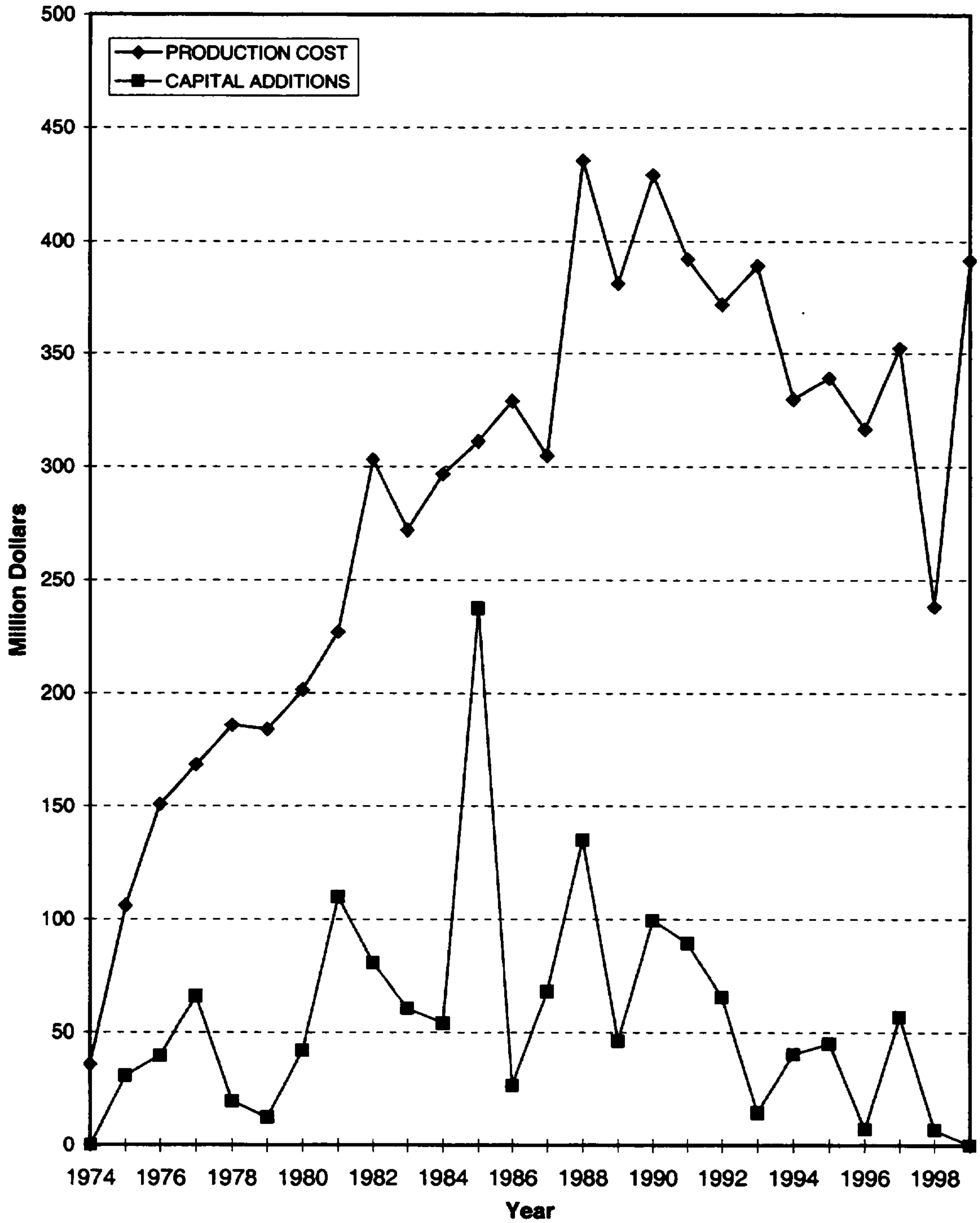
PEACH BOTTOM
(Units 2 and 3)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**PEACH BOTTOM 2**	Nameplate Rating (MWe):	**1221**
Location:	**York and Lancaster County, Pennsylvania**	MDC Net MWe:	**1093**
Operator:	**PECO Energy Co.**	Cumul. Avail. Factor:	**66.3**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**60.2**
Construction Permit:	**1/31/68**	Cumul. Forced Outage Rate:	**10.0**
Operating License:	**12/14/73**	3-Year Avg. Cap. Factor (MDC Net):	**92.9**
Commercial Oper. Date:	**7/5/74**	License Expiration:	**8/8/13**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jul 1998		The NRC proposed and the licensee paid a $55,000 fine for an inoperable core spray (CS) pump.
Sep 1998	Nov 1998	The unit was taken off-line and shut down for 33 d for the 12th refueling and maintenance outage.
Sep 1999	Oct 1999	The unit was taken off-line and shut down for 6 d following a reactor scram.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**PEACH BOTTOM 3**	Nameplate Rating (MWe):	**1221**
Location:	**York and Lancaster County, Pennsylvania**	MDC Net MWe:	**1093**
Operator:	**PECO Energy Co.**	Cumul. Avail. Factor:	**66.9**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**60.2**
Construction Permit:	**1/31/68**	Cumul. Forced Outage Rate:	**10.1**
Operating License:	**7/2/74**	3-Year Avg. Cap. Factor (MDC Net):	**86.9**
Commercial Oper. Date:	**12/23/74**	License Expiration:	**7/2/14**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Oct 1997	Nov 1997	The unit was taken off-line and shut down for 30 d for the 11th refueling and maintenance outage.
Mar 1998		The unit was taken off-line and shut down for 18 d to repair the recirculation system jet pump risers.
Jul 1998		The NRC proposed and the licensee paid a $55,000 fine for an inoperable CS pump.
Nov 1998	Dec 1998	The unit was taken off-line and shut down for 7 d to repair an instrument nitrogen supply line.
Sep 1999	Oct 1999	The unit was taken off-line and shut down for 28 d for the 12th refueling and maintenance outage.

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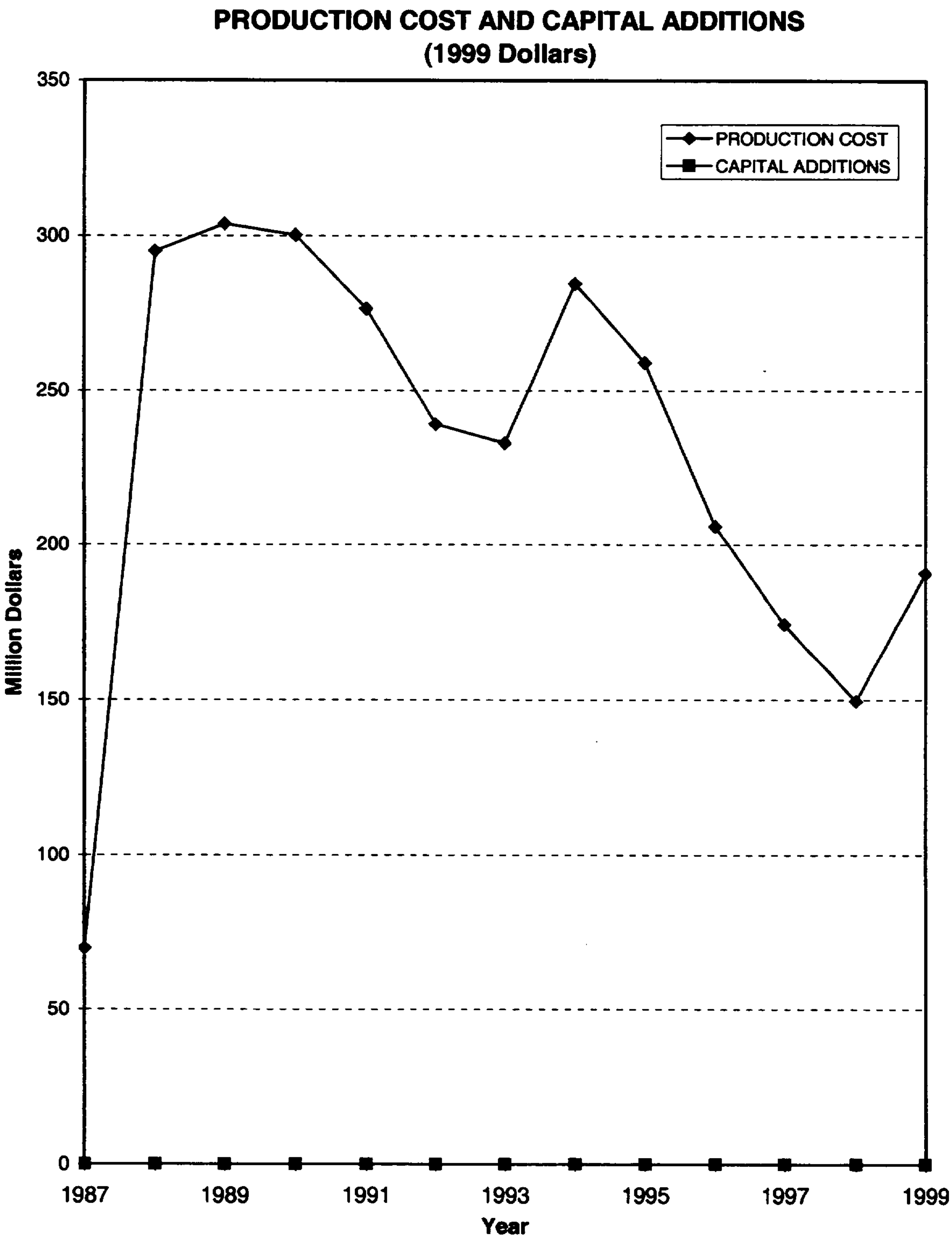
PERRY 1


PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)
PRODUCTION COST
CAPITAL ADDITIONS
Million Dollars
Year
350
300
250
200
150
100
50
0
1987
1989
1991
1993
1995
1997
1999

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

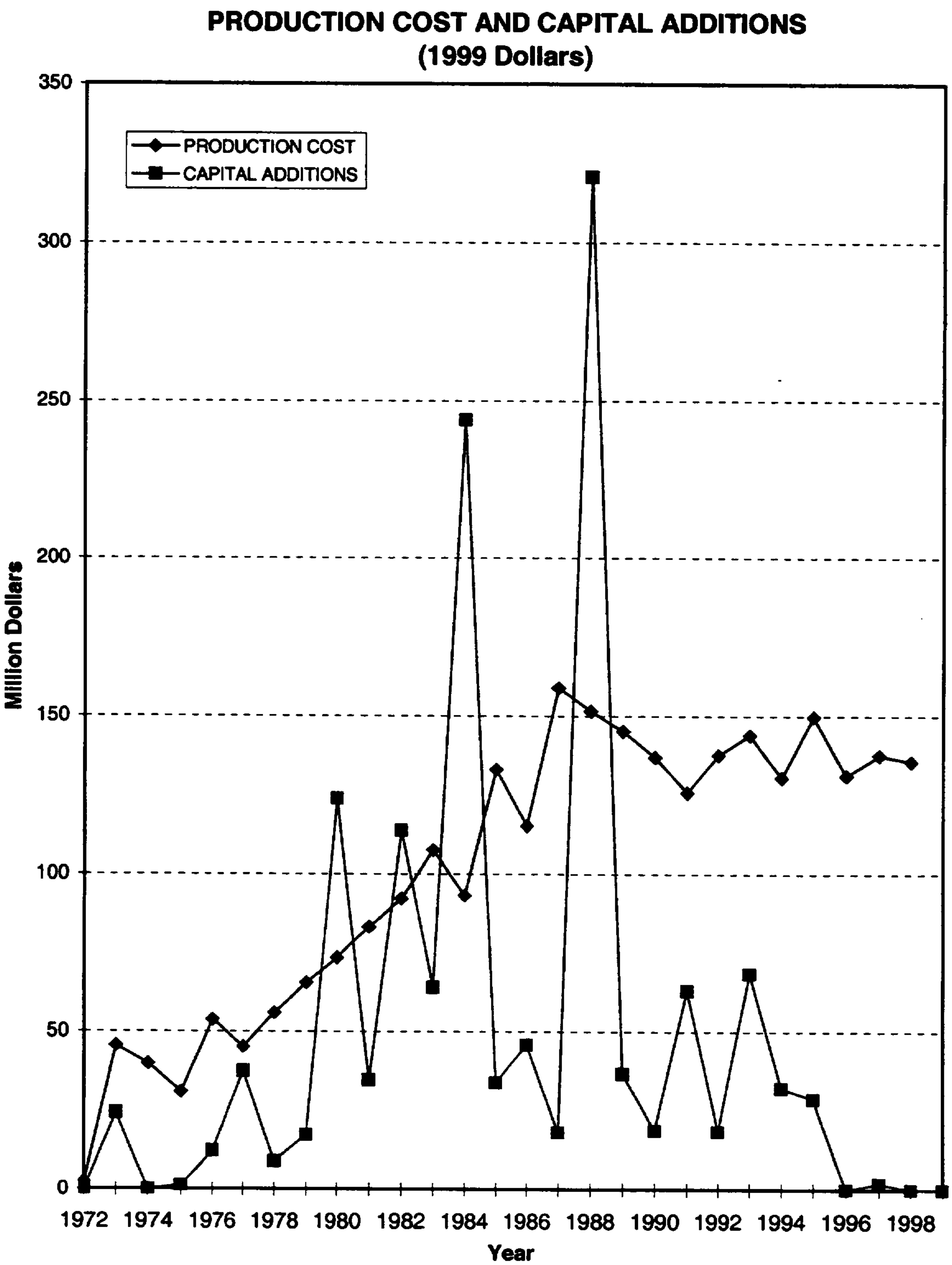
Unit Data Summary (Through December 1999)

Unit:	**PERRY 1**	Nameplate Rating (MWe):	**1250**
Location:	**Lake County, Ohio**	MDC Net MWe:	**1166**
Operator:	**FirstEnergy Nuclear Operating Co.**	Cumul. Avail. Factor:	**71.4**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**72.0**
Construction Permit:	**5/3/77**	Cumul. Forced Outage Rate:	**7.9**
Operating License:	**11/13/86**	3-Year Avg. Cap. Factor (MDC Net):	**90.1**
Commercial Oper. Date:	**11/18/87**	License Expiration:	**3/18/26**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jun 1997		The unit was taken off-line and shut down for 16 d to repair the terminal box on the auxiliary transformer and address several NRC concerns.
Sep 1997	Oct 1997	The unit was taken off-line and shut down for 42 d for the sixth refueling and maintenance outage.
Apr 1998		The NRC proposed and the licensee paid a $100,000 fine for inadequate corrective actions regarding repeated reactivity excursions, for failing to incorporate certain design aspects into the construction of the plant, and for failing to identify certain unreviewed safety questions (USQs).
Mar 1999	May 1999	The unit was taken off-line and shut down for 38 d for the seventh refueling and maintenance outage.
May 1999		The NRC proposed a $110,000 fine for discriminating against a radiation protection supervisor, which resulted from the supervisor engaging in protected activities.

PILGRIM 1


PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)
PRODUCTION COST
CAPITAL ADDITIONS
Million Dollars
0
50
100
150
200
250
300
350
1972
1974
1976
1978
1980
1982
1984
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1988
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1992
1994
1996
1998
Year

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**PILGRIM 1**	Nameplate Rating (MWe):	**678**
Location:	**Plymouth County, Massachusetts**	MDC Net MWe:	**670**
Operator:	**Entergy Nuclear Generation Co.**	Cumul. Avail. Factor:	**63.0**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**56.8**
Construction Permit:	**8/26/68**	Cumul. Forced Outage Rate:	**10.5**
Operating License:	**9/15/72**	3-Year Avg. Cap. Factor (MDC Net):	**82.2**
Commercial Oper. Date:	**12/1/72**	License Expiration:	**6/8/12**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997	Apr 1997	The unit was taken off-line and shut down for 65 d. The plant was originally shut down for the 11th scheduled refueling and maintenance outage, but the outage was extended for 23 d to replace a failed main transformer.
Mar 1997		The plant was in a refueling outage on March 7, and the transformer supplying 345-kV off-site power through a backscuttle arrangement isolated. As a result, two safety-related buses lost power and caused an EDG to automatically start and supply emergency power to one of the buses. The shutdown transformer powered by another off-site source provided power for the other safety-related bus. After the transformer failure, almost 6,000 gal of oil was lost from the transformer and entered the turbine building through the isophase ductwork for the main turbine. Most of the oil collected in the turbine building truck lock and radwaste sumps, but some of this oil entered the "B" switchgear room. The remainder of the oil that was lost from the transformer collected in the outdoor rock trap surrounding the transformer. Approximately 6 h after the event, the station blackout diesel failed to start when initiated by the plant operators.
Apr 1997		On April 1, the Pilgrim plant experienced a complete LOSP for about 3 h during a major storm that hit the Cape Cod area on March 31 and lasted through April 1. The main transformer was still out of service from the event on March 7. Although the transformer had been replaced with another transformer, the new transformer had not been mechanically or electrically connected. In addition, the unit auxiliary transformer was also electrically unavailable as was the main generator. The plant was in cold shutdown, with the RPV head on, and refueled following an outage that began on February 15. Additional information indicates that the plant lost one 345-kV (Bridgewater Substation) off-site power source first and the switching authority, REMVEC, ordered the plant to disconnect (tag open) the air-circuit breakers. The second off-site 345-kV line from Canal Substation was lost almost 45 min later (again

		REMVEC ordered one of the air circuit breakers tagged open). The last line loss caused a lockout on the startup transformer. When the first 345-kV line was tagged open, the plant in accordance with its coastal storm procedures and preparations, separated from the grid (i.e., the startup transformer) and started and loaded both EDGs so that the plant was independent of the grid. When the second 345-kV line tripped, the plant started and placed in standby the station blackout EDG. The last off-site power source (23 kV from Maromet Substation) was lost about 45 min after the last 345-kV line was lost. Power was restored to the 23-kV line about 3 h later. The 345-kV lines were restored about 5 h later.
Sep 1997		The licensee issued a new release on September 22 regarding an investigation being conducted concerning an allegation that 8 years earlier an entry into a control room log was falsified.
Nov 1997	Dec 1997	The unit was taken off-line and shut down for 11 d for a forced outage to investigate why two MSIVs did not indicate "fully closed" during a TS surveillance test.
Apr 1998		On April 23, NRC Region I performed a risk assessment for an NRC Inspection Report for an inspection conducted from May 14 until August 28, 1997. The inspection reviewed the results of a self-assessment performed by the licensee for the Pilgrim Nuclear Power Plant safety-related cooling water systems during January 1995. The inspection examined corrective actions associated with the self-assessment and found four violations. Further, the inspection report found 14 areas of concern and addressed each separately with accompanying findings.
May 1998		The NRC proposed a $55,000 fine for equipment failures associated with the protected area assessment system
May 1998		The NRC proposed and the licensee paid a $165,000 fine for violating 10 CFR 50.59 regulations at its plant.
May 1999	Jul 1999	The unit was taken off-line and shut down for 59 d for the 12th scheduled refueling and maintenance outage.
Sep 1999		The unit was taken off-line and shut down for 6 d for a forced outage to investigate a loss of condenser vacuum and to repair the augmented off-gas system.

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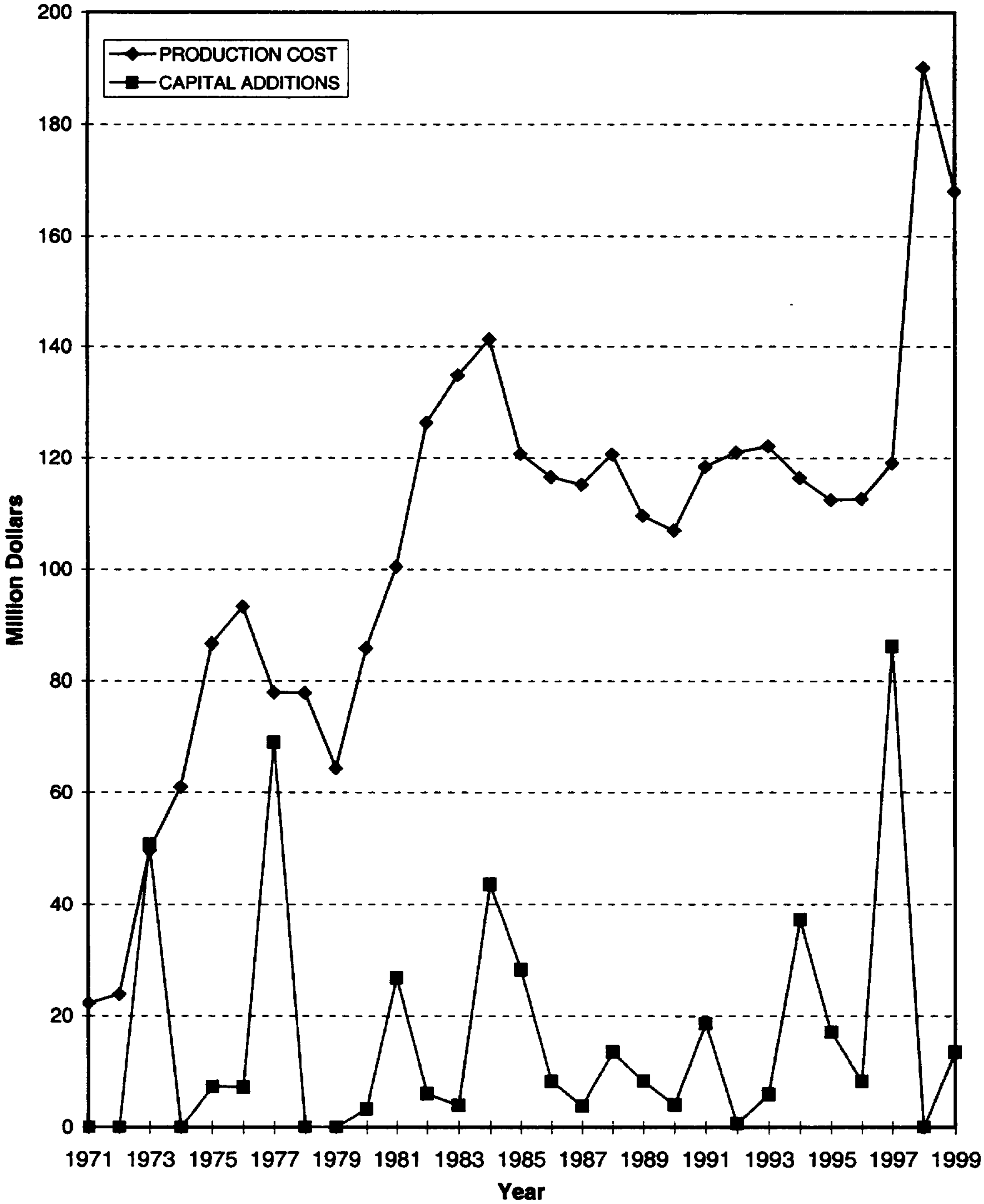
POINT BEACH
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**POINT BEACH 1**	Nameplate Rating (MWe):	**524**
Location:	**Manitowoc County, Wisconsin**	MDC Net MWe:	**485**
Operator:	**Wisconsin Electric Power Co.**	Cumul. Avail. Factor:	**80.8**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**71.9**
Construction Permit:	**7/19/67**	Cumul. Forced Outage Rate:	**4.6**
Operating License:	**10/5/70**	3-Year Avg. Cap. Factor (MDC Net):	**52.7**
Commercial Oper. Date:	**12/21/70**	License Expiration:	**10/5/10**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997	Dec 1997	The unit was taken off-line and shut down for 286 d from February 18 until November 29, for a scheduled maintenance outage to repair the P-32A SW pump and the 1P-11A component cooling water pump.
Mar 1997		Each unit at the Point Beach plant has two component cooling water pumps and one component cooling water HX. Two component cooling water HXs are common for both units, and either one can be aligned to either unit. Two component cooling water pumps and two component cooling water HXs are normally utilized to remove decay heat during plant shutdown. FSAR, Sect. 9.3, allows a cross-connect valve at the component cooling water pump discharge between units to be opened in abnormal situations when only one pump is available on a given unit. On March 4, during valve manipulation testing, this cross-connect valve could not be opened. The licensee indicated that "... since this cross-tie feature was not available due to the inoperability of Valve CC-722B, the plant was in a condition outside its design basis." The cross-connect valve had been unavailable since the 1980s, and the LER states that there had been periods when only one component cooling water pump on a unit was operable.
Apr 1997		On April 3, the licensee indicated that the suction piping from the hot leg to the suction of the RHR pumps (inside containment) was normally water filled and was not provided with relief protection. If an accident increased containment environmental temperatures, this section of piping could rupture and impact the operability of the RHR system in the decay heat removal mode. The affected piping and valves could have also been subject to thermal locking under these same circumstances. This possible piping or valve failure would have impacted the ability of the plant to initiate RHR for decay heat removal; however, it would not have affected the ability of RHR to operate in the injection mode. Long-term cooling could be continued with the SGs and low-pressure injection/sump recirculation.

