APPENDIX E-3

Nuclear Power Plant Analysis[1]

This appendix examines the treatment of nuclear power plants (NPP) in the Annual Energy Outlook 1999 (AEO99), prepared by the Energy Information Administration (EIA) of the U.S. Department of Energy, and possible policy pathways to address barriers to continued operation of NPPs in the future.

In the AEO99, a retrofit costing $150/kWe is assumed to be required after 30 years of operation to take the plant to the end of its 40-year license life. If its going forward cost, including the 10-year $150/kWe incremental capital charge, is less than the EIA-estimated cost of new baseload capacity, then the nuclear unit is assumed to continue in operation through its 40-year license period. If not, then the plant is assumed to retire at age 30.

The $150/kWe charge is intended to account for large equipment replacement expenditures; for example, the steam generator in a pressurized water reactor (PWR). If a PWR has already replaced its steam generator, then the $150/kWe charge is not applied.

Finally, the AEO99 Reference Case assumes that an NPP operating license will be extended from 40 to 60 years if the sum of the going forward cost—including capitalization of a $250/kWe life extension cost—is less than the cost of constructing replacement baseload capacity; otherwise the plant is retired.

Examination of current (and projected) NPP expenditures indicates that life extension (from age 40 to 60) and license renewal costs are on the order of $180/kWe—not $150/kWe at age 30, plus $250/kWe at age 40 as assumed in AEO99. Based on this finding nuclear plant refurbishment and relicensing costs have been modified in the Clean Energy Future/National Energy Modeling System (CEF-NEMS) to more closely reflect actual (and projected) costs.

In addition to modifying NPP going forward costs, impediments to continued operation and economic competitiveness were investigated, together with alternative policy pathways to address the barriers. The impediments include: 1) definitive resolution to the spent fuel storage/disposal issue, 2) licensing reform in the area of ownership requirements, and 3) federal mechanisms to ensure full funding of nuclear plant decommissioning without penalties due to corporate restructuring or ownership transfers.

Spent fuel storage/disposal policy: Many nuclear plants are faced with a near-term problem of lack of storage space for their spent nuclear fuel. Some state regulations stipulate that a nuclear power plant cannot operate if it does not have sufficient on-site storage capacity. Uncertainty about how and when the federal government will meet its obligation to provide storage and disposal facilities for used nuclear fuel represents one of the most significant business risk factors for nuclear power plants. Resolution of this issue is needed to prevent premature shutdown or additional costs (beyond those paid into the Nuclear Trust Fund for development of the permanent repository) to maintain the spent fuel storage at individual facilities.

Licensing reform regarding foreign ownership requirements: Sections 103d and 104d of the Atomic Energy Act prohibit foreign ownership of commercial nuclear facilities. In the evolving power market such restrictions impact competition. These restrictions could be removed, except where they pertain to national security concerns. As a barrier to entry, these restrictions limit the number of potential investors in U.S. nuclear assets, resulting in a downward bias in the value of such assets and a likelihood of premature shutdown. Existing owners that are not willing to continue operating a plant but unable to sell it to those most willing to, may choose to retire the plant instead.

Federal mechanisms to ensure full funding of nuclear plant decommissioning: Because decommissioning of nuclear power plants is a public health and safety issue, a federal mandate and mechanism could be established to ensure recovery of unfunded decommissioning obligations—via a non-bypassable charge—when a nuclear asset is sold. In addition, the Internal Revenue Service (IRS) Code could be amended to ensure that, with the sale of a nuclear asset, the transfer of decommissioning funds are not taxed as capital gains. Without these mechanisms, nuclear plant economics are negatively affected.

In addition to these impediments, to date nuclear power plants have not received explicit credit for the pollution they avoid. Such avoided emissions are becoming increasingly important for compliance with more stringent Clean Air Act (CAA) requirements, since they can eliminate (or reduce) the need for pollution control technologies on fossil-fueled power plants.

The transition from a regulated to a competitive power market is also altering valuation of these avoided emissions. In a regulated, cost-of-service environment, where all costs and services are bundled, society could arguably afford to ignore the substantial compliance value associated with emission-free generation. However, in a competitive power market, where costs and services are unbundled and priced separately, emission-free sources like nuclear energy should—to be equitable—receive explicit economic credit for their compliance value (environmental service). There are several means to capture this economic value: emission free portfolio standard; fuel-neutral, output based cap-and-trade system; production tax credits; and investment tax credits.

While each of these impediments and related policy pathways will enhance the economic competitiveness of nuclear power, not all of them can be quantified or explicitly represented in the CEF-NEMS model.

E-3.1. INTRODUCTION

Oak Ridge National Laboratory (ORNL) and Lawrence Berkley National Laboratory (LBNL) were tasked by the U.S. Department of Energy (USDOE), Office of Energy Efficiency and Renewable Energy (EERE), to examine alternative policy pathways and related barriers to a Clean Energy Future.

The principal goal of the Clean Energy Future Study is to produce fully documented scenarios showing how energy-efficient and clean energy technologies can address key energy and environmental challenges of the next century while enabling continued economic growth. A particular focus of this study is on the impacts of different public policies and programs, and the identification of policy implementation pathways that can lead to least-cost scenarios. The Clean Energy Futures Project extends the study, undertaken in 1996-97 by a multi-laboratory team (led by ORNL and LBL), *Scenarios of U.S. Carbon Reduction, Potential Impacts of Energy Technologies in 2010 and Beyond*.

This appendix addresses the nuclear power plant (NPP) component of the Clean Energy Futures Project. It examines 1) how NPPs are dealt with in the National Energy Modeling System (NEMS), developed and operated by the Energy Information Administration (EIA); 2) recent evidence on NPP license renewal; 3) the implications of spent fuel storage and disposal on future NPP operations; and 4) potential actions to remove barriers or modify policies that would enhance continued operation of NPPs in the future.

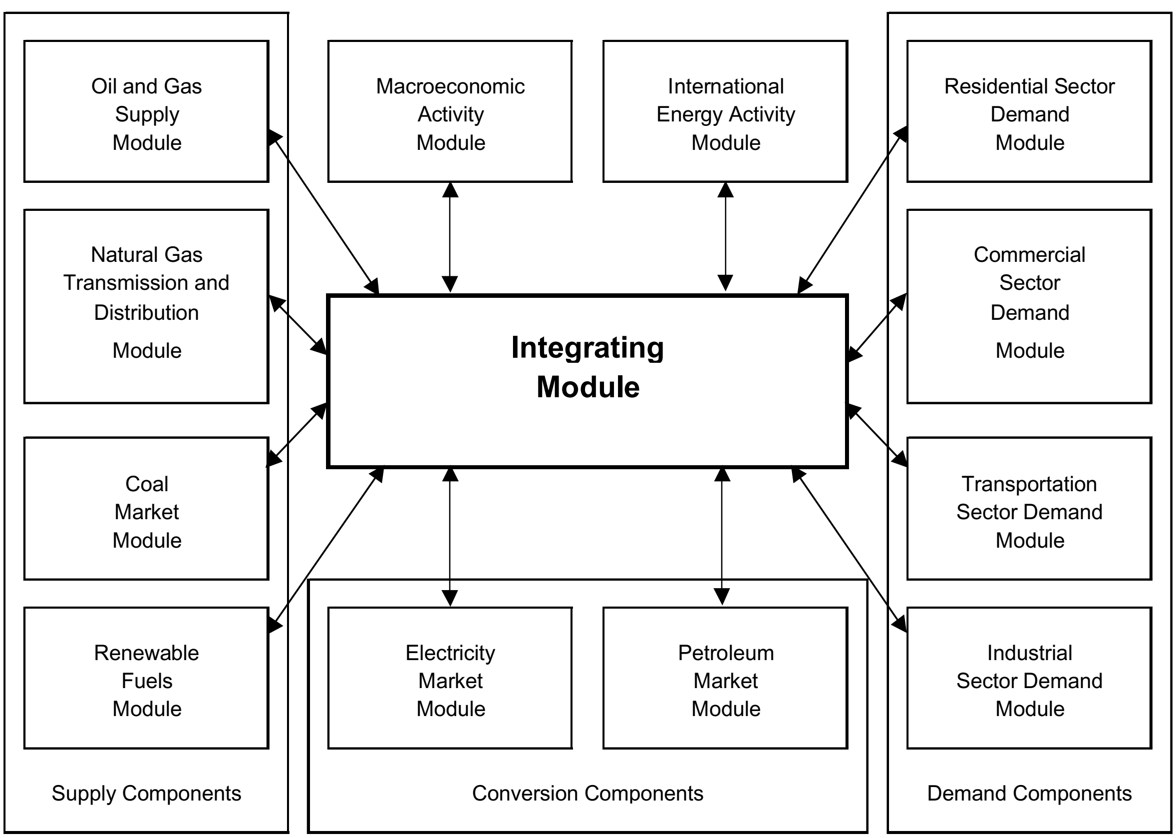
E-3.2. TREATMENT OF NUCLEAR POWER IN AEO99

The National Energy Modeling System (NEMS) is used to produce the Annual Energy Outlook (AEO) each year by the Energy Information Administration (EIA). The 1999 Annual Energy Outlook (AEO99) presents forecasts of energy supply, demand, and prices through the year 2020. A complete description of the current NEMS configuration and AEO99 assumptions are found in Appendix G of the Annual Energy Outlook 1999 [DOE/EIA-0383(99)].

As depicted in Figure E-3.1, NEMS does not explicitly model nuclear power plant (NPP) or the nuclear fuel cycle. This section describes how operating NPPs are handled within NEMS and the AEO99 forecast.

Based on NEMS documentation and discussions with EIA staff, the following information on the treatment of NPPs in NEMS was compiled. It should be noted that in AEO99 determining the breakeven cost (going forward cost, plus life extension at age 30, and life extension and license renewal at age 40) of NPPs remains an external calculation to the Electricity Market Model (EMM). Within the EMM, when an NPP reaches age 30 (or 40), its corresponding breakeven cost is compared against the cost of new baseload generation (natural gas combined cycle, NGCC) to determine if the NPP continues to operate or is retired. In previous AEOs and EIA special reports, the NPP operation/retirement decision was determined off-line and hardwired in the forecast.

Fig, E-3.1 Basic NEMS Structure



E-3.2.1 AEO99: Nuclear Results

In the AEO99 *Reference Case*, NEMS forecasts nuclear power declining from 99 GWe in 1997 to 49 GWe by 2020. With 50 GWe of NPPs retired, this corresponds to a negative average annual growth rate of 3.0%. In the *Low Case*, nuclear power is forecast to decline even further, to 32 GWe by 2020. In the *High Case*, nuclear power declines to 78 GWe by 2020 [see Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99), for more details].

E-3.2.2 AEO99: NPP Competitiveness Analysis

In AEO99, the economic competitiveness and dispatch of NPPs is determined within the Electric Market Module (EMM). In each year, the EMM dispatches plants—including NPPs—based on their going forward costs.[2] A list of operating NPPs, with selected NEMS decision data, is presented in Table E-3.1. The exception to this rule occurs when an NPP reaches age 30 and 40.

