Entergy

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Laura Landreaux
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March 14, 2014

Mr. David Foster
Chief, Utility Division
Tennessee Regulatory Authority
500 Dederick Street, 4th Floor
Nashville, TN 37242-0002

Docket No. 14-00027

Re: Tennessee Regulatory Authority – Tariff Filing No. 2013-_____
Entergy Arkansas, Inc.'s Annual Tariff Revision to the Energy Cost Rate for the Energy Cost Recovery Rider (Rider ECR)

Dear Mr. Foster:

On March 15, 2014, Entergy Arkansas, Inc. (EAI) filed with the Arkansas Public Service Commission (APSC) in Docket No. 13-028-U the annual redetermination of the Energy Cost Rate for EAI's Rider ECR (Rate Schedule No. 38) along with supporting workpapers which becomes effective beginning with the first billing cycle of April 2014, which begins on April 1, through March 2015. The annual updates for Rider ECR do not require the APSC to issue an approving order to be placed into effect.

Attached are the original and one electronic copy of this annual update for filing with the Tennessee Regulatory Authority (TRA) per the provisions within the Rider. The revised Energy Cost Rate of $0.01566 per kWh will supersede the current rate of $0.01302 per kWh. All other existing Rate Schedules remain in effect as currently approved.

The data required for this annual update does not require it to be finalized 30 days prior to the April 1 effective date for EAI's application to its Arkansas retail customers; therefore, EAI requests the TRA waive the 30-day rule established in Chapter 1220-4-1-.04 of the TRA General Public Utilities Rules to allow EAI to also place this revised rate in effect on April 1, 2014, for EAI's retail customers residing in Tennessee.

The current bill for a typical residential customer using 1,000 kWh is $91.97 excluding taxes, which reflects the Rider ECR rate of $0.01302 per kWh that was implemented with the first billing cycle of April 2013. With the revised Rider ECR Energy Cost Rate, the typical residential bill will be $94.61, a 2.87 percent increase.

The increase in the Energy Cost Rate from the rate approved in the last annual update in April 2013 is primarily attributable to three factors, as shown in the table below.

Factors in 2014 Rider ECR Update

	$ per kWh	$ per kWh
Rate (effective April 2013)		0.01302
+ Nuclear Refueling Outage Adjustment[1]	0.00119	
+ Under Recovery Balance	0.00128	
Fuel and Purchased Energy Cost Increase	0.490	
Less ANO Incident	(0.314)	
Less DOE Credit	(0.158)	
+ Net Fuel and Purchased Energy Cost Increase	0.00018	
Total Adjustments		0.00264
New ECR Rate (effective first billing cycle April 2014)		0.01566

1. The Nuclear Refueling Outage Adjustment (NRFA) increased due to more planned nuclear refueling outages.[1] EAI owns the two units at Arkansas Nuclear One (ANO) and has a long-term agreement to buy power from the Grand Gulf Nuclear Station (Grand Gulf). Rider ECR specifies that this adjustment be made to the Energy Cost Rate to account for the replacement power costs incurred while these units are down for refueling. In 2013, ANO Unit 1 had a scheduled refueling outage. In 2014, ANO Unit 2 and Grand Gulf are scheduled for refueling. This results in an increase in the NRFA. See WP-2 for the calculation of the NRFA.

2. The under-recovered balance at the end of 2013 as compared to the over-recovered balance at the end of 2012 results in an increase in the Energy Cost Rate.

[1] The NRFA is unrelated to the ANO Incident described in footnote 2 below.

3. Fuel and purchased energy expenses increased due to the ANO unit 1 refueling outage[2] and higher market prices for fossil fuels and purchased power. The increases were offset by reductions as a result of the adjustments in fuel related expenses for the ANO Incident[3] and the Department of Energy (DOE) Refund[4] to customers.

Should you have any questions concerning this filing, please call me at (501) 377-5876.

Sincerely,

Laura Landreaux, Manager
Arkansas Regulatory Affairs

Attachments

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[2] The APSC authorized EAI to exclude $65.9 million of costs related to the ANO Incident from its annual Rider ECR rate redetermination and continue to record this amount as deferred fuel in Deferred Fuel Account 182.335 until the APSC has completed its review of the incident and rendered a final decision determining the amount, if any, that should be recovered and the manner in which any recovery should be effected. *See* Order No. 23 in this docket.

[3] On March 31, 2013, during a scheduled refueling outage at ANO Unit 1, a contractor-owned and operated heavy lifting apparatus collapsed while moving the generator stator out of the turbine building in preparation for replacement. The damage was to non-nuclear portions of ANO, and at no time was the general public in danger. Repairs were completed on ANO 2, and it returned to service on April 28, 2013. Repairs were made on ANO 1, and the refueling was completed; that unit returned to service on August 7, 2013.

[4] On August 19, 2013, EAI received payment from the U.S. Government as a result of the judgment in EAI's spent fuel litigation against the DOE, U.S. Court of Federal Claims No. 03-2623C. This resolves damages claims through June 30, 2006. EAI booked this award as income in June 2013.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

RIDER ECR REPORTING REQUIREMENT NO. 1

SIGNIFICANT CHANGES IN COSTS

Identify and explain all significant changes in costs included in the ECR Rider.

	Cents/kWh	Cents/kWh	% Contribution
Rate (effective April 2013)		1.302	
+ Nuclear Refueling Outage Adjustment[1]	0.119		45.0%
+ Under Recovery Balance	0.128		48.3%
Fuel and Purchased Energy Cost Increase	0.490		
Less ANO Incident	(0.314)		
Less DOE Credit	(0.158)		
+ Net Fuel and Purchased Energy Cost Increase	0.018		6.7%
Total Adjustments		0.264	100.0%
New ECR Rate (effective first billing cycle April 2014)		1.566	

Nuclear Refueling Outage Adjustment

Entergy Arkansas, Inc. (EAI) owns two nuclear generating units, Arkansas Nuclear One (ANO) Units 1 and 2, and has a long-term purchase agreement from the Grand Gulf Nuclear Station (Grand Gulf) in Mississippi. Rider ECR specifies that an adjustment be made to the Energy Cost Rate to account for the replacement power costs incurred while these units are down for refueling. This adjustment is known as the Nuclear Refueling Outage Adjustment (NRFA)[1]. Replacement cost is the annual average avoided energy cost rate at generation level for the energy cost period from the most recent filing with the Commission for the Small Cogeneration Rider (Rider SCR)[2]. In 2013, ANO Unit 1 had a scheduled refueling outage. In 2014, ANO Unit 2 and Grand Gulf are scheduled for refueling. This results in an increase in the NRFA and accounts for 45 percent of the increase in the Energy Cost Rate. This adjustment is not related to the ANO Incident[3].

Unrecovered balance recovery

The unrecovered balance is intended to recover or reimburse the difference between the estimated and actual fuel and purchased energy cost during the rate year. At the end of 2012, there was an over-recovered balance of $25.2 million and by the

[1] The NRFA is unrelated to the ANO Stator Incident (ANO Incident) described in footnote 3 below.
[2] Rider SCR was approved by the Commission in Order Nos. 21 and 24 in this docket.
[3] On March 31, 2013, during a scheduled refueling outage at ANO Unit 1, a contractor-owned and operated heavy lifting apparatus collapsed while moving the generator stator out of the turbine building in preparation for replacement. The damage was to non-nuclear portions of ANO, and at no time was the general public in danger. Repairs were completed on ANO 2, and it returned to service on April 28, 2013. Repairs were made on ANO 1, and the refueling was completed; that unit returned to service on August 7, 2013.

end of 2013, there was an under-recovered balance of $2.2 million. This $27.4 million change in the recovery balance accounts for about 48 percent of the increase in the Energy Cost Rate.

Fuel and Purchased Energy Cost

Fuel and purchased energy expenses increased due to the ANO unit 1 refueling outage and increases in market prices of fossil fuels and purchase power. The increases were offset by reductions as a result of the adjustments in fuel related expenses for the ANO Incident[4] and the Department of Energy Refund[5] to customers. This results in about 7 percent of the increase in the Energy Cost Rate.

[4] The Commission authorized EAI to exclude an estimated $65.9 million of costs related to the incident from its annual Rider ECR rate redetermination and continue to record this amount as deferred fuel in Deferred Fuel Account 182.335 until the Commission has completed its review of the incident and rendered a final decision determining the amount, if any, that should be recovered and the manner in which any recovery should be effected. See Order No. 23 in this docket.

[5] On August 19, 2013, EAI received payment from the U.S. Government as a result of the judgment in EAI's spent fuel litigation against the DOE, U.S. Court of Federal Claims No. 03-2623C. This resolves damages claims through June 30, 2006. EAI booked this award to income in June 2013.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

RIDER ECR REPORTING REQUIREMENT NO. 2

SIGNIFICANT CHANGES IN ACCOUNTING PROCEDURES

Identify and explain all significant changes in accounting procedures that affect fuel and purchased energy costs.

During the year of 2013 there have been no significant changes in accounting procedures that affect fuel and purchased energy costs in Arkansas.

BEFORE THE
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RETAIL ELECTRIC SERVICE	)	

RIDER ECR REPORTING REQUIREMENT NO. 3

DETAILED ACCOUNTING INFORMATION

Please provide detailed accounting information that specifically identifies cost recovered in the ECR Rider.

This information can be found in workpapers 15 through 21.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

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RETAIL ELECTRIC SERVICE	)	

RIDER ECR REPORTING REQUIREMENT NO. 4

COAL SUPPLY AND INVENTORY LEVELS

THIS EXHIBIT CONTAINS HIGHLY SENSITIVE PROTECTED INFORMATION PROVIDED PURSUANT TO THE INTERIM PROTECTIVE ORDER NO. 2 IN APSC DOCKET NO. 13-028-U DATED FEBRUARY 21, 2013.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

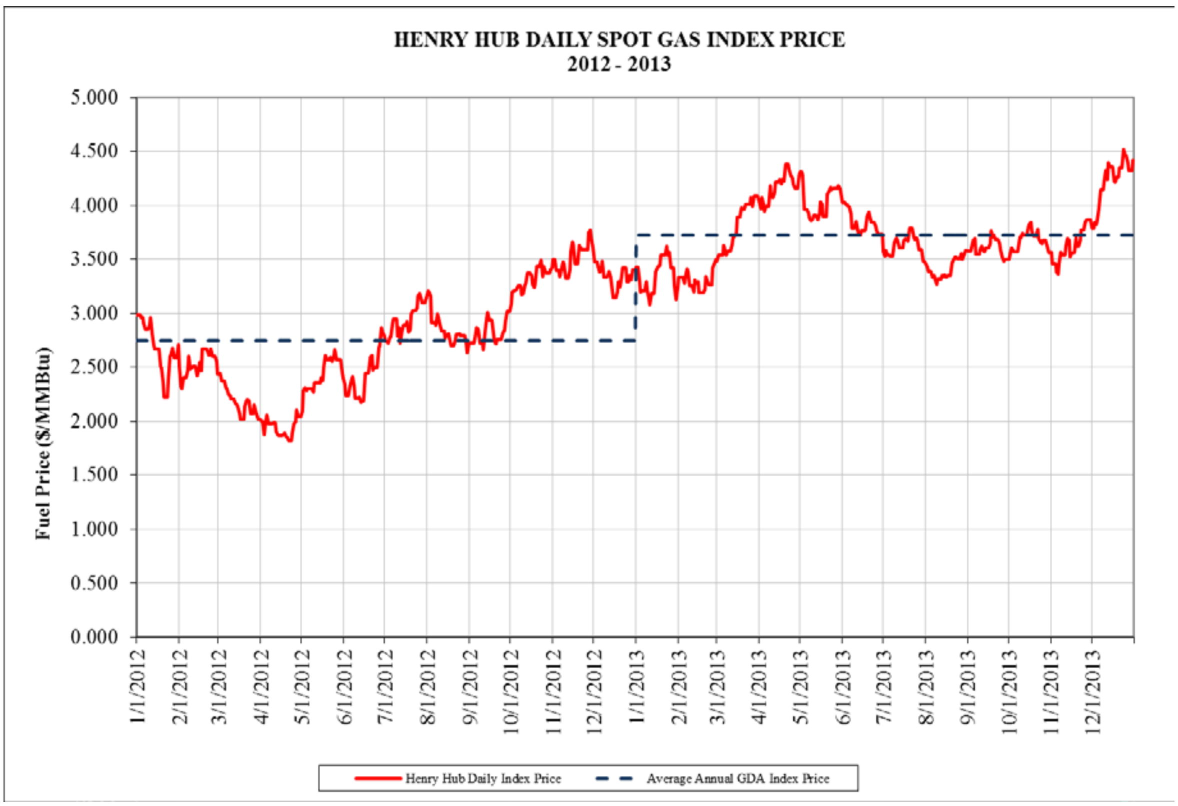
IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE	))))	DOCKET NO. 13-028-U

RIDER ECR REPORTING REQUIREMENT NO. 5

CHANGES IN GAS COSTS

Identify and explain significant changes in gas costs.

The graph below shows the Henry Hub daily spot gas index prices for 2012 - 2013. The average annual index price of spot gas in 2012 was $2.75/MMBtu, with a high price of $3.75/MMbtu in November and a low of $1.89/MMBtu in April. The average annual index price of spot gas in 2013 was $3.72/MMBtu, an increase of approximately 35.3 percent from 2012, with a high price of $4.52/MMBtu in December and a low of $3.08/MMBtu in January.



BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE	))))	DOCKET NO. 13-028-U

RIDER ECR REPORTING REQUIREMENT NO. 6

CHANGES IN PUCHASED POWER AND PROCUREMENT PRACTICES

Identify and explain significant changes in purchased power and procurement practices.

