Entergy

September 23, 2004

Steve P. Rodgers
Director
Division of Tariffs and Market
Development
888 First Street, N.E.
Washington, D.C. 20426

RE: *Entergy Services, Inc., Docket Nos. ER04-699 and ER03-1272*

Dear Mr. Rodgers:

Please find enclosed the responses of Entergy Services, Inc., on behalf of the Entergy Operating Companies, to the Post Technical Conference Data Request issued on August 17, 2004. Entergy also responds to certain items that arose during the Commission's August 26, 2004 meeting held to address products that Entergy is interested in purchasing through the Weekly Procurement Process. If you have any questions about the data responses please feel free to contact me at 504-576-4267.

Sincerely

KH Despeaux /AVC

Kimberly H. Despeaux
Associate General Counsel
Entergy Services, Inc.

cc: Anna Cochrane
Division of Tariffs and Market Development - South
Office of Markets, Tariffs and Rates

Attachments

DEFINITIONS

Unless designated otherwise in the accompanying Responses, these acronyms represent the following terms:

ACRONYM	TERM
AFC	Available Flowgate Capacity
AGC	Automatic Generation Control
APSC	Arkansas Public Service Commission
ATC	Available Transfer Capability
Calpine	Calpine Corp.
CERA	Cambridge Energy Research Associates
CIAC	Contributions in Aid of Construction
Cleco	Cleco Power LLC
DSG	Downstream-of-Gypsy
ECAR	East Central Area Reliability Coordination Agreement
EGSI	Entergy Gulf States, Inc.
EMO	Energy Management Organization
EMS	Energy Management System
EOC	Entergy Operating Companies
ERIS	Energy Resource Interconnection Service
ESI	Entergy Services, Inc.
ETO	Entergy Transmission Organization
FTR	Financial Transmission Rights

GOL	Generator Operating Limits
ICT	Independent Coordinator of Transmission
IPP	Independent Power Producer (also referred to as "merchant generators")
ISES	Independence Steam Electric Station
ISO	Independent System Operator
LMP	Locational Marginal Pricing
LPSC	Louisiana Public Service Commission
LUS	Lafayette Utilities System
MAIN	Mid-America Interconnected Network, Inc.
NERC	North American Electric Reliability Council
NITS	Network Integration Transmission Service
NRG	NRG Energy, Inc.
NRIS	Network Resource Interconnection Service
O&M	Operation and Maintenance
OASIS	Open Access Same-time Information System
OATT	Open Access Transmission Tariff
OG&E	Oklahoma Gas & Electric
PJM	PJM Interconnection
QF	Qualifying Facility

RFCalc	Response Factor Calculator
RFP	Request for Proposals
RTO	Regional Transmission Organization
SEARUC	Southeast Association of Regulatory Utility Commissioners
SIS	System Impact Study
SPP	Southwest Power Pool, Inc.
TO	Transmission Owner
TSR	Transmission Service Request
TVA	Tennessee Valley Authority
WOTAB	West of the Atchafalya Basin
WPP	Weekly Procurement Process

Entergy Services, Inc.
FERC Technical Conference
Docket No. ER04-699-000
Docket No. ER03-1272-002

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: Federal Energy Regulatory Commission

Question No. 1

Question:

1. Mr. Jolly Hayden, representing Calpine stated that, based on Entergy's Form 1 filings, over the last four years Entergy invested in the range of $30 million in new transmission investment while merchant generators (IPP) have contributed in excess of $200 million. (Tr. at 108-109). However, in response, Entergy's representative, Mr. Bartlett stated that over the 5-year period from 1998 to 2002, Entergy invested $350 million in transmission upgrades. (Tr. at 140)

    a. Please provide workpapers and documentation to support Mr. Bartlett's assertions.

    b. Please provide a breakdown of transmission O&M expense and transmission investment during 1998 through 2002 by year, by Operating Company, and by type (*e.g.*, transmission line, software, etc.).

    c. Please provide a copy of Entergy's most recent short-term and long-term transmission investment plans. Indicate any significant changes that have been made to those plans in the last two years and the reasons for those changes.

    d. Does Entergy agree with Mr. Hayden's assertion that merchant generators have contributed in excess of $200 million over the last four years? If not, what level of investment does Entergy believe merchant generators have contributed during that time period? Please provide documentation to support the estimate.

Response:

a. Mr. Bartlett's $350 million answer to this question was a conservative estimate of the investment amount. Between 1998 and 2002 total investment in transmission assets, per the Entergy Operating Companies' FERC Form 1s, in fact totaled

$591 million. Between 1998 and 2003, that total increased to $861 million. That total amount ($861 million) will be recovered from Entergy customers.

Of these total amounts, for the period 1998-2002, $72 million represents unrefunded IPP investment in required and optional upgrades. For 2003, the amount is $57 million. Because these dollar amounts are credit eligible, they will be paid for by Entergy customers.

These investments are summarized in the following table, and shown in Attachment A hereto:

	1998 - 2002	2003	1998 - 2003
Total Transmission Investment	$ 591,229,323	$ 270,681,530	$ 861,910,853
Investment Initially Funded by IPPs (unrefunded)	(71,707,038)	(56,743,231)	(128,450,269)
Investment Initially Funded by Entergy	$ 519,522,285	$ 213,938,299	$ 733,460,584

b. Transmission O&M expense per the Entergy Operating Companies' FERC Form 1s for the years 1998 through 2003 is shown in Attachment A and are summarized in the table below:

	Total O&M 1998 - 2002	Total O&M 2003	Total O&M 1998 - 2003
EAI	$ 78,587,063	$ 17,438,368	$ 96,025,431
EMI	46,303,364	10,784,091	57,087,455
ELI	58,541,029	15,780,876	74,321,905
ENOI	32,096,769	7,461,977	39,558,746
EGSI	208,442,294	40,346,040	248,788,334
Total	$ 423,970,519	$ 91,811,352	$ 515,781,871

Transmission investment during this same time frame is shown in Attachment A and summarized in the table below:

Category	Total Investment 1998 - 2002	Total Investment 2003	Total Investment 1998 - 2003
Lines	$ 330,191,837	$ 114,267,319	$ 444,459,156
Substations	255,153,357	154,565,618	409,718,975
Other	5,884,129	1,848,593	7,732,722
Total	$ 591,229,323	$ 270,681,530	$ 861,910,853

c. Entergy's current transmission investment plans for 2004 through 2008 are summarized below:[1]

Forecasted Transmission Investment – System-wide (millions)	**2004**	**2005**	**2006**	**2007**	**2008**
Entergy Investment - Reliability	$120	$120	$120	$120	$120
Entergy Investment - Supplemental Projects	120	150	75	75	25
IPP Investment	27	3	24	3	0
Total	$267	$273	$219	$198	$145

The significant changes that have been made to Entergy's transmission investment plans over the past few years include significant investments in transmission projects for reliability and economic reasons.

In northern Arkansas, the Company is building a new 161 kV transmission line between ISES and Newport Substations at a cost of approximately $8 million. This line is needed to reliably serve the load within this area.

In early 2004, the Company committed to performing approximately $88 million of transmission investments in the DSG area in southeast Louisiana to maintain reliability under peak load conditions in the local area. Beginning in the summer of 2003, Transmission Operations established revised operating guidelines that require the commitment of all eight of the generating units at the Ninemile and Michoud generating facilities to maintain adequate system voltage support during high loading conditions under certain double contingencies. Given the age and availability of these units, transmission projects were identified that will reduce this reliability must-run requirement. These transmission investments increase power transfer capability into the DSG area.

Additionally, the Company has committed to significant transmission investment to increase the load-serving capability within the Company's EGSI-Texas service territory. Through its transmission analyses, the Company recognized a need to

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1 Forecasted investments by year are based on estimated spending plans at the time of preparation of these data responses and are subject to change based on various factors, including system needs. The IPP investment forecast is based on signed Interconnection and Operating Agreements as well as valid interconnection requests in the interconnection queue.

increase the transmission system's load serving capability to serve the EGSI-Texas load reliably under various double contingency events. Thus, in late 2003, the Company incorporated into its transmission plan approximately $92 million of various transmission projects in Entergy's Texas region to increase the area's load-serving capability.

In northern Louisiana, all generating units at Sterlington Substation must be in-service to reliably serve the load in the City of Monroe and surrounding area under high loading conditions. To relieve the generation must-run requirements at Sterlington, the Company will be installing a new 500kV/115kV transformer at Sterlington Substation as well as reconfiguring Sterlington Substation at a cost of approximately $15 million.

Also in early 2004, the Company incorporated into its transmission plan transmission expansion of its 230 kV transmission system in the Amite South area in southeast Louisiana to increase the area's power transfer capability. The committed projects resulted from a cost/benefit study undertaking by the Company and the LPSC. The projects include the construction of a new 230 kV transmission line as well as the upgrades of two existing 230 kV transmission lines. These projects, at a cost of approximately $50 million, are expected to yield economic benefits to Entergy's native load customers.

Further details of some of the projects described above are shown in Attachment B.[2]

d. Optional and certain required upgrades funded by IPPs, which are eligible for refund through transmission service credits, are reported in the EOCs' FERC Form 1s as part of additions. Payments made by IPPs that are not credit eligible, which are funded by CIAC, are not reported in the Form 1s. A recap of transmission investment by the IPPs is included in Attachment A and summarized below.

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[2] Due to its length, Attachment B is located at:

http://oasis.eterrasolutions.com/documents/EES/Independent_Coordinator_Filing.htm.

Entergy also is including an electronic version of Attachment B with its filing.

	1998 – 2002	2003*	1998 - 2003
Credit Eligible Investment Initially Funded by IPPs (unrefunded)	$ 71,707,038	$ 56,743,231	$ 128,450,269
IPP investment (CIAC)	172,853,212	(40,145,752)	132,707,460
Total IPP Investment	$ 244,560,250	$ 16,597,479	$ 261,157,729

* The Commission issued several orders in early 2003 that resulted in costs that were previously not credit eligible becoming credit eligible with various effective dates. These orders resulted in a cumulative adjustment in 2003 of $70 million of CIAC being reclassified to credit eligible.

Entergy Services, Inc.
Docket NO. ER04-699-000
Docket NO. ER03-1272-002
Attachment A

Question 1 a.

Entergy FERC Form 1, Transmission Plant Additions by Jurisdiction
Source: Pages 206 & 207: Total Transmission Plant

	Additions						Additions (1)	
	1998	1999	2000	2001	2002	Total Investment 1998 - 2002	2003	Total Investment 1998 - 2003
EAI	$14,651,162	$13,559,796	$58,671,450	$40,903,892	$73,589,872	$201,376,172	$69,877,716	$271,253,888
EMI	7,183,671	6,964,639	25,334,866	12,201,404	36,191,961	87,876,541	57,910,218	145,786,759
ELI	5,816,700	7,762,746	24,701,779	29,466,378	17,059,071	84,806,674	40,581,146	125,387,820
ENOI	1,233,794	310,417	631,273	4,123,716	1,317,817	7,617,017	1,478,049	9,095,066
EGSI	27,298,646	30,206,921	45,320,550	61,925,327	44,801,475	209,552,919	100,834,401	310,387,320
Total	$56,183,973	$58,804,519	$154,659,918	$148,620,717	$172,960,196	$591,229,323	$270,681,530	$861,910,853

	1998 - 2002	2003 (1)	1998 - 2003
Total Additions	$591,229,323	$270,681,530	$861,910,853
IPP investment (*Refundable (Optional and Required) upgrades included in Form 1) (2)*)	(71,707,038)	(56,743,231)	(128,450,269)
Entergy Investment	$519,522,285	$213,938,299	$733,460,584

(1) In early 2003, FERC issued various orders requiring interconnection costs to be reclassified as required upgrades.
$70,371,328 was reclassified from non-credit eligible to credit eligible and is reported in 2003 Form 1 additions.

(2) Net of amounts refunded through Transmission service credits.

Question 1 b.

Entergy FERC Form 1, Operation and Maintenance Expense (Accounts 560 - 573)
Source: Page 321; Total Transmission Expenses

	1998	1999	2000	2001	2002	Total O&M 1998 - 2002	2003	Total O&M 1998 - 2003
EAI	$13,181,284	$13,151,304	$16,905,455	$18,956,636	$16,392,384	$78,587,063	$17,438,368	$96,025,431
EMI	8,238,430	8,723,497	10,042,732	9,339,333	9,959,372	46,303,364	10,784,091	57,087,455
ELI	11,586,217	8,211,890	10,945,820	12,835,722	14,961,380	58,541,029	15,780,876	74,321,905
ENOI	6,717,502	5,856,856	6,510,006	6,486,877	6,525,528	32,096,769	7,461,977	39,558,746
EGSI	41,837,076	40,767,792	42,761,659	43,659,397	39,416,370	208,442,294	40,346,040	248,788,334
Total	$81,560,509	$76,711,339	$87,165,672	$91,277,965	$87,255,034	$423,970,519	$91,811,352	$515,781,871

Entergy Services, Inc.
Docket NO. ER04-699-000
Docket NO. ER03-1272-002
Attachment A

Question 1 b. (continued)

Entergy FERC Form 1, Transmission Plant Additions by Category
Source: Pages 206 & 207: Total Transmission Plant