When an individual NPP reaches age 30 (or 40), the EMM compares the market clearing price for a *new* baseload generation plant—predominantly natural gas combined cycle (NGCC) in AEO99—against the corresponding going forward cost (including an EIA-defined life extension cost at age 30, and an aging and license renewal cost at age 40) for the NPP listed in Table E-3.1.[3] If the going forward cost of an NPP is below the market-clearing price in that year then the plant is dispatched, otherwise it is retired.

More specifically, if an NPP is 30 years old in a forecast year, the EMM uses the year 30 going forward cost (column 14, Table E-3.1) to determine if the NPP is economic to operate until age 40.[4] The year 30 going forward cost was computed exogenously (off-line) by EIA using a levelized cash flow method. The method consists of current operating costs (1995-97 average) and a life extension charge of $150/kW, to ensure that the plant operates to year 40. In the case of a pressurized water reactor (PWR) the $150/kW charge is not included if the NPP already replaced its steam generator (and made other related equipment improvements). While it is assumed that this charge is recovered through annual payments over the remaining 10 years of life, the capital outlay is made in year 30.

A similar NPP competitiveness screen is conducted at year 40. In the NEMS *Reference Case* an NPP license is extended from 40 to 60 years if the aggregate going forward cost —operating cost and capitalization of $250/kWe refurbishing cost over 20 years—is less than the cost of a competing new baseload technology, otherwise the plant is retired. This charge, which is assumed to refurbish aging capital equipment, is assumed by EIA to be expended completely in year 40, even though in reality it will be annualized over the remaining 20 years of NPP operation.

For both the 30- and 40-year *Reference Case* investment decisions, EIA indicated that it made other (undefined) adjustments to reflect technological improvements.

In *the Low Case*, higher capital investments (relative to the reference case) are assumed after 30 and 40 years of operation. In the *High Case* it was assumed that *no* capital expenditures—such as those incurred in the *Reference Case*—were required during the current license period (30-year) or for license renewal (40-year); this resulted in less retirements of NPP capacity.

Table E-3.1 - Nuclear Power Plants in NEMS for AEO99

Company ID	Plant ID	Unit ID	Plant Name	State	Reactor Type	Name Plate Capacity	Summer Capacity	Winter Capacity	Refurbishment Date	On-Line Year	Retire Year	Nuclear Endogenous Ret. Switch	Lev Cost for Nuc Life Ext (Phase 1) (87¢/kWh)	Lev Cost for Nuc Life Ext (Phase 2) (87¢/kWh)	Average Capacity Factor
18642	46	1	Browns Ferry	AL	B	1152	1065	1065	2013	1974	1997	0	0	0	0
18642	46	2	Browns Ferry	AL	B	1152	1065	1065	2014	1975	2014	1	2	2.47	0.8
18642	46	3	Browns Ferry	AL	B	1152	1065	1065	2016	1977	2016	1	2	2.47	0.8
195	6001	2	Joseph M Farley	AL		888.25	825	825	2021	1981	2021	1	2	2.54	0.84
195	6001	1	Joseph M Farley	AL		888.25	814.8	814.8	2017	1977	2017	1	2	2.54	0.87
814	8055	1	Arkansas Nuclear One	AR	P	902.518	836	836	2014	1974	2014	1	1.93	2.47	0.87
814	8055	2	Arkansas Nuclear One	AR	B	942.526	858	858	2018	1980	2018	1	1.93	2.47	0.87
15473	6008	2	Palo Verde	AZ	P	143.125	129.54	129.54	2025	1986	2025	1	2	2.7	0.74
803	6008	2	Palo Verde	AZ	P	408.328	369.57	369.57	2025	1986	2025	1	2	2.7	0.74
5701	6008	2	Palo Verde	AZ	P	221.704	200.66	200.66	2025	1986	2025	1	2	2.7	0.74
15473	6008	1	Palo Verde	AZ	P	143.125	129.54	129.54	2024	1986	2024	1	2	2.7	0.8
803	6008	1	Palo Verde	AZ	P	408.328	369.57	369.57	2024	1986	2024	1	2	2.7	0.8
5701	6008	1	Palo Verde	AZ	P	221.704	200.66	200.66	2024	1986	2024	1	2	2.7	0.8
803	6008	3	Palo Verde	AZ	P	408.328	369.57	369.57	2027	1988	2027	1	2	2.7	0.8
15473	6008	3	Palo Verde	AZ	P	143.125	129.54	129.54	2027	1988	2027	1	2	2.7	0.8
5701	6008	3	Palo Verde	AZ	P	221.704	200.66	200.66	2027	1988	2027	1	2	2.7	0.8
17513	6008	2	Palo Verde	AZ	P	82.929	75.057	75.057	2025	1986	2025	1	2	2.7	0.74
16572	6008	2	Palo Verde	AZ	P	245.418	222.123	222.123	2025	1986	2025	1	2	2.7	0.74
17513	6008	1	Palo Verde	AZ	P	82.929	75.057	75.057	2024	1986	2024	1	2	2.7	0.8
16572	6008	1	Palo Verde	AZ	P	245.418	222.123	222.123	2024	1986	2024	1	2	2.7	0.8
16572	6008	3	Palo Verde	AZ	P	245.418	222.123	222.123	2027	1988	2027	1	2	2.7	0.8
17513	6008	3	Palo Verde	AZ	P	82.929	75.057	75.057	2027	1988	2027	1	2	2.7	0.8
17609	6008	2	Palo Verde	AZ	P	221.704	200.66	200.66	2025	1986	2025	1	2	2.7	0.74
17609	6008	1	Palo Verde	AZ	P	221.704	200.66	200.66	2024	1986	2024	1	2	2.7	0.8
17609	6008	3	Palo Verde	AZ	P	221.704	200.66	200.66	2027	1988	2027	1	2	2.7	0.8
11208	6008	2	Palo Verde	AZ	P	79.982	72.39	72.39	2025	1986	2025	1	2	2.7	0.74
11208	6008	1	Palo Verde	AZ	P	79.982	72.39	72.39	2024	1986	2024	1	2	2.7	0.8
11208	6008	3	Palo Verde	AZ	P	79.982	72.39	72.39	2027	1988	2027	1	2	2.7	0.8
14328	6099	1	Diablo Canyon	CA	P	1136.487	1073	1073	2021	1985	2021	1	2.08	2.62	0.87
14328	6099	2	Diablo Canyon	CA	P	1164.093	1087	1087	2025	1986	2025	1	2.08	2.62	0.87
16534	6176	1	Rancho Seco	CA	P	963	873	903	1990	1975	1990	0	0	0	0
16609	360	1	San Onofre	CA	P	91.2	87.2	87.2	1992	1968	1992	0	0	0	0.732
17609	360	1	San Onofre	CA	P	364.8	348.8	348.8	1992	1968	1992	0	0	0	0.732
16609	360	3	San Onofre	CA	P	225.4	216	216	2013	1984	2022	1	1.85	2.47	0.84
17609	360	3	San Onofre	CA	P	845.814	810.54	810.54	2013	1984	2022	1	1.85	2.47	0.84
17609	360	2	San Onofre	CA	P	845.814	803.035	803.035	2013	1983	2022	1	1.85	2.47	0.84
16609	360	2	San Onofre	CA	P	225.4	214	214	2013	1983	2022	1	1.85	2.47	0.84
16088	360	2	San Onofre	CA	P	20.173	19.153	19.153	2013	1983	2022	1	1.85	2.47	0.84
16088	360	3	San Onofre	CA	P	20.173	19.332	19.332	2013	1984	2022	1	1.85	2.47	0.84
590	360	2	San Onofre	CA	P	35.613	33.812	33.812	2013	1983	2022	1	1.85	2.47	0.84
590	360	3	San Onofre	CA	P	35.613	34.128	34.128	2013	1984	2022	1	1.85	2.47	0.84
13433	558	1	Haddam Neck	CT		90.045	84.015	87.48	2007	1968	1997	0	0	0	0

B = Boiling Water Reactor

P = Pressurized Water Reactor

Table E-3.1 - Nuclear Power Plants in NEMS for AEO99

Company ID	Plant ID	Unit ID	Plant Name	State	Reactor Type	Name Plate Capacity	Summer Capacity	Winter Capacity	Refurbishment Date	On-Line Year	Retire Year	Nuclear Endogenous Ret. Switch	Lev Cost for Nuc Life Ext (Phase 1) (87¢/kWh)	Lev Cost for Nuc Life Ext (Phase 2) (87¢/kWh)	Average Capacity Factor
4187	558	1	Haddam Neck	CT		207.104	193.235	201.204	2007	1968	1997	0	0	0	0
20455	558	1	Haddam Neck	CT		57.029	53.21	55.404	2007	1968	1997	0	0	0	0
3292	558	1	Haddam Neck	CT		12.006	11.202	11.664	2007	1968	1997	0	0	0	0
3266	558	1	Haddam Neck	CT		36.018	33.606	34.992	2007	1968	1997	0	0	0	0
1998	558	1	Haddam Neck	CT		57.029	53.21	55.404	2007	1968	1997	0	0	0	0
19497	558	1	Haddam Neck	CT		57.029	53.21	55.404	2007	1968	1997	0	0	0	0
2886	558	1	Haddam Neck	CT		27.014	25.205	26.244	2007	1968	1997	0	0	0	0
15472	558	1	Haddam Neck	CT		30.015	28.005	29.16	2007	1968	1997	0	0	0	0
12833	558	1	Haddam Neck	CT		27.014	25.205	26.244	2007	1968	1997	0	0	0	0
20455	566	1	Millstone	CT	B	125.685	121.796	123.063	2010	1970	1998	1	3.39	4.24	0.63
21687	566	1	Millstone	CT	B	535.815	519.234	524.637	2010	1970	1998	1	3.39	4.24	0.63
21687	566	2	Millstone	CT	P	737.019	707.211	708.345	2015	1975	2015	1	2.87	4.55	0.62
20455	566	2	Millstone	CT	P	172.881	165.889	166.155	2015	1975	2015	1	2.87	4.55	0.62
3477	566	3	Millstone	CT	P	16.917	15.115	15.467	2025	1986	2025	1	1.93	2.54	0.74
19497	566	3	Millstone	CT	P	46.239	41.313	42.276	2025	1986	2025	1	1.93	2.54	0.74
13433	566	3	Millstone	CT	P	153.003	136.703	139.89	2025	1986	2025	1	1.93	2.54	0.74
5618	566	3	Millstone	CT	P	50.249	44.896	45.943	2025	1986	2025	1	1.93	2.54	0.74
4180	566	3	Millstone	CT	P	13.659	12.204	12.488	2025	1986	2025	1	1.93	2.54	0.74
24559	566	3	Millstone	CT	P	852.357	761.552	779.305	2025	1986	2025	1	1.93	2.54	0.74
3266	566	3	Millstone	CT	P	31.327	27.99	28.643	2025	1986	2025	1	1.93	2.54	0.74
19899	566	3	Millstone	CT	P	26.691	23.847	24.403	2025	1986	2025	1	1.93	2.54	0.74
11806	566	3	Millstone	CT		55.136	49.262	50.411	2025	1986	2025	1	1.93	2.54	0.74
99999	566	3	Millstone	CT		7.769	6.942	7.103	2025	1986	2025	1	1.93	2.54	0.74
6455	628	3	Crystal River	FL	P	805.421	734.454	755.257	2016	1977	2016	1	2.54	3.16	0.8
99996	628	3	Crystal River	FL	P	55.654	50.75	52.188	2016	1977	2016	1	2.54	3.16	0.8
14610	628	3	Crystal River	FL	P	14.247	12.992	13.36	2016	1977	2016	1	2.54	3.16	0.8
21554	628	3	Crystal River	FL	P	15.138	13.804	14.195	2016	1977	2016	1	2.54	3.16	0.8
6452	6045	1	St Lucie	FL	P	850	839	853	2016	1976	2016	1	1.28	2.54	0.84
6452	6045	2	St Lucie	FL	P	723.435	714.073	725.988	2023	1983	2023	1	1.28	2.54	0.84
6567	6045	2	St Lucie	FL	P	74.885	73.916	75.149	2023	1983	2023	1	1.28	2.54	0.84
14186	6045	2	St Lucie	FL	P	51.68	51.011	51.862	2023	1983	2023	1	1.28	2.54	0.84
6452	621	3	Turkey Point	FL	P	759.92	666	688	2012	1972	2012	1	1.72	2.85	0.84
6452	621	4	Turkey Point	FL	P	759.92	666	688	2013	1973	2013	1	1.72	2.85	0.84
7140	6051	2	Edwin I Hatch	GA		410.82	407.313	407.313	2018	1979	2018	1	2.24	2.85	0.8
7140	6051	1	Edwin I Hatch	GA		405.81	380.459	380.459	2014	1975	2014	1	2.24	2.85	0.86
13994	6051	2	Edwin I Hatch	GA		246	243.9	243.9	2018	1979	2018	1	2.24	2.85	0.8
4744	6051	2	Edwin I Hatch	GA		18.04	17.886	17.886	2018	1979	2018	1	2.24	2.85	0.8
13100	6051	2	Edwin I Hatch	GA		145.14	143.901	143.901	2018	1979	2018	1	2.24	2.85	0.8
13100	6051	1	Edwin I Hatch	GA		143.37	134.414	134.414	2014	1975	2014	1	2.24	2.85	0.86