There were no significant changes in purchased power and procurement practices throughout most of 2013. Effective December 19, 2013, Entergy Arkansas exited from the Entergy Services System Agreement. Simultaneously, the Company completed its integration into the Midcontinent Independent System Operator ("MISO") organization. Going forward, MISO will be responsible for the commitment and dispatch of generating plants as well as for the management of the Company's transmission facilities.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE	))))	DOCKET NO. 13-028-U

RIDER ECR REPORTING REQUIREMENT NO. 7

CHANGES IN APPLICATION OF THE SYSTEM AGREEMENT

Identify and explain changes in or application of the System Agreement that affects fuel costs recovered in the ECR.

There were no significant changes to the System Agreement affecting fuel costs recovered in the ECR in 2013. However, effective December 19, 2013, Entergy Arkansas exited from the Entergy Services System Agreement. Simultaneously, the Company completed its integration into the Midcontinent Independent System Operator ("MISO") organization. Going forward, MISO will be responsible for the commitment and dispatch of generating plants as well as for the management of the Company's transmission facilities.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
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RETAIL ELECTRIC SERVICE	)	

RIDER ECR REPORTING REQUIREMENT NO. 8

PLANT OUTAGES

Identify and explain plant outages and the cause of the outages.

Unit	Event Type	Start Date & Hour	End Date & Hour	Cause
ANO-1	PO	3/24/13 8:00 AM	8/7/13 10:43 PM	Unit 1 taken off line for planned 1R24 Refueling Outage.
ANO-1	FO	8/14/13 12:03 PM	8/17/13 6:11 AM	Offline due to Steam Generator chemistry and condensate polisher issues.
ANO-2	FO	3/31/13 7:50 AM	4/28/13 3:00 PM	A crane failure in the turbine building during 1R24 Refueling Outage resulted in reactor and turbine trip.
ANO-2	FO	12/9/13 7:48 AM	12/22/13 10:42 PM	Automatic Scram-Auxiliary Transformer Failure.
ANO-2	SF	12/22/13 10:42 PM	1/10/14 6:39 PM	Start-Up Failure due to steam leak on Main Steam valve.
CARPENTER DAM-1	FO	6/6/13 12:53 PM	6/6/13 2:09 PM	After putting the unit back on line, called TOC and they said it may have been a lightning strike on the transmission line between Arklahoma and Carpenter substations. No relay flags at Carpenter were dropped. Event blinked the lights at Lake Catherine.
GGNS	FO	12/29/12 12:18 AM	1/1/13 4:04 PM	Forced outage 19-02. Scram from Unit Differential relay as a result of a short in a current transformer on the generator neutral phase A.
GGNS	FO	1/4/13 11:37 PM	1/8/13 10:01 AM	FO-19-03 short in generator - current transformer clearance.
GGNS	FO	1/14/13 6:05 PM	1/29/13 10:21 AM	FO-19-04 fault in isophase bus duct.
GGNS	FO	7/30/13 2:32 PM	8/4/13 2:49 PM	FO 19-05 reactor scram on high pressure due to turbine trip caused by Turbine Stress Evaluator (TSE) failure.
GGNS	FO	10/4/13 11:23 AM	10/13/13 12:21 AM	Unplanned outage to repair ground bushing on generator output transformer A.
GGNS	FO	11/1/13 2:58 PM	11/5/13 10:30 AM	Hydraulic fluid leak reparative maintenance could not be performed online due to radiological conditions in the area when online.
HOT SPRING-1	FO	1/3/13 10:43 PM	1/5/13 5:02 PM	LP Economizer tube second from north end of header in HRSG #2 failed at the weld between the header and tube by mechanical fatigue.
HOT SPRING-1	MO	3/18/13 10:28 PM	3/22/13 5:30 PM	Crack in auxiliary steam piping
HOT SPRING-1	FO	3/26/13 5:44 PM	3/27/13 2:27 AM	Lost gas pressure in the Spectra Gas Yard
HOT SPRING-1	MO	6/21/13 11:53 PM	6/24/13 4:30 PM	Installed new cooling tower fan blades on cells H and I that were damaged.
HOT SPRING-1	FO	7/2/13 8:00 AM	7/2/13 10:49 AM	GT1 Tripped due to IGV position feedback
INDEPENDENCE-1	FO	1/14/13 11:09 AM	1/16/13 9:18 PM	Unit was taken offline due to 2 reheat terminal tube leaks in the pentouse roof enclosure on the finishing reheat outlet header.
INDEPENDENCE-1	FO	1/16/13 9:18 PM	1/16/13 9:38 PM	Could not get a start permit at breaker for primary air fans.
INDEPENDENCE-1	PO	3/29/13 10:27 PM	5/1/13 12:00 AM	Critical Path Outage Drive is Main Turbine Low Pressure (LP) A & B Turbine Inspection.Also Inspecting High Pressure (HP) turbine, Generator and Generator TIL 1292 Rotor Tooth.
INDEPENDENCE-1	PO	5/1/13 12:00 AM	5/26/13 10:57 AM	Critical Path Outage Drive is Main Turbine Low Pressure (LP) A & B Turbine Inspection.Also Inspecting High Pressure (HP) turbine, Generator and Generator TIL 1292 Rotor Tooth.
INDEPENDENCE-1	PO	5/26/13 6:34 PM	5/27/13 6:58 PM	Perform a TIL 1292 (rotor tooth cracking) inspection and a field rewind with existing copper. Brought unit off to perform balance shot on #9 bearing.
INDEPENDENCE-1	PO	6/6/13 9:39 PM	6/7/13 7:59 PM	24 Hr Outage to install generator weights due to bearing #9 vibration elevated after Generator field rewind was performed along with the TIL-1292 inspection. Declared for 836 NMW after event.
LAKE CATHERINE-1	PO	3/3/13 1:00 AM	3/18/13 9:00 AM	Replacement of poles and crossarms between synchronizing breaker and step up transformer.
LAKE CATHERINE-2	PO	3/3/13 1:00 AM	3/18/13 9:00 AM	Replacement of poles and crossarms between synchronizing breaker and step up transformer.
LAKE CATHERINE-3	PO	1/19/13 12:00 AM	2/10/13 4:15 PM	Replacement of unit and pilot wire relaying
LAKE CATHERINE-3	FO	4/14/13 12:33 AM	4/14/13 3:18 PM	As a result of the open metering CT circuit, the equalizing reactor used for reactive compensation in the voltage regulator overheated. This was the device that was smoking on top of the BTG board.
LAKE CATHERINE-4	FO	11/25/12 12:00 AM	6/12/13 10:37 AM	Discovered high temperature creep and cracking in the SH outlet header. Replaced header, hangers, and other outage work.
LAKE CATHERINE-4	MO	6/12/13 8:51 PM	6/12/13 10:59 PM	Test of new reverse power relay trip and turbine overspeed testing.
LAKE CATHERINE-4	MO	6/13/13 10:24 AM	6/13/13 11:28 AM	Test of reverse power relay
LYNCH DIESEL	MO	3/26/13 9:20 AM	3/26/13 6:17 PM	Replace transformer low side bushing gaskets
LYNCH-3	MO	3/26/13 9:20 AM	3/26/13 6:17 PM	Replace transformer low side bushings
MABELVALE-2	FO	1/18/13 8:17 AM	3/28/13 4:00 PM	Short in control card
MABELVALE-4	MO	2/25/13 7:00 AM	3/7/13 5:30 PM	Shut down to repair generator stator internal heaters. Also control system showing erroneous faults
MOSES-1	FO	10/1/11 12:00 AM	2/6/13 12:00 AM	Extended Forced Outage. Non-operational due to deterioration of equipment that pose an unacceptable level of risk to operated and/or the lead time for repairs prevent unit from being deployed as required by the system operator. This designation does not apply to those units currently undergoing repairs.
MOSES-2	FO	10/1/11 12:00 AM	2/6/13 12:00 AM	Extended Forced Outage. Non-operational due to deterioration of equipment that pose an unacceptable level of risk to operated and/or the lead time for repairs prevent unit from being deployed as required by the system operator. This designation does not apply to those units currently undergoing repairs.
OUACHITA UNIT 1	FO	1/5/13 12:45 AM	1/5/13 1:20 AM	Unit 1 was dispatched off line by EMO. Then within the hour was requested for emergency dispatch. While starting up the HP steam start up dump valve hung closed causing a high pressure condition in the HRSG. The Unit 1 CT was shutdown until the HP steam start up dump could be opened. WR written for repairs to be made to valve.
OUACHITA UNIT 1	FO	1/14/13 7:26 PM	1/14/13 7:58 PM	Turbine shutdown on a high hotwell level to protect equipment.Unit started back up and released for dispatch at 19:58.
OUACHITA UNIT 1	MO	3/22/13 9:35 AM	3/22/13 3:57 PM	Repair leaking control valve for RH attemperator.
OUACHITA UNIT 1	FO	5/6/13 10:05 AM	5/9/13 7:00 PM	Hot Reheat Steam section tube leak. Unit brought down for repairs. Window was cut in HRSG skin inorder to access where tube leak was. Tube was repaired access window was welded back up Unit released back for reserve.
OUACHITA UNIT 2	MO	4/25/13 8:23 AM	4/25/13 5:46 PM	Inspection and repair of the U2 STG lube oil cooling water regulator, U2 HP turbine expansion probe adjustment, and U2 IP steam valve LVDT reading adjustments.
OUACHITA UNIT 2	FO	6/9/13 8:12 AM	6/9/13 8:13 AM	86 lockout 86SST2A rolled on 52-LVM2A 480V transformer switchgear causing power loss to roughly half the Unit 2 electrical room.
OUACHITA UNIT 2	FO	6/9/13 8:13 AM	6/9/13 1:01 PM	During normal start up checks on U2 STG the 2A STG lube oil pump was being shutdown when the 86 Lockout, 86SST2A rolled. By rolling this 86 lockout relay it is interlocked to 52-LVM2A the 'A' of the 480V switchgear and tripped open 52-LVM2A. This same 86 Lockout relay prevented the tie breaker from closing in which caused a loss of power to approx half of the 480V electrical feed in U2 electrical room. This caused the U2 to have a failed startup
REMMEL DAM-1	MO	3/7/13 2:01 PM	3/7/13 2:23 PM	Shutdown to investigate vibration issues
REMMEL DAM-1	MO	3/26/13 7:08 AM	3/28/13 2:17 PM	Transmission line isolated for relay maintenance at Arklahoma Substation.
REMMEL DAM-1	FO	3/30/13 10:05 AM	3/30/13 6:24 PM	Crossarm broke on transmission line between Remmel and Arklahoma Substation
REMMEL DAM-1	FO	4/24/13 1:55 AM	4/24/13 4:40 AM	Flow switch on lower guide bearing cooling water hung low due to moss in the water.
REMMEL DAM-1	FO	5/14/13 1:24 PM	5/14/13 1:54 PM	Unit tripped during vibration testing
REMMEL DAM-1	MO	5/30/13 9:27 AM	5/30/13 9:52 AM	Visual inspection of generator CTs and PTs
REMMEL DAM-1	MO	6/12/13 8:00 AM	6/12/13 8:35 AM	Another NERC inspection of additional PTs
REMMEL DAM-2	MO	3/26/13 7:07 AM	3/28/13 2:25 PM	Transmission line isolated for relay maintenance at Arklahoma Substation.
REMMEL DAM-2	FO	3/30/13 10:05 AM	3/31/13 4:38 PM	Crossarm broke on transmission line between Remmel and Arklahoma Substation
REMMEL DAM-2	FO	6/24/13 6:58 AM	6/24/13 7:39 AM	Flow switch on lower guide bearing cooling water malfunctioned showing low flow.
REMMEL DAM-3	PO	1/19/13 12:00 AM		Planned outage to replace runner and wicket gates
RITCHIE-3	FO	4/24/12 12:00 AM	6/21/13 12:00 AM	Extended Forced Outage. Non-operational due to deterioration of equipment that pose an unacceptable level of risk to operated and/or the lead time for repairs prevent unit from being deployed as required by the system operator. This designation does not apply to those units currently undergoing repairs.
WHITE BLUFF-1	MO	5/29/13 11:04 PM	6/2/13 4:33 AM	Reheat tube leak.
WHITE BLUFF-1	FO	6/2/13 7:05 PM	6/2/13 9:34 PM	In start up Changing Relay
WHITE BLUFF-2	PO	2/9/13 1:24 AM	3/22/13 2:33 PM	Planned Outage-Air Heater Basket Change out, Boiler Inspection, Misc. Balance of Plant Repairs
WHITE BLUFF-2	FO	3/22/13 2:33 PM	3/23/13 1:06 AM	Service air pressure to ignitors low Serv air drier chambers swapping
WHITE BLUFF-2	FO	3/23/13 1:14 AM	3/23/13 2:15 AM	Service air pressure to ignitors low Serv air drier chambers swapping

FO - Forced Outage
MO - Maintenance Outage
PO - Planned Outage
SF - Startup Failure

Identify and explain plant outages and the cause of the outages.