	Category (3)	1998	1999	2000	2001	2002	Total Investment 1998 - 2002	2003	Total Investment 1998 - 2003
EAI	Lines	$11,131,767	$10,493,261	$27,763,933	$29,709,591	$42,190,425	$121,288,977	$23,376,508	$144,665,485
	Substations	3,519,395	2,127,721	30,703,646	10,867,400	31,104,274	78,322,436	46,342,561	124,664,997
	Other	0	938,814	203,871	326,901	295,173	1,764,759	158,647	1,923,406
	Total	14,651,162	13,559,796	58,671,450	40,903,892	73,589,872	201,376,172	69,877,716	271,253,888
EMI	Lines	3,881,397	2,370,460	14,790,308	6,949,645	25,955,363	53,947,173	24,691,615	78,638,788
	Substations	3,301,183	4,592,954	9,868,705	5,251,759	9,413,541	32,428,142	33,218,470	65,646,612
	Other	1,091	1,225	675,853	0	823,057	1,501,226	133	1,501,359
	Total	7,183,671	6,964,639	25,334,866	12,201,404	36,191,961	87,876,541	57,910,218	145,786,759
ELI	Lines	627,305	2,745,904	6,886,076	14,769,355	12,061,520	37,090,160	25,407,830	62,497,990
	Substations	5,189,395	5,016,842	17,774,116	14,287,852	4,837,436	47,105,641	14,101,324	61,206,965
	Other	0	0	41,587	409,171	160,115	610,873	1,071,992	1,682,865
	Total	5,816,700	7,762,746	24,701,779	29,466,378	17,059,071	84,806,674	40,581,146	125,387,820
ENOI	Lines	854,211	260,219	201,026	2,186,726	533,679	4,035,861	31,543	4,067,404
	Substations	379,583	50,198	430,247	1,936,990	784,138	3,581,156	1,446,506	5,027,662
	Other	0	0	0	0	0	0	0	0
	Total	1,233,794	310,417	631,273	4,123,716	1,317,817	7,617,017	1,478,049	9,095,066
EGSI	Lines	19,100,820	15,649,383	21,105,448	34,279,084	23,694,931	113,829,666	40,759,823	154,589,489
	Substations	8,124,486	14,560,677	24,194,972	27,218,677	19,617,170	93,715,982	59,456,757	153,172,739
	Other	73,340	(3,139)	20,130	427,566	1,489,374	2,007,271	617,821	2,625,092
	Total	27,298,646	30,206,921	45,320,550	61,925,327	44,801,475	209,552,919	100,834,401	310,387,320
Total	Lines	35,595,500	31,519,227	70,746,791	87,894,401	104,435,918	330,191,837	114,267,319	444,459,156
	Substations	20,514,042	26,348,392	82,971,686	59,562,678	65,756,559	255,153,357	154,565,618	409,718,975
	Other	74,431	936,900	941,441	1,163,638	2,767,719	5,884,129	1,848,593	7,732,722
	Total	$56,183,973	$58,804,519	$154,659,918	$148,620,717	$172,960,196	$591,229,323	$270,681,530	$861,910,853

(3) FERC Accounts included by category: Lines - 354 through 358; Substations - 352, 353; Other - 350 (Land and Land Rights), 359 (Roads and Trails) and 359.1 (Asset Retirement Costs for Transmission Plant).
Investment in transmission software is reported in FERC account 303, Intangibles. The transmission portion, however, is not specifically broken out from software for other purposes and is not reported in these transmission plant additions.

Entergy Services, Inc.
Docket NO. ER04-699-000
Docket NO. ER03-1272-002
Attachment A

Question 1 d.

	1998 - 2002	2003 (4)	1998 - 2003
IPP investment (*Refundable (Optional and Required) upgrades included in Form 1) (5)*)	$71,707,038	$56,743,231	$128,450,269
IPP investment *(CIAC)*	172,853,212	(40,145,752)	132,707,460
Total IPP Investment	$244,560,250	$16,597,479	$261,157,729

(4) In early 2003, FERC issued various orders requiring interconnection costs to be reclassified as required upgrades. $70,371,328 was reclassified from non-credit eligible to credit eligible and is reported in 2003 Form 1 additions.

(5) Net of amounts refunded through Transmission service credits.

IPP Investment in Transmission - Required and Optional Upgrades
These investments are included in FERC Form 1s as additions and are eligible for refund to the IPP through transmission service credits.

	Project No.	IPP Generator Name	2000	2001	2002	1998 - 2002 (6)	2003	1998 - 2003
EAI	U50146	SKYGEN-UPGRADE TRANS SYS IN PINE BLUFF	$5,945,341	$617,091	$1,726,934	$8,289,367	$117,912	$8,407,279
	U50244	IPP PERRYVILLE CONNECT CLECO MIDSTREAM				0	(7,547)	(7,547)
	U65001	IPP KINDER-MORGAN CONNECT @ WRIGHTVILLE		52,688	15,875,447	15,928,135	13,442,232	29,370,367
	U65006	IPP TAMPA POWER SERVICES TPS DELL			813,021	813,021	(769,935)	43,086
	U65020	IPP TRACTEBEL HOT SPRING POWER COMPANY				0	2,579,494	2,579,494
	U65023	IPP MDEA INTERCONNECT FACILITY CHARGES				0	191,614	191,614
	U75073	STERLINGTON: CONNECT COGENTRIX 800 MW		4,470,454	6,432,096	10,902,550	54,249	10,956,799
	U75108	PANDA INTERCONNECTION @ ELDORADO, ARK			4,012,820	4,012,820	267,160	4,279,980
	U75111	IPP DUKE-ETTA SUBSTATION INTERCONNECT			7,452,656	7,452,656	17,890,255	25,342,911
EAI Total			5,945,341	5,140,233	36,312,975	47,398,549	33,765,434	81,163,983

EMI	U50079	LS POWER BATESVILLE: CONNECT LLC TO ENT	6,419,630	86	(220,973)	6,198,743	152,810	6,351,553
	U50244	IPP PERRYVILLE CONNECT CLECO MIDSTREAM			(10,000)	(10,000)		(10,000)
	U65000	IPP GENPOWER: CONNECT AT MCADAMS, MS		1,779,730	284,353	2,064,084	6,167,061	8,231,145
	U65002	IPP DUKE @ FREEPORT 640MW				0	6,430,343	6,430,343
	U65011	IPP MDEA INTERCONNECTION & UPGRD 300MW				0	3,377,279	3,377,279
	U65012	IPP RELIANT ENERGY CHOCTAW COUNTY LLC				0	1,899,075	1,899,075
	U65023	IPP MDEA INTERCONNECT FACILITY CHARGES			(609)	(609)	8,189,264	8,188,655
	U75070	MCADAMS: CONNECT DUKE ENERGY NA 550 MW	489,836	917,656	139,728	1,547,220		1,547,220
	U75071	LAKEOVER: CONNECT DUKE ENERGY 550 MW	4,395,702	409,368	80,202	4,885,273	6,566,337	11,451,610
	U75072	BAXTER WILSON: CONNECT WARREN POWER	734,439	3,050,622	124,047	3,909,108	68,267	3,977,375
	U75073	STERLINGTON: CONNECT COGENTRIX 800 MW			761,665	761,665		761,665
	U75089	FREEPORT: CONNECT COGENTRIX 800 MW, MS		90,049	6,952,128	7,042,177	101,667	7,143,844
EMI Total			12,039,607	6,247,512	8,110,542	26,397,661	32,952,103	59,349,764

ELI	U50244	IPP PERRYVILLE CONNECT CLECO MIDSTREAM			(104,862)	(104,862)	(5,244)	(110,106)
	U65004	IPP OXY-TAFT COGENERATION PROJ INTERCON			2,612,260	2,612,260	1,854,152	4,466,412
	U65008	IPP CAPLINE-BOGALUSA INTERCONNECTION PRO			(145,383)	(145,383)	3,254,286	3,108,903
	U65013	IPP DOW / AEP INTERCONNECTION PID032			286,160	286,160	302	286,462
	U75040	CONNECT KOCH POWER - AT STERLINGTON	132,255	147	53,619	186,021	92,931	278,952
	U75073	STERLINGTON: CONNECT COGENTRIX 800 MW		8,597,799	6,295,553	14,893,352	15,442	14,908,794
	U75108	PANDA INTERCONNECTION @ ELDORADO, ARK				0	(100)	(100)
ELI Total			132,255	8,597,947	8,997,347	17,727,549	5,211,769	22,939,318

Entergy Services, Inc.
Docket NO. ER04-699-000
Docket NO. ER03-1272-002
Attachment A

Question 1 d. (continued)

	Project No.	IPP Generator Name	2000	2001	2002	1998 - 2002 (6)	2003	1998 - 2003
EGSI	U50083	CONNECT TENASKA FRONTIER PARTNER		167,680		167,680	190	167,870
	U50086	BAYER COGEN PROJECT - ORANGE, TEXAS	342,510	173,410	23,259	539,178		539,178
	U50144	SRW LP COGEN 555MW IPP ORANGE, TX	629,407	2,445,896	6,856,360	9,931,663	14,845	9,946,508
	U65003	IPP INTERGEN COTTONWOOD - HARTBURG			340	340	40,707,786	40,708,126
	U65005	IPP EPG/PPG RS COGEN PROJECT			(736)	(736)		(736)
	U65013	IPP DOW / AEP INTERCONNECTION PID032			709,736	709,736	8,525,782	9,235,518
	U65014	IPP NRG DEVELOPMENT 319MW JENNINGS			5,901	5,901	430,852	436,753
	U65016	IPP SHELL AT WOODSTOCK, GEISMAR			36,136	36,136	(54,386)	(18,250)
	U65019	IPP EXXON MOBIL COGENERATION PROJECT				0	250,182	250,182
	U65021	IPP BRAZOS ELECTRIC NEW 138KV BISHOP SUB				0	(3,459)	(3,459)
	U75074	RICHARD SUB: INSTALL 138KV FAC FOR CLECO		(7,303)	3,247,483	3,240,180	(1,500)	3,238,680
	U75109	IPP SKYGEN @ CARVILLE: INTERCONNECT FAC		391,601	955,299	1,346,900	(1,433,493)	(86,593)
EGSI Total			971,917	3,171,284	11,833,780	15,976,980	48,436,797	64,413,779
Grand Total			$19,089,120	$23,156,975	$65,254,644	$107,500,740	$120,366,103	$227,866,845

(6) Although costs may have been incurred in years prior to 2000, the IPP projects did not start closing to plant until the year 2000. Because these project costs are being reported from the FERC Form 1s, they are reported in the year they were closed to plant-in-service versus the year the costs were incurred.

Entergy Services, Inc.
Docket NO. ER04-699-000
Docket NO. ER03-1272-002
Attachment A

Question 1 d. (continued)

IPP Investment in Transmission - Interconnection and Metering Costs/Contribution in Aid of Construction (CIAC)
These investments are not included in FERC Form 1s as additions and are not eligible for refund to the IPP.

	Project No.	IPP Generator Name	1998 - 2002 (7)	2003	1998 - 2003
EAI	U50146	SKYGEN-UPGRADE TRANS SYS IN PINE BLUFF	$126,976	$21,093	$148,069
	U65001	IPP KINDER-MORGAN CONNECT @ WRIGHTVILLE	11,478,214	1,906,730	13,384,944
	U65006	IPP TAMPA POWER SERVICES TPS DELL	20,759,241	3,448,469	24,207,710
	U65020	IPP TRACTEBEL HOT SPRING POWER COMPANY	17,318,126	2,876,840	20,194,966
	U75108	PANDA INTERCONNECTION @ ELDORADO, ARK	22,986,629	3,818,477	26,805,106
	U75111	IPP DUKE-ETTA SUBSTATION INTERCONNECT	13,533,116	2,248,085	15,781,201
EAI Total			86,202,302	14,319,694	100,521,996
EMI	U50079	LS POWER BATESVILLE: CONNECT LLC TO ENT	851,570	141,460	993,030
	U65000	IPP GENPOWER: CONNECT AT MCADAMS, MS	2,259,236	375,298	2,634,534
	U65002	IPP DUKE @ FREEPORT 640MW	1,265,978	210,301	1,476,279
	U65012	IPP RELIANT ENERGY CHOCTAW COUNTY LLC	785,357	1,642,129	2,427,486
	U65018	IPP SMEPA SILVER CREEK	571,459	94,929	666,388
	U75070	MCADAMS: CONNECT DUKE ENERGY NA 550 MW	3,310,801	549,981	3,860,782
	U75071	LAKEOVER: CONNECT DUKE ENERGY 550 MW	5,630,941	935,397	6,566,338
	U75072	BAXTER WILSON: CONNECT WARREN POWER	2,388,441	396,761	2,785,202
	U75089	FREEPORT: CONNECT COGENTRIX 800 MW, MS	2,097,322	348,402	2,445,724
EMI Total			19,161,105	4,694,658	23,855,763
ELI	U50244	IPP PERRYVILLE CONNECT CLECO MIDSTREAM	7,538,498	1,252,275	8,790,773
	U65004	IPP OXY-TAFT COGENERATION PROJ INTERCON	14,173,495	2,354,463	16,527,958
	U65008	IPP CAPLINE-BOGALUSA INTERCONNECTION PRO	1,835,782	304,955	2,140,737
	U65010	IPP DUKE RUSTON MT. OLIVE	1,022,415	169,841	1,192,256
	U75040	CONNECT KOCH POWER - AT STERLINGTON	1,238,007	205,654	1,443,661
	U75073	STERLINGTON: CONNECT COGENTRIX 800 MW	7,007,904	1,164,134	8,172,038
ELI Total			32,816,101	5,451,322	38,267,423
EGSI	U50144	SRW LP COGEN 555MW IPP ORANGE, TX	2,195,111	364,646	2,559,757
	U65003	IPP INTERGEN COTTONWOOD - HARTBURG	16,207,776	2,692,392	18,900,168
	U65005	IPP EPG/PPG RS COGEN PROJECT	222,074	36,890	258,964
	U65013	IPP DOW / AEP INTERCONNECTION PID032	4,172,920	693,194	4,866,114
	U65014	IPP NRG DEVELOPMENT 319MW JENNINGS	495,348	82,286	577,634
	U65016	IPP SHELL AT WOODSTOCK, GEISMAR	305,990	50,830	356,820
	U65019	IPP EXXON MOBIL COGENERATION PROJECT	4,979,696	827,214	5,806,910
	U75074	RICHARD SUB: INSTALL 138KV FAC FOR CLECO	3,471,106	576,611	4,047,717
	U75109	IPP SKYGEN @ CARVILLE: INTERCONNECT FAC	2,623,683	435,839	3,059,522
EGSI Total			34,673,704	5,759,902	40,433,606
Grand Total			$172,853,212	$30,225,576	$203,078,788

(7) These interconnection project costs are being reported based on when the costs were estimated as incurred versus when the project was placed in service as the required and optional upgrades are reported.