B = Boiling Water Reactor

P = Pressurized Water Reactor

Table E-3.1 - Nuclear Power Plants in NEMS for AEO99

Company ID	Plant ID	Unit ID	Plant Name	State	Reactor Type	Name Plate Capacity	Summer Capacity	Winter Capacity	Refurbishment Date	On-Line Year	Retire Year	Nuclear Endogenous Ret. Switch	Lev Cost for Nuc Life Ext (Phase 1) (87¢/kWh)	Lev Cost for Nuc Life Ext (Phase 2) (87¢/kWh)	Average Capacity Factor
4744	6051	1	Edwin I Hatch	GA		17.82	16.707	16.707	2014	1975	2014	1	2.24	2.85	0.86
13994	6051	1	Edwin I Hatch	GA		243	227.82	227.82	2014	1975	2014	1	2.24	2.85	0.86
7140	649	1	Vogtle	GA		530.12	531.948	531.948	2027	1987	2027	1	1.31	1.77	0.87
7140	649	2	Vogtle	GA		530.12	531.948	531.948	2029	1989	2029	1	1.31	1.77	0.87
4744	649	1	Vogtle	GA		18.56	18.624	18.624	2027	1987	2027	1	1.31	1.77	0.87
13100	649	1	Vogtle	GA		263.32	264.228	264.228	2027	1987	2027	1	1.31	1.77	0.87
13994	649	1	Vogtle	GA		348	349.2	349.2	2027	1987	2027	1	1.31	1.77	0.87
13100	649	2	Vogtle	GA		263.32	264.228	264.228	2029	1989	2029	1	1.31	1.77	0.87
13994	649	2	Vogtle	GA		348	349.2	349.2	2029	1989	2029	1	1.31	1.77	0.87
4744	649	2	Vogtle	GA		18.56	18.624	18.624	2029	1989	2029	1	1.31	1.77	0.87
9162	1060	1	Duane Arnold	IA	B	418.005	369.6	371	2014	1975	2014	1	2.54	3.16	0.86
3258	1060	1	Duane Arnold	IA	B	119.43	105.6	106	2014	1975	2014	1	2.54	3.16	0.86
4363	1060	1	Duane Arnold	IA	B	59.715	52.8	53	2014	1975	2014	1	2.54	3.16	0.86
21770	50340	GEN1	Argonne N	ID		19.5	18.077	18.077	9999	1964	1990	0	0	0	0.338
4110	6022	1	Braidwood	IL	P	1224.9	1090	1120	2026	1988	2026	1	0.76	1.85	0.74
4110	6022	2	Braidwood	IL	P	1224.9	1090	1120	2027	1988	2027	1	0.76	1.85	0.84
4110	6023	1	Byron	IL	P	1224.9	1120	1120	2024	1985	2024	1	0.7	1.7	0.74
4110	6023	2	Byron	IL	P	1224.9	1120	1120	2026	1987	2026	1	0.7	1.7	0.84
9208	204	1	Clinton	IL	B	984.875	930	944	2026	1987	2026	1	1.85	2.47	0.74
4110	869	2	Dresden	IL	B	828.315	772	794	2006	1970	2006	1	3.16	3.85	0.51
4110	869	3	Dresden	IL	B	828.315	773	794	2011	1971	2011	1	3.16	3.85	0.51
4110	6026	1	La Salle	IL	B	1170.27	1048	1078	2022	1984	2022	1	1.62	2.16	0.74
4110	6026	2	La Salle	IL	B	1170.27	1048	1078	2023	1984	2023	1	1.62	2.16	0.74
4110	880	2	Quad Cities	IL	B	621.236	576.75	591.75	2012	1972	2012	1	3.16	3.85	0.51
4110	880	1	Quad Cities	IL	B	621.236	576.75	591.75	2012	1972	2012	1	3.16	3.85	0.51
9438	880	1	Quad Cities	IL	B	207.079	192.25	197.25	2012	1972	2012	1	3.16	3.85	0.51
9438	880	2	Quad Cities	IL	B	207.079	192.25	197.25	2012	1972	2012	1	3.16	3.85	0.51
4110	885	2	Zion	IL		1098	1040	1040	2013	1974	1998	0	0	0	0.4
4110	885	1	Zion	IL		1098	1040	1040	2013	1973	1998	0	0	0	0.4
10000	210	1	Wolf Creek	KS	P	580.821	548.49	556.48	2025	1985	2025	1	1.39	1.85	0.84
20893	210	1	Wolf Creek	KS	P	580.821	548.49	556.48	2025	1985	2025	1	1.39	1.85	0.84
99996	210	1	Wolf Creek	KS	P	74.147	70.02	71.04	2025	1985	2025	1	1.39	1.85	0.84
7806	6462	1	River Bend	LA	B	725.193	655.2	655.2	2025	1986	2025	1	2.78	3.47	0.8
2777	6462	1	River Bend	LA	B	310.797	280.8	280.8	2025	1986	2025	1	2.78	3.47	0.8
11241	4270	3	Waterford	LA	P	1199.88	1075	1075	2024	1985	2024	1	1.7	2.24	0.87
1998	1590	1	Pilgrim	MA	B	678	668.63	668.97	2012	1972	2012	1	3.78	4.63	0.74
3292	1645	1	Yankee Rowe	MA		6.475	5.845	5.845	1992	1961	1992	0	0	0	0
15472	1645	1	Yankee Rowe	MA		12.95	11.69	11.69	1992	1961	1992	0	0	0	0
1998	1645	1	Yankee Rowe	MA		17.575	15.865	15.865	1992	1961	1992	0	0	0	0

B = Boiling Water Reactor

P = Pressurized Water Reactor

Table E-3.1 - Nuclear Power Plants in NEMS for AEO99

Company ID	Plant ID	Unit ID	Plant Name	State	Reactor Type	Name Plate Capacity	Summer Capacity	Winter Capacity	Refurbishment Date	On-Line Year	Retire Year	Nuclear Endogenous Ret. Switch	Lev Cost for Nuc Life Ext (Phase 1) (87¢/kWh)	Lev Cost for Nuc Life Ext (Phase 2) (87¢/kWh)	Average Capacity Factor
20455	1645	1	Yankee Rowe	MA		12.95	11.69	11.69	1992	1961	1992	0	0	0	0
21083	1645	1	Yankee Rowe	MA		55.5	50.1	50.1	1992	1961	1992	0	0	0	0
2886	1645	1	Yankee Rowe	MA		3.7	3.34	3.34	1992	1961	1992	0	0	0	0
12833	1645	1	Yankee Rowe	MA		8.325	7.515	7.515	1992	1961	1992	0	0	0	0
3266	1645	1	Yankee Rowe	MA		17.575	15.865	15.865	1992	1961	1992	0	0	0	0
4176	1645	1	Yankee Rowe	MA		45.325	40.915	40.915	1992	1961	1992	0	0	0	0
4089	1645	1	Yankee Rowe	MA		4.625	4.175	4.175	1992	1961	1992	0	0	0	0
1167	6011	1	Calvert Cliffs	MD	P	918	835	865	2014	1975	2014	1	1.7	2.93	0.8
1167	6011	2	Calvert Cliffs	MD	P	910.71	840	865	2016	1977	2016	1	1.7	2.93	0.84
11525	1517	1	Maine Yankee	ME		920	870	880	2008	1972	1998	0	0	0	0.74
4254	1697	1	Big Rock Point	MI		75	67	67	2000	1965	1997	0	0	0	0.74
9324	6000	1	Donald C Cook	MI	P	1152	1000	1020	2014	1975	2014	1	1.89	3.31	0.74
9324	6000	2	Donald C Cook	MI	P	1133.3	1060	1090	2017	1978	2017	1	1.89	3.31	0.74
5109	1729	2	Fermi	MI	B	1154	1100	1110	2025	1988	2025	1	2.47	3.24	0.63
4254	1715	1	Palisades	MI	P	811.7	762	780	2007	1972	2007	1	2.14	3.62	0.74
13781	1922	1	Monticello	MN	B	568.8	544	553	2010	1971	2010	1	1.59	2.7	0.86
13781	1925	1	Prairie Island	MN	P	593.1	514	533	2013	1974	2013	1	1.7	2.16	0.87
13781	1925	2	Prairie Island	MN	P	593.1	513	531	2014	1974	2014	1	1.7	2.16	0.87
19436	6153	1	Callaway	MO	P	1235.8	1125	1167	2024	1984	2024	1	1.31	1.77	0.87
17568	6072	1	Grand Gulf	MS	B	137.25	117.3	117.3	2022	1985	2022	1	1.46	2	0.86
12465	6072	1	Grand Gulf	MS	B	1235.25	1055.7	1055.7	2022	1985	2022	1	1.46	2	0.86
3046	6014	2	Brunswick	NC	B	707.834	615.792	615.792	2014	1975	2014	1	3.47	4.32	0.74
3046	6014	1	Brunswick	NC	B	707.834	626.409	626.409	2016	1977	2016	1	3.47	4.32	0.8
13687	6014	2	Brunswick	NC	B	158.866	138.208	138.208	2014	1975	2014	1	3.47	4.32	0.74
13687	6014	1	Brunswick	NC	B	158.866	140.591	140.591	2016	1977	2016	1	3.47	4.32	0.8
3046	6015	1	Harris	NC	P	797.181	720.938	720.938	2026	1987	2026	1	1.62	2.16	0.84
13687	6015	1	Harris	NC	P	153.769	139.062	139.062	2026	1987	2026	1	1.62	2.16	0.84
5416	6038	1	McGuire	NC	P	1220.31	1129	1129	2021	1981	2021	1	1.62	2.16	0.74
5416	6038	2	McGuire	NC	P	1220.31	1129	1129	2023	1984	2023	1	1.62	2.16	0.84
13337	8036	1	Cooper Station	NE	B	835.55	778	778	2014	1974	2014	1	3.08	3.85	0.63
14127	2289	1	Fort Calhoun	NE	P	502	476	492	2013	1973	2013	1	3.24	4.01	0.8
19497	6115	1	Seabrook	NH	P	217.35	203.35	203.35	2026	1990	2026	1	1.93	2.54	0.8
13433	6115	1	Seabrook	NH	P	123.703	115.735	115.735	2026	1990	2026	1	1.93	2.54	0.8
2951	6115	1	Seabrook	NH	P	43.718	40.902	40.902	2026	1990	2026	1	1.93	2.54	0.8
12833	6115	1	Seabrook	NH	P	36.018	33.698	33.698	2026	1990	2026	1	1.93	2.54	0.8
4176	6115	1	Seabrook	NH	P	50.425	47.177	47.177	2026	1990	2026	1	1.93	2.54	0.8
11806	6115	1	Seabrook	NH	P	143.948	134.676	134.676	2026	1990	2026	1	1.93	2.54	0.8
5971	6115	1	Seabrook	NH	P	150.655	140.951	140.951	2026	1990	2026	1	1.93	2.54	0.8
13441	6115	1	Seabrook	NH	P	26.951	25.215	25.215	2026	1990	2026	1	1.93	2.54	0.8

