Entergy

Entergy Operations, Inc.
1340 Echelon Parkway
Jackson, Mississippi 39213-8298
Tel 601-368-5758

F. G. Burford
Acting Director
Nuclear Safety & Licensing

CNRO-2005-00022

March 31, 2005

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
11555 Rockville Pike
Rockville, MD 20852-2738
(301) 415-7000

SUBJECT: Entergy Operations, Inc
Status of Decommissioning Funding Report

River Bend Station
Docket No. 50-458
License No. NPF-47

Grand Gulf Nuclear Station
Docket No. 50-416
License No. NPF-29

Arkansas Nuclear One
Units 1 & 2
Docket Nos. 50-313 & 50-368
License Nos. DPR-51 & NPF-6

Waterford 3 Steam Electric Station
Docket No. 50-382
License No. NPF-38

Dear Sir or Madam:

On behalf of the captioned reactor licensees, Entergy Operations, Inc. ("EOI"), submits documentation in accordance with the biennial reporting requirements contained in 10 CFR Section 50.75(f). In accordance with these requirements, EOI provides reports on the status of its decommissioning funding at least once every two years from this date.

Since EOI's last biennial report, the Louisiana Public Service Commission has ordered that the decommissioning collections for River Bend be based on an assumption that the operating license and the useful life of River Bend will be extended. This results in a collection rate of zero dollars per year for decommissioning for the Louisiana regulated share of River Bend. As EOI noted in its last biennial report, the Arkansas Public Service Commission took a similar action for the Arkansas Nuclear One plant.

This submittal contains no new commitments.

Rec'd With
Poor quality pages
in Enclosure A001

Please address any comments or questions regarding this matter to Mr. L. A. England at 601-368-5766.

Sincerely,

FGB/LAE/baa

Attachments:

1. ANO Report
2. GGNS Report
3. RBS Report – 70% Regulated; 30% Non-Regulated
4. WF3 Report

cc: (All Below w/o Attachments – See File Copy for Attachments)
Mr. T. A. Burke (M-ECH-62)
Mr. W. R. Campbell (M-ECH-65)
Mr. J. P. DeRoy (M-ECH-579)
Mr. W. A. Eaton (M-ECH-3X)
Mr. J. S. Forbes (N-GSB-46)
Mr. P. D. Hinnenkamp (R-GSB-40)
Mr. J. R. McGaha (M-ECH-65)
Mr. N. S. Reynolds (W&S)
Mr. L. Jager Smith (Wise, Carter)
Mr. G. J. Taylor (M-ECH-65)
Mr. J. E. Venable (W-GSB-300)
Mr. G. A. Williams (G-ESC3-VPO)

Mr. T. W. Alexion, Project Manager, ANO
Mr. D. G. Holland, Project Manager, ANO-2
Mr. N. Kalyanam, Project Manager, W-3
Dr. B. S. Mallett, Regional Administrator, Region IV
Mr. B. K. Vaidya, Project Manager, GGNS
Mr. M. K. Webb, Project Manager, RBS

Report on Status of Decommissioning Funding
Required by 10 CFR 50.75(f)(1)
March 31, 2005

Arkansas Nuclear One - Units 1 and 2

Minimum Reporting Requirements as per 10 CFR 50.75(f)(1):

1. Decommissioning funds estimated pursuant to 10 CFR 50.75(b) and (c) (2004$):		
Arkansas Nuclear One - Unit 1:		$ 542,535,478 [1]
Arkansas Nuclear One - Unit 2:		$ 554,597,998 [1]
Total		$ 1,097,133,476
2. Market value of funds accumulated as of December 31, 2004:		
Arkansas Nuclear One - Unit 1:		$ 214,604,834 [2]
Arkansas Nuclear One - Unit 2:		$ 176,359,981 [2]
Total		$ 390,964,815
3. Current schedule of annual amounts remaining to be collected:		See Attachment 1-C [4]
4. Assumed rate of decommissioning cost escalation used in funding projections (Attachment 1-C):		CPI
5. Assumed average after-tax rates of earnings used in funding projections:	Unit 1	6.18% [5]
	Unit 2	6.53% [5]
6. Assumed rates of other factors used in funding projections:		See Attachment 1-C [4]
7. Contracts assuring collection of decommissioning funds:		None
8. Modifications to method of providing financial assurance since March 31, 2003 filing (external sinking fund):		See Footnote 4
9. Material changes to trust agreements since March 31, 2003 filing:		See Footnote 6

Supplemental Information:

1. Site-Specific cost estimate escalated to 2004(2002 Base Year Dollars):	
Arkansas Nuclear One - Unit 1:	$ 391,163,807 [3]
Arkansas Nuclear One - Unit 2:	$ 385,462,170 [3]
Total	$ 776,625,977
2. Decommissioning method assumed for planning purposes in site-specific estimate:	DECON [7]
3. Year site-specific estimate complete:	2003
4. Frequency of updates (approximately):	once every 5 years
5. Funding based on NRC minimum or site-specific estimate?:	Site-specific
6. Decommissioning rate regulation (approximately):	
Arkansas Public Service Commission	86%
Federal Energy Regulatory Commission	14%

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[1] See Attachment 1-A calculations.

[2] Source: December 31, 2004 ANO Trust Fund Reports.

[3] See Attachment 1-B for calculations. Also see footnotes 4 and 5 to Attachment 1-A for information on the generic baseline cost estimate using the waste vendor disposal factor (Barnwell).

[4] On October 3, 2000, the APSC ordered Entergy Arkansas to reflect a 20 yr. life extension in its determination of the ANO1 and ANO2 decommissioning revenue requirements for rates to be effective January 1, 2001. The amount of decommissioning costs collected in rates for ANO was set to zero as a result of the APSC order. See Attachment 1-C.

[5] Assumed weighted average after-tax earnings rate for the non-qualified and tax qualified decommissioning funds for the period 2005-2045 for Unit 1 and 2005-2026 for Unit 2 (Docket 87-166-TF Orders No. 27, 32 and 41).

[6] The following section was added to all trust agreements on December 17, 2003:
Notice Regarding Disbursements or Payments. *Notwithstanding anything to the contrary in this Agreement, except for (i) payments of* ordinary administrative costs (including taxes) and other incidental expenses of the Trust Fund (including legal, accounting, actuarial, and Successor Trustee expenses) in connection with the operation of the Trust Fund, (ii) withdrawals being made under 10 CFR 50.82(a)(8), and (iii) transfers between Qualified and Nonqualified Funds in accordance with the provisions of this Agreement, no disbursement or payment may be made from the Trust Fund until written notice of the intention to make a disbursement or payment has been given to the Director, Office of Nuclear Reactor Regulation, or the Director, Office of Nuclear Material Safety and Safeguards, as applicable, at least 30 working days before the date of the intended disbursement or payment. The disbursement or payment from the Trust Fund, if it is otherwise in compliance with the *terms and conditions of this Agreement, may be made following the 30-working day notice period if no written notice of objection from the* Director, Office of Nuclear Reactor Regulation, or the Director, Office of Nuclear Material Safety and Safeguards, as applicable, is received by the Successor Trustee or the Company within the notice period. The required notice may be made by the Successor Trustee or on the *Successor Trustee's behalf. This Section 8.04 is intended to qualify each and every provision of this Trust Agreement allowing distributions* from the Trust Fund, and in the event of any conflict between any such provision and this Section, this Section shall control.

[7] Unit 2 will be in SAFSTOR until Unit 1 shuts down, at which time DECON will be the decommissioning method used for both.

ARKANSAS NUCLEAR ONE - UNITS 1 AND 2
CALCULATION OF MINIMUM AMOUNT AS PER 10CFR 50.75 (b) AND (c)

Determination of Minimum Amount

Entergy Arkansas, Inc.: 100% ownership interest
Plant Location: Russellville, Arkansas
Reactor Type: Pressurized Water Reactor ("PWR")
ANO Unit 1 Power Level: <3,400 MWt. (2,568 MWt)
ANO Unit 1 PWR Base Year 1986$: $97,600,000
ANO Unit 2 Power Level: <3,400 MWt. (3,026 MWt)
ANO Unit 2 PWR Base Year 1986$: $99,770,000
Labor Region: South
Waste Burial Facility: Barnwell, South Carolina

10CFR50.75(c)(2) Escalation Factor Formula:
0.65(L) + 0.13(E) + 0.22(B)

	Factor
L=Labor (South)	1.925 [1]
E=Energy (PWR)	1.434 [2]
B=Waste Burial (PWR)	18.732 [3]

PWR Escalation Factor:

0.65(L) + 0.13(E) + 0.22(B) =	5.55877

1986 PWR Base Year $ Escalated:

ANO 1: $97,600,000 * Escalation Factor=	$ 542,535,478 [4]
ANO 2: $99,770,000 * Escalation Factor=	$ 554,597,998 [5]
Total ANO Units 1 and 2:	**$ 1,097,133,476**

[1] Source: Bureau of Labor Statistics: series report id ecu13202i (March 2005).
[2] Source: Bureau of Labor Statistics: series report id wpu0543 and wpu0573 (March 2005).
[3] Source: Nuclear Regulatory Commission:Table 2.1 of "Report on Waste Bunal Charges", NUREG-1307 revision 10 (October 2002).
[4] Application of the 9.467 waste vendor disposal factor (South Carolina) from Table 2.1 of "Report on Waste Burial Charges", NUREG 1307 Revision 10 (October 2002) yields a generic baseline cost = $ 343,597,398
[5] Application of the 9.467 waste vendor disposal factor (South Carolina) from Table 2.1 of "Report on Waste Burial Charges", NUREG 1307 Revision 10 (October 2002) yields a generic baseline cost = $ 351,236,807

ARKANSAS NUCLEAR ONE - UNIT 1
CALCULATION OF SITE-SPECIFIC COST ESTIMATE
ESCALATED TO 2004 DOLLARS

Site-Specific Cost Estimate (2002$)

	Unit 1	Unit 2
Site-Specific Cost Estimate (2002$):		
NRC License Termination Cost:	$ 353,840,000	$ 321,714,000
Non-NRC License Termination Cost:	$ 18,002,000 [2]	$ 44,708,000 [2]
Total Site-Specific Cost Estimate:	$ 371,842,000	$ 366,422,000
Annual Escalation Factor:	CPI [1]	CPI [1]
Years of Escalation (2002 Base Year to 2004):	2	2
Cumulative Factor :	1.0520	1.0520
Site-Specific Cost Estimate (2004$):		
NRC License Termination Cost * Cumulative Factor:	$ 372,226,379	$ 338,431,035
Non-NRC License Termination Cost: * Cumulative Factor:	$ 18,937,427	$ 47,031,135
Total Site-Specific Cost Estimate:	$ 391,163,807	$ 385,462,170

[1] Based on site-specific cost estimates in 2002$ and escalation rates tied to projections of the Consumer Price Index-Urban ("CPI") for the period from 2002 through 2004 of 5.2%.

[2] The APSC Order 41 in Docket # 87-166-TF excluded spent fuel management costs from this amount.

Entergy Arkansas, Inc.
ANO Decommissioning Model
Unit 1 Summary
($000)

Line No.	Year	Revenue Rqmt.	Non-Tax Qualified Trust Net Additions	Non-Tax Qualified Trust Trust Balance	Deferred Tax Bal.	Tax Qualified Trust Net Additions	Tax Qualified Trust Trust Balance	Decomm. Expend.[1]	Decomm. Fund Balance
1	Beginning Balance			38,856	7,830		159,359		206,045
2	2005	0	2,339	41,195	7,830	9,378	168,737	0	217,762
3	2006	0	2,489	43,684	7,830	9,983	178,720	0	230,233
4	2007	0	2,648	46,332	7,830	10,612	189,331	0	243,493
5	2008	0	2,819	49,151	7,830	11,828	201,159	0	258,140
6	2009	0	3,006	52,157	7,830	13,232	214,392	0	274,379
7	2010	0	3,207	55,364	7,830	14,126	228,518	0	291,712
8	2011	0	3,427	58,792	7,830	15,082	243,600	0	310,222
9	2012	0	3,640	62,432	7,830	16,079	259,679	0	329,941
10	2013	0	3,866	66,297	7,830	17,142	276,821	0	350,949
11	2014	0	4,106	70,403	7,830	18,275	295,096	0	373,330
12	2015	0	4,360	74,764	7,830	19,483	314,579	0	397,173
13	2016	0	4,631	79,395	7,830	20,771	335,350	0	422,575
14	2017	0	4,918	84,313	7,830	22,144	357,494	0	449,637
15	2018	0	5,224	89,537	7,830	23,607	381,101	0	478,467
16	2019	0	5,548	95,085	7,830	25,168	406,268	0	509,183
17	2020	0	5,892	100,977	7,830	26,831	433,099	0	541,906
18	2021	0	6,258	107,234	7,830	28,604	461,704	0	576,768
19	2022	0	6,646	113,880	7,830	30,495	492,199	0	613,909
20	2023	0	7,058	120,938	7,830	32,511	524,710	0	653,478
21	2024	0	7,496	128,435	7,830	34,660	559,369	0	695,634
22	2025	0	7,961	136,396	7,830	36,951	596,320	0	740,546
23	2026	0	8,455	144,852	7,830	39,393	635,713	0	788,394
24	2027	0	8,980	153,832	7,830	41,997	677,709	0	839,371
25	2028	0	9,537	163,369	7,830	44,772	722,482	0	893,681
26	2029	0	10,129	173,498	7,830	47,732	770,214	0	951,542
27	2030	0	10,758	184,256	7,830	50,887	821,100	0	1,013,187
28	2031	0	11,425	195,682	7,830	54,250	875,351	0	1,078,862
29	2032	0	11,630	207,312	7,830	56,210	931,560	0	1,146,702
30	2033	0	11,491	218,803	7,830	56,076	987,637	0	1,214,269
31	2034	0	11,207	185,275	0	55,694	1,043,331	52,565	1,228,605
32	2035	0	9,090	37,961	0	56,799	1,100,130	156,404	1,138,091
33	2036	0	1,868	0	0	60,232	994,927	205,264	994,927
34	2037	0	0	0	0	54,470	896,855	152,542	896,855
35	2038	0	0	0	0	49,559	861,839	84,574	861,839
36	2039	0	0	0	0	48,420	824,021	86,238	824,021
37	2040	0	0	0	0	46,633	812,678	57,976	812,678
38	2041	0	0	0	0	47,412	823,764	36,325	823,764
39	2042	0	0	0	0	48,144	845,432	26,476	845,432

Notes:
[1] Funding amounts are based on site-specific cost estimates in 2002$ (see Attachment 1-B).