Entergy Services, Inc.
FERC Technical Conference
Docket No. ER04-699-000
Docket No. ER03-1272-002

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: Federal Energy Regulatory Commission

Question No. 2

Question:

2. Mr. Hayden (Calpine) indicated that Calpine's large fleet of generators provides them the flexibility to offer regulation service in the market. (Tr. at 151) Mr. Hurstell, representing Entergy, indicated that Entergy asks generators, through the WPP, to provide the minimum load and maximum load that Entergy can take during the day but that generators have provided little variability during the day. As Chairman Wood requested, (Tr. at 153) please confirm, based on a review of Entergy's records, that generators have not offered the load following attributes that Mr. Hurstell stated Entergy needs to serve its load. Please also confirm Mr. Hurstell's statement that Entergy has not received any offers for AGC capability through the WPP. (Tr. at 152)

Response:

As stated at the Technical Conference, Entergy's load following needs are much greater (in MW) than its regulation needs. Mr. Hayden's statement that Calpine offers regulation service in other markets is not responsive to Entergy's largest need. Entergy has received approximately 1,150 offers to its Weekly RFP. Forty-six of those offers (4%) provided some degree of flexibility (*i.e.*, Entergy could adjust the schedule with advance notice). None of the offers submitted in response to the Weekly RFP provided for AGC service. Of the offers submitted by Calpine in the Weekly RFP, only one offer has provided any flexibility.

Entergy Services, Inc.
FERC Technical Conference
Docket No. ER04-699-000
Docket No. ER03-1272-002

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: Federal Energy Regulatory Commission

Question No. 3

Question:

3. Chairman Sandra Hochstetter of the Arkansas Public Service Commission, citing a study performed by the CERA, stated that the study found that if Entergy spent approximately $150 million in transmission upgrades to eliminate key bottlenecks, the southern Louisiana ratepayers could save about 11% on their wholesale generation costs. She stated that applying the 11% savings to Entergy's $30 million per percentage point savings figure would result in $330 million in benefits to southern Louisiana. (Tr. at 45) Chairman Hochstetter asked "what are we going to do to eliminate these transmission constraints that are preventing us from getting the cheapest power into Arkansas, Louisiana and Mississippi?"

    a. What plans, including timetables, does Entergy have to eliminate the key bottlenecks referenced by Chairman Hochstetter?

    b. Has Entergy performed any studies to determine the potential cost savings if coal-fired generation in the Midwest were available through the WPP or by other means? If so, please provide those studies along with a descriptive summary of the assumptions underlying its conclusions.

    c. Has Entergy performed any studies to determine the decline of import and/or export capability on its system over the last four years? If so, please provide a copy of the study.

Response:

a. Please note that the CERA study referenced by Chairman Hochstetter is proprietary. Entergy's access to the study was recently arranged and is subject to confidentiality restrictions. Entergy's review of this study is still preliminary as it has not yet been granted access to the supporting information.

Entergy is not able to respond to the specific figures referenced in the question because Entergy was unable to locate the specific figures -- either the $150 million in transmission upgrades or the 11% wholesale savings to southern Louisiana ratepayers -- that were referenced. Entergy also discussed the cited statistics with CERA representatives and they, too, were unable to find any reference to these figures within the study or within any of the material distributed by CERA during the accompanying workshops.

Further, an 11% savings on wholesale generation costs in Southern Louisiana would not necessarily translate to $330 million in annual savings in the manner suggested at the Technical Conference. The $30 million-per-percentage point savings potential that was identified by Entergy refers to percentage point decreases in the share of annual energy requirements provided by Entergy oil and gas units, not to percentage point decreases in wholesale power costs. Thus, even if the CERA study did estimate an 11% Louisiana wholesale generation cost savings figure, it would not be appropriate to multiply it by $30 million to estimate an annual savings potential.

The information provided below reflects a more general response to the questions based on Entergy's preliminary review of the CERA study as it relates to the Entergy system.

First, the CERA study is not an assessment of a current savings opportunity on the Entergy system. Rather, it is largely an analysis of a potential future scenario for the year 2010 and beyond. More specifically, the CERA study calculates the potential benefits across the Eastern Interconnection that could be created *if* there is *both* substantial new investment in coal fired and nuclear generation in the Midwest *and* transmission investments to eliminate bottlenecks to the East and South. If and when the generation investments posited in the CERA study move closer to fruition, the EOCs will certainly evaluate whether there is an opportunity to save money for loads in their region through transmission investments – on the Entergy system and other systems. ESI fully expects that any such evaluation would need to be undertaken on a regional basis, as has been the case with previous major transmission upgrades between regions.

More specifically, the CERA study identifies three distinct transmission constraints related to the Entergy system. The first is a transmission constraint between Entergy and adjoining regions. The second is a transmission constraint within the Entergy system between the northern part of the system and the southern part of the system. The third is another internal constraint that largely impacts the

Lafayette area of Louisiana. Each of these constraints is discussed below.

Into-Entergy Constraints

The first of these constraints appears to be the one that precipitated the suggestion at the Technical Conference -- based on the CERA study -- that Entergy may currently be overlooking an opportunity to import substantially more coal-fired energy by making modest transmission investments to its system. This is not the case.

- First, excess coal-fired generation in the Midwest and TVA is not being offered to the EOCs on a long-term firm basis, for reasons that have nothing to do with transfer limits into the Entergy system.

    - The most recent evidence of this is the absence of any such offers from existing units in the Midwest or TVA in the two long-term RFPs that ESI issued in 2002 and 2003. Any generation owner in TVA, ECAR or MAIN (or any other neighboring region) could have offered its unit into the RFP so long as it obtained firm transmission to an interface with Entergy. Transmission *into* the Entergy system footprint (across the interface) was not required.

    - Were such offers to materialize, ESI would evaluate them. If transmission constraints on the Entergy system were a factor in ESI's ability to accept such offers, and if it was economic to reduce or eliminate those constraints in light of the offers, the EOCs would undertake such upgrades on behalf of their native load customers.

    - The lack of offers from off-system generators relative to on-system generators is not surprising, given the current capacity glut in the Entergy system, relative to the tighter supply/demand picture in the Midwest. Publicly available data shows that reserve margins in TVA and the Midwest are today considerably tighter than in the Entergy system. Indeed, given the capacity glut on the Entergy system, much regulatory attention in recent years has been focused on transmission investments to *export* power, and who should pay for such investments. For instance, the SEARUC study, issued in late 2002 and discussed more fully in response to Question APSC 1-13, projected that prices within the Entergy system would be lower than the rest of the Southeast but concluded that the differentials were not sufficient to justify expansion to export from the Entergy system.

- Second, ESI currently takes full advantage of opportunities to purchase low-cost power from off-system when it is offered. ESI's ability to buy economy energy from the Midwest/TVA is almost never constrained by transfer limits into the Entergy system.

    - Data for the last twelve months (September 2003 – August 2004) shows that a total of 235 GWh of low-cost economy offers were rejected for transmission reasons, out of approximately 4800 GWh actually purchased during that period – meaning less than 5% were rejected due to transfer limits into the Entergy system.

    - During on-peak hours, the limiting factor on economy purchases is the amount and price of what is offered, not transmission constraints at the border of the Entergy system. The relatively limited quantity of attractively priced on-peak offers may be a function of supply/demand conditions in neighboring regions, as noted earlier, or it may be a function of transmission limitations on other systems, or both.

    - During off-peak hours, there is more low-cost energy available to Entergy from off-system, but ESI's ability to buy it has been increasingly constrained by QF energy puts. Nonetheless, *the EOCs' customers realize the economic benefit of the off-system prices*, because lost purchase opportunities due to QF puts are factored into--and therefore reduce--the "avoided cost" payments to QFs.

- Third, Entergy has studied the potential to increase import capability. As part of a study commenced in 2001, the ETO in conjunction with the LPSC, identified the Ft. Smith, Arkansas and the McAdams, Mississippi transformers as transmission constraints that, if relieved, could potentially increase the EOCs' transfer capability across external interfaces. Subsequent to the identification of these constraints, OG&E committed to proceed with installing a new 500/161 kV autotransformer at Ft. Smith, in order to increase the ability to import into its own service territory across the Entergy-OG&E interface. This upgrade at Ft. Smith will have the effect of also increasing transfer capability into the Entergy system. As to the McAdams transformer, the EOCs' analysis showed that the bottleneck is not causing an economic detriment to the system (*i.e.*, foregone economic imports) sufficient to justify transmission expenditures at this time. This and other constraints will be reviewed on a periodic basis for possible upgrades as a part of ETO's planning process.

Thus, contrary to the suggestion at the Technical Conference, transmission constraints do not currently limit Entergy's ability to displace on-system gas-fired generation with off-system coal fired generation. As a result, Entergy has no current plan to make transmission investments that would increase the import capability of the Entergy system. Nor does the CERA study contradict the Company's conclusion. As noted above, the CERA study is primarily a study of a potential opportunity in 2010 and beyond; it does not mean that the opportunity exists *today*, and the study does not so conclude. The CERA study does suggest that there may be an opportunity to benefit from investments internal to the Entergy system to improve the flow of power from the north to the south of Entergy's system. The EOCs have already made some of these investments, as described below, but it is important to recognize that the benefit from such investments for the foreseeable future will be more efficient use of gas-fired generation on the Entergy system rather than displacement of gas-fired generation with imports, as the CERA study might suggest.

North-to-South Constraints

The second constraint identified in the CERA study -- limits on the flow of power from the north to the south of Entergy's system -- have been extensively studied by the Company, not for further displacement of natural gas generation with off-system coal, but rather for displacement of generation from Entergy oil/gas units with more efficient on-system IPPs. The Company has invested and will invest in internal transmission upgrades to allow it to buy more from on-system IPPs when it has a reasonable expectation that it can lower costs to native load by doing so.

- No IPP in the Entergy system region had any commercial arrangement to sell power to the EOCs--or, to the best of ESI's knowledge, to any other load serving entity--at the time it came on line. IPPs did not begin offering their power to

Entergy's weekly procurement process in substantial quantities until the Spring of 2003.

- The Entergy Operating Companies do not make transmission investments on the Entergy system to improve their ability to buy from merchants on behalf of native load customers unless: (a) they have a long term commercial arrangement with a *specific* merchant that would justify the transmission investment, or (b) the transmission investment will allow them to buy from *competing* merchant generators, and the Company has a reasonable expectation that these merchants will regularly offer their power to the EOCs on a short-term basis on commercial terms that are attractive for serving native load customers.

- As it became apparent in 2001 and 2002 that IPP development inside the Amite South region would not match the level elsewhere in the Entergy system (particularly the Central and WOTAB regions), and in 2003 that merchant generators in the Central region would regularly offer power at lower heat rates than EGSI's own Amite South generation, transmission projects were identified to expand the interface between Amite and Central in order to displace EGSI generation with IPPs and thereby reduce production costs for the EOCs' native load customers.

    - These projects include a new 230 kV line from Panama to Dutch Bayou, and an upgrade of existing 230 kV lines from Coly to Vignes and from Conway to Bagatelle. The estimated cost of these projects is $43.5 million, and the net benefits for the EOCs' customers are expected to be in the range of $126 to $260 million.

    - These approved investments, which are scheduled to be in place on the Entergy system long in advance of the first year of the CERA analysis (2010), were not included in the CERA study. Had they been included it is not clear that the CERA Study results would have been the same. The $25 to $39 million annual benefit of the Amite South upgrades results from more efficient on-system gas generation displacing less efficient on-system gas generation, thus reducing the remaining displacement opportunity for low cost imports.

- In the WOTAB region, the picture is still not clear. While there are roughly 4000 MW of merchant generation operating in WOTAB, unlike the situation in the Central region, much of the IPP capacity in WOTAB that is deliverable on a firm basis to the Entergy system is QF capacity that does not often participate in the current weekly procurement process. This means that the EOCs must commit their own units to ensure reliable operation within WOTAB. If the proposed enhancements to the WPP are successful, and merchant bids from IPPs in WOTAB materialize, then that would allow the EOCs not to commit their own units. In that case it likely would not be economic to increase the import capability from Central to WOTAB.

- There are other transmission investments that may be economic for the EOCs' customers, when coupled with long term commitments to secure output from a specific generator. The Perryville facility is one such example. However, except in a case such as the Amite South upgrades where customers can benefit from purchases from a number of demonstrable merchant sellers outside of Amite, it would not be prudent to undertake a transmission investment without any assurance that benefits would flow back to native load.

Lafayette Area Constraints

The third constraint identified in the CERA study is in the Lafayette area of Louisiana. (Three utilities own transmission assets in the area: Entergy, Cleco and LUS. LUS is not a network customer of Entergy and does not take long-term transmission service from Entergy. It has an agreement with Cleco to deliver power from the Rodemacher generating unit, which is jointly owned by Cleco and LUS.) While the CERA study addresses the issue of potential economic transmission upgrades in the Lafayette area, at the Technical Conference both reliability and economic issues in the area were discussed.

The reliability discussion revolved around events on July 24, 2004, that resulted in a public appeal for energy conservation in the Lafayette area. On that day, system operators were confronted with a combination of peak load conditions and multiple outages of non-Entergy generators in the Lafayette area. Faced with the fact of an unusual contingency (multiple generator outages during hot weather), the operators took the necessary steps to ensure that the system could withstand an *additional* contingency without involuntary load shedding. Short of returning to service the generators that were in forced outage conditions, a public appeal to reduce load levels voluntarily was the next best way to accomplish this. Thus, the July 24 public appeal was not caused by inadequate transmission planning or investment; it was caused by generator outages. In fact, the existing transmission system is planned using the coordinated models developed by the three transmission owners in the area and it meets the planning criteria established by NERC, which are consistent with the Entergy planning guidelines.

The WOTAB area as a whole (in which Lafayette is located) has turned from a mostly net importing region to a lesser net importing region, and sometimes even a net exporting region, as a result of QF/IPP generation within WOTAB. As a result, power flows have shifted dramatically in the WOTAB region, creating a very strong source of power at the main injection point of the Entergy transmission network that brings power into the local Lafayette area. At the same time, customers in the Lafayette area are buying from IPPs rather than running their older, less efficient designated network resources in the local area (LUS' Bonin and Cleco's Teche units). As a result of these two factors, when Lafayette area load is high but there is only a small amount of Lafayette area capacity operating to serve this load, the power flow will shift from the transmission lines of the other transmission providers in the region to the Entergy transmission system between the Richard Substation and the city of Lafayette. If nothing is done, these 138 kV lines can overload. To avoid the overload, the long-term network resources previously designated must increase operations and be dispatched at higher levels of output to reduce the pressure on the 138 kV lines and bring the system back into balance.