B = Boiling Water Reactor

P = Pressurized Water Reactor

Table E-3.1 - Nuclear Power Plants in NEMS for AEO99

Company ID	Plant ID	Unit ID	Plant Name	State	Reactor Type	Name Plate Capacity	Summer Capacity	Winter Capacity	Refurbishment Date	On-Line Year	Retire Year	Nuclear Endogenous Ret. Switch	Lev Cost for Nuc Life Ext (Phase 1) (87¢/kWh)	Lev Cost for Nuc Life Ext (Phase 2) (87¢/kWh)	Average Capacity Factor
13714	6115	1	Seabrook	NH	P	446.872	418.088	418.088	2026	1990	2026	1	1.93	2.54	0.8
99996	6115	1	Seabrook	NH	P	2.36	2.208	2.208	2026	1990	2026	1	1.93	2.54	0.8
15477	6118	1	Hope Creek	NJ	B	1111.5	979.45	1019.35	2026	1987	2026	1	2	2.54	0.86
963	6118	1	Hope Creek	NJ	B	58.5	51.55	53.65	2026	1987	2026	1	2	2.54	0.86
7423	2388	1	Oyster Creek	NJ	B	640.7	619	637	2004	1969	2009	1	3.62	4.39	0.8
5027	2410	1	Salem	NJ	P	86.697	81.955	82.992	2016	1977	2016	1	3.16	3.85	0.74
15477	2410	1	Salem	NJ	P	498.303	471.045	477.008	2016	1977	2016	1	3.16	3.85	0.74
963	2410	1	Salem	NJ	P	86.697	81.955	82.992	2016	1977	2016	1	3.16	3.85	0.74
14940	2410	1	Salem	NJ	P	498.303	471.045	477.008	2016	1977	2016	1	3.16	3.85	0.74
963	2410	2	Salem	NJ	P	86.697	81.955	82.992	2020	1981	2020	1	3.16	3.85	0.74
14940	2410	2	Salem	NJ	P	498.303	471.045	477.008	2020	1981	2020	1	3.16	3.85	0.74
15477	2410	2	Salem	NJ	P	498.303	471.045	477.008	2020	1981	2020	1	3.16	3.85	0.74
5027	2410	2	Salem	NJ	P	86.697	81.955	82.992	2020	1981	2020	1	3.16	3.85	0.74
16183	6122	1	Ginna	NY	P	517.14	470	470	2009	1970	2009	1	2.08	3.39	0.84
4226	2497	2	Indian Point	NY	P	1309.672	931	951	2003	1973	2013	1	2.78	3.39	0.74
15296	8907	3	Indian Point 3	NY	P	1013	980	1000	2015	1976	2015	1	2.54	4.16	0.74
15296	6110	1	James A FitzPatrick	NY	B	883	820	820	1997	1975	2014	1	2.93	3.7	0.74
13573	2589	1	Nine Mile Point	NY	B	641.75	617	625	2009	1969	2009	1	2.7	3.39	0.8
13511	2589	2	Nine Mile Point	NY	B	218.441	189.921	191.16	1995	1988	1995	1	2.24	2.93	0.8
11172	2589	2	Nine Mile Point	NY	B	218.441	189.921	191.16	1995	1988	1995	1	2.24	2.93	0.8
13573	2589	2	Nine Mile Point	NY	B	497.56	432.598	435.42	1995	1988	1995	1	2.24	2.93	0.8
3249	2589	2	Nine Mile Point	NY	B	109.22	94.96	95.58	1995	1988	1995	1	2.24	2.93	0.8
16183	2589	2	Nine Mile Point	NY	B	169.898	147.716	148.68	1995	1988	1995	1	2.24	2.93	0.8
11172	2589	2	Nine Mile Point	NY	B	226.674	197.079	198.365	2026	1995	2026	1	2.24	2.93	0.8
16183	2589	2	Nine Mile Point	NY	B	176.302	153.284	154.284	2026	1995	2026	1	2.24	2.93	0.8
13573	2589	2	Nine Mile Point	NY	B	516.312	448.902	451.83	2026	1995	2026	1	2.24	2.93	0.8
3249	2589	2	Nine Mile Point	NY	B	113.337	98.54	99.183	2026	1995	2026	1	2.24	2.93	0.8
13511	2589	2	Nine Mile Point	NY	B	226.674	197.079	198.365	2026	1995	2026	1	2.24	2.93	0.8
18997	6149	1	Davis-Besse	OH	P	449.845	424.453	424.453	2017	1977	2017	1	1.93	2.47	0.87
3755	6149	1	Davis-Besse	OH	P	475.381	448.547	448.547	2017	1977	2017	1	1.93	2.47	0.87
13998	6020	1	Perry	OH	B	441.399	411.956	420.766	2026	1987	2026	1	3.08	3.93	0.74
5487	6020	1	Perry	OH	B	172.101	160.621	164.056	2026	1987	2026	1	3.08	3.93	0.74
3755	6020	1	Perry	OH	B	389.669	363.676	371.453	2026	1987	2026	1	3.08	3.93	0.74
18997	6020	1	Perry	OH	B	249.383	232.748	237.725	2026	1987	2026	1	3.08	3.93	0.74
15248	6107	1	Trojan	OR	P	820.8	745.2	745.2	1993	1976	1993	0	0	0	0
14356	6107	1	Trojan	OR	P	30.4	27.6	27.6	1993	1976	1993	0	0	0	0
6022	6107	1	Trojan	OR	P	364.8	331.2	331.2	1993	1976	1993	0	0	0	0
5487	6040	1	Beaver Valley	PA	P	438.615	384.75	384.75	2016	1976	2016	1	1.93	2.54	0.74
14716	6040	1	Beaver Valley	PA	P	161.595	141.75	141.75	2016	1976	2016	1	1.93	2.54	0.74