Sep 1997		The licensee reported on September 26 that EDG 03 was inoperable for approximately 383 h between August 18 and September 3. EDG 03 provides standby power to Unit 1 "B" train 4160-V bus, 1A06. Unit 1 was shut down throughout this entire period and was not affected by the failure. However, because of shared equipment considerations, Unit 2, which was in power operation throughout this entire period, required that this bus be operable. Operability was established by aligning EDG 04 as the standby power source for the "B" train 4160-V buses on both Units 1 and 2 (2A06).
Jan 1998		Point Beach 1 was operating at 98% power on January 8 when the unit lost a 345-kV off-site power line and a station auxiliary transformer (1X03). The fast bus transfer to the Unit 2 station auxiliary transformer (2X03) failed, and three of four EDGs automatically started. The fourth EDG for Unit 2 was unavailable because of maintenance. The gas turbine was started within 3 h, and the EDGs were secured. Unit 1 remained at 98% power throughout the incident because the MFW pumps and RCPs are powered from the unit auxiliary transformer, which was receiving its power from the Unit 1 generator. However, if a trip had occurred during the 69 h that 1X03 was unavailable, the nonvital buses would have lost power and forced the unit into a natural circulation condition.
Feb 1998	Jun 1998	The unit was taken off-line and shut down for 136 d for the 24th scheduled refueling and maintenance outage.
Jan 1999		On January 5, the minirecirculation line to the reactor water storage tank (RWST) from the SI and CS pumps was discovered frozen. It was determined that this condition had existed for 14 d. LOCAs larger than 2 in. in break size would allow for SI pump injection immediately and prevent pump damage. However, smaller leaks would allow the SI pumps to run with reduced flow or at shutoff head, possibly causing pump damage or failure because of the limited flow. Analysis by the licensee indicated that the SI pumps remained operable throughout the 14-d period that the SI recirculation line was frozen. Although the system leakage may have been significant, sufficient RWST volume and SI flow would have been maintained.
Apr 1999		The unit was taken off-line and shut down for 5 d for a scheduled maintenance outage to repair an AFW pump recirculation line weld, the containment hatch, the MS dump valves, the CRD W-3A mechanism cooling fan, the main generator disconnect, and some blowdown system valves.
May 1999		The unit was taken off-line and shut down for 9 d for a forced maintenance outage to repair a steam leak on the No. 4B FW heater.
Oct 1999	Dec 1999	The unit was taken off-line and shut down for 54 d for the 25th scheduled refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

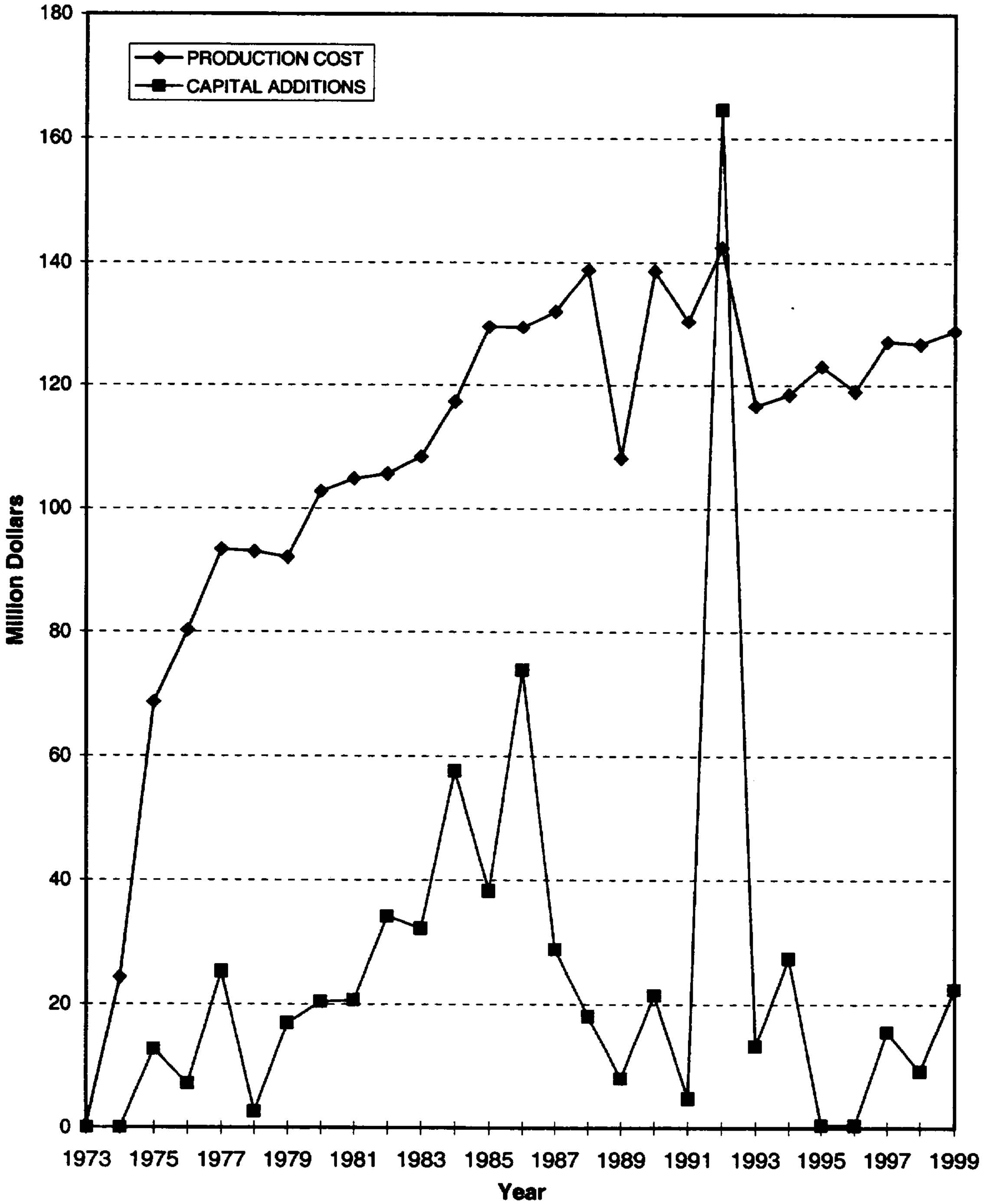
Unit:	**POINT BEACH 2**	Nameplate Rating (MWe):	**524**
Location:	**Manitowoc County, Wisconsin**	MDC Net MWe:	**485**
Operator:	**Wisconsin Electric Power Co.**	Cumul. Avail. Factor:	**83.3**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**75.5**
Construction Permit:	**7/25/68**	Cumul. Forced Outage Rate:	**2.3**
Operating License:	**3/8/73**	3-Year Avg. Cap. Factor (MDC Net):	**57.4**
Commercial Oper. Date:	**10/1/72**	License Expiration:	**3/8/13**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Sep 1997		The unit was taken off-line and shut down for 16 d to correct coincidental start deficiencies in the 480-V undervoltage protection circuit functions.
Nov 1997	Feb 1998	The unit was taken off-line and shut down for 85 d to accommodate testing of the RPS logic permissives.
Mar 1998		The unit was taken off-line and shut down for 24 d to investigate the potential inability to mitigate an accident.
Nov 1998		The unit was taken off-line and shut down for 6 d for a maintenance outage.
Dec 1998	Feb 1999	The unit was taken off-line and shut down for 86 d for the 23rd refueling and maintenance outage.

PRAIRIE ISLAND
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**PRAIRIE ISLAND 1**	Nameplate Rating (MWe):	**593**
Location:	**Goodhue County, Minnesota**	MDC Net MWe:	**513**
Operator:	**Northern States Power Co.**	Cumul. Avail. Factor:	**85.2**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**81.0**
Construction Permit:	**6/25/68**	Cumul. Forced Outage Rate:	**4.6**
Operating License:	**4/5/74**	3-Year Avg. Cap. Factor (MDC Net):	**87**
Commercial Oper. Date:	**12/16/73**	License Expiration:	**8/9/13**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997		The NRC proposed and the licensee paid a $50,000 fine for taking credit for operator actions to isolate cooling water loads following an accident.
Jun 1997		The unit was taken off-line and shut down for 15 d for a forced outage to repair the CRD cable that was shorted to ground.
Oct 1997	Dec 1997	The unit was taken off-line and shut down for 58-1/2 d for the 18th scheduled refueling and maintenance outage.
Nov 1997		The NRC proposed and the licensee paid a $50,000 fine for violations associated with the AFW system.
Jun 1998		The unit was taken off-line and shut down for 13 d for a forced outage to repair a short in a CRD stationary gripper-coil cable.
Oct 1998	Nov 1998	The unit was taken off-line and shut down for 20 d for a forced outage following a reactor trip caused by a CRD cable short.
Jan 1999		The unit was taken off-line and shut down for 7 d for a forced outage to replace the 1M transformer that was destroyed in an explosion. The licensee declared a UE when the Unit 1 station auxiliary transformer exploded. A large amount of oil was dumped and ignited, which caused an oil fire that extinguished about 15 min later. The smoke and flames caused the Unit 1 reserve auxiliary transformer to lock out. All the nonsafeguard buses on Unit 1 were deenergized. One Unit 1 safeguard bus fast transferred to its alternate source of power, while the other safeguard bus remained powered from off-site. Neither Unit 1 EDG started; however, an automatic start of an EDG was not required. The reactor tripped, and the loss of power to the nonsafeguard buses caused all condensate pumps, MFW pumps, CW pumps, and RCPs to trip, which resulted in the plant going into the natural circulation mode.

Apr 1999	May 1999	The unit was taken off-line and shut down for 40 d for the 19th scheduled refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

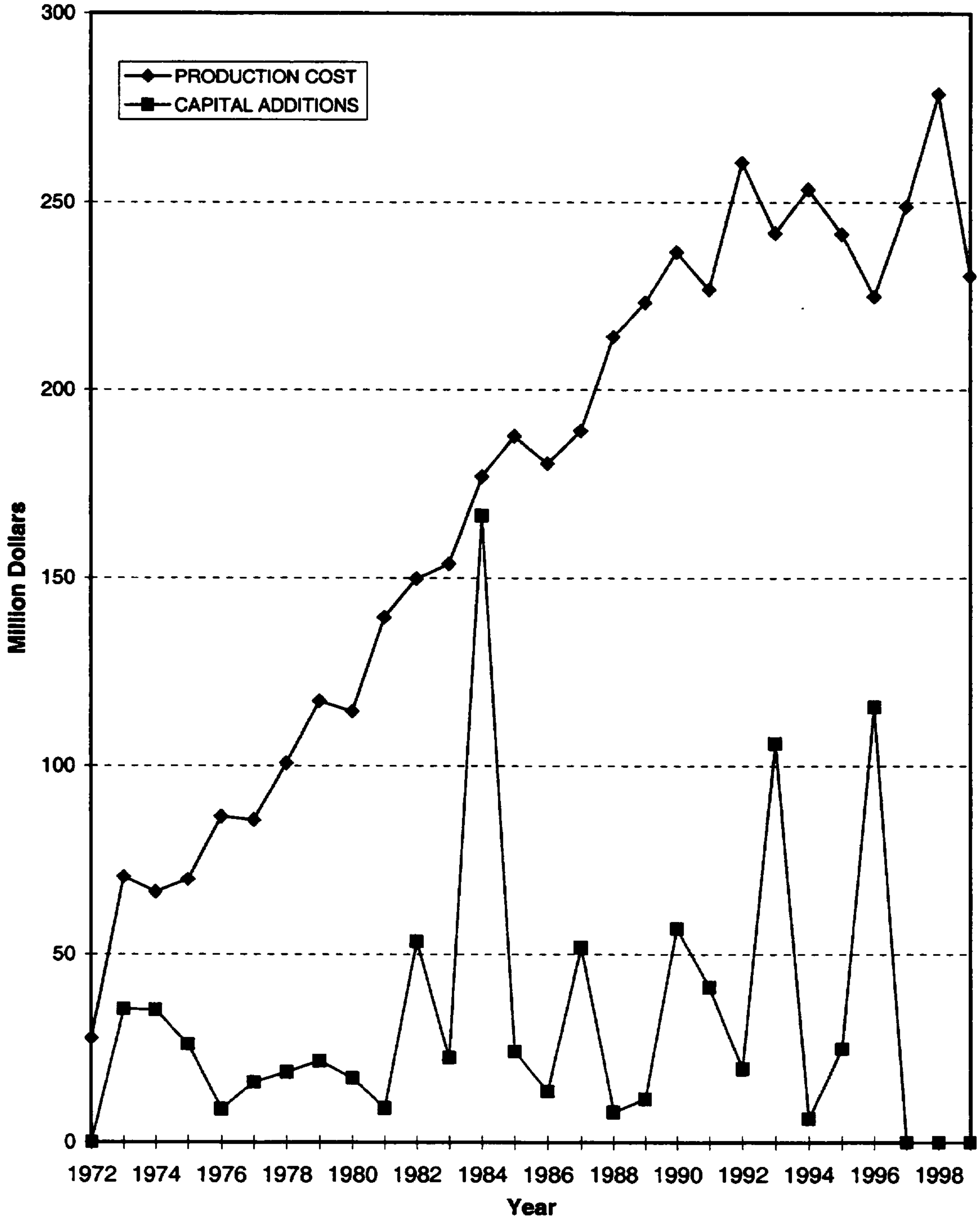
Unit:	**PRAIRIE ISLAND 2**	Nameplate Rating (MWe):	**593**
Location:	**Goodhue County, Minnesota**	MDC Net MWe:	**512**
Operator:	**Northern States Power Co.**	Cumul. Avail. Factor:	**87.5**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**83.3**
Construction Permit:	**6/25/68**	Cumul. Forced Outage Rate:	**2.9**
Operating License:	**10/29/74**	3-Year Avg. Cap. Factor (MDC Net):	**85.3**
Commercial Oper Date:	**12/21/74**	License Expiration:	**10/29/14**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jan 1997	Mar 1997	The unit was taken off-line and shut down for 61 d for the 17th refueling and maintenance outage. The original outage was extended 21 d to address concerns with the cooling water emergency intake line.
Jan 1997		The NRC proposed and the licensee paid a $50,000 fine for taking credit for operator actions to isolate cooling water loads following an accident.
Nov 1997		The NRC proposed and the licensee paid a $50,000 fine for violations associated with the AFW system.
Jan 1998	Mar 1998	The unit was taken off-line and shut down for 39 d for a maintenance outage to repair an RV leak at part length rod "G9."
Nov 1998	Jan 1999	The unit was taken off-line and shut down for 54 d for the 18th refueling and maintenance outage.

QUAD CITIES
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**QUAD CITIES 1**	Nameplate Rating (MWe):	**828**
Location:	**Rock Island County, Illinois**	MDC Net MWe:	**769**
Operator:	**Commonwealth Edison Co.**	Cumul. Avail. Factor:	**73.4**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**64.9**
Construction Permit:	**2/15/67**	Cumul. Forced Outage Rate:	**7.3**
Operating License:	**12/14/72**	3-Year Avg. Cap. Factor (MDC Net):	**72.9**
Commercial Oper. Date:	**2/18/73**	License Expiration:	**12/14/12**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997		The unit was taken off-line and shut down for 6 d for a forced outage to replace a RPS scram relay.
Mar 1997		The unit was taken off-line and shut down for 8 d for a forced outage to repair a level control valve for the MSR drain tank and to repair the EHC system.
Apr 1997		The unit was taken off-line and shut down for 16 d for a forced outage to repair cracked mounting channels in the 4-kV breaker auxiliary switches.
Jul 1997		The NRC proposed and the licensee paid a $50,000 fine for failing to maintain secondary containment as safety related.
Dec 1997		The unit was taken off-line and shut down for 12 d for a forced outage to investigate FP issues.
Jan 1998		The unit was taken off-line and shut down for 150 d for the 15th scheduled maintenance outage.
Jan 1998		While performing a CS logic function test, an electrical technician bumped a relay, which caused a CS initiation signal and a resulting EDG automatic start signal. However, the EDG did not start, and when the operator attempted to reset the alarm, the EDG started.
Apr 1998		The NRC proposed and the licensee paid a $55,000 fine for a maintenance rule violation.
Apr 1998		The NRC proposed and the licensee paid a $330,000 fine for using critical heat to perform code-required leak testing and for having a failed inner O-ring in the RV for more than 1 year.

Oct 1998		The NRC proposed and the licensee paid an $88,000 fine for one Severity Level II violation. There were significant inadequacies in the licensee's capability to shut down the Quad Cities facility and maintain both units in a safe shutdown condition following a postulated design basis fire.
Nov 1998	Dec 1998	The unit was taken off-line and shut down for 28 d for the 16th scheduled refueling and maintenance outage.
Apr 1999	May 1999	The unit was taken off-line and shut down for 21 d for a scheduled outage for routine maintenance and surveillance testing.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**QUAD CITIES 2**	Nameplate Rating (MWe):	**828**
Location:	**Rock Island County, Illinois**	MDC Net MWe:	**769**
Operator:	**Commonwealth Edison Co.**	Cumul. Avail. Factor:	**70.7**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**62.7**
Construction Permit:	**2/15/67**	Cumul. Forced Outage Rate:	**10.5**
Operating License:	**12/14/72**	3-Year Avg. Cap. Factor (MDC Net):	**64.5**
Commercial Oper. Date:	**3/10/73**	License Expiration:	**12/14/12**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997	Jun 1997	The unit was taken off-line and shut down for 114 d for the 14th scheduled refueling and maintenance outage.
Jun 1997		Replacement air start motors were installed on EDGs 1/2 and 2. The replacement air start motors were a different design than the original motors; this resulted in the potential unavailability of both EDGs. On May 8, during a Unit 2 refueling outage, routine maintenance was being performed on the Unit 2 EDG, including replacement of the air start motors. The dimensions of the replacement motors differed slightly from the original ones, and they failed to start the EDG during testing. On May 16, new air start motors were installed on EDG 1/2 with the added spacers. On May 19, EDG 1/2 passed its surveillance test and was declared operable. The inoperability of the EDGs during this event was a design-change process issue and not an actual inoperability.
Jul 1997		The NRC proposed and the licensee paid a $50,000 fine for failing to maintain secondary containment as safety related.
Sep 1997	Oct 1997	The unit was taken off-line and shut down for 241 d for a forced outage to remove and replace a leaking fuel bundle and address safe shutdown issues.
Apr 1998		The NRC proposed and the licensee paid a $55,000 fine for a maintenance rule violation.
Apr 1998		The NRC proposed and the licensee paid a $330,000 fine for using critical heat to perform code-required leak testing and for having a failed inner O-ring in the RV for more than 1 year.

Oct 1998		The NRC proposed and the licensee paid an $88,000 fine for one Severity Level II violation. There were significant inadequacies in the licensee's capability to shut down the Quad Cities facility and maintain both units in a safe shutdown condition following a postulated design basis fire.
Feb 1999	Mar 1999	The unit was taken off-line and shut down for 9 d for a scheduled surveillance outage.