To allow customers to access a different mix of network resources and QF generation or reduce the output of the previously planned designated network resources, the transmission system can be expanded. Entergy, Cleco and LUS are currently jointly planning investments to allow LUS and Cleco to reduce their reliance on the older network resources in the region. But this planning could not have occurred until now. The IPPs did not seek Entergy permission to site where they did to be able to displace the local area generation. And the load serving entities did not seek, until recently, to designate the IPPs as new long-term network resources. Entergy, Cleco and others had planned and built their transmission systems long in advance of the IPP/QF development based on the then-designated long term network resources. To suggest that any of these entities should have been able to predict how much, where, and when all of this new capacity would be built and, once built, how it would operate is unreasonable. Entergy's transmission planning properly relies on network resource information provided by load serving entities such as Cleco and LUS through the coordinated modeling process with the SPP. The constraints identified by CERA in the Lafayette area are real. The three utilities in the area are well along in their efforts to identify transmission upgrades that will both address future reliability needs and facilitate a more economic dispatch. There is no "problem" or "opportunity" that is going unaddressed.

b. No studies have been performed; current experience indicates that available coal purchases are not limited by transmission but rather by mandatory QF purchases. See response to question 3(a).

c. See response to question 3(a).

Entergy Services, Inc.
FERC Technical Conference
Docket No. ER04-699-000
Docket No. ER03-1272-002

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: Federal Energy Regulatory Commission

Question No. 4

Question:

4. Entergy's representative, Mr. Schnitzer, stated that the potential annual savings associated with the WPP would be less than $600 million due to reliability must-run units and due to oil-fired units being cheaper to run than current offers from IPPs. (Tr. at 157) Mr. Hurstell, (Entergy) stated that less than 20% of Entergy's generation is displaceable by the IPP's. (Tr. at 157) However, page 13 ("Energy Cost Savings (WPP)") of Entergy's July 30 presentation on Transmission Pricing and ICT Benefits indicates that 20% of Entergy's 2003 energy requirements represent "remaining opportunity" for savings through the WPP.

   a. Please explain this apparent discrepancy.

   b. Please indicate the amount of generation that Entergy currently estimates is displaceable by merchant generators and the savings that Entergy expects to realize through the WPP.

   c. Please provide an explanation of all assumptions underlying those estimates, including the types of resources to be displaced, the assumed products bid into the WPP, and any assumed limitations on the generators ability to deliver into the WPP.

Response:

   a. There is no discrepancy. The remaining opportunity of 20% is the maximum displacement opportunity--the "outer envelope" as was noted by Chairman Wood (Tr. at 157). This amount includes the minimum-run generation from Entergy's gas/oil units committed for reliability as well as the load-following energy utilized from Entergy's units. The amount of displacement that can be realized is likely to be less than the 20% figure. As discussed during the Technical Conference, merchant capacity cannot displace all of Entergy's units committed for reliability. In the DSG area, for example, there are no merchant units. Since the reliability service typically required in the

DSG area must come from a unit located in the area, no merchant unit can displace the reliability service that Entergy's DSG unit(s) provide.

b. The WPP is designed for the maximum amount of displacement possible under the constraints of the system. Constraints such as that described above associated with DSG reliability requirements will remain under the WPP. Displacement and savings realized through the WPP depend on a number of factors. The bidding behavior of the IPPs, both in terms of price and the flexibility offered, will determine the displacement and savings realized. As stated above, Entergy units currently provide load-following service to the system; IPPs will need to offer comparable products at a more favorable price. Entergy has not estimated a specific value other than the $30 million-for-every-percentage-point-reduction previously described.

c. Not applicable. Please refer to Entergy's response above.

Entergy Services, Inc.
FERC Technical Conference
Docket No. ER04-699-000
Docket No. ER03-1272-002

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: Federal Energy Regulatory Commission

Question No. 5

Question:

5. Please provide a response to the following question, posed by Ms. Mackey, representing InterGen:

    a. When comparing bids into the WPP, what level of costs are attributed to Entergy's own units? (Tr. at 99 – 100) Does the analysis include the costs of ancillary services associated with Entergy's units, such as regulation services? (Tr. at 101) Does the analysis include redispatch costs associated with Entergy's own units? If not, why not?

    b. Does Entergy only bid in its variable O&M costs into the current weekly procurement process? If not, please describe the costs attributable to Entergy's units.

    c. Will the information regarding costs attributable to Entergy's units be available to those generators attempting to compete with those units through the WPP at any time? If not, why not?

Response:

a. The proposed WPP will consider all avoidable costs associated with Entergy's units. In the evaluation of IPP bids, the value attributed to the bid will include the avoidable costs of load following, regulation and/or spin from Entergy's units, if the merchants bid sufficient flexibility to provide any or all of these functions. There is no need for separate ancillary services markets (as claimed by some) to allow IPPs to provide those services through the WPP and be appropriately compensated for them. As to the question of whether redispatch costs will be incorporated in the WPP algorithm: if the question refers to existing out of merit dispatch by Entergy units, the potential for IPP bids to avoid or reduce such out of merit dispatch will be included in the WPP comparison. To the extent that the question refers to the costs of redispatching Entergy units to sell more transmission service through the WPP, those costs will be paid by the customers receiving the new service.

b. There are no Entergy "bids" in the current Weekly RFP. A production cost model is used to determine whether accepting IPP bids will reduce Entergy's variable production costs. The production cost model compares the IPP bids to the avoidable (*i.e.*, incremental) cost of Entergy's units.

c. Information regarding the costs of Entergy's units will not be made available to third-party generators through the WPP. The EMO will submit to Weekly Operations (and thereby also the ICT) the cost information for its resources that reflects the projected variable production costs of running the applicable unit. Such cost information is highly sensitive, and if disclosed to third parties would harm Entergy's ability to procure economic resources to supply its retail load requirements. Suppliers would be able to submit bids at a price just below Entergy's variable production costs, rather than competing vigorously to supply power at lower prices. The ability of sellers to submit bids specifically tailored to the buyer's cost information would not provide results consistent with competitive outcomes.

   Retaining the confidentiality of this sensitive information is consistent with the treatment of data in RTO and ISO markets. Entergy does not believe the Commission has ever found that incremental cost data should be made publicly available through such markets. The only data made public by such markets is not incremental cost information, but rather (i) market clearing prices, which are made available immediately, and (ii) market based bid data, which is made available only after a six month delay and with the participants' names masked. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163 at P 559 (2004). Neither is comparable to Entergy's incremental costs data at issue here. Since the WPP is a pay-as-bid procurement process, there are no "market clearing prices" similar to those in LMP markets. Rather, there will only be *market-based* bids from third-party suppliers that are accepted on a pay-as-bid basis if they reduce costs for ratepayers relative to the cost of operating the existing network resources of Entergy and other Participating Network Customers. Entergy does not believe that these supplier bids should be released because doing so would harm customers. At a minimum, the Commission's policy in RTO markets should be followed, so that such bids would be kept confidential for at least six months and the suppliers' names would be masked. Under no circumstances, however, should Entergy's incremental *cost* data (or the cost data for other Participating Network Customers) be released, even on a delayed basis. Such information represents neither market clearing prices nor market based bid information and thus no Commission policy supports releasing it. Moreover, a delayed release would provide no protection because the incremental heat rate of a unit is relatively constant and does not change over time. As explained above, release of such cost data would allow suppliers to cluster around Entergy's costs rather than engaging in competition that lowers costs to ratepayers.

Finally, Entergy notes that (like most public utilities) it currently purchases short-term supply in the market under bilateral contracts. There is no requirement that Entergy provide competitors its cost information in this context. Future purchases under the WPP also will be bilateral transactions. There is no reason to require any change in the current policy.

Entergy Services, Inc.
FERC Technical Conference
Docket No. ER04-699-000
Docket No. ER03-1272-002

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: Federal Energy Regulatory Commission

Question No. 6

Question:

6. Entergy's representative, Mr. Schnitzer, estimated that for every percentage of Entergy's resource requirements that can be served through the WPP there will be an annual savings of approximately $30 million (Tr. at 25).

   a. Please provide work papers, calculations and underlying assumptions used to develop the $30 million figure.

   b. As requested by Chairman Wood (Tr. at 52 – 53), if Entergy were to join an RTO, please indicate whether that would that have any impact on the existing WPP program and the savings realized from that program.

Response:

a. The $30 million figure was developed based on information related to the Company's purchases in 2003. The average implied heat rate of the Company's 2003 purchases--hourly, daily, weekly, and monthly purchases--was roughly 7500 btu/kWh. These purchases were estimated to displace Company generation with costs--start-up, no load, minimum run, and incremental fuel costs--equivalent to an average implied heat rate of approximately 12000 btu/kWh. Reducing costs through displacement by an implied heat rate of 4500 btu/kWh is equivalent to roughly $27 per MWh of savings using an assumed natural gas price of $6 per mmbtu. Applying savings of $27 per MWh to 1% of the Company's total energy requirements--over 115000 GWH in 2003--results in approximately $30 million of savings.

b. The ability to continue the WPP in its current form would depend upon the RTO's tariff provisions and business practices with respect to evaluating applications for short-term network resource designations.

   Today, EMO generally will buy in the current WPP only from resources that can qualify as short-term network resources, because EMO alters its "weekly lineup" of unit commitment in reliance on its WPP purchases.

(Other EMO purchases such as economy energy may be made with non-firm transmission.) Entergy Transmission's current practice is to grant applications for short-term network resource designation based on transmission availability as determined by AFCs.

Prior to initiation of AFCs, short-term network resource status was granted without study based on a unit's pre-determined GOL. Prior to GOLs, Entergy Transmission granted applications for short-term designation of network resources only through a study process. In the absence of a study, the designation would be granted on a secondary or non-firm basis, which was not a sufficiently reliable basis on which to alter the EMO weekly lineup. Thus the GOLs and the successor AFCs have enabled EMO to buy an increasing amount through the current WPP.

As to an RTO, the question would be whether Entergy's current AFC process (or its functional equivalent) is already or could be incorporated in the RTO tariff, either on an RTO-wide basis, or for the Entergy system only. In the case of the SPP, it is Entergy's understanding that the SPP does not currently use an AFC process for the evaluation of applications for short-term network resource designations. Rather, the current SPP business practice with respect to such applications is to rely on the evaluation of the applicable Transmission Owner--the TO on whose system the requested network resource is located. If the TO approves the application, then the SPP will grant the short-term designation.

If Entergy were to join the SPP, in order to preserve the AFC process for use by Entergy, either the SPP would have to incorporate Entergy's AFC process into the SPP tariff (on an SPP-wide basis or an Entergy-only basis) or Entergy would have to be permitted to continue to have its own transmission tariff for purposes of implementing AFCs. Without AFCs or GOLs, Entergy would need to revert to its prior practice of requiring a study to grant short-term network resource status on a firm basis. This, in turn, would impair the viability of the current WPP.

The foregoing discussed the potential continuation of the current WPP in the context of an SPP RTO. It is important to note, however, that the *enhanced* WPP that is proposed by Entergy as part of its ICT proposal would involve a different approach to short-term transmission service than the current WPP. Rather than obtaining network resource status separate from the procurement decision, the enhanced WPP would grant such service as part of the optimization process itself. The question of whether the *enhanced* WPP could be implemented if Entergy were to join the SPP RTO thus involves a different set of issues, particularly whether the SPP would permit such an optimized process to be performed for the Entergy system alone (given that no other SPP entity, to Entergy's knowledge, has a similar process).

Entergy Services, Inc.
FERC Technical Conference
Docket No. ER04-699-000
Docket No. ER03-1272-002

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: Federal Energy Regulatory Commission

Question No. 7

Question:

7. Mr. Schnitzer (Entergy) provided a summary of estimated costs and savings associated with the ICT proposal and also provided similar estimates associated with potential Entergy participation in a SPP RTO. (Tr. at 24-27)

    a. Please provide any calculations, work papers, and underlying assumptions used in developing these estimates and a descriptive summary of the study including reasons for inclusion or exclusion of relevant variables.

    b. Please explain the assumptions regarding how the WPP program was incorporated in your benefit-cost analyses of the ICT versus RTO options.

Response:

a. The data in response to this question is included in the Attachment hereto.[3]

b. Entergy's analysis compared the benefits of the proposed ICT/WPP with those of (a) a "status quo" case in which Entergy assumed the transmission pricing methodology applicable prior to Orders 2003 and 2003-A would be maintained and (b) a case in which Entergy joins the SPP RTO and is subject to the transmission pricing protocols currently in place in that RTO.

   The analysis focused on the impact to retail ratepayers of the transmission pricing applicable in each scenario and the potential savings from the WPP.

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[3] Due to its length, the Attachment to question 7(a) is located at:
http://oasis.eterrasolutions.com/documents/EES/Independent_Coordinator_Filing.htm.
Entergy also is including an electronic version of the Attachment with its filing.

The quantifiable benefits associated with the ICT proposal, as compared to the existing status quo or participation in the SPP RTO (as currently defined), fall into four categories:

- The treatment of previously incurred interconnection costs and optional upgrades. Under the ICT proposal, uncredited amounts will be directly assigned to the extent the ICT determines that the investments would not have been included in the Base Plan to serve load reliably. This is a benefit compared to the status quo and to the SPP RTO alternative.

- The treatment of transmission upgrades associated with obtaining NITS or NRIS network resource status. Under the ICT proposal, these costs would be directly assigned to the requesting customer. This is a benefit compared to the SPP RTO alternative and, possibly, to the status quo.[4]

- The increase in costs associated with the loss of wholesale transmission revenues due to the elimination of rate pancaking. Under the ICT proposal, there would be none. This is a benefit compared to the SPP RTO alternative.

- The production cost savings associated with implementation of the enhanced WPP, as included in the ICT proposal. This is a benefit compared to the status quo and to the SPP RTO alternative.

The table below summarizes the estimated benefits in each of these categories.

[4] While Order No. 2003-A indicated that the "higher of" pricing policies were available to integrated utilities, regardless of whether they were part of an RTO, the Companies believe that the opportunity to obtain Commission approval of the "higher of" pricing proposal contained in the ICT proposal may be enhanced when such proposal is combined with the additional independence provided through the proposed role of the ICT in determining which upgrades are needed for reliability and which upgrades are properly defined as Supplemental.