B = Boiling Water Reactor

P = Pressurized Water Reactor

Table E-3.1 - Nuclear Power Plants in NEMS for AEO99

Company ID	Plant ID	Unit ID	Plant Name	State	Reactor Type	Name Plate Capacity	Summer Capacity	Winter Capacity	Refurbishment Date	On-Line Year	Retire Year	Nuclear Endogenous Ret. Switch	Lev Cost for Nuc Life Ext (Phase 1) (87¢/kWh)	Lev Cost for Nuc Life Ext (Phase 2) (87¢/kWh)	Average Capacity Factor
13998	6040	1	Beaver Valley	PA	P	323.19	283.5	283.5	2016	1976	2016	1	1.93	2.54	0.74
13998	6040	2	Beaver Valley	PA	P	386.72	343.416	343.416	2027	1987	2027	1	1.93	2.54	0.84
18997	6040	2	Beaver Valley	PA	P	183.849	163.262	163.262	2027	1987	2027	1	1.93	2.54	0.84
3755	6040	2	Beaver Valley	PA	P	225.956	200.654	200.654	2027	1987	2027	1	1.93	2.54	0.84
5487	6040	2	Beaver Valley	PA	P	126.875	112.668	112.668	2027	1987	2027	1	1.93	2.54	0.84
70899	10118	GEN1	Harrisburg	PA		8.214	7.697	7.697	9999	1986	9999	0	0	0	0.509
70899	10118	GEN2	Harrisburg	PA		15.5	14.524	14.524	9999	1994	9999	0	0	0	0.5
14940	6105	2	Limerick	PA	B	1138.473	1115	1115	2029	1990	2029	1	1.54	2.08	0.86
14940	6105	1	Limerick	PA	B	1138.473	1055	1062	2024	1986	2024	1	1.54	2.08	0.86
14940	3166	2	Peach Bottom	PA	B	489.485	464.416	475.463	2013	1974	2013	1	2.39	3.01	0.8
15477	3166	2	Peach Bottom	PA	B	489.485	464.416	475.463	2013	1974	2013	1	2.39	3.01	0.8
5027	3166	2	Peach Bottom	PA	B	86.515	82.084	84.037	2013	1974	2013	1	2.39	3.01	0.8
963	3166	2	Peach Bottom	PA	B	86.515	82.084	84.037	2013	1974	2013	1	2.39	3.01	0.8
5027	3166	3	Peach Bottom	PA	B	86.515	77.729	77.729	2014	1974	2014	1	2.39	3.01	0.8
15477	3166	3	Peach Bottom	PA	B	489.485	439.772	439.772	2014	1974	2014	1	2.39	3.01	0.8
963	3166	3	Peach Bottom	PA	B	86.515	77.729	77.729	2014	1974	2014	1	2.39	3.01	0.8
14940	3166	3	Peach Bottom	PA	B	489.485	439.772	439.772	2014	1974	2014	1	2.39	3.01	0.8
14715	6103	1	Susquehanna	PA	B	1036.8	981	981	2022	1983	2022	1	1.85	2.47	0.8
14715	6103	2	Susquehanna	PA	B	1051.555	984.6	999	2024	1985	2024	1	1.85	2.47	0.8
332	6103	1	Susquehanna	PA	B	115.2	109	109	2022	1983	2022	1	1.85	2.47	0.8
332	6103	2	Susquehanna	PA	B	116.839	109.4	111	2024	1985	2024	1	1.85	2.47	0.8
9726	8011	1	Three Mile Island	PA	P	218	196.5	202.5	2014	1974	2014	1	2.24	2.85	0.87
14711	8011	1	Three Mile Island	PA	P	218	196.5	202.5	2014	1974	2014	1	2.24	2.85	0.87
7423	8011	1	Three Mile Island	PA	P	436	393	405	2014	1974	2014	1	2.24	2.85	0.87
5416	6036	1	Catawba	SC	P	301.273	282.25	282.25	2024	1985	2024	1	1.39	1.85	0.84
5416	6036	2	Catawba	SC	P	903.818	846.75	846.75	2026	1986	2026	1	1.39	1.85	0.84
40217	6036	1	Catawba	SC	P	225.955	211.688	211.688	2024	1985	2024	1	1.39	1.85	0.84
13683	6036	1	Catawba	SC	P	677.864	635.063	635.063	2024	1985	2024	1	1.39	1.85	0.84
15028	6036	2	Catawba	SC	P	301.273	282.25	282.25	2026	1986	2026	1	1.39	1.85	0.84
3046	3251	2	H B Robinson	SC	P	768.681	683	718	2010	1971	2010	1	1.91	3.24	0.8
5416	3265	2	Oconee	SC	P	886.669	846	846	2013	1974	2013	1	1.77	2.24	0.84
5416	3265	1	Oconee	SC	P	886.669	846	846	2013	1973	2013	1	1.77	2.24	0.84
5416	3265	3	Oconee	SC	P	893.271	846	846	2014	1974	2014	1	1.77	2.24	0.84
17539	6127	1	Summer	SC	P	635.997	632.031	632.031	1996	1984	2022	1	1.16	2.31	0.8
17543	6127	1	Summer	SC	P	317.951	315.969	315.969	1996	1984	2022	1	1.16	2.31	0.8
18642	6152	1	Sequoyah	TN	P	1220.58	1111	1141	2020	1981	2020	1	2.31	2.93	0.74
18642	6152	2	Sequoyah	TN	P	1220.58	1106	1136	2021	1982	2021	1	2.31	2.93	0.8
18642	3419	1	Watts Bar	TN	P	1269.9	1122	1164	9999	1996	2036	0	0	0	0.8
44372	6145	2	Comanche Peak	TX	P	1215	1150	1150	2033	1993	2033	1	1.46	2	0.74

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Table E-3.1 - Nuclear Power Plants in NEMS for AEO99

Company ID	Plant ID	Unit ID	Plant Name	State	Reactor Type	Name Plate Capacity	Summer Capacity	Winter Capacity	Refurbishment Date	On-Line Year	Retire Year	Nuclear Endogenous Ret. Switch	Lev Cost for Nuc Life Ext (Phase 1) (87¢/kWh)	Lev Cost for Nuc Life Ext (Phase 2) (87¢/kWh)	Average Capacity Factor
44372	6145	1	Comanche Peak	TX	P	1215	1150	1150	2030	1990	2030	1	1.46	2	0.84
8901	6251	1	South Texas	TX	P	417.131	385.308	385.308	2027	1988	2027	1	2.08	2.7	0.8
3278	6251	1	South Texas	TX	P	341.289	315.252	315.252	2027	1988	2027	1	2.08	2.7	0.8
3278	6251	2	South Texas	TX	P	341.289	315.252	315.252	2028	1989	2028	1	2.08	2.7	0.84
8901	6251	2	South Texas	TX	P	417.131	385.308	385.308	2028	1989	2028	1	2.08	2.7	0.84
1015	6251	1	South Texas	TX	P	216.691	200.16	200.16	2027	1988	2027	1	2.08	2.7	0.8
16604	6251	1	South Texas	TX	P	379.21	350.28	350.28	2027	1988	2027	1	2.08	2.7	0.8
1015	6251	2	South Texas	TX	P	216.691	200.16	200.16	2028	1989	2028	1	2.08	2.7	0.84
16604	6251	2	South Texas	TX	P	379.21	350.28	350.28	2028	1989	2028	1	2.08	2.7	0.84
19876	6168	1	North Anna	VA	P	866.09	789.412	789.412	2018	1978	2018	1	1.11	2.08	0.87
19876	6168	2	North Anna	VA	P	866.09	792.948	784.948	2020	1980	2020	1	1.11	2.08	0.87
40229	6168	1	North Anna	VA	P	113.65	103.588	103.588	2018	1978	2018	1	1.11	2.08	0.87
40229	6168	2	North Anna	VA	P	113.65	104.052	104.052	2020	1980	2020	1	1.11	2.08	0.87
19876	3806	1	Surry	VA	P	847.53	801	801	2012	1972	2012	1	1.85	2.39	0.84
19876	3806	2	Surry	VA	P	847.53	801	801	2013	1973	2013	1	1.85	2.39	0.8
19796	3751	1	Vermont Yankee	VT		563.4	496	521.8	2012	1972	2012	1	2.54	3.08	0.86
20160	3928	247	Hanford Gen Project	WA		400	420	420	1992	1966	1992	0	0	0	0
20160	3928	248	Hanford Gen Project	WA		400	420	420	1992	1966	1992	0	0	0	0
20160	371	2	WNP 1 & 2	WA	B	1200	1107	1112	2023	1984	2023	1	2.24	2.85	0.63
20856	8024	1	Kewaunee	WI	P	219.35	212.749	212.749	2013	1974	2013	1	1.52	2.62	0.87
20860	8024	1	Kewaunee	WI	P	220.42	213.787	213.787	2013	1974	2013	1	1.52	2.62	0.87
11479	8024	1	Kewaunee	WI	P	95.23	92.364	92.364	2013	1974	2013	1	1.52	2.62	0.87
20847	4046	1	Point Beach	WI	P	523.8	493	497	2010	1970	2010	1	1.23	2.24	0.87
20847	4046	2	Point Beach	WI	P	523.8	441	441	2013	1972	2013	1	1.23	2.24	0.87

B = Boiling Water Reactor

P = Pressurized Water Reactor

E-3.2.3 AEO99: Other NPP Assumptions

In the AEO99, EIA reduces annual nuclear O&M expenditures over time to reflect retirements in the later years of the forecast; for example, 5% below the 1997 level in 2020.

No new NPPs are assumed to be constructed and operable before 2020 in AEO99. This assumption is based on uncertainties associated with the fact that 1) post-construction hearings and judicial review, and 2) waste disposal, regulatory, and financial issues are so large, they would prevent investment in new NPP capacity until resolved, which EIA assumes to be 2020.

E-3.3 NUCLEAR PLANT LICENSE RENEWAL

One of the significant going forward costs in the AEO99 for nuclear power plants (NPPs) is the additional capital cost included in year 40 for license renewal and replacement of aging equipment. The assumed cost is $250/kW. This cost is considerably higher than the cost experienced to date (or projected) with the two NPPs who have submitted license renewal applications to the Nuclear Regulatory Commission (NRC)—Baltimore Gas & Electric, Calvert Cliffs plant and Duke Energy, Oconee plant.

E-3.3.1 NPP License Renewal: Activity to Date

As of early 2000, approximately 29 license renewal applications or letters of intent have been filed with the NRC. Selected license renewal application activities are summarized below.

On April 10, 1998, Baltimore Gas & Electric (BG&E) filed an application with the NRC to extend the operating license of its two unit Calvert Cliffs plant by 20 years. The 825 MWe C-E Units 1 and 2 began commercial operation in 1975 and 1977, respectively. On February 4, 1999, NRC Chairman Shirley Jackson reported to the Senate that barring any hiccups , the BG&E Calvert Cliffs review should result in a decision in May 2000, only 25 months after the application was filed. Approval of the Calvert Cliffs license renewal was issued on March 23, 2000.

On July, 7, 1998, Duke Power Company filed an application with the NRC to extend the operating license of its three-unit Oconee plant by 20 years. Oconee 1 began commercial operation in 1973 and Units 2 and 3 in 1974; all three units are 846 MWe pressurized water reactors (PWRs) manufactured by B&W. At the time of its application, Duke anticipated that the technical and environmental review process and public hearings would take close to three years. The NRC has stated that its review would be concluded in 585 days, plus time for public hearings. For the longer term, Duke is also considering license renewal of its McGuire and Catawba stations.

On January 22, 1999, Entergy Operations informed the NRC that it intended to file a license renewal application for its Arkansas Number One (ANO 1) unit in December 1999, even though its current 40-year license does not expire until 2014. ANO 1 is a 836 MWe B&W pressurized water reactor (PWR) that began commercial operation in 1974. Current condenser replacement and planned steam generator replacement make Entergy s ANO 2 a strong candidate for license renewal (2018). Entergy has stated that license renewal also makes sense for Pilgrim, which it recently acquired from Boston Edison.

Southern Nuclear Operating Co. (SNOC) has stated its plans to spend $13.2 million on development costs and some NRC fees (but nothing on equipment) over five years for license renewal activities for its Hatch-1 and —2, 860 and 910MWe units respectively. Both units are General Electric boiling water reactors (BWR). The Hatch decision will be made at the end of 1999. After that SNOC will consider license renewal for the Farley and Vogtle stations.

PECO Energy indicated in 1998 that it is seriously considering license renewal for its two GE 1100 MWe BWR Peach Bottom units and for the B&W 786 MWe PWR TMI-1 unit, which PECO and its partner, British Energy, are acquiring from GPU under the corporate entity AmerGen.

In July 1998, Florida Power & Light sent the NRC a letter of intent to file a license extension renewal application in several years for its Turkey Point-3 and -4 693 MWe Westinghouse PWR units, which have license expiration dates in 2012 and 2013.

Even though both Donald C. Cook units (1020 and 1090 MWe PWRs, respectively) have been shutdown since September 1997 for regulatory compliance, American Electric Power (AEP) has indicated that it will replace the four steam generators at Cook-1 in the next few years. AEP also intends to seek license renewal for Cook-1 in early 2000. The steam generators at Cook-2 were replaced in 1988. Both plants are expected to re-start in the third quarter of 1999.

E-3.3.2 License Renewal Costs: Experience to Date

As part of its decision to seek license renewal, BG&E decided to replace the two steam generators at each of its two Calvert Cliff units. It awarded a contract in the amount of $100 million for the supply of four generators, and a second contract in the amount of $200 million to implement the generator change outs.