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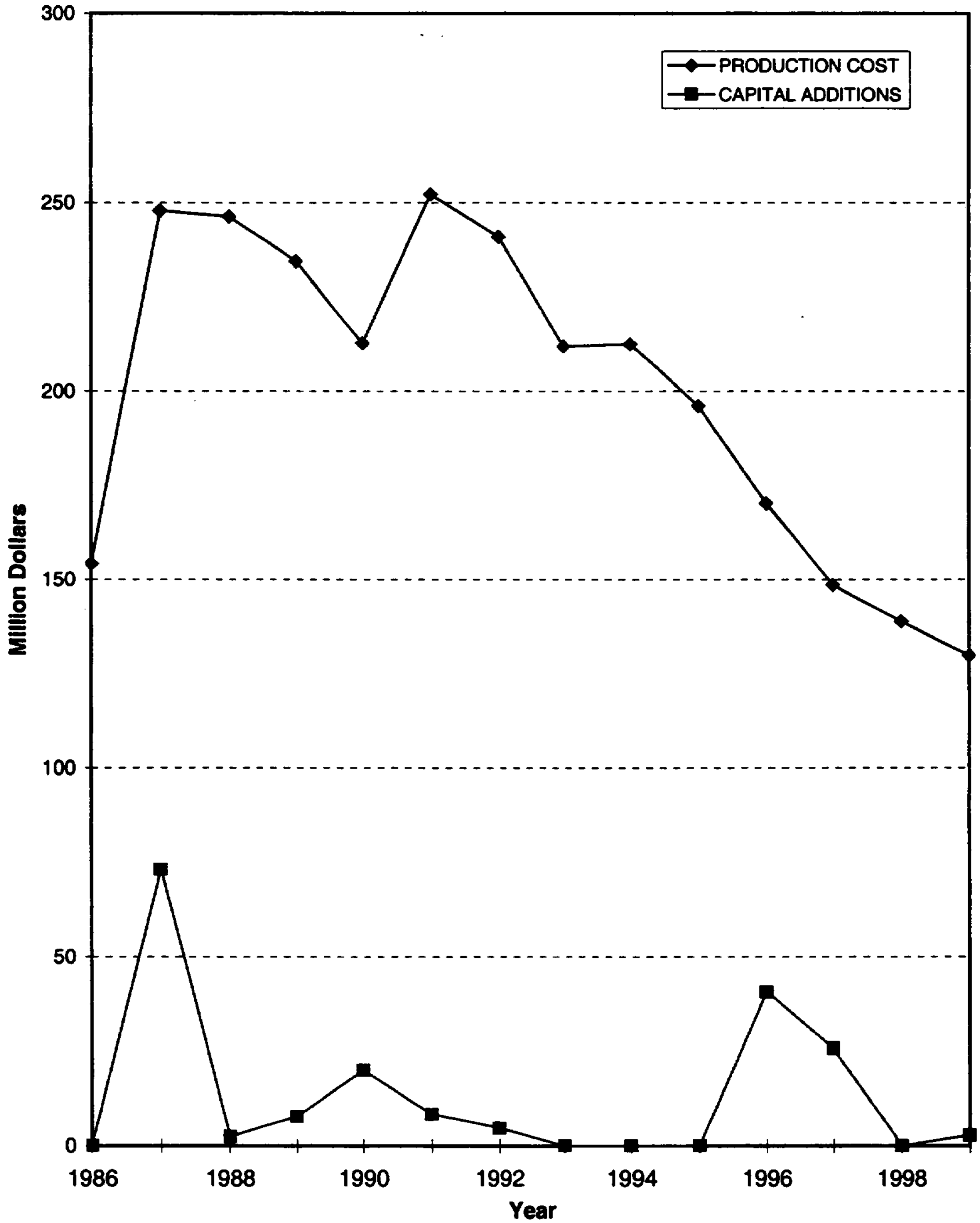
RIVER BEND 1

PRODUCTION COST ANDCAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**RIVER BEND 1**	Nameplate Rating (MWe):	**936**
Location:	**West Feliciana County, Louisiana**	MDC Net MWe:	**936**
Operator:	**Entergy Operations Inc.**	Cumul. Avail. Factor:	**73.3**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**69.6**
Construction Permit:	**3/25/77**	Cumul. Forced Outage Rate:	**10.7**
Operating License:	**11/20/85**	3-Year Avg. Cap. Factor (MDC Net):	**82.8**
Commercial Oper. Date:	**6/16/86**	License Expiration:	**8/29/25**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
May 1997		The unit was taken off-line and shut down for 11 d for a forced outage when an energized cable was damaged during a plant modification.
May 1997		Operators manually scrammed the reactor after two of the three MFW pumps tripped when three nonvital buses and one vital bus were lost. As a result of the loss of the vital bus, one train of RPS was also lost, the Division 2 and 3 EDGs automatically started and loaded onto their respective safety buses, and a reactor recirculation system pump tripped off. Operators secured the remaining operating reactor recirculation system pump, placing the plant in a natural circulation condition. It was subsequently determined that maintenance workers, who were removing fire seal material from a penetration in the turbine building short-circuited and severed a control cable that supplied protective lockout relays for the breakers, which supplied power to the lost buses.
Jul 1997		The unit was taken off-line and shut down for 4 d for a forced outage to replace the mechanical seal in the "A" reactor recirculation pump.
Sep 1997	Oct 1997	The unit was taken off-line and shut down for 39 d for the seventh scheduled refueling and maintenance outage.
Sep 1997		While performing a postmodification test of the new alternate decay heat removal system with the plant shutdown, the licensee allowed both the reactor to change modes and boiling in the core without shutdown cooling in service. The licensee later calculated that the temperature inside the shroud reached about 240°F. Steam was released into the containment as a result of the boiling; however, there were no offsite releases, and air-borne monitors inside the containment did not alarm. Pretest calculations indicated that time-to-boil was about 55 min, and it took the licensee about 1 h and 37 min to get an alternate decay heat removal system into service.

Jan 1998		The NRC proposed and the licensee paid a $50,000 fine for an inadvertent mode change.
Apr 1998		The unit was taken off-line and shut down for 15 d for a forced outage due to the failure of the end-shield sealing material for the main generator. The generator was disassembled and repaired.
Mar 1999		The NRC proposed and the licensee paid a $55,000 fine for design deficiencies concerning the Division I and II EDGs.
Mar 1999		The NRC proposed and the licensee paid a $55,000 fine for deliberately providing an NRC inspector with incomplete and inaccurate information.
Apr 1999	May 1999	The unit was taken off-line and shut down for 40 d for the eighth scheduled refueling and maintenance outage. The end of the refueling outage was declared on May 13, and the plant entered a 51-d forced outage to investigate fuel assembly (FA) corrosion. Several fuel assemblies were replaced.
Oct 1999	Nov 1999	The unit was taken off-line and shut down for 4 d for a forced outage to investigate a reactor scram. Improper use of test equipment caused a trip signal to the main generator output breakers, which resulted in main turbine trip and reactor scram.

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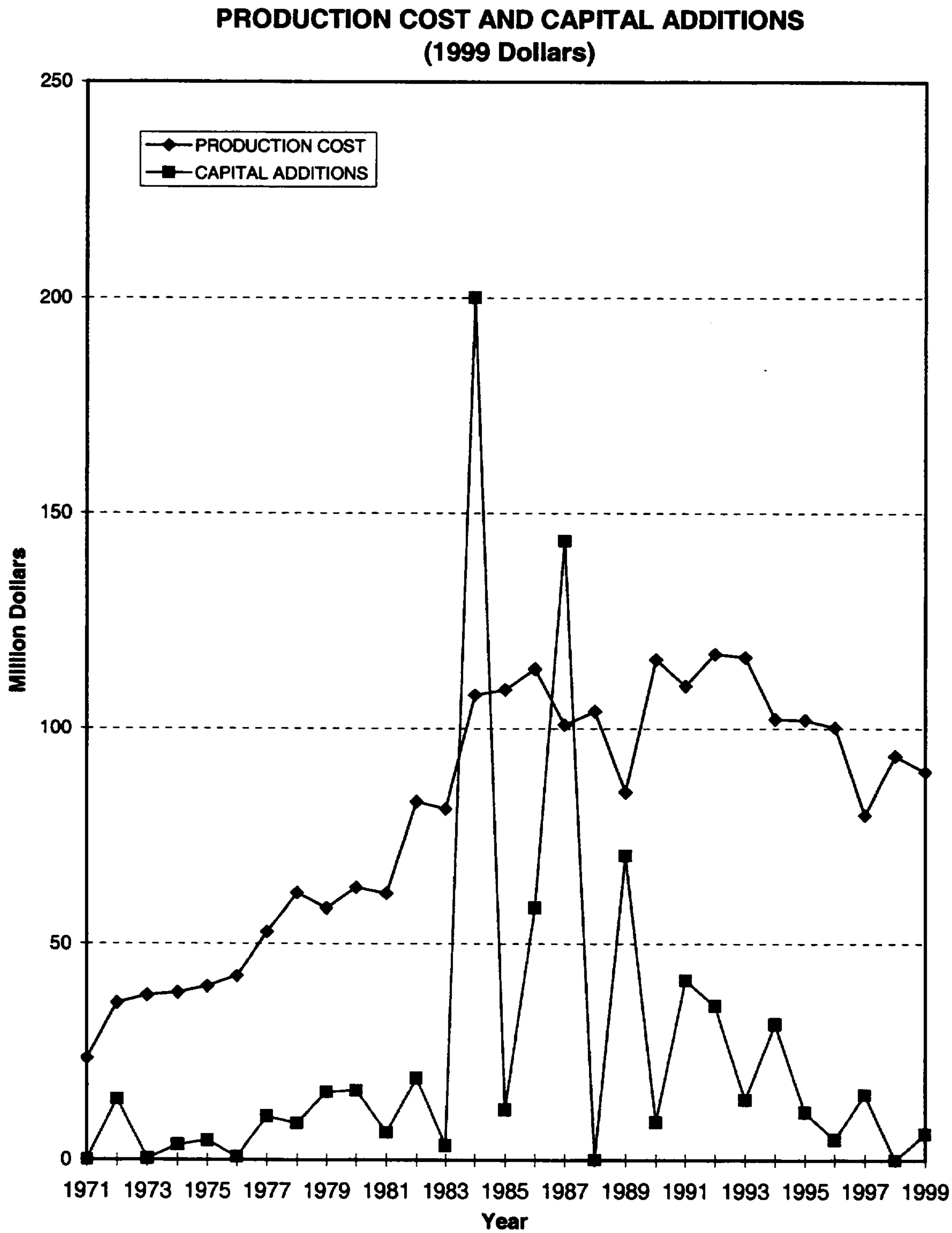
H. B. ROBINSON 2



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

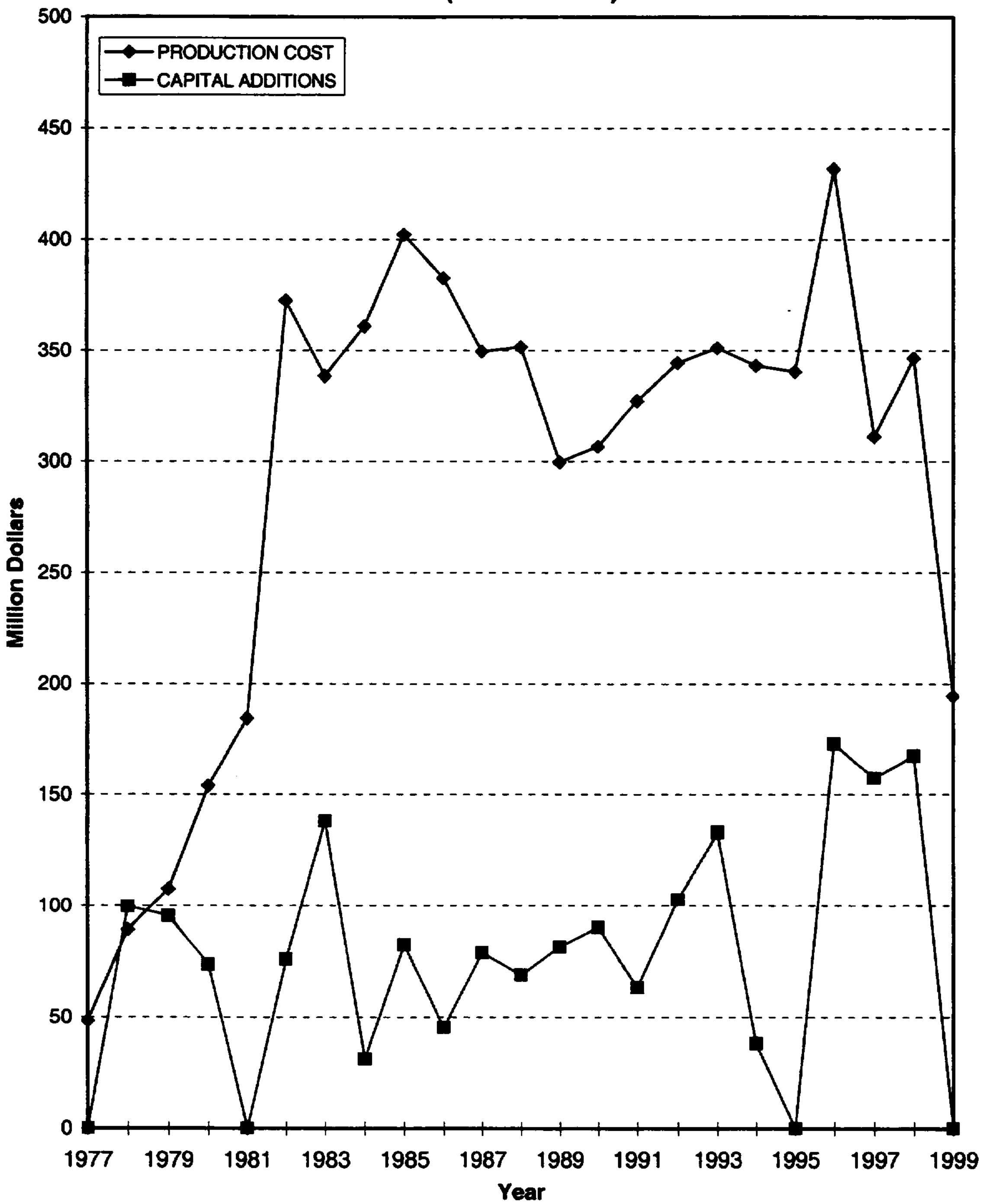
Unit:	**H. B. ROBINSON 2**	Nameplate Rating (MWe):	**739**
Location:	**Darlington County, South Carolina**	MDC Net MWe:	**683**
Operator:	**Carolina Power & Light Co.**	Cumul. Avail. Factor:	**71.5**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**68.7**
Construction Permit:	**4/13/67**	Cumul. Forced Outage Rate:	**12.5**
Operating License:	**9/23/70**	3-Year Avg. Cap. Factor (MDC Net):	**96.9**
Commercial Oper. Date:	**3/7/71**	License Expiration:	**7/31/10**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Nov 1997		The unit was taken off-line and shut down for 4 d to repair the broken shaft on the B condensate pump.
Jan 1998		The NRC proposed and the licensee paid a $55,000 fine for an inoperable EDG.
Mar 1998	Apr 1998	The unit was taken off-line and shut down for 39 d for the 18th refueling and maintenance outage.
Sep 1999	Oct 1999	The unit was taken off-line and shut down for 30 d for the 19th refueling and maintenance outage

SALEM
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**SALEM 1**	Nameplate Rating (MWe):	**1170**
Location:	**Salem County, New Jersey**	MDC Net MWe:	**1106**
Operator:	**Public Service Electric & Gas Co.**	Cumul. Avail. Factor:	**55.3**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**52.5**
Construction Permit:	**9/25/68**	Cumul. Forced Outage Rate:	**29.3**
Operating License:	**12/1/76**	3-Year Avg. Cap. Factor (MDC Net):	**49.8**
Commercial Oper. Date:	**6/30/77**	License Expiration:	**8/13/16**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
May 1995	Apr 1998	The unit was taken off-line and shut down for 1057 d from May 16, 1995, until April 8, 1998. The plant was originally shut down for the 12th scheduled refueling and maintenance outage and to replace the SGs; however, the outage was extended due to regulatory concerns.
Apr 1997		On April 18, it was discovered that prior to July 1994, the potential existed for excessive RHR pump flows during hot-leg recirculation mode alignments in LOCA mitigation scenarios. The plant's emergency operating procedures were changed in 1994 to limit the amount of flow required in hot-leg recirculation. Additionally, on Salem Unit 2, the switchover from the injection mode of LOCA mitigation to the recirculation mode, without the possibility of interrupting ECCS flow to the core, had not been demonstrated since the installation of the semiautomatic switchover modification in 1989 as required by plant TS. These multiple accident-analysis issues could potentially have affected ECCS performance at both Salem 1 and 2. Before changes to the emergency operating procedures in 1994, the first concern was that the RHR system could have been operated with NPSH during certain modes of post-LOCA recirculation operation. An analysis by the plant vendor credited the actual conditions, which would exist during cold-leg recirculation following a LOCA. With the expected elevation in containment pressure, it can be confirmed that adequate NPSH would be assured during cold-leg recirculation; however, this is an NRC USQ. Another concern was also raised regarding the hot-leg recirculation NPSH. If an RHR pump failed along with an unfavorable system alignment, it is possible that the other RHR pump would lose its NPSH during a postulated LOCA. The last concern involved the adequacy of the suction supply of the RWST to the RHR system during switchover to recirculation. The licensee and vendor performed an analysis that, for some scenarios, credited core cooling as adequate, despite brief interruptions to pumped flow. Inventory in the RV downcomer region

		and (for accumulator line breaks) the RCS cold leg was credited to provide core coverage (and, thence, core cooling) during 1.8-min flow interruption for SBLOCAs and up to 5-min interruption for accumulator line breaks. Crediting this additional time assured that operators would have adequate time to complete switchover under all conditions. However, allowing for the potential interruption of pumped flow was identified as an NRC USQ.
Feb 1999	Mar 1999	The unit was taken off-line and shut down for 4 d for a forced outage.
Sep 1999	Oct 1999	The unit was taken off-line and shut down for 38-1/2 d for a scheduled refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**SALEM 2**	Nameplate Rating (MWe):	**1170**
Location:	**Salem County, New Jersey**	MDC Net MWe:	**1106**
Operator:	**Public Service Electric and Gas Co.**	Cumul. Avail. Factor:	**55.5**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**52.6**
Construction Permit:	**9/25/68**	Cumul. Forced Outage Rate:	**30.0**
Operating License:	**5/20/81**	3-Year Avg. Cap. Factor (MDC Net):	**62.7**
Commercial Oper. Date:	**10/13/81**	License Expiration:	**4/18/20**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jun 1995	Aug 1997	The unit was taken off-line and shut down for 800 d from June 7, 1995, until August 16, 1997. The plant was originally shut down for the 12th scheduled refueling and maintenance outage and to replace the SGs; however, the outage was extended due to regulatory concerns.
Oct 1997		The unit was taken off-line and shut down for a forced outage to investigate a reactor trip caused by a loss of both MFW pumps.
Feb 1998		The unit was taken off-line and shut down for 31-1/2 d for a forced maintenance outage to investigate the 2A EDG failure, repair a PORV, and correct SW system biofouling.
Jul 1998		The unit was taken off-line and shut down for 7 d for a forced maintenance outage to replace a pressurizer safety valve.
Aug 1998		The unit was taken off-line and shut down for 9 d for a forced maintenance outage to replace a pressurizer safety valve.
Dec 1998		The unit was taken off-line and shut down for 11 d for a forced maintenance outage to repair RCP seal leakage.
Dec 1998		On December 8, Salem Unit 2 was being prepared for a return to power following a planned shutdown to repair leakage on RCP 21 seal. The RCS temperature and pressure were being increased to normal operating levels. As systems were being aligned from shutdown to normal operating configurations, the RCS pressure was allowed to rise to the relief valve set point. This was within the normal operating band established by plant procedures. The operating crew in the control room was notified by operators inside containment that there was steam in the building. The operating crew also noticed at the same time that the RCS water level was decreasing. The pressurizer level decreased from 26% to 14.7%. The operators declared a UE in accordance with the

		emergency operating procedures, the UE was later upgraded to an alert. The letdown system automatically isolated. The plant was stabilized at an RCS temperature of 330°F and a pressure of 330 psig. Following the event, a containment inspection found no system or component damage; however, indications were that a relief valve had opened in the decay heat removal system. Subsequent calculations indicated that approximately 1200 gal of water had been discharged to the plant waste collection system.
Apr 1999	May 1999	The unit was taken off-line and shut down for 55 d for the 13th scheduled refueling and maintenance outage.

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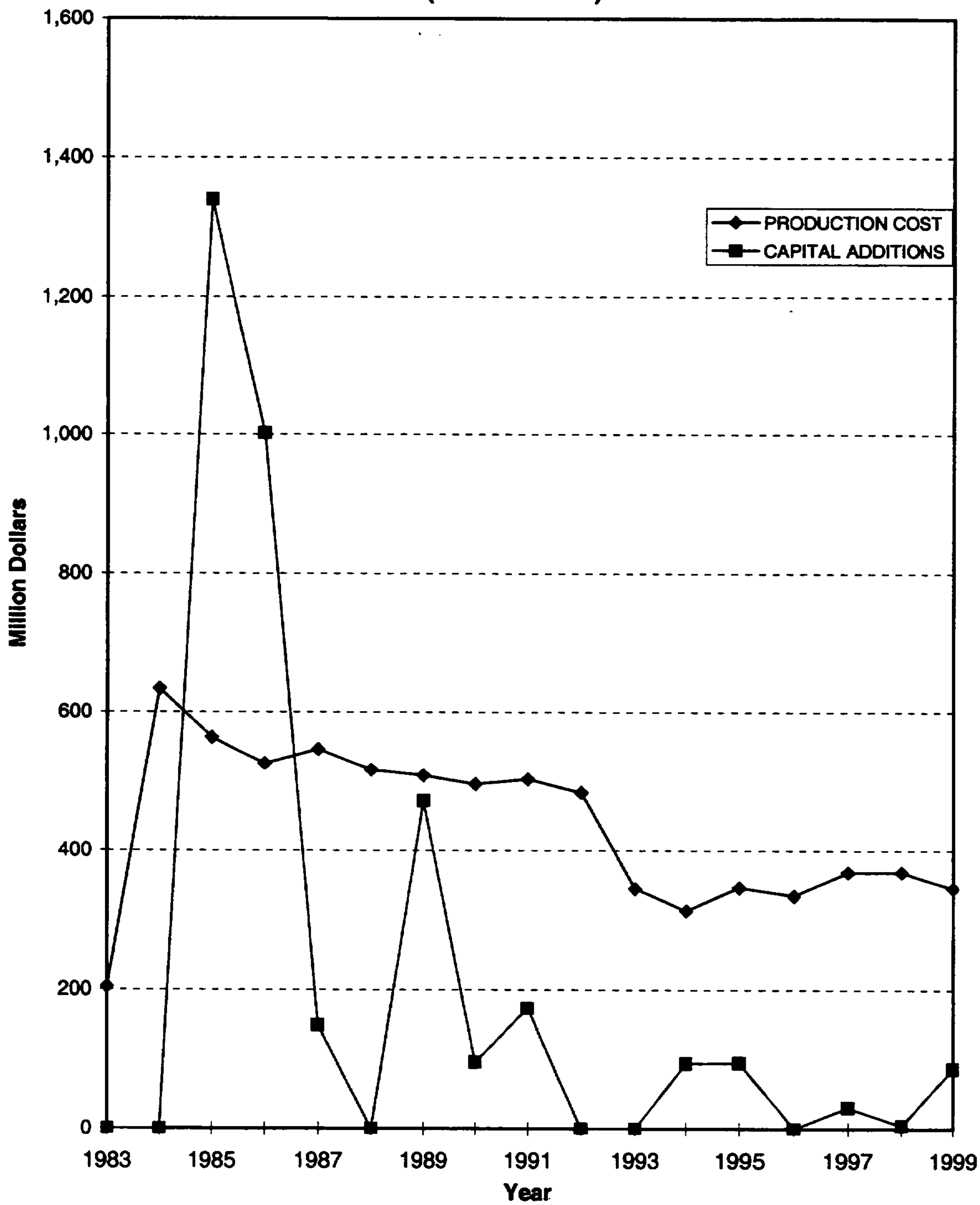
SAN ONOFRE
(Units 2 and 3*)

PRODUCTION COST AND CAPITAL ADDITION
(1999 Dollars)



*1983–1992 includes Unit 1 costs.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**SAN ONOFRE 2**	Nameplate Rating (MWe):	**1127**
Location:	**San Diego County, California**	MDC Net MWe:	**1070**
Operator:	**Southern California Edison Co.**	Cumul. Avail. Factor:	**76.3**
Type:	**Combustion Engineering PWR**	Cumul. Cap. Factor (MDC Net):	**76.8**
Construction Permit:	**10/18/73**	Cumul. Forced Outage Rate:	**4.5**
Operating License:	**9/7/82**	3-Year Avg. Cap. Factor (MDC Net):	**82.8**
Commercial Oper. Date:	**8/8/83**	License Expiration:	**10/18/13**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jun 1997	Jul 1997	The unit was taken off-line and shut down for 17 d for a forced outage to replace a stuck-closed check valve in the charging system.
Aug 1997		On August 5, a single engine aircraft hit two 500-kV lines near Hesperia, California. Although the lines were not downed, Southern California Edison cut power to the lines. The resulting grid disturbance affected three facilities; Diablo Canyon, Palo Verde, and San Onofre. All three sites experienced increased frequency ranging from 60.3 Hz to 63 Hz. The grid instability lasted approximately 15 min. San Onofre had an increase in RCP speed of about 2 rpm. This resulted in core protection calculator alarms; however, no other effects were noted on either unit.
Jan 1998	Feb 1998	The unit was taken off-line and shut down for 29 d for a scheduled midcycle outage.
Feb 1998		The recirculation modes of HPSI and CS were unavailable for about 18 d. For approximately 45 h during this time, the opposite train of HPSI was unavailable. One sump recirculation valve on train "A" of HPSI was unavailable for 18 d (432 h) before the unit shut down on January 24. A linestarter's mechanical interlock was jammed because grit was caught in the sliding cam. This would have prevented the valve from opening on a recirculation actuation signal, which made one train of HPSI and containment spray inoperable in the recirculation mode. The licensee thought that the interlock jammed on January 6.
Sep 1998		The unit was taken off-line and shut down for 11 d for a forced maintenance outage to repair a leaking SG tube plug.
Jan 1999	Feb 1999	The unit was taken off-line and shut down for 55 d for the ninth scheduled refueling and maintenance outage.