Scenario	Category of Cost/Benefit Included in Each Scenario				WPP Feasible?
	ICT Annual Operating Cost	Benefit from Reclassification of Prior Interconnection Costs	Benefit from Higher of Pricing for Prospective NITS/NRIS Upgrades	Lost Pancake Revenues	
ICT Proposal Accepted by FERC	Yes	Yes	Yes	No	Yes
Status Quo Case - No ICT, No "higher-of" pricing for NRIS/NITS	No	No	No	No	No
RTO Case - Join SPP, No 'higher-of" pricing for NRIS/NITS	Yes (SPP grid mgn't charge)	No	No	Yes	Uncertain

Entergy Services, Inc.
FERC Technical Conference
Docket No. ER04-699-000
Docket No. ER03-1272-002

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: Federal Energy Regulatory Commission

Question No. 8

Question:

8. In response to questioning by Chairman Irma Dixon and Commissioner James Field, of the LPSC, Ms. Despeaux, representing Entergy, indicated that Entergy would include its system-wide cost-benefit analysis as an attachment to its filing before the LPSC. Chairman Dixon further asked that any studies, information, papers, etc. that Entergy used in its analyses be provided as well. (Tr. at 56-58). As requested by Chairman Wood (Tr. at 151), please provide this information in the response to this data request. Please also identify who conducted the study, who paid for the study, and when and for what purposes(s) was the study done.

Response:

The system-wide cost-benefit analysis of the Entergy ICT proposal provided as part of the filing to the Louisiana commission is the same analysis as provided in response to data request 7(a) above. This study was completed by Entergy's transmission staff and its consultants, The NorthBridge Group, Inc., and was funded by Entergy. The study was commenced shortly after the April 2004 ICT filing with the Commission and is intended to inform the state commissions of the retail rate benefits of Entergy's ICT proposal.

Entergy Services, Inc.
FERC Technical Conference
Docket No. ER04-699-000
Docket No. ER03-1272-002

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: Federal Energy Regulatory Commission

Question No. 9

Question:

9. Mr. Schnitzer (Entergy) explained Entergy's transmission pricing proposals. (Tr. at 4 – 16) Mr. Schnitzer states that transmission investments fall into two basic categories: the investments that are considered to be reliability investments (Base Plan), the costs of which would be rolled-in for recovery through system-wide rates, and investments beyond the base plan (economic) the costs of which would be charged based on "the higher of" rolled-in cost or incremental cost. Mr. Schnitzer also stated that the determination of which investments fall into the two categories, base and economic, would be done by the ICT. However, the April 1, 2004 filing in Docket No. ER04-699-000 indicates that Entergy, not the ICT, would develop the Base Plan and accordingly, the upgrades that are considered to be Base Plan upgrades. All other upgrades would fall into the supplemental category. Please clarify this apparent discrepancy. Describe and explain the latitude that the ICT has in determining which transmission investments fall into the two categories.

Response:

There is no discrepancy. A more careful reading of the filing shows that the ICT makes the ultimate determination as to whether projects triggered by service requests should be rolled into transmission rates (Base Plan Upgrades) or subject to the "higher of" test for transmission pricing (Supplemental Upgrades.)

As outlined in the filing, Entergy has primary responsibility for:

- determining the applicable reliability standards for transmission service;
- identifying upgrades necessary to meet those standards for existing service commitments (Base Plan Upgrades); and
- identifying upgrades necessary to meet those standards when granting requests for new transmission and interconnection service (Supplemental Upgrades).

The ICT does not have the authority to alter those reliability standards, nor can it overrule Entergy on what upgrades are required to meet reliability standards. Entergy believes that it must retain ultimate responsibility for those decisions, in order to fulfill its obligation to serve customers reliably and to avoid triggering transfer of control issues. (The ICT does have oversight on those decisions, as described below.)

However, the ICT has final authority over the assignment of cost responsibility for Supplemental Upgrades. The ICT determines whether a Supplemental Upgrade "would defer or eliminate the need for a project in the Base Plan", or whether, "based on its independent review, such project should have been in the Base Plan under the planning standards developed and applied by Entergy." (*See* Entergy OATT, Attachment T, § III.) If the ICT makes either finding, the cost of the Supplemental Upgrade will be rolled into Entergy's transmission rates. If the ICT finds that the Supplemental Upgrade is properly characterized as incremental to the Base Plan, then the project is subject to the "higher of" pricing policy outlined in the filing. Thus the ICT cannot change Entergy's planning standards, but it does have the ability to order an upgrade to be rolled into rates based on its independent review of what is needed to meet those standards. The ICT can also apportion the cost recovery of a project between Base Plan and Supplemental treatment.

Under Attachment S, Section 5, the ICT will have oversight with respect to the following, and may report to regulators on any aspect of these:

- whether the Transmission Provider's planning standards are consistent with Good Utility Practice (accepting that there is judgment involved and that regional variations exist);

- whether those standards have been applied in a non-discriminatory fashion in the planning process (*i.e.*, similarly situated customers are treated comparably);

- whether the Base Plan is consistent with the Transmission Provider's planning standards;

- the reasonableness of the Transmission Provider's standards for granting transmission and interconnection service requests (*e.g.*, deliverability standard for NRIS applicants);

- whether those standards have been applied in a non-discriminatory fashion in the granting of transmission service and interconnection requests (*i.e.*, similarly situated customers are treated comparably);

- the appropriateness of the identified required upgrades for new transmission service or interconnection, given the Transmission Provider's standards for granting such service, including a review of SISs and Feasibility Studies; and

- given a set of required upgrades, the general reasonableness of the cost estimates and schedule for construction developed by the Transmission Provider in the Facilities Study process.

Entergy Services, Inc.
FERC Technical Conference
Docket No. ER04-699-000
Docket No. ER03-1272-002

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: Federal Energy Regulatory Commission

Question No. 10

Question:

10. Mr. Schnitzer (Entergy) provided a numerical example related to a hypothetical network customer whose supply contract is expiring and is seeking a replacement resource. (Tr. at 8 – 13) Mr. Schnitzer concluded that, in order to hold native load harmless, the network customer must be charged both the pre-existing load-based transmission charge and the incremental upgrade cost. (Tr. at 12) In return for paying for the upgrade cost, the interconnection customer would receive portable network status (that is, it could be a network resource for any network customer on Entergy's system) and free point-to-point service as available. (Tr. at 13) Please provide any studies or other evidence Entergy has which shows the benefits which native load customers derive from the addition of transmission upgrades paid for by interconnection customers. Please indicate whether and how these benefits are used to offset the upgrade costs that interconnection customers must pay.

Response:

The only reliability benefits that native load customers should be required to pay for are those necessary to meet applicable reliability standards. Under the planning proposal in the ICT filing, projects necessary to meet those standards would be included in the Base Plan. To the extent a transmission upgrade funded by an interconnection customer (at the ERIS or NRIS level) eliminates the need for a Base Plan investment, as determined by the ICT, the funding interconnection customer would receive a credit for that benefit. Thus, all upgrades necessary to meet reliability standards are ultimately funded by native load customers, not by interconnection customers. Entergy has not performed any study as to whether there might be economic benefits or costs to native load or other transmission customers as a result of upgrades funded by interconnection customers. Benefits could arise if a future network resource designation was made feasible by the funded investment or if future point-to-point service was made feasible by the funded investment. There also has been no study as to whether, in the event there are any such benefits, they would be larger or smaller than the foregone native load benefits associated with the free point-to-point allowance. Costs could arise from interconnection customers, if the upgrades required for some future network resource designation become more expensive because the interconnection customer used "headroom" on the existing system that would otherwise have remained available. Costs in the form of foregone point-to-point revenues could also arise if future point-to-point service was made more expensive by a similar use of valuable "headroom."

Entergy Services, Inc.
FERC Technical Conference
Docket No. ER04-699-000
Docket No. ER03-1272-002

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: Federal Energy Regulatory Commission

Question No. 11

Question:

11. Order No. 2003-A allows an independent transmission provider to charge both a rolled-in access charge and directly assign upgrade costs if the customer receives FTRs associated with the upgrades. Entergy does not propose to offer FTRs but would, instead, offer as available point-to-point service. Please explain why Entergy believes this is consistent with or superior to offering FTRs, and provide any studies or other evidence Entergy has supporting its position.

Response:

First, Entergy notes that Order No. 2003 established a policy of distinguishing between pricing allowed for independent transmission providers and that allowed for non-independent transmission providers.

> The Commission notes that the transmission pricing policies that the Commission has permitted for an RTO or ISO with locational pricing, in which the Interconnection Customer bears the cost of all facilities and upgrades that would not be needed but for the interconnection of the new Generating Facility and receives valuable transmission rights in return, are acceptable forms of participant funding. .... However, the Commission remains concerned that, when the Transmission Provider is not independent and has an interest in frustrating rival generators, the implementation of participant funding, including the "but for" pricing approach, creates opportunities for undue discrimination....... Therefore, the Commission continues in this Final Rule its current policy, as modified below, of requiring a Transmission Provider that is not an independent entity to provide transmission credits for the cost of Network Upgrades needed for a Generating Facility interconnection.

See Standardization of Generation Interconnection Agreements and Procedures, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 695-696 (2003), *order on* *reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 (2004). In Order No. 2003-A, the Commission "clarified" Order No. 2003 as follows:

> In this Order on Rehearing, we clarify that, consistent with the Commission's "higher of" ratemaking policy, a non-independent Transmission Provider continues to have the option to charge the Interconnection Customer the "higher of" an average embedded cost (rolled-in) rate or an incremental cost rate for the Network Upgrades needed for either Energy Resource Interconnection Service and Network Resource Integration Service.

Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 8. The Commission explicitly stated that it was doing this for purposes of protecting native load.

> Allowing [non-independent] transmission providers to charge the higher of an incremental cost rate or an embedded cost rate ensures that other transmission customers, including the Transmission Provider's native load, will not subsidize Network Upgrades required to interconnect merchant generation.

Id. at P 580.

It is Entergy's view that the only way for non-independent transmission providers to accomplish native load protection is through the form of "higher of" pricing that is included in Entergy's ICT proposal, and that the pricing proposed by Entergy is superior to the pricing policy for non-independent transmission providers that was included in Order No. 2003. Any policy which requires credits against network service charges results in the socialization of the cost of network upgrades to all transmission customers including native load. On the Entergy system, this would result in cost shifting and uneconomic investments, for the reasons explained in the Schnitzer affidavit. In contrast, the proposed pricing policy in the ICT filing would protect native load against uneconomic upgrades being made at their expense.

As to the FTR comparison, Entergy notes that under Commission policy, a Day Two market with LMP and FTRs is not available to stand-alone non-independent Transmission Providers. Thus Entergy is not offering FTRs as part of its proposal. However, the Entergy proposal contains some features that are analogous to the property rights contained in a Day Two market structure. First, Entergy proposes to make two forms of network resource integration available to customers, NRIS and NITS. NRIS status is portable; a generator qualifying as an NRIS resource can be a network resource for any network customer on the Entergy system without further upgrades. NRIS status is a form of property right, just as Capacity Resource status is in PJM, and once achieved, Entergy proposes to maintain NRIS status for generators on a rolled in basis, as in PJM. Second, customers electing the higher NITS level integration (which is available only at network customer request) get the ability to schedule from the NITS resource without a congestion charge, which is the pre-LMP equivalent of an FTR. (NITS resources will automatically qualify as NRIS resources, so they will receive that portable property right as well.)

In sum, Entergy believes that its pricing proposal is clearly superior to the Order 2003 pricing policy for non-independent transmission providers, is consistent with native load protection policy of Order No. 2003-A, and provides the closest analogy to the Day Two property rights that are available in Day Two RTO markets.

Entergy Services, Inc.
FERC Technical Conference
Docket No. ER04-699-000
Docket No. ER03-1272-002

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: FERC Commission

Question No. 12

Question:

12. Mr. Marone, representing Occidental Chemical (Occidental), stated that Occidental had requested Entergy to provide workpapers explaining the reasons for denial of transmission service requests under the Available Flowgate Capability (AFC) process. (Tr. at 90) After two months, Entergy had yet to comply with the request. (Tr. at 91)

    a. Has Entergy provided Occidental with the requested workpapers?

        i. If so, when? Please provide a copy of the workpapers in your response to this data request.

        ii. If not, why not? Indicate when Entergy provided, or plans to provide, those workpapers.

    b. Please provide a list of customers who have requested workpapers to explain denials of transmission service under the AFC and indicate when those workpapers were provided. If they have not been provided, explain why not.

Response:

a. Entergy does not agree that it has failed to make workpapers available to Occidental during the two-month period claimed by Occidental. Attached to this data response is a September 20, 2004 letter from Entergy to Occidental detailing the information Occidental has had access to since the time its service requests were denied. As Entergy discussed in that letter and in Entergy's March 12, 2004 compliance filing in the AFC docket, Entergy believes that the best process for evaluating reasons for transmission service denials is by reviewing power flow models Entergy posts on OASIS and the AFC data for the flowgates at issue provided by OASIS Automation. The daily peak-hour and monthly power flow models are the same models used by the AFC process to evaluate transmission service requests. Entergy posts these models for the express purpose of providing transmission customers with information regarding transmission service denials.

Entergy currently posts – and Occidental has had access to – approximately 140-150 daily peak-hour models every day, and 70-90 monthly models per month, since implementation of AFC process on April 27, 2004. All of these models contain the OxyTaft generating facility. With respect to Occidental's service requests, Entergy has previously posted the monthly and daily on-peak hourly models that pertain to each of the days for which Occidental requested service. These models were available to Occidental at the time its service requests were denied.

For the reasons discussed in Entergy's letter to Occidental, Entergy also disagrees with Occidental's assertion that these power flow models do not satisfy Entergy's "workpapers" obligation under the Commission's orders approving the AFC process. These are the same power flow models Entergy itself uses to calculate transfer capability and evaluate service requests. Moreover, when used in conjunction with a commercial power flow application, these models enable transmission customers to test and evaluate the impact of various assumptions and data inputs on the resulting power flows. For these reasons, Entergy's consistent position has been that these power flow models provide the highest level of detail available for evaluating the reasons for transmission service denials.

The only power flow models or workpapers that Occidental has not had access to are non-peak hourly models that are not posted by Entergy. Entergy is unaware of any transmission provider that provides such models. Entergy's understanding is that neither of the other transmission providers using the AFC process (e.g., SPP and the Midwest ISO) provide such models. SPP does not post any models within the Day 1 to Day 31 time frame and the Midwest ISO only posts the noon hour model. Entergy did not commit to provide such models as part of its original AFC filing and expressed concerns about the extent to which the conversion of EMS-based models was possible.