Miscellaneous Input Data

Nuclear Cost Escalator	CPIU	Composite Tax Rate	39.35%
		TQ Fund Federal Tax Rate	20.00%

Entergy Arkansas, Inc.
ANO Decommissioning Model
Unit 2 Summary
($000)

			Non-Tax Qualified Trust		Deferred	Tax Qualified Trust			Decomm.
Line		Revenue	Net	Trust	Tax	Net	Trust	Decomm.	Fund
No	Year	Rqmt.	Additions	Balance	Bal.	Additions	Balance	Expend.[1]	Balance
1	Beginning Balance			15,880	4,240		147,936		168,056
2	2005	0	951	16,831	4,240	8,948	156,884	0	177,955
3	2006	0	1,012	17,843	4,240	9,522	166,406	0	188,489
4	2007	0	1,077	18,920	4,240	10,153	176,559	0	199,719
5	2008	0	1,146	20,066	4,240	11,265	187,824	0	212,131
6	2009	0	1,223	21,289	4,240	12,528	200,353	0	225,882
7	2010	0	1,304	22,593	4,240	13,407	213,759	0	240,593
8	2011	0	1,394	23,987	4,240	14,328	228,087	0	256,314
9	2012	0	1,488	25,475	4,240	15,360	243,447	0	273,162
10	2013	0	1,591	27,065	4,240	16,421	259,868	0	291,174
11	2014	0	1,699	28,765	4,240	17,664	277,533	0	310,537
12	2015	0	1,818	30,583	4,240	19,068	296,600	0	331,423
13	2016	0	1,934	32,517	4,240	20,379	316,979	0	353,736
14	2017	0	2,057	34,573	4,240	21,781	338,760	0	377,573
15	2018	0	2,187	21,588	0	23,279	362,039	19,412	383,627
16	2019	0	1,363	0	0	24,880	346,387	63,482	346,387
17	2020	0	0	0	0	23,804	365,357	4,834	365,357
18	2021	0	0	0	0	25,108	390,465	0	390,465
19	2022	0	0	0	0	26,835	417,301	0	417,301
20	2023	0	0	0	0	28,681	445,982	0	445,982
21	2024	0	0	0	0	30,654	476,636	0	476,636
22	2025	0	0	0	0	32,762	509,398	0	509,398
23	2026	0	0	0	0	35,016	544,414	0	544,414
24	2027	0	0	0	0	37,424	581,839	0	581,839
25	2028	0	0	0	0	39,999	621,838	0	621,838
26	2029	0	0	0	0	42,750	664,588	0	664,588
27	2030	0	0	0	0	45,690	710,278	0	710,278
28	2031	0	0	0	0	48,833	759,111	0	759,111
29	2032	0	0	0	0	52,192	811,303	0	811,303
30	2033	0	0	0	0	55,782	867,085	0	867,085
31	2034	0	0	0	0	59,619	926,704	0	926,704
32	2035	0	0	0	0	63,720	990,423	0	990,423
33	2036	0	0	0	0	66,260	1,031,658	25,026	1,031,658
34	2037	0	0	0	0	64,123	1,030,524	65,257	1,030,524
35	2038	0	0	0	0	59,491	888,477	201,538	888,477
36	2039	0	0	0	0	49,917	712,212	226,182	712,212
37	2040	0	0	0	0	40,303	651,181	101,334	651,181
38	2041	0	0	0	0	37,986	617,480	71,686	617,480
39	2042	0	0	0	0	36,082	605,902	47,661	605,902

Notes:
[1] Funding amounts are based on site-specific cost estimates in 2002$ (see Attachment 1-B).

Report on Status of Decommissioning Funding
Required by 10 CFR 50.75(f)(1)
March 31, 2005

Grand Gulf Nuclear Station

Minimum Reporting Requirements as per 10 CFR 50.75(f)(1):

1. Decommissioning funds estimated pursuant to 10 CFR 50.75(b) and (c) (2004$):	
System Energy Resources, Inc. ("System Energy") 90% ownership/leasehold interest:	$ 621,417,825 [1]
South Mississippi Electric Power Association ("SMEPA") 10% ownership interest:	$ 69,046,425 [1]
Total	$ 690,464,250
2. Market value of funds accumulated as of December 31, 2004:	
System Energy 90% ownership/leasehold interest:	$ 210,036,129 [2]
SMEPA 10% ownership interest:	$ 15,055,000 [2]
Total	$ 225,091,129
3. Current schedule of annual amounts remaining to be collected:	
System Energy 90% ownership/leasehold interest:	See Attachment 2-C
SMEPA 10% ownership interest:	See Attachment 2-D
4. Assumed rate of decommissioning cost escalation used in funding projections (Attachment 2-C):	
System Energy 90% ownership/leasehold interest:	5.50%
SMEPA 10% ownership interest:	4.00%
5. Assumed average after-tax rates of earnings used in funding projections:	
System Energy 90% ownership/leasehold interest:	6.74% [5]
SMEPA 10% ownership interest:	See Attachment 2-D
6. Assumed rates of other factors used in funding projections:	
System Energy 90% ownership/leasehold interest:	See Attachment 2-C
SMEPA 10% ownership interest:	See Attachment 2-D
7. Contracts assuring collection of decommissioning funds:	See Attachment 2-E&F
8. Modifications to method of providing financial assurance since March 31, 2003 filing (external sinking fund):	None
9. Material changes to trust agreements since March 31, 2003 filing:	
System Energy 90% ownership/leasehold interest:	See Footnote 6
SMEPA 10% ownership interest:	None

Supplemental Information:

1. Site-Specific cost estimate escalated to 2004 (1993 Base Year Dollars):	
System Energy 90% ownership/leasehold interest:	
NRC License Termination Cost:	$ 587,194,158 [3]
Non-NRC License Termination Cost:	$ 27,508,897 [3]
Total	$ 614,703,054
SMEPA 10% ownership interest:	
NRC License Termination Cost:	$ 55,735,114 [3]
Non-NRC License Termination Cost:	$ 2,611,081 [3]
Total	$ 58,346,195
2. Decommissioning method assumed for planning purposes in site-specific estimate:	DECON

Report on Status of Decommissioning Funding
Required by 10 CFR 50.75(f)(1)
March 31, 2005

Grand Gulf Nuclear Station

3. Year site-specific estimate complete:	1994 [4]
4. Frequency of updates (approximately):	once every 5 years [4]
5. Funding based on NRC minimum or site-specific estimate?:	Site-specific
6. Decommissioning rate regulation:	
System Energy 90% ownership/leasehold interest (Federal Energy Regulatory Commission):	100%
SMEPA 10% ownership interest (Rural Utilities Service):	100%

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[1] See Attachment 2-A for calculation.

[2] Source: December 31, 2004 Grand Gulf Trust Fund Reports.

[3] See Attachment 2-B for calculations. Also see footnotes 4 and 5 to Attachment 2-A for information on the generic baseline cost estimate using the waste vendor disposal factor (Barnwell, South Carolina).

[4] On July 31, 2000, the FERC issued an order approving a lower decommissioning costs than requested. In July 2001, FERC denied a request for rehearing and the July 2000 order became final. SERI made refunds in December 2001. SERI collects at the '93 cost study amount of $365.9 million less $24.8 million for reduced greenfielding cost. The 1999 cost update ($600.9 million) of $540.8 million for SERI's 90% has not yet been filed with the FERC. The 2004 cost update has not been finalized.

[5] Assumed weighted average after-tax earnings rate for the non-qualified and tax qualified decommissioning funds for the period 2004-2031 (FERC Order No. ER95 1042-000 July 2000).

[6] The following section was added to all trust agreements on December 17, 2003:
Notice Regarding Disbursements or Payments Notwithstanding anything to the contrary in this Agreement, except for (i) payments of ordinary administrative costs (including taxes) and other incidental expenses of the Trust Fund (including legal, accounting, actuarial, and Successor Trustee expenses) in connection with the operation of the Trust Fund, (ii) withdrawals being made under 10 CFR 50.82(a)(8), and (iii) transfers between Qualified and Nonqualified Funds in accordance with the provisions of this Agreement, no disbursement or payment may be made from the Trust Fund until written notice of the intention to make a disbursement or payment has been given to the Director, Office of Nuclear Reactor Regulation, or the Director, Office of Nuclear Material Safety and Safeguards, as applicable, at least 30 working days before the date of the intended disbursement or payment. The disbursement or payment from the Trust Fund, if it is otherwise in compliance with the terms and conditions of this Agreement, may be made following the 30-working day notice period if no written notice of objection from the Director, Office of Nuclear Reactor Regulation, or the Director, Office of Nuclear Material Safety and Safeguards, as applicable, is received by the Successor Trustee or the Company within the notice period. The required notice may be made by the Successor Trustee or on the Successor Trustee's behalf. This Section 8.04 is intended to qualify each and every provision of this Trust Agreement allowing distributions from the Trust Fund, and in the event of any conflict between any such provision and this Section, this Section shall control.

GRAND GULF NUCLEAR STATION
CALCULATION OF MINIMUM AMOUNT AS PER 10CFR 50.75 (b) AND (c)

Determination of Minimum Amount

System Energy Resources, Inc.: 90% ownership/leasehold interest
South Mississippi Electric Power Association ("SMEPA"): 10% ownership interest.
Plant Location: Port Gibson, Mississippi
Reactor Type: Boiling Water Reactor ("BWR")
Power Level: >3,400 MWt.
1986 BWR Base Year $: $135,000,000
Labor Region: South
Waste Burial Facility: Barnwell, South Carolina

10CFR50.75(c)(2) Escalation Factor Formula:
0.65(L) + 0.13(E) + 0.22(B)

	Factor
L=Labor (South)	1.925 [1]
E=Energy (BWR)	1.448 [2]
B=Waste Burial (BWR)	16.705 [3]

BWR Escalation Factor:
0.65(L) + 0.13(E) + 0.22(B) = 5.11455

1986 BWR Base Year $ Escalated:
$135,000,000 * Escalation Factor = $\boxed{\$\ 690{,}464{,}250}$

System Energy Interest (90%):	$ 621,417,825 [4]
SMEPA Interest (10%)	$ 69,046,425 [5]
Total	$ 690,464,250

[1] Source: Bureau of Labor Statistics: series report id ecu13202i (March 2005).
[2] Source: Bureau of Labor Statistics: series report id wpu0543 and wpu0573 (March 2005).
[3] Source: Nuclear Regulatory Commission:Table 2.1 of "Report on Waste Burial Charges", NUREG-1307revision 10(October 2002).
[4] Application of the 8.860 waste vendor disposal factor (South Carolina) from Table 2.1 of "Report on Waste Burial Charges", NUREG 1307 Revision 10 (October 2002) yields a generic baseline cost = $ 411,720,993
[5] Application of the 8.860 waste vendor disposal factor (South Carolina) from Table 2.1 of "Report on Waste Burial Charges", NUREG 1307 Revision 10 (October 2002) yields a generic baseline cost = $ 45,746,777

GRAND GULF NUCLEAR STATION
CALCULATION OF SITE-SPECIFIC COST ESTIMATE
ESCALATED TO 2004 DOLLARS

Site-Specific Cost Estimate (1993$)

	System Energy (90% Interest) [1]	SMEPA (10% Interest) [2]	Total Estimate
Site-Specific Cost Estimate (1993$):			
NRC License Termination Cost:	$ 325,840,205	$ 36,204,467	$ 362,044,672
Non-NRC License Termination Cost:	$ 15,264,976	$ 1,696,108	$ 16,961,084
Total Site-Specific Cost Estimate:	$ 341,105,180	$ 37,900,576	$ 379,005,756
Annual Escalation Factor:	5.50% [1]	4.00% [2]	-
Years of Escalation (1993 Base Year to 2004):	11	11	-
Cumulative Factor (1 + Factor)^{11}:	1.80	1.54	-
Site-Specific Cost Estimate (2004$):			
NRC License Termination Cost * Cumulative Factor:	$ 587,194,158	$ 55,735,114	$ 642,929,272
Non-NRC License Termination Cost: * Cumulative Factor	$ 27,508,897	$ 2,611,081	$ 30,119,978
Total Site-Specific Cost Estimate:	$ 614,703,054	$ 58,346,195	$ 673,049,249

[1] Funding amounts (Attachment 2-C) based on site-specific cost estimate in 1993$ (with reduced greenfielding, as shown above) and 5.50% annual escalation rate.

[2] Funding amounts (Attachment 2-D) based on site-specific cost estimate in 1993$ (with reduced greenfielding, as shown above) and 4.0% annual escalation rate.

System Energy Resources, Inc.
Grand Gulf Decommissioning Model
Owned Portion Summary
($000)

			Decommissioning Fund Balances			
Line No	Year	Revenue Rqmt.	Non-Tax Qualified (2)	Tax Qualified (2)	Total	Decomm. Expend. (1)
1	Beginning Balance		486	25,920	26,406	
2	1995	6,813	616	34,579	35,195	0
3	1996	11,195	818	48,282	49,100	0
4	1997	11,195	1,033	62,907	63,940	0
5	1998	11,195	1,261	78,517	79,778	0
6	1999	11,195	1,503	95,178	96,681	0
7	2000	11,195	1,760	112,961	114,721	0
8	2001	13,624	2,068	134,415	136,483	0
9	2002	13,624	2,395	157,314	159,710	0
10	2003	13,624	2,743	181,755	184,498	0
11	2004	13,624	3,111	207,842	210,953	0
12	2005	13,624	3,502	235,685	239,187	0
13	2006	16,590	3,961	268,423	272,385	0
14	2007	16,590	4,448	303,367	307,815	0
15	2008	16,590	4,965	340,663	345,628	0
16	2009	16,590	5,514	380,471	385,985	0
17	2010	16,590	6,097	422,959	429,055	0
18	2011	20,184	6,768	471,967	478,735	0
19	2012	20,184	7,480	524,275	531,755	0
20	2013	20,184	8,236	580,106	588,342	0
21	2014	20,184	9,038	639,696	648,734	0
22	2015	20,184	9,592	703,597	713,189	0
23	2016	24,550	10,180	776,311	786,491	0
24	2017	24,550	10,804	853,921	864,725	0
25	2018	24,550	11,467	936,757	948,224	0
26	2019	24,550	12,170	1,025,171	1,037,341	0
27	2020	24,550	12,916	1,119,538	1,132,454	0
28	2021	29,878	13,708	1,225,765	1,239,473	0
29	2022	17,429	0	1,303,048	1,303,048	37,784
30	2023	0	0	1,305,389	1,305,389	85,375
31	2024	0	0	1,140,563	1,140,563	252,699
32	2025	0	0	951,474	951,474	265,864
33	2026	0	0	732,399	732,399	283,117
34	2027	0	0	482,996	482,996	298,693
35	2028	0	0	203,197	203,197	312,296
36	2029	0	0	86,632	86,632	130,222
37	2030	0	0	6,095	6,095	86,344
38	2031	0	0	0	0	6,491

Notes:

1) Nuclear cost escalator is 5.5% per year.
2) Assumed weighted average after-tax earnings rate is:

non-tax qualified	tax qualified	
3,111	207,842	210,953
6.14%	6.75%	
0.09%	6.65%	6.74%

System Energy Resources, Inc.
Grand Gulf Decommissioning Model
Leased Portion Summary
($000)

			Decommissioning Fund Balances			
Line No	Year	Revenue Rqmt.	Non-Tax Qualified (2)	Tax Qualified (2)	Total	Decomm. Expend. (1)
1	Beginning Balance		81	4,578	4,659	
2	1995	1,208	104	6,104	6,208	0
3	1996	1,997	139	8,534	8,673	0
4	1997	1,997	177	11,123	11,300	0
5	1998	1,997	217	13,886	14,103	0
6	1999	1,997	259	16,833	17,093	0
7	2000	1,997	304	19,978	20,282	0
8	2001	2,431	359	23,774	24,133	0
9	2002	2,431	416	27,825	28,241	0
10	2003	2,431	477	32,148	32,625	0
11	2004	2,431	542	36,762	37,305	0
12	2005	2,431	611	41,688	42,298	0
13	2006	2,960	692	47,483	48,175	0
14	2007	2,960	777	53,669	54,446	0
15	2008	2,960	868	60,272	61,140	0
16	2009	2,960	965	67,319	68,284	0
17	2010	2,960	1,067	74,840	75,908	0
18	2011	3,601	1,186	83,521	84,707	0
19	2012	3,601	1,311	92,787	94,098	0
20	2013	3,601	1,444	102,676	104,120	0
21	2014	3,601	1,586	113,231	114,817	0
22	2015	2,101	1,683	123,000	124,683	0
23	2016	0	1,786	131,257	133,043	0
24	2017	0	1,895	140,069	141,964	0
25	2018	0	2,011	149,475	151,486	0
26	2019	0	2,134	159,515	161,649	0
27	2020	0	2,265	170,230	172,495	0
28	2021	0	2,403	181,667	184,070	0
29	2022	0	0	190,893	190,893	5,531
30	2023	0	0	191,222	191,222	12,499
31	2024	0	0	167,078	167,078	36,994
32	2025	0	0	139,382	139,382	38,921
33	2026	0	0	107,294	107,294	41,447
34	2027	0	0	70,766	70,766	43,727
35	2028	0	0	29,786	29,786	45,719
36	2029	0	0	12,701	12,701	19,064
37	2030	0	0	896	896	12,640
38	2031	0	0	0	0	950

Notes:

1) Nuclear cost escalator is 5.5% per year.
2) Assumed weighted average after-tax earnings rate is 6.74%.