Feb 1999	The plant was in a refueling outage with licensee personnel preparing to rack out an electrical breaker for maintenance when the breaker unexpectedly closed. The breaker supplied power from the reserve auxiliary transformer to a 4160-V class "1-E" bus. As a result, both the operating train shutdown cooling pump and the cross-tied CS pump that supplied spent fuel pool cooling tripped off. Even though the associated EDG automatically started, it did not load onto its respective bus because of a protective relay lockout. Shutdown cooling was lost for about 26 min, and the RCS temperature increased approximately 3°F. The licensee declared a UE due to a loss of shutdown cooling for more than 10 min. The UE declaration lasted about 30 min.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

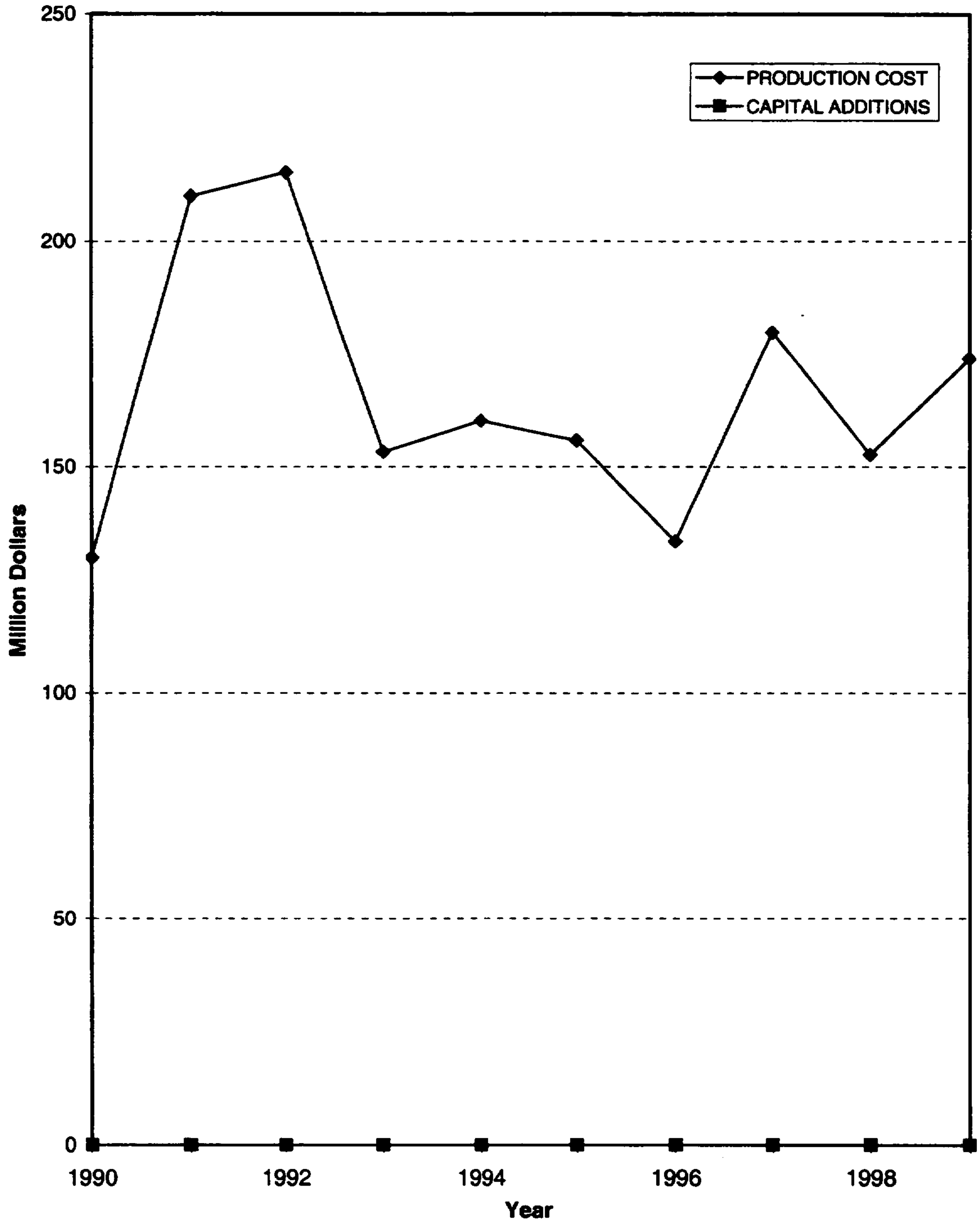
Unit:	**SAN ONOFRE 3**	Nameplate Rating (MWe):	**1127**
Location:	**San Diego County, California**	MDC Net MWe:	**1080**
Operator:	**Southern California Edison Co.**	Cumul. Avail. Factor:	**79.0**
Type:	**Combustion Engineering PWR**	Cumul. Cap. Factor (MDC Net):	**77.8**
Construction Permit:	**10/18/73**	Cumul. Forced Outage Rate:	**3.9**
Operating License:	**9/16/83**	3-Year Avg. Cap. Factor (MDC Net):	**85.6**
Commercial Oper. Date:	**4/1/84**	License Expiration:	**10/18/13**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Apr 1997	Jul 1997	The unit was taken off-line and shut down for 100 d for the seventh refueling and maintenance outage.
Aug 1997		On August 5, a single engine aircraft hit two 500-kV lines near Hesperia, California. Although the lines were not downed, Southern California Edison cut power to the lines. The resulting grid disturbance affected three facilities; Diablo Canyon, Palo Verde, and San Onofre. All three sites experienced increased frequency ranging from 60.3 Hz to 63 Hz. The grid instability lasted approximately 15 min. San Onofre had an increase in RCP speed of about 2 rpm. This resulted in core protection calculator alarms; however, no other effects were noted on either unit.
Mar 1998	Mar 1998	The unit was taken off-line and shut down for 19 d for a midcycle outage to inspect the SGs.
Mar 1999	May 1999	The unit was taken off-line and shut down for 43 d for the eighth refueling and maintenance outage.

SEABROOK

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**SEABROOK**	Nameplate Rating (MWe):	**1197**
Location:	**Rockingham County, New Hampshire**	MDC Net MWe:	**1158**
Operator:	**North Atlantic Energy Service Corp.**	Cumul. Avail. Factor:	**56.4**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**57.8**
Construction Permit:	**7/7/76**	Cumul. Forced Outage Rate:	**6.9**
Operating License:	**3/15/90**	3-Year Avg. Cap. Factor (MDC Net):	**82.3**
Commercial Oper. Date:	**8/19/90**	License Expiration:	**10/17/26**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jan 1997		Several containment isolation valves were found to have the potential for overpressurization due to the heatup of trapped fluid in the piping inboard of the inner containment isolation valve. The SI and waste disposal systems were affected. A vent valve in each system was opened to provide a controlled relief path if the postulated condition developed. The licensee indicated that containment penetrations were not at risk for overpressurizations. The concern is that air-operated valves inside containment could be forced off their closed seat due to a thermally induced pressure increase that results from hot fluid being trapped within the valve in a postaccident environment. This could cause containment bypass situation, following a design basis accident, if the outside containment isolation valve fails to close (or in the case of the SI system, if adequate SI system pressure does not force flow into the core/containment).
May 1997	Jun 1997	The unit was taken off-line and shut down for 50 d for a fifth scheduled refueling and maintenance outage.
Dec 1997	Jan 1998	The unit was taken off-line and shut down for 43 d for a forced maintenance outage to repair through-wall seepage in a spool piece connecting a relief valve to a 12-in. suction line for RHR train "B." The outage was extended to resolve operability concerns with the control building air system.
Jun 1998	Jul 1998	The unit was taken off-line and shut down for 30 d for a forced outage to resolve inoperability concerns with both trains of the control building air system.
Nov 1998		The unit was taken off-line and shut down for 12 d for a scheduled outage to inspect the main generator step-up transformer links and bus works.
Mar 1999	May 1999	The unit was taken off-line and shut down for 48 d for the sixth scheduled refueling and maintenance outage.

Aug 1999	The NRC proposed a $55,000 fine for discriminating against an electrician who brought up safety issues.

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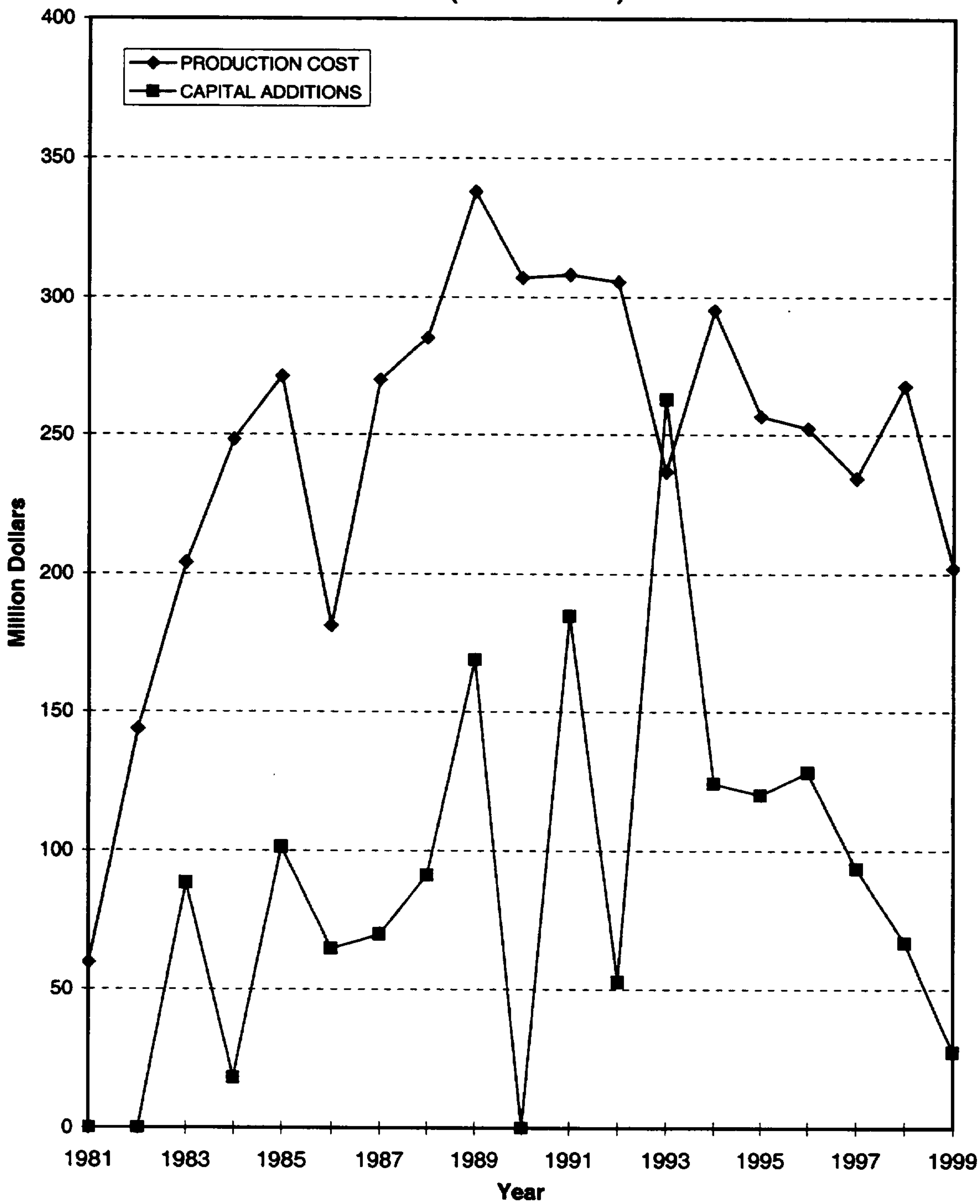
SEQUOYAH
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**SEQUOYAH 1**	Nameplate Rating (MWe):	**1221**
Location:	**Hamilton County, Tennessee**	MDC Net MWe:	**1117**
Operator:	**Tennessee Valley Authority**	Cumul. Avail. Factor:	**58.4**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**59.1**
Construction Permit:	**5/27/70**	Cumul. Forced Outage Rate:	**26.5**
Operating License:	**9/17/80**	3-Year Avg. Cap. Factor (MDC Net):	**92.4**
Commercial Oper. Date:	**7/1/81**	License Expiration:	**9/17/20**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997		The NRC proposed and the licensee paid a $100,000 fine for threatening the chemistry manager with employment termination for raising safety concerns.
Mar 1997	May 1997	The unit was taken off-line and shut down for 52 d for the eighth scheduled refueling and maintenance outage.
Apr 1997		Unit 1 was shut down for a refueling outage with all fuel removed to the spent fuel pool. Unit 2 was operating at 100% power when maintenance personnel who were drilling into a control panel for Unit 1 accidentally drilled into a control power cable; that caused a normal ac supply breaker to trip and deenergize a vital shutdown board. Three of the plant's four EDGs automatically started; one loaded onto its respective bus. However, the other two did not tie onto their buses because the buses were still receiving normal power. The plant's fourth EDG did not start because it had been removed from service for maintenance.
May 1998		The plant was at 100% power performing meter calibration on a 480-V ac shutdown board when the alternate feeder breaker failed to carry the load after a transfer from normal to alternate power. The resulting loss of the shutdown board caused a vital ac instrument bus to be lost and, subsequently, SG level control. The reactor automatically tripped on SG low-low water level. Following the reactor trip, power was lost to the steam dump valves as a result of the instrument bus loss as well as normal letdown. Several instruments lost power to one channel, and the RCS temperature decreased to approximately 540°F, at which time the operators started borating.
Sep 1998	Oct 1998	The unit was taken off-line and shut down for 29 d for the ninth scheduled refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**SEQUOYAH 2**	Nameplate Rating (MWe):	**1221**
Location:	**Hamilton County, Tennessee**	MDC Net MWe:	**1117**
Operator:	**Tennessee Valley Authority**	Cumul. Avail. Factor:	**63.7**
Type:	**Westinghouse PWR**	Cumul Cap. Factor (MDC Net):	**62.8**
Construction Permit:	**5/27/70**	Cumul. Forced Outage Rate:	**25.7**
Operating License:	**9/15/81**	3-Year Avg. Cap. Factor (MDC Net):	**93.7**
Commercial Oper. Date:	**6/1/82**	License Expiration:	**9/15/21**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997		The NRC proposed and the licensee paid a $100,000 fine for threatening the chemistry manager with employment termination for raising safety concerns.
Oct 1997	Nov 1997	The unit was taken off-line and shut down for 27 d for the eighth refueling and maintenance outage.
Apr 1999	May 1999	The unit was taken off-line and shut down for 24 d for the ninth refueling and maintenance outage.

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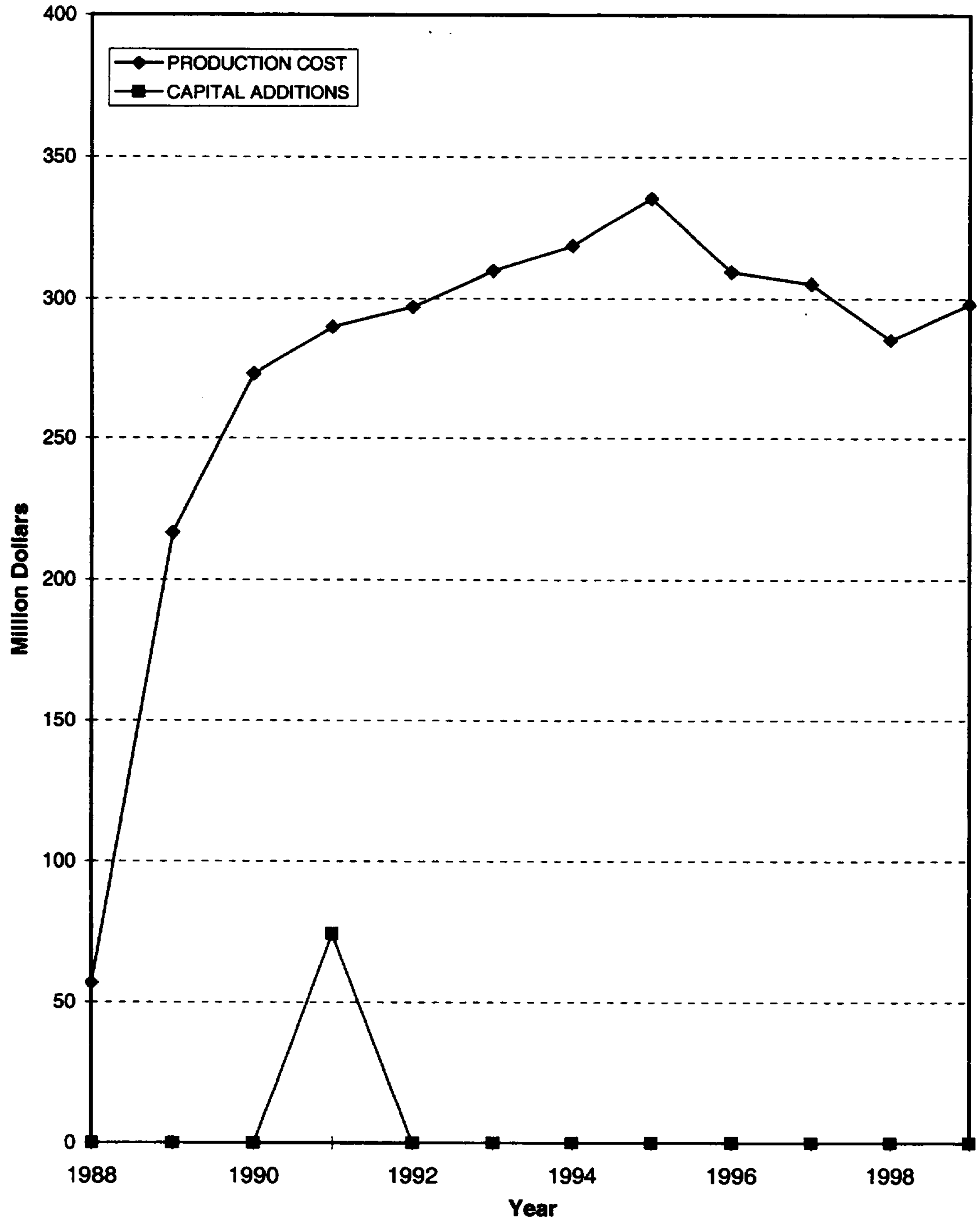
SOUTH TEXAS PROJECT
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**SOUTH TEXAS PROJECT 1**	Nameplate Rating (MWe):	**1311**
Location:	**Matagorda County, Texas**	MDC Net MWe:	**1251**
Operator:	**STP Nuclear Operating Co.**	Cumul. Avail. Factor:	**70.9**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**71.6**
Construction Permit:	**12/22/75**	Cumul. Forced Outage Rate:	**16.7**
Operating License:	**3/22/88**	3-Year Avg. Cap. Factor (MDC Net):	**92.4**
Commercial Oper. Date:	**8/25/88**	License Expiration:	**8/20/27**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Sep 1997	Oct 1997	The unit was taken off-line and shut down for 21 d for the sixth refueling and maintenance outage.
Mar 1999	Apr 1999	The unit was taken off-line and shut down for 33 d for the seventh refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**SOUTH TEXAS PROJECT 2**	Nameplate Rating (MWe):	**1311**
Location:	**Matagorda County, Texas**	MDC Net MWe:	**1251**
Operator:	**STP Nuclear Operating Co.**	Cumul. Avail. Factor:	**72.5**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**72.6**
Construction Permit:	**12/22/75**	Cumul. Forced Outage Rate:	**16.2**
Operating License:	**3/28/89**	3-Year Avg. Cap. Factor (MDC Net):	**90.5**
Commercial Oper. Date:	**6/19/89**	License Expiration:	**12/15/28**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997		The unit was taken off-line and shut down for 18 d for the fifth scheduled refueling and maintenance outage.
Dec 1997	Jan 1998	The unit was taken off-line and shut down for 4 d for a forced outage to replace the sudden pressure relief valve and one of the oil coolers on the 2B main transformer.
Oct 1998		The unit was taken off-line and shut down for 22 d for the sixth scheduled refueling and maintenance outage.
Mar 1999		The plant was operating at 100% power when the No. 2 standby transformer lost power because of a fault in a switchyard breaker. ESF buses on two trains actuated on LOSP, and several ESF systems automatically started.
Oct 1999	Nov 1999	The unit was taken off-line and shut down for 26-1/2 d for the seventh scheduled refueling and maintenance outage.