Unit	Event Type	Start Date & Hour	End Date & Hour	Cause
GGNS	FO	12/29/12 12:18 AM	1/1/13 4:04 PM	Forced outage 19-02. Scram from Unit Differential relay as a result of a short in a current transformer on the generator neutral phase A.
GGNS	FO	1/4/13 11:37 PM	1/8/13 10:01 AM	FO-19-03 short in generator - current transformer clearance.
GGNS	FO	1/14/13 6:05 PM	1/29/13 10:21 AM	FO-19-04 fault in isophase bus duct.
ANO-1	PO	3/24/13 8:00 AM	8/7/13 10:43 PM	Unit 1 taken off line for planned 1R24 Refueling Outage.
ANO-2	FO	3/31/13 7:50 AM	4/28/13 3:00 PM	A crane failure in the turbine building during 1R24 Refueling Outage resulted in reactor and turbine trip.
WHITE BLUFF-1	MO	7/3/13 11:29 PM	7/6/13 5:35 PM	Maint Outage Opacityspikes (A-2 and A-4 /Removed Wires) also removed Discharge Electrode wires from other boxes also as needed to improve ash collection
REMMEL DAM-2	MO	7/9/13 12:35 PM	7/9/13 1:00 PM	Requested by William Norwood to take measurements in preparation for fall outage.
REMMEL DAM-1	MO	7/9/13 1:07 PM	7/9/13 1:29 PM	Requested by William Norwood to take measurements in preparation for fall outage.
LAKE CATHERINE-4	FO	7/9/13 11:30 PM	7/10/13 1:29 AM	A gas burner valve on the first elevation did not close when coming to minimum load. Since the valve showed open after being commanded to close, the flame safeguard system tripped the boiler. Operators tripped the turbine & generator when a purge could not be completed.
OUACHITA UNIT 1	FO	7/10/13 12:21 AM	7/10/13 12:25 AM	While working to adjusted turbine voltage to meet NERC voltage schedule requirements, we adjusted the Unit 1 STG turbine to -.94 powerfactor from -.95 powerfactor at -26 MVars and the STG breaker opened just before the exciter alarm came in. We had a 27/59- Undervolatge/overvoltage relay and 50- Instantaneous Overcurrent Relay alarms in on the STG DGP panel after the trip U1 CTG went to full speed no load. Unit was caught and put back on line.
HOT SPRING-1	FO	7/18/13 7:12 PM	7/19/13 3:10 AM	During storm a light pole fell across Spectra Gas Line and broke a 1" gas sensing line. Plant was shut down until Spectra Personnel could make repair in the gas yard.
INDEPENDENCE-1	FO	7/26/13 9:26 PM	7/29/13 11:32 AM	Tube leak brought the unit off line with makeup going to 600 GPM. The main leak was a fishmouth failure on a rear wall tube three tubes off the North (Left) sidewall of B box. Leak was cause from an old repair at the nose of the lower coutant on the same circuit.
OUACHITA UNIT 1	FO	7/27/13 1:02 PM	7/28/13 6:35 AM	Unit 1 STG EHC system fluid leak. There was a failed o-ring on the discharge line of the EHC skid piping. Unit was unavailable due to repair of failed o-ring, clean up of Fyrquel and testing of equipment after repairs.
INDEPENDENCE-1	FO	7/29/13 11:32 AM	7/29/13 4:29 PM	Lockout relay 27DL-G1-50180 inside BTG Board Burnt Up with none in Stock. Repaired lockout relay on 2nd alternate, jumpered both contacts on relay to show generator voltage is present for both breakers, and tied Unit On Line. Released for full load.
GGNS	FO	7/30/13 2:32 PM	8/4/13 2:49 PM	FO 19-05 reactor scram on high pressure due to turbine trip caused by Turbine Stress Evaluator (TSE) failure.
OUACHITA UNIT 2	FO	8/4/13 9:40 AM	8/4/13 10:21 AM	U2 STG tripped when the exciter loss of 125VDC alarm came in. Found to have a bad connection on a ribbon cable. Unit released and put back in service.
WHITE BLUFF-2	FO	8/6/13 8:02 PM	8/8/13 5:40 AM	2A PA FAN MOTOR FAILURE
LAKE CATHERINE-4	MO	8/8/13 10:59 PM	8/11/13 4:00 PM	Short outage to fix five waterwall tube leaks, #4 & #5 heater tube leaks, repair casing leaks and hot spots, and other maintenance work.
ANO-1	FO	8/14/13 12:03 PM	8/17/13 6:11 AM	Offline due to Steam Generator chemistry and condensate polisher issues.
OUACHITA UNIT 1	FO	8/17/13 7:39 AM	8/18/13 4:08 PM	Unit 1 STG lube oil cooling control valve will not open more than 40%. Found parts of check valve in cooling water control valve. 1A Aux cooling water pump discharge check valve has failed. 1A ACW Pump is isolated. This allows water to back flow thru pump when 1B ACWP is in service. Unit released back to reserve shutdown 16:08
WHITE BLUFF-1	FO	8/30/13 10:09 PM	8/31/13 12:35 AM	Boiler tripped on unit#1 while swapping equipment. Stator pumps caused a runback and the ID & FD fans tripped. Reheat temps got low and we tripped the turbine.
OUACHITA UNIT 1	FO	8/31/13 10:50 AM	8/31/13 12:55 PM	Unit 1 was delayed during start up due to 89ND limit switch was not showing correct position in control room.
OUACHITA UNIT 2	FO	9/6/13 7:47 AM	9/7/13 5:37 PM	IP evaporator tube leak. Repairs will start as soon as HRSG is cool enough to enter. Leak was repaired and unit was released back for reserve shutdown status.
WHITE BLUFF-1	MO	9/7/13 12:17 AM	9/9/13 2:03 AM	No AGC due to Bearing Vibration Trouble on 1A ID Fan. Hydraulic Cylinder leaked oil onto fan blades causing ash build-up and balance issues.
REMMEL DAM-2	PO	9/9/13 7:10 AM	9/9/13 7:23 AM	Operator traing on unit shutdown and startup procedures
REMMEL DAM-1	PO	9/9/13 7:11 AM	9/9/13 7:59 AM	Operator traing on unit shutdown and startup procedures
WHITE BLUFF-2	FO	9/10/13 8:59 AM	9/14/13 12:29 AM	Found a leak on Condenser Expansion Joint on the mezzanine level, It is suspected this is the source of the vaccum leak.
REMMEL DAM-2	FO	9/13/13 2:48 PM	9/13/13 6:54 PM	Developed air leak at wicket gate oil accumulator
REMMEL DAM-1	PO	9/14/13 8:08 AM	10/22/13 2:01 PM	Replacement of PLC controls
REMMEL DAM-2	PO	9/14/13 8:10 AM	10/1/13 12:00 AM	Replacement of PLC controls
OUACHITA UNIT 1	PO	9/28/13 12:00 AM	10/1/13 12:00 AM	Planned Fall outage: Reliability PMs and Testing, BOP Work, Borescope inspections, Water Washing, relay testing, HRSG work, HRSG Seal replacement, BOP Repairs.
OUACHITA UNIT 1	PO	10/1/13 12:00 AM	10/30/13 7:55 AM	Planned Fall outage: Reliability PMs and Testing, BOP Work, Borescope inspections, Water Washing, relay testing, HRSG work, HRSG Seal replacement, BOP Repairs.
REMMEL DAM-2	PO	10/1/13 12:00 AM	10/22/13 2:01 PM	Replacement of PLC controls
GGNS	FO	10/4/13 11:23 AM	10/13/13 12:21 AM	Unplanned outage to repair ground bushing on generator output transformer A.
WHITE BLUFF-2	FO	10/6/13 3:08 AM	10/7/13 1:46 PM	Generator H2 Seal Oil Tank Float Switch Failure
LAKE CATHERINE-4	MO	10/8/13 9:32 PM	10/11/13 3:13 PM	Maintenance outage to repair #1 HP heater tube leak, boiler casing leak, "A" BFP recirculation line flange leak, and other issues.
WHITE BLUFF-1	FO	10/10/13 11:10 AM	10/10/13 4:28 PM	1A BOILER FEEDPUMP TURBINE FIRE. Opened Breakers and tripped 1B Boiler Feedpump.
HOT SPRING-1	PO	10/12/13 12:00 AM	11/8/13 10:00 PM	Feedwater valve inspections, HRSGs inspection, cooling tower PMs, Gas Turbine Inspections, NERC Relay Testing, Chemistry Panel Installation. Fuel Gas Simultaneuous Flow Control System, Plant Metering Installation, CEMS conversion
OUACHITA UNIT 2	PO	10/12/13 12:01 AM	10/28/13 8:25 AM	Planned Fall outage, Reliability PMs and testing, BOP work, Borescope inspections, Water Washing, Relay Testing,HRSG Work, HRSG Seal Replacement BOP repairs.
WHITE BLUFF-1	PO	10/15/13 10:20 PM	11/15/13 8:50 PM	Summer run cleaning and repairs PMs and SRCMs
REMMEL DAM-1	PO	10/22/13 4:46 PM	10/24/13 1:30 PM	Unit testing following Replacement of PLC controls during PO.
REMMEL DAM-2	PO	10/22/13 4:56 PM	10/24/13 1:30 PM	Unit testing following Replacement of PLC controls during PO.
REMMEL DAM-1	PO	10/24/13 3:30 PM	10/25/13 9:27 AM	Unit testing following Replacement of PLC controls during PO.
REMMEL DAM-2	PO	10/24/13 3:30 PM	10/25/13 9:27 AM	Unit testing following Replacement of PLC controls during PO.
INDEPENDENCE-1	FO	10/25/13 9:09 PM	10/26/13 2:11 PM	Bringing unit off-line in order to go install blank on 1A Induced Draft Fan and then bring the unit back on with one fan operation while investigating the cause of the high vibrations and make repairs.
CARPENTER DAM-1	PO	10/26/13 8:24 AM		Planned outage to replace 440V switchgear
CARPENTER DAM-2	PO	10/26/13 8:38 AM		Planned outage to replace 440V switchgear
INDEPENDENCE-1	FO	10/29/13 12:27 PM	10/30/13 2:42 AM	Bringing unit off-line in order to remove blank on 1A Induced Draft Fan. Blank was installed while investigating the cause of the high vibrations and making repairs.
GGNS	FO	11/1/13 2:58 PM	11/5/13 10:30 AM	Hydraulic fluid leak reparative maintenance could not be performed online due to radiological conditions in the area when online.
OUACHITA UNIT 2	FO	11/2/13 9:21 AM	11/3/13 12:07 PM	HP drum door leaking. Brought unit down to repair leak on drum door. Released unit back for service.
HOT SPRING-1	FO	11/13/13 6:33 PM	11/19/13 7:15 PM	B phase of the 89ST was arcing and fused to the shoe of the switch where it is stuck in position.
WHITE BLUFF-1	FO	11/15/13 8:50 PM	11/16/13 3:04 AM	Feed Water Problems
WHITE BLUFF-2	MO	12/3/13 8:34 AM	12/5/13 1:41 PM	2A PA Fan Motor
REMMEL DAM-2	FO	12/5/13 9:25 AM	12/5/13 2:42 PM	Failure of speed sensor card.
OUACHITA UNIT 1	FO	12/7/13 12:30 AM	12/8/13 9:39 PM	We were getting an alarm in on the CTG breaker 'Hydraulic power failure' It was found that the Hyd pump keyway had gotten out of place which did not allow the pump to pressure up properly and time out on run time. Keyway problem was repaired and breaker back to operating properly.
ANO-2	FO	12/9/13 7:48 AM	12/22/13 10:42 PM	Automatic Scram-Auxiliary Transformer Failure.
WHITE BLUFF-1	FO	12/9/13 4:30 PM	12/11/13 4:09 PM	The tube leak was found to be located just below where two furnace wall tubes were cut out and replaced at the Fall, 2013 maintenance outage. Based on the evidence found, this leak was considered to be from a matabo grinder cutting disk that had cut into the tube during this process.
WHITE BLUFF-2	FO	12/11/13 2:27 PM	12/11/13 5:09 PM	GE HFA relay(52XC3) behind the Unit2 BTG board that did not latch in the last time switchyard GCB B7942 was closed.
WHITE BLUFF-1	FO	12/11/13 4:09 PM	12/11/13 8:47 PM	Start up failure due to Unit 2 Trip.
WHITE BLUFF-1	FO	12/11/13 8:47 PM	12/12/13 6:30 AM	Atomizing Steam Pressure
OUACHITA UNIT 2	FO	12/22/13 6:28 PM	12/22/13 7:44 PM	Unit trip. Hi exhaust pressure instrument failure.
ANO-2	SF	12/22/13 10:42 PM	1/10/14 6:39 PM	Start-Up Failure due to steam leak on Main Steam valve.
OUACHITA UNIT 2	FO	12/24/13 7:00 PM	12/24/13 9:59 PM	Unit trip. Hi exhaust pressure instrument failure.

FO - Forced Outage
MO - Maintenance Outage
PO - Planned Outage
SF - Startup Failure

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE	))))	DOCKET NO. 13-028-U

RIDER ECR REPORTING REQUIREMENT NO. 9

ENVIRONMENTAL REGULATIONS

THIS EXHIBIT CONTAINS HIGHLY SENSITIVE PROTECTED INFORMATION PROVIDED PURSUANT TO THE INTERIM PROTECTIVE ORDER NO. 2 IN APSC DOCKET NO. 13-028-U DATED FEBRUARY 21, 2013.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

RIDER ECR REPORTING REQUIREMENT NO. 10

ATTACHMENT I
CONSTRAINTS ON ECONOMIC DISPATCH

ATTACHMENT I

Identify when units are being run out of economic dispatch because of transmission constraints or other factors, identify and explain the factors affecting such dispatch and quantify and explain the associated impact on EAI's fuel and purchased energy costs.

I. Identify when units are being run out of economic dispatch because of transmission constraints or other factors

Utilities dispatch owned and purchased resources to meet loads in an environment known as security constrained economic dispatch. Security constrained economic dispatch is the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing the real operational limits of generation and transmission facilities. These operational limits to supplying electricity generally include such factors as 1) production must occur simultaneously with demand, which varies greatly over the course of a day, week, and season; 2) varying costs of generation from different types of units; and 3) expected and unexpected conditions on the transmission network which affect generation units that can be used to serve load reliably.

Because owned generating units and purchased resources are committed and dispatched in such a way as to both minimize costs and to maintain reliability, neither component can be ignored for the benefit of the other. The following are some of the typical constraints encountered during the normal course of planning and operating a security constrained economic dispatch:

1. load constraints
2. unit constraints

3. fuel constraints
4. transmission constraints
5. operating reserve constraints
6. purchase power constraints

A brief discussion of how each of these factors can exert a constraining influence on the economic dispatch follows.