Attachment 2-D
GGNS Report

GGDecomModROI04
1-26-05

SMEPA'S EXTERNAL TRUST FOR GRAND GULF DECOMMISSIONING

$ in 000s

Year	Updated Proforma Plan 10% ROI Cumulative EOY Market Value	Current Year Contrib'n	Current Year Earnings	Value Current Year Change	1999 Study SMEPA's 10%Liability Escalated at 4 %
1999	NA	NA	NA	NA	60,093
2000	NA	NA	NA	NA	62,497
2001	NA	NA	NA	NA	64,997
2002	NA	NA	NA	NA	67,596
2003	NA	NA	NA	NA	70,300
2004	15,055	NA	NA	15,055	73,112
2005	17,663	1,050	1,558	2,608	76,037
2006	20,532	1,050	1,819	2,869	79,078
2007	23,687	1,050	2,106	3,156	82,241
2008	27,159	1,050	2,421	3,471	85,531
2009	30,977	1,050	2,768	3,818	88,952
2010	35,177	1,050	3,150	4,200	92,510
2011	39,798	1,050	3,570	4,620	96,211
2012	44,880	1,050	4,032	5,082	100,059
2013	50,470	1,050	4,540	5,590	104,062
2014	56,620	1,050	5,100	6,150	108,224
2015	63,384	1,050	5,714	6,764	112,553
2016	70,825	1,050	6,391	7,441	117,055
2017	79,010	1,050	7,135	8,185	121,737
2018	88,014	1,050	7,954	9,004	126,607
2019	97,918	1,050	8,854	9,904	131,671
2020	108,812	1,050	9,844	10,894	136,938
2021	120,796	1,050	10,934	11,984	142,416
2022	133,978	1,050	12,132	13,182	148,112
2023	148,478	1,050	13,450	14,500	154,037
2024	164,428	1,050	14,900	15,950	160,198
		21,000	128,373	164,428	

The 2004 cumulative market value is actual value at December 31.

GGDecomModROI04
1-26-05

SYSTEM ENERGY RESOURCES, INC.
GRAND GULF POWER CHARGE FORMULA

1. GENERAL

This Grand Gulf Power Charge Formula ("PCF") sets out the procedures that shall be used to determine the monthly amounts which System Energy Resources, Inc. ("SERI") shall charge Arkansas Power & Light Company; Louisiana Power & Light Company; Mississippi Power & Light Company; and New Orleans Public Service Inc. (referred to hereafter, collectively, as "Purchasers", or, individually, as "Purchaser"), for capacity and energy from the Grand Gulf Nuclear Station ("Grand Gulf") pursuant to the Unit Power Sales Agreement ("UPSA") between SERI and the Purchasers to which this document is attached as Appendix 1. The monthly charges for capacity ("Monthly Capacity Charges") shall be determined in accordance with the provisions of Section 2 below; the monthly charges for fuel ("Monthly Fuel Charges") shall be determined in accordance with the provisions of Section 3 below. The Monthly Capacity Charges and the Monthly Fuel Charges determined in accordance with the provisions of this PCF shall be billed to the Purchasers monthly in accordance with the provisions of Section 4 below.

2. MONTHLY CAPACITY CHARGE

A. Monthly Capacity Charge Formula

The Monthly Capacity Charge Formula, as set out in Attachment A, and as applied in accordance with the procedures set out below, shall determine the Monthly Capacity Charge which SERI shall bill to each of the Purchasers.

B. ANNUAL REDETERMINATION

On or about May 1 of each year, beginning in 1996, SERI shall submit an informational filing to the Federal Energy Regulatory Commission ("FERC" or "Commission") containing a redetermination of the Monthly Capacity Charges prepared in accordance with the provisions set out in this Section 2.B. Each annual redetermination of the Monthly Capacity Charges shall reflect application of the Monthly Capacity Charge Formula set out in Attachment A to data for the twelve month period ending December 31 of the prior calendar year ("Test Year"). All data utilized in each such redetermination shall be based on actual results for the Test Year as recorded on the books of SERI in accordance with the Uniform System of Accounts, or such other documentation as may be appropriate or applicable. Each such informational filing shall include workpapers supporting the data and calculations reflected in the redetermined Monthly Capacity Charges. A copy of each such annual informational filing shall also be provided to each of the Purchasers and each of the Purchasers' retail regulators.

The FERC and the Purchasers shall then have until June 15 of the filing year to review the informational filing to ensure that it complies with the requirements of this Section 2.B. If the FERC or the Purchasers should detect an error(s) in the application of the procedure set out in this Section 2.B, such error(s) shall be formally communicated in writing to SERI on or before June 15 of the filing year. Similarly, if SERI should detect an error(s) subsequent to the submission of any annual filing, SERI shall formally notify the FERC and the Purchasers in writing of such error(s). All such indicated errors shall include documentation of the proposed correction(s). SERI shall then have until June 25 of the filing year to file corrected Monthly Capacity Charges. SERI shall provide the FERC with workpapers supporting any corrections made to the Monthly Capacity Charges initially filed on May 1 of that year. A copy of any such correcting filing shall also be provided to each of the Purchasers' retail regulators.

The Monthly Capacity Charges initially filed, or such corrected Monthly Capacity Charges as may be determined pursuant to the terms of this Section 2.B, shall, after acceptance by the FERC, become effective for bills rendered in July for service in June of the filing year. Those Monthly Capacity Charges shall then remain in effect until changed pursuant to the provisions of this PCF.

The Monthly Capacity Charges to be initially effective under this PCF shall be based on the most recently available calendar year data as of the date this PCF becomes effective. Such calendar year data shall be adjusted to reflect on an annualized basis 1) the cost and accounting changes proposed by SERI in its May 12, 1995 filing with the FERC requesting approval of this PCF and 2) the effects of the Stipulation and Agreement approved by the FERC on November 30, 1994, in FERC Docket No. FA89-28 ("1994 FERC Settlement").

C. Interim Redetermination

In the event that either the statutory state (Mississippi) or federal corporate income tax rates decrease after the annual redetermination is submitted in any year, then the Monthly Capacity Charges shall be redetermined on an interim basis to reflect such tax rate decrease. Should such state or federal income tax rates increase, then SERI may, at its sole discretion, redetermine the then effective Monthly Capacity Charges on an interim basis to reflect such tax rate increase. Should such an interim redetermination be made, all other parameters utilized in the determination of the then effective Monthly Capacity Charges shall remain unchanged. The redetermined Monthly Capacity Charges shall become effective commencing with the billing month in which the tax rate(s) change. Any such redetermination shall be submitted to the FERC in an informational filing consisting of the following:

(a) transmittal letter setting out basis for the change

(b) copy of documentation supporting the change in statutory tax rate(s)

(c) redetermination of the Monthly Capacity Charges reflecting the revised tax rate(s)

Any such interim redetermination filing shall be reviewed in the same general manner as an annual redetermination filed pursuant to Section 2.B above.

3. MONTHLY FUEL CHARGE

A. Monthly Fuel Charge Formula

The Monthly Fuel Charge Formula, as set out in Attachment B, applied in accordance with the procedures set out in Section 3.B below shall determine the Monthly Fuel Charge which SERI shall bill to each of the Purchasers.

B. Determination of Monthly Fuel Charge

Each month SERI shall determine the Monthly Fuel Charge applicable to each of the Purchasers, which amount shall be included in SERI's monthly billings to the Purchasers in accordance with the provisions of Section 4 below. The Monthly Fuel Charge to be billed to each of the Purchasers in any month shall be determined by applying the Monthly Fuel Charge Formula set out in Attachment B to fuel cost data for the immediately preceding month.

4. BILLING

SERI shall render a billing to each of the Purchasers each month for service provided during the immediately preceding month. Each such monthly billing shall reflect the Monthly Capacity Charge in effect for that Purchaser during the preceding month together with that Purchaser's Monthly Fuel Charge for the preceding month. In addition, any applicable and appropriate adjustments shall be reflected in each of the monthly billings. The monthly billings shall be submitted to the Purchasers on or before the fifth workday of each month for service provided in the preceding month and shall be payable in immediately available funds on or before the 15th day of such month. After the 15th day of such month, interest shall accrue on any balance due at the rate required for refunds rendered pursuant to FERC Regulations under the Federal Power Act. Entergy Services Inc., acting as agent for SERI and the Purchasers, may prepare the necessary billings to the Purchasers and arrange for payment in accordance with the above requirements.

5. EFFECTIVE DATE AND TERM

This PCF shall be effective for service rendered on and after September 1, 1995, or such later date as the FERC may specify, and shall continue in effect until modified or terminated in accordance with the provisions of this PCF or applicable regulations or laws.

6. FORCE MAJEURE

In addition to the rights of SERI under this PCF, or as provided by law, to make a filing for a change in rates outside the terms of this PCF, if any event or events beyond the reasonable control of SERI, including natural disaster, damage or loss of generating capacity, and orders or acts of civil or military authority, cause increased costs to SERI and result in a deficiency in revenues which is not readily capable of being redressed in a timely manner under this PCF, SERI may unilaterally file for rate or other relief outside the provisions of this PCF. Such request shall be considered by the Commission in accordance with its regulations and applicable law governing such filings.

SYSTEM ENERGY RESOURCES, INC.
MONTHLY CAPACITY CHARGE FORMULA
DETERMINATION OF MONTHLY CAPACITY CHARGES

LINE NO	DESCRIPTION	TEST YEAR AMOUNT	REFERENCE
1	CAPACITY REVENUE REQUIREMENT		Page 3, Line 1
2	MONTHLY CAPACITY CHARGE FOR AP&L		36% * Line 1 / 12
3	MONTHLY CAPACITY CHARGE FOR LP&L		14% * Line 1 / 12
4	MONTHLY CAPACITY CHARGE FOR MP&L		33% * Line 1 / 12
5	MONTHLY CAPACITY CHARGE FOR NOPSI		17% * Line 1 / 12

SYSTEM ENERGY RESOURCES, INC.
MONTHLY CAPACITY CHARGE FORMULA
DEVELOPMENT OF RATE BASE (1)

LINE NO	DESCRIPTION	TEST YEAR AMOUNT	REFERENCE
1	PLANT IN SERVICE		FERC Accounts 101, 106
2	ACCUMULATED DEPRECIATION & AMORTIZATION		FERC Accounts 108, 111 (2)
3	NET UTILITY PLANT		Line 1 Plus Line 2
4	NUCLEAR FUEL		FERC Accounts 120.2-120.4
5	AMORTIZATION OF NUCLEAR FUEL		FERC Account 120.5
6	MATERIALS & SUPPLIES		FERC Accounts 154, 163
7	PREPAYMENTS		FERC Account 165
8	DEFERRED REFUELING OUTAGE COSTS		FERC Account 174
9	ACCUMULATED DEFERRED INCOME TAXES		FERC Accounts 190, 281, 282, 283
10	RATE BASE		Sum of Lines 3 - 9

NOTES:

(1) TO BE DETERMINED AS A 13 MONTH AVERAGE BALANCE ENDING WITH DECEMBER OF THE TEST YEAR.

(2) THE BALANCE FOR ACCUMULATED DEPRECIATION AND AMORTIZATION IS TO BE REDUCED BY ANY DECOMMISSIONING RESERVE AND RESERVE FOR DISPOSAL OF NUCLEAR FUEL INCLUDED IN FERC ACCOUNTS 108 AND 111.

SYSTEM ENERGY RESOURCES, INC.
MONTHLY CAPACITY CHARGE FORMULA
DEVELOPMENT OF CAPACITY REVENUE REQUIREMENT

LINE NO	DESCRIPTION	TEST YEAR AMOUNT	REFERENCE
1	CAPACITY REVENUE REQUIREMENT		Determined as described in Note 2 below.
2	OPERATION & MAINTENANCE EXPENSE (1)		FERC Accounts 517, 519-525, 528-532, 556,567, 560-573, 901-905, 920-931, 935
3	DEPRECIATION EXPENSE		FERC Account 403-Excluding Decommissioning Expense
4	DECOMMISSIONING EXPENSE (3)		FERC Account 403
5	AMORTIZATION EXPENSE		FERC Accounts 404-407
6	TAXES OTHER THAN INCOME TAXES		FERC Account 408.1
7	CURRENT STATE INCOME TAX		Page 4, Line 18
8	CURRENT FEDERAL INCOME TAX		Page 4, Line 25
9	PROVISION FOR DEFERRED INCOME TAX-STATE		State Portion of FERC Accounts 410.1, 411.1 (4)
10	PROVISION FOR DEFERRED INCOME TAX-FEDERAL		Federal Portion of FERC Accounts 410.1, 411.1 (4)
11	INVESTMENT TAX CREDIT-NET		FERC Account 411.4
12	GAINS/LOSSES ON DISPOSITION OF UTILITY PLANT		FERC Accounts 411.6, 411.7
13	UTILITY OPERATING EXPENSES		Sum of Lines 2 - 12
14	UTILITY OPERATING INCOME		Line 1 minus Line 13
15	VERIFICATION:		
16	RATE BASE		Page 2, Line 10
17	RATE OF RETURN ON RATE BASE		Line 14 / Line 16 (Must equal Line 18)
18	COST OF CAPITAL		Page 5, Line 16, Column D

NOTE:

1) EXCLUSIVE OF FUEL EXPENSE IN FERC ACCOUNT 518.

2) THE CAPACITY REVENUE REQUIREMENT FOR THE TEST YEAR IS THE VALUE THAT RESULTS IN A UTILITY OPERATING INCOME WHICH, WHEN DIVIDED BY THE RATE BASE (DETERMINED IN ACCORDANCE WITH PAGE 2) PRODUCES A RATE OF RETURN ON RATE BASE EQUAL TO THE COST OF CAPITAL (DETERMINED IN ACCORDANCE WITH PAGE 5).

3) SHOULD THE FERC APPROVE A CHANGE IN SYSTEM ENERGY'S SCHEDULE OF ANNUAL DECOMMISSIONING EXPENSES DURING THE TEST YEAR, THE ANNUALIZED LEVEL IN EFFECT ON DECEMBER 31 OF THE TEST YEAR SHALL BE UTILIZED. OTHERWISE, THE AMOUNT CHARGED TO FERC ACCOUNT 403 IN THE TEST YEAR SHALL BE UTILIZED.

4) RESTRICTED TO THOSE ITEMS FOR WHICH CORRESPONDING TIMING DIFFERENCES ARE INCLUDED IN THE ADJUSTMENTS TO NET INCOME BEFORE INCOME TAX (SEE PAGE 4, LINE 10).

SYSTEM ENERGY RESOURCES, INC.
MONTHLY CAPACITY CHARGE FORMULA
DEVELOPMENT OF CURRENT INCOME TAX EXPENSE

LINE NO	DESCRIPTION	TEST YEAR AMOUNT	REFERENCE
1	CAPACITY REVENUE REQUIREMENT		Page 3, Line 1
2	OPERATION & MAINTENANCE EXPENSE		Page 3, Line 2
3	DEPRECIATION EXPENSE		Page 3, Line 3
4	DECOMMISSIONING EXPENSE		Page 3, Line 4
5	AMORTIZATION EXPENSE		Page 3, Line 5
6	TAXES OTHER THAN INCOME		Page 3, Line 6
7	NET INCOME BEFORE INCOME TAXES		Line 1 - (Sum of Lines 2-6)
8	ADJUSTMENTS TO NET INCOME BEFORE INCOME TAX:		
9	INTEREST SYNCHRONIZATION		Rate Base (Page 2, Line 10) * Total Debt Rate (Page 5, Line 16)
10	OTHER ADJUSTMENTS		See Note 1
11	TOTAL ADJUSTMENTS		Line 9 plus Line 10
12	TAXABLE INCOME		Line 7 plus Line 11
	COMPUTATION OF STATE INCOME TAX		
13	STATE TAXABLE INCOME BEFORE ADJUSTMENTS		Line 12
14	NET ADJUSTMENT TO STATE TAXABLE INCOME		See Note 1
15	STATE TAXABLE INCOME		Line 13 plus Line 14
16	STATE INCOME TAX BEFORE ADJUSTMENTS		Line 15 * Mississippi State Tax Rate(2)
17	ADJUSTMENTS TO STATE TAX		See Note 1
18	CURRENT STATE INCOME TAX		Sum of Lines 16 - 17
	COMPUTATION OF FEDERAL INCOME TAX		
19	FEDERAL TAXABLE INCOME BEFORE ADJUSTMENTS		Line 12
20	CURRENT STATE INCOME TAX DEDUCTION		Line 18 (Shown as deduction)
21	OTHER ADJUSTMENTS TO FEDERAL TAXABLE INCOME		See Note 1
22	FEDERAL TAXABLE INCOME		Sum of Lines 19-21
23	FEDERAL INCOME TAX BEFORE ADJUSTMENTS		Line 22 * Federal Tax Rate(2)
24	ADJUSTMENTS TO FEDERAL TAX		See Note 1
25	CURRENT FEDERAL INCOME TAX		Sum of Lines 23 - 24

OTE:
1) ITEMS FROM TEST YEAR TAX DETERMINATION THAT ARE APPROPRIATE FOR RATEMAKING PURPOSES.