Both Duke and BG&E have estimated the cost of preparing a license application and NRC review at between $15-20 million. To date, Duke and BG&E have spent approximately $8 and $7 million, respectively, on preparing their applications; they expect the NRC review to cost them each $8 million. These costs do not include the cost for equipment upgrades or refurbishment. For example, in the case of BG&E, $300 million is needed for steam generator replacement; Duke is expected to replace its steam generators if its application is approved.

Duke s decision to seek license renewal was driven by the Oconee station s efficient operation and economics. On a production cost basis the company s nuclear units are the lowest cost producing generators on Duke s system. The Oconee production costs averaged 17.4 mills/kWhr during the 1995-1997 period, compared to the industry median cost of 19.6 mills/kWh.

The BG&E and Duke experience indicates that the cost of a license extension application and review process for a two-unit, 2 GWe nuclear station should not exceed $20 million, or $10 million per GWe. The cost of equipment refurbishment (steam generator, etc.) for the same typical 2 GWe station is estimated to be $340 million, or $170/GWe ($150 M*(1000 GWe/825 GWe)**0.7). This estimate uses the chemical engineering economies-of-scale power law.

Thus, the **total** license renewal cost should not exceed $180 million per GWe ($180/kW) in year 30.[5] This corresponds to approximately 4.0 mills/kWhe, assuming a 15% fixed charge rate for 20 years and a capacity factor of 75-80%. For Oconee, using its 1995-1997 operating data, this would result in a total generation going forward cost of about 21 mills/ kWhe. This compares favorably with a market clearing price of 2.5 cents/kWh (25 mills). As indicated in Table E-3.2, a large number of plants would be economically competitive when a 4 mill/kWh relicensing charge is added to their average 1995-97 operating costs.

Table E-3.2
U.S. NPP OPERATING COSTS, 1995-97

		1997		Average, 1995-97	
UTILITY	PLANT	Net MWh	CAPACITY FACTOR (%)	PRODUCTION COSTS ($)	Mills/ kWh
Virgina Power	North Anna	14,992,315	95.61	157,953,260	11.36
Southern NOC	Vogtle	18,580,935	91.27	221,984,203	12.17
Virgina Power	Surry	12,091,744	86.16	164,856,343	13.63
Commonwealth Edison	Braidwood	16,331,078	83.23	220,956,098	13.93
Commonwealth Edison	Byron	16,264,616	84.01	218,382,072	14.33
PECO Energy	Limerick	17,534,940	89.04	241,278,302	14.33
TVA	Sequoyah	17,092,109	85.05	236,734,047	14.52
Arizona Public Service	Palo Verde	29,514,200	90.25	418,087,537	14.75
South Carolina E&G	Summer	7,253,069	87.34	108,649,156	14.85
Northern States Power	Prairie Island	7,162,437	79.77	117,679,078	14.91
Entergy Operations	Arkansas Nuclear I	14,208,157	95.75	199,343,997	15.18
Houston L&P	South Texas	19,846,127	90.58	302,498,674	15.21
Union Electric	Callaway	8,954,604	90.86	133,166,472	15.36
Duke Power	Catawba	17,766,777	89.82	257,072,285	15.44
TVA	Browns Ferry-2,-3	17,282,973	92.63	207,102,361	16.11
Duke Power	McGuire	13,650,071	69.01	252,492,052	16.11
Carolina P&L	Robinson - 2	6,197,588	104	89,765,531	16.23
Wolf Creek NOC	Wolf Creek	8,430,455	82.75	142,868,134	16.34
Texas Utilities	Comanche Peak	17,536,122	87.04	271,810,283	16.49
Northern States Power	Monticello	3,656,745	76.81	67,450,572	16.63
Carolina P&L	Brunswick	12,912,405	96.91	197,189,877	16.64
Entergy Operations	Grand Gulf	10,817,079	102.90	153,298,111	16.64
Pennsylvania P&L	Susquehanna	16,809,563	87.86	274,393,246	16.72
Carolina P&L	Shearon-Harris	59,002,566	78.32	106,855,326	17.17
Baltimore G&E	Calvert Cliffs	13,133,441	86.41	218,920,852	17.24
Southern NOC	Farley	14,700,404	88.19	209,531,512	17.28
Duke Power	Oconee	13,698,065	61.61	279,607,754	17.42
North Atlantic Energy	Seabrook	7,945,705	78.33	149,681,636	17.49
Niagra Mohawk Power	Nine Mile Point - 2	8,863,272	91.53	145,073,726	17.72
Florida P&L	Turkey Point	10,692,395	88.07	197,040,712	18.13
Pacific G&E	Diablo Canyon	17,070,798	90.22	303,511,991	18.19
WPPSS	WNP-2	6,965,278	71.83	130,913,388	18.21
Florida P&L	St. Lucie	12,218,065	83.12	220,619,121	18.86
IM Power	Cook	10,421,482	57.75	250,816,229	18.92
Entergy Operations	Waterford-3	6,708,783	71.24	145,154,330	18.92
PECO Energy	Peach Bottom	17,024,244	88.90	321,292,190	19.08
Southern NOC	Hatch	12,042,579	84.96	230,741,606	19.12
Toledo Edison	Davis-Besse	7,176,303	93.84	135,790,423	19.16
Commonwealth Edison	Zion	1,079,324	5.92	244,690,934	19.37
Wisconsin Public Serv.	Kewaunee	2,363,803	52.81	59,725,117	19.57
GPU Nuclear	Three Mile Island-1	5,918,770	85.96	126,874,899	19.68
Consumers Power	Palisades	5,776,398	90.33	107,985,568	20.52
Duquesne Light	Beaver Valley	10,201,478	71.44	226,883,764	21.09
N.Y. Power Authority	FitzPatrick	6,624,580	94.69	117,010,667	21.34
Rochester G&E	Ginna	3,891,660	92.55	76,326,249	22.31
Commonwealth Edison	LaSalle	0	0	240,825,140	22.33

Table E-3.2
U.S. NPP OPERATING COSTS, 1995-97 (cont'd.)

		1997		Average, 1995-97	
UTILITY	PLANT	Net MWh	CAPACITY FACTOR (%)	PRODUCTION COSTS ($)	MILLS/ kWh
Nebraska PPD	Cooper	5,455,697	81.52	115,351,602	22.51
Entergy Operations	River Bend	6,822,661	83.21	163,715,312	22.72
Southern Cal Edison	San Onofre	13,437,389	71.35	334,736,076	22.80
Vermont Yankee	Vermont Yankee	4,266,866	95.51	93,896,573	23.70
Public Service E&G	Hope Creek	6,385,163	70.7	158,946,771	23.73
Iowa Electric L&P	Duane Arnold	4,149,109	91.09	93,642,768	23.90
CEI	Perry	8,099,049	79.70	203,226,981	24.69
Niagra Mohawk Power	Nine Mile Point - 1	2,698,574	54.52	91,525,436	24.75
Illinois Power	Clinton	0	0	140,295,594	25.87
GPU Nuclear	Oyster Creek	5,073,283	93.56	131,271,528	27.13
Commonwealth Edison	Quad Cities	8,193,198	60.81	220,853,931	28.30
Boston Edison	Pilgrim	4,310,431	73.44	133,292,588	28.65
Omaha PPD	Fort Calhoun	3,813,166	91.07	104,944,324	30.84
Florida Power Corp.	Crystal River-3	0	0	151,985,908	32.55
Detroit Edison	Fermi	5,523,020	57.42	167,595,699	32.98
Wisconsin Elec. Power	Point Beach	1,637,509	19.27	109,723,598	33.68
Consoidated Edison	Indian Point-2	3,140,007	37.69	161,055,817	36.60
Commonwealth Edison	Dresden	9,616,912	84.01	232,650,004	44.75
N.Y. Power Authority	Indian Point-3	4,337,341	51.31	162,326,333	52.98
Northeast Utilities	Millstone-3	0	0	217,920,972	55.04
Consumers Energy	Big Rock Point	193,708	50.19	23,948,514	76.17
Public Service E&G	Salem	2,418,384	12.48	345,132,905	98.08
Northeast Utilities	Millstone-1,-2	0	0	110,052,428	179.34
Maine Yankee APC	Main Yankee	0	0	110,052,428	312.96
TVA	Watts Bar-1	7,632,501	75.50		
SUM		**630,507,470**			
AVERAGE		**8,880,387**	**71.38**		**29.60**

Source: McGraw Hill, Utility Data Institute, FERC Form 1, DOE/EIA Form 412, as reported in Nucleonics Week, June 18, 1998.

Note: The average license renewal cost of $180 million per GWe (with steam generator replacement) is representative for two-unit or multi-unit PWR stations, which comprise the majority of NPP stations. Approximately two-thirds (70 NPPs) of U.S. reactors are PWRs (see Table E-3.1). There are 24 two-unit and 2 three-unit PWR stations; approximately three-quarters of the domestic PWR reactor fleet. There are also 16 single reactor PWR stations. License renewal costs for single PWR reactor stations could be higher, by perhaps as much as 25%.

Table E-3.3 STEAM GENERATORS REPLACED at U.S. NUCLEAR PLANTS					
UTILITY	**PLANT**	**Operational Years**	**Cost ($M)**	**Outage (days)**	**Year Replaced**
Virginia Power	Surry 2	7	94	260	1979
Virginia Power	Surry 1	8	94	200	1981
FPL Group	Turkey Point 3	10	90	210	1981
FPL Group	Turkey Point 4	9	90	150	1982
Wisconsin Electric	Point Beach 1	13	47	118	1983
Carolina Power & Light	Robinson	13	85	130	1984
AEP	Cook 2	11	115	175	1988
New York Power Auth.	Indian Point 3	13	120	140	1989
CMS Energy	Palisades	19	100	121	1990
Northeast Utilities	Millstone	17	190	192	1992
Virginia Power	North Anna 1	15	114	68	1995
Duke Power	Catawba 1	11	153	115	1996
Rochester Gas & Elec.	Ginna	25	108	70	1996
Wisconsin Electric	Point Beach 2	24	90	N/A	1997

E-3.3.3 Steam Generator Replacement: Experience and Cost

All PWRs use steam generators to produce the steam that drives the plant s turbines to produce electricity. Water heated by the plant s fuel— the primary water —flows into thousands of tubes (4,000-15,000 depending on the design) in the steam generator under high pressure, so it does not boil. Heat is transferred from the primary water through the tube walls to water inside the steam generator. This secondary water , which does not have direct contact with the fuel, boils to create steam to drive the plant s turbine.

These steam generator tubes are susceptible to degradation from corrosion, cracking, fatigue and wear. Severely damaged tubes are either repaired or taken out of service. If enough tubes are damaged, a steam generator may have to be replaced. Replacement, although the most expensive and complex solution, is an economical option in the longer term, when required. Table E-3.3 tabulates the steam generators replaced at U.S. NPPs as of 1997. The costs range from $90-190 million for two steam generators. Total costs vary depending on plant size and number of steam generators replaced. Table E-3.4 identifies those NPPs with plans for steam generator replacement (as of May 1998).