II. <u>Identify and explain the factors affecting such dispatch</u>

A. Typical Load Constraints

Load constraints affect the planning and operations in three different ways. First, the main focus of planning and operations is to ensure that sufficient resources will be available at the anticipated peak load hour. Insufficient resources could lead to the shedding of firm load. Second, typical load constraints involve planning and operating through the minimum load of the day. Here, while still remembering that there will be a peak hour later in the day, units have to be backed down or taken off-line to ensure there is not excess generation. If too many units are on-line, there may be a problem with aggregate minimum generation levels. One consequence is that economic purchased power opportunities may have to be foregone. At the extreme, excess power must be sold at a loss. While the phenomenon must be watched carefully on any day, it becomes more difficult in the winter when the minimum load might occur in the early morning hours and the peak load may occur only a few hours later. The third typical way in which load constraints affect the short-run planning and operations processes involves the normal increases and decreases of load as load moves from maximum to minimum and back. Here, adequate resources must be available to meet these ever-changing variations in load.

B. Typical Unit Constraints

Some generating unit constraints are the result of the physical design characteristics of the power generating equipment. These constraints include startup time, shutdown time, ramp rate (the rate at which units can change output expressed in MW per minute), and high and low operating limits. High and low operating limits can vary depending upon circumstances. For example, certain equipment on some units can be bypassed (such as feedwater heaters) and some boilers can be operated at above normal pressure to produce additional capability during extreme peak load conditions. On the other hand, if the load is extremely low, special operating modes can temporarily be invoked (such as removing a steam-driven boiler feed pump from service) to achieve lower minimum capability. By operating in this fashion, a unit shutdown can be avoided on a unit that might be needed to meet peak load requirements the next day.

Generating units also require scheduled maintenance and equipment testing. Tests include unit efficiency testing, capability testing and emissions testing. All of these tests are performed periodically on the generating units. While being tested, a unit's availability and output level can be affected. To the maximum extent possible, these tests are scheduled to minimize any adverse impact of the testing on reliability and economics.

C. Typical Fuel Constraints

Fuel supply and transportation contract terms generally include limits on the delivery rates of fuel. These include hourly, daily, weekly, monthly, and annual minimum and maximum delivery constraints. Units consuming fuels with constraints must be operated to meet the constraints or a contract penalty may be incurred. In addition, inventoried fuels are subject to the physical limits of the storage and transfer facilities.

D. Typical Transmission Constraints

The Entergy Transmission System[1] is designed to continue providing power without interruption and without constraint to the generation system under most expected single contingency situations (where a single transmission component or generation unit is out of service) and under typical weather conditions. In the event of multiple equipment outages or extreme weather conditions, constraints on the Entergy Transmission System become a factor that must be considered in unit commitment decisions to maintain reliability. Another limitation imposed by the transmission system that might affect unit commitment is the ability to import power from or export power to neighboring electric systems. Some generating units are required to be on-line to prevent a single contingency event from causing a violation of a voltage limit,

[1] The Entergy Transmission System is comprised of the bulk transmission facilities of the Entergy Operating Companies. The Entergy Operating Companies include EAI; Entergy Gulf States Louisiana, L.L.C.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc.

a transient stability limit, or transmission element rating. For more information on transmission constraints, see Highly Sensitive Attachment II.

E. Typical Operating Reserve Constraints

The North American Electric Reliability Corporation's ("NERC")[2] Reliability Standards establish the general requirement that every electric system maintain adequate operating reserve. Each Regional Entity with delegated authority from NERC may establish its own more specific requirements for its members. Operating reserve is provided by sources of power that can be called upon within a short period of time in the event of a contingency, such as a unit trip, a transmission line trip, or a sudden increase in load.

The Entergy Electric System[3] meets its operating reserve requirements by participation in the Southwest Power Pool ("SPP") Reserve Sharing Group. Through participation in the SPP Reserve Sharing Group, the Entergy Electric System is able to save fuel expenses associated with meeting its operating reserve requirements compared to the fuel expenses the Entergy Electric System would have incurred had it met its operating reserve requirements as a stand-alone system. In particular, NERC requires operating reserves equal to the worst single contingency on the electrical system - usually defined as the loss of the electrical system's largest single generator – plus regulating margin. The SPP Reserve Sharing Group represents an

[2] The North American Electric Reliability Corporation's mission is to improve the reliability and security of the bulk power system in North America.
[3] The Entergy Electric System is comprised of the generation and bulk transmission facilities of the six individual Operating Companies, which facilities are operated as a single integrated electric system.

electrical system that is roughly three times the peak load of the Entergy Electric System, but has a worst single contingency that is slightly smaller than the Entergy Electric System's stand-alone worst single contingency. Operating reserves are shared proportionately based on peak load by the members of the SPP Reserve Sharing Group, so that the Entergy Electric System, by participating in the SPP Reserve Sharing Group, is able to reduce its operating reserves to less than half of the operating reserves it would otherwise need on a stand-alone basis.

F. Typical Purchase Power Constraints

With the separation of transmission from the power merchant function under FERC Order Nos. 888 and 889, there is the need not only to find a seller of power at the appropriate price, but also the necessity to secure transmission for the power purchase. Transmission limitations on other electric systems can impact the ability to flow some or all of the power into a utility's system.

Further, the purchased power market is composed of several distinct markets that operate in parallel, but cover different time frames. For example, the time frames include hourly, daily, weekly, monthly and longer term markets. Within each market there exist constraints. Many sellers are unwilling to sell power in the size (MW) and shape (hours during the day) needed to completely optimize a buyer's overall cost. Consequently, purchased power has hourly, daily, weekly, monthly, and annual minimum and maximum delivery constraints much like those discussed for fuels.

Finally, much of the power purchased on behalf of the Operating Companies is "non-firm" power. Non-firm power is supplied on an "if, as and when available" basis. These non-firm purchases include all purchases from Qualifying Facilities ("QFs") that are "put" pursuant to the Public Utilities Regulatory Policy Act ("PURPA") and some purchases from other suppliers. QF Puts under PURPA are non-firm by definition. Purchases from other suppliers may be non-firm due to contractual provisions, because of the location of the other suppliers' power plant on the transmission system, due to the fuel supply arrangements for the other suppliers' power plant, or for other reasons. When such non-firm power is purchased, it is necessary for a utility to back up the non-firm power, such as by running its own generation at minimum load, to continue to reliably serve customers should the non-firm power cease to be supplied.

III. Quantify and explain the associated impact on EAI's fuel and purchased energy costs

EAI cannot calculate the effect of the constraints reported by Entergy's Energy Delivery[4] Attachment II. To do so would require an assumption that, but for the directive imposed by the ICT or Entergy's Energy Delivery organization on the System Operator, the dispatch would have been precisely as set forth in a different case (consider that case to be "Case X" for purposes of this response). However, that assumption fails because there is no basis to assert that every directive

[4] Energy Delivery refers to the Entergy Services, Inc. organization that plans, constructs, maintains, and operates the Entergy Operating Companies' transmission facilities system.

imposed by the ICT or Entergy's Energy Delivery organization caused or resulted in a change of dispatch that resulted in some change in fuel and purchased power costs.

EAI turned functional control of its transmission system to the Midcontinent Independent System Operator, Inc. ("MISO") Regional Transmission Operator ("RTO") on December 19, 2013. Concurrent with that event, the ICT was abolished and no longer is involved in the operation of EAI's transmission system. See the introduction to Attachment II for more information.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE	))))	DOCKET NO. 13-028-U

RIDER ECR REPORTING REQUIREMENT NO. 10

ATTACHMENT II
CONSTRAINTS ON ECONOMIC DISPATCH

THIS EXHIBIT CONSISTS OF HIGHLY SENSITIVE PROTECTED INFORMATION THAT WILL BE PROVIDED WHEN THE COMMISSION APPROVES THE COMPANY'S MOTION FOR AMENDED PROTECTIVE ORDER THAT WAS FILED ON MARCH 12, 2014.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

RIDER ECR REPORTING REQUIREMENT NO. 11

MANAGEMENT OF FUEL SUPPLY AT THE HOT SPRING PLANT

Reporting Requirement established by Arkansas Public Service Commission ("APSC" or the "Commission") Docket No. 11-069-U, Order No. 8.

Entergy Arkansas, Inc. ("EAI") shall file its plan to cost effectively manage its fuel supply at the Hot Spring Plant to minimize cost to ratepayers while maintaining adequate reliability.

Overview

EAI's fuel supply arrangements for the Hot Spring Plant are designed to facilitate 1) adequate supply reliability to the plant, 2) flexibility of supply – (both from an operational and cost perspective), and 3) operations within the Midcontinent Independent System Operator, Inc. ("MISO") Regional Transmission Organization. In this way, EAI manages its fuel supply and associated costs at the Hot Spring Plant for the benefit of EAI's customers.

Adequate Supply Reliability

Adequate supply reliability is achieved through the balancing of costs associated with reliable supply to the plant considering the level of protection sought (reliability) against events that could conceivably disrupt the ability to deliver fuel to the Hot Spring Plant. The supply arrangements first put into place by KGen Power Corporation ("KGen"), the seller of the Hot Spring Plant, and subsequently upgraded by EAI strike a reasonable balance between reliability and cost because they provide EAI with the ability to obtain fuel over two different pipelines -- CenterPoint Energy Gas Transmission, now Enable

Gas Transmission ("EGT"), or Texas Eastern Transmission Company ("TETCO"). The EGT and TETCO pipelines draw from different supply basins, allowing EAI to take advantage of price differentials, i.e. procurement of the most economical fuel. The TETCO and EGT contracts can now be utilized simultaneously, if warranted by the economics and generation schedule.

Flexibility of Supply

The value of a dual-pipeline approach to reliability of supply lies in the fact that at any point in time where there is pipeline capacity that is nominally underutilized, such that if a supply disruption were to occur on one pipeline providing service to the facility at that time, the plant would be able to turn to the other pipeline to deliver fuel necessary to keep the plant in service at its full capacity. Redundancy is important for reliability, and the need for that reliability has increased in importance now that EAI has transitioned to MISO because EAI can no longer rely on the dependable and flexible gas-fired capability from the other Entergy Operating Companies that it had access to as a party to the Entergy System Agreement.

EAI also has secured flexible supply tariffs with both EGT and TETCO. These flexibility supply tariffs provide EAI with the option to change the level of gas supply from either or both gas suppliers to match generation to follow load swings and other balancing needs for the electric system.

In addition, the Hot Spring Plant controls and metering equipment have been upgraded to allow simultaneous flow from both the TETCO and EGT pipelines. Therefore, depending on the economics and generation schedule, both the TETCO and

EGT contracts can now be utilized simultaneously. The CenterPoint meter will operate under volume control to ensure ratable flow and the TETCO meter will operate under pressure control as the swing pipe to account for any fluctuations in hourly flow.

Operations within MISO

The Hot Spring Plant follows a generation schedule determined by MISO. This schedule is unknown until the Day Ahead ("DA") clearing process occurs. The DA clearing process occurs after the day-ahead nomination deadline for EAI to schedule gas supply for the Hot Spring Plant. MISO also has a Forward Reliability Assessment Commitment ("FRAC") process that occurs after the DA clearing process. If a unit is not cleared in the DA market, there is still a chance that the unit could be picked up in the FRAC process. In addition, the Hot Spring Plant may participate in MISO's Real-Time ("RT") market. The RT clearing process occurs on an hourly basis.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 13-028-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

WORKPAPERS SUPPORTING THE
2014 ENERGY COST RATE REDETERMINATION

ENERGY COST RATE DEVELOPMENT
ENERGY COST RATE FORMULA
TEST YEAR ENDED DECEMBER 31, 2013
($)

Line No				Amount	Workpaper Reference
1	ECR	=	ENERGY COST RATE		
2	ECR	=	(TUA + (PEC*EAF)) / PES		
3	WHERE,				
4	TUA	=	TRUE-UP ADJUSTMENT FOR THE ENERGY COST PERIOD INCLUDING CARRYING		
5			CHARGES (1) (4)		
6	TUA	=	$\sum_{j=1}^{12}$		
7			((EC* EAF–(RR$_j$ – PTU$_j$)) + (((BB$_j$ + EB$_j$)/2) * (CCR/ 12))		
8	WHERE,				
9	ECj	=	ENERGY COST FOR MONTH j OF THE ENERGY COST PERIOD		
10	ECj	=	FEj + PEj + RSCj - SO2j		
11	WHERE,				
12	FEj	=	FUEL EXPENSE CHARGED TO ACCOUNTS 501, 509, 518, AND 547		
13			AND ACTIVATED CARBON AND CALCIUM BROMIDE COSTS CHARGED TO		
14			ACCOUNT 502 IN MONTH j OF THE ENERGY COST PERIOD		
15	PEj	=	PURCHASED ENERGY EXPENSE CHARGED TO ACCOUNT 555 (7)		
16			OR CREDITED TO ACCOUNT 447 IN MONTH j OF THE ENERGY COST PERIOD,		
17			BUT EXCLUDING THE RETAINED SHARE PORTION OF GRAND GULF FUEL		
18			(8) CHARGES		
19	RSCj	=	GRAND GULF RETAINED SHARE ENERGY CHARGE IN MONTH j OF THE		
20			ENERGY COST PERIOD (2)		
21	SO2j	=	REVENUES ASSOCIATED WITH THE SALES OF SO2 EMISSIONS		
22			ALLOWANCES RECORDED IN ACCOUNTS 447 AND 411.8.		
23	RRj	=	REVENUE UNDER RIDER ECR FOR MONTH j OF THE ENERGY COST PERIOD		
24			PLUS AN IMPUTED LEVEL OF REVENUES FOR SALES UNDER SPECIAL RATE		
25			CONTRACTS WHERE THE ENERGY COST RATE IS NOT SEPARATELY BILLED		
26	PTUj	=	PRIOR PERIOD TRUE-UP ADJUSTMENT APPLICABLE FOR MONTH j OF THE		
27			ENERGY COST PERIOD (3)		
28	BBj	=	BEGINNING CUMULATIVE OVER(UNDER)-RECOVERY BALANCE FOR MONTH j		
29			(Excluding carrying charges)		
30	EBj	=	ENDING CUMULATIVE OVER(UNDER)-RECOVERY BALANCE FOR MONTH j		
31			(Excluding carrying charges)		
32	CCR	=	CARRYING CHARGE RATE (4)		
33	TUA	=	TRUE-UP ADJUSTMENT FOR THE ENERGY COST PERIOD INCLUDING CARRYING	= 2,517,981	WP - 4
34			CHARGES (1) (4)		
35	PEC	=	PROJECTED ENERGY COST FOR THE PROJECTED ENERGY COST PERIOD (5)		
36	PEC	=	$\sum_{j=1}^{12} EC_j + NRFA$ (6)		
37	WHERE,				
38	ECj	=	ENERGY COST FOR MONTH j OF THE ENERGY COST PERIOD (1)	= 388,969,516	WP - 5