2) RATE IN EFFECT AT TIME OF ANNUAL REDETERMINATION FILING.

SYSTEM ENERGY RESOURCES, INC.
MONTHLY CAPACITY CHARGE FORMULA
DEVELOPMENT OF COST OF CAPITAL

LINE NO	CAPITALIZATION	(A) CAPITAL AMOUNT (1) (2)	(B) CAPITALIZATION RATIO (3)	(C) COST RATE	(D) WEIGHTED COST RATE (7)
1	BEGINNING OF TEST YEAR				
2	DEBT				
3	LONG TERM			(4)	
4	SHORT TERM			(5)	
5	TOTAL DEBT			(6)	
6	COMMON EQUITY			13.00%	
7	TOTAL		100.00%	NA	
8	END OF TEST YEAR				
9	DEBT				
10	LONG TERM			(4)	
11	SHORT TERM			(5)	
12	TOTAL DEBT			(6)	
13	COMMON EQUITY			13.00%	
14	TOTAL			NA	
15	AVERAGE RATE FOR TEST YEAR				
16	TOTAL DEBT	NA	NA	NA	(8)
17	COMMON EQUITY	NA	NA	NA	(8)
18	COST OF CAPITAL	NA	NA	NA	

NOTES:

(1) LONG TERM DEBT SHALL INCLUDE ALL ISSUES AND REFLECT THE PRINCIPAL AMOUNT, NET OF: 1) UNAMORTIZED DEBT DISCOUNT, 2) DEBT PREMIUM, 3) DEBT EXPENSE AND 4) ANY LOSS ON REACQUIRED DEBT.

(2) SHORT TERM DEBT SHALL INCLUDE ONLY THAT PORTION NOT REFLECTED IN THE CALCULATION OF SERI'S RATE FOR ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION.

(3) APPLICABLE CAPITAL AMOUNT DIVIDED BY THE TOTAL CAPITAL AMOUNT.

(4) AVERAGE COST RATE FOR ALL OUTSTANDING ISSUES INCLUDING APPLICABLE AMORTIZATION OF DEBT DISCOUNT, PREMIUM, AND EXPENSE TOGETHER WITH AMORTIZATION OF LOSS ON REACQUIRED DEBT.

(5) THE AVERAGE COST RATE FOR ELIGIBLE SHORT TERM DEBT.

(6) WEIGHTED AVERAGE COST RATE FOR LONG TERM DEBT AND SHORT TERM DEBT.

(7) CAPITALIZATION RATIO FOR THE APPLICABLE CAPITAL SOURCE MULTIPLIED BY THE CORRESPONDING COST RATE.

(8) WEIGHTED AVERAGE RATE BASED ON AMOUNTS AT BEGINNING AND ENDING OF THE TEST YEAR.

ATTACHMENT B

SYSTEM ENERGY RESOURCES, INC.
MONTHLY FUEL CHARGE FORMULA

LINE NO	DESCRIPTION	SERVICE MONTH AMOUNT	REFERENCE
1	FUEL EXPENSE FOR APPLICABLE SERVICE MONTH		FERC Account 518
2	MONTHLY FUEL CHARGE FOR AP&L		36% * Line 1
3	MONTHLY FUEL CHARGE FOR LP&L		14% * Line 1
4	MONTHLY FUEL CHARGE FOR MP&L		33% * Line 1
5	MONTHLY FUEL CHARGE FOR NOPSI		17% * Line 1

Offer of Settlement, Docket Nos. ER89-678-000, EL90-16-000, and EL90-45-000

APPENDIX F

Second Revised Sheet

FILING PUBLIC UTILITY

System Energy Resources, Inc.

Rate Schedule FERC No. 2

PUBLIC UTILITIES RECEIVING SERVICE UNDER RATE SCHEDULE

Arkansas Power & Light Company
Louisiana Power & Light Company
Mississippi Power & Light Company
New Orleans Public Service Inc.

SERVICE TO BE PROVIDED UNDER RATE SCHEDULE

Wholesale Sale of Electric Power

Unit Power Sales Agreement

THIS AGREEMENT, made, entered into, and effective as of this 10th day of June, 1982, by and among Arkansas Power & Light Company ("AP&L"), Louisiana Power & Light Company ("LP&L"), Mississippi Power & Light Company ("MP&L"), New Orleans Public Service Inc., ("NOPSI") and Middle South Energy, Inc. ("MSE")*,

WITNESSETH THAT:

WHEREAS, MSE* was incorporated on February 11, 1974 under the laws of the State of Arkansas to own certain future generating capacity for the Middle South System, of which AP&L, LP&L, MP&L and NOPSI ("System Companies") are members; and

WHEREAS, System Energy has accordingly undertaken the ownership and financing of an undivided interest in, and construction of, the Grand Gulf Generating Station, a two-unit, nuclear-fueled electric generating station on the east bank of the Mississippi River near Port Gibson, Mississippi ("Project"); and

WHEREAS, the System Companies own and operate electric generating, transmission and distribution facilities in Arkansas, Louisiana, Mississippi and Missouri and generate, transmit and sell electric energy both at retail and wholesale in such states; and

WHEREAS, System Energy has agreed to sell to AP&L, LP&L, MP&L and NOPSI ("Purchasers") specified percentages of all of the capacity and energy available to System Energy from the Project, and the System Companies have agreed to join with System Energy, before the date Unit 1 of the Project is placed in service, in executing an agreement which will set forth in detail the terms and conditions for the sale of such capacity and energy by System Energy to the System Companies; and

WHEREAS, Unit 1 is expected to be placed in commercial operation in the first quarter of 1983;

NOW, THEREFORE, System Energy and the System Companies mutually understand and agree as follows:

* Middle South Energy, Inc.'s name was changed to System Energy Resources, Inc. ("System Energy") on July 21, 1986.

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1.1 System Energy shall, subject to the terms and conditions of this Agreement, make available, or cause to be made available, to the Purchasers all of the capacity and energy which shall be available to System Energy at the Project, including test energy produced during the course of the construction and testing of Unit 1 and Unit 2 of the Project ("Power").

1.2 The Purchasers shall, subject to the terms and conditions of this Agreement, be entitled to receive all of the Power which shall be available to System Energy at the Project in accordance with their respective Entitlement Percentages. The Entitlement Percentages are as follows:

	Entitlement Percentages	
	Unit No. 1	Unit No. 2
AP&L	36%	
LP&L	14%	
MP&L	33%	
NOPSI	17%	
	100%	

1.3 Commencing with the earlier of (a) the date of commercial operation of each Unit or (b) December 31, 1984 (with respect to Unit 1) or December 31, 1988 (with respect to Unit 2) and, respectively continuing monthly thereafter until this Agreement is terminated pursuant to the provisions of Section 9 hereof, in consideration of the right to receive its Entitlement Percentage of such Power from each Unit, each Purchaser will pay System Energy an amount equal to such Purchaser's Entitlement Percentage multiplied by System Energy's Total Cost of Service for such Unit for such month.

The "Total Cost of Service" for each Unit for any month shall be the sum of (a) System Energy's Operating Expenses for such month for such Unit, plus (b) an amount equal to one-twelfth of the Composite Percentage multiplied by the Net Unit Investment for such Unit.

"FERC" shall mean the Federal Energy Regulatory Commission (or any successor governmental authority).

"Uniform System" shall mean the Uniform System of Accounts prescribed by the FERC for Major Public Utilities and Licensees, as from time to time in effect.

Offer of Settlement, Docket Nos. ER89-678-000, EL90-16-000, and EL90-45-000

APPENDIX C

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Third Revised Sheet

System Energy's "Operating Expenses" shall include, with respect to each Unit, all amounts properly chargeable to System Energy's operating expense accounts, less any applicable credit thereto, in accordance with the Uniform System; it being understood that for purposes of this Agreement "Operating Expenses" shall include (but not be limited to) (a) depreciation accrued at a rate at least sufficient to fully amortize the non-salvageable plant investment, including the cost of removal of interim retirements, over the estimated then remaining useful life of the unit; (b) obligations incurred in connection with the leasing of fuel inventory and/or amortization of fuel burned; (c) accruals to any reserve established by System Energy to provide for decommissioning the unit over the estimated then remaining useful life of the unit; and (d) accruals for disposal of spent nuclear fuel.

"Net Unit Investment" for any month shall be computed as of the last day of the previous month and shall consist with respect to each Unit, of (a) the aggregate amount properly chargeable at the time in accordance with the Uniform System to System Energy's utility plant accounts (including, but not limited to, (I) construction work in progress, to the extent allowed by the FERC, related to each Unit after its respective Commercial Operation date, and (II) nuclear fuel accounts other than nuclear fuel in process of fabrication), less the balance, at the time of any accumulated provision for depreciation and amortization of utility plant (exclusive of any decommissioning reserve), including amortization of the cost of nuclear fuel (exclusive of any reserve for disposal of nuclear fuel), as determined in accordance with the Uniform System; plus (b) the aggregate amount properly chargeable at the time in accordance with the Uniform System to accounts representing materials and supplies; plus (c) such reasonable allowances for prepaid items and cash working capital as may from time to time be determined by System Energy; plus (d) recoverable income taxes to the extent previously credited to utility plant accounts and not yet realized excluding amounts related to construction work in progress that are not included in net unit investment but that are included in the allowance for funds used during construction computation; and less (e) accumulated provision for deferred income taxes and less (f) other deferred credits.

"Composite Percentage" for any month shall be that computed as of the last day of the previous month ("computation date") Composite Percentage as of a computation date shall be the sum of (a) thirteen percent (13%) multiplied by the ratio which the Equity Investment, as of such date, is to the Total Capital as of such date; plus (b) the "effective interest rate" per annum of each principal amount of debt (other than loans or advances made by the common stockholder of System Energy) outstanding on such date for money borrowed, multiplied by the ratio which such principal amount is to Total Capital as of such date; plus (c) the "effective dividend rate" per annum of each series of preferred stock outstanding as of such date multiplied by the

First Revised Sheet

ratio which the amount at which such preferred stock would be reflected on a balance sheet of System Energy is to Total Capital as of such date. The "effective interest rate" of each principal amount of debt referred to in clause (b) will reflect the annual interest requirements and to the extent applicable, amortization of issue expenses, discounts and premiums, sinking fund call premiums, expenses and discounts, refunding and retirement expenses, discounts and premiums, and all other expenses applicable to the issue of such indebtedness. The "effective dividend rate" of each series of preferred stock referred to in clause (c) will reflect the annual dividend requirements applicable to each such series of preferred stock.

"Equity Investment" as of any date shall consist of the sum of (a) all amounts theretofore paid to System Energy for all common capital stock theretofore issued, plus all capital contributions, advances or pro rata loans pursuant to any capital contribution agreement, less the sum of any amounts paid by System Energy to its common stockholder in the form of stock retirements, repurchases or redemptions, return of capital or repayments of such advances or loans; plus (b) any credit balance (i) in the paid in capital account not included under (a) and (ii) in the retained earnings account on the books of System Energy as of such date.

"Total Capital" as of any date shall be the Equity Investment, plus the total of the amount which would be reflected on a balance sheet of System Energy for all other securities, debt and preferred stock then outstanding.

Prior to the earlier of (a) the date of commercial operation of each Unit or (b) December 31, 1984 (with respect to Unit 1) or December 31, 1988 (with respect to Unit 2), the Purchasers shall pay System Energy monthly in accordance with their respective Entitlement Percentages for any Power delivered to them from each such Unit hereunder at a rate equal to the incremental cost of energy displaced by such Power on the Middle South System.

2. The performance of the obligations of System Energy hereunder shall be subject to the receipt and continued effectiveness of all authorizations of governmental regulatory authorities at the time necessary to permit System Energy to perform its duties and obligations hereunder, including the receipt and continued effectiveness of all authorizations by governmental regulatory authorities at the time necessary to permit the completion by System Energy of the construction of the Project, the operation of the Project, and for System Energy to make available to the Purchasers all of the Power available to System Energy at the Project. System Energy shall use its best efforts to secure and maintain all such authorizations by governmental regulatory authorities.

First Revised Sheet

3. System Energy shall operate and maintain the Project in accordance with good utility practice. Outages for inspection, maintenance, refueling, repairs and replacements shall be scheduled in accordance with good utility practice and, insofar as practicable, shall be mutually agreed to by System Energy and the Purchasers.

4. Delivery of Power sold to the Purchasers pursuant to this Agreement shall occur at the Project's step-up transformer and shall be made in the form of three-phase, sixty hertz alternating current at a nominal voltage of 500 kilovolts. System Energy will supply and maintain all necessary metering equipment for determining the quantity and conditions of delivery under this Agreement. System Energy will furnish to the Purchasers such summaries of meter readings and other metering information as may reasonably be requested.

5. Monthly bills calculated in accordance with the provisions of Section 1.3 shall be issued by System Energy on the fifth working day of each month and shall be payable in immediately available funds on or before the 15th day of such month. After the 15th day, interest shall accrue on any balance due at the rate required for refunds ordered pursuant to FERC Regulations under the Federal Power Act.

6. Nothing contained herein shall be construed as affecting in any way the right of System Energy to unilaterally make application to FERC for a change in the rates contained herein or any other term or condition of this Agreement under Section 205 of the Federal Power Act and pursuant to FERC Rules and Regulations promulgated thereunder.

7. No Purchaser shall be entitled to set off against any payment required to be made by it under this Agreement (a) any amounts owed by System Energy to any Purchaser or (b) the amount of any claim by any Purchaser against System Energy. The foregoing, however, shall not affect in any other way the rights and remedies of any Purchaser with respect to any such amounts owed to any Purchaser by System Energy or any such claim by any Purchaser against System Energy.

8. The invalidity and unenforceability of any provision of this Agreement shall not affect the remaining provisions hereof.

9. This Agreement shall continue until terminated by mutual agreement of all parties hereto.

10. This Agreement shall be binding upon the parties hereto and their successors and assigns, but no assignment hereof, or of any right to any funds due or to become due under this Agreement, shall in any event relieve either any Purchaser or System Energy of any of their respective obligations hereunder, or, in the case of the Purchasers, reduce to any extent their entitlement to receive all of the Power available to System Energy from time to time at the Project.

11. The agreements herein set forth have been made for the benefit of the Purchasers and System Energy and their respective successors and assigns and not other person shall acquire or have any right under or by virtue of this Agreement.

12. The Purchasers and System Energy may, subject to the provisions of this Agreement, enter into a further agreement or agreements between the Purchasers and System Energy, setting forth detailed terms and provisions relating to the performance by the Purchasers and System Energy of their respective obligations under this Agreement. No agreement entered into under this Section 12 shall, however, alter to any substantive degree the obligations of any party to this Agreement in any manner inconsistent with any of the foregoing sections of this Agreement.

13. Each of the Purchasers shall, at any time and from time to time, be entitled to assign all of its right, title and interest in and to all of the Power to which any of them shall be entitled under this Agreement, but no Purchaser shall, by such assignment, be relieved of any of its obligations and duties under this Agreement except through the payment to System Energy, by or on behalf of such Purchaser, of the amount or amounts which such Purchaser shall be obligated to pay pursuant to the terms of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed as of the day and year first above written.

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MIDDLE SOUTH ENERGY, INC. *

By ______________________

ARKANSAS POWER & LIGHT COMPANY

By ______________________

LOUISIANA POWER & LIGHT COMPANY

By ______________________

MISSISSIPPI POWER & LIGHT COMPANY

By ______________________

NEW ORLEANS PUBLIC SERVICE INC.