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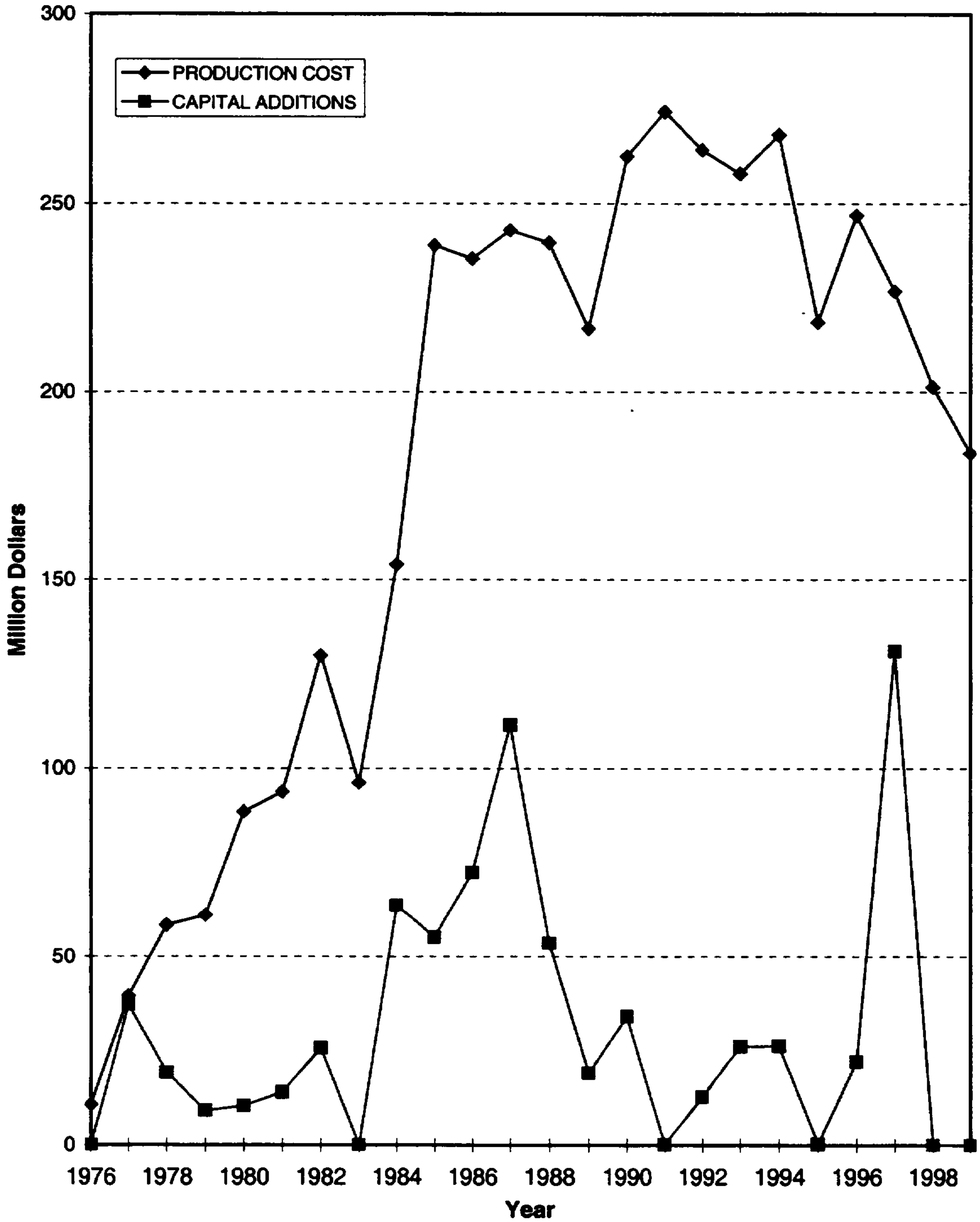
ST LUCIE
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**ST LUCIE 1**	Nameplate Rating (MWe):	**850**
Location:	**St Lucie County, Florida**	MDC Net MWe:	**839**
Operator:	**Florida Power & Light Co.**	Cumul. Avail. Factor:	**77.3**
Type:	**Combustion Engineering PWR**	Cumul. Cap. Factor (MDC Net):	**75.8**
Construction Permit:	**7/1/70**	Cumul. Forced Outage Rate:	**4.6**
Operating License:	**3/1/76**	3-Year Avg. Cap. Factor (MDC Net):	**87.5**
Commercial Oper. Date:	**12/21/76**	License Expiration:	**3/1/16**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997		The NRC proposed and the licensee paid $100,000 for fines based on miswiring errors, an unauthorized individual entry into the protected area, emergency preparedness failures involving the phone system, mistakes in procedures, and training deficiencies.
Apr 1997		The unit was taken off-line and shut down for 4 d for the a forced outage to repair an SI tank header valve.
Oct 1997	Jan 1998	The unit was taken off-line and shut down for 80 d for the 14th scheduled refueling, maintenance, and SG replacement outage.
Nov 1997		Unit 1 was defueled to support SG replacement. During the outage, obsolete ESF actuation signal bistables were being replaced to improve system reliability. It was determined that the ESF actuation signal recirculation bistable set point for the reactor water tank level had been set less conservative than required by the plant TS. It was subsequently determined that the bistables would indicate a 1-ft level instead of 0 ft when the tank had been emptied during the injection phase of SI, and correspondingly they would indicate a 51-ft level instead of 50 ft when the tank was full. Four channels of reactor water tank level indication are available to the operators that were not affected by the set point error. The operators would have had correct readings if they had to manually initiate recirculation. The key to this event is the amount of ECCS flow present at the time the recirculation actuation signal is required to actuate. The licensee indicates that full flow [such as that following a large-break loss-of-coolant accident (LBLOCA)], with all ECCS components in operation, is approximately 13,000 gpm. Air binding and failure of the HPSI pumps can occur within approximately 90 s if recirculation is not initiated at the expected set point. The LPSI pumps will be impacted within approximately 240 s. The time duration from the TS minimum level in the reactor

water tank to the expected recirculation actuation signal set point is approximately 20 min under worst-case conditions. The emergency operating procedures direct the operators to reduce spray flow when the containment pressure is reduced below 5 psig. LPSI and HPSI flow can be reduced under certain circumstances per the emergency operating procedures, but this is unlikely during the initial 20 min following a LBLOCA. If the flow is below 7000 gpm at the time the recirculation actuation signal should initiate, the pumps probably would not experience air binding and fail before reaching the 3-ft recirculation actuation signal set point. This is based on licensee engineering evaluations. If the flow exceeds 7000 gpm, chugging flow may occur and reduce the pump flow rate such that the 3-ft recirculation actuation signal set point is not reached prior to pump failure.

The time before reaching the recirculation actuation signal set point during a SBLOCA is sufficiently long enough to allow the spray pumps and the LPSI pumps to be secured. This would avoid any consideration of ECCS pump failure as a result of a SBLOCA.

Also, the FSAR indicates that containment pressure would be reduced below 5 psig in approximately 20 min following a LBLOCA.

Feb 1998		The unit was taken off-line and shut down for 7 d for a scheduled maintenance outage to replace the 1B2 RCP pump seals.
Apr 1998		The NRC proposed and the licensee paid an $88,000 fine for an incorrect instrument set point regarding the refueling water tank switchover setting.
Sep 1999	Oct 1999	The unit was taken off-line and shut down for 35 d. First, the plant entered a forced outage for 5 d to prepare for Hurricane Floyd, and, then immediately following this, for 30 d for the 15th scheduled refueling and maintenance outage.

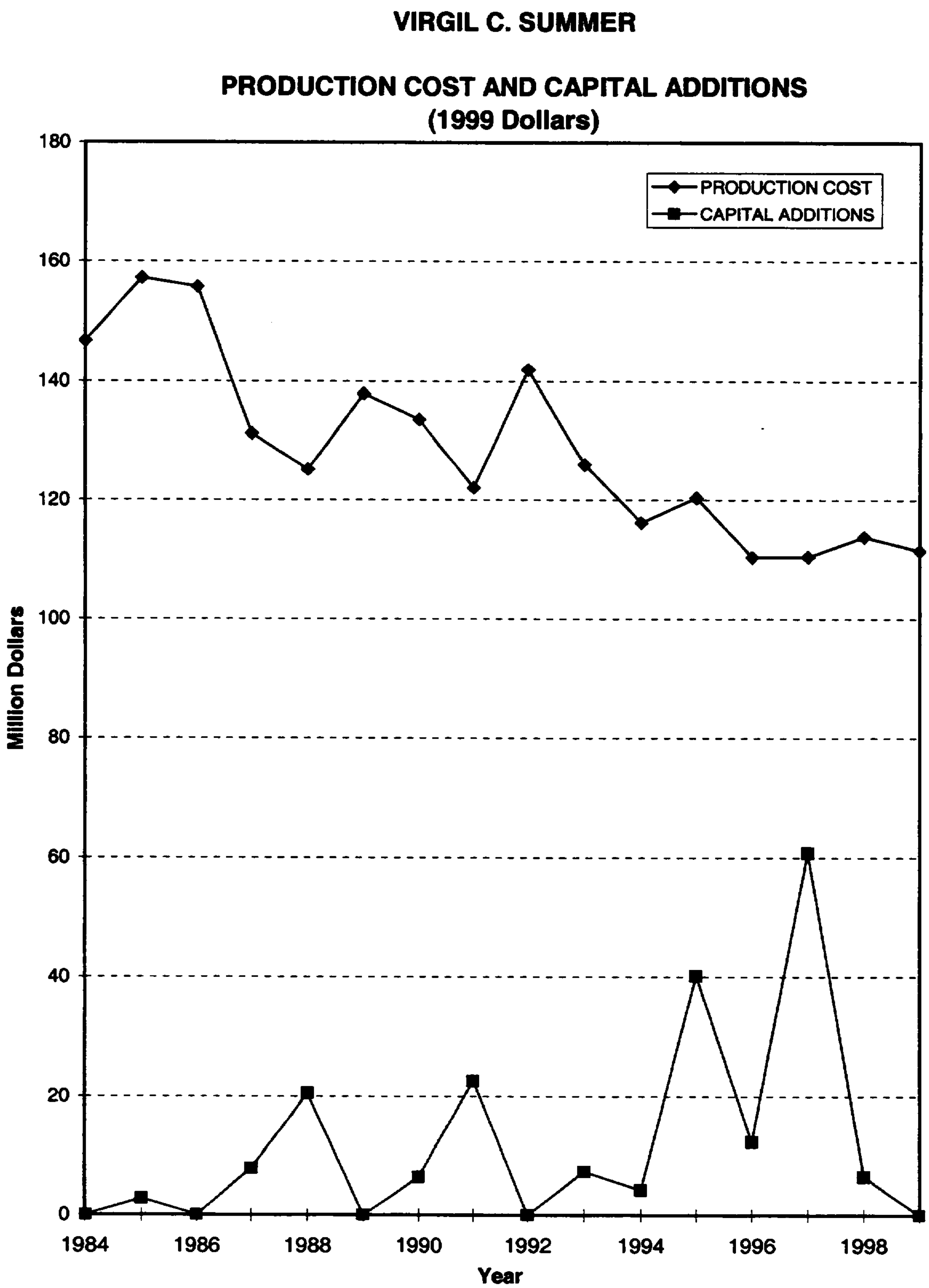
NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**ST LUCIE 2**	Nameplate Rating (MWe):	**850**
Location:	**St Lucie County, Florida**	MDC Net MWe:	**839**
Operator:	**Florida Power & Light Co.**	Cumul. Avail. Factor:	**84.1**
Type:	**Combustion Engineering PWR**	Cumul. Cap. Factor (MDC Net):	**83.1**
Construction Permit:	**5/2/77**	Cumul. Forced Outage Rate:	**5.3**
Operating License:	**6/10/83**	3-Year Avg. Cap. Factor (MDC Net):	**92.7**
Commercial Oper. Date:	**8/8/83**	License Expiration:	**4/6/23**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997		The NRC proposed and the licensee paid $100,000 for fines based on miswiring errors, unauthorized individual entry into the protected area, emergency preparedness failures involving the phone system, mistakes in procedures, and training deficiencies.
Apr 1997	May 1997	The unit was taken off-line and shut down for 42 d for the ninth refueling and maintenance outage.
Apr 1998		The NRC proposed and the licensee paid an $88,000 fine for an incorrect instrument set point regarding the refueling water tank switchover setting.
Nov 1998	Dec 1998	The unit was taken off-line and shut down for 30 d for the tenth refueling and maintenance outage.
Jun 1999		The unit was taken off-line and shut down for 8 d for a forced outage to investigate a plant trip caused by a control element assembly (CEA) subgroup drop.



VIRGIL C. SUMMER
PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)
PRODUCTION COST
CAPITAL ADDITIONS
Million Dollars
180
160
140
120
100
80
60
40
20
0
1984
1986
1988
1990
1992
1994
1996
1998
Year

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

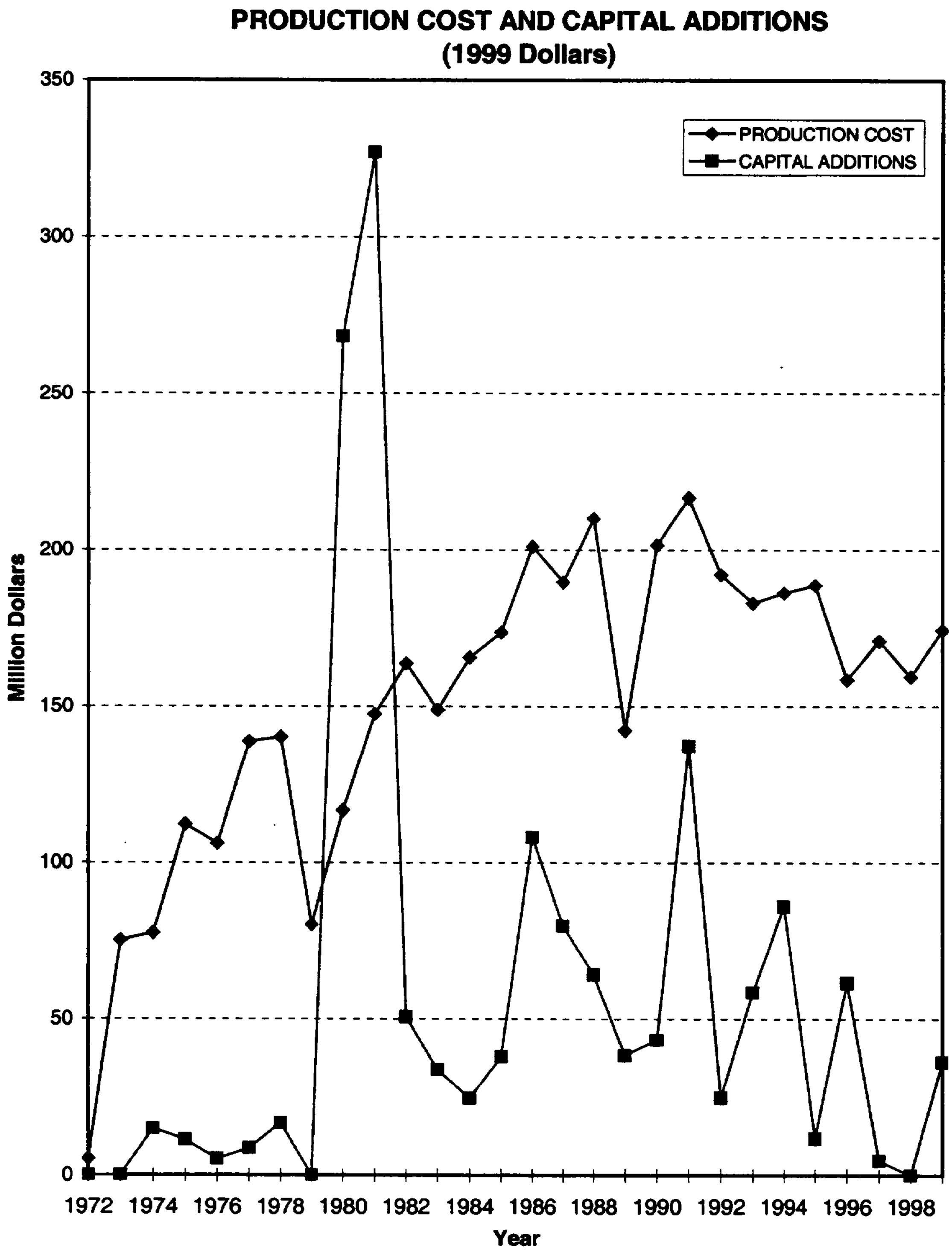
Unit Data Summary (Through December 1999)

Unit:	**VIRGIL C. SUMMER**	Nameplate Rating (MWe):	**900**
Location:	**Fairfield County, South Carolina**	MDC Net MWe:	**945**
Operator:	**South Carolina Electric & Gas Co.**	Cumul. Avail. Factor:	**81.5**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**74.1**
Construction Permit:	**3/21/73**	Cumul. Forced Outage Rate:	**3.6**
Operating License:	**11/12/82**	3-Year Avg. Cap. Factor (MDC Net):	**91.1**
Commercial Oper. Date:	**1/1/84**	License Expiration:	**8/6/22**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Apr 1997		The reactor was manually tripped in anticipation of a main turbine trip caused by an EHC system leak. Following the trip, one MFW regulating valve failed to close as expected, and two of the three operating MFW pumps were manually tripped.
Oct 1997	Nov 1997	The unit was taken off-line and shut down for 34 d for the tenth scheduled refueling and maintenance outage.
Jan 1998		The unit was taken off-line and shut down for 5 d for a forced outage to repair the "A" DG.
Apr 1999	May 1999	The unit was taken off-line and shut down for 38 d for the 11th scheduled refueling and maintenance outage.
May 1999		The licensee made a report pursuant to 10 CFR 21.21 identifying a substantial safety hazard with General Electric (GE) 7.2-kV Magne-Blast breakers. Several 7.2-kV Magne-Blast breakers failed to close during testing. The licensee also reported that the existing condition represented a potential common mode failure of these breakers. These breakers are used in eight separate sets of switchgear, including the EDG output breakers.
Aug 1999		The licensee made a report pursuant to 10 CFR 21.21 that identified a substantial safety hazard with an Asea Brown Boveri (ABB) line breaker. The licensee reported that these breakers could fail to trip. The licensee also reported that the existing condition represented a potential common mode failure of these breakers. These breakers are used in many applications including the 480-V ac safety-related electrical buses.

SURRY
(Units 1 and 2)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**SURRY 1**	Nameplate Rating (MWe):	**848**
Location:	**Surry County, Virginia**	MDC Net MWe:	**801**
Operator:	**Dominion Generation**	Cumul. Avail. Factor:	**71.0**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**65.4**
Construction Permit:	**6/25/68**	Cumul. Forced Outage Rate:	**13.8**
Operating License:	**5/25/72**	3-Year Avg. Cap. Factor (MDC Net):	**87.9**
Commercial Oper. Date:	**12/22/72**	License Expiration:	**5/25/12**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jan 1997	Feb 1997	The unit was taken off-line and shut down for 9 d for a forced maintenance outage to repair a pinhole leak on 2-in. MS piping.
Mar 1997	May 1997	The unit was taken off-line and shut down for 56 d for a scheduled refueling and maintenance outage.
Sep 1997		The NRC proposed and the licensee paid a $55,000 fine for maintenance rule violations.
Mar 1998		The unit was taken off-line and shut down for 11 d for a scheduled preventive maintenance outage.
May 1998		The licensee noted an increase in the RCS leak rate even though the total leakage remained within TS limits. A containment entry indicated boundary leakage on the 1.5-in. seal injection line to the "C" RCP.
		The unit was taken off-line and shut down for 16 d for a forced maintenance outage to repair a nonisolable weld leak on the "C" RCP seal injection line.
Oct 1998	Nov 1998	The unit was taken off-line and shut down for 33 d for a scheduled refueling and maintenance outage.
Nov 1998		The plant was at 28 % power and ascending in power after a refueling outage when an unexplained increase in steam flow occurred on "B" SG. The "B" SG reached the high turbine trip set point and caused a turbine trip and subsequent reactor trip. All MSIVs closed as designed, and a SI occurred following the trip.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**SURRY 2**	Nameplate Rating (MWe):	**848**
Location:	**Surry County, Virginia**	MDC Net MWe:	**801**
Operator:	**Dominion Generation**	Cumul. Avail. Factor:	**69.5**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**65.5**
Construction Permit:	**6/25/68**	Cumul. Forced Outage Rate:	**11.0**
Operating License:	**1/29/73**	3-Year Avg. Cap. Factor (MDC Net):	**92.6**
Commercial Oper. Date:	**5/1/73**	License Expiration:	**1/29/13**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997		The unit was at 100% power when a loss of EHC power occurred. An automatic turbine trip should have occurred followed by a reactor trip; however, an EHC relay card failed. The operator inserted a manual trip signal. Three control rods did not indicate fully inserted, so emergency boration was initiated. Seventeen minutes after the trip, conditions existed for the TDAFW pump to automatically shut down; however, within seconds, the TDAFW pump received another start signal due to small tolerances between the SG levels that initiate and clear the TDAFW pump start signal. The TDAFW pump governor did not have time to reset itself on the low-speed set point, thus allowing the TDAFW pump to overspeed and subsequently trip on excessive speed. The EHC failure caused the turbine governor valves to move in the closed direction, and the loss of load caused the RCS temperature to increase. The three rods that did not fully insert did initiate rod bottom lights. The rods were likely on the bottom and certainly indicated below 15 steps.
Sep 1997		The NRC proposed and the licensee paid a $55,000 fine for maintenance rule violations.
Oct 1997		The unit was taken off-line and shut down for 26 d for a scheduled refueling and maintenance outage.
Apr 1999	May 1999	The unit was taken off-line and shut down for 42 d for a scheduled refueling and maintenance outage.
Jul 1999		The unit was taken off-line and shut down for 10 d for a forced maintenance outage to repair a motor-operated valve (MOV).