ENERGY COST RATE DEVELOPMENT
ENERGY COST RATE FORMULA
TEST YEAR ENDED DECEMBER 31, 2013
($)

Line No							Amount	Workpaper Reference
39		NRFA	=	NUCLEAR REFUELING OUTAGE ADJUSTMENT				
40		NFRA	=	GACR * (RHD1 * CAP1 + RHD2 * CAP2 + RHDGG * CAPGG)				
41		WHERE,						
42			GACR	= ANNUAL AVERAGE AVOIDED ENERGY COST RATE ($/kWh) AT				
43				GENERATION LEVEL FOR THE ENERGY COST PERIOD AS SET OUT IN THE				
44				MOST RECENT FILING WITH THE COMMISSION PURSUANT TO SMALL				
45				COGENERATION RIDER SCR OR ANY SUPERSEDING RATE SCHEDULE		=	0.03400	WP - 6
46			RHD1	= INCREASE (+) OR DECREASE (-) IN REFUELING OUTAGE HOURS FOR ANO				
47				UNIT 1 BETWEEN THE ENERGY COST PERIOD AND THE PROJECTED				
48				ENERGY COST PERIOD		=	(960.00)	
49				ACTUAL REFUELING HOURS	960			WP - 7
50				PROJECTED REFUELING HOURS	0			WP - 7
51			CAP1	= NET CAPABILITY (kW) OF ANO UNIT 1 AT THE END OF THE ENERGY COST				
52				PERIOD THAT IS AVAILABLE TO THE COMPANY'S RETAIL CUSTOMERS		=	787,874	WP - 8
53			RHD2	= INCREASE (+) OR DECREASE (-) IN REFUELING OUTAGE HOURS FOR ANO				
54				UNIT 2 BETWEEN THE ENERGY COST PERIOD AND THE PROJECTED				
55				ENERGY COST PERIOD		=	720.00	
56				ACTUAL REFUELING HOURS	0			WP - 7
57				PROJECTED REFUELING HOURS	720			WP - 7
58			CAP2	= NET CAPABILITY (kW) OF ANO UNIT 2 AT THE END OF THE ENERGY COST				
59				PERIOD THAT IS AVAILABLE TO THE COMPANY'S RETAIL CUSTOMERS		=	932,558	WP- 8
60			RHDGG	= INCREASE (+) OR DECREASE (-) IN REFUELING OUTAGE HOURS FOR				
61				GRAND GULF BETWEEN THE ENERGY COST PERIOD AND THE PROJECTED				
62				ENERGY COST PERIOD		=	600.00	
63				ACTUAL REFUELING HOURS	0			WP - 7
64				PROJECTED REFUELING HOURS	600			WP - 7
65			CAPGG	= NET CAPABILITY (kW) OF EAI'S ALLOCATED SHARE OF GRAND GULF AT				
66				THE END OF THE ENERGY COST PERIOD AS REDUCED BY THE RETAINED				
67				SHARE AND THAT IS AVAILABLE TO THE COMPANY'S RETAIL CUSTOMERS		=	307,651	WP- 8
68		NRFA	=	NUCLEAR REFUELING OUTAGE ADJUSTMENT		=	3,388,893	
69	PEC	=		PROJECTED ENERGY COST FOR THE PROJECTED ENERGY COST PERIOD (5)		=	392,358,409	
70	EAF	=		ENERGY ALLOCATION FACTOR BASED ON PRODUCTION ENERGY FOR THE RETAIL		=	0.99999	WP - 9
71				JURISDICTION FOR THE ENERGY COST PERIOD (1)				
72	PES	=		PROJECTED SALES (kWh) SUBJECT TO THIS RIDER ECR FOR THE PROJECTED ENERGY		=	20,999,435,000	WP - 10
73				COST PERIOD				
74 ECR	=	ENERGY COST RATE ($/kWh)				=	0.01880	
75	LESS	=		INCREMENTAL FUEL & PURCHASED ENERGY EXPENSE RESULTING FROM ANO		=	65,985,592	
76				INCIDENT PER EAI EXHIBIT KWC-1 FROM APSC DOCKET NO. 13-028-U				
77 ECR	=	ENERGY COST RATE ($/kWh) less Incremental fuel & purchased energy expense resulting from the ANO inciden				=	0.01566	

ENERGY COST RATE DEVELOPMENT
ENERGY COST RATE FORMULA
TEST YEAR ENDED DECEMBER 31, 2013
($)

NOTES:

1) The Energy Cost Period is the calendar year immediately preceding the filing year.
2) RSCj is to be determined by multiplying the Grand Gulf Retained Share energy (kWh) supplied to the Company's retail customers in each month by the annual average avoided energy cost rate ($/kWh) at generation level most recently filed with the Commission pursuant to Small Cogeneration Rider SCR or any superseding rate schedule.
3) The value of PTUj for month j of the then current Energy Cost Period shall be equal to one-twelfth of the True-up Adjustment (TUA) previously determined under the provisions of this Rider ECR for the second preceding Energy Cost Period for j=1,3 (January through March) and equal to one-twelfth of the True-up Adjustment (TUA) for the immediately preceding Energy Cost Period for j=4,12 (April through December).
4) Monthly carrying charges shall be calculated on the average beginning and ending over(under)-recovery balances, excluding carrying charges, using the Commission approved customer deposit simple interest rate for the period.
5) The Projected Energy Cost Period is the twelve-month period commencing on April 1 of the filing year.
6) Should there be unusual circumstances associated with any Projected Cost Period either the Company or the Staff may propose use of a Projected Energy Cost (Variable PEC) different from that defined by this formula.
7) PEj shall include energy costs associated with long-term renewable energy resources recorded in FERC Account 555 when approved by the Commission prior to inclusion in this Rider ECR.
8) PEj shall exclude FERC-Ordered System Agreement payments/receipts.

Entergy Arkansas, Inc.
True-up Adjustment
Energy Cost Period January 2013 - December 2013

Line No.	Month	(1) EC Energy Cost	(2) (EC*EAF) (EC*EAF)	(3) RR ECR Rider Revenue	(4) Subtotal Col 2 - Col 3	(5) BB & EB Cumulative (Over)/Under Recovery	(6) CCR Monthly Carrying Charge Rate	(7) Monthly Interest	(8) Cumulative Interest	(9) Cumulative Total
1	Beginning Balance (10)					(25,315,034)			497,897	
2	January	27,321,277	27,320,894	31,496,304	(4,175,410)	(29,490,444)	0.00042	(11,509)	486,388	(29,004,056)
3	February	21,252,337	21,252,039	30,152,506	(8,900,467)	(38,390,911)	0.00042	(14,255)	472,133	(37,918,778)
4	March	26,962,355	26,582,454	29,734,530	(3,152,076)	(41,542,986)	0.00042	(16,786)	455,347	(41,087,640)
5	April	44,649,875	27,874,548	20,170,637	7,703,910	(33,839,076)	0.00042	(15,830)	439,516	(33,399,560)
6	May	37,702,676	25,920,353	18,833,124	7,087,228	(26,751,848)	0.00042	(12,724)	426,792	(26,325,056)
7	June	9,703,819	(7,292,443)	21,671,812	(28,964,255)	(55,716,103)	0.00042	(17,318)	409,474	(55,306,629)
8	July	52,675,109	35,610,555	26,564,068	9,046,487	(46,669,617)	0.00042	(21,501)	387,973	(46,281,644)
9	August	43,695,285	40,705,045	26,223,452	14,481,593	(32,188,023)	0.00042	(16,560)	371,413	(31,816,610)
10	September	33,305,935	33,305,469	26,492,354	6,813,115	(25,374,908)	0.00042	(12,088)	359,325	(25,015,584)
11	October	27,033,188	27,032,810	23,089,174	3,943,636	(21,431,272)	0.00042	(9,829)	349,495	(21,081,777)
12	November	22,963,361	22,963,040	19,160,302	3,802,738	(17,628,534)	0.00042	(8,203)	341,293	(17,287,241)
13	December	41,704,300	41,703,716	21,895,249	19,808,466	2,179,932	0.00042	(3,244)	338,049	2,517,981
14	**Total (Over)/**									
15	**Under Recovery for 2013**	**388,969,516**	**322,978,478**	**295,483,513**	**27,494,966**			**(159,848)**		

Notes:

(1) Reference WP-5
(2) Where EAF = 0.99999 Reference WP-9
((EC x EAF) – Incremental fuel and purchased energy expense resulting from the ANO incident per EAI Exhibit KWC-1 from APSC Docket No. 13-028-U)
(3) Reference WP-23
(4) Over/Under Recovery before Carrying Charges.
(5) The Cumulative Over/Under Recovery before Carrying Charges
(6) The Carrying Charge Rate for the Over/Under Recovery Period uses the Commission approved rate of interest on Customer Deposits in accordance with Order No. 10 in Docket No. 06-101-U.
The interest rate on Customer Deposits for 2013 was 0.5% as set in Order No. 3 Docket No. 12-084-U
(7) Monthly Carrying Charges on Average Cumulative Over/Under Recovery for the month
(8) Cumulative Carrying Charges on Average Cumulative Over/Under Recovery for the month
(9) True-Up Adjustment for the energy cost period including carrying charges
(10) Reference WP-24

Entergy Arkansas, Inc.
Energy Costs for the True-Up Adjustment
January 2013 - December 2013
($)

Line No.	Month	(1) FE Fuel Expense	(2) PE Net Purchased Energy Expense	(3) RSC Grand Gulf Retained Share Charge	(4) SO2 Sale of SO2 & NOX Emissions Allowances	(5) EC Total Energy Cost
1	January	11,529,982	15,791,870	0	576	27,321,277
2	February	8,915,717	12,337,422	0	802	21,252,337
3	March	12,107,479	14,855,327	0	451	26,962,355
4	April	24,676,297	19,973,736	0	158	44,649,875
5	May	18,668,501	19,034,870	0	695	37,702,676
6	June	(14,621,220)	24,325,775	0	737	9,703,819
7	July	31,460,224	21,215,388	0	502	52,675,109
8	August	24,153,292	19,546,569	0	4,577	43,695,285
9	September	16,972,632	16,341,462	0	8,158	33,305,935
10	October	14,219,882	12,813,259	0	(47)	27,033,188
11	November	13,939,940	9,023,592	(0)	170	22,963,361
12	December	23,127,859	18,576,473	0	33	41,704,300
13	Total	185,150,585	203,835,741	(0)	16,810	388,969,516

Notes:

1) Reference WP - 11. Includes ANO DOE recovery amount of $33.4M in June.
2) Reference WP - 12
3) Reference WP - 13
4) Reference WP - 14
5) FE + PE + RSC - SO2

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ENTERGY ARKANSAS, INC.
AVOIDED CAPACITY AND ENERGY COSTS
APPLICABLE TO RIDER SCR
- ARKANSAS -

AVOIDED CAPACITY COSTS:

Capacity - $0.0 per kW of capacity under a long-term contract subject to approval of the Arkansas Public Service Commission.

AVOIDED ENERGY COSTS:

Voltage Level of Purchase		Summer Period Energy Deliveries On-Peak	Summer Period Energy Deliveries Off-Peak	Other Period Energy Deliveries On-Peak	Other Period Energy Deliveries Off-Peak	Annual Average
Generation -	¢/kWh	3.813	2.892	3.662	3.011	3.400
Transmission ≥230kV -	¢/kWh	3.867	2.918	3.669	3.002	3.417
Transmission <230kV -	¢/kWh	3.946	2.978	3.745	3.064	3.488
Primary -	¢/kWh	4.118	3.107	3.907	3.197	3.639
Secondary -	¢/kWh	4.222	3.186	4.006	3.278	3.731

SEASON/TIME PERIOD DEFINITION:

Summer Period:	April 1st – September 30th
On-Peak Hours:	7:00 a.m. - 11:00 p.m., Monday – Saturday
Off-Peak Hours	All hours not designated as on-peak hours

Other Period:	October 1st – March 31st
On-Peak Hours:	7:00 a.m. - 11:00 p.m., Monday - Saturday
Off-Peak Hours	All hours not designated as on-peak hours

NOTES:

(1) The avoided energy costs in this Bulletin were developed to be applicable to total energy of 100 MW per hour.

(2) The avoided energy costs in this Bulletin are adjusted to reflect the various losses appropriate to the voltage level at which purchases are made.

(3) This Bulletin is applicable in the EAI load control area only.

(4) Average annual numbers are shown for informational purposes and may be used for purchases from small qualified facilities if time of use metering is not economical.

Avoided Costs Bulletin No. 67
Effective January 1, 2014
ESI Rate Administration
Little Rock, Arkansas

Entergy Arkansas, Inc.
Nuclear Refueling Hours

Actual During Energy Cost Period January, 2013 through December, 2013

ANO-1	960	**(1)**
ANO-2	0	
Grand Gulf	0	

Projected Refueling Hours for 2014

ANO-1	0
ANO-2	720
Grand Gulf	600

(1) ANO 1 refueling hours reflect 40 days which do not include additional days associated with the ANO incident. Incremental fuel and purchased energy expense resulting from the ANO incident is being removed. Therefore, refueling hours do not include additional hours associated with the incident.