By James M. Cain

* Middle South Energy, Inc.'s name was changed to System Energy Resources, Inc. ("System Energy") on July 22, 1986.

First Revised Sheet

System Energy Resources, Inc.

Billing Format

Fourth Revised Sheet

SYSTEM ENERGY RESOURCES, INC.

BILLING FORMAT

COST OF SERVICE

MONTH, 199X

GRAND GULF UNIT 1

OPERATING EXPENSES

OPERATION EXPENSES:		
FUEL EXPENSE (ACCOUNT 518)		$
OTHER OPERATION EXPENSES (ACCOUNTS 517, 519-525, 556, 557, 560-567, 901-905, 920-931)		
MAINTENANCE EXPENSES (ACCOUNTS 528-532, 568-573, 935)		
DEPRECIATION EXPENSE (ACCOUNT 403) - SCHEDULE A		
DECOMMISSIONING EXPENSE (ACCOUNT 403) 1/		
AMORTIZATION EXPENSES (ACCOUNTS 404-407)		
TAXES OTHER THAN INCOME TAXES (ACCOUNT 408.1)		
TAXES - INCOME (ACCOUNTS 409.1, 409.3, 410.1, 411.1, 411.4)		
GAINS/LOSSES FROM DISPOSITION OF UTILITY PLANT (ACCOUNTS 411.6-411.7)		
TOTAL OPERATING EXPENSES		$
ADJUSTMENT OF PRIOR BILLINGS - SCHEDULE -		
OPERATING EXPENSES AS BILLED	$	
OPERATING EXPENSES ACTUAL		
RETURN ON NET UNIT INVESTMENT - SCHEDULE B		
TOTAL COST OF SERVICE		$

1/ THE MONTHLY DECOMMISSIONING EXPENSE FOR GRAND GULF UNIT 1 IS IN ACCORDANCE WITH FERC SETTLEMENT AGREEMENT. THE AMOUNT VARIES EACH YEAR BASED ON THE APPROVED DECOMMISSIONING SCHEDULE.

Sixth Revised Sheet

SYSTEM ENERGY RESOURCES, INC. SCHEDULE A

DEPRECIATION EXPENSE

MONTH, 199X

PLANT FUNCTION	DEPRECIABLE PLANT BALANCES	EFFECTIVE ACCRUAL RATES 1/	DEPRECIATION EXPENSE
NUCLEAR PLANT (ACCOUNT 101)	$	2.85%	$
TRANSMISSION PLANT (ACCOUNT 101)	$	2.85%	$
GENERAL PLANT OFFICE EQUIPMENT (ACCOUNT 101)	$	2.85%	$
TRANSPORTATION EQUIPMENT (ACCOUNT 101)	$	2.85%	$
TOTAL	$		$

1/ EFFECTIVE JANUARY 1, 1987

Third Revised Sheet

SYSTEM ENERGY RESOURCES, INC. — **SCHEDULE B**
Page 1 of 2

RETURN ON NET UNIT INVESTMENT AND COMPOSITE PERCENTAGE

MONTH, 199X

PLANT IN SERVICE		
UTILITY PLANT IN SERVICE (ACCOUNTS 101, 106, 120.2-120.4)	$	1/
LESS: ACCUMULATED PROVISION FOR DEPRECIATION/ AMORTIZATION (ACCOUNTS 108, 111, 120.5)	________	1/
(EXCLUSIVE OF ANY DECOMMISSIONING RESERVE AND ANY RESERVE FOR DISPOSAL OF NUCLEAR FUEL)		
NET UTILITY PLANT IN SERVICE	$	1/
WORKING CAPITAL		
MATERIALS & SUPPLIES (ACCOUNTS 154, 163)	$	1/
PREPAYMENTS (ACCOUNT 165 - EXCLUDING PREPAID INTEREST)		1/
WORKING CAPITAL ALLOWANCE	________	2/
TOTAL WORKING CAPITAL	$ ________	
RECOVERABLE INCOME TAXES (ACCOUNT 186)	$ ________	3/
OTHER DEFERRED CREDITS (ACCOUNT 253 - SALE AND LEASEBACK OF A PORTION OF GRAND GULF UNIT 1)	$ ________	4/
ACCUMULATED PROVISION FOR DEFERRED INCOME TAX (ACCOUNTS 190, 282, 283)	$ ________	1/
NET UNIT INVESTMENT	$ ________	1/
RETURN & COMPOSITE PERCENTAGE (SCH. B2) x NET UNIT INVESTMENT DIVIDED BY 12	$ ________	1/

1/ CALCULATED ON PREVIOUS MONTH BALANCES.

2/ EFFECTIVE APRIL, [illegible] WORKING CAPITAL ALLOWANCE IS ZERO IN ACCORDANCE WITH THE FERC SETTLEMENT AGREEMENT.

3/ BALANCES ARE EXCLUDED FROM NET UNIT INVESTMENT IN ACCORDANCE WITH SEPTEMBER, [illegible] SETTLEMENT AGREEMENT.

4/ REMAINING UNAMORTIZED DEFERRED GAIN WAS AMORTIZED AS A CREDIT TO THE UPSA BILLING RATABLY OVER THE PERIOD JUNE TO DECEMBER 1991.

Fourth Revised Sheet

SYSTEM ENERGY RESOURCES, INC. — SCHEDULE E, Page 2 of 2

RETURN ON NET UNIT INVESTMENT AND COMPOSITE PERCENTAGE

(Continued)

MONTH, 199X

CAPITALIZATION	AMOUNT	CAP. RATIO	RATE	COMPONENT
DEBT (ACCOUNTS 181, 189, 221, 224, 226, 231)	A1	A1/A4	D%	(A1/A4)D%
PREFERRED STOCK (ACCOUNTS 204, 205, 206)	A2	A2/A4	P%	(A2/A4)P%
COMMON EQUITY (ACCOUNTS 201, 202, 203, 207-216.1)	A3	A3/A4	C%	(A3/A4)C%
TOTAL CAPITALIZATION	A4	100%		Composite%

WHERE: D IS WEIGHTED AVERAGE DEBT RATE INCLUDING SHORT TERM DEBT TO THE EXTENT NOT UTILIZED IN AFUDC CALCULATION.

WHERE: P IS WEIGHTED AVERAGE PREFERRED STOCK DIVIDEND RATE.

WHERE: C IS 13% RETURN ON COMMON EQUITY. 1/

1/ EFFECTIVE APRIL 2, 1990

Second Revised Sheet

SCHEDULE C
PAGE 1 OF 2

SYSTEM ENERGY RESOURCES, INC.

INCOME TAX EXPENSE

MONTH, 199X

CURRENT INCOME TAX EXPENSE

FORMULA DESCRIPTION	
• OPERATING EXPENSES (EXCLUDING INCOME TAXES)	$
• INCOME TAX DEDUCTIONS	
• DEFERRED TAX PROVISIONS	
• RETURN ON NET UNIT INVESTMENT (DEBT COMPONENT)	
• TOTAL RETURN ON NET UNIT INVESTMENT	
• ITC AMORTIZATION (ACCOUNT 411.4)	
• TAXABLE INCOME	$
• TAX RATE / (1 - TAX RATE)	
• INCOME TAXES BEFORE ITC PROVISION	$
• ITC PROVISION	
• CURRENT FEDERAL AND STATE INCOME TAXES	$

DEFERRED INCOME TAX EXPENSE

DESCRIPTION	(1) OPERATING EXPENSES	(2) 1/ ADJUSTMENT FOR PERMANENT DIFFERENCES	(3) OPERATING EXPENSES AS ADJUSTED	(4) 1/ TIMING DIFFERENCES	(5) INCOME TAX DEDUCTION
FUEL EXPENSE (ACCOUNT 518)	$	$	$	$	$
OTHER OPERATIONS EXPENSE (ACCOUNTS 517, 519-525, 526, 537, [illegible]-[illegible], 901-905, 920-931)					
MAINTENANCE EXPENSE (ACCOUNTS 528-532, [illegible]-[illegible], 935)					
DEPRECIATION EXPENSE (ACCOUNTS 403-407)					
DECOMMISSIONING EXPENSE (ACCOUNT 403)					
TAXES OTHER THAN INCOME TAX (ACCOUNT 408.1)					
TAXES CAPITALIZED PER BOOKS					
	$	$	$	$	$
DEFERRED STATE INCOME TAX PROVISION					
NET TIMING DIFFERENCES				$	
DEFERRED FEDERAL INCOME TAX PROVISION				$	

SUMMARY:	CURRENT FEDERAL TAX EXPENSE (ACCOUNT 409.1)	$
	CURRENT STATE TAX EXPENSE (ACCOUNT 409.1)	
	DEFERRED FEDERAL TAX EXPENSE (ACCOUNTS 410.1, 411.1)	
	DEFERRED STATE TAX EXPENSE (ACCOUNTS 410.1, 411.1)	
	ITC PROVISION	
	ITC AMORTIZATION (ACCOUNT 411.4)	
	TOTAL INCOME TAXES	$

1/ Supporting [illegible] follow on page 2 of 2. These [illegible] as necessary to comply with the FERC's normalization rules under order no. 144 and 144-A, and with normalization rules under the Internal Revenue Code.

Second Revised Sheet

SYSTEM ENERGY RESOURCES, INC. SCHEDULE C
Page 2 of 2

INCOME TAX EXPENSE
(Continued)
MONTH, 199X

DEFERRED INCOME TAX EXPENSE SUPPORTING CALCULATIONS

PERMANENT DIFFERENCES:

DEPRECIATION OF AFUDC - $	
TAX BASIS OF UNIT #1	$
TAXES CAPITALIZED PER BOOKS NET OF TEST ENERGY (ACCOUNTS 101.33, 101.34)	
BASIS FOR DEFERRED TAX CALCULATION	$
BOOK BASIS	$
RATIO OF BASIS FOR DEFERRED TAX CALCULATIONS TO BOOK BASIS:	%
BOOK DEPRECIATION OF BASIS FOR DEFERRED TAX CALCULATION	$
BOOK DEPRECIATION (ACCOUNT 403)	( )
DEPRECIATION OF AFUDC	$
MEAL AND ENTERTAINMENT EXPENSE (ACCOUNTS 517, 519-525, 528-532, 556, 557, 560-573, 901-905, 920-931, 935)	$
PENSION EXPENSE (ACCOUNT 926)	$

TIMING DIFFERENCES:

FUEL EXPENSE - $	$
TAX DEPRECIATION OF NUCLEAR FUEL	$
INTEREST AND OTHER DEDUCTIBLE EXPENSES (ACCOUNT 518)	
NUCLEAR FUEL EXPENSE PER BOOKS (ACCOUNT 518)	( )
EXCESS	$
DEPRECIATION EXPENSE - $	
TAX DEPRECIATION OF UNIT 1 (ACCOUNT 403)	$
DEPRECIATION OF BASIS FOR DEFERRED TAX CALCULATION	( )
EXCESS	$
DECOMMISSIONING EXPENSE - $	
TAX DEDUCTION FOR ACCRUED DECOMMISSIONING EXPENSES	$
BOOK ACCRUAL FOR DECOMMISSIONING EXPENSES (ACCOUNT 403)	( )
EXCESS	$
PENSION EXPENSE - $	
TAX DEDUCTION FOR ACCRUED PENSION EXPENSES	$
BOOK ACCRUAL FOR PENSION EXPENSES (ACCOUNT 926)	( )
EXCESS	$

Report on Status of Decommissioning Funding
10 CFR 50.75(f)(1)
March 31, 2005

Attachment 3
RBS-70% Report

River Bend Station-70% Regulated Interest

Minimum Reporting Requirements as per 10 CFR 50.75(f)(1):

1. Decommissioning funds estimated pursuant to 10 CFR 50.75(b) and (c) (2004$):	
Regulated 70% Funding Interest	$ 471,936,421 [1]
2. Market value of funds accumulated as of December 31, 2004:	
Louisiana Jurisdiction	$ 42,801,282 [2,9]
Texas Jurisdiction	$ 77,401,160 [2,9]
FERC Jurisdiction	$ 3,895,331 [2,9]
3. Current schedule of annual amounts remaining to be collected:	
Louisiana Jurisdiction	See Attachment 3-E [4]
Texas Jurisdiction	See Attachment 3-E
FERC Jurisdiction	See Attachment 3-G
4. Assumed rate of decommissioning cost escalation used in funding projections:	
Louisiana Jurisdiction - Attachment 3-E	CPI/2.53% [8]
Texas Jurisdiction - Attachment 3-F	4.81%
FERC Jurisdiction - Attachment 3-G	4.00%
5. Assumed average after-tax rates of earnings used in funding projections :	
Louisiana Jurisdiction	5.65% [6]
Texas Jurisdiction	6.62% [7]
FERC Jurisdiction	See Attachment 3-G
6. Assumed rates of other factors used in funding projections :	
Louisiana Jurisdiction	See Attachment 3-E
Texas Jurisdiction	See Attachments 3-E & F
FERC Jurisdiction	See Attachment 3-G
7. Contracts assuring collection of decommissioning funds:	None
8. Modifications to method of providing financial assurance since March 31, 2003 filing (external sinking fund):	None
9. Material changes to trust agreements since March 31, 2003 filing:	See Footnote 10

Supplemental Information:

1. Site-Specific cost estimate escalated to 2004 (Jurisdictional basis):	
Regulated 70% Funding Interest - Louisiana Jurisdiction (1996 Base Year Dollars)	
NRC License Termination Cost:	$ 309,744,540 [3]
Non-NRC License Termination Cost:	$ 41,897,983 [3]
Total	$ 351,642,522
Regulated 70% Funding Interest - Texas Jurisdiction (1996 Base Year Dollars)	
NRC License Termination Cost:	$ 345,869,231 [3]
Non-NRC License Termination Cost:	$ 46,784,434 [3]
Total	$ 392,653,665

Report on Status of Decommissioning Funding
10 CFR 50.75(f)(1)
March 31, 2005

Attachment 3
RBS-70% Report

River Bend Station-70% Regulated Interest

Regulated 70% Funding Interest - FERC Jurisdiction (1985 Base Year Dollars)	
NRC License Termination Cost:	$ 197,893,077 [3]
Non-NRC License Termination Cost:	$ 99,139,368 [3]
Total	$ 297,032,446
2. Decommissioning method assumed for planning purposes in site-specific estimate:	DECON
3. Year site-specific estimate complete:	1996 [4]
4. Frequency of updates (approximately):	once every 5 years
5. Funding based on NRC minimum or site-specific estimate?:	Site-specific
6. Decommissioning rate regulation (approximately):	
Louisiana Public Service Commission (based on 70% funding interest)	20.03%
Public Utility Commission of Texas (based on 70% funding interest)	30.10%
Federal Energy Regulatory Commission (based on 70% funding interest)	2.10%
Unregulated (based on 70% funding interest)	17.77% [5]
	70.00%

[1] See Attachment 3-A for calculations.

[2] Source: December 31, 2004 River Bend Station Trust Fund Report.

[3] See Attachments 3-B, 3-C, and 3-D for calculations. Also see footnote 4 to Attachment 3-A for information on the generic baseline cost estimate using the waste vendor disposal factor (Barnwell, South Carolina).

[4] A 1999 cost update was prepared and filed with the LPSC and the PUCT. Based upon a settlement in the 8th Earnings Review in Louisiana, the LPSC reflected an assumed life extension using the 1996 decommissioning cost estimate, and correspondingly set the amount of decommissioning costs collected in rates to zero beginning January 2003. The 2004 cost update of $466.97 million (70% of $667.1 million in '04 $) has not been filed.

[5] This amount is below the 20% threshold provided in footnote No. 8 to NUREG 1577, Rev 1, "Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance" dated March 1999.

[6] Assumed weighted average after-tax earnings rate for the non-qualified and tax qualified decommissioning funds for the period 2004-2038 (LPSC Consolidated Dockets No. U-22491, U-23358, U-24182, U-24993 and U-25687).