In 1992, Wisconsin Electric Power Company (WEPCo), in hearings before the Wisconsin Public Service Commission, presented an estimate of $119 million as the cost to replace the steam generators (in 1996) at Point Beach Unit-2, a 485 MWe Westinghouse PWR. Point Beach is a two-loop, closed cycle, PWR; hence, it has two steam generators. If this cost is compared with the $170 million per GWe steam generator replacement cost calculated above, an equivalent cost of approximately $200 million is obtained. This cost reflects an increase of 18% for the relatively small, 485 MWe Point Beach unit over the average (for a 1 GWe unit); it also neglects inflation since 1994.

Table E-3.4 PLANNED STEAM GENERATOR REPLACEMENTS			
UTILITY	**PLANT**	**Net Capacity (MW)**	**Projected Year of Replacement**
Duke	McGuire 1	1129	1997 (completed)
Duke	McGuire 2	1129	1997 (completed)
Unicom	Byron 1	1120	1998 (completed)
Florida P&L	St. Lucie 1	839	1998 (completed)
Unicom	Braidwood	1120	1998
Entergy	ANO 2	850	2000
AEP	Cook 1	1020	2000
Southern Company	Farley 1 & 2	1720	2000
Houston P & L	S. Texas Proj. 1	1251	2000
BG&E	Calvert Cliffs 1	850	2000
BG&E	Calvert Cliffs 2	850	2000

WEPCo estimated that the generator change-out would take 113 days, 71 days longer than the normal refueling outage during which it was to occur. In 1994, the lead time for steam generator fabrication was assumed to be 36 months. At that time it was estimated that 117 steam generators in one- and two-loop reactors would be replaced between 1995 and 2000.

When Commonwealth Edison s 25-year old 1,040 MWe Zion-1 and Zion-2 units were permanently shutdown in February 1997 and November 1996, respectively, the estimated $400 million cost to replace the plant s steam generators was a key factor, among others.

While BWRs do not have steam generators that may need to be changed out, they will undoubtedly have ancillary equipment in need of replacement or refurbishment in order to qualify for license renewal. The only publicly-available data on BWR license renewal and refurbishment costs have been published by the NRC. In a 1996 Generic Environmental Impact Statement (NUREG-1437), NRC estimated typical incremental costs associated with license renewal as $90 and $110 million for PWRs and BWRs, respectively. These incremental costs cover additional labor, waste disposal, capital, and off-site engineering and administrative support. Although these costs may be incurred over the remaining life of the plant, more than half may be incurred in the first few years after a renewed license is issued.

The NRC notes that the incremental costs associated with license renewal will amount to an increase of less than 5% in annualized expenditures for non-fuel O&M and capital additions. These costs are considerably less than those experienced where steam generators have to be replaced. However, they are in line with the statements by the Nuclear Energy Institute (NEI) that license renewal costs will be in the range of $10-50/kWhe.

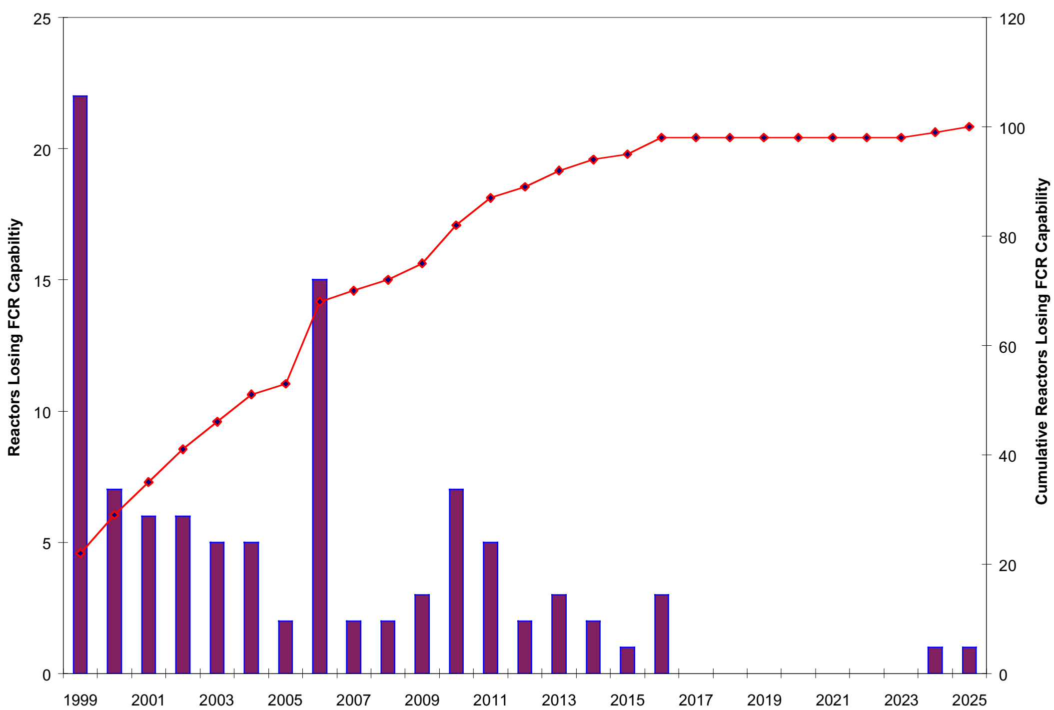
E-3.4. STORAGE AND DISPOSAL OF SPENT NUCLEAR FUEL

This section analyzes the implications of the spent fuel storage and disposal issues on the future operation of nuclear power plants in the U.S. The analysis includes impacts on 1) U.S. nuclear power plants during the term of original operating licenses, 2) following plant shutdown upon expiration of the original license, and 3) for continued operation after expiration of the original license.

E-3.4.1 On-Site Spent Fuel Storage

U.S. utilities are running out of storage capacity in their on-site spent nuclear fuel (SNF) storage pools. Although there are a number of U.S. utilities that can still gain storage capacity through re-racking the storage pools, the majority of U.S. utilities have exhausted the ability to re-rack leaving dry storage as the remaining avenue for these utilities to increase on-site SNF storage capacity. Figure E-3.2 provides a projection of the annual and cumulative number of U.S. nuclear power plants that lose the ability to discharge a full-core of fuel into their SNF storage pools each year, resulting in the need to add additional storage capacity. This projection is based on information supplied by utilities to the U.S. Nuclear Regulatory Commission (NRC) during 1998.[6]

Fig. E-3.2 Nuclear Power Plants Losing Full Core Discharge Capability



A significant need for additional on-site storage capacity outside the SNF storage pool already exists in the U.S. As of December 1998, approximately 18 nuclear power plants at 10 sites have added storage capacity equivalent to 1,300 metric tons of uranium (MTU) using dry storage technologies. By 2010, the earliest date that the U.S. Department of Energy (DOE) projects a permanent repository to become available, 82 nuclear power plants at 52 sites will have to add approximately 10,000 MTU of dry cast storage capacity. Figure E-3.3 presents the locations of additional twelve ISFSIs in the U.S. In addition, utilities have announces firm plans to construct an additional twelve ISFSIs during the next several years, and at least another six utilities are in the planning stages of developing on-site dry storage facilities that are planned to be operational in the 2005 time frame.

E-3.4.2 U.S. DOE Civilian Radioactive Waste Management

The Nuclear Waste Policy Act of 1982 (NWPA) and its amendments created a process and a set of milestones by which DOE would select and characterize potential sites for geologic repositories and begin development of the first repository. The NWPA established the Office of Civilian Radioactive Waste Management (OCRWM) within DOE to carry out the federal waste management program.

The NWPA also provided that DOE contract with utilities and others to dispose of civilian SNF and high-level radioactive waste (HLW) beginning not later than January 31, 1998. This contract requires utilities to pay 1 mill per kilowatt-hour-electric (kWhe) sold into a fund established in the Federal treasury the Nuclear Waste Fund (NWF) in order to cover the costs of disposal of SNF from commercial nuclear power plants. As of December 31, 1998, $15.3 billion in nuclear waste fees have been collected through utility rates, including interest earned on the balance of the NWF and utility fees collected but not yet paid into the NWF.

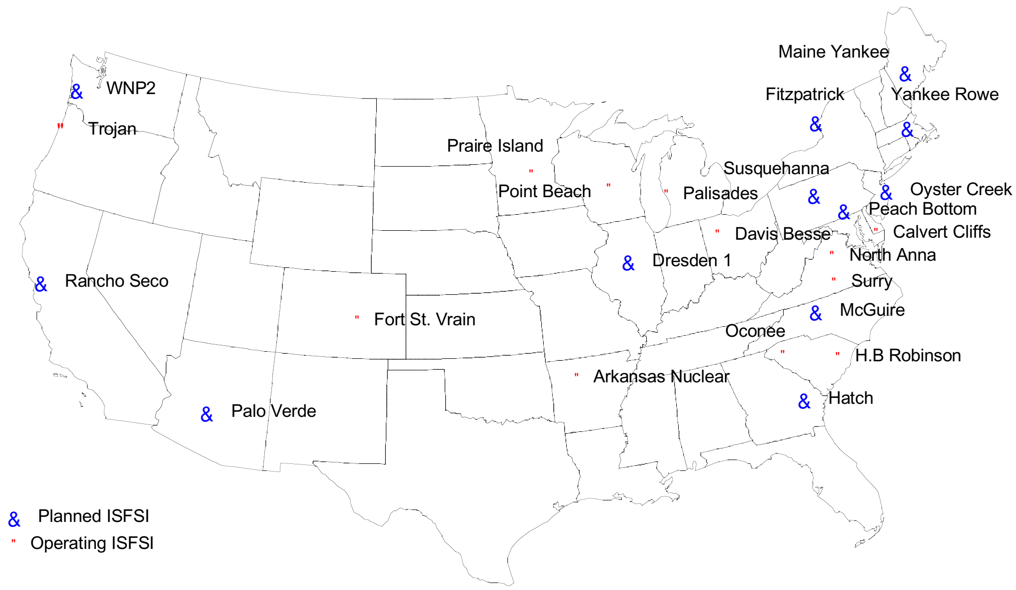
Historically, the 1 mill per kWhe nuclear waste fee had been passed on to electricity customers through rate bases. The fees are retained in the NWF and any fees received in excess of annual funding requirements are invested in U.S. Treasury obligations and earn interest at prevailing rates. The fees plus interest earned must cover the costs of civilian radioactive waste management activities that extend far beyond the operating life of current nuclear power plants.