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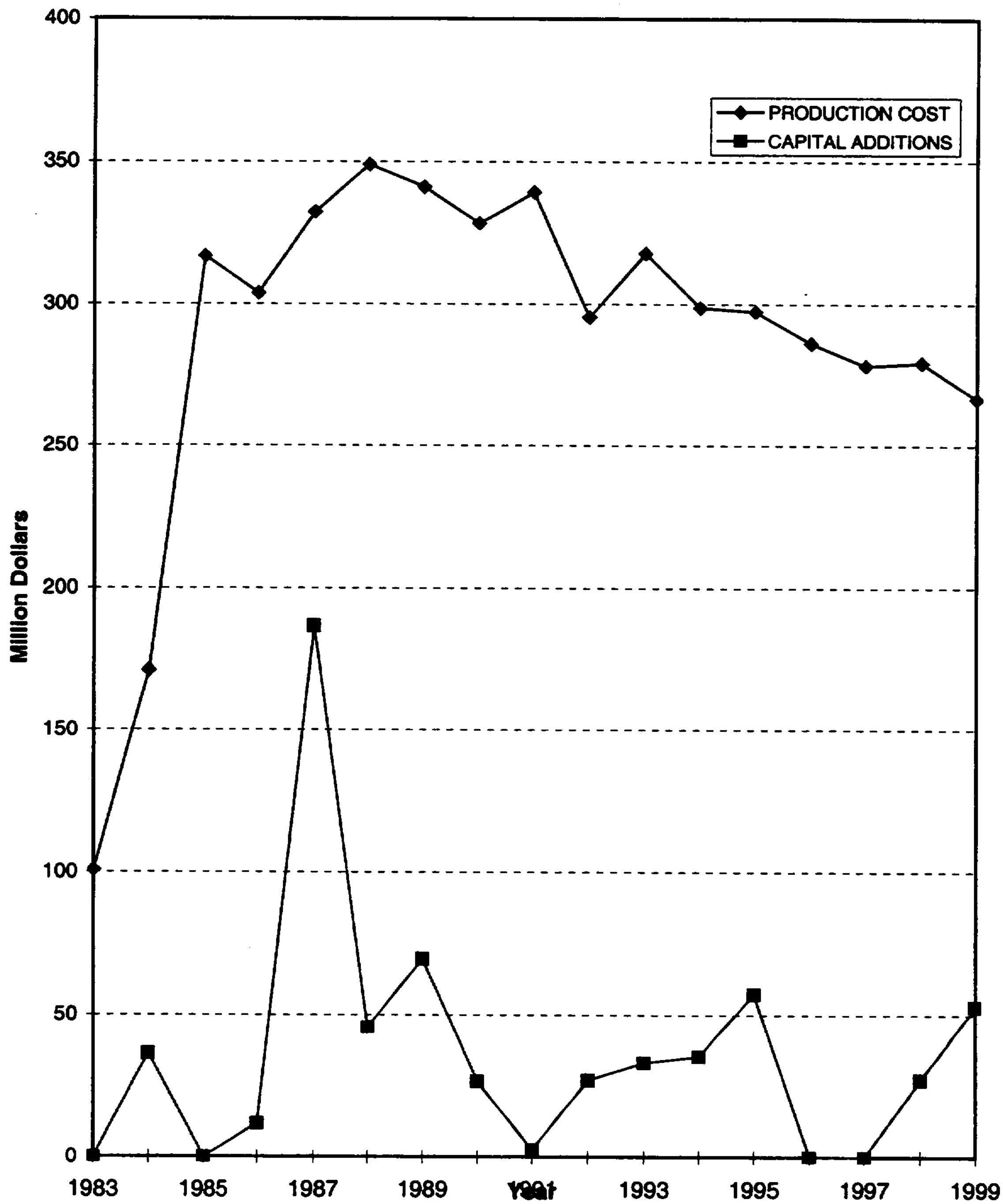
SUSQUEHANNA
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**SUSQUEHANNA 1**	Nameplate Rating (MWe):	**1165**
Location:	**Luzerne County, Pennsylvania**	MDC Net MWe:	**1090**
Operator:	**PP&L, Inc.**	Cumul. Avail. Factor:	**78.5**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**74.4**
Construction Permit:	**11/2/73**	Cumul. Forced Outage Rate:	**6.6**
Operating License:	**11/12/82**	3-Year Avg. Cap. Factor (MDC Net):	**89.2**
Commercial Oper. Date:	**6/8/83**	License Expiration:	**7/17/22**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997	Mar 1997	The unit was taken off-line and shut down for 20 d for a forced outage to investigate problems associated with the EHC system and the main turbine bypass valves.
Jul 1997		The NRC proposed and the licensee paid a $210,000 fine for having an EDG inoperable beyond the TS limiting condition for operation (LCO) time limit, for an erroneous breaker alignment for the "E" DG in violation of procedures, and for operator violations of TS surveillance requirements.
Feb 1998		The NRC proposed and the licensee paid a $55,000 fine for insufficient control of an adjustment knob settings on an EDG voltage regulator. The licensee was unable to ensure that voltage remained appropriately set at 100%.
Apr 1998	May 1998	The unit was taken off-line and shut down for 48 d for the tenth scheduled refueling and maintenance outage.
Jul 1998		The unit was taken off-line and shut down for 8 d for a scheduled maintenance outage to modify all 16 SRV acoustic monitors.
Oct 1998		The unit was taken off-line and shut down for 12 d for a forced outage to investigate fast closure of a main turbine control valve and subsequent reactor scram. High contact resistance was found on the generator ground relay.
Feb 1999		The "B" RHR loop was removed from service for scheduled maintenance. During an investigation of why the keep-fill system was not performing correctly, it was discovered that the injection control valve had failed closed, which prevented injection into the RV from that loop. The valve stem had sheared from the disc. Preliminary investigation determined that low-cycle fatigue from several backseating events in 1989 coupled with intergranular stress corrosion cracking caused the separation and subsequent failure. The propagating mechanism was also thought to be hydrogen-assisted, with an influence of stress corrosion cracking.

May 1999	Jun 1999	The unit was taken off-line and shut down for 7 d for a forced outage to investigate fast-acting solenoid valve problems on the main turbine control valves.
Jul 1999		The unit was taken off-line and shut down for 15 d for a forced outage to repair the "C" MSIV. The valve disc had separated from its stop plate and valve stem while the plant was at 100% power.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**SUSQUEHANNA 2**	Nameplate Rating (MWe):	**1168**
Location:	**Luzerne County, Pennsylvania**	MDC Net MWe:	**1094**
Operator:	**PP&L, Inc.**	Cumul. Avail. Factor:	**83.6**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**79.2**
Construction Permit:	**11/2/73**	Cumul. Forced Outage Rate:	**4.8**
Operating License:	**6/27/84**	3-Year Avg. Cap. Factor (MDC Net):	**84.6**
Commercial Oper. Date:	**2/12/85**	License Expiration:	**3/23/24**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	May 1997	The unit was taken off-line and shut down for 57 d for the eighth scheduled refueling and maintenance outage.
Jul 1997		The NRC proposed and the licensee paid a $210,000 fine for having an EDG inoperable beyond the TS LCO time limit, for an erroneous breaker alignment for the "E" DG in violation of procedures, and for operator violations of TS surveillance requirements.
Sep 1997		The unit was taken off-line and shut down for 8 d for a forced outage shutdown to investigate drywell leakage. A 180° through-wall crack at a welded connection was found on the discharge valve bonnet vent line of the "B" reactor recirculation system pump.
Feb 1998		The NRC proposed and the licensee paid a $55,000 fine for insufficient control of adjustment knob settings on an EDG voltage regulator. The licensee was unable to ensure voltage remained appropriately set at 100%.
Apr 1998		The unit was taken off-line and shut down for 8 d for a forced outage shutdown to repair a leak in the stator cooling system for the main generator and to perform local leak rate testing instrumentation.
Jun 1998		The unit was taken off-line and shut down for 6 d for a forced outage to replace the pump seal on the "A" reactor recirculation pump.
		The unit was taken off-line and shut down for 5 d for a forced outage to repair a leak at a weld on a flow element of the condensate filtration system.

Jul 1998		The reactor scrammed from approximately 1% power during a normal startup evolution. Although the safety significance of this event was minimal, an NRC Events Assessment Panel determined that there was a significant breakdown of command and control on the part of the control room staff and operating procedures. Five specific areas were cited: (1) procedures were less than adequate, (2) the senior reactor operator (SRO) and reactor operators (Ros) responsible for reactivity management did not recognize that the reactor had become subcritical during a delay in the startup, (3) team dynamics were inadequate, (4) management and supervisory oversight failed, and (5) during a previous startup several days earlier a similar event occurred that was not documented and corrected by the licensee.
Mar 1999	Apr 1999	The unit was taken off-line and shut down for 46-1/2 d for the ninth scheduled refueling and maintenance outage.
Jun 1999		The unit was taken off-line and shut down for 8 d for a forced maintenance outage to replace the failed 2A main transformer.
Dec 1999		The unit was taken off-line and shut down for 7 d for a forced outage to investigate a suspected upper seal leak on the "2A" reactor recirculation system pump. A pressure sensing line external to the upper seal was found failed, repairs were made, and related lines were inspected.

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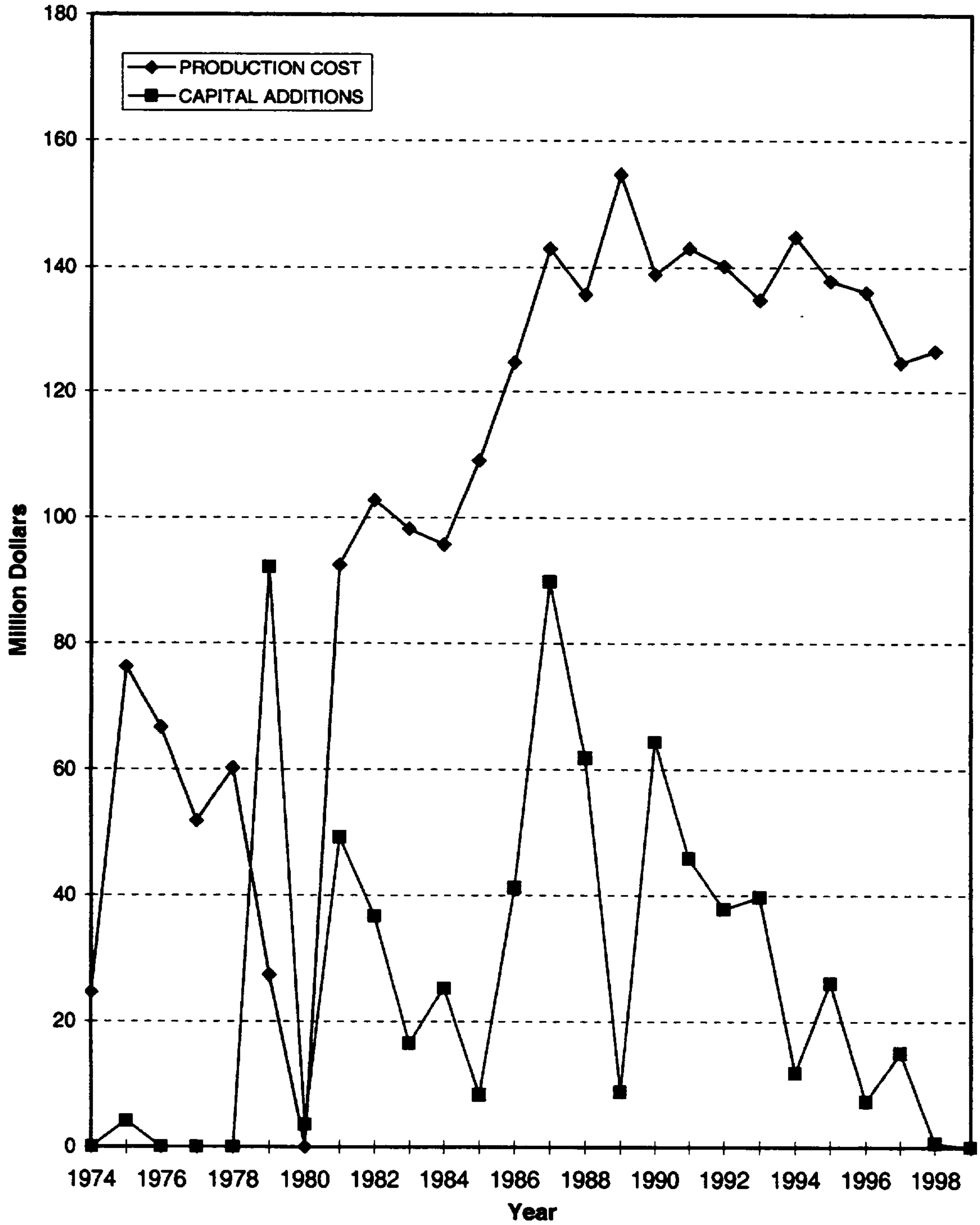
THREE MILE ISLAND 1

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**THREE MILE ISLAND 1**	Nameplate Rating (MWe):	**872**
Location:	**Dauphin County, Pennsylvania**	MDC Net MWe:	**786**
Operator:	**AmerGen Energy Co.**	Cumul. Avail. Factor:	**61.6**
Type:	**Babcock & Wilcox PWR**	Cumul. Cap. Factor (MDC Net):	**63.3**
Construction Permit:	**5/18/68**	Cumul. Forced Outage Rate:	**30.2**
Operating License:	**4/19/74**	3-Year Avg. Cap. Factor (MDC Net):	**93.5**
Commercial Oper. Date:	**9/2/74**	License Expiration:	**4/19/14**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jun 1997		The plant was operating at 100% power on June 21 when off-site power was lost and the unit tripped. A ceramic insulator on a generator output breaker in the switchyard catastrophically failed and caused the other generator output breaker in the switchyard, as well as seven other breakers in the substation, to open, either on fault logic or relay safety actuation. This caused the 230-kV buses that supply the station auxiliary transformers to deenergize. With both its output breakers open, the main generator tripped and, in turn, tripped the reactor. The licensee declared a UE within 15 min of the unit trip. All RCPs tripped, both EDGs automatically started on undervoltage and closed onto their respective buses, and EFW automatically started. The operators followed emergency operating procedures and established natural circulation for the reactor. Later, the station blackout diesel was started and aligned to reenergize one balance-of-plant bus. Three control rods had slow insertion times during the scram, and subsequent investigation revealed that a PORV could not have opened if required. Off-site power was restored about 1 h later. The unit was taken off-line and shut down for 7 d for a forced maintenance outage to repair a failed generator breaker, GB-1-02, in the 230-kV switchyard, which caused a reactor trip.
Sep 1997	Oct 1997	The unit was taken off-line and shut down for 44 d for the 11th scheduled refueling and maintenance outage.
Nov 1997		The unit was taken off-line and shut down for 7 d for a forced maintenance outage to repair an instrument line leak.
Nov 1997		The NRC proposed and the licensee paid a $210,000 fine for failures related to the operability of ECCS.
May 1999		On May 10 with the plant at 100% power, the licensee discovered a failed pump bearing during an oil change on the motor-driven EFW pump. The licensee further indicated that the pump had been out of service for approximately 45 d. Subsequent

		investigations indicated that inadequate maintenance for the past 10 years was responsible. A set screw that secured the oil thrower to the pump shaft was never properly tightened; consequently, the set screw loosened during operation thus reducing the bearing oil circulation rate. The reduced oil circulation rate resulted in ineffective heat removal from the bearing and eventually caused the bearing to fail.
Sep 1999	Oct 1999	The unit was taken off-line and shut down for 39 d for the 12th scheduled refueling and maintenance outage.

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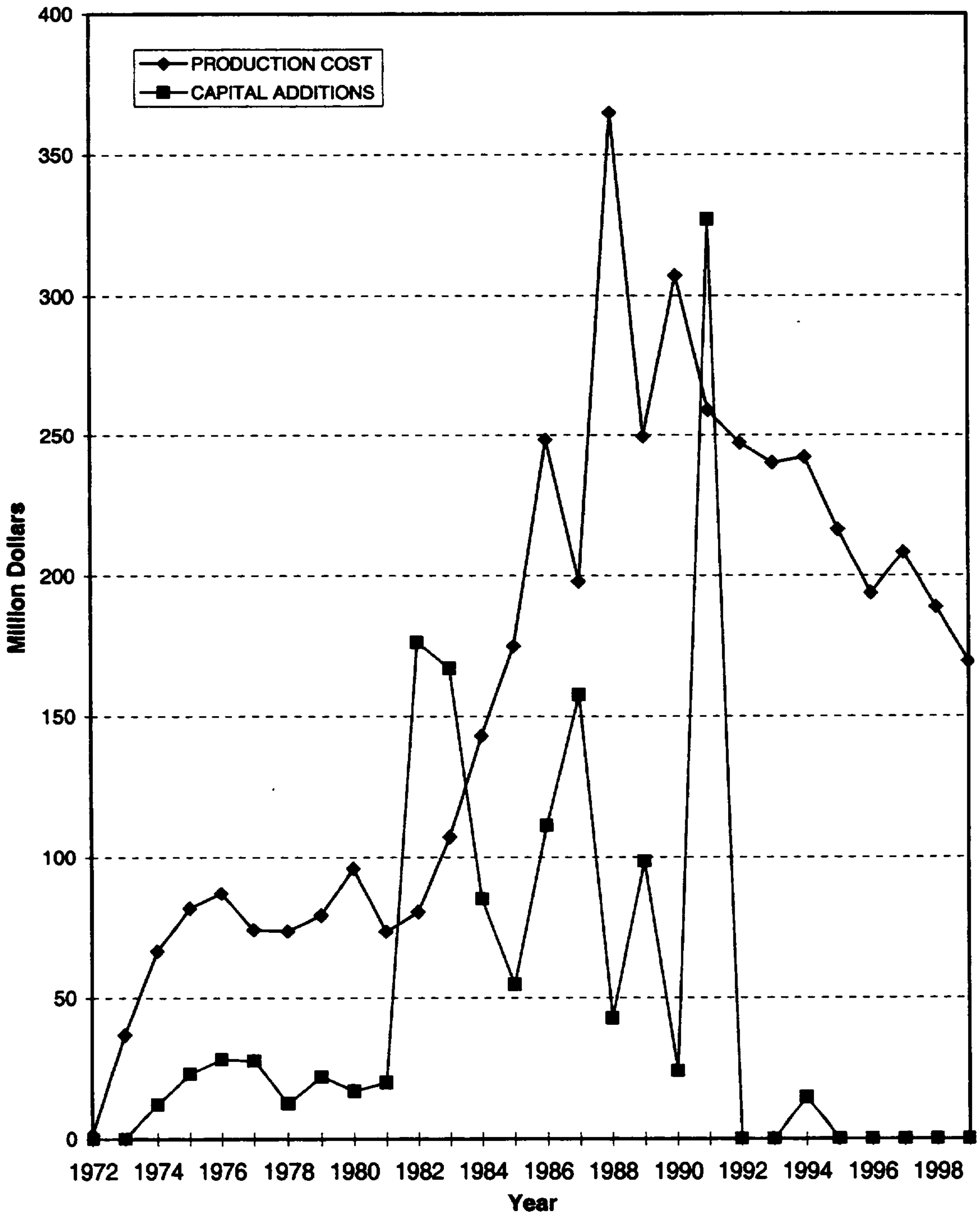
TURKEY POINT
(Units 3 and 4)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**TURKEY POINT 3**	Nameplate Rating (MWe):	**760**
Location:	**Dade County, Florida**	MDC Net MWe:	**693**
Operator:	**Florida Power and Light Co.**	Cumul. Avail. Factor:	**69.2**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor(MDC Net):	**65.6**
Construction Permit:	**4/27/67**	Cumul. Forced Outage Rate:	**9.2**
Operating License:	**7/19/72**	3-Year Avg. Cap. Factor (MDC Net):	**92.1**
Commercial Oper. Date:	**12/14/72**	License Expiration:	**7/19/12**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	Apr 1997	The unit was taken off-line and shut down for 44 d for a forced maintenance outage to repair a rod control urgent failure alarm.
Jul 1997		The reactor was manually tripped from 100% power after multiple control rods dropped into the core. All three AFW pumps automatically started on low-low SG level. One SG AFW control valve stuck open and had to be isolated.
Feb 1998		The plant was at 100% power on February 16 when an overly sensitive test lever on the turbine auxiliary governor was inadvertently bumped during maintenance, which caused a loss of turbine control oil pressure and, subsequently, closed the turbine intercept and control valves. A manual reactor trip was initiated, and the MSIVs were manually closed to control RCS temperature. The pressure response caused both PORVs to lift. A secondary-side steam leak occurred following the scram. The leak was in a 2-in. steam drain line to AFW Train 2; however, despite the steam leak, the AFW system provided adequate FW flow to the SGs for the duration of the event.
Sep 1998	Oct 1998	The unit was taken off-line and shut down for 35 d for a scheduled refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**TURKEY POINT 4**	Nameplate Rating (MWe):	**760**
Location:	**Dade County, Florida**	MDC Net MWe:	**693**
Operator:	**Florida Power and Light Co.**	Cumul. Avail. Factor:	**68.7**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**65.8**
Construction Permit:	**4/27/67**	Cumul. Forced Outage Rate:	**8.6**
Operating License:	**4/10/73**	3-Year Avg. Cap. Factor (MDC Net):	**95.3**
Commercial Oper. Date:	**9/7/73**	License Expiration:	**4/10/13**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Sep 1997	Oct 1997	The unit was taken off-line and shut down for 36 d for a refueling and maintenance outage.
Mar 1999	Apr 1999	The unit was taken off-line and shut down for 24 d for a refueling and maintenance outage.

