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APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES AND RECONCILE FUEL COSTS	§ § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

DIRECT TESTIMONY AND EXHIBITS

OF

KARL J. NALEPA

ON BEHALF OF

CITIES SERVED BY ENTERGY TEXAS, INC.

JANUARY 10, 2014

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DIRECT TESTIMONY OF
KARL J. NALEPA

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DIRECT TESTIMONY OF
KARL J. NALEPA

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Karl J. Nalepa. I am the President of ReSolved Energy Consulting, LLC ("REC"). REC is an independent utility consulting company. My business address is 11044 Research Blvd., Suite D-230, Austin, Texas 78759.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am presenting testimony on behalf of Cities served by Entergy Texas, Inc. ("Cities").[1]

[1] Cities of Anahuac, Beaumont, Bridge City, Cleveland, Conroe, Dayton, Groves, Houston, Huntsville, Liberty, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Pinehurst, Port Arthur, Port Neches, Rose City, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, and West Orange.

Q. PLEASE OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a Bachelor of Science degree in Mineral Economics and a Master of Science degree in Petroleum Engineering, and am a certified mediator. My professional experience includes eight years in the reservoir engineering department of an exploration company affiliated with a major interstate pipeline company, then four years as a Fuels Analyst with the Texas Public Utility Commission ("PUC"). This was followed by five years with two different consulting firms providing expert advice regarding a broad range of electric and natural gas industry issues. Immediately prior to my current position, I served for more than five years as an Assistant Director with the Texas Railroad Commission ("RRC"). In that position, I was responsible for overseeing the economic regulation of natural gas utilities in Texas. I joined R.J. Covington Consulting, LLC in June of 2003. R.J. Covington Consulting became ReSolved Energy Consulting in August 2011. My Statement of Qualifications is attached as Appendix A.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I have testified a number of times before both the Texas PUC and the Texas RRC on a variety of regulatory issues. A summary of my previously filed testimony is provided as Attachment B. In addition, I supervised the staff case in proceedings before the RRC and served as a Technical Rate Examiner on behalf of the RRC. I have also provided analysis and recommendations in numerous city-level regulatory proceedings that resulted in agreements without written testimony.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE AND SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose and scope of my testimony is: First, to sponsor the cost of service model supporting the Cities' case. Second, to review Entergy Texas, Inc.'s ("ETI") proposed base rate and revenue Rider request and present Cities' recommendations regarding the Company's proposed cost of service, based on a test year ending March 31, 2013.[2] Third, to review fuel related issues and present Cities' recommendations regarding ETI's request to reconcile its fuel costs incurred during the period July 1, 2011 through March 31, 2013 (the "Reconciliation Period").[3] Within my testimony, references to "ETI" or the "Company" may be used interchangeably.

III. SUMMARY AND RECOMMENDATIONS

Q. WHAT IS ETI REQUESTING IN THIS PROCEEDING?

A. ETI is requesting an increase in rates of $53,133,797, which consists of a $38,602,873 base rate increase and $14,530,924 surcharge increase.[4]

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[2] Statement of Intent and Application for Authority to Change Rates and Reconcile Fuel Costs at 6.

[3] *Id.* at 1.

[4] Schedule Q-1.

Q. HOW DOES THIS COMPARE TO CITIES' RECOMMENDATION?

A. Cities recommend an overall increase in rates of $9,068,117, consisting of a $2,140,259 increase in base rates, and a $6,927,858 increase in surcharge revenue. A comparison of ETI's request and Cities' recommendation is shown in Table 1:

Table 1

	ETI Request	Cities' Recommendation	Difference
Base Rate Increase	$38,602,873	$2,140,259	($35,816,818)
Surcharge Increase	$14,530,924	$6,927,858	($7,602,862)
Total Increase	$53,133,797	$9,068,117	($43,419,680)

Q. HOW WAS THE CITIES'S RECOMMENDED REVENUE REQUIREMENT DETERMINED?

A. The Cities' revenue requirement was derived from a cost of service model modified by Cities.

Q. ARE YOU SPONSORING THE CITIES' COST OF SERVICE MODEL IN THIS PROCEEDING?

A. Yes. I sponsor the Cities' cost of service model and compile adjustments to the Company's proposed revenue requirement recommended by each of the Cities' experts. Table 2 provides the detailed adjustments supporting the totals shown in Table 1:

Table 2

Adjustment	Amount	Sponsor
ETI Base Rate Revenue Deficiency/(Excess)	$38,603,077	
Cities' Base Rate Adjustments		
ROR	($13,626,382)	Parcell
Replace Expiring Purchased Power Contracts	($9,580,240)	Nalepa
Annualize Carville PPA	$1,847,205	Nalepa
[redacted]	[redacted]	Nalepa
Loss of ETEC Wholesale Load	($1,397,866)	Nalepa
Distribution Allocation Factor	($8,820)	Nalepa
Injuries and Damages	($3,449,979)	Garrett
Payroll	($1,169,145)	Garrett
HCM	($6,349,510)	Garrett
Decommissioning	($2,301,770)	Pous
Cities' Total Base Rate Adjustment	($36,462,818)	Note 1
Cities' Base Rate Deficiency/(Excess)	$2,140,259	
ETI Rider Revenue Deficiency/(Excess)	$14,530,924	Note 2
Cities' RPCE Rider Adjustment	($7,602,862)	Nalepa
Cities' Rider Revenue Deficiency/(Excess)	$6,927,858	
Cities' Total Revenue Deficiency/(Excess)	$9,068,117	

Note 1. Individual adjustments reflect stand-alone impact. Totals reflect composite impact of all adjustments.
Note 2. Includes Rider RPCE ($11,404,602) and RCE ($3,126,322).

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING ETI'S REQUESTED BASE RATES AND REVENUE RIDERS IN THIS PROCEEDING.

A. I make the following recommendations regarding the Company's proposed rate request:

1. Regarding the Company's request to include the test year level of purchased power capacity costs, I recommend a revised amount of test year purchased power capacity costs reflecting:
    a. replacement of expiring contracts,
    b. annualization of the Carville PPA,
    c. [redacted]
    d. loss of ETEC wholesale load;
2. Regarding the Company's request to include a rider to recover RPCE payments over one year, I recommend the payments be amortized over three years,
3. Regarding the Company's proposed cost allocation factors, I recommend a revision to the secondary lines and transformers allocation factor.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING ETI'S FUEL COSTS IN THIS PROCEEDING?

A. Regarding the Company's reconcilable fuel costs, I recommend the Commission deny ETI's request for a special circumstances exception to the Fuel Rule to recover certain purchased power capacity costs as reconcilable fuel costs.

Q. WHAT IS THE TOTAL DOLLAR AMOUNT OF YOUR RECOMMENDATIONS?

A. My recommended adjustments to the Company's proposed base rate and Rider request are summarized by issue in Table 3.

Table 3

Adjustment	Rate Base	Revenue Requirement
Replacement of Expiring Purchased Power Contracts	-	($9,497,309)
Annualization of Carville PPA		$1,830,972
[redacted]	-	[redacted]
Loss of ETEC Wholesale Load		($1,385,940)
Total Base Rate Adjustment		($9,474,170)
Rider RPCE	-	($7,602,708)
Total Adjustment	-	**($17,076,878)**

In addition, I recommend a total adjustment to reconcilable fuel costs of $22,942,706 to remove the effect of the Company's proposed special circumstances exception to the Fuel Rule. However, if the Commission determines to allow ETI's special circumstances exception, then I recommend adjustments to the Company's cost/benefit calculations to reduce its request by $16,745,692.

IV. COST OF SERVICE MODEL

Q. ARE THE CITIES PROPOSING AN OVERALL REVENUE REQUIREMENT IN THIS PROCEEDING?

A. Yes. I am sponsoring a cost of service model based on the Company's model, and have compiled the adjustments to the Company's proposed revenue requirement recommended by each of the Cities' experts. A summary of the cost of service model results is included as Attachment KJN-1.

Q. HOW WAS THE COST OF SERVICE MODEL DEVELOPED?

A. The starting point for the cost of service model is a reproduction of the Company's model. It incorporates all of the components of the Company's model, and generates the same results as the Company's model prior to any adjustments by the City.

Q. ARE YOU SPONSORING THE CITIES' ADJUSTMENTS TO THE COST OF SERVICE MODEL?

A. I have compiled the adjustments to the cost of service model, but I am only sponsoring the model and the adjustments reflected elsewhere in my testimony. Other experts retained by the Cities will sponsor their own adjustments. A summary of the adjustments proposed by Cities' experts is included in my workpapers.

Q. WHAT IS THE CITIES' PROPOSED REVENUE REQUIREMENT?

A. A comparison of the Company's requested revenue requirement with Cities' recommended adjustments is summarized in Table 4:

Table 4

	ETI Proposed	Cities' Recommended	Difference
Base Rate Revenue	$709,705,118	$673,242,300	($36,462,818)
Rider RPCE	$11,404,602	$3,801,740	($7,602,862)
Rider RCE	$3,126,322	$3,126,322	$0
Other Riders	$112,552,170	$112,552,170	$0
Fuel Revenue	$561,450,571	$561,450,571	$0
Total	$1,398,238,783	$1,354,173,103	($44,065,680)

V. COST OF SERVICE ADJUSTMENTS

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENTS YOU ARE RECOMMENDING.

A. I am recommending adjustments to the following cost of service issues:

1. Purchased power capacity costs
2. Rider RPCE amortization
3. Secondary Line/Transformer allocation factor

A. PURCHASED POWER CAPACITY COSTS

Q. WHAT PURCHASED POWER CAPACITY COSTS IS ETI REQUESTING IN THIS PROCEEDING?

A. ETI is requesting the test year level of $260,317,272 in purchased capacity costs.[5] The total by source is summarized in Table 5:[6]

[5] Direct Testimony of Robert Cooper at 5.

[6] ETI response to TIEC RFI 1-2 (Public).

Table 5

Source	Amount
Non-system purchases (Toledo Bend)	$619,181
Renewable Energy Credit purchases	$987,553
MSS-1 reserve equalization costs	$1,068,065
MSS-4 affiliate unit power purchases	$189,090,446
Non-associated (3rd party) purchases	$65,982,688
Other book adjustments	$2,569,339
River Bend Decommissioning Adjustment[7]	$2,058,750
Renewable Energy Credit Adjustment[8]	$510,589
Total	$260,317,272

Q. DID THE COMMISSION ORDER THAT TEST YEAR PURCHASED POWER CAPACITY COSTS BE USED TO SET RATES IN DOCKET NO. 39896?

A. Yes, it did.

Q. WHAT WAS THE BASIS FOR THE COMMISSION'S DECISION?

A. The decision was based on Entergy failing to prove that its proposed $31 million adjustment to test year purchased power capacity expense was known and measurable, and it violated the matching principle.[9]

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[7] WP/P AJ16M.

[8] WP/P AJ23.

[9] Docket No. 39896, Final Order at 6.

Q. WHAT IMPLICATION DOES THE ORDER IN DOCKET NO. 39896 HAVE FOR THIS CASE?

A. The Order in Docket No. 39896 is reflective of Commission Rule 25.231(b):

> ***Allowable expenses.*** *Only those expenses which are reasonable and necessary to provide service to the public shall be included in allowable expenses. In computing an electric utility's allowable expenses, only the electric utility's historical test year expenses as adjusted for known and measurable changes will be considered...*

An adjustment to test year expense is appropriate if it is known and measurable and reflects all attendant impacts. In Docket No. 39896, the Company was unable to show that its proposed adjustments were known and measurable, and all attendant impacts could be identified, quantified, and matched. Therefore, the Commission set rates using the test year capacity costs.

In the instant case, if test year capacity costs do not represent the level of costs expected going forward, then a known and measurable adjustment to test year expense is required to ensure that the appropriate level of capacity expense is used to set rates.

1. <u>REPLACE EXPIRING CAPACITY</u>

Q. DO TEST YEAR COSTS REASONABLY REPRESENT THE COMPANY'S EXPECTED LEVEL OF PURCHASED POWER CAPACITY COSTS DURING THE RATES YEAR?

A. No, they do not.

Q. PLEASE EXPLAIN WHY NOT.

A. For the primary reason that the Company is proposing to include in rates $33.6 million in capacity costs for contracts that will have expired before or during the rate year.

Q. PLEASE IDENTIFY THE CONTRACTS THAT WILL BE EXPIRING.

A. Table 6 summarizes the purchased power capacity contracts that expire before or during the rate year:[10]

Table 6

Supplier	Contract End Date	Test Year Expense	Capacity (kW)	Cost / kW-Month
Conoco Phillips SRW	5/31/13	[redacted]	100,000	[redacted]
Dow Pipeline	3/31/14	[redacted]	50,000	[redacted]
[redacted][11]	[redacted]	[redacted]	[redacted]	[redacted]
NRG	11/30/13	[redacted]	75,000	[redacted]
EAI WBL	12/18/13	[redacted]	186,000	[redacted]
Total		$33,551,213	487,000	5.741

Q. DOES THE COMPANY EXPECT TO REPLACE THE EXPIRING CONTRACTS?

A. Yes. The Company asserts that it is capacity short and must acquire additional capacity to replace the expiring capacity contracts. However, it has not yet determined how it will replace the capacity, so ETI proposes to include $33.6 million

[10] Schedule I-4 (Public).

[11] [redacted].

of expired purchased power contracts in rates with no adjustments to the test year costs.[12]

Q. HAS ETI INDICATED POSSIBLE ALTERNATIVES TO THE EXPIRING PURCHASED POWER CONTRACTS?

A. Yes. The Company suggests a number of alternatives to replace the expiring capacity:[13]

1. Construction of new generating resources,
2. Traditional purchased power agreements (PPAs) for capacity and energy,
3. Request for Proposals (RFP) once ETI integrates into MISO,
4. The MISO capacity auction, and
5. Schedule MSS-1 of the System Agreement, which allows the Company to share in the resources of other Entergy Operating Companies.

Q. ARE ANY OF THESE ALTERNATIVES A VIABLE OPTION TO REPLACE THE EXPIRING CONTRACTS?

A. The only alternative that is available now and has a known cost is Schedule MSS-1. [redacted].[14] Moreover, ETI's discovery responses also reflect that [redacted]

[12] ETI response to TIEC RFI 1-4.

[13] *Id.*

[14] Deposition of Robert Cooper at 32 (Confidential).

[redacted]

Q. PLEASE EXPLAIN WHY THE OTHER ALTERNATIVES IDENTIFIED BY THE COMPANY ARE NOT REASONABLE OPTIONS.

A. First, construction of new generating resources will take years to obtain approvals and to construct and are not available in the timeframe needed.[16] Second, the Company claims it is evaluating certain purchased capacity transactions that may be in effect during the rate year, but these are only speculative at this point.[17] As I explain in more detail below, EAI's exit from the system agreement will leave the remaining Entergy System with an excess of capacity. Because the Entergy System will have an excess of capacity, the excess resources may be used to meet the capacity needs of ETI through the operation of Entergy Service Schedule MSS-1 without the need to enter into additional capacity contracts. Third, ETI has just joined MISO and no RFP for capacity has yet been developed. Fourth, the last annual MISO capacity auction was held in March 2013, where costs cleared at only about $1.05 per kW because of excess capacity in the MISO market. The next annual MISO capacity auction will be held in March 2014, which is beyond the expiration date of most of the subject contracts and the cost is not known at this time.[18]

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15 [redacted]

16 Deposition of Robert Cooper at 65.

17 *Id.* at 57.

18 *Id.* at 61-64.

Q. DO YOU PROPOSE A KNOWN AND MEASURABLE CHANGE TO TEST YEAR CAPACITY EXPENSE?

A. Yes. The test year capacity expense is overstated because it includes expenses that the Company acknowledges it will not incur during the rate year. Relying on the Company's claim that it will be short capacity, the test year expense for the capacity contracts that are expiring cannot just be removed, but rather, the cost must be replaced with the cost of an available and known and measurable resource. As I explained previously, other than MSS-1 capacity, none of the other alternatives identified by ETI will be available or are known and measureable when rates are set in this case.

Q. WHAT IS YOUR ADJUSTMENT THEN?

A. I replace the expiring capacity with an equivalent amount of MSS-1 capacity.

Q. HOW DID YOU DETERMINE THE COST OF THE MSS-1 CAPACITY?

A. Service Schedule MSS-1 prescribes a method for sharing fixed costs of generating capability among the Entergy Operating Companies. Some Operating Companies own more than their share of the System's total capability relative to their load, and thus own more than their share of System reserves. Other Companies own less than their share. These Operating Companies are known as "long" and "short" Operating Companies, respectively. A company's position and the extent to which it is "long" or "short" can change over time. The Service Schedule MSS-1 formula provides for payments by "short" Companies to "long" Companies. The payments are computed monthly by multiplying the Company's MW shortfall – the difference between Capability Responsibility and Company Capability – times a $/MW rate for the cost of owning reserve capability.[19]

Q. WHAT COST OF MSS-1 CAPACITY DID YOU USE?

A. The Service Schedule MSS-1 cost per MW is recalculated annually based on the fixed operating costs of certain oil- and gas-fired generating units owned by the "long" Companies.[20] The last MSS-1 rates for ETI are summarized in Table 7:[21]

Table 7

Effective Date	MSS-1 Rate ($/MW)
June 2011	$3,619
June 2012	$3,568
June 2013	$4,116

I recommend using the MSS-1 rate of $4,116 per MW effective June 2013, as this is the current known rate and will be the rate in effect when new rates are set in this proceeding.

Q. WHAT IS YOUR RESULTING ADJUSTMENT TO PURCHASED POWER CAPACITY COSTS?

A. There are 487,000 KW of capacity expiring under the five contracts shown in Table 5 at an annual cost of $33,551,213. The evidence in this case demonstrates that the

[19] Direct Testimony of Michael Goin at 12-14.

[20] *Id.*

[21] ETI response to TIEC RFI 1-6, Intra-System Bills.

487,000 kW of capacity will be replaced with MSS-1 purchases. Table 8 shows the capacity cost reduction under the MSS-1 purchases.

Table 8

	Expiring Contracts	Replacement MSS-1 Purchases
Capacity	487,000 kW	487,000 kW
Unit Cost	$5.741 / kw-month	$4.116 / kW-month
Cost	$33,551,213	$24,053,904
Difference		$9,497,309

Thus the known and measurable change that must be made for the expired and expiring contracts is a reduction to purchased power capacity costs of $9,497,309. This represents a reduction to 3rd party purchases of $5,307,328 and a reduction to affiliate purchases of $28,243,885, but an increase in MSS-1 purchases of $24,053,904. The impact on the Company's request is shown in Table 9:

Table 9

Source	Test Year Amount	Remove Expiring Capacity	Replace Expiring Capacity	Net Adjustment
Capacity		(487,000 kW)	487,000 kW	
Non-system purchases (Toledo Bend)	$619,181			
Renewable Energy Credit purchases	$987,553			
MSS-1 reserve equalization costs	$1,068,065		$24,053,904	$24,053,904
MSS-4 affiliate unit power purchases	$189,090,446	($28,243,885)		($28,243,885)
Non-associated (3rd party) purchases	$65,982,688	($5,307,328)		($5,307,328)
River Bend Decommissioning Adjustment	$2,058,750			
Renewable Energy Credit Adjustment	$510,589			
Total	$260,317,272	($33,551,213)	$24,053,904	($9,497,309)

2. ANNUALIZE CARVILLE PPA

Q. MUST THE ATTENDANT IMPACT OF OTHER PURCHASED POWER AGREEMENTS BE RECOGNIZED?

A. Yes. The Company failed to recognize that it has included only 10 months of its Carville PPA capacity costs in the test year. It would be reasonable to annualize the payments under this contract.

Q. HOW WOULD THIS BE ACCOMPLISHED?

A. The test year included the twelve months ending March 31, 2013. The Carville PPA started in June 2012, or 2 months after the beginning of the test year. I calculated the capacity costs for April and May, the first 2 months of the test year, based on the contract capacity rates, applied to the contract capacity. The result is an increase in test year capacity costs of $1,830,972, as reflected in Table 10:

Table 10

Month	Capacity	Capacity Charge	Total Cost
April	242.5 MW	[redacted]	[redacted]
May	242.5 MW	[redacted]	[redacted]
Total			$1,830,972

Q. WHAT IS YOUR RESULTING ADJUSTMENT TO PURCHASED POWER CAPACITY COSTS?

A. I recommend that test year purchased power capacity costs be increased by $1,830,972 to recognize a full year of the Carville PPA. The cumulative impact on the Company's request is shown in Table 11:

Table 11

Source	Test Year Amount	Remove Expiring Capacity	Replace Expiring Capacity	Annualize Carville PPA	Net Adjustment
Capacity		(487,000 kW)	487,000 kW		
Non-system purchases (Toledo Bend)	$619,181				
Renewable Energy Credit purchases	$987,553				
MSS-1 reserve equalization costs	$1,068,065		$24,053,904		$24,053,904
MSS-4 affiliate unit power purchases	$189,090,446	($28,243,885)			($28,243,885)
Non-associated (3rd party) purchases	$65,982,688	($5,307,328)		$1,830,972	($3,476,356)
River Bend Decommissioning Adjustment	$2,058,750				
Renewable Energy Credit Adjustment	$510,589				
Total	$260,317,272	($33,551,213)	$24,053,904	$1,830,972	($7,666,337)

3. <u>LOSS OF EAI FROM SYSTEM AGREEMENT</u>

Q. ARE THERE OTHER ATTENDANT IMPACTS THAT MUST BE RECOGNIZED?

A. Yes. Entergy Arkansas Inc. ("EAI") has exited the Entergy System Agreement effective December 18, 2013.[22] This event impacts the cost of system resources allocated among the remaining system members and the responsibility ratio of each remaining operating company. "Responsibility ratio" is an allocator that reflects the relative contribution of each Operating Company to the system's coincident peak load.

[22] ETI response to Cities RFI 2-5.

Q. HOW DOES EAI EXITING THE ENTERGY SYSTEM AGREEMENT CAUSE THIS TO OCCUR?

A. As I discussed earlier, Service Schedule MSS-1 prescribes a method for sharing fixed costs of generating capability among the Entergy Operating Companies. When EAI left the System Agreement, EAI's load and resources were removed from the resource sharing calculation, so the relative costs and responsibility ratios of the remaining Operating Companies changed.

Q. WHAT EFFECT DOES THIS HAVE?

A. EAI was a "short" Operating Company during the test year, so it owned less than its share of system resources. It relied on other Operating Companies to provide this difference through MSS-1 purchases. During the test year, this difference averaged about 530 MW.[23] Once EAI left the System, the excess resources provided to EAI must now be allocated to the remaining Operating Companies.

Q. HOW DOES THIS CHANGE AFFECT ETI?

A. The Company estimates that the impact on the test year MSS-1 reserve equalization payments by removing EAI would be [redacted]

Q. SHOULD TEST YEAR CAPACITY COSTS BE ADJUSTED TO REFLECT THIS CHANGE?

A. No, it should not.

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[23] ETI response to TIEC RFI 1-6 (Intra-System Bills).

[24] ETI response to Cities RFI 2-7 (Highly Sensitive).

Q. PLEASE EXPLAIN WHY NOT.

A. As I've already discussed, ETI will be replacing 487 MW of expiring capacity with MSS-1 purchases. Furthermore, EAI exiting the System Agreement will leave excess capacity to be allocated among the remaining Operating Companies. Under the MSS-1 reserve equalization formula, capacity is allocated among the Operating Companies according to their respective responsibility ratios. Any additional amount would be allocated to ETI according to its responsibility ratio of about [redacted] Since ETI will be 487 MW short, it is reasonable to expect that most of the EAI capacity will be allocated to ETI. Therefore, the impact of EAI exiting the system will already be accounted for by re-pricing the replacement capacity at the MSS-1 rate.

[redacted]

[redacted]

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[25] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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[26] [redacted]

[27] [redacted]

4. LOSS OF ETEC WHOLESALE LOAD

Q. WHAT OTHER ATTENDANT IMPACTS MUST BE RECOGNIZED?

A. East Texas Electric Cooperative, Inc. ("ETEC") was ETI's only wholesale power customer[28] under a minimum 150 MW partial requirements contract.[29] In May 2013, ETI and ETEC entered into a contract amendment to terminate the wholesale service contract effective upon ETI's integration into MISO.[30]

Q. WHAT IS THE EFFECT OF THIS CONTRACT TERMINATION?

A. The test year capacity resources needed by ETI to serve the ETEC wholesale load would not need to be replaced. To the extent that adjusted test year capacity exceeds ETI's retail load and reserve requirements, an adjustment to capacity costs is necessary.

Q. HAVE YOU CALCULATED SUCH AN ADJUSTMENT?

A. Yes, I have. I compared the net capacity available to ETI to the test year retail peak demand requirement for ETI, and determined that ETI will have more resources available than it needs to meet its peak demand. I then make an adjustment for this excess capacity at the ETI MSS-1 rate described earlier in my testimony. Table 12 shows this calculation:

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[28] Direct Testimony of Michael Goin at 5.

[29] *Id.* at 41.

[30] *Id.*

Table 12

Value of Reduction in Capacity Needed to Serve ETEC	
ETI Capacity[31]	3,886.26 MW
Less:	
Expired Capacity[32]	(387.00 MW)
ETEC Purchase Capacity[33]	(243.91 MW)
Net Capacity	3,255.35 MW
Test Year Requirement[34]	3,714.29 MW
Difference	(458.94 MW)
Add MSS-1 Replacement Capacity[35]	487.00 MW
Excess Capacity	28.06 MW
Annualize Capacity[36]	336.72 MW
MSS-1 rate[37]	$4,116 / MW
Value of Excess Capacity	$1,385,940

Q. PLEASE EXPLAIN WHY YOU REMOVED THE ETEC PURCHASE CAPACITY ON TABLE 12.

A. Contracts for purchase of capacity at ETEC's Hardin, Harrison, Sam Rayburn and Willis plants were tolling agreements used to support the wholesale requirements power agreement with ETEC and only served the wholesale load during the test year. The wholesale requirements agreement between ETI and ETEC provides for ETI to supply ETEC a minimum of 150 MW or ETEC's load in excess of the Hardin, Harrison, Sam Rayburn, and Willis capacity levels. These agreements will terminate with the ETEC wholesale power agreement.

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[31] Docket No. 40979, *MISO Compliance Filing*, November 2013 ISB, Operating Company Capacity.

[32] See Table 6. Since Conoco Phillips contract expired prior to November 2013, it is not reflected in the November 2013 ISB, so is not removed again. 487,000 MW-100,000 MW (Conoco) = 387,000 MW.

[33] Docket No. 40979, MISO Compliance Filing, November 2013 ISB, Operating Company Capacity.

[34] Schedule O-1.9, retail peak demand of 3,316,330 kW x reserve requirement of 12% =3,714,290 kW

[35] See Table 6.

[36] 28.06 MW x 12 months = 336.72 MW.

[37] See Table 7.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THIS EXCESS CAPACITY?

A. I recommend that purchased power capacity be reduced by the value of the excess capacity resulting from the loss of the ETEC wholesale load. This amount is $1,385,940. The cumulative impact on the Company's request is shown in Table 13:

Table 13

Source	Test Year Amount	Remove Expiring Capacity	Replace Expiring Capacity	Annualize Carville PPA	ETEC Load Adjustment	Net Adjustment
Capacity		(487,000 kW)	487,000 kW		(28,060 kW)	(28,060 kW)
Non-system purchases (Toledo Bend)	$619,181					
Renewable Energy Credit purchases	$987,553					
MSS-1 reserve equalization costs	$1,068,065		$24,053,904		($1,385,940)	$22,667,964
MSS-4 affiliate unit power purchases	$189,090,446	($28,243,885)				($28,243,885)
Non-associated (3rd party) purchases	$65,982,688	($5,307,328)		$1,830,972		($3,476,356)
River Bend Decommissioning Adjustment[38]	$2,058,750					
Renewable Energy Credit Adjustment[39]	$510,589					
Total	$260,317,272	($33,551,213)	$24,053,904	$1,830,972	($1,385,940)	($9,052,277)

The net adjustment is a reduction of $9,052,277 to the Company's purchased power capacity request.

[38] WP/P AJ16M.

[39] WP/P AJ23.

B. RPCE PAYMENT

Q. WHAT IS A ROUGH PRODUCTION COST EQUALIZATION ("RPCE") PAYMENT?

A. The FERC determined in its Orders 480 and 480-A that no Entergy Operating Company's ("EOC") production costs should be more than 11% above or more than 11% below the System average production costs. The remedy ordered by the FERC, and incorporated into Entergy's Service Schedule MSS-3, provides that, if any EOC's production costs for a given calendar year were below or above that bandwidth, payments ("RPCE payments") must be made by the low-cost Company(ies) to the high-cost Company(ies) to "roughly equalize" their respective production costs, such that, after reflecting the payments and receipts, no EOC would have production costs more than 11% above the System average or more than 11% below the System average.[40]

Q. WHAT IS ETI'S RPCE PAYMENT OBLIGATION IN 2013?

A. Under the FERC calculation methodology, ETI had the lowest production cost during calendar year 2012 and is obligated to make an RPCE payment of $14,599,000 to Entergy New Orleans ("ENO") to equalize their respective production costs.[41]

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[40] Direct Testimony of Michael Goins at 26.

[41] Entergy's 2013 MSS-3 FERC compliance filing.

Q. WHAT IS ETI'S HISTORY OF MAKING OR RECEIVING THESE PAYMENTS?

A. Until this year, ETI has only received RCPE payments. Table 14 summarizes these payments since 2007.[42]

Table 14

RPCE Base Year Ending	RPCE Filing Year	Total Company	Retail	Wholesale	Date Fully Credited	Months between incurred and credited
2006	2007	$30,399	$48,977	$0	Jan. 2011[43]	49
2007	2008	$64,228	$64,228	$0	Oct. 2009[44]	22
2008	2009	$118,568	$116,209	$2,359	Aug. 2010[45]	20
	2010	$0	$0	$0		
2005	2011	$43,298	$37,407	$5,891	Jan. 2013[46]	85
	2012	$0	$0	$0		
2012	2013	($14,599)	($11,378)	($3,221)		
	Total	$241,894	$255,443	$5,029		

Q. WHICH EOCS MADE RPCE PAYMENTS IN PRIOR YEARS?

A. In each of the prior years, Entergy Arkansas Inc. ("EAI") had the lowest production cost and made payments to the other EOCs.[47]

Q. HOW DOES ETI INTEND TO COLLECT THE RPCE PAYMENT AMOUNT?

A. ETI is requesting an RPCE Rider to collect the retail portion of the RPCE payment, plus interest, over one year.[48]

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[42] ETI response to Beaumont RFI 1-25.

[43] Docket No. 37744, Final Order FoF 30.

[44] Docket No. 37036, Final Order FoF 13.

[45] Docket No. 38098, Final Order FoF 14.

[46] Docket No. 40542, Final Order FoF 12.

[47] Entergy's MSS-3 FERC compliance filings.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. Although I do not dispute the amount of the RPCE payment, it is not reasonable to collect the payment from customers over just one year.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the RPCE payment be amortized over three years consistent with the amortization of ETI's proposed rate case expense rider and ETI's proposal for recovery of MISO transition expenses. My recommendation would reduce the Company's annual RPCE rider revenues by $7,602,708, as shown in Table 15:

Table 15

	Annual RPCE Revenue
ETI Proposed 1 Year Amortization	$11,404,062
Cities Proposed 3 Year Amortization	$3,801,354
Adjustment	($7,602,708)

Q. IS YOUR PROPOSAL CONSISTENT WITH PRIOR RPCE CREDITS?

A. Yes. The time period between the date that customers actually incurred higher than system average production costs and the date that customers were credited for those higher than system average production costs through a RPCE refund is consistent with the prior RPCE credits. For the initial RPCE filing, the RPCE payments were intended to credit higher than system average production costs of ETI incurred throughout 2006. The RPCE credit for ETI's high production costs in 2006 was not fully credited to customers until January 2011, more than four years after the production costs were incurred.

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[48] Direct Testimony of Margaret McCloskey at 18-19.

For the 2011 RPCE filing, the RPCE credits were intended to refund higher than system average production costs of ETI incurred in the final seven months of 2005. The RPCE credit for ETI's high production costs in 2005 was not fully credited to customers until January 2013, more than seven years after the production costs were incurred.

C. COST ALLOCATION

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED COST ALLOCATION METHODOLOGY.

A. The Company allocates plant using two different allocation factors. It allocates substation and primary distribution line facilities using class peak demands. However, the Company allocates secondary distribution lines and transformer plant using a combination of the class peak and customer maximum demand ("(MDD+NCP)/2") allocation method.[49]

Q. PLEASE EXPLAIN MDD AND NCP DEMAND.

A. The class peak is referred to as the maximum diversified demand ("MDD") by ETI.[50] MDD is the maximum demand of an entire rate class, whenever that occurs. It reflects the loads of individual customers aggregated into rate classes, where the Company and those individual customers benefit from the diversity of the customers' individual loads. ETI's defined non-coincident peak demand ("NCP") is simply the sum of the maximum demands during the month for each individual customer within a rate class

[49] Schedule P-7.2, page 2.

[50] Schedule P-7.2, pages 23 & 24.

regardless of when each customer's maximum demand occurs.[51] The NCP is analogous to actual billing demands excluding any ratchet provisions.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED ALLOCATION METHODOLOGIES.

A. I agree with the Company's proposed methodology to allocate distribution substation and primary lines facility based on the class peak ("MDD"). However, I propose an alternative to the allocation of secondary lines and transformer plant.

Q. PLEASE DESCRIBE YOUR PROPOSED DISTRIBUTION PLANT ALLOCATION METHODOLOGY.

A. I do not believe that secondary lines and transformer plant should be allocated on a combination of the MDD and NCP. The Company has not shown that the average of MDD and NCP represents the appropriate allocation of this plant. The NCP, which is the sum of the maximum load of each individual customer, does not recognize customer diversity. The Company admits that on average there are multiple customers supplied by a single transformer[52] and the class peak MDD factor more closely recognizes the diverse usage characteristics of the connected customers. Therefore, I recommend that the class peak MDD factor be used to allocate secondary line and transformer costs.

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[51] Schedule P-7.2, pages 25 & 26.

[52] ETI response to OPUC RFI 1-48.

Q. DO OTHER UTILITIES IN TEXAS ALLOCATE SECONDARY LINE AND TRANSFORMER COSTS THE SAME WAY AS ETI?

A. No, they do not. I have reviewed the allócation methodologies proposed by other investor owned utilities in Texas and found that the overwhelming majority[53] allocate all of the demand related distribution facilities, including secondary lines and transformers, on the basis of the class peak demand. I would note that the class peak is often times referred to as the NCP by some of the other utilities, but a review of supporting testimony and workpapers in these cases clearly demonstrates that the data equates to the class peak, or the MDD as defined by ETI.

Q. WHAT IS THE RESULT OF THE COMPANY'S ALLOCATION METHODOLOGY?

A. Table 16 shows the results of my recommendation compared to ETI's proposed methodology, at the Company's proposed revenue requirement:

Table 16

Customer Class	ETI (MDD+NCP)/2	Cities (MDD)	Difference
Residential	$2,045,977	($488,057)	($2,534,034)
Small General Service	$170,843	($56,863)	($227,706)
General Service	$23,547,773	$25,395,030	$1,847,257
Large General Service	$3,759,022	$4,542,388	$783,366
Large Industrial Service	$9,254,604	$9,250,363	($4,241)
Lighting	($175,142)	($48,807)	$126,335
Total Retail	$38,603,077	$38,594,054	($9,023)

[53] SPS Docket No. 40824, SWEPCO Docket No. 40443, Oncor Docket No. 38929, AEP-TNC Docket No. 33310 and AEP-TCC Docket No. 33309.

As can be seen in Table 16, the unconventional allocation methodology proposed by the Company results in a significant rate subsidy by residential customers.

VI. OVERVIEW OF ETI'S FUEL COSTS

Q. WHAT ARE THE COMPANY'S TOTAL FUEL AND PURCHASED POWER EXPENSES DURING THE RECONCILIATION PERIOD?

A. For the period July 1, 2011 through March 31, 2013, ETI generated or purchased 41,135,858 MWh at a total cost of $1,268,388,652 or an average cost of $30.83 per MWh. The Company had off-system sales of 9,416,854 MWh with total revenues of $358,984,379 or average revenue of $38.12 per MWh. The net cost during the period was $28.67 per MWh.[54]

Q. WHAT IS THE STANDARD BY WHICH ETI'S FUEL COSTS SHOULD BE EVALUATED?

A. PUC Rule §25.236 (d) requires that in a proceeding to reconcile fuel factor revenues and expenses, an electric utility has the burden of showing that:

> (A) its eligible fuel expenses during the reconciliation period were reasonable and necessary expenses incurred to provide reliable electric service to retail customers;
>
> (B) if its eligible fuel expenses for the reconciliation period included an item or class of items supplied by an affiliate of the electric utility, the prices charged by the supplying affiliate to the electric utility were reasonable and necessary and no higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items; and

[54] Direct Testimony of Margaret McCloskey, Exhibit MLM-1.

(C) it has properly accounted for the amount of fuel-related revenues collected pursuant to the fuel factor during the reconciliation period.

VII. SPECIAL CIRCUMSTANCES EXCEPTION

Q. PLEASE DESCRIBE THE FUEL COST ISSUES YOU ARE ADDRESSING.

A. I am addressing ETI's requested special circumstances exception to the Fuel Rule regarding certain purchased power capacity costs.

Q. PLEASE EXPLAIN ETI'S REQUESTED SPECIAL CIRCUMSTANCES REQUEST.

A. As explained by Company Witness Cooper, ETI is requesting to recover $22,942,706 in prior capacity costs associated with the Carville and Frontier purchased power agreements ("PPAs") as reconcilable fuel costs incurred during the Reconciliation Period. These costs were previously disallowed by the Commission for inclusion as adjustments to base rates.[55] The Commission's Fuel Rule explicitly states that demand or capacity costs are not eligible fuel costs,[56] but the Commission may allow recovery of such costs upon demonstration that the fuel expense or transaction giving rise to the ineligible fuel expense results in increased reliability of supply or lower fuel expenses than would otherwise be the case, and that such benefits received

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[55] Direct Testimony of Robert Cooper at 27-28.

[56] §25.236(a)(4).

exceed the costs that ratepayers otherwise would have paid or would reasonably expect to pay.[57]

Q. DO YOU RECOMMEND THAT THE COMMISSION GRANT ETI'S SPECIAL CIRCUMSTANCES REQUEST?

A. No. There are several reasons for denying ETI's special circumstances request, which I will explain in more detail below. As a summary, the special circumstances request of ETI should be rejected for the following reasons:

1. The Commission concluded in Docket No. 39896 that the rate year costs of capacity, including the Carville and Frontier capacity costs should not be included in ETI's base rates, which were effective in June 2012.

2. ETI could have requested a Purchased Power Capacity Cost Recovery Factor ("PCRF")[58] beginning in July 2013 to recover changes in all third party capacity purchases, including the Carville and Frontier capacity contracts, occurring after June 2012. If ETI were able to prove that any of its third party capacity purchases subsequent to June 2012 - the date base rates from Docket No. 39896 went into effect - were going unrecovered, then ETI could have and should have recovered such costs through a PCRF.

3. Any capacity costs incurred prior to July 2012 would have been incurred during the time period when the base rates established by the Commission in Docket No. 37744 were in effect. The rates resulting from Docket No. 37744 were set pursuant to agreement between ETI and the parties and did not specify any amount of capacity costs embedded in rates. Because ETI agreed to the sufficiency of rates in Docket No. 37744, ETI should not be permitted to now make the claim that the rates agreed to by the utility were insufficient to recover any particular cost of service item included in those rates.

4. ETI's special circumstances request does not take into consideration offsetting reductions in third party capacity or affiliate capacity costs since the test year in Docket No. 39896 as would be required if ETI were seeking recovery of capacity costs pursuant to the PCRF Rule. For example, the test year capacity costs approved in Docket No. 39896 include $25,461,353 of capacity costs incurred pursuant to Entergy Service Schedule MSS-1. The Entergy Service

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[57] §25.236(a)(6).

[58] §25.238.

Schedule MSS-1 capacity costs incurred during the test year in this case, Docket No. 40791, and requested for recovery total $1,068,065, a reduction of $24,393,288 in Service Schedule MSS-1 capacity costs. This reduction in the 12 month test year capacity costs alone would more than offset ETI's requested special circumstances request for the entire 21 months of Frontier capacity costs and 10 months of Carville capacity costs combined.

5. ETI's special circumstances request does not take into consideration the recovery of Carville or Frontier capacity costs through increased revenues attributable to load growth from the test year in Docket Nos. 37744 and 39896 as would be required if ETI were seeking recovery of capacity costs pursuant to the PCRF Rule. Instead, ETI requests recovery of the Carville and Frontier capacity costs as if there were no offsetting revenues from load growth since the test year in Docket No. 39896.

6. ETI's special circumstances request should not be approved because the Carville and Frontier Capacity contracts do not exhibit any characteristic that should qualify for a special circumstance exception to the Fuel Rule. The Carville and Frontier capacity contracts 1) are not demonstrated to be the least cost alternative source of capacity and energy, and 2) were acquired to meet ETI's minimum reliability requirements, but have not been demonstrated to increase reliability above ETI's reliability requirements.

7. ETI's special circumstances request should not be approved because ETI's formula used to demonstrate and quantify costs eligible for special circumstance recovery is self-serving in that under the formula, virtually any capacity contract acquired by ETI would qualify for recovery through the special circumstance exception to the Fuel Rule.

Q. PLEASE DESCRIBE THE CARVILLE AND FRONTIER PPAs.

A. The Carville PPA is a ten-year 485 MW agreement which commenced on June 1, 2012. The PPA is allocated 50% to ETI and 50% to EGSL.[59] ETI's special circumstances request is based upon the 242.5 MW retained by ETI beginning in June of 2012. The Frontier PPA is a ten-year agreement that commenced on May 1, 2010 at an initial capacity level of 150 MW. On May 1, 2011, the capacity provided under the PPA increased from 150 MW to 300 MW (the "Step-up Capacity"). ETI retains

[59] Direct Testimony of Robert Cooper at 29.

100% of the capacity and energy from the PPA. ETI's special circumstance request is based upon the 150 MW Step-Up Capacity beginning in May 2011.

Q. DID ETI REQUEST THAT THE COMMISSION INCLUDE THE CAPACITY COSTS FROM THE CARVILLE AND FRONTIER PPAS IN ETI'S BASE RATES IN DOCKET NO. 39896?

A. Yes. ETI requested that the Commission use rate year capacity costs to set the base rates in Docket No. 39896. The rate year capacity costs included a full year's worth of capacity contracted under both the Carville and Frontier PPAs.[60]

Q. DID THE COMMISSION INCLUDE THE RATE YEAR CAPACITY COSTS FROM THE CARVILLE AND FRONTIER PPAS IN BASE RATES TO BE CHARGED TO CUSTOMERS?

A. No. The Commission found that there was "substantial uncertainty with regard to ETI's projection of its rate-year third-party capacity-contract payments."[61] The Commission also found that there was substantial uncertainty with regard to ETI's projection of Service Schedule MSS-1 capacity and rate year affiliate capacity contracts sourced through Service Schedule MSS-4.[62] Any reductions in affiliate capacity costs may offset cost increases in third party capacity costs. The Commission also found that "ETI experienced substantial load growth in the two years before the test-year, and it continues to project similar load growth in the

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[60] Docket No. 39896, Direct Testimony of Robert Cooper at 20-22.

[61] Docket No. 39896, Final Order on Rehearing at FoF 78.

[62] Docket No. 39896, Final Order on Rehearing at FoF 76 & 79-82.

future."[63] ETI's increase in revenues resulting from actual load growth following the test year may also offset any increases in capacity costs following the test year.

Q. DID ETI FILE A SUBSEQUENT CASE SEEKING RECOVERY OF THE CARVILLE AND FRONTIER PPA CAPACITY COSTS?

A. Yes. On November 30, 2012, ETI filed an *Application for Special Circumstance Purchased Capacity Recovery* requesting the recovery of the Carville and Frontier capacity costs.[64] ETI's request was substantially the same request as in this case.

Q. DID THE COMMISSION GRANT ETI'S REQUEST FOR SPECIAL CIRCUMSTANCE RECOVERY?

A. No. On March 15, 2013, Commission Staff, Cities, and TIEC filed a joint motion to dismiss ETI's application.[65] One of the arguments raised in the joint motion to dismiss was that the Commission was currently considering a rulemaking which would allow the recovery of purchased power capacity costs through a rider.[66]

Subsequent to the filing of the joint motion to dismiss, the Commission approved a new rule, Subst. R. 25.238, Purchased Power Capacity Cost Recovery Factor ("PCRF"), relating to the recovery of third party capacity and the Order adopting the new rule was issued on May 28, 2013.[67] On June 5, 2013 the

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[63] Docket No. 39896, Final Order on Rehearing at FoF 84.

[64] Docket No. 41003, *Application of Entergy Texas, Inc. for Special Circumstance Purchased Capacity Recovery.*

[65] Id., Order No. 6 at 1.

[66] *Id.*

[67] *Id.*

Commission issued Order No. 6 in Docket No. 41003 requesting parties to comment on how the case should proceed in light of the new PCRF Rule.[68]

On June 11, 2013, ETI filed its response to Order No. 6 and withdrew its application. Although ETI withdrew its application, ETI stated that "[t]he cost recovery allowed under the now finalized PCRF rule, PUC SUBST. R. 25.238, does not moot the need for this proceeding because, among other reasons, the time period covered by ETI's special circumstances request for cost recovery extends farther back than that allowed in Rule 25.238."[69]

Q. COULD ETI HAVE FILED A PCRF APPLICATION TO RECOVER COST INCREASES IN ITS THIRD PARTY PURCHASED CAPACITY?

A. Yes, ETI could have filed a PCRF application. The PCRF Rule became effective on June 12, 2013. The PCRF Rule states as follows:

> A utility may apply for establishment of a PCRF rider only if all of the following conditions are met:
> (A) the utility's most recent comprehensive base-rate proceeding established sufficient information to allow for the determination of values for the parameters in subsection (h) of this section;
> (B) no more than two years have passed since the final order in the utility's most recent comprehensive base-rate proceeding;
> (C) the utility has not had a PCRF in effect within the last year; and
> (D) no PCRF has been in effect for the utility since the final order in the utility's most recent comprehensive base-rate proceeding.

ETI's most recent comprehensive base-rate proceeding established sufficient information to allow for the determination of values for the parameters listed in subsection (h) of the PCRF Rule. In fact, the Commission's Final Order in

[68] *Id.*

[69] Docket No. 41003, ETI Response to Order No. 6 and Withdrawal of Application at 1.

Docket No. 39896 specifically addressed a baseline for total capacity costs,[70] and ETI filed base line values for each subset of capacity costs—third party capacity costs, affiliate capacity costs, and Service Schedule MSS-1 capacity costs—in the Compliance Docket No 40979 following the Commission's decision in Docket No. 39896. ETI also filed a detailed cost of service approved by the Commission and a proof of revenues in the compliance docket. So the first condition is met for ETI.

ETI could have, and may still, file an application under the PCRF Rule as not more than two years have passed since the Final Order in Docket No. 39896, so the second condition is met.

ETI has not had a PCRF within the last year and has not had a PCRF since the Final Order in Docket No. 39896 so the third and fourth conditions are met.

Q. WOULD ETI HAVE BEEN ABLE TO RECOVER ANY CHANGES IN THIRD PARTY CAPACITY CONTRACTS IF ETI HAD FILED A PCRF APPLICATION?

A. Yes. Although I am not an attorney and do not purport to give a legal opinion, I have reviewed the technical components and formula in subsection (h) of the PCRF Rule and the ratemaking cost of service inputs are within my scope of expertise. To the extent that ETI could demonstrate that its third party capacity contracts as a whole were not being recovered through base rates

[70] Docket No. 39896, Final Order on Rehearing at 9 and FoF 256.

taking into consideration both increases and decreases in third party capacity costs and affiliate capacity costs as well as load growth since the test year in Docket No. 39896, then ETI could recover any third party capacity costs deemed unrecovered through base rates. The PCRF Rule states that "the reasonableness and necessity of expenses recovered through the PCRF shall be reviewed, and such costs and corresponding PCRF revenues shall be reconciled, as part of any proceeding initiated under the [Fuel Rule]."[71] So in its initial PCRF application, ETI needed only to make a factual showing that the costs were incurred and unrecovered. For an initial PCRF application, ETI is not required to make a legal showing that the costs are reasonable or necessary or that they justify any special exception to Commission Rules.

Q. DOES THE PCRF RULE (PUC SUBST. R. 25.238) STATE ANY TIME LIMITATION ON THE COSTS THAT COULD BE INCLUDED IN A PCRF APPLICATION?

A. Yes. The PCRF Rule only allows recovery of third party capacity costs for a "cost-year."[72] "Cost-year" is defined in the PCRF Rule as "the most recent historical 12 month period for which data are available at the time a utility prepares an application to establish, adjust, or terminate a PCRF."[73] If ETI had begun preparing a PCRF application in July 2013, the month after the PCRF Rule became effective, then the latest possible historical 12 month period for which data would have been available

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[71] PUC Subst. R. 25.238(j).

[72] PUC Subst. R. 25.238(h)(1).

[73] PUC Subst. R. 25.238(b)(2).

would be the year from July 1, 2012 through June 30, 2013. This time period is significant because it covers the first full year that the rates established by the Commission in Docket No. 39896 became effective. If ETI had thought that the rates established by the Commission in Docket No. 39896 were insufficient to recover ETI's third party capacity costs, then ETI should have filed a PCRF application pursuant to the