DOE is required to perform an annual assessment of the adequacy of the nuclear waste fee. The most recent issued assessment *Nuclear Waste Fund Fee Adequacy: An Assessment,* (DOE/RW-0509; December 1998) found that the current 1 mill per kWhe fee is adequate. Moreover, it determined that the NWF is projected to have a $10 billion balance (constant 1998 dollars) at the end of waste emplacement activities, based on current program cost estimated, fee revenue projections, and projections of inflation and interest rates. According to DOE, this balance is more than sufficient to cover long-term monitoring, closure and decommissioning activities. In fact, when one considers the current NWF balance, estimated future fee collections and projected interest earnings, there should be sufficient monies to build an interim storage facility to begin accepting SNF from commercial reactors as part of an integrated waste management system.

However, it should be noted that while the current NWF balance is more than $8 billion, due to Congressional budget caps and the way in which the federal budget is structured, DOE does not have ready access to the NWF balance or the increased annual appropriations needed to ensure that an operational repository is available by 2010. This funding problem would be even greater if an interim storage facility were authorized by Congress. Congress must provide access to the NWF balance and ensure that future payments into the NWF are not used to offset other federal spending in the long-term federal waste management system is to be successful.

Without a central interim storage facility as part of an integrated waste management system, nuclear power plant operators must rely on the uncertain repository schedule for the removal of SNF from nuclear power plant sites. DOE projects that the earliest a repository will be in operation is 2010. A 2010 repository is considered to be highly optimistic given that the repository program is a first-of-a-kind scientific, engineering and licensing effort and there is likely to be a drawn out licensing process that includes intervention by the State of Nevada and others. In contrast, central interim storage would be based on a proven regulatory process and on proven dry storage technologies that have been used at U.S. nuclear power plants since 1986. The integration of an interim storage facility in the federal waste management system would curtail the need for dry storage facilities at the majority

Fig. E-3.3 Operating and Planned ISFSIs in the United States



of reactor sites as discussed in Section E-3.4.1. It would also limit the amount of time that SNF remains at reactor sites after the nuclear power plants shut down for decommissioning.

E-3.4.3 State Role in On-Site Storage Decisions

Several states have played key roles in on-site SNF storage decisions made by utilities in their jurisdictions. The Public Utilities Commissions (PUC) and State Attorneys General in the States of Minnesota, Michigan, and Wisconsin have been particularly active in on-site SNF storage issues. Many states have enacted statutes or regulations applicable to the storage of SNF at nuclear power plant sites. State statutes regarding SNF storage and disposal cover a wide range of alternatives including: a prohibition on in-state storage of SNF, restrictions on storage of SNF generated in another state, requirements for state approval of storage facilities, restrictions on the disposal of SNF within the state, and the need for state certification before constructing a facility related to the generation of electricity. As more and more nuclear power plants need to add additional storage capacity, either through dry storage of SNF pool re-racking, it is expected that additional states will use state statutes to oppose increased on-site SNF storage capacity.

E-3.4.4 Implications for Operation of Nuclear Power Plants

The impacts of continued at-reactor SNF storage in lieu of centralized storage on U.S. nuclear power plants will be analyzed for three situations: (1) impacts during the term of original plant licensed, (2) impacts following plant shutdown upon expiration of original licenses, and (3) impacts on plant license renewal.

E-3.4.4.1 Impact During Term of Original Plant License

Nuclear power plants in states that have passed regulations requiring state approval of additional SNF storage capacity are likely to experience delays and possible restrictions related to adding dry storage facilities or even re-racking SNF storage pools that could result in early plant shutdown. The situations in Minnesota and Wisconsin are illustrative of the expectations in this regard.

For example, in 1991, Northern States Power Company (NSP) applied to the Minnesota Public Utilities Commission for a Certificate-of-Need to build a dry storage facility at Prairie Island. The application for a Certificate of Need was referred to an administrative law judge due to a contested hearing. The State of Minnesota has allowed NSP to build only enough dry storage capacity to continue operation of the Prairie Island plant until 2007. Its operating license expires in 2013 for Unit 1 and 2014 for Unit 2. The State of Wisconsin also requires a Certificate-of-Need to add additional storage capacity for SNF. In reviewing the Wisconsin Electric Power Company (WEPCO) application for a Certificate of Need, the Wisconsin Public Service Commission decided to include a full Environmental Impact Statement and public hearings as part of its review process. The Wisconsin Public Service Commission approved the use of 12 casks at Point Beach, which will allow continued operation through 2002. This capacity will not be sufficient to store SNF through the end of the Point Beach plants licenses in 2010 and 2013.

Nuclear power plants that do not have SNF capacity restrictions imposed by state agencies should be able to implement dry storage at reactor sites under existing NRC regulations. Costs for on-site storage will vary depending on the type of storage technology selected, its licensing status, nuclear power plant site topography, and the projected capacity of the dry storage facility.

One-time ISFSI upfront costs include the costs for design, engineering, licensing, equipment, construction of storage pads and security systems, and startup testing for the facility. Upfront costs are estimated to be approximately $9 million to $14 million depending on the technology s licensing status, facility size, the type of equipment required, and the site s topography. It should be noted that these upfront costs are incurred on a site basis. For example, if a reactor site has more than one nuclear power plant requiring additional storage capacity, the upfront costs would only be incurred one time for that site since only one ISFSI would be constructed to handle fuel from one or more plants.

Storage system and loading costs are the costs associated with loading fuel into the ISFSI, including the costs for transportable metal storage containers and concrete overpacks, metal casks, storage system loading, and consumables. Annual operating costs are the costs required to operate the facility that are not associated with loading fuel to dry storage. This would include NRC annual license fees, fabrication surveillance, monitoring costs, personnel costs, utilities, etc. these costs will vary depending upon whether the ISFSI is located at an operating reactor site or a shutdown reactor site. Costs for storage systems and loading are approximately $2 million to $4 million per year during reactor operation. During reactor operation, operating costs are approximately $500,000 to $700,000 annually. Thus, annual costs during operation range from $2.5 to $4.7 million.

Decommissioning costs are the costs associated with dismantling, decontaminating, and disposing of the material in the dry storage facility. Decommissioning costs are estimated to be approximately $2-4 million. These costs would be incurred after all of the SNF has been shipped offsite.

It might be illustrative to provide an example of how one might calculate dry storage costs. For a one-reactor site that loses the ability to discharge a full core of SNF into its storage pool in 2011 and with a 2018 expiration on its 40-year operating license, dry storage would be needed for 8 years during plant operation. Assume that upfront costs of $10 million would be incurred in 2011. From 2011 through 2018, assuming annual costs of $3 million would be incurred to place fuel into dry storage and operate the ISFSI, the total costs during reactor operation would be $34 million. If the license were extended for 20 years, an additional $60 million might be required if no SNF was shipped offsite by DOE during that time. However, if one assumes that a DOE repository will be operational between 2010 and 2015, additional dry storage may not be necessary during the period of license extension.

E-3.4.4.2 Impact Following Shutdown on Expiration of Original License

In addition to considering the cost of additional SNF storage at operating nuclear power plants, utilities must consider the very significant cost increases that will result for post-shutdown storage to the extent that the SNF remains at the sites for extended periods of time. These costs include security, operations and maintenance, NRC license fees, insurance, taxes, etc. Annual operations and maintenance costs to store SNF at shutdown nuclear power plants must be calculated from the time the plant shuts down for decommissioning until the last SNF leaves the plant site. Cost estimates for post-shutdown SNF storage operating and maintenance costs range from $4-to-$12 million per year per plant site, where the variance reflects the post-shutdown storage method selected. Depending upon when DOE begins SNF acceptance from nuclear power plant sites and the date of nuclear power plant shutdown, the amount of time that SNF will remain at shutdown reactors will vary.

Table E-3.5 provides a summary of the average length of time that SNF will remain at reactor sites for several SNF acceptance scenarios. As one can easily calculate, there are potentially significant savings associated with early SNF acceptance at an interim storage facility. For example, if SNF acceptance begins in 2003 at an interim storage facility, and SNF remains at a nuclear plant site for 12 years following reactor shutdown for decommissioning, the cost to store that SNF would be $96 million, assuming an annual operating cost of $8 million per year per site. If SNF acceptance is delayed until 2015 and SNF must be stored for 24 years, the cost to store that same amount of SNF would now be $192 million. Thus there is a potential savings of $96 million associated with early spent fuel acceptance under the assumptions made.

The significance of these post-shutdown storage costs is that they are part of the nuclear power plant decommissioning costs that must be collected through electricity rates while the plant is operating. Sine the DOE has not announced a date certain for the acceptance of SNF from commercial nuclear power plants, SNF could remain at reactor sites for decades. The uncertainties in decommissioning cost requirements for storing the SNF will play a role in utility decisions to continue operation of nuclear power plants in a competitive market and will affect decisions related to nuclear plant license renewal. Theses post-shutdown storage costs can be minimized by the inclusion of a central interim storage facility as part of an integrated federal waste management system and the timely removal of SNF from reactor sites by DOE.

E-3.4.4.3 Impact on Plant License Renewal

To the extent that significant uncertainty remains regarding the viability of a functional Federal waste management system, or a states unwillingness to permit expansion of on-site SNF storage capacity, there may be great reluctance on the part of electric utility companies to pursue license renewal.

Table E-3.5 Average Time SNF Remains at Nuclear Power Plant Sites Following Reactor Shutdown for Decommissioning	
Date SNF Acceptance Begins	**Average Number of Years**
2003 Interim Storage	12
2010 Repository	19
2015 Repository	24

Policy issues that must be resolved to ensure the future operation of nuclear power plants as well as the option of renewing the plant operating licenses:

- A federal policy that supports a federal interim storage facility to begin operation in the 2003 through 2005 time frame as part of an integrated federal waste management system.

- Changes to the Congressional budgeting process to allow access to the balance of the NWF and full use of annual nuclear waste fees such that the fees are not used to offset other federal spending. Fixing the funding mechanism for the waste program will allow access to the monies needed to complete a repository in the 2010 to 2015 time frame. Without such changes, a repository may never be operational.

- Working with the state governments to ensure that utilities are not prohibited from the addition of storage capacity, either through re-racking, dry storage or some other means, such that nuclear power plants can continue to operate and may renew their operating licenses for an additional 20 years.

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[1] Author: David South, Energy Resources International, Inc.

[2] For nuclear power plants, going forward costs include production costs, waste management fees (for current and long-term disposal) , and decommissioning fees (paid to the Nuclear Decommissioning Trust Fund).

[3] The cost data (Lev Cost in Columns 14 & 15) in Table E-3.1 does not include post-operational capital expenditures or the FERC-defined Administrative and General (A&G) costs that typically add 6-7 mills/kWh.

[4] These "going forward" costs represent the cost of the alternative (or the price of the output) that would result in the NPP just being economic (relative to a competitive power source, NGCC). Thus, they represent the break-even cost.

[5] This value compares with the $150/kW charge at year 30, and $250/kW charge at year 40, assumed by EIA in AEO99.

[6] "*Reactor Spent Fuel Storage, Spent Fuel Pool and Full Core Offload Capability*" , U.S. Nuclear Regulatory Commission, (www.nrc.gov/OPA/drycask/sfdata.htm).