Entergy Arkansas, Inc.
Retail / Wholesale Split for PPA Units

December 2013 [December 19-31]
Winter 2013 Ratings

Line	Unit	Total MW	EAI MW	ENO %	ENO PPA MW	ELL %	ELL PPA MW	EMI %	EMI PPA MW	EAI Retail %	EAI Retail MW	3rd Party - Unidentified %	3rd Party - Unidentified MW	Retail MW	Total Non-Retail	Total WBL
		a	b	c	d	e	f	g	h	i	j	k	l	m	n	o
		(1)		(4)		(4)		(4)		(4)		(4)				
1	ANO 1	833,200	833,200	2.72%	22,663	2.72%	22,663	0.00%	0	8.43%	70,239			787,874	45,326	833,200
2	ANO 2	986,000	986,000	2.71%	26,721	2.71%	26,721	0.00%	0	8.45%	83,317			932,558	53,442	986,000
3	WB 1	815,000	464,550	2.60%	12,078	2.82%	13,100	0.00%	0			8.45%	39,254	400,117	64,433	464,550
4	WB 2	820,600	467,742	2.82%	13,190	2.60%	12,161	0.00%	0			8.45%	39,524	402,866	64,876	467,742
5	ISES 1	836,000	263,340	2.72%	7,163	2.72%	7,163	0.00%	0			8.43%	22,200	226,815	36,525	263,340
6	ISES 2		0	0.00%	0	0.00%	0	0.00%	0					0	0	0
7	GG 1 non-RS (3)	1,413,400	357,194	2.78%	9,930	2.78%	9,930	8.31%	29,683					307,651	49,543	357,194
8	GG1 RS (2) (3)	1,413,400	100,746	20.88%	21,036	20.88%	21,036	58.24%	58,674					0	100,746	100,746
			3,472,772		112,781		112,774		88,357		153,556		100,978	3,057,881	414,891	3,472,772

Notes:

(1) Column "a" could change due to a re-rating of the unit
(2) Retained share of GG not sold as part of PPA is either 100% wholesale if sold to a 3rd party, or 100% retail if not sold to 3rd party
(3) Total MW for GG 1 represents the total plant capability, includes SMEPA 10% ownership
(4) % expressed as percentage of EAI MW -- Col b

Entergy Arkansas Inc.
Summary of Pro Formed Allocation Factors
For the Twelve Months Ended December, 2013

Line No.	Rate Class	MWH Sales	Rate Class Energy Allocator Factor
(a)	(b)	(c)	(d)
1	Residential	8,605,224	0.378285
2	Small General Service	4,919,045	0.216241
3	Large General Service	8,933,816	0.392731
4	Lighting	289,566	0.012729
5	Total Retail	22,747,651	0.999986
6	Wholesale for Resale	318	0.000014
7	Total Company	22,747,969	1.000000

NOTE: Please refer to Rate Case Docket No. 13-028-U, Order No. 21 which supports the Energy Allocation Factor methodology.

Entergy Arkansas, Inc.
Forecasted MWH Sales for ECR - April 2014-March 2015

April	1,508,367
May	1,487,008
June	1,736,614
July	2,054,967
August	2,124,582
September	2,034,867
October	1,712,452
November	1,532,580
December	1,613,677
January	1,796,557
February	1,747,619
March	1,650,145
12 month Total	20,999,435

Entergy Arkansas, Inc.
Fuel Costs Accounts 501, 502, 518, 547, 509, and Substitute & Replacement Fuel Energy
January 2013 - December 2013
($)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Month	A/C 501	A/C 502	A/C 518	A/C 547	A/C 509	Substitute & Replacement Generation Energy	Fuel Recovery Revenue	TOTAL FE
1	January	25,514,083	0	11,451,511	41,120	346	(901,690)	(24,575,388)	11,529,982
2	February	21,093,928	0	10,091,319	13,040	261	(983,971)	(21,298,858)	8,915,717
3	March	26,092,814	0	9,620,469	6,520	588	(1,775,704)	(21,837,208)	12,107,479
4	April	31,219,184	0	1,002,347	43,597	465	(369,744)	(7,219,551)	24,676,297
5	May	22,582,591	0	7,319,207	28,586	8,470	(465,498)	(10,804,855)	18,668,501
6	June	28,286,516	0	(26,249,957)	51,211	6,943	(753,752)	(15,962,180)	(14,621,220)
7	July	32,624,747	0	7,470,737	43,648	24,911	(546,361)	(8,157,459)	31,460,224
8	August	33,654,249	0	10,608,375	43,648	25,715	(713,449)	(19,465,246)	24,153,292
9	September	29,321,699	0	12,316,701	43,648	26,347	(1,257,296)	(23,478,468)	16,972,632
10	October	21,456,682	0	12,487,195	43,648	(4,781)	(1,782,774)	(17,980,089)	14,219,882
11	November	19,992,199	0	12,207,388	43,648	205	(3,040,028)	(15,263,474)	13,939,940
12	December	29,228,452	0	7,431,986	43,648	677	(1,605,876)	(11,971,028)	23,127,859
13	Total Fuel for ECR	321,067,144	0	75,757,279	445,963	90,147	(14,196,143)	(198,013,805)	185,150,585

Notes:

(1) Reference WP - 16
(2) Reference WP - 17
(3) Reference WP - 19. Includes ANO DOE recovery amount of $33.4M in June.
(4) Reference WP - 20
(5) Reference WP - 18
(6) Reference WP - 22, Column 1
(7) Reference WP - 15
(8) Sum of A/C 501, A/C 502, A/C 518, A/C 547, A/C 509, Substitute & Replacement Generation Energy and Fuel Recovery Revenue

Entergy Arkansas, Inc.
Purchased Energy Expense
January 2013 - December 2013
($)

		(1)	(2)	(3)	(4)	(5)	(6)
		Net Purchase Energy Expense			Grand Gulf Retained Share Fuel Charges		
Line No.	Month	Purchased Power Expense	Substitute & Replacement Purch Energy	Net Purchase Energy Expense	Grand Gulf Costs	Retained Share	TOTAL PE
1	January	16,336,398	(300,117)	16,036,282	1,110,962	244,412	15,791,870
2	February	13,499,624	(468,821)	13,030,802	3,151,730	693,381	12,337,422
3	March	16,645,817	(1,024,155)	15,621,662	3,483,343	766,335	14,855,327
4	April	23,431,168	(2,715,163)	20,716,005	3,373,953	742,270	19,973,736
5	May	22,072,602	(2,273,476)	19,799,126	3,473,891	764,256	19,034,870
6	June	26,846,524	(1,763,218)	25,083,306	3,443,321	757,531	24,325,775
7	July	25,134,482	(3,204,409)	21,930,073	3,248,569	714,685	21,215,388
8	August	20,816,103	(588,364)	20,227,739	3,096,228	681,170	19,546,569
9	September	17,946,512	(864,585)	17,081,927	3,365,752	740,465	16,341,462
10	October	14,369,586	(978,228)	13,391,358	2,627,720	578,098	12,813,259
11	November	11,749,472	(2,058,632)	9,690,841	3,032,949	667,249	9,023,592
12	December	20,791,251	(1,378,664)	19,412,587	3,800,520	836,114	18,576,473
13	Total	229,639,539	(17,617,832)	212,021,707	37,208,937	8,185,966	203,835,741

Notes:
(1) Reference WP-21
(2) Reference WP-22, Column 2
(3) Purchased Power Expense less Substitute and Replacement Purchased Energy
(4) Reference WP-21 (Account 555200, resource code 181)
(5) 22% of Grand Gulf Energy costs ($)
(6) Col 3 - Col 5

Entergy Arkansas, Inc.
Grand Gulf Retained Share Energy Charge
January 2013 - December 2013

		(1)	(2)	(3)	(4)	(5)	(6)
		Grand Gulf Retained Share Calculation (kWh)					RSC
Line No.	Month	Total Grand Gulf kWh	22% Retained Share	Less: 3rd Party Sales	Less: Sales to Opcos	Net Retained Share	Grand Gulf Retained Share Charge ($)
1	January	103,430,520	22,754,714	0	22,754,714	0	0
2	February	309,200,040	68,024,009	0	68,024,009	0	0
3	March	346,605,120	76,253,126	0	76,253,126	0	0
4	April	333,704,520	73,414,994	0	73,414,994	0	0
5	May	345,626,280	76,037,782	0	76,037,782	0	0
6	June	318,562,920	70,083,842	0	70,083,842	0	0
7	July	317,431,080	69,834,838	0	69,834,838	0	0
8	August	285,061,680	62,713,570	0	62,713,570	0	0
9	September	320,797,440	70,575,437	0	70,575,437	0	0
10	October	227,619,000	50,076,180	0	50,076,180	0	0
11	November	276,364,440	60,800,177	0	60,800,177	(0)	(0)
12	December	341,277,620	75,081,076	0	75,081,076	0	0
13	Total	3,525,680,660	775,649,745	0	775,649,745	(0)	(0)

Notes:

(1) Reference WP-21 (Account 555200, resource code 181)
(2) 22% of Grand Gulf Energy kWh
(3) Sales from the retained share of Grand Gulf Energy to Third Parties.
(4) Sales from the retained share of Grand Gulf Energy to Operating Companies.
(5) Grand Gulf Retained Share Less Third Party Sales and Sales to Operating Companies.
(6) Grand Gulf Retained Share Energy (Col 5) * (average annual avoided energy cost rate at generation level as set out in the most recently filed Avoided Cost Bulletin) Avoided Cost = $0.03400/kWh   Reference WP-6

Entergy Arkansas, Inc.
ɔm Disposition of Allowance Account 4118 and SO2 and NOX 447 Re
January 2013 - December 2013
($)

Line No.	Month	(1) A/C 4118	(2) NOX & SO2 A/C 447 Revenues	(3) TOTAL SO2
1	January	0	576	576
2	February	0	802	802
3	March	0	451	451
4	April	143	15	158
5	May	0	695	695
6	June	0	737	737
7	July	0	502	502
8	August	0	4,577	4,577
9	September	0	8,158	8,158
10	October	0	(47)	(47)
11	November	0	170	170
12	December	0	33	33
13	Total Fuel for ECR	143	16,668	16,810

Notes:

(1) Reference WP - 18
(2) Reference WP - 15
(3) Sum of A/C 4118 and A/C 447 SO2 and NOX Revenues.

Entergy Arkansas, Inc.
Energy Cost Recovery Rider ECR
Twelve Months Ended December 31, 2013
($)