[7] Assumed average after-tax earnings rate for the decommissioning fund (tax qualified) for the period 2004-2032 (PUCT Docket No. 20150).

[8] The Nuclear Escalator is 2.53% beginning 2003, based on a Settlement Agreement between the LPSC and Entergy Gulf States, setting the 4th, 5th, 6th, 7th, and 8th Post Earnings Reviews pursuant to Order U-19904, instead of using CPI as in prior periods.

[9] Funds accumulated for each jurisdiction may only be used for decommissioning costs associated with that jurisdiction.

[10] The following section was added to all trust agreements on December 17, 2003:
Notice Regarding Disbursements or Payments. Notwithstanding anything to the contrary in this Agreement, except for (i) payments of ordinary administrative costs (including taxes) and other incidental expenses of the Trust Fund (including legal, accounting, actuarial, and Successor Trustee expenses) in connection with the operation of the Trust Fund, (ii) withdrawals being made under 10 CFR 50.82(a)(8), and (iii) transfers between Qualified and Nonqualified Funds in accordance with the provisions of this Agreement, no disbursement or payment may be made from the Trust Fund until written notice of the intention to make a disbursement or payment has been given to the Director, Office of Nuclear Reactor Regulation, or the Director, Office of Nuclear Material Safety and Safeguards, as applicable, at least 30 working days before the date of the intended disbursement or payment. The disbursement or payment from the Trust Fund, if it is otherwise in compliance with the terms and conditions of this Agreement, may be made following the 30-working day notice period if no written notice of objection from the Director, Office of Nuclear Reactor Regulation, or the Director, Office of Nuclear Material Safety and Safeguards, as applicable, is received by the Successor Trustee or the Company within the notice period. The required notice may be made by the Successor Trustee or on the Successor Trustee's behalf. This Section 8.04 is intended to qualify each and every provision of this Trust Agreement allowing distributions from the Trust Fund, and in the event of any conflict between any such provision and this Section, this Section shall control.

RIVER BEND STATION
CALCULATION OF MINIMUM AMOUNT AS PER 10CFR 50.75 (b) AND (c)

Determination of Minimum Amount - Regulated 70% Interest

Entergy Gulf States, Inc.: 100% ownership interest
Plant Location: St. Francisville, Louisiana
Reactor Type: Boiling Water Reactor ("BWR")
Power Level: <3400 MWt (Approx. 3091 MWt.)
1986 BWR Base Year $: $131,819,000
Waste Burial Facility: Barnwell, South Carolina

10 CFR 50.75(c)(2) Escalation Factor Formula:
0.65(L) + 0.13(E) + 0.22(B)

	Factor	
L= Labor (South)	1.925	[1]
E= Energy (BWR)	1.448	[2]
B= Waste Burial (BWR)	16.705	[3]

BWR Escalation Factor:
0.65(L) + 0.13(E) + 0.22(B) = 5.11455

1986 BWR Base Year $ Escalated:
1986 BWR Base Year $ * Escalation Factor = $ 674,194,886 [4]

Regulated 70% Funding Interest **$ 471,936,421** [4]

[1] Source: Bureau of Labor Statistics: series report id ecu13202i (March 2005).
[2] Source: Bureau of Labor Statistics: series report id wpu0543 and wpu0573 (March 2005).
[3] Source:Nuclear Regulatory Commission:Table 2.1 of "Report on Waste Burial Charges", NUREG-1307 revision 10(October 2002).
[4] Application of the 8.860 waste vendor disposal factor (South Carolina) from Table 2.1 of "Report on Waste Burial Charges", NUREG 1307 Revision 10 (October 2002) yields a generic baseline cost of:
Regulated 70% Funding Interest = $ 312,681,932

RIVER BEND STATION
CALCULATION OF SITE-SPECIFIC COST ESTIMATE
ESCALATED TO 2004 DOLLARS
RIVER BEND 70% FUNDING INTEREST
LOUISIANA JURISDICTION

Site-Specific Cost Estimate (1996$)

Site-Specific Cost Estimate (1996$ - 70%):	**(1996$)**
NRC License Termination Cost:	$ 258,324,954 [2]
Non-NRC License Termination Cost:	$ 34,942,648 [3]
Total Site-Specific Cost Estimate:	$ 293,267,602 [1]
Annual Escalation Factor:	CPI (1996-2002), 2.53% (2002-present) [1]
Years of Escalation:	6 yrs at CPI, 2 yrs at 2.53%
Cumulative Factor :	1.199

Site-Specific Cost Estimate (escalated):	**(2004$)**
NRC License Termination Cost * Cumulative Factor:	$ 309,744,540
Non-NRC License Termination Cost: * Cumulative Factor:	$ 41,897,983
Total Site-Specific Cost Estimate:	$ 351,642,522

[1] The Louisiana Public Service Commission (LPSC) authorized funding amounts (Attachment 3-E) based on 70% of the site-specific cost estimate of $418,953,716 in 1996$ and escalated annually at rates tied to projections of the Consumer Price Index-Urban ("CPI"). The projection for the CPI from the period 1996 through 2002 was 14.06%. The Nuclear escalation factor is 2.53% beginning 2003, based on a Settlement Agreement between the LPSC and Entergy Gulf States, settling the 4th, 5th, 6th, 7th, and 8th Post Merger Earnings Reviews pursuant to Order U-19904.

[2] From 1996 Decommissioning Cost Estimate for River Bend, Table C, times 70%.

[3] From 1996 Decommissioning Cost Estimate for River Bend, Table C, times 70%.

RIVER BEND STATION
CALCULATION OF SITE-SPECIFIC COST ESTIMATE
ESCALATED TO 2004 DOLLARS
RIVER BEND 70% FUNDING INTEREST
TEXAS JURISDICTION

Site-Specific Cost Estimate (1996$)

Site-Specific Cost Estimate (1996$ - 70%):	
NRC License Termination Cost:	$ 237,514,518 [2]
Non-NRC License Termination Cost:	$ 32,127,698 [3]
Total Site-Specific Cost Estimate:	$ 269,642,216 [1]
Annual Escalation Factor:	4.81% [1]
Years of Escalation (1996 Base Year to 2004):	8
Cumulative Factor $(1+\text{Factor})^{\wedge 8}$:	1.456
Site-Specific Cost Estimate (2004$):	
NRC License Termination Cost * Cumulative Factor:	$ 345,869,231
Non-NRC License Termination Cost: * Cumulative Factor.	$ 46,784,434
Total Site-Specific Cost Estimate:	$ 392,653,665

[1] The Public Utility Commission of Texas authorized funding amounts (Attachment 3-F) based on 70% of site-specific cost estimate of $418,953,716 in 1996$ adjusted to reflect statutory contingency limit of 10% for ratemaking purposes. Cost estimate escalated annually at 4.81%.

[2] From 1996 Decommissioning Cost Estimate for River Bend, Table C, times 70%.

[3] From 1996 Decommissioning Cost Estimate for River Bend, Table C, times 70%.

RIVER BEND STATION
CALCULATION OF SITE-SPECIFIC COST ESTIMATE
ESCALATED TO 2004 DOLLARS
RIVER BEND 70% FUNDING INTEREST
FERC JURISDICTION

Site-Specific Cost Estimate (1985$)

Site-Specific Cost Estimate (1985$ - 70%):	
NRC License Termination Cost:	$ 93,928,450
Non-NRC License Termination Cost:	$ 47,055,750
Total Site-Specific Cost Estimate:	$ 140,984,200 [1]
Annual Escalation Factor:	4.00% [1]
Years of Escalation (1985 Base Year to 2004):	19
Cumulative Factor $(1+\text{Factor})^{\wedge 19}$:	2.107
Site-Specific Cost Estimate (2004$):	
NRC License Termination Cost * Cumulative Factor:	$ 197,893,077
Non-NRC License Termination Cost: * Cumulative Factor	$ 99,139,368
Total Site-Specific Cost Estimate:	$ 297,032,446

[1] FERC authorized funding amounts (Attachment 3-G) based on 70% of site-specific cost estimate in 1985$ escalated annually at 4.0%.

Entergy Gulf States, Inc.
River Bend Decommissioning Model - Louisiana Retail
Non-DAP Portion
Revenue Requirement, Fund Balance and Expenditure Summary
($000)

Line No	Year	Revenue Rqmt.	Decommissioning Fund Balances Non-Tax Qualified	Tax Qualified	Total	Decomm. Expend.
1	Beginning Balance		1,909	25,099	27,008	
2	2002	0	2,021	26,830	28,851	0
3	2003	0	2,140	28,687	30,827	0
4	2004	0	2,266	30,673	32,938	0
5	2005	0	2,399	32,796	35,195	0
6	2006	0	2,540	35,067	37,607	0
7	2007	0	2,690	37,496	40,186	0
8	2008	0	2,848	40,095	42,943	0
9	2009	0	3,016	42,874	45,890	0
10	2010	0	3,194	45,847	49,041	0
11	2011	0	3,383	49,026	52,409	0
12	2012	0	3,583	52,427	56,011	0
13	2013	0	3,795	56,065	59,861	0
14	2014	0	4,020	59,957	63,977	0
15	2015	0	4,258	64,119	68,377	0
16	2016	0	4,510	68,571	73,081	0
17	2017	0	4,777	73,333	78,111	0
18	2018	0	5,061	78,427	83,488	0
19	2019	0	5,361	83,875	89,236	0
20	2020	0	5,676	89,607	95,283	0
21	2021	0	5,996	95,427	101,423	0
22	2022	0	6,314	101,192	107,507	0
23	2023	0	6,627	106,849	113,476	0
24	2024	0	6,934	112,351	119,284	0
25	2025	0	0	115,155	115,155	9,861
26	2026	0	0	96,483	96,483	24,119
27	2027	0	0	75,887	75,887	25,157
28	2028	0	0	53,569	53,569	25,903
29	2029	0	0	29,879	29,879	26,217
30	2030	0	0	4,539	4,539	26,744
31	2031	0	0	-22,763	-22,763	27,510
32	2032	0	0	-37,724	-37,724	13,869
33	2033	0	0	-48,493	-48,493	8,960
34	2034	0	0	-59,367	-59,367	8,548
35	2035	0	0	-62,994	-62,994	779
36	2036	0	0	-66,816	-66,816	801
37	2037	0	0	-70,840	-70,840	819
38	2038	0	0	-82,473	-82,473	8,236

LA Income Tax Rate is 8.0%, however, in LA Federal income taxes are deductible, therefore the effective LA rate is 5.35%. The effective Federal Rate is 33.13% resulting in a Composite Rate of 38.48%.

Entergy Gulf States funding interest in River Bend is 70%.

Nuclear Cost Escalator is 2.53% effective 1/1/03 per the Settlement Agreement pursuant to Order U-19904.

Entergy Gulf States, Inc.
River Bend Decommissioning Model - Texas
Revenue Requirement, Fund Balance and Expenditure Summary
($000)

Line No	Year	Revenue Rqmt.	Decommissioning Fund Balances Non-Tax Qualified	Tax Qualified	Total	Decomm. Expend.
1	Beginning Balance		0	41,503	41,503	
2	1997	8,551	0	53,042	53,042	0
3	1998	8,551	0	65,342	65,342	0
4	1999	8,551	0	79,068	79,068	0
5	2000	8,551	0	93,820	93,820	0
6	2001	8,551	0	109,675	109,675	0
7	2002	8,551	0	126,715	126,715	0
8	2003	8,551	0	145,030	145,030	0
9	2004	8,551	0	164,714	164,714	0
10	2005	8,551	0	185,869	185,869	0
11	2006	8,551	0	208,606	208,606	0
12	2007	8,551	0	233,043	233,043	0
13	2008	8,551	0	259,307	259,307	0
14	2009	8,551	0	287,535	287,535	0
15	2010	8,551	0	317,873	317,873	0
16	2011	8,551	0	350,480	350,480	0
17	2012	8,551	0	385,524	385,524	0
18	2013	8,551	0	423,188	423,188	0
19	2014	8,551	0	463,668	463,668	0
20	2015	8,551	0	507,175	507,175	0
21	2016	8,551	0	553,935	553,935	0
22	2017	8,551	0	604,190	604,190	0
23	2018	8,551	0	658,203	658,203	0
24	2019	8,551	0	716,254	716,254	0
25	2020	8,551	0	778,645	778,645	0
26	2021	8,551	0	829,458	829,458	0
27	2022	8,551	0	883,015	883,015	0
28	2023	8,551	0	939,464	939,464	0
29	2024	8,551	0	998,962	998,962	0
30	2025	5,701	0	1,043,086	1,043,086	15,274
31	2026	0	0	1,051,288	1,051,288	46,774
32	2027	0	0	924,532	924,532	178,356
33	2028	0	0	755,709	755,709	212,585
34	2029	0	0	567,884	567,884	222,190
35	2030	0	0	358,131	358,131	233,642
36	2031	0	0	145,837	145,837	225,104
37	2032	0	0	0	0	149,378

Nuclear Cost Escalator is 4.81%.

Entergy Gulf States, Inc.
River Bend Decommissioning Model - Louisiana Retail
DAP Portion
Revenue Requirement, Fund Balance and Expenditure Summary
($000)

Line No	Year	Revenue Rqmt.	Decommissioning Fund Balances Non-Tax Qualified	Tax Qualified	Total	Decomm. Expend.
1	Beginning Balance		9,151	6,251	15,402	
2	2002	0	9,696	6,678	16,374	0
3	2003	0	10,274	7,136	17,410	0
4	2004	0	10,887	7,626	18,512	0
5	2005	0	11,536	8,149	19,685	0
6	2006	0	12,224	8,709	20,933	0
7	2007	0	12,953	9,308	22,261	0
8	2008	0	13,726	9,948		0
9	2009	0	14,546	10,633	25,178	0
10	2010	0	15,414	11,365	26,779	0
11	2011	0	16,335	12,148	28,482	0
12	2012	0	17,310	12,985	30,295	0
13	2013	0	18,344	13,881	32,225	0
14	2014	0	19,440	14,838	34,279	0
15	2015	0	20,602	15,863	36,465	0
16	2016	0	21,833	16,958	38,791	0
17	2017	0	23,139	18,129	41,268	0
18	2018	0	24,522	19,382	43,904	0
19	2019	0	25,989	20,722	46,711	0
20	2020	0	27,528	22,131	49,659	0
21	2021	0	29,094	23,560	52,654	0
22	2022	0	30,650	24,976	55,626	0
23	2023	0	32,182	26,364	58,547	0
24	2024	0	33,683	27,714	61,397	0
25	2025	0	26,709	29,044	55,753	8,459
26	2026	0	7,177	30,409	37,586	20,686
27	2027	0	0	17,753	17,753	21,570
28	2028	0	0	-3,618	-3,618	22,204
29	2029	0	0	-26,259	-26,259	22,467
30	2030	0	0	-50,431	-50,431	22,913
31	2031	0	0	-76,411	-76,411	23,562
32	2032	0	0	-91,951	-91,951	11,875
33	2033	0	0	-104,031	-104,031	7,670
34	2034	0	0	-116,336	-116,336	7,315
35	2035	0	0	-122,582	-122,582	666
36	2036	0	0	-129,147	-129,147	685
37	2037	0	0	-136,041	-136,041	700
38	2038	0	0	-149,605	-149,605	7,040

PUC DOCKET NO. 16705
SOAH DOCKET NO. 473-96-2285

APPLICATION OF ENTERGY TEXAS FOR APPROVAL OF ITS TRANSITION TO COMPETITION PLAN AND THE TARIFFS IMPLEMENTING THE PLAN, AND FOR THE AUTHORITY TO RECONCILE FUEL COSTS, TO SET REVISED FUEL FACTORS, AND TO RECOVER A SURCHARGE FOR UNDER-RECOVERED FUEL COSTS	§ § § § § § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

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PUBLIC UTILITY COMMISSION
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SECOND ORDER ON REHEARING

This Second Order on Rehearing (Order) addresses the application filed by Entergy Gulf States, Inc. (EGS or the Company) on November 27, 1996, in accordance with Paragraph 9b of the Stipulation and Agreement approved by the Commission in Docket No. 11292.[1] Through this Order, the Commission adopts in part and modifies in part the Proposal for Decision (PFD) as corrected and the Supplemental Proposal for Decision (SPFD) issued by the State Office of Administrative Hearings (SOAH) Administrative Law Judges (ALJs) in late March 1998.[2]

I. Introduction

The SOAH ALJs conducted separate evidentiary hearings on the four component parts of this docket: fuel, revenue requirement, cost allocation/rate design, and competitive issues. After completion of the hearings and review of the record evidence, the ALJs recommended that the Commission order EGS to reduce its current Texas retail base rates by $137 million, which

[1] *Application of Entergy Corporation and Gulf States Utilities Company for Sale, Transfer or Merger,* Docket No. 11292, 19 P.U.C. BULL. 2040, 2041 (Ordering Paragraph 5) (Dec. 29, 1993).