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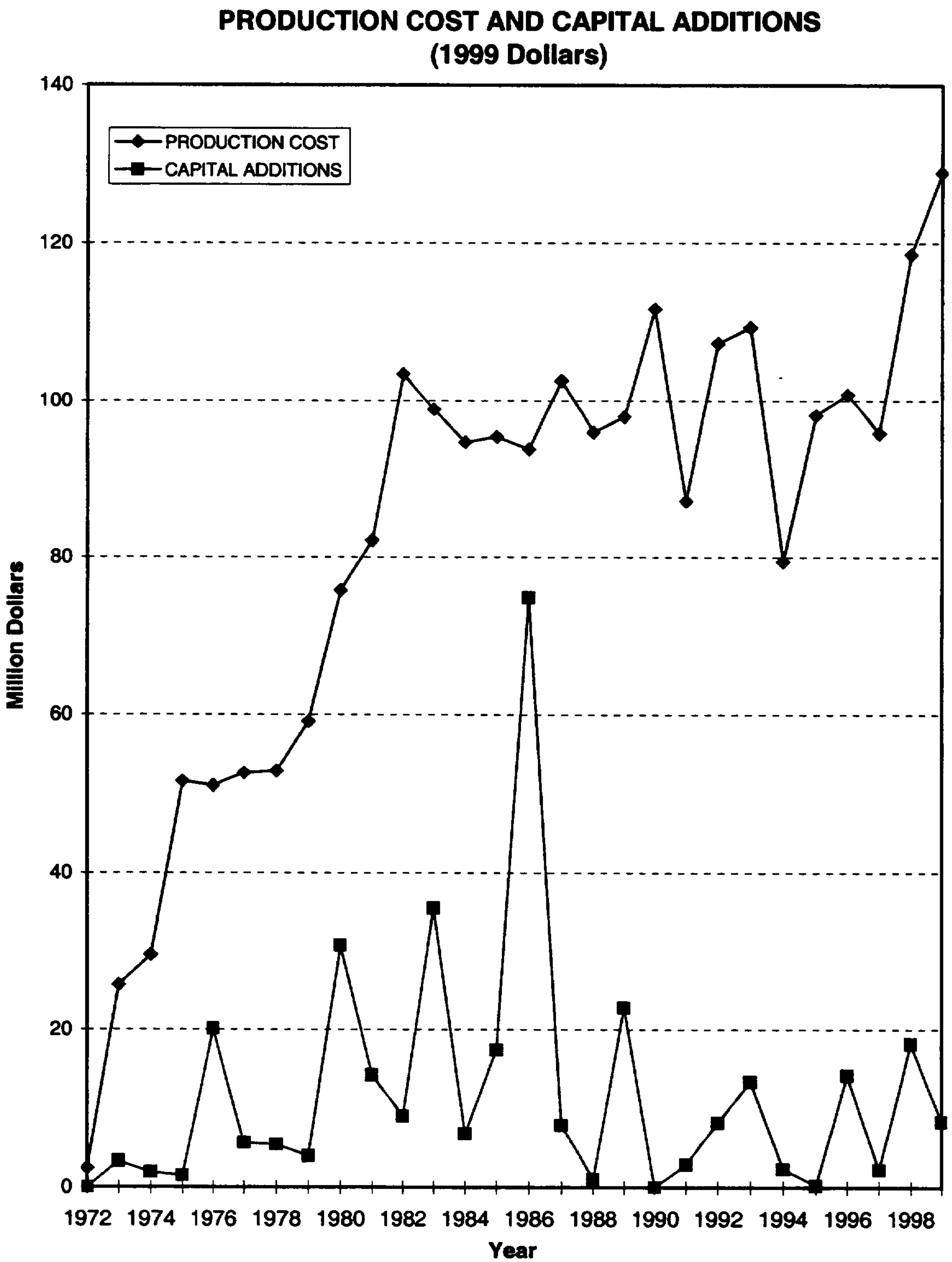
VERMONT YANKEE



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**VERMONT YANKEE**	Nameplate Rating (MWe):	**540**
Location:	**Windham County, Vermont**	MDC Net MWe:	**510**
Operator:	**Vermont Yankee Nuclear Power**	Cumul. Avail. Factor:	**81.4**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**77.2**
Construction Permit:	**12/11/67**	Cumul. Forced Outage Rate:	**4.5**
Operating License:	**2/28/73**	3-Year Avg. Cap. Factor (MDC Net):	**87.2**
Commercial Oper. Date:	**11/30/72**	License Expiration:	**3/21/12**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Apr 1997	May 1997	The unit was taken off-line and shut down for 9 d for a forced maintenance outage.
Mar 1998		On March 18, following a CS pump TS surveillance test, the pump motor supply breaker failed to open as required. The breaker is a GE Magne-Blast 4-kV breaker. Investigation found the driving pawl "frozen" in the disengaged position. This means that the pawl failed to recharge the closing springs. The licensee's analysis indicated that this was due to three things: dried lubricant, an improperly installed bushing, and an extra washer. The condition had existed since 1982. Further, the licensee determined that the dried lubricant was "... acting as an adhesive." The licensee inspected a representative sample of all the GE Magne-Blast 4-kV type breakers. Thirty-seven breakers were inspected, and none of these had all three conditions present. All three conditions (failures) had to be present to cause the breaker to fail to open.
Mar 1998	May 1998	The unit was taken off-line and shut down for 73 d for a scheduled refueling and maintenance outage.
May 1998		The NRC proposed and the licensee paid a $55,000 fine for design control errors, corrective action deficiencies, and reporting violations.
Jun 1998		The plant was at 68 % power on June 9 when the "A" MFW regulating valve failed closed for unknown reasons. This caused an RPV high water level, which caused a turbine trip and an associated automatic reactor scram. The MFW pumps also tripped. While the operators were restoring an MFW pump to service, two safety-related 4-kV and two safety-related 480-V buses were lost. This caused an EDG to start and load to its respective bus. Additionally, the MSIVs inadvertently closed, a RPS MG set tripped, and SRVs were used to control reactor pressure. The NRC began a special inspection to investigate the circumstances regarding the shutdown.

		The unit was taken off-line and shut down for 5 d for a forced outage to repair a stuck-open FW regulating valve.
Oct 1999	Nov 1999	The unit was taken off-line and shut down for 33 d for a scheduled refueling and maintenance outage.

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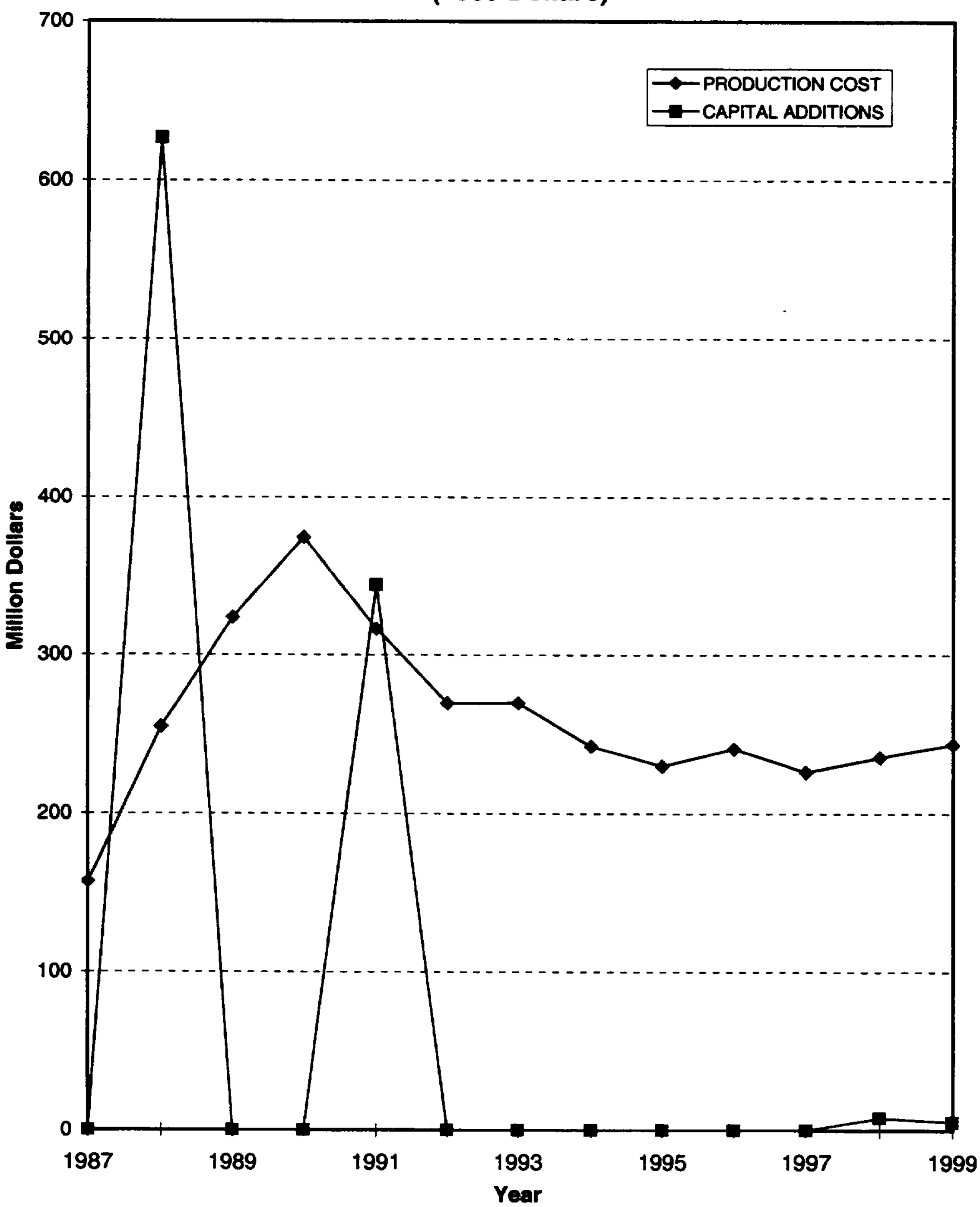
ALVIN W. VOGTLE
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**ALVIN W. VOGTLE 1**	Nameplate Rating (MWe):	**1215**
Location:	**Burke County, Georgia**	MDC Net MWe:	**1162**
Operator:	**Southern Nuclear Operating Co.**	Cumul. Avail. Factor:	**86.4**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**84.3**
Construction Permit:	**6/28/74**	Cumul. Forced Outage Rate:	**3.7**
Operating License:	**3/16/87**	3-Year Avg. Cap. Factor (MDC Net):	**91.7**
Commercial Oper. Date:	**6/1/87**	License Expiration:	**1/16/27**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	Apr 1997	The unit was taken off-line and shut down for 8 d for a planned outage to repair hydrogen leakage in the main generator.
Apr 1997	May 1997	The unit was taken off-line and shut down for 14 d for a forced outage to investigate a hydrogen seal ground in a generator.
Sep 1997	Oct 1997	The unit was taken off-line and shut down for 45 d for the seventh refueling and maintenance outage.
Feb 1999	Mar 1999	The unit was taken off-line and shut down for 27 d for the eighth refueling and maintenance outage.

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**ALVIN W. VOGTLE 2**	Nameplate Rating (MWe):	**1215**
Location:	**Burke County, Georgia**	MDC Net MWe:	**1162**
Operator:	**Southern Nuclear Operating Co.**	Cumul. Avail. Factor:	**89.2**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**86.6**
Construction Permit:	**6/28/74**	Cumul. Forced Outage Rate:	**1.7**
Operating License:	**3/31/89**	3-Year Avg. Cap. Factor (MDC Net):	**91.0**
Commercial Oper. Date:	**5/20/89**	License Expiration:	**2/9/29**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1998	Apr 1998	The unit was taken off-line and shut down for 43 d for the sixth scheduled refueling and maintenance outage.
May 1998		The unit was taken off-line and shut down for 6-1/2 d for a forced outage to place a spare transformer into service and inspect the main generator for insulation degradation.
Jun 1998		The plant was operating at 100% power when an electrical fault on the 2C condensate pump motor caused the loss of a 13.8-kV bus and the 2B unit auxiliary transformer. This resulted in a main generator load rejection, followed shortly by a turbine trip and subsequent reactor trip. Also, two of the four operating RCPs tripped. Non-1E electrical loads did not transfer to the reserve auxiliary transformer as expected; consequently, the remaining RCPs tripped along with the loss of the non-1E loads. The initial plant transient generated a low pressurizer pressure condition and resulted in an SI signal and injection. The unit was taken off-line and shut down for 6 d for a forced outage to investigate an equipment fault that caused the loss of all non-1E 13.8-kV switchgear and a subsequent reactor trip.
Sep 1999		Excess volumes of air were discovered in both SI pump casings. Both trains of SI were declared inoperable.
Oct 1999	Nov 1999	The unit was taken off-line and shut down for 33 d for the seventh scheduled refueling and maintenance outage.

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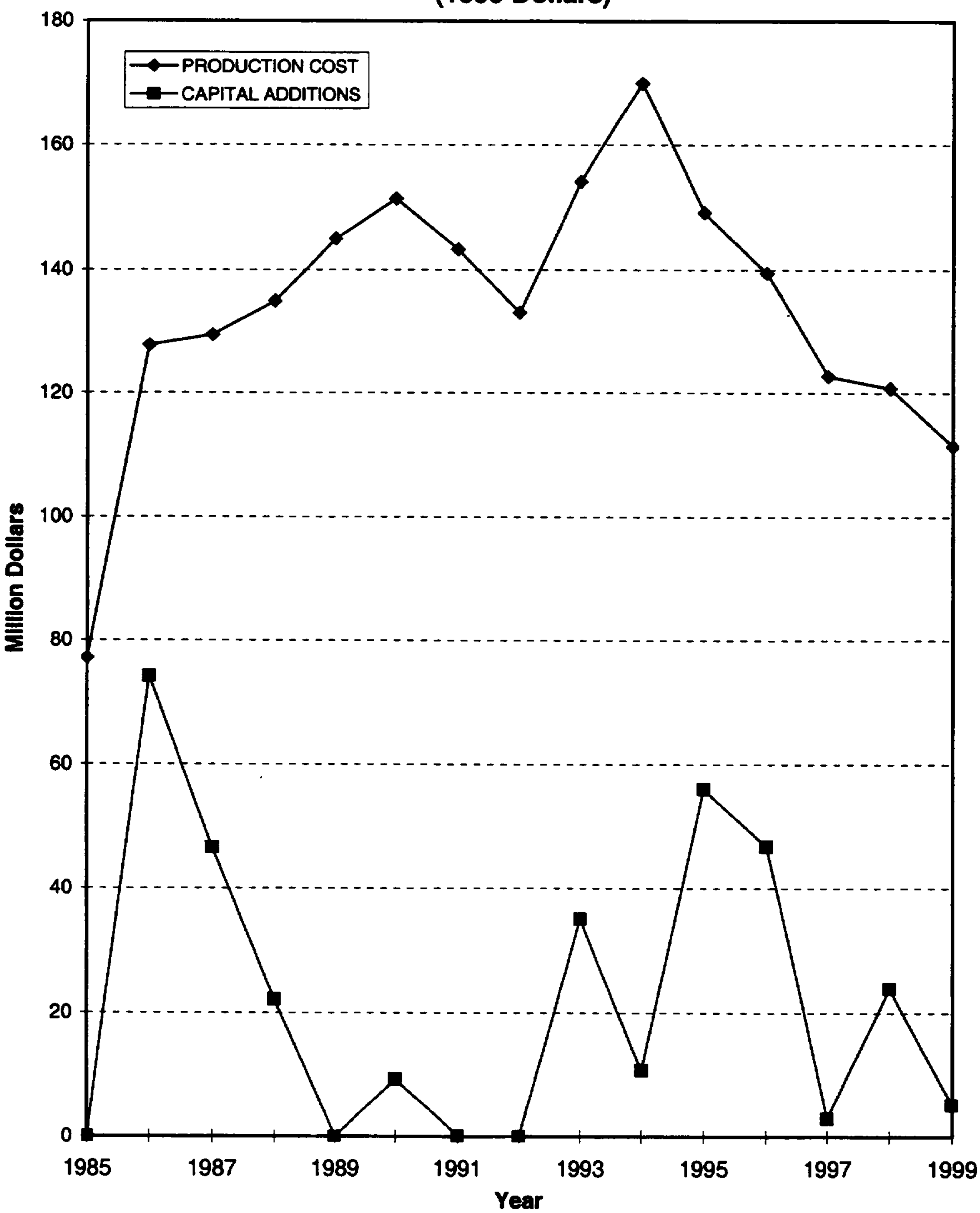
WASHINGTON NUCLEAR 2

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**WASHINGTON NUCLEAR 2**	Nameplate Rating (MWe):	**1199**
Location:	**Benton County, Washington**	MDC Net MWe:	**1107**
Operator:	**Energy Northwest**	Cumul. Avail. Factor:	**71.9**
Type:	**General Electric BWR**	Cumul. Cap. Factor (MDC Net):	**61.2**
Construction Permit:	**3/19/73**	Cumul. Forced Outage Rate:	**9.4**
Operating License:	**4/13/84**	3-Year Avg. Cap. Factor (MDC Net):	**65.7**
Commercial Oper. Date:	**12/13/84**	License Expiration:	**12/20/23**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Mar 1997	Apr 1997	The unit was taken off-line and shut down for 22 d for the 11th scheduled maintenance outage for economic dispatch.
Apr 1997	Jul 1997	The unit was taken off-line and shut down for 82 d for the 12th scheduled refueling and maintenance outage.
Mar 1998		The plant was operating at 100% power on March 11 when an instrument air line on the "D" inboard MSIV failed, which caused the MSIV to close. The closure of the MSIV resulted in a high steam flow isolation signal on the three other lines. The subsequent closure of the MSIVs caused a reactor scram and subsequent main generator trip. The NRC sent a special inspection team to the site to investigate the operators' response to the event and some equipment indications that did not initially appear to be expected for such an event. The unit was taken off-line and shut down for 9 d for a forced outage to repair an instrument air line.
Apr 1998	Jun 1998	The unit was taken off-line and shut down for 56 d for the 13th scheduled refueling and maintenance outage.
Jun 1998	Jul 1998	The unit was taken off-line and shut down for 20 d for a forced maintenance outage. The plant entered the outage to troubleshoot problems with a tip detector that would not withdraw completely. The outage was extended due to the failure of a FP valve that caused subsequent flooding of the reactor building basement.
Jun 1998		The plant was in cold shutdown on June 17 after a forced outage that occurred during a restart from an extended refueling outage. Maintenance personnel were removing hanger material in the Division II DG room. Smoke from the work drifted down the corridor and actuated two FP preaction systems. These actuations caused associated preaction valves to open and fill a normally dry sprinkler line header. This depressurized the fire water system and caused an automatic start signal for all main fire pumps. Three of the pumps started immediately, and the

		fourth pump began a 30-s time delay sequence for starting. The concurrent operation of the three pumps resulted in a rapid reflooding of the depressurized lines and caused a significant water hammer. A 12-in. FP system isolation valve ruptured and before the operators could isolate the ruptured line, water level in the stairwell where the valve was located crested at 19 ft. Water from the stairwell entered the "C" RHR room and eventually submerged the pump motor. A valve located in a line connecting the sumps of RHR "C" and low-pressure core spray (LPCS) pump rooms failed to close and allowed water into the LPCS pump room. The water level rose to within 1 ft of the LPCS pump motor. The licensee declared a UE, and the NRC sent an AIT to the site to investigate the circumstance surrounding the incident.
Aug 1998		The unit was operating at 100% power on August 5 when the plant had multiple containment isolations and a half-scram shortly after a vital bus was deenergized. EDG 2 was paralleled to the startup off-site power source for voltage regulator testing. The EDG tripped and locked out on an overload signal, and a vital bus input breaker also tripped open and deenergized the bus. After the bus was reenergized, an operating MFW pump tripped, and the reactor recirculation system pumps were reset to the "runback" set point, rapidly reducing power and core flow. The unit was taken off-line and shut down for 15 d for a forced outage to repair the EDG 2 voltage regulation system.
Apr 1999	Jul 1999	The unit was taken off-line and shut down for 78 d for a scheduled outage. The plant was shut down for a fuel savings dispatch outage.
Sep 1999	Oct 1999	The unit was taken off-line and shut down for 36-1/2 d for a scheduled refueling and maintenance outage.