Account 447001 Description	January	February	March	April	May	June	July	August	September	October	November	December	Total
ASSOC ENERGY	(20,246,659.93)	(18,008,297.37)	(18,163,682.59)	(4,252,157.59)	(9,789,678.97)	(9,485,835.57)	(4,425,927.18)	(14,985,621.34)	(19,264,456.55)	(16,791,744.67)	(11,535,662.42)	(3,715,845.80)	(150,665,569.98)
ASSOC ENERGY ADDER	(635,560.01)	(727,482.86)	(589,170.00)	(23,961.89)	(92,974.03)	(122,552.78)	(50,536.83)	(330,105.87)	(585,836.18)	(443,109.49)	(326,881.84)	(64,623.09)	(3,992,794.87)
ASSOC ENERGY NOX ADDER	4.49	(62.59)	(89.99)	(23.60)	(662.87)	(712.00)	(506.87)	(4,328.25)	(7,820.32)	321.97	(7.24)	(13.32)	(13,900.59)
ASSOC ENERGY SO2 ADDER	(580.17)	(739.65)	(360.54)	8.41	(32.48)	(24.51)	4.58	(248.37)	(337.25)	(275.13)	(159.95)	(20.34)	(2,765.40)
RESERVE EQUAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(334,762.64)	(578,234.93)	(475,369.97)	(282,353.55)	(1,670,721.09)
Total Account 447001	(20,882,795.62)	(18,736,582.47)	(18,753,303.12)	(4,276,134.67)	(9,883,348.35)	(9,609,124.86)	(4,476,966.30)	(15,320,303.83)	(20,193,212.94)	(17,813,042.25)	(12,338,081.42)	(4,062,856.10)	(156,345,751.93)
Account 447002 Description													
NET BALANCE-DEMAND	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GIS CAP CHARGE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NET BALANCE-ENERGY	19,836.90	57,166.15	93,783.95	43,000.25	163,084.02	76,816.13	36,599.60	35,065.46	(1,759.72)	93,817.11	181,876.97	97,847.39	897,134.21
CALL OPTIONS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal Net Balance	19,836.90	57,166.15	93,783.95	43,000.25	163,084.02	76,816.13	36,599.60	35,065.46	(1,759.72)	93,817.11	181,876.97	97,847.39	897,134.21
GIS ENERGY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LOAD IMBALANCE ENERGY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GRAND GULF SALES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NON-ASSOC ENERGY	(63,912.32)	(91,875.72)	(89,365.71)	(126,500.27)	(147,002.00)	(135,134.38)	(83,517.23)	(64,462.91)	(133,745.77)	(49,085.22)	(133,937.48)	(103,884.47)	(1,222,423.48)
NON-ASSOC ENERGY ADDER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(2,789.80)	887.45	(1,902.35)
NON-ASSOC ENERGY SO2 ADDER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(2.77)	0.86	(1.91)
MISO ENERGY SALES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(5,579,152.66)	(5,579,152.66)
Subtotal	(63,912.32)	(91,875.72)	(89,365.71)	(126,500.27)	(147,002.00)	(135,134.38)	(83,517.23)	(64,462.91)	(133,745.77)	(49,085.22)	(136,730.05)	(5,682,148.82)	(6,803,480.40)
Total Account 447002	(44,075.42)	(34,709.57)	4,418.24	(83,500.02)	16,082.02	(58,318.25)	(46,917.63)	(29,397.45)	(135,505.49)	44,731.89	45,146.92	(5,584,301.43)	(5,906,346.19)
Account 447005 Description													
Imputed Rev - Sch 1	(64.76)	(348.94)	(359.82)	(149.81)	(522.22)	(228.37)	(89.01)	(99.12)	(47.77)	(376.66)	(672.23)	(345.49)	(3,304.20)
Imputed Rev - Sch 10	(61.52)	(331.50)	(341.83)	(142.32)	(496.11)	(213.75)	(83.32)	(92.77)	(44.72)	(352.55)	(629.21)	(323.38)	(3,112.98)
Imputed Rev - Non Firm	(2,939.12)	(16,245.40)	(13,013.92)	(5,719.13)	(17,214.12)	(7,278.00)	(2,392.10)	(2,871.37)	(3,090.06)	(9,632.88)	(23,381.20)	(10,047.41)	(113,824.71)
Total Account 447005	(3,065.40)	(16,925.84)	(13,715.57)	(6,011.26)	(18,232.45)	(7,720.12)	(2,564.43)	(3,063.26)	(3,182.55)	(10,362.09)	(24,682.64)	(10,716.28)	(120,241.89)
Account 447115 Description													
MSS-4 Energy	(4,153,030.05)	(2,815,748.30)	(3,230,343.46)	(2,483,388.95)	(487,876.55)	(5,997,000.52)	(3,250,650.66)	(4,118,546.84)	(3,696,298.23)	(880,872.16)	(3,236,257.45)	(2,165,697.22)	(36,515,710.39)
MSS-4 GG EAI Portion	(111,786.13)	(382,937.08)	(353,815.75)	(357,504.22)	(380,297.41)	(344,209.99)	(397,364.22)	(296,614.80)	(383,967.71)	(258,386.64)	(357,616.64)	(406,447.74)	(4,030,948.33)
Subtotal ENERGY 447115	(4,264,816.18)	(3,198,685.38)	(3,584,159.21)	(2,840,893.17)	(868,173.96)	(6,341,210.51)	(3,648,014.88)	(4,415,161.64)	(4,080,265.94)	(1,139,258.80)	(3,593,874.09)	(2,572,144.96)	(40,546,658.72)
MSS-4 Capacity	(4,275,618.96)	(4,855,865.30)	(5,349,460.71)	(7,464,099.18)	(5,081,821.05)	(3,737,242.49)	(3,529,257.05)	(5,076,349.85)	(4,647,550.66)	(3,567,891.81)	(4,754,840.90)	(5,084,991.73)	(57,424,989.69)
MSS-4 Cap EAI	(2,585,807.17)	(1,662,297.30)	(1,947,652.17)	(1,946,135.22)	(1,958,820.54)	(1,892,893.86)	(2,148,243.47)	(2,378,315.97)	(2,180,126.70)	(2,353,452.68)	(2,169,130.91)	(2,559,518.79)	(25,782,394.78)
Subtotal CAPACITY 447115	(6,861,426.13)	(6,518,162.60)	(7,297,112.88)	(9,410,234.40)	(7,040,641.59)	(5,630,136.35)	(5,677,500.52)	(7,454,665.82)	(6,827,677.36)	(5,921,344.49)	(6,923,971.81)	(7,644,510.52)	(83,207,384.47)
Total Account 447115	(11,126,242.31)	(9,716,847.98)	(10,881,272.09)	(12,251,127.57)	(7,908,815.55)	(11,971,346.86)	(9,325,515.40)	(11,869,827.46)	(10,907,943.30)	(7,060,603.29)	(10,517,845.90)	(10,216,655.48)	(123,754,043.19)
Account 447515 Description													
Grand Gulf Retained Shares RP	(5,485,994.84)	(4,159,130.18)	(4,680,163.67)	(4,684,573.55)	(4,756,722.46)	(4,549,265.22)	(5,176,630.98)	(5,439,613.06)	(5,214,219.62)	(5,311,310.23)	(5,138,276.69)	(6,031,444.29)	(60,627,344.79)
Total Account 447115	(5,485,994.84)	(4,159,130.18)	(4,680,163.67)	(4,684,573.55)	(4,756,722.46)	(4,549,265.22)	(5,176,630.98)	(5,439,613.06)	(5,214,219.62)	(5,311,310.23)	(5,138,276.69)	(6,031,444.29)	(60,627,344.79)
Grand Total	(37,542,173.59)	(32,664,196.04)	(34,324,036.21)	(21,301,347.07)	(22,551,036.79)	(26,195,775.31)	(19,028,594.74)	(32,662,205.06)	(36,454,063.90)	(30,150,585.97)	(27,973,739.73)	(25,905,973.58)	(346,753,727.99)
TOTAL SO2 & NOX REVENUES	(575.68)	(802.24)	(450.53)	(15.19)	(695.35)	(736.51)	(502.29)	(4,576.62)	(8,157.57)	46.84	(169.96)	(32.80)	(16,667.90)
SALES FOR RESALE/RESOURCE PLAN	(24,575,388.43)	(21,298,858.47)	(21,837,207.51)	(7,219,551.03)	(10,804,854.93)	(15,962,180.46)	(8,157,459.29)	(19,465,245.89)	(23,478,468.26)	(17,980,088.69)	(15,263,473.99)	(11,971,027.89)	(198,013,804.84)
TOTAL ENERGY FOR ECR	(24,575,964.11)	(21,299,660.71)	(21,837,658.04)	(7,219,566.22)	(10,805,550.28)	(15,962,916.97)	(8,157,961.58)	(19,469,822.51)	(23,486,625.83)	(17,980,041.85)	(15,263,643.95)	(11,971,060.69)	(198,030,472.74)

Entergy Arkansas, Inc.
Energy Cost Recovery Rider ECR
Twelve Months Ended December 31, 2013
($)

Account Number	January	February	March	April	May	June	July	August	September	October	November	December	Total
501000	(23,774.32)	336,231.55	173,424.32	943,831.93	28,234.78	24,704.08	(52,248.60)	(12,186.75)	(52,856.38)	321,591.12	36,164.65	38,799.73	1,761,916.11
501100	56,484.62	36,750.19	158,361.84	5,133.83	114,908.65	29,491.66	195,280.69	101,017.13	186,413.50	151,613.18	85,763.21	409,165.51	1,530,384.01
501203	5,534,371.86	7,879,178.37	11,734,428.81	14,749,259.65	7,241,157.71	10,328,791.83	13,966,414.73	13,566,354.93	11,622,284.78	6,848,217.77	6,985,456.14	11,418,472.71	121,874,389.29
501301	19,947,000.98	12,841,767.43	14,026,598.78	15,520,958.32	15,198,290.27	17,903,528.44	18,515,300.01	19,999,063.65	17,565,857.45	14,135,260.13	12,884,815.48	17,362,013.63	195,900,454.57
Grand Total	25,514,083.14	21,093,927.54	26,092,813.75	31,219,183.73	22,582,591.41	28,286,516.01	32,624,746.83	33,654,248.96	29,321,699.35	21,456,682.20	19,992,199.48	29,228,451.58	321,067,143.98

Entergy Arkansas, Inc.
Energy Cost Recovery Rider ECR
Twelve Months Ended December 31, 2013
($)

Account Number	January	February	March	April	May	June	July	August	September	October	November	December	Total
502000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grand Total	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Entergy Arkansas, Inc.
Energy Cost Recovery Rider ECR
Twelve Months Ended December 31, 2013
($)

Account Number	Resource Code	January	February	March	April	May	June	July	August	September	October	November	December	Total
509100	901	346.29	260.55	587.98	464.92	225.62	362.36	519.61	458.08	218.78	123.07	205.12	676.86	4,449.24
509101	901	0.00	0.00	0.00	0.00	8,244.03	6,580.97	24,391.56	25,256.94	26,128.46	(4,903.72)	0.00	0.00	85,698.24
Grand Total		346.29	260.55	587.98	464.92	8,469.65	6,943.33	24,911.17	25,715.02	26,347.24	(4,780.65)	205.12	676.86	90,147.48

Account Number	Resource Code	January	February	March	April	May	June	July	August	September	October	November	December	Total
411800	178	0.00	0.00	0.00	(142.57)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(142.57)

Entergy Arkansas, Inc.
Energy Cost Recovery Rider ECR
Twelve Months Ended December 31, 2013
($)

Account Number	January	February	March	April	May	June (1)	July	August	September	October	November	December	Total
518100	8,358,865.12	7,478,898.60	7,353,820.19	248,590.32	5,509,132.48	5,331,853.06	5,760,752.34	8,169,418.00	9,227,153.08	9,508,615.32	9,343,096.12	5,432,917.16	81,723,111.79
518200	1,290,780.97	1,166,589.32	1,068,255.44	30,597.71	692,940.19	666,245.97	686,397.22	1,036,673.21	1,204,244.96	1,255,909.37	1,247,414.65	779,967.36	11,126,016.37
518300	957,558.86	666,528.77	434,289.80	25,008.00	436,854.78	562,312.20	358,243.77	367,318.28	882,475.44	797,855.36	719,197.47	514,126.50	6,721,769.23
518400	618,686.26	553,682.26	538,483.04	472,530.28	454,659.57	411,319.02	479,456.80	849,077.96	816,940.52	738,927.54	711,792.99	519,088.13	7,164,644.37
518500	225,620.27	225,620.27	225,620.27	225,620.27	225,620.27	(33,221,687.74)	185,887.26	185,887.26	185,887.26	185,887.26	185,887.26	185,887.26	(30,978,262.83)
518600	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grand Total	11,451,511.48	10,091,319.22	9,620,468.74	1,002,346.58	7,319,207.29	(26,249,957.49)	7,470,737.39	10,608,374.71	12,316,701.26	12,487,194.85	12,207,388.49	7,431,986.41	75,757,278.93

(1) ANO DOE recovery amount of $33,407,575 included in Account 518500.

Entergy Arkansas, Inc.
Energy Cost Recovery Rider ECR
Twelve Months Ended December 31, 2013
($)

Account Number	Resource Code	January	February	March	April	May	June	July	August	September	October	November	December	Total
547200	172	41,119.56	13,039.76	6,519.88	43,596.89	28,585.65	51,210.88	43,648.38	43,648.38	43,648.38	43,648.38	43,648.38	43,648.38	445,962.90
	175	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	177	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grand Total		41,119.56	13,039.76	6,519.88	43,596.89	28,585.65	51,210.88	43,648.38	43,648.38	43,648.38	43,648.38	43,648.38	43,648.38	445,962.90

Entergy Arkansas, Inc.
Energy Cost Recovery Rider ECR
Twelve Months Ended December 31, 2013
($)

Account Number	Resource Code	January	February	March	April	May	June	July	August	September	October	November	December	Total
555001	210	8,228.33	34,033.93	459,320.83	6,170,701.44	1,267,994.27	3,969,982.31	7,743,824.32	595,928.24	514,120.10	264,392.49	352,695.41	3,773,268.86	25,154,490.53
	215	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	229	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
555001 Total		8,228.33	34,033.93	459,320.83	6,170,701.44	1,267,994.27	3,969,982.31	7,743,824.32	595,928.24	514,120.10	264,392.49	352,695.41	3,773,268.86	25,154,490.53
555002	179	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	205	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	215	4,795,540.72	3,635,119.24	8,042,506.49	10,240,332.46	10,317,338.41	11,489,723.62	6,834,735.08	7,397,545.26	5,836,822.15	4,336,913.34	2,466,980.90	8,801,378.78	84,194,936.45
	229	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
555002 Total		4,795,540.72	3,635,119.24	8,042,506.49	10,240,332.46	10,317,338.41	11,489,723.62	6,834,735.08	7,397,545.26	5,836,822.15	4,336,913.34	2,466,980.90	8,801,378.78	84,194,936.45
555003	221	19,838.89	21,929.62	17,227.69	16,876.57	17,040.30	11,224.58	19,124.99	20,085.43	14,809.67	19,428.77	5,405.53	25,341.64	208,333.68
	959	1,377.54	165.21	298.25	1,168.68	764.02	1,774.12	1,851.82	473.97	180.74	653.22	463.18	95.05	9,265.80
	983	4,171,513.10	2,055,819.75	641,094.52	939,641.29	1,098,653.78	1,573,994.14	1,316,662.74	2,240,371.76	2,112,119.72	1,552,951.71	475,329.19	604,224.00	18,782,375.70
	985	16,248.67	12,193.29	54,429.49	38,245.56	44,646.37	60,172.20	27,379.38	172,159.65	307,237.69	242,295.60	103,782.75	13,151.02	1,091,941.67
	986	0.00	0.00	0.00	0.00	0.00	805,890.62	960,073.17	1,297,378.85	805,279.56	841,553.47	813,443.68	629,753.41	6,153,372.76
	987	1,027,094.44	581,832.89	721,542.78	1,217,337.82	1,208,587.96	1,577,339.99	928,571.58	1,242,859.80	857,098.00	496,931.84	694,800.30	483,581.87	11,037,579.27
	992	19,241.91	14,544.44	17,278.43	12.86	2,901.43	31,036.74	28,833.12	31,513.89	24,042.70	9,810.27	15,296.09	14,842.82	209,354.70
	995	7,873.44	5,671.05	26,802.50	19,700.42	21,547.27	29,280.16	13,006.76	86,640.30	155,144.72	119,153.45	56,666.46	6,796.22	548,282.75
555003 Total		5,263,187.99	2,692,156.25	1,478,673.66	2,232,983.20	2,394,141.13	4,090,712.55	3,295,503.56	5,091,483.65	4,275,912.80	3,282,778.33	2,165,187.18	1,777,786.03	38,040,506.33
555005	221	4,307,661.59	3,563,277.57	2,906,780.51	1,381,091.48	4,316,185.61	3,652,036.17	3,849,259.69	4,129,527.43	3,673,838.74	3,570,512.88	3,785,653.94	2,598,200.21	41,734,025.82
555116	212	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	222	850,817.38	423,307.12	275,192.69	32,106.84	303,051.60	200,747.58	162,590.14	505,390.85	280,066.91	287,268.98	(53,994.48)	40,097.70	3,306,643.31
555116 Total		850,817.38	423,307.12	275,192.69	32,106.84	303,051.60	200,747.58	162,590.14	505,390.85	280,066.91	287,268.98	(53,994.48)	40,097.70	3,306,643.31
555200	181	1,110,962.30	3,151,729.67	3,483,343.12	3,373,952.67	3,473,891.17	3,443,321.46	3,248,568.78	3,096,227.56	3,365,751.55	2,627,719.86	3,032,949.38	3,800,519.51	37,208,937.03
	210	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
555200 Total		1,110,962.30	3,151,729.67	3,483,343.12	3,373,952.67	3,473,891.17	3,443,321.46	3,248,568.78	3,096,227.56	3,365,751.55	2,627,719.86	3,032,949.38	3,800,519.51	37,208,937.03
555390	179	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	215	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
555390 Total		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Energy Purchases		**16,336,398.31**	**13,499,623.78**	**16,645,817.30**	**23,431,168.09**	**22,072,602.19**	**26,846,523.69**	**25,134,481.57**	**20,816,102.99**	**17,946,512.25**	**14,369,585.88**	**11,749,472.33**	**20,791,251.09**	**229,639,539.47**
555	180	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
555	182	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
555	204	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
555015	219	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	24,526.22	24,526.22
555002	219	639.30	638.40	638.40	637.20	638.70	639.30	631.20	625.80	623.70	615.30	609.90	610,904.80	617,842.00
555003	219/220	13,019.65	12,394.90	11,836.30	15,143.80	13,725.25	14,333.20	14,095.76	14,514.64	14,640.71	22,619.59	34,215.09	12,579.28	193,118.17
555200	180	18,887,572.04	18,445,264.22	17,992,520.32	18,441,678.53	18,106,190.22	17,496,802.43	19,857,104.89	21,983,760.28	20,151,814.76	21,753,938.54	20,050,176.05	23,658,693.13	236,825,515.41
555200	182	(492,774.26)	(494,202.47)	(495,260.52)	(490,288.00)	(491,716.21)	(492,174.80)	(493,603.01)	(495,489.81)	(496,918.03)	(497,376.61)	(498,804.83)	(499,633.58)	(5,938,242.13)
555200	204	1,646,871.47	1,655,530.86	1,629,310.84	1,664,379.10	3,793,552.10	3,818,276.15	1,978,822.35	1,968,254.73	9,313.74	0.00	0.00	33,197.74	18,197,509.08
Total Demand Purchases		**20,055,328.20**	**19,619,625.91**	**19,139,045.34**	**19,631,550.63**	**21,422,390.06**	**20,837,876.28**	**21,357,051.19**	**23,471,665.64**	**19,679,474.88**	**21,279,796.82**	**19,586,196.21**	**23,840,267.59**	**249,920,268.75**
Total Purchased Power $		**36,391,726.51**	**33,119,249.69**	**35,784,862.64**	**43,062,718.72**	**43,494,992.25**	**47,684,399.97**	**46,491,532.76**	**44,287,768.63**	**37,625,987.13**	**35,649,382.70**	**31,335,668.54**	**44,631,518.68**	**479,559,808.22**
Grand Gulf kwh		**103,430,520**	**309,200,040**	**346,605,120**	**333,704,520**	**345,626,280**	**318,562,920**	**317,431,080**	**285,061,680**	**320,797,440**	**227,619,000**	**276,364,440**	**341,277,620**	**3,525,680,660**

Resource Code Descriptions

180 PURCHASED PWR FRM GGNS(DEMAND)
181 PURCHASED PWR FRM GGNS(ENERGY)
182 PURCH PWR-ACCELERATED AMORT GG
210 PURCH PWR FR ASSC CO(EXCHNG ENG)
212 PUR PWR FR ASSC CO(ALL OTH CRG)
215 PUR PWR FR NONASS CO(ECON EN)
219 PUR PWR FR NONASS CO(NON-ENERG)
221 PUR PWR FR NONASS CO(COGEN)
222 PUR PWR FR NONASS CO(ALL OTH C)
223 PUR PWR PUT/CALL OPTIONS
229 PUR PWR IMPUTED CAPACITY CHRGS
959 CO OWNER - ETEC
983 CO OWNER - AECC
986 CO OWNER - EPI
987 CO OWNER - JONESBORO

Entergy Arkansas, Inc.
Substitute & Replacement Energy Summary
January 2013 - December 2013
($)

Line No.	Month	Generation	Purchased Energy	Total Sources Supplying Co-Owners
1	January 2013	901,690	300,117	1,201,806
2	February 2013	983,971	468,821	1,452,793
3	March 2013	1,775,704	1,024,155	2,799,859
4	April 2013	369,744	2,715,163	3,084,907
5	May 2013	465,498	2,273,476	2,738,974
6	June 2013	753,752	1,763,218	2,516,970
7	July 2013	546,361	3,204,409	3,750,769
8	August 2013	713,449	588,364	1,301,813
9	September 2013	1,257,296	864,585	2,121,882
10	October 2013	1,782,774	978,228	2,761,002
11	November 2013	3,040,028	2,058,632	5,098,660
12	December 2013	1,605,876	1,378,664	2,984,540
13	Total	14,196,143	17,617,832	31,813,975

Entergy Arkansas, Inc.
ECR Revenue Summary
January 2013 - December 2013
($)

Line No.	Month	Total ECR Revenue
1	January 2013	$31,496,303.78
2	February 2013	$30,152,506.35
3	March 2013	$29,734,529.50
4	April 2013	$20,170,637.42
5	May 2013	$18,833,124.32
6	June 2013	$21,671,812.24
7	July 2013	$26,564,068.09
8	August 2013	$26,223,451.73
9	September 2013	$26,492,354.23
10	October 2013	$23,089,173.87
11	November 2013	$19,160,301.65
12	December 2013	$21,895,249.33
13	**Total**	**$295,483,512.51**

Entergy Arkansas, Inc.
True-up Adjustment as Filed in Prior Year ECR
Energy Cost Period January 2012 - December 2012

		(1)	(2)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	**Month**	**Energy Cost**	**Revenue Under Rider ECR**	**SUBTOTAL Col 1 - Col 2**	**CUMULATIVE OVER/UNDER RECOVERY**	**Monthly Carrying Charge Rate**	**MONTHLY INTEREST**	**CUMULATIVE INTEREST**	**CUMULATIVE TOTAL**
					18,786,405			**586,358**	
1	January 2012	22,199,289	34,248,539	(12,049,250)	6,737,155	0.00058	7,402	593,760	7,330,915
2	February 2012	20,195,441	32,308,274	(12,112,832)	(5,375,677)	0.00058	395	594,155	(4,781,522)
3	March 2012	18,404,003	30,315,400	(11,911,397)	(17,287,074)	0.00058	(6,572)	587,583	(16,699,492)
4	April 2012	18,903,517	25,656,404	(6,752,886)	(24,039,961)	0.00058	(11,985)	575,598	(23,464,363)
5	May 2012	29,808,183	27,102,381	2,705,802	(21,334,158)	0.00058	(13,158)	562,439	(20,771,719)
6	June 2012	35,978,423	33,710,866	2,267,557	(19,066,602)	0.00058	(11,716)	550,723	(18,515,879)
7	July 2012	48,826,729	38,775,891	10,050,838	(9,015,764)	0.00058	(8,144)	542,579	(8,473,185)
8	August 2012	41,135,404	41,070,885	64,519	(8,951,245)	0.00058	(5,210)	537,369	(8,413,876)
9	September 2012	34,989,702	36,482,561	(1,492,859)	(10,444,104)	0.00058	(5,625)	531,744	(9,912,359)
10	October 2012	23,820,133	29,880,515	(6,060,382)	(16,504,485)	0.00058	(7,815)	523,929	(15,980,556)
11	November 2012	18,856,304	26,324,916	(7,468,612)	(23,973,097)	0.00058	(11,738)	512,190	(23,460,907)
12	December 2012	25,739,700	27,081,636	(1,341,937)	(25,315,034)	0.00058	(14,294)	497,897	**(24,817,137)**
13									
14									
15	**Total (Over)/ Under Recovery for 2012**	**338,856,829**	**382,958,267**	**(44,101,439)**		**N/A**	**(88,461)**	**N/A**	

Note:
(1) Reference WP-5
(2) Reference WP-6
(3) Reference WP-8
(4) Net of the ECR Revenue and Prior Period True-up Adjustment.
(5) Over/Under Recovery before Carrying Charges.
(6) The Cumulative Over/Under Recovery before Carrying Charges
(7) The Carrying Charge Rate for the Over/Under Recovery Period uses the Commission
approved rate of interest on Customer Deposits in accordance with Order No. 10 in Docket No. 06-101-U.
The interest rate on Customer Deposits for 2011 was 1.2% as set in Order No. 3 Docket No. 10-082-U
(8) Monthly Carrying Charges on Average Cumulative Over/Under Recovery for the month.
approved rate of interest on Customer Deposits in accordance with Order No. 10 in Docket No. 06-101-U.
The interest rate on Customer Deposits for 2011 was 1.2% as set in Order No. 3 Docket No. 10-082-U
(8) Monthly Carrying Charges on Average Cumulative Over/Under Recovery for the month.

COPY OF PAGE 2 FROM APRIL 2013 ECR FILING INCLUDED FOR EASE OF REFERENCE
DEVELOPMENT OF ENERGY COST RATE

Line No	Term		Description			Amount	Workpaper Reference
1	PEC	=	PROJECTED ENERGY COST FOR THE PROJECTED ENERGY COST				
2			PERIOD (6)				
3	PEC	=	$\left[\sum_{J=1}^{12} EC_j + NRFA\right]$ (7)				
4	WHERE,						
5	Eχφ	=	ENERGY COST FOR MONTH j OF THE ENERGY COST PERIOD (1) (9)		=	326,356,829	WP -5
6	NRFA	=	NUCLEAR REFUELING OUTAGE ADJUSTMENT				
7	NRFA	=	GACR * (RHD1 * CAP1 + RHD2 * CAP2 + RHDGG * CAPGG)				
8	WHERE,						
9	GACR	=	ANNUAL AVERAGE AVOIDED ENERGY COST RATE ($/kWh) AT				
10			GENERATION LEVEL FOR THE ENERGY COST PERIOD AS SET OUT				
11			IN THE MOST RECENT FILING WITH THE COMMISSION PURSUANT				
12			TO SMALL COGENERATION SERVICE RIDER SCR OR ANY				
13			SUPERSEDING RATE SCHEDULE		=	0.03092	WP - 7
14	RHD1	=	INCREASE (+) OR DECREASE (-) IN REFUELING OUTAGE HOURS				
15			FOR ANO UNIT 1 BETWEEN THE ENERGY COST PERIOD				
16			AND THE PROJECTED ENERGY COST PERIOD		=	960.00	
17			ACTUAL REFUELING HOURS	0			WP - 9
18			PROJECTED REFUELING HOUR	960			WP - 9
19	CAP1	=	NET CAPABILITY (kW) OF ANO UNIT 1 AT THE END OF THE				
20			ENERGY COST PERIOD THAT IS AVAILABLE TO THE				
21			COMPANY'S RETAIL CUSTOMERS.		=	732,966	WP-10
22	RHD2	=	INCREASE (+) OR DECREASE (-) IN REFUELING OUTAGE				
23			HOURS FOR ANO UNIT 2 BETWEEN THE ENERGY COST PERIOD				
24			AND THE PROJECTED ENERGY COST PERIOD		=	(600.00)	
25			ACTUAL REFUELING HOURS	600			WP - 9
26			PROJECTED REFUELING HOUR	0			WP - 9
27	CAP2	=	NET CAPABILITY (kW) OF ANO UNIT 2 AT THE END OF THE				
28			ENERGY COST PERIOD THAT IS AVAILABLE TO THE				
29			COMPANY'S RETAIL CUSTOMERS.		=	865,607	WP-10
30	RHDG	=	INCREASE (+) OR DECREASE (-) IN REFUELING OUTAGE				
31			HOURS FOR GRAND GULF BETWEEN THE ENERGY COST PERIOD				
32			AND THE PROJECTED ENERGY COST PERIOD		=	(2,819.70)	
33			ACTUAL REFUELING HOURS	2820			WP - 9
34			PROJECTED REFUELING HOUR	0			WP - 9
35	CAPG(	=	NET CAPABILITY (kW) OF EAI'S ALLOCATED SHARE OF GRAND				
36			GULF AT THE END OF THE ENERGY COST PERIOD AS REDUCED				
37			BY THE RETAINED SHARE THAT IS AVAILABLE				
38			TO THE COMPANY'S RETAIL CUSTOMERS		=	318,448	WP-10
39	NRFA	=	NUCLEAR REFUELING OUTAGE ADJUSTMENT		=	(22,065,893)	
40	PEC	=	PROJECTED ENERGY COST FOR THE PROJECTED ENERGY				
41			COST PERIOD		=	304,290,936	
42	PES	=	RETAIL SALES (kWh) SUBJECT TO THIS RIDER ECR FOR THE				
43			PROJECTED ENERGY COST PERIOD (6)		=	21,467,436,570	WP - 11
44	ECR	=	ENERGY COST RATE ($/kWh)		=	0.01302	See Note

ENTERGY ARKANSAS, INC.
ENERGY COST RATE
PROJECTED ENERGY COST RATE FOR APRIL 2014 THROUGH MARCH 2015

		Estimated Energy Cost Rate			Prior Year	
LINE NO.		Amount ($)	Projected Sales (kWh)	Energy Cost Rate ($/kWh)	Energy Cost Rate ($/kWh)	Difference ($/kWh)
1	Projected Energy Cost Rate	392,352,916	20,999,435,000	0.01868	0.01417	0.00451
2	(Over)Under Recovery Balance including Carrying Charges	2,517,981	20,999,435,000	0.00012	(0.00116)	0.00128
3	Energy Cost Rate	394,870,897		0.01880	0.01302	0.00579
4	Less: Adjustment for ANO Incident	(65,985,592)	20,999,435,000	(0.00314)	0.00000	(0.00314)
5	Adjusted Energy Cost Rate	328,885,305		0.01566	0.01302	0.00264