[2] The ALJs issued the PFD on March 25, 1998, as revised by clarifications, revised text, and revised schedules filed on June 4, 12, and 16, 1998. The ALJs issued the SPFD, which addresses supplemental fuel-related issues, on March 27, 1998. The Commission considered the matters addressed in this Order at its open meetings convened on June 30, July 8 through 10, July 13, July 16, and July 22, 1998. The Commission issued its "final" order in this docket on July 22, 1998. The Commission considered motions for rehearing at its open meetings convened on August 26, and October 8, 1998. A more detailed procedural history of this case is contained in Attachment A to the PFD and the Findings of Fact (FoF) and Conclusions of Law (CoL), as modified, contained in this Order.

Non-Reconcilable Fuel and Purchased Power Expenses

177. It is reasonable to include non-reconcilable coal, gas, and purchased power expenses in the amount of $4,853,684 in cost of service.

Decommissioning Expense

178. The cost to decommission the River Bend plant, adjusted for a ten percent ceiling value for contingencies, will be $385.2 million. EGS' 70% share of this amount is $269,640,000.

179. Based on the Commission's previous adoption of low level radioactive waste disposal costs at 7.5%, the fact that River Bend specific inflation factor has been very low in the past several years, and the fact that decommissioning does escalate at a rate higher than general inflation, a 4.81% escalation rate is reasonable.

180. An 11.47% trust equity return and overall 6.6% return for the trust fund results from the most reasonable assessment of return projections.

181. Total company annual decommissioning expense of $8,551,000 is EGS' reasonable and necessary share of River Bend decommissioning costs as evaluated in PFD §VII.B.

Depreciation Rates and Expense

182. The total reasonable depreciation expense for EGS is stated on Commission Schedule I.

Production Plant

183. Because EGS has no specific plan to retire any generating unit soon, it is reasonable to assume that the units will be retired in the middle of the year, because they may, in fact, be retired at any time during the year.

184. The retirement dates for planning purposes should be used for depreciation purposes, as well. The River Bend license expiration date of August 29, 2025 should be used as the

SIGNED AT AUSTIN, TEXAS the 13th day of October 1998.

PUBLIC UTILITY COMMISSION OF TEXAS

PAT WOOD, III, CHAIRMAN

JUDY WALSH, COMMISSIONER

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Summary of Texas Retail Revenue Requirement Allocation
(Thousands of Dollars)

Description	Texas Retail	Resid.	SGS	GS	LGS	LPS	HLFS	LTG
Eligible Fuel & Purch Power	257,233	79,128	3,781	40,234	22,104	54,567	56,086	1,332
Non-Eligible Fuel & Purch Power	6,481	2,419	141	1,122	512	1,142	1,119	27
Operating and Maintenance	125,312	62,481	4,385	21,035	7,939	14,594	13,483	1,396
Decommissioning Expense	3,665	1,458	90	658	280	596	570	14
Depreciation Expense	60,177	27,332	1,900	11,926	4,233	6,982	6,337	1,466
Amortization	(7,778)	(3,095)	(190)	(1,396)	(594)	(1,265)	(1,210)	(29)
Interest on Customer Deposits	501	230	16	102	36	59	53	7
Taxes Other Than State Income Tax	39,737	17,006	1,109	7,341	2,914	5,599	5,317	450
State Income Taxes	0	0	0	0	0	0	0	0
Federal Income Taxes	27,586	12,459	842	5,469	1,934	3,247	3,005	630
Return on Invested Capital (Return on Rate Base)	108,476	49,683	3,401	21,961	7,761	12,659	11,529	1,483
Gains From Disposition of Allowance	-	-	-	-	-	-	-	-
TOTAL REVENUE REQUIREMENT	621,390	249,101	15,475	108,452	47,119	98,179	96,289	6,775
Quality of Service Adj. Allocated-Rate Base	2,211	1,013	69	448	158	258	235	30
Quality of Service Adj. Reallocated -Distribution Lines	(2,211)	(1,285)	(81)	(615)	(164)	(49)	-	(19)
Adjustment due to IS-Credits to LPS & HLFS	(5,918)					(4,944)	(974)	
Adjustment due to IS-Credits allocated to Firm Classes	5,918	2,463	151	1,113	475	805	887	23
Adjustment due to Senior Citizen Discount Residential	(457)	(457)						
Adjustment due to Senior Citizen Discount Allocated to All	457	183	11	80	35	72	71	5
TOTAL REVENUE REQUIREMENT ADJUSTED	621,390	251,019	15,626	109,477	47,623	94,322	96,508	6,815
Fixed Fuel Factor Revenue	228,784	79,128	3,781	40,234	22,104	30,507	51,697	1,332
Non Fixed Fuel Factor Revenue	28,449					24,060	4,389	
Other Revenues	16,926	7,980	515	3,671	1,290	1,767	1,554	150
BASE RATE REVENUE Before Imputation	347,230	163,911	11,330	65,573	24,229	37,988	38,868	5,332
Imputation due to SSTS	7,222					5,393	1,829	
Imputation due to EEDS	1,261			29	452	585	195	
BASE RATE REVENUE w/ Imputation	338,747	163,911	11,330	65,544	23,777	32,010	36,844	5,332

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Martha O. Hesse, Chairman;
Anthony G. Sousa, Charles G. Stalon
and Charles A. Trabandt.

Gulf States Utilities Company) Docket Nos. ER86-558-002, ER86-558-011 and ER86-558-013

ORDER CLARIFYING PREVIOUS ORDERS

(Issued May 18, 1988)

On February 16, 1988, Gulf States Utilities Company (Gulf States) filed a petition for clarification of certain letter orders approving settlements in this proceeding. 1/ The letter orders approved settlement rates reflecting decommissioning expenses funded through an external fund (River Bend Nuclear Decommissioning Fund) adjusted for a forty-year funding period.

On March 2, 1988, Cajun Electric Power Cooperative, Inc. (Cajun) requested that the Commission explicitly recognize that its contributions to Gulf States' decommissioning fund are, and have been, on the basis of unadjusted decommissioning expenses, and that the instant order will have no application to the rates being charged to Cajun.

Discussion

Gulf States requests that the Commission expressly recognize the amount of yearly decommissioning costs which it is entitled to collect. Gulf States asserts that absent such express recognition, the Internal Revenue Service (IRS) will not permit its deduction of yearly cash contributions to the River Bend Nuclear Decommissioning Fund.

Gulf States contends that it must first receive a "schedule of ruling amounts" from the IRS in order to take this deduction. Gulf States further maintains that the IRS will not provide a taxpayer with a schedule of ruling amounts "unless a public utility commission that establishes or approves rates for electric energy generated by the nuclear power plant to which the

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1/ See Gulf States Utilities Company, 40 FERC ¶ 61,081 (1987); Gulf States Utilities Company, 40 FERC ¶ 61,380 (1987); and Gulf States Utilities Company, 42 FERC ¶ 61,098 (1988).

258016

nuclear decommissioning fund relates has determined the amount of decommissioning costs of such nuclear power plant to be included in the taxpayer's cost of service for ratemaking purposes." 2/ Gulf States maintains that the Commission's letter orders approving the settlements do not expressly address decommissioning costs, although the settlement rates which the Commission has approved are expressly based upon specified decommissioning costs. Gulf States also claims that the IRS has determined that the Commission's letter orders approving the settlements do not satisfy the requirements of its regulations.

We are not convinced that the instant clarifications are necessary. It appears that Gulf States has never submitted to the IRS the letter orders approving the settlements that specified the amount of decommissioning costs that will be reflected in Gulf States' wholesale rates. Based on Gulf States' filing it appears that they requested approval from the IRS on June 24, 1987. 3/ The letter orders were not issued until July 22 and September 25, 1987 and January 31, 1988, respectively. We believe that had Gulf States properly submitted the letter orders that are the subject of our order today to the IRS that no clarification of these orders would be necessary.

We shall nevertheless grant the requests of Gulf States and Cajun. In approving the settlements reached in this docket the Commission has authorized Gulf States to reflect in its wholesale rates yearly decommissioning costs of $112,914. We believe such action to be in the public interest to allow Gulf States to receive the proper tax deduction for its yearly cash contributions to the River Bend Nuclear Decommissioning Fund. This order will also have no application to the rates being charged to Cajun.

The Commission orders:

The Gulf States' and Cajun's requests for clarification are hereby granted.

By the Commission.

(S E A L)

Lois D. Cashell

Lois D. Cashell,
Acting Secretary.

2/ See Petition for Clarification at 3-4, quoting Temp. Treas. Reg. § 1.468A-3T(g) (1986).

3/ See letter of September 22, 1987 of William J. Dwyer, Chief, Branch 6 Corporation Tax Division, IRS at 1.

FEDERAL ENERGY REGULATORY COMMISSION

IRS Schedule Of Ruling Amounts,
dated May 22, 1989

Internal Revenue Service

Department of the Treasury

Attachment 3-G
RBS Repor
Page 4 of 6

P.O. Box 7604
Ben Franklin Station
Washington, DC 20044

Index No.: 0468A.10-03

Person to Contact:
Martin Schaffer

Telephone Number:
(202) 566-6589

Refer Reply to:
CC:P&SI:6 TR-31-824-89

Date: MAY 22 1989

B.J. Willis, Vice President
and Controller
Gulf States Utilities Co.
350 Pine St., P.O. Box 2951
Beaumont, TX 77704

In re: Schedule of Ruling Amounts
Gulf States Utilities Co.
River Bend Nuclear Power Plant

Company:	Gulf States Utilities Co. EIN: 74-0662730
Plant:	River Bend Nuclear Power Plant (a 940MW boiling water reactor)
Location:	Just south of St. Francisville, LA (28 miles north of Baton Rouge, LA)
Utility:	Cajun Electric Power Cooperative
Commission A:	Federal Energy Regulatory Commission
Commission B:	Public Utility Commission of Texas
Commission C:	Louisiana Public Service Commission
State A:	Texas
State B:	Louisiana

Dear Mr. Willis:

This is in response to your request dated February 24, 1989, for a revised schedule of ruling amounts. Information was submitted by the Company in accordance with section 1.468A-3(h)(2) of the Income Tax Regulations. The facts as represented by the Company follow.

The Company, incorporated in State A, is an electric utility operating in States A and B. The Company owns 70 percent of the Plant as a tenant in common. The Utility owns the other 30 percent.

The Plant began commercial operations on June 16, 1986, and its operating license is scheduled to expire on August 29, 2025.

The rates for electric energy generated by the Plant are established by Commissions A, B, and C. The Internal Revenue Service approved a schedule of ruling amounts within the jurisdiction of Commission B on November 15, 1988, and within Commission C's jurisdiction on September 27, 1988.

The original schedule of ruling amounts under Commission A's jurisdiction was approved by the Internal Revenue Service on September 27, 1988. However, the Company failed to make a contribution to the nuclear decommissioning fund for the year 1986 with thirty days of receipt of the approved schedule, as required by section 1.468A-8(b)(2) of the regulations. This failure shortened the funding period, as defined in section 1.468A-3(c)(1), and thus changed the qualifying percentage, as defined in section 1.468-3(d)(4).

By orders dated July 22, 1987, September 25, 1987, January 21, 1988, and May 18, 1988, Commission A (jurisdictional percentage: 5.6358 percent) determined the amount of decommissioning costs to be included in the Company's cost of service for ratemaking purposes. There is no proceeding pending before Commission A that may result in an increase or decrease in the amount of these decommissioning costs.

The estimated cost of decommissioning the Plant is $201,406,000 in 1985 dollars. This estimate, based on the prompt removal/dismantlement method of decommissioning, was calculated by a site-specific engineering study ordered by the Company. The Company's share of the total estimated cost of decommissioning is $140,984,200, and its Commission A jurisdictional share is $7,945,588.

Based on an assumed inflation rate of four percent, the total cost of decommissioning expressed in future dollars is $966,950,206. The Company's share of this amount is $676,865,144. The Commission A jurisdictional amount is $38,146,766.

Using an assumed after-tax rate of return of nine percent, Commission A determined the amount of decommissioning costs to be included in the Company's 1988 cost of service (~~the Company~~'s annual share of the total estimated costs) to be $112,914.

The estimated year in which substantial decommissioning costs will first be incurred is 2026. The estimated year in which decommissioning of Plant will be substantially complete is 2031.

The first taxable year for which a deductible payment was made to the nuclear decommissioning fund is 1988. The taxable year that includes the estimated date on which decommissioning costs will no longer be included in the Company's cost of service is 2025. The taxable year that includes the estimated date on which the Plant will no longer be included in the Company's rate base is 2026 (January 1).

The funding period, the level funding limitation period, and the estimated period over which the nuclear decommissioning fund is to be in effect all are 38 years. The estimated useful life of the Plant is 40 years.

The Company's qualifying percentage is 95 percent.

Section 88 of the Internal Revenue Code provides that a taxpayer who is required to include nuclear decomissioning costs in its cost of service for ratemaking purposes shall include this amount in its gross income.

Section 468A(a) of the Code provides that a taxpayer may elect to deduct the amount of payments made to a qualified nuclear decommissioning fund. However, section 468A(b) limits the amount paid into the fund for any taxable year to the lesser of the amount of nuclear decomissioning costs allocable to the fund which is included in the taxpayer's cost of service for ratemaking purposes for the taxable year or the ruling amount applicable to this year.

Section 468A(d)(1) of the Code provides that no deduction shall be allowed for any payment to the fund unless the taxpayer requests and receives from the Secretary a schedule of ruling amounts. The "ruling amount" for any taxable year is defined under section 468A(d)(2) as the amount which the Secretary determines to be necessary to fund that portion of nuclear decommissioning costs which bears the same ratio to the total nuclear decommissioning costs in regard to the nuclear power plant as the period for which the decommissioning fund is in effect bears to the estimated

Report on Status of Decommissioning Funding
10 CFR 50.75(f)(1)
March 31, 2005

Attachment 3
RBS-30% Report

River Bend Station-Non Regulated 30% Interest

Minimum Reporting Requirements as per 10 CFR 50.75(f)(1):

1. Decommissioning funds estimated pursuant to 10 CFR 50.75(b) and (c) (2004$):	
Non-Regulated 30% Interest	$ 202,258,466 [1]
2. Market value of funds accumulated as of December 31, 2004:	
Non-Regulated 30% Interest	$ 173,248,315 [2,4]
3. Current schedule of annual amounts remaining to be collected:	N/A [4]
4. Assumed rate of decommissioning cost escalation used in funding projections:	N/A [4]
5. Assumed average after-tax rates of earnings used in funding projections :	N/A [4]
6. Assumed rates of other factors used in funding projections :	N/A [4]
7. Contracts assuring collection of decommissioning funds:	N/A [4]
8. Modifications to method of providing financial assurance since March 31, 2003 filing (external sinking fund):	None
9. Material changes to trust agreements since March 31, 2003 filing:	See Footnote 6

Supplemental Information:

1. Site-Specific cost estimate escalated to 2004:	
Non-Regulated 30% Prefunded Interest (1996 Base Year Dollars)	
NRC License Termination Cost:	$ 132,838,872 [3]
Non-NRC License Termination Cost:	$ 17,968,616 [3]
Total	$ 150,807,487
2. Decommissioning method assumed for planning purposes in site-specific estimate:	DECON
3. Year site-specific estimate complete:	1996 [5]
4. Frequency of updates (approximately):	once every 5 years
5. Funding based on NRC minimum or site-specific estimate?:	Site-specific
6. Decommissioning rate regulation (approximately):	
Unregulated Interest (prefunded)	30.00% [4]

[1] See Attachment 3-A for calculations.