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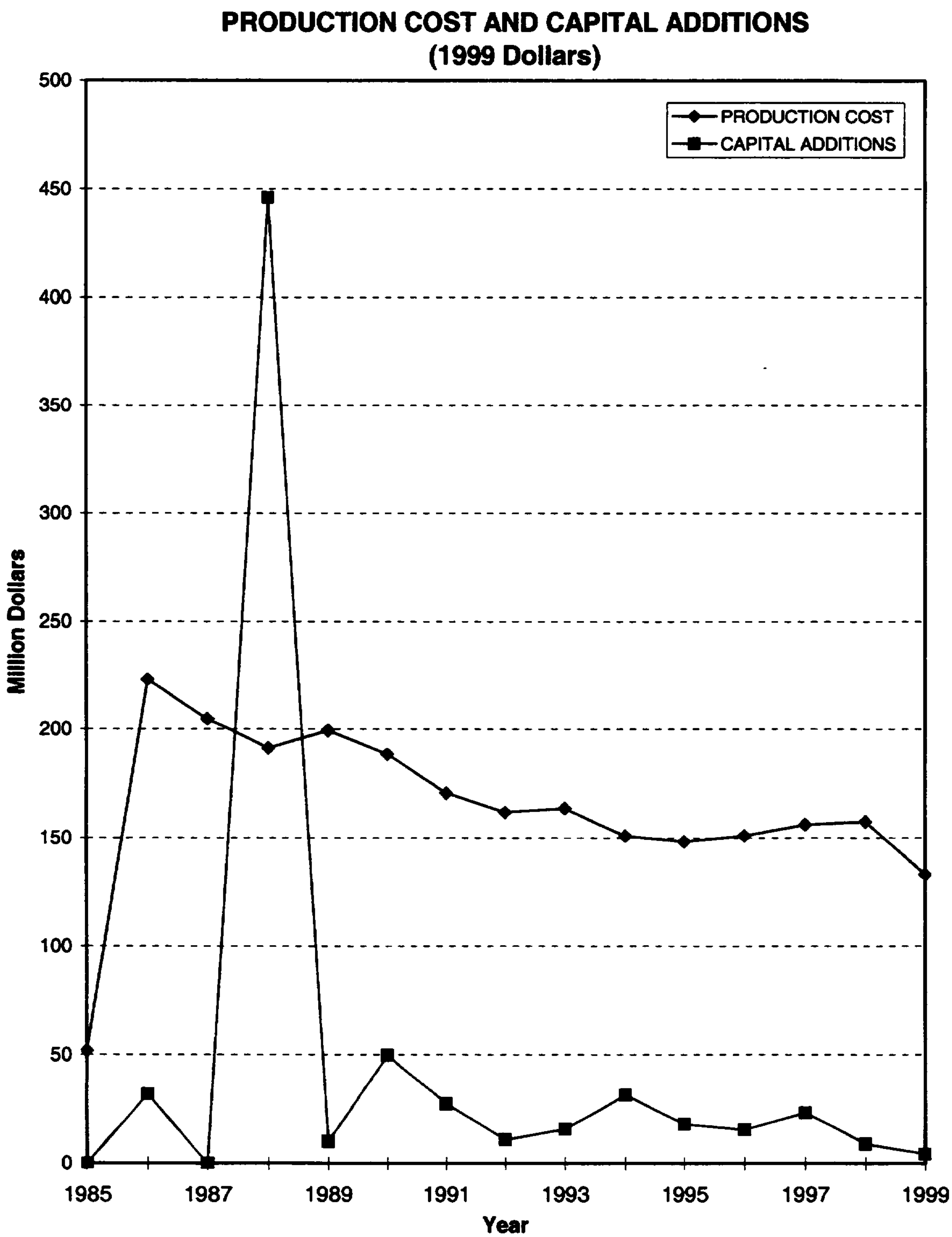
WATERFORD 3


PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)
PRODUCTION COST
CAPITAL ADDITIONS
Million Dollars
500
450
400
350
300
250
200
150
100
50
0
1985
1987
1989
1991
1993
1995
1997
1999
Year

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**WATERFORD 3**	Nameplate Rating (MWe):	**1200**
Location:	**St. Charles County, Louisiana**	MDC Net MWe:	**1075**
Operator:	**Entergy Operations, Inc.**	Cumul. Avail. Factor:	**83.7**
Type:	**Combustion Engineering PWR**	Cumul. Cap. Factor (MDC Net):	**82.3**
Construction Permit:	**11/14/74**	Cumul. Forced Outage Rate:	**4.4**
Operating License:	**3/16/85**	3-Year Avg. Cap. Factor (MDC Net):	**80.6**
Commercial Oper. Date:	**9/24/85**	License Expiration:	**12/18/24**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Apr 1997	Jul 1997	The unit was taken off-line and shut down for 108 d for the eighth scheduled maintenance outage.
May 1997		The plant was in midloop operations with the RCS temperature at 100°F when the "B" startup transformer was lost. This loss resulted in EDG "B" automatically starting and energizing the safety-related Train "B" buses.
Jun 1997		The NRC proposed and the licensee paid a $55,000 fine for a Severity Level III violation. The violation consisted of four problems: (1) failing to assure that containment fan cooler flows met TS surveillance acceptance requirements, (2) failing to properly translate design basis information into accident analyses and specifications, (3) failing to test containment fan cooler flows under postaccident conditions, and (4) failing to take prompt action to resolve discrepancies between design basis documents and empirical results.
Sep 1998		The unit was taken off-line and shut down for 14 d for a scheduled maintenance outage to replace the pressurizer code safety valves, to replace the main transformer with a spare, and to prepare for Hurricane George.
Nov 1998	Dec 1998	The unit was taken off-line and shut down for 15 d for a scheduled maintenance outage to replace a seal on RCP 2B.
Feb 1999	Apr 1999	The unit was taken off-line and shut down for 42 d for the ninth scheduled refueling and maintenance outage.
Aug 1999		The unit was taken off-line and shut down for 9 d for a forced maintenance outage to repair an apparent seal failure on RCP 2B caused by cracked baffle.
Sep 1999		The plant was at 100% power on September 10 when the seals on RCP 2B failed. The operators manually tripped the reactor, and EFW automatically initiated following the trip. The seals failed because the seal water HX baffle failed. The

		plant had shut down on August 1 because of a similar failure of the baffle, which was replaced on August 10.
		The unit was taken off-line and shut down for 19 d for a forced outage to replace the cracked baffle on RCP 2B.
Nov 1999		On November 26, the plant was shut down to repair a small unisolable leak on a MSL drain line upstream of an MSIV. On November 27, the operators were aligning Train "B" of LPSI for shutdown cooling operations. The operators began opening the suction valve for the LPSI B pump; as the valve opened, the pressurized level dropped from 35% to off-scale low. A loud bang was also heard, and the operators closed the valve. RCS pressure decreased from 350 psia to 100 psia, and as a result, the operators stopped the two operating RCPs. At this time it was noticed that the refueling water storage pool level had increased about 1%. This corresponds to an approximate inventory transfer of 5500 gal. The licensee declared an alert. HPSI pump "A" was started to add inventory to the RCS until the pressurizer level was restored to the normal shutdown band, and then HPSI pump "A" was secured.
		Subsequent investigations found a valve that had been inadvertently left open because its reach rod had become disconnected from the valve operator. Although the position indication at the reach rod handwheel indicated that the valve was closed, the valve was actually open. As a result, when the LPSI pump suction valve was opened, a flow path was established from the RCS to the refueling water storage pool.
Nov 1999	Dec 1999	The unit was taken off-line and shut down for 5-1/2 d for a forced maintenance outage to repair a nonisolable leak on a drip pot on the MS piping.

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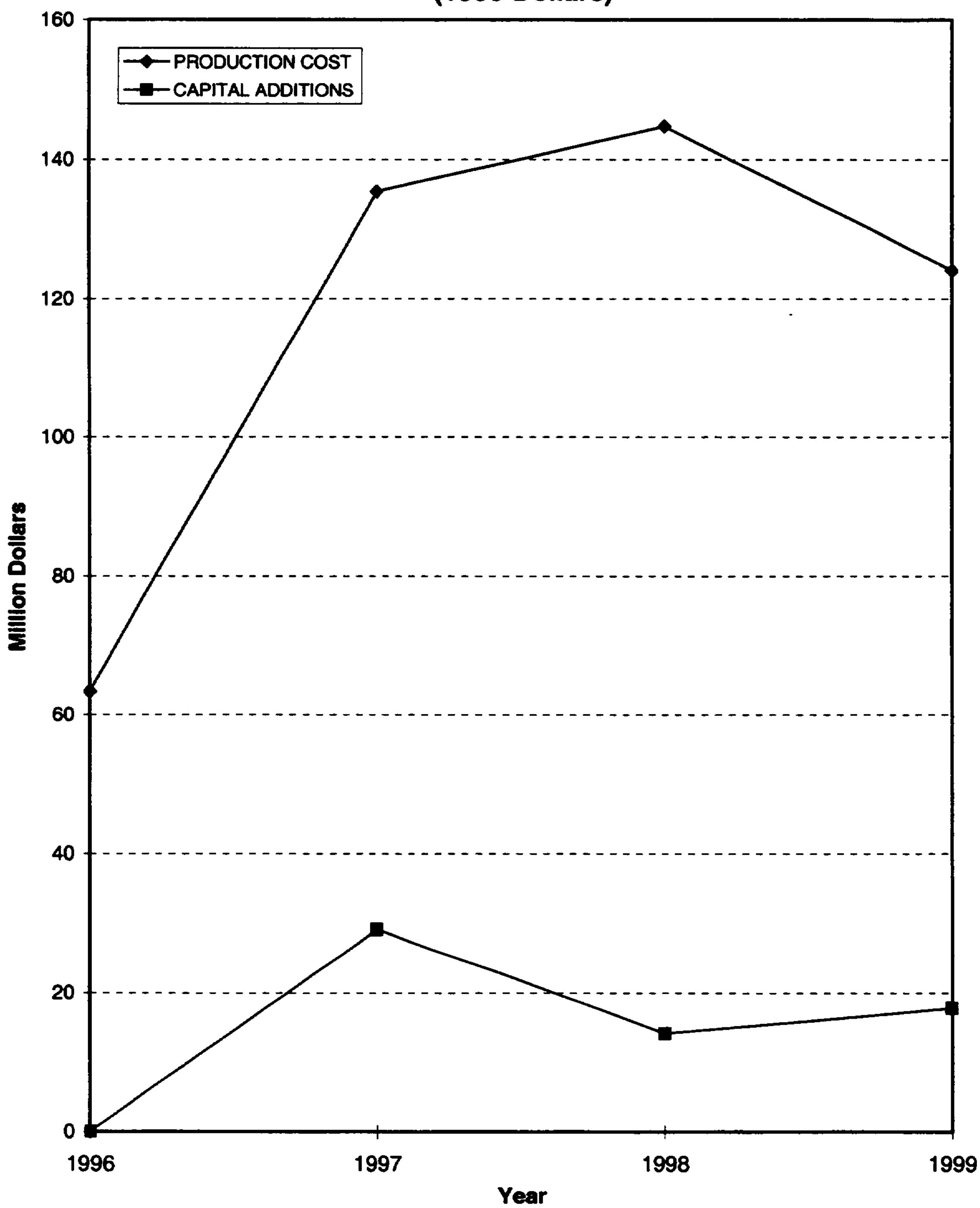
WATTS BAR 1

PRODUCTION COST AND CAPITAL ADDITIONS (1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

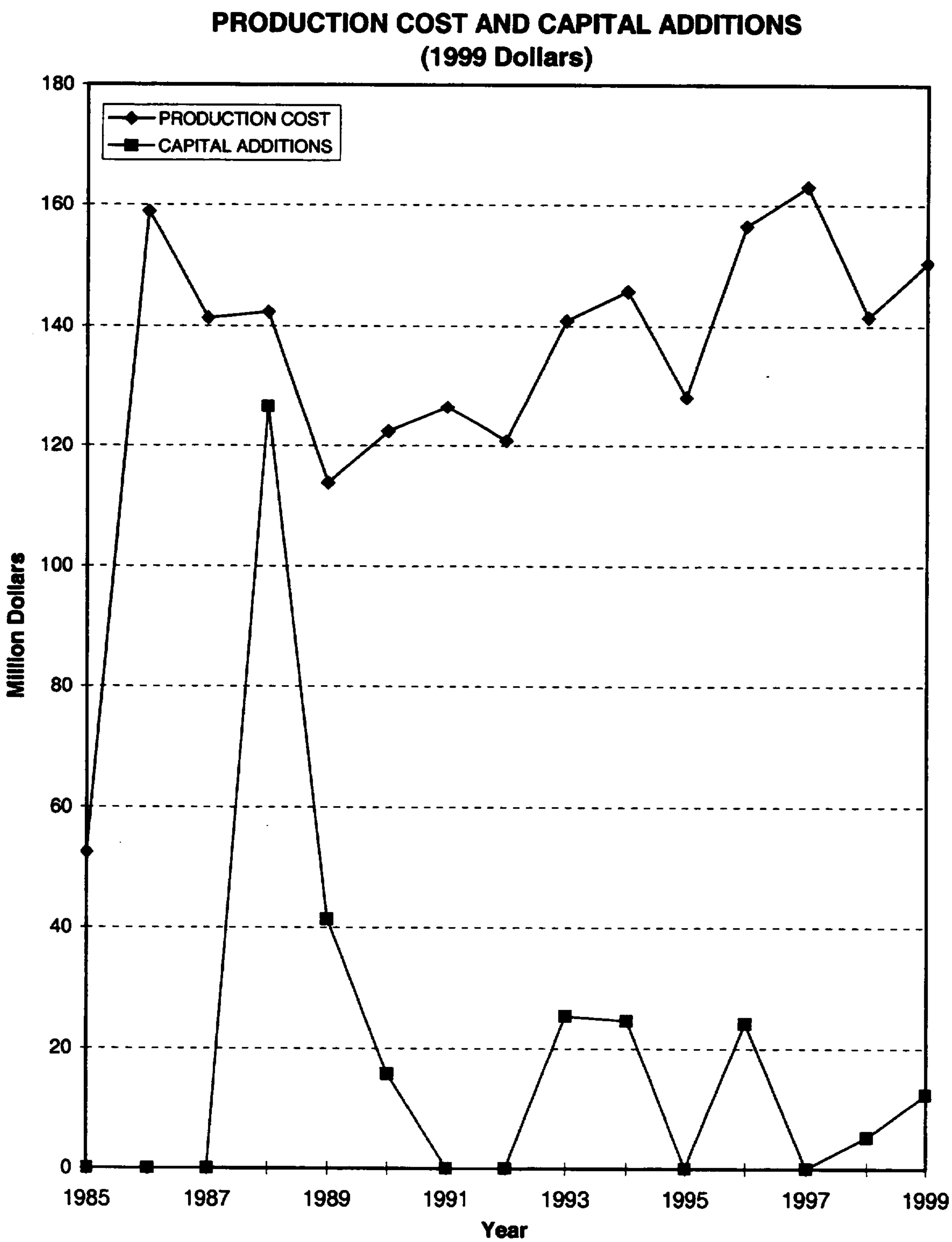
Unit Data Summary (Through December 1999)

Unit:	**WATTS BAR 1**	Nameplate Rating (MWe):	**1270**
Location:	**Rhea County, Tennessee**	MDC Net MWe:	**1117**
Operator:	**Tennessee Valley Authority**	Cumul. Avail. Factor:	**88.5**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**87.0**
Construction Permit:	**1/23/73**	Cumul. Forced Outage Rate:	**1.8**
Operating License:	**2/7/96**	3-Year Avg. Cap. Factor (MDC Net):	**87.0**
Commercial Oper. Date:	**5/27/96**	License Expiration:	**11/9/35**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Jan 1997		The unit was taken off-line and shut down for 4 d for a forced outage to repair a ruptured main condenser tube.
Mar 1997		The unit was taken off-line and shut down for 9 d for a forced outage to repair an MFW pump shaft failure, an out-of-service recirculation line for the standby MFW pump, and to remove foreign material lodged in the No. 4 SG FW inlet.
Sep 1997	Oct 1997	The unit was taken off-line and shut down for 44 d for the first refueling and maintenance outage.
Feb 1999	Apr 1999	The unit was taken off-line and shut down for 48 d for the second refueling and maintenance outage.

WOLF CREEK 1


PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)
PRODUCTION COST
CAPITAL ADDITIONS
Million Dollars
180
160
140
120
100
80
60
40
20
0
1985
1987
1989
1991
1993
1995
1997
1999
Year

NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

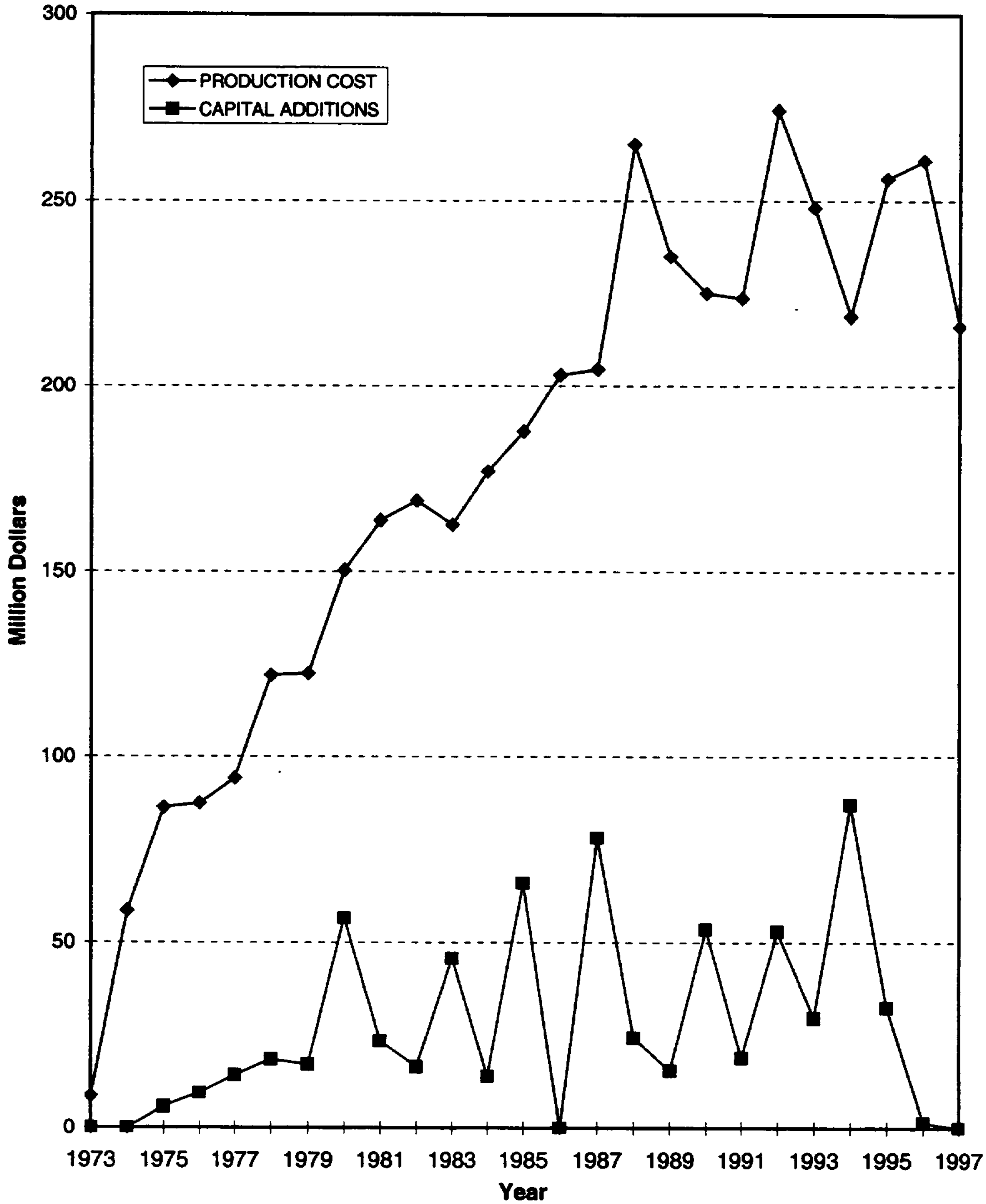
Unit:	**WOLF CREEK 1**	Nameplate Rating (MWe):	**1236**
Location:	**Coffey County, Kansas**	MDC Net MWe:	**1163**
Operator:	**Wolf Creek Nuclear Operating**	Cumul. Avail. Factor:	**82.1**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**80.5**
Construction Permit:	**5/31/77**	Cumul. Forced Outage Rate:	**3.0**
Operating License:	**6/4/85**	3-Year Avg. Cap. Factor (MDC Net):	**91.6**
Commercial Oper. Date:	**9/3/85**	License Expiration:	**3/11/25**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Apr 1997		The NRC proposed and the licensee paid a $100,000 fine for a Severity Level III problem consisting of three violations: (1) failing to correct erroneous TS clarifications after being alerted of their existence by findings from a licensee QA audit, (2) the continued existence of an erroneous TS clarification after being informed by the NRC that it was incorrect, and (3) an unauthorized change to the TS.
May 1997		The unit was taken off-line and shut down for 4 d for a forced outage to repair a FW heater valve.
Oct 1997	Dec 1997	The unit was taken off-line and shut down for 58 d for the ninth refueling and maintenance outage.
Apr 1999	May 1999	The unit was taken off-line and shut down for 37 d for the tenth refueling and maintenance outage.

ZION
(Units 1 and 2)

PRODUCTION COST AND CAPITAL ADDITIONS
(1999 Dollars)



NUCLEAR POWER PLANT OPERATING EXPERIENCE SUMMARY

Unit Data Summary (Through December 1999)

Unit:	**ZION 1**	Nameplate Rating (MWe):	**1085**
Location:	**Lake County, Illinois**	MDC Net MWe:	**1040**
Operator:	**Commonwealth Edison Co.**	Cumul. Avail. Factor:	**63.0**
Type:	**Westinghouse PWR**	Cumul. Cap. Factor (MDC Net):	**52.1**
Construction Permit:	**12/26/68**	Cumul. Forced Outage Rate:	**15.8**
Operating License:	**10/19/73**	3-Year Avg. Cap. Factor (MDC Net):	**3.9**
Commercial Oper. Date:	**12/31/73**	License Expiration:	**4/6/13**

Operating History (January 1997 Through December 1999)

Beginning Date	Ending Date	Comment
Feb 1997		The unit was taken off-line and shut down for a routine maintenance outage; however, due to extensive regulatory concerns and operating cost issues, the licensee decided to shut down the unit permanently.
Mar 1997		Zion Unit 1 was shut down permanently on February 21. The licensee declared a UE when Unit 1 lost off- site power. The system auxiliary transformer tripped off, and its associated deluge system actuated for unknown reasons. Both Unit 1 EDGs automatically started as well as the shared EDG for Units 1 and 2.
Apr 1997		The NRC proposed and the licensee paid a $100,000 fine for multiple violations for failing to (1) perform adequate 10 CFR 50.59 analyses for modifications on safety-related systems; (2) follow procedures regarding modifications, corrective actions, operations, and maintenance; (3) conduct tests to demonstrate that systems would perform satisfactorily following modification; and (4) take prompt corrective action for repeated out-of-tolerance settings for the CS system tank level indication for sodium hydroxide spray additive and repeated failures of a 4-kV breaker.
Jul 1997		The NRC proposed and the licensee paid a $50,000 fine for multiple low-level program deficiencies regarding transportation of radioactive materials and the failure of a QA audit to identify the deficiencies.
Aug 1997		The station battery direct current (dc) bus 111 was being supplied from dc bus 211 through a cross-tie connection. Battery 111 was removed for discharge testing. When dc buses are cross-tied and a battery is removed (for testing), the associated buses are inoperable. Thus, the 125-V dc buses were inoperable.
Oct 1997		The NRC proposed and the licensee paid a $330,000 fine for allowing a nitrogen bubble to form in the reactor head vent.

Feb 1998	The NRC proposed and the licensee paid a $110,000 fine for a breakdown in the fitness-for-duty program.
Nov 1999	The NRC proposed a $110,000 fine for discriminating against a senior reactor operator for raising nuclear safety issues.

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(2-89)
NRCM 1102,
3201, 3202

U.S. NUCLEAR REGULATORY COMMISSION

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(See instructions on the reverse)

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U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

10. SUPPLEMENTARY NOTES

R.S. Wood, NRC Project Manager

11. ABSTRACT *(200 words or less)*

The "U.S. Nuclear Power Plant Operating Cost and Experience Summaries" (NUREG/CR-6577, Supp. 1) report has been prepared to provide historical operating cost and experience information on U.S. commercial nuclear power plants. Costs incurred after initial construction are characterized as annual production costs, which represent fuel and plant operating and maintenance expenses, and capital expenditures related to facility additions/modifications, which are included in the plant capital asset base. As discussed in the report, annual data for these two cost categories were obtained from publicly available reports and must be accepted as having different degrees of accuracy and completeness. Treatment of inconclusive and incomplete data is discussed.

As an aid to understanding the fluctuations in the cost histories, operations summaries for each nuclear unit are provided. The intent of these summaries is to identify important operating events; refueling, major maintenance, and other significant outages; operating milestones; and significant licensing or enforcement actions. Information used in the summaries is condensed from operating reports submitted by the licensees, the Nuclear Regulatory Commission (NRC) database for enforcement actions, and outage reports.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*

operating experience, operating cost, plant history

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