Nevertheless, in response to Occidental's request, Entergy investigated whether it could provide such models. As discussed in Entergy's letter to Occidental and in a July 27, 2004 conversation between Entergy and Occidental, the reason for the delay in providing these models was due to the need for software upgrades to recreate non-peak hourly models from archived data and convert those models from the EMS-based format. The final version of this software was not available until approximately August 30, 2004, and Entergy is in the process of resolving the remaining technical issues. Because of this delay, Entergy is providing additional information regarding Occidental's hourly non-firm transmission service requests that Occidental can review while Entergy attempts to resolve the remaining technical issues associated with the hourly models.

Finally, Entergy strongly disagrees with Occidental's assertion that the delay in addressing the technical issues associated with converting non-peak hourly power flow models is in any way a deliberate attempt to make the AFC process less transparent. In fact, the delay in responding to Occidental is due solely to

Entergy's efforts to provide Occidental with off-peak hourly models related to non-firm transmission service requests – something that Entergy believes no other transmission provider does. Although Entergy anticipates providing the hourly models to Occidental, Entergy believes that providing non-peak hourly models as "workpapers" in the future may not be possible due to the number of models and conversion issues that have delayed this response. To the extent that non-peak hourly models cannot be provided, Entergy will notify the Commission as part of the ongoing compliance filing proceeding in the AFC docket.

b. No other customers have requested workpapers to explain transmission service denials beyond the power flow models that Entergy currently posts on OASIS. Customers may download these models directly from the Entergy OASIS without submitting a formal request to Entergy, and Entergy is aware that a number of other customers have done so.

Entergy Services, Inc.
FERC Technical Conference
Docket No. ER04-699-000
Docket No. ER03-1272-002

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: FERC Commission

Question No. 13

Question:

13. Mr. Marone (Occidental) explained that, prior to the implementation of the AFC program, Occidental regularly obtained transmission service to support bilateral negotiated sales of power in the wholesale market but, since the AFC methodology has been implemented, even non-firm transmission for power sourced from its facility has consistently been unavailable. (Tr. at 89) Please explain why implementation of the AFC methodology results in a loss of historically available transmission capability from the Occidental facility. If Entergy disagrees with Mr. Marone's assertion, please provide a detailed explanation and all supporting documentation.

Response:

Firm Transmission Service

Based on the same data and methodology described in Entergy's response to Data Request 15, Entergy believes that, overall, the AFC process has led to acceptance of *more* MWhs of firm transmission service (particularly daily and weekly) than would otherwise have been possible under the previous GOL/ATC/SIS process. However, individual customers may see more or less availability of firm service under the AFC process, because the AFC process provides a different – and more accurate – assessment of transmission availability than the previous GOL approach. For example, to the extent a generator located in a constrained area, the AFC process will accurately reflect those constraints and less service may be available, particularly where those constraints were not captured by the GOL/ATC/SIS process. The reverse is also true. To the extent a generator located in an unconstrained area, the AFC process will accurately reflect the lack of such constraints and more service may be available, particularly where the full amount of available capacity may not have been captured by the GOL/ATC/SIS process. Overall, though, Entergy believes that the AFC process improvements makes more firm transmission service available as compared to the previous methodology.

The Occidental facility has experienced a reduction in firm service availability under the AFC process. This reduction, however, does not necessarily reflect any flaw in the AFC process and most likely is a function of the different and more accurate assessment of transfer capability under the AFC process and the fact that Occidental is located in a constrained area.

As discussed in Entergy's response to Data Request 15, Entergy is committing to report back to the Commission regarding the implementation of the AFC process over the summer of 2004, and will provide an analysis of differences between the AFC process and the GOL/ATC/SIS process that could produce different assessments of transfer capability. To provide the Commission with additional information with this response, we address on a generic basis the differences between the AFC process and the previous GOL/ATC/SIS methodology that could result in both reductions and increases in transmission availability for individual generators or customers. Again, though, Entergy's initial analysis indicates that the improvements in accuracy brought about by the AFC process have resulted in Entergy accepting *more* MWhs of daily and weekly firm service overall than would have otherwise been possible under the previous methodology.

The differences between the AFC methodology and the previous GOL/ATC/SIS methodology are a reason why AFC calculations can reflect less or more transmission service depending on the circumstances. Examples of these differences include the following:

First, the GOL and ATC values were updated on a less-frequent basis than the current AFC values. The new AFC software allows Entergy to update many AFC values on an hourly basis, as compared to GOL values which were updated on a weekly or monthly basis depending on the timeframe at issue. The AFC updates incorporate more recent data regarding system conditions. The inclusion of more recent data improves the accuracy of these calculations, but does not ensure that in all instances more service will be available. Under certain conditions, more up-to-date data (for example with respect to transmission outages) may indicate that less service is available.

Second, as discussed in more detail in response to Data Request 14, the GOL calculations made certain assumptions about the simultaneous impact of daily and weekly transmission reservations from the generator requesting service, but ignored the impact of simultaneous reservations from other generators. The AFC software enables Entergy to eliminate both practices by incorporating actual reservation data, in lieu of ignoring some reservations and making assumptions regarding other reservations. Consequently, the AFC process will indicate less service is available where constraints were not apparent because some reservations were ignored, and it will indicate more service is available where constraints were due to GOL/ATC assumptions no longer necessary under the AFC process.

Third, the GOL and ATC calculations were based on system conditions during a single peak hour in the day or month for which firm service was requested. During the GOL process, a number of generators complained that peak-hour modeling was overly conservative in that the peak hour was the most likely to be constrained. The AFC software departed from peak-hour modeling by calculating independent values for every hour of the next seven days. Thus, many hourly and daily service requests are evaluated based on each hour for which service is requested, rather than just the peak hour. This improvement in accuracy means that less service may be available where a particular generator was not limited in the peak-hour but is limited in non-peak hours, because the previous GOL/ATC process did not examine off-peak hours. This improvement in accuracy also means that Entergy can sell more hourly non-firm service during days when the peak hour is limited, but the non-peak hours are not. However, this may not mean that more *firm* service would be available for those generators that were only limited in the peak hour, but were not limited in non-peak hours. This is because Entergy's OATT – which is based on the *pro forma* OATT – does not contain provisions for hourly firm service. Thus, if firm service is unavailable in any hour including a non-peak hour, it is unavailable in all hours. Entergy does not believe this is a flaw in the AFC process, but it does raise the question of whether more firm service could be granted by taking advantage of non-peak hour calculations through a more granular transmission product, such as an hourly firm or non-peak firm transmission product. Entergy is evaluating the impact of these practices and will address this impact in its report to the Commission on the AFC process.

Non-Firm Service

With respect to non-firm service, Entergy believes that in general there is less non-firm transmission service accepted under the AFC process compared to the previous treatment of non-firm service requests. Under the GOL process approved by the Commission, Entergy did not apply the GOL calculations to non-firm transmission service requests. This meant that internal non-firm requests (*i.e.*, requests from generators internal to the Entergy control area for service to the Entergy control areas) were accepted up to a generating facility's "P-Max" (maximum nameplate rating). It also meant that export non-firm requests (*i.e.*, requests from generators internal to the Entergy control area for service to other control areas) were only subject to interface ATC values.

Entergy considered continuing this policy as part of the AFC process, but concluded it could not for two reasons. First, the Commission twice rejected a similar proposal by the Midwest ISO for its AFC process. *See Midwest Independent System Operator, Inc.* 103 FERC ¶ 61,191 (2003), *reh'g denied*, 107 FERC ¶ 61,015 (2004). In those orders, the Commission concluded that applying non-firm AFC values to generators outside of one control area, while not applying those same AFC values to generators inside of that control area, was not just and reasonable. Therefore, Entergy concluded it could not excuse generators in the Entergy control area from non-firm AFC values, while applying those values to generators outside of the Entergy control area. Second, Entergy concluded it could not excuse all generators – both inside and outside of the Entergy control area – from any limit whatsoever on non-firm service due to the operational problems associated with allowing any and all generators to obtain non-firm service beyond any calculated limit.

Consequently, Entergy's AFC process now analyzes the impact of all non-firm service on system reliability, and non-firm service requests are only accepted when available and consistent with reliability criteria. Entergy does increase the availability of non-firm transmission service by releasing unscheduled firm service for use by non-firm customers. Entergy does not believe, however, that is a flaw in the AFC process, and it instead reflects the Commission's determination that all non-firm service requests should be equally subject to transfer capability determinations. As with the other matters discussed in this response, Entergy will evaluate the impact of this practice and address it the report to the Commission on the AFC process.

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September 22, 2004

VIA FEDERAL EXPRESS

Mr. Joseph Marone
Director, Power Purchasing
Occidental Energy Ventures Corporation
Five Greenway Plaza, Suite 1500
Houston, TX 77046

Dear Mr. Marone:

This letter responds to Occidental's request for "workpapers" regarding specified transmission service denials on the Entergy transmission system. Occidental's request for workpapers includes 81 OASIS requests sourced from the OxyTaft generating facility that were refused under Entergy's AFC process. As discussed below, Entergy has already provided Occidental with access to literally thousands of power flow models reflecting system conditions and the OxyTaft facility, including models applicable to the days when Occidental sought transmission service. Although Entergy has not resolved technical issues associated with processing archived data regarding non-peak hourly models, Entergy is providing additional data with this letter that Occidental may review while these technical issues are addressed. While Entergy does not agree with Occidental's claim that Entergy has not complied with its obligations under the Open Access Transmission Tariff ("OATT"), Entergy is willing to continue to work with Occidental to address its concerns regarding transmission access.

<u>Information Available under the AFC Process</u>

Entergy has already made available to Occidental every daily peak-hour and monthly model posted on OASIS since the inception of the AFC process on April 27, 2004. As Mr. McCulla noted in his May 5, 2004 e-mail to Mr. Kimbrough, Entergy posts on OASIS a large number of daily peak-hour and monthly power flow models used by the AFC process to evaluate transmission service requests. These postings include frequent updates for each of these models.

Entergy currently posts a daily peak-hour model for each day of the Day 1 to Day 31 timeframe and a monthly peak-hour model for each month of the Month 2 to Month 18 timeframe. The number of daily peak-hour models posted on OASIS is a function of the frequency with which these models are updated.

- For the operating horizon (*i.e.*, the current day and part of the next day), Entergy posts the peak-hour of the current day. Because these models are updated on an hourly basis, the peak hour of the day may (or may not) vary. Thus, the number of models posted during the operating horizon varies from a minimum of 1 to 24 peak-hour models per day.

- For the planning horizon (*i.e.*, the end of the operating horizon to Day 31), Entergy also posts the peak-hour of each individual day. These models are refreshed every 6 hours every day. Entergy posts each updated model for a total of 4 peak-hour models being posted per day for each day within the 31 day window.

- For the study horizon (*i.e.*, Month 2 to Month 18), Entergy posts the peak-hour of each individual month. These monthly models are updated on a weekly basis. Entergy posts each updated model for a total of 4 peak-hour models being posted per week for each month within the 16-month window.

In sum, Entergy currently posts approximately 140-150 daily peak-hour models every day, and approximately 70-90 monthly models per month. Since the inception of the AFC process on April 27, 2004, Entergy has posted approximately 21,000 daily models and over 200 monthly models. Entergy is unaware of any other transmission provider that posts this number of models for use by transmission customers. With respect to the two other AFC transmission providers – SPP and the Midwest ISO – Entergy's understanding is that SPP does not post any daily models for Days 1 to 31 and the Midwest ISO posts only the noon hour model for each day.

The power flow models posted by Entergy are a representation of anticipated system conditions based on the information available at that time. Each of these models contains the OxyTaft generating facility and includes the following forecasted data embedded in the power flow model, which can be obtained by accessing the ".raw" format file using any commercially available power flow application: (a) the load level in Entergy and all other modeled control areas; (b) the generation dispatch at every single generation facility; (c) the status of every single transmission facility (this information can be processed to produce a list of outages); (d) the net summation of all the exports out of and imports into the control area; (e) flow on all lines; and (f) voltages on all buses. While Entergy's OASIS software itself automatically provides the response factor and the power flows on the most limiting flowgate, the response factors and power flows on other flowgates can be obtained from the model by applying any commercial power flow application.

The information contained in the power flow models posted by Entergy is the same information that Entergy itself uses to calculate transfer capability. Moreover, when used in conjunction with a commercial power flow application, these models enable transmission customers to test and evaluate the impact of various assumptions and data inputs on the resulting power flows. For these reasons, Entergy's consistent position has been that these power flow models provide the highest level of detail available for evaluating the reasons for transmission service denials.

Occidental's Request for Workpapers

Occidental has requested "workpapers" regarding 81 transmission service requests that were denied under the AFC process. Entergy's OASIS software automatically identifies the most limiting flowgate (and the associated response factor) for each denied service request. Additionally, as Entergy made clear in its March 12, 2004 compliance filing in the AFC proceeding, the publicly-posted power flow models that Entergy uses to evaluate transmission service requests provide additional data and constitute the "workpapers" related to transmission service denials. Providing customer's with the ability to replicate and evaluate transmission service denials is the very purpose for which these models are posted. If these models were simply intended for informational purposes, it would hardly be necessary for Entergy to post as many models or update those postings with the frequency currently being undertaken. Moreover, these models contain more information and functionality than any other type of "workpaper" Entergy is aware of. For example, a customer cannot run "sensitivities" or test the impact of data inputs with any other type of "workpaper." Not only does the posting of these models satisfy Entergy's obligation to provide such workpapers, but it also far exceeds the level of information provided by other AFC transmission providers regarding transmission service denials. Although the posting of power flow models may not be the only way for a transmission provider to comply with its obligation to provide "workpapers," Entergy cannot agree with Occidental's assertion that the thousands of power flow models Entergy currently posts do not satisfy this obligation.

With respect to Occidental's specific service requests, Entergy has previously posted the monthly and daily on-peak hourly models that pertain to each of the days for which Occidental requested service. For example, of the 81 requests referred to by Occidental, 5 of those requests were for weekly or monthly service that was evaluated with daily or monthly models that have been previously posted on Entergy's OASIS. These models are included with this letter in the event that Occidental did not previously download those models. The remaining 76 service requests were for hourly non-firm service on various days. To the extent that Occidental did not download the daily peak hour model for the days that coincide with these service requests, please contact Mr. Oliver Burke at Entergy and he will provide copies of those models also. These models and the flowgate information provided by Entergy's OASIS software in response to the service requests fully comply with Entergy's obligation to provide workpapers for Occidental's request.