[2] Source: December 31, 2004 River Bend Station Trust Fund Report.

[3] See Attachment 3-B for calculations. Also see footnote 4 to Attachment 3-A for information on the generic baseline cost estimate using the waste vendor disposal factor (Barnwell, South Carolina).

[4] Cajun contributed $132 million to prefund its decommissioning obligation with respect to its former 30% ownership share. This fund may only be used to decommission the non-regulated 30% interest. Any excess funds after decommissioning must be returned to Rural Utilitiy Services.

[5] The 2004 cost update for $200.13 million (30% of $667.1 million in '04 $) has not been filed.

[6] The following section was added to all trust agreements on December 17, 2003:
Notice Regarding Disbursements or Payments Notwithstanding anything to the contrary in this Agreement, except for (i) payments of ordinary administrative costs (including taxes) and other incidental expenses of the Trust Fund (including legal, accounting, actuarial, and Successor Trustee expenses) in connection with the operation of the Trust Fund, (ii) withdrawals being made under 10 CFR 50.82(a)(8), and (iii) transfers between Qualified and Nonqualified Funds in accordance with the provisions of this Agreement, no disbursement or payment may be made from the Trust Fund until written notice of the intention to make a disbursement or payment has been given to the Director, Office of Nuclear Reactor Regulation, or the Director, Office of Nuclear Material Safety and Safeguards, as applicable, at least 30 working days before the date of the intended disbursement or payment. The disbursement or payment from the Trust Fund, if it is otherwise in compliance with the terms and conditions of this Agreement, may be made following the 30-working day notice period if no written notice of objection from the Director, Office of Nuclear Reactor Regulation, or the Director, Office of Nuclear Material Safety and Safeguards, as applicable, is received by the Successor Trustee or the Company within the notice period. The required notice may be made by the Successor Trustee or on the Successor Trustee's behalf. This Section 8.04 is intended to qualify each and every provision of this Trust Agreement allowing distributions from the Trust Fund, and in the event of any conflict between any such provision and this Section, this Section shall control.

RIVER BEND STATION
CALCULATION OF MINIMUM AMOUNT AS PER 10CFR 50.75 (b) AND (c)

Determination of Minimum Amount-Non Regulated 30% Interest

Entergy Gulf States, Inc.: 100% ownership interest
Plant Location: St. Francisville, Louisiana
Reactor Type: Boiling Water Reactor ("BWR")
Power Level: <3400 MWt (Approx. 3091 MWt.)
1986 BWR Base Year $: $131,819,000
Waste Burial Facility: Barnwell, South Carolina

10 CFR 50.75(c)(2) Escalation Factor Formula:
0.65(L) + 0.13(E) + 0.22(B)

	Factor
L= Labor (South)	1.925 [1]
E= Energy (BWR)	1.448 [2]
B= Waste Burial (BWR)	16.705 [3]

BWR Escalation Factor:
0.65(L) + 0.13(E) + 0.22(B) = 5.11455

1986 BWR Base Year $ Escalated:
1986 BWR Base Year $ * Escalation Factor = $ 674,194,886 [4]

Non-regulated 30% Interest $ 202,258,466 [4,5]

[1] Source: Bureau of Labor Statistics: series report id ecu13202i (March 2005).
[2] Source: Bureau of Labor Statistics: series report id wpu0543 and wpu0573 (March 2005).
[3] Source: Nuclear Regulatory Commission:Table 2.1 of "Report on Waste Burial Charges", NUREG-1307 revision 10(October 2002).
[4] Application of the 8.860 waste vendor disposal factor (South Carolina) from Table 2.1 of "Report on Waste Burial Charges", NUREG 1307 Revision 10 (October 2002) yields a generic baseline cost of:
Non-regulated 30% Interest = $ 134,006,542
[5] Cajun contributed $132 million to prefund its decommissioning obligation with respect ot its former 30% ownership share.

RIVER BEND STATION
CALCULATION OF SITE-SPECIFIC COST ESTIMATE
ESCALATED TO 2004 DOLLARS
RIVER BEND 30% PREFUNDED INTEREST

Site-Specific Cost Estimate (1996$)

Site-Specific Cost Estimate (1996$ - 30%):	
NRC License Termination Cost:	$ 110,710,694 [2]
Non-NRC License Termination Cost:	$ 14,975,420 [3]
Total Site-Specific Cost Estimate:	$ 125,686,114 [1]
Annual Escalation Factor:	CPI
Years of Escalation (1996 Base Year to 2004):	8
Cumulative Factor :	1.200
Site-Specific Cost Estimate (2004$):	
NRC License Termination Cost * Cumulative Factor:	$ 132,838,872
Non-NRC License Termination Cost: * Cumulative Factor:	$ 17,968,616
Total Site-Specific Cost Estimate:	$\boxed{\$\ 150,807,487}$ [1]

[1] Based on 30% of the site-specific cost estimate of $418,953,716 in 1996$ and escalated annually at rates tied to projections of the Consumer Price Index-Urban ("CPI"). The projection for the cumulative CPI from the period 1996 through 2004 was 19.99%.
[2] From 1996 Decommissioning Cost Estimate for River Bend, Table C, times 30%.
[3] From 1996 Decommissioning Cost Estimate for River Bend, Table C, times 30%.

Report on Status of Decommissioning Funding
Required by 10 CFR 50.75(f)(1)
March 31, 2005

Waterford 3 Steam Electric Station

Minimum Reporting Requirements as per 10 CFR 50.75(f)(1):

1. Decommissioning funds estimated pursuant to 10 CFR 50.75(b) and (c) 2004$:	$ 583,670,340	1
2. Market value of funds accumulated as of December 31, 2004:	$ 176,042,107	2
3. Current schedule of annual amounts remaining to be collected:	See Attachment 4-C	
4. Assumed rate of decommissioning cost escalation used in funding projections:	5.50%	
5. Assumed average after-tax rates of earnings used in funding projections :	7.44%	5
6. Assumed rates of other factors used in funding projections:	See Attachment 4-C	
7. Contracts assuming collection of decommissioning funds:	None	
8. Modifications to method of providing financial assurance since March 31, 2003 filing (external sinking fund):	None	
9. Material changes to trust agreements since March 31, 2003 filing:	See Footnote 6	

Supplemental Information:

1. Site-Specific cost estimate escalated to 2004 (1993 Base Year Dollars):		
NRC License Termination Amount:	$ 522,670,324	3
Non-NRC License Termination Cost:	$ 54,226,741	3
Total	$ 576,897,065	
2. Decommissioning method assumed for planning purposes in site-specific estimate:	DECON	
3. Year site specific estimate complete:	1994	4
4. Frequency of updates (approximately):	once every 5 years	4
5. Funding based on NRC minimum or site-specific estimate?:	Site-specific	
6. Decommissioning rate regulation (approximately):		
Louisiana Public Service Commission	97%	
Council of the City of New Orleans	3%	

[1] See Attachment 4-A for caluculations.

[2] Source: December 31, 2004 Waterford 3 Trust Fund Report.

[3] See Attachment 4-B for caluculations. Also see footnote 4 to Attachment 4-A for information on the generic baseline cost estimate using the waste vendor disposal factor (Barnwell, South Carolina).

[4] Entergy Louisiana refiled a 1999 decommissioning cost update of $481.5 million for Waterford 3 with the LPSC in the third quarter in a full rate case with the LPSC in July, 2003. The 2004 cost update has not been finalized.

[5] Assumed after-tax earnings rate for the decommissioning fund for the period 2005-2040 (LPSC Docket No. U-17906-A).

[6] The following section was added to all trust agreements on December 17, 2003:

Notice Regarding Disbursements or Payments . Notwithstanding anything to the contrary in this Agreement, except for (i) payments of ordinary administrative costs (including taxes) and other incidental expenses of the Trust Fund (including legal, accounting, actuarial, and Successor Trustee expenses) in connection with the operation of the Trust Fund, (ii) withdrawals being made under 10 CFR 50.82(a)(8), and (iii) transfers between Qualified and Nonqualified Funds in accordance with the provisions of this Agreement, no disbursement or payment may be made from the Trust Fund until written notice of the intention to make a disbursement or payment has been given to the Director, Office of Nuclear Reactor Regulation, or the Director, Office of Nuclear Material Safety and Safeguards, as applicable, at least 30 working days before the date of the intended disbursement or payment. The disbursement or payment from the Trust Fund, if it is otherwise in compliance with the terms and conditions of this Agreement, may be made following the 30-working day notice period if no written notice of objection from the Director, Office of Nuclear Reactor Regulation, or the Director, Office of Nuclear Material Safety and Safeguards, as applicable, is received by the Successor Trustee or the Company within the notice period. The required notice may be made by the Successor Trustee or on the Successor Trustee's behalf. This Section 8.04 is intended to qualify each and every provision of this Trust Agreement allowing distributions from the Trust Fund, and in the event of any conflict between any such provision and this Section, this Section shall control.

WATERFORD 3 STEAM ELECTRIC STATION
CALCULATION OF MINIMUM AMOUNT AS PER 10CFR 50.75 (b) AND (c)

Determination of Minimum Amount

Entergy Louisiana, Inc.: 100% ownership/leasehold interest
Plant Location: Taft, Louisiana
Reactor Type: Pressurized Water Reactor ("PWR")
Power Level: >3,400 MWt.
1986 PWR Base Year $: $105,000,000
Labor Region: South
Waste Burial Facility: Barnwell, South Carolina

10 CFR 50.75(c)(2) Escalation Factor Formula:
0.65(L) + 0.13(E) + 0.22(B)

	Factor
L= Labor (South)	1.925 [1]
E= Energy (PWR)	1.434 [2]
B= Waste Burial (PWR)	18.732 [3]

PWR Escalation Factor:
0.65(L) + 0.13(E) + 0.22(B) = 5.55877

1986 PWR Base Year $ Escalated:
$ 105,000,000 * Escalation Factor = $ 583,670,340 [4]

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[1] Source: Bureau of Labor Statistics: series report id ecu13202i (March 2005).
[2] Source: Bureau of Labor Statistics: series report id wpu0543 and wpu0573 (March 2005).
[3] Source: Nuclear Regulatory Commission:Table 2.1 of "Report on Waste Burial Charges", NUREG-1307revision10(October 2002).
[4] Application of the 9.467 waste vendor disposal factor (South Carolina) from Table 2.1 of "Report on Waste Burial Charges", NUREG 1307 Revision 10 (October 2002) yields a generic baseline cost = $ 369,648,840

WATERFORD 3 STEAM ELECTRIC STATION
CALCULATION OF SITE-SPECIFIC COST ESTIMATE
ESCALATED TO 2004 DOLLARS

Site-Specific Cost Estimate (1993$)

Site-Specific Cost Estimate (1993$):		
NRC License Termination Cost:	$ 290,035,252	
Non-NRC License Termination Cost:	$ 30,090,988	
Total Site-Specific Cost Estimate:	$ 320,126,240	1
Annual Escalation Factor:	5.50%	1
Years of Escalation (1993 Base Year to 2004):	11	
Cumulative Factor (1 + Factor)^11	1.802	
Site-Specific Cost Estimate (2004$):		
NRC License Termination Cost * Cumulative Factor:	$ 522,670,324	
Non-NRC License Termination Cost * Cumulative Factor:	$ 54,226,741	
Total Site-Specific Cost Estimate:	$ 576,897,065	

[1]The funding amounts (Attachment 4-C) are based on site-specific cost estimates in 1993$ and an escalation rate of 5.50%.

Attachment 4-C
WF3 Report

Louisiana Power & Light Company
Waterford-3 Decommissioning Model
Trust Fund Summary
($000)

			Tax Qualified Trust						
Line No	Year	Revenue Rqmt. [1]	Earning Rate [2]	Transfer To Trust	Earnings [3]	Management Fee	Net Additions	Decomm. Funding [5]	Balance
1	Beginning Balance								29,172
2	1995	8,786	0.0675	8,786	2,299	(74)	11,011	0	40,183
3	1996	8,786	0.0675	8,786	3,055	(90)	11,750	0	51,934
4	1997	8,786	0.0675	8,786	3,861	(105)	12,542	0	64,475
5	1998	8,786	0.0675	8,786	4,722	(122)	13,386	0	77,862
6	1999	8,786	0.0800	8,786	6,705	(140)	15,351	0	93,213
7	2000	10,420	0.0800	10,420	8,023	(161)	18,282	0	111,495
8	2001	10,420	0.0800	10,420	9,515	(185)	19,750	0	131,244
9	2002	10,420	0.0800	10,420	11,126	(211)	21,335	0	152,580
10	2003	10,420	0.0800	10,420	12,867	(239)	23,048	0	175,628
11	2004	10,420	0.0800	10,420	14,748	(269)	24,899	0	200,527
12	2005	12,353	0.0800	12,353	16,857	(303)	28,907	0	229,434
13	2006	12,353	0.0800	12,353	19,216	(341)	31,228	0	260,662
14	2007	12,353	0.0800	12,353	21,764	(382)	33,735	0	294,397
15	2008	12,353	0.0800	12,353	24,517	(426)	36,444	0	330,841
16	2009	12,353	0.0800	12,353	27,491	(474)	39,370	0	370,211
17	2010	14,743	0.0800	14,743	30,799	(527)	45,014	0	415,225
18	2011	14,743	0.0800	14,743	34,472	(586)	48,629	0	463,854
19	2012	14,743	0.0800	14,743	38,440	(650)	52,533	0	516,387
20	2013	14,743	0.0800	14,743	42,727	(719)	56,751	0	573,138
21	2014	14,743	0.0800	14,743	47,358	(793)	61,307	0	634,445
22	2015	17,598	0.0800	17,598	52,475	(876)	69,197	0	703,642
23	2016	17,598	0.0800	17,598	58,121	(966)	74,753	0	778,395
24	2017	17,598	0.0800	17,598	64,221	(1,064)	80,755	0	859,150
25	2018	17,598	0.0800	17,598	70,811	(1,170)	87,238	0	946,388
26	2019	17,598	0.0800	17,598	77,929	(1,285)	94,243	0	1,040,631
27	2020	20,998	0.0800	20,998	85,755	(1,410)	105,343	0	1,145,974
28	2021	20,998	0.0675	20,998	79,367	(1,539)	98,826	0	1,244,800
29	2022	20,998	0.0675	20,998	86,151	(1,668)	105,481	0	1,350,281
30	2023	20,998	0.0675	20,998	93,391	(1,805)	112,584	0	1,462,865
31	2024	20,998	0.0675	20,998	101,118	(1,950)	120,167	(3,333)	1,579,699
32	2025	0	0.0675	0	108,429	(2,033)	106,396	(91,609)	1,594,486
33	2026	0	0.0675	0	109,444	(2,049)	107,395	(96,647)	1,605,234
34	2027	0	0.0675	0	110,182	(2,043)	108,139	(128,670)	1,584,703
35	2028	0	0.0675	0	108,773	(1,863)	106,910	(372,283)	1,319,329
36	2029	0	0.0675	0	90,558	(1,501)	89,056	(397,480)	1,010,905
37	2030	0	0.0675	0	69,388	(1,089)	68,298	(413,229)	665,975
38	2031	0	0.0675	0	45,712	(626)	45,086	(434,804)	276,256
39	2032	0	0.0675	0	18,962	(288)	18,674	(164,583)	130,346
40	2033	0	0.0675	0	8,947	(114)	8,833	(139,179)	0
								(2,241,818)	
			7.44%						

Notes:

1. The 2005 Revenue Requirement (10,420) is chosen and escalated by Cumulative CPIU From 2005 every fifth year so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
   The average annual CPIU rate is 3.6%.
2. Projected after-tax earnings rate, assumed average after-tax earnings rate is 7.44%.
   (Assumed after-tax earnings rate is 7.44% for the period 2005-2040.)
3. Prior Year Balance compounded semiannually at Current Year Earning Rate + ½ Current Year Transfer * Current Year Earning Rate.
4. Transfer + Earnings + Management Fee.
5. The Nuclear Cost Escalator is 5.5%.