The only power flow models or workpapers that Occidental has not had access to are the non-peak hourly models that were not posted on OASIS.[1] Entergy is unaware of any transmission provider that provides such hourly models. Entergy did not commit to post such models as part of its original AFC filing and expressed concerns about the extent to which conversion of EMS-based models was possible. Nevertheless, when Entergy received Occidental's request for workpapers related to non-firm hourly transmission service, Entergy began to investigate whether the EMS-based, non-peak models could be recreated with archived data on a case-by-case basis. This effort was driven by Entergy's position that the actual power flow models provided the best opportunity for understanding transmission service denials.

As Mr. Burke discussed with Mr. Kimbrough on July 27, 2004, the recreation of non-peak hourly models from archived data and the conversion of those models from the EMS-based format was technically difficult for a number of reasons. Entergy first needed to obtain a software modification from AREVA (the company that designed the AFC software) that allows for the recreation of EMS-based models from archived data. AREVA delivered an initial version of this software modification at the end of July, but after testing Entergy concluded the software modification was not functioning properly. AREVA provided another version of the software modification on or around August 27, 2004. After additional testing and further changes, AREVA delivered a final version on August 30, 2004. Even with this software modification, the recreation process produces EMS-based models using the current version of the AFC calculation software, which may be different from the version used to create the original hourly models. Based on testing conducted after August 30th, Entergy believes that the software modification is currently recreating models from archived data generally within an 85-90% accuracy range.

These technical issues have been more challenging than Entergy originally anticipated. This in turn has led to the delay in providing Occidental with those hourly models.[2] Because of this delay, Entergy is providing additional information regarding Occidental's hourly non-firm

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1 Entergy cannot post all hourly models due to the sheer number of models (at least 365,000 models per year) generated by the AFC software and the conversion process required convert EMS-based models into a format used by commercially available power flow applications. Thus, while the data that can be used to recreate non-peak hourly models is archived by Entergy, the non-peak hourly models themselves are not converted or posted on OASIS.

2 Based on its experience to date, Entergy does not anticipate being able to provide non-peak hourly models as "workpapers" in the future due to the number of models and conversion issues that have delayed this response.

transmission service requests that Occidental can review while Entergy attempts to resolve the remaining technical issues associated with the hourly models. Included with this letter is an "AFC Impact Log" that includes the following information: the OASIS identification for the transmission service request, the type and amount of transmission service requested, the time of study for the transmission service request, flowgate AFC values for the 15 most limiting flowgates, the name of the limiting flowgates, firm (or non-firm) AFC available, firm (or non-firm) AFC remaining, the response factor for the flowgate, the rating of the flowgate and the existing flow over the flowgate prior to the request. This log data is taken from the archived data and does not require conversion. It is the same flowgate information used by Entergy as the basis in evaluating the transmission service requests at issue. Entergy is also providing an explanatory memorandum describing each field of data provided from the AFC Impacts Log to assist Occidental in its review of the data. If there is additional information Occidental believes should be included in the alternative data set, Entergy is willing to consider that request while it is addressing the technical issues associated with non-peak power flow models.

Other Matters

Entergy strongly disagrees with Occidental's assertion that the delay in addressing the technical issues associated with converting non-peak hourly power flow models is in any way a deliberate attempt to make the AFC process less transparent.[3] In fact, the delay in responding to Occidental is due to Entergy's efforts to provide Occidental with non-peak hourly models related to non-firm transmission service requests – something that Entergy believes no other transmission provider does. In any event, since implementation of the AFC process, Occidental has had access to literally thousands of power flow models that Entergy uses to evaluate service requests from the Occidental facility. The level of transparency provided by these models is unparalleled.

Nevertheless, Entergy does recognize the AFC process is indicating significant transmission constraints associated with power flows from the Occidental facility. To evaluate any concern Occidental may have in this regard, Entergy recommends that Occidental review the available AFC power flow models and propose any changes it believes are warranted. Entergy will also continue reviewing these models. Although Entergy believes the AFC power flow models are an accurate forecast of transmission availability, Entergy is willing to respond to any specific concerns Occidental identifies regarding the AFC models. Second, Entergy recommends a face-to-face meeting to discuss any modeling issues raised by Occidental, the impact of the new AFC process on the OxyTaft facility, and the next-steps in addressing Occidental's concerns.

3 In addition to its request for workpapers, Occidental has also made a series of other allegations regarding the sufficiency of Entergy's response and the AFC process itself. Entergy strongly disagrees with those allegations and will respond to those allegations in the forum in which Occidental has raised them.

Please contact me at your earliest convenience to discuss the timing of this meeting.

Very Truly Yours,

Floyd L. Norton IV

Floyd L. Norton IV

Enclosures

AFC Impacts Log – Key

The information below is presented as an explanation of the data that is included in Entergy's AFC Impacts Log, as shown in Figure 1.

FIGURE 1 – Example of the AFC Impacts Log

724	1	"1234567"	"04/29/04 10:00:59"	Weekly:Firm	"SOURCE"	"SINK"	""	"05/10/2004 00:00"	"05/11/2004 00:00"
724	2	"1234567"	"04/29/04 10:00:59"	Weekly:Firm	"SOURCE"	"SINK"	"Capacity Requested"	100	100
724	2	"1234567"	"04/29/04 10:00:59"	Weekly:Firm	"SOURCE"	"SINK"	"Capacity Available"	0	0
724	3	"1234567"	"04/29/04 10:00:59"	Weekly:Firm	"SOURCE"	"SINK"	"WATNM_GYPSN: TTC"	640	640
724	4	"1234567"	"04/29/04 10:00:59"	Weekly:Firm	"SOURCE"	"SINK"	"WATNM_GYPSN: Firm Flow/CBM/TRM"	520	650
724	5	"1234567"	"04/29/04 10:00:59"	Weekly:Firm	"SOURCE"	"SINK"	"WATNM_GYPSN: Firm Commitments"	0	0
724	6	"1234567"	"04/29/04 10:00:59"	Weekly:Firm	"SOURCE"	"SINK"	"WATNM_GYPSN: Firm New Reservation Total"	-30	0
724	7	"1234567"	"04/29/04 10:00:59"	Weekly:Firm	"SOURCE"	"SINK"	"WATNM_GYPSN: Firm AFC Remaining"	150	-10
724	8	"1234567"	"04/29/04 10:00:59"	Weekly:Firm	"SOURCE"	"SINK"	"WATNM_GYPSN: NonFirm Flow/CBM/TRM"	520	650
724	9	"1234567"	"04/29/04 10:00:59"	Weekly:Firm	"SOURCE"	"SINK"	"WATNM_GYPSN: NonFirm Commitments"	0	0
724	10	"1234567"	"04/29/04 10:00:59"	Weekly:Firm	"SOURCE"	"SINK"	"WATNM_GYPSN: NonFirm New Reservation Total"	-30	0
724	11	"1234567"	"04/29/04 10:00:59"	Weekly:Firm	"SOURCE"	"SINK"	"WATNM_GYPSN: NonFirm AFC Remaining"	150	-10
724	12	"1234567"	"04/29/04 10:00:59"	Weekly:Firm	"SOURCE"	"SINK"	"WATNM_GYPSN: Sensitivity"	0.0483034	0.0483034
724	13	"1234567"	"04/29/04 10:00:59"	Weekly:Firm	"SOURCE"	"SINK"	"WATNM_GYPSN: Firm Impact"	5	0
724	14	"1234567"	"04/29/04 10:00:59"	Weekly:Firm	"SOURCE"	"SINK"	"WATNM_GYPSN: NonFirm Impact"	5	0

Column 1 – Control Sequence Number
This number is generated by the program to aid with sorting.

Column 2 – Line Identifier
This number is generated by the program for each line of data in the log.

Column 3 – Request ID
This is the Transmission Service Request (TSR) identification number. This number is identical to the OASIS identification number.

Column 4 – Time Stamp
This is the date and time that the study was performed.

Column 5 – Service Type
This column indicates the increment and the class of service being requested. For example DAILY : FIRM.

Column 6 – Source

Column 7 – Sink

Column 8 – Data Profiled
This column describes the data that is being reported in the subsequent columns. The data fields shown below will be reported for every time point for which the request is made. In Figure 1, the request has been made for 2 days in the study horizon. If the request in Figure 1 had been made for 2 days in the operating horizon, 48 columns representing each hourly time point would be shown.

Capacity Requested – the amount of transmission service being requested. Capacity Requested will be displayed at the top of the log only. It is not displayed for each of the flowgates shown in the log.

Capacity Available – the amount of transmission service available for the entire period of the request. If the request is denied based upon any time point, the capacity available will show zero, even if sufficient AFC existed at one or more of the time points. Capacity Available will be displayed at the top of the log only. It is based on all flowgates and all time points and is not shown for each individual flowgate.

Flowgate Name: TTC – the total transfer capability of the flowgate before any base flows and reservations are accounted for. This is the maximum amount of power that can flow on the flowgate due to its physical characteristics and is typically the MVA rating of the flowgate.

Flowgate Name: Firm Flow/CBM/TRM – the firm flow on the flowgate prior to the impact of the requested transfer (firm component of base flow).

Flowgate Name: Firm Commitments – the impact of approved firm transfers on the flowgate, not included in firm flow. Firm commitments become a part of Firm Flow at the time of a resynchronization in RFCALC, which involves physical modeling of the transactions into the power flow model.

Flowgate Name: Firm New Reservations Total – the summed impacts of new firm reservations (including the requested amount) on the flowgate between resynchronizations of Oasis Automation (OA). During this period, OA accounts for new reservations by algebraically decrementing the flowgate AFC. During this period, the impacts of these reservations are not part of Firm Commitments or Firm Flow.

Flowgate Name: Firm AFC Remaining – The amount of AFC available on the flowgate after the impacts of base flows, firm commitments, and firm new reservations (including the requested amount). To calculate Firm AFC Remaining, use the following formula:

(Flowgate Name: TTC)-(Flowgate Name: Firm Flow/CBM/TRM)-(Flowgate Name: Firm Commitments)-(Flowgate Na
Firm New Reservation Total)

Flowgate Name: NonFirm Flow/CBM/TRM - the non-firm flow on the flowgate prior to the impact of the requested transfer (non-firm component of base flow).

Flowgate Name: NonFirm Commitments - the impact of approved non-firm transfers on the flowgate, not included in non-firm flow. Non-firm commitments become a part of Non-firm Flow at the time of a resynchronization in RFCALC, which involves physical modeling of the transactions into the power flow model.

Flowgate Name: NonFirm New Reservation Total - – the summed impacts of new non-firm reservations (including the requested amount) on the flowgate between resynchronizations of Oasis Automation (OA). During this period, OA accounts for new reservations by algebraically decrementing the flowgate AFC. During this period, the impacts of these reservations are not part of Non-firm Commitments or Non-firm Flow.

Flowgate Name: NonFirm AFC Remaining - The amount of non-firm AFC available on the flowgate after the impacts of base flows, non-firm commitments, and non-firm new reservations (including the requested amount). To calculate NonFirm AFC Remaining, use the following formula:

> (Flowgate Name: TTC)-(Flowgate Name: NonFirm Flow/CBM/TRM)-(Flowgate Name: NonFirm Commitments)-(Flowgate Name: NonFirm New Reservation Total)

Flowgate Name: Sensitivity – The percentage impact of the transfer on the flowgate; otherwise known as the "Response Factor." For example, if generator A has requested service for 100 MW and the sensitivity on flowgate X is 0.05, then 5 MW of flow will be added to the flowgate if the transfer is approved.

Flowgate Name: Firm Impact – The actual impact of the reservation on the flowgate. This value is calculated using the sensitivity and the requested amount. Using the example above, this column would show 5 MW. The Firm Impact field will be zero for all time points where the Firm and/or NonFirm AFC Remaining fields are zero or negative even though a non-zero number can be calculated. The program places a zero in this field and does not calculate an impact value because there is no capacity available to accommodate the request. Even though this value may be zero, customers may calculate this value by multiplying the capacity requested by the sensitivity in order to see the impact of the request on the flowgate.

Flowgate Name: NonFirm Impact – The actual impact of the reservation on the flowgate. This value is calculated using the sensitivity and the requested amount. Using the example above, this column would show 5 MW. The NonFirm Impact field will be zero for all time points where the Firm and/or NonFirm AFC Remaining fields are zero or negative even though a non-zero number can be calculated. The program places a zero in this field and does not calculate an impact value because there is no capacity available to accommodate the request.

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: FERC Commission

Question No. 14

Question:

14. Mr. Adams, representing NRG, stated that, as a result of the AFC process, NRG is not able to get firm day-ahead transmission, but is only able to get non-firm day-of transmission. (Tr. at 84) Please explain why implementation of the AFC methodology leads to this result. If Entergy disagrees with Mr. Adams' assertion, please provide a detail explanation and all supporting documentation.

Response:

To the extent Mr. Adams is suggesting that firm daily transmission service is not available under the AFC process, we do not agree. Based on the same data and methodology described in Entergy's response to Data Request 15, Entergy has accepted more MWhs of daily firm point-to-point transmission service during the summer of 2004 under the AFC process, than was accepted during the summer of 2003 under the prior GOL/ATC/SIS process. In fact, daily firm point-to-point service queued and accepted under the AFC process totaled approximately 4.6 million MWhs in the summer of 2004, while daily firm point-to-point service queued and accepted during the same period in the summer of 2003 under the GOL process totaled approximately 1.6 million MWhs.

We do agree, however, that additional transmission service is made available on a non-firm basis after the scheduling deadline for firm transmission expires. This has more to do with the scheduling and reservation deadlines in the *pro forma* OATT rather than Entergy's AFC process. Under the *pro forma* OATT, firm transmission service customers are not obligated to schedule that service until the 12:00 pm on the day prior to actual power flows. Entergy also allows customers to schedule firm pass that deadline with twenty-minutes notice prior to the start of each hour. Under the AFC process, Entergy releases unscheduled firm transmission service once the noon scheduling deadline passes. This unscheduled capacity is then available for new non-firm transmission service requests. This unscheduled capacity is not available for new firm transmission service requests because, under the *pro forma* OATT, firm point-to-point transmission service must be reserved no later than noon on the day prior to actual power flows and because released firm capacity can be used on a firm basis by a scheduled submitted twenty-minutes prior to each hour, even hours beyond the noon scheduling deadline.

The impact of these procedures can be different under the AFC process (as compared to the GOL process) because the AFC process contains a more accurate process for accounting for simultaneous impacts of multiple transmission reservations. Under the GOL process, Entergy only took into account limits created by daily and weekly service requests from the same generator requesting additional service by limiting service to lowest of paths over which service was reserved. Although intervenors in the GOL proceeding claimed that this was an overly conservative assumption, Entergy pointed out that this conservatism was balanced by the more permissive practice of ignoring simultaneous impacts of daily and weekly reservations from generators other than the generator actually requesting additional service. Entergy justified these practices based in part on the fact that updating GOL calculations every time a new daily or weekly reservation was submitted was not practical under the GOL process. When Entergy transitioned to the AFC process, it implemented software revisions that allowed it to frequently update AFC calculations to reflect all new reservations. The more frequent updating eliminated the need to make the conservative assumption questioned by the intervenors, but it also eliminated the need to ignore simultaneous impacts of daily and weekly reservations from other generating facilities.

In sum, if a particular generator is more likely to be limited by the simultaneous impact of daily and weekly reservations from other generators, then the AFC process would correctly reflect those limitations by indicating that less firm transmission service would be available on a day-ahead basis. This capacity would be released on a non-firm basis when the scheduling deadline passes. On the other hand, if a particular generator was more likely to be limited by the "lowest of the reserved paths" rule under the old GOL process, then the AFC process would reflect the elimination of that rule by indicating that more firm transmission service would be available. In both circumstances, the AFC process is an improvement in the accuracy of transfer capability calculations because it reduces the reliance on assumptions and increases reliance on actual reservation data. Overall, however, this improvement in accuracy does lead to maximizing the availability of transmission capacity. As stated above, Entergy accepted more MWhs of daily firm point-to-point transmission service under the AFC process during the period in question. Nevertheless, as discussed in Entergy's answer to Data Response 15, Entergy will analyze the impact of the AFC process on day-ahead firm transmission service in general and report back to the Commission.

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: FERC Commission

Question No. 15

Question:

15. Please indicate whether Entergy has conducted any studies that projected the effect of the AFC program on transmission access before that program was launched or that have examined the effects of that program since its inception using historical data. Please provide a copy of all such studies or evaluations of the AFC program's effects on transmission access.

Response:

The AFC methodology involves two new software programs – RFCalc and OASIS Automation – to calculate AFC values based on data taken directly from Entergy's Energy Management System (EMS). Thus, a study to project the effect of the AFC process could only be performed after purchasing and implementing the AFC software improvements, while also maintaining the then-current GOL/ATC/SIS procedures for evaluating service requests. Entergy noted in its answer to comments regarding the initial AFC filing that such study was not a feasible.

Since implementation of the AFC process on April 27, 2004, Entergy has not performed any formal analysis of the effects of the AFC methodology on transmission access. Entergy does intend to review the performance of the AFC process during the summer of 2004 using historical data. However, because the summer period did not close until several weeks ago, Entergy has not had sufficient time to conduct this analysis. Entergy is evaluating the timeframe and resources necessary to conduct such an analysis and will notify the Commission within the next two weeks of the expected completion date for this analysis.

In an effort to respond to this question immediately, Entergy has reviewed data from 2003 and 2004 in an effort to compare transmission service acceptance rates under the AFC process and the previous GOL/ATC/SIS process. The results of this initial review indicate that Entergy has granted more MWhs of daily and weekly firm service under the AFC process in 2004, than under the GOL/ATC/SIS process in 2003.

The AFC process was implemented on April 27, 2004 and was applied to many – but not all – of the requests for service during the summer of 2004. Therefore, to ensure an "apples to apples" comparison, Entergy focused on two subsets of short-term transmission service requests ("TSRs"):

- AFC TSRs: This data set includes those TSRs that were queued after April 27, 2004, and were for service during the summer of 2004 (*i.e.*, the period from April 27th to August 31st). All of these TSRs were evaluated under the AFC process.

- GOL/ATC/SIS TSRs: This data set includes those TSRs that were queued after April 27, 2003 for service during the summer of 2003 (*i.e.*, the period from April 27th to August 31st). All of these TSRs were evaluated under the GOL/ATC/SIS process.

This comparison ensures that the analysis of acceptance rates under the AFC process includes only those TSRs that were actually evaluated under the AFC process and does not include TSRs for service during the summer of 2004 that were evaluated under the GOL/ATC/SIS process. Entergy treated a TSR as "accepted" if Entergy accepted the TSR after making a transfer capability determination, even if the customer chose not to confirm the TSR. Entergy also analyzed separately the acceptance rates for affiliate and non-affiliate generating units. This analysis was based on affiliate/non-affiliate ownership of the generating facility designated as the source of each TSR, rather than the affiliate/non-affiliate designation of the transmission customer.

Monthly Firm Service

Entergy analyzed monthly firm TSRs and concluded that approximately 90-95% of the MWhs of monthly firm point-to-point and network service requested for the summer of 2004 were requested prior to implementation of the AFC process and were evaluated under the GOL/ATC/SIS process. The few monthly firm TSRs that were evaluated under the AFC process all appear to have been accepted, but this sample is relatively small. Therefore, Entergy concluded that data regarding monthly firm TSRs does not yet provide a meaningful evaluation of the impact of the AFC process.

Daily and Weekly Firm Service

In contrast to monthly firm TSRs, all of the daily and weekly firm and non-firm point-to-point TSRs for the summer of 2004 were submitted after the implementation of the AFC process. Likewise, all of the weekly firm network TSRs and more than 95% of the daily firm network TSRs for the summer of 2004 were submitted after the implementation of the AFC process. The results of this preliminary analysis are contained in the attached table and demonstrate the following:

- Entergy has accepted more MWhs of daily and weekly firm transmission service (both network and point-to-point) under the AFC process than was accepted under the GOL/ATC/SIS process during a similar period in 2003. The vast majority of the MWhs of accepted short-term firm transmission service have been from non-affiliate generating facilities.

- Entergy has accepted less MWhs of daily and weekly non-firm point-to-point transmission service under the AFC process than was accepted under the GOL/ATC/SIS process during a similar period in 2003. This difference appears to be due to the fact that Entergy did not apply GOL calculations to non-firm service requests from generators within Entergy's control area. This practice was not carried through to the AFC process for the reasons discussed in Entergy's response to Data Request 13.

As discussed above, because the summer 2004 period just ended, this analysis is preliminary and subject to change. In order to fully understand the impact of the AFC process on transmission access, a more detailed analysis is necessary and will be provided to the Commission in the AFC docket.

Nevertheless, this data refutes the general assertion by a number of intervenors in the ICT filing that Entergy has used the AFC process to unfairly limit the availability of transmission service to non-affiliates. In fact, under the AFC process, Entergy has granted more MWhs of daily and weekly firm transmission service under the AFC process. The vast majority of this service was sourced from generators not affiliated with Entergy.

COMPARISON OF DAILY AND WEEKLY TRANSMISSION SERVICE REQUESTS – SUMMERS OF 2003 AND 2004						
	Firm PTP		**Non-Firm PTP**		**Firm Network**	
	Requested (mwh)	Accepted (mwh)	Requested (mwh)	Accepted (mwh)	Requested (mwh)	Accepted (mwh)
All Sources						
2003	3,616,597	1,713,809	1,181,954	906,358	12,324,835	10,265,068
2004	12,519,002	4,908,308	985,956	530,144	27,757,074	12,185,146
Affiliate						
2003	828,135	196,439	195,896	176,960	931,414	837,086
2004	1,311,345	385,656	464,448	260,472	865,146	366,206
Non-affiliate						
2003	2,788,462	1,517,370	986,058	729,398	11,393,421	9,427,982
2004	11,207,657	4,522,652	521,508	269,672	26,890,728	11,818,940

Entergy Services, Inc.
FERC Technical Conference
Docket No. ER04-699-000
Docket No. ER03-1272-002

Response of: Entergy Services, Inc.
The request for data at the ICT Technical Conference
Of Requesting Party: Federal Energy Regulatory Commission

Additional Matters Raised at the Commission's August 26, 2004 Meeting

The Commission on August 26, 2004 held a meeting to address products that Entergy is interested in procuring. At that meeting Entergy provided a detailed explanation of its recent purchase history and further explained the products that would best be able to further displace Entergy's resources in its wholesale purchased power portfolio. Entergy specifically explained the need for offers of flexible products. Other parties asked a number of questions and raised a number of their concerns, many of which have been addressed repeatedly in Docket No. ER04-699-000. Entergy believes that the meeting was informative, and agreed to follow-up on a number of items at a subsequent meeting that has now been scheduled for September 21, 2004. Commission Staff also encouraged Entergy to further respond in writing to certain matters that were discussed during the August 26 meeting. Entergy therefore will discuss three matters that arose during that meeting: (i) the ICT's access to data, (ii) how the desire for flexible products affects supplier offers, and (iii) transparency.

ICT Access to Data

A question was raised during the August 26 meeting regarding the ICT's authority to view offer data submitted to Weekly Operations. Entergy clarifies that the ICT will have access to all such offer data. Section 6.1 of Attachment S to the Entergy OATT provides that the ICT will "have complete access to all data or other information that is: (i) gathered or generated by Entergy Transmission in the course of its operations; and (ii) reasonably necessary to achieve the purposes or objectives of this Attachment and not subject to a legal privilege." Entergy OATT, Attachment S § 6.1; *see also id.* § 2.2(b) ("the ICT will have the authority to collect and analyze data relevant to its responsibilities"). One purpose of Attachment S is to provide the ICT with authority to oversee "all activities of Entergy Transmission in evaluating TSRs submitted as part of the WPP, including such TSRs submitted by the Transmission Provider's wholesale merchant function." *Id.* § 3.3.

The ICT will not, however, be empowered unilaterally to change the specific data that is input into the WPP's security-constrained optimization software, to second-guess EMO's or Participating Network Customers' commercial decisions, or to alter the results of the WPP. The ICT's role instead will be to monitor the operation of the WPP and to recommend any improvements that may be appropriate. The ICT also will report any violations of Entergy's OATT, including provisions related to the WPP, directly to the

Commission and Entergy's retail regulators. *See id.* § 7; Entergy Transmittal Letter, Docket No. ER04-699-000 at 13 (March 31, 2004) ("the ICT will have authority to pro-actively recommend . . . changes to the tariff provisions, business practices and protocols to promote comparability and improve Entergy's transmission processes.").

Flexibility and Offers

Entergy explained the need for flexible products in its August 31, 2004 Supplemental Comments. The oil and gas fired units that Entergy is seeking to displace provide Entergy significant operational flexibility that is required to meet Entergy's obligations as a load serving entity. That flexibility must be maintained as a condition of displacement. Certain parties asserted during the August 26 meeting that it can be difficult on a week-ahead basis to offer the flexibility Entergy is seeking. These parties complained that they face opportunity costs to make their resources available on a week-ahead basis—costs which they may not recover if their units are not dispatched—and certain parties argued that they should be able to include a capacity component in their offers.

Entergy does not believe that the addition of a capacity component is either necessary or appropriate. It is not necessary because a supplier can include the very same revenues—reflecting opportunity costs, expected profit, *etc.* —in the existing offer components (heat rate, gas basis, gas basis adder, start-up costs). For example, a supplier will be able to offer a minimum block with a heat rate that is above the supplier's actual costs, with the difference based on the supplier's expected opportunity cost or any other adder the supplier desires. The supplier's heat rate for the power offered above the minimum block also could reflect any adder above the supplier's actual costs that reflects the supplier's desired profit when such power is called on. A supplier also could include an opportunity cost or capacity cost component in its start-up offer, and require at least one start. Under a pay-as-bid structure such as the WPP, the supplier will perform the same analysis of its desired profit regardless of whether it includes that profit in a minimum block heat rate adder, a start-up cost adder, or a fuel cost adder, or if its profit is in a separate capacity component.

Finally, it is important to note that Entergy is not attempting to purchase through the WPP (or its current weekly procurement procedure) "capacity" that it requires to meet its installed reserve requirement. Entergy instead is seeking to displace energy production from its existing portfolio of owned units and purchased power contracts (for which Entergy's customers already have paid for the capacity) when such displacement can occur on an economic and reliable basis. Entergy acquires capacity through its other procurement processes, including its longer-term RFPs.

Transparency

Transparency remained a topic of considerable discussion during the August 26 meeting. Entergy addressed claims about transparency in its August 31 Supplemental Comments, and addresses claims that Entergy should divulge its variable production costs above. Entergy would like to add only one fact of note arising from the August 26 discussions: suppliers cannot even agree among themselves about the level of disclosure they would like. There are certain suppliers that have argued that the current procurement process and WPP proposal do not provide sufficient transparency. Other suppliers believe that Entergy has provided more than enough information to permit suppliers to successfully participate in Entergy's short-term energy procurement processes, and oppose the level of disclosure other suppliers are advocating. This latter group of suppliers does not, for example, want their winning offers disclosed. Entergy believes that sufficient transparency is provided to permit suppliers to successfully participate in Entergy's short-term energy procurement processes, as evidenced by the significant amounts of third party power Entergy purchases. Further, for the reasons it has explained, Entergy believes that the WPP will be a transparent process.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Entergy Services, Inc. Docket Nos. ER04-699-000
ER03-1272-002

NOTICE OF FILING

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Take notice that on September 23, 2004 Entergy Services, Inc., on behalf of Entergy Arkansas, Inc., Entergy Gulf States, Inc., Entergy Louisiana, Inc., Entergy Mississippi, Inc., and Entergy New Orleans, Inc., filed a response to the Post Technical Conference Data Request issued on August 17, 2004 in the above-captioned proceedings.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on all parties to the proceeding.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Magalie R. Salas
Secretary

<u>CERTIFICATE OF SERVICE</u>

I hereby certify that I have this day caused the foregoing document to be served by first-class mail, postage-prepaid to all parties on the Commission's official service lists compiled in these proceedings.

Dated this 23rd day of September, 2004, in Washington, D.C.

G. Bernstein /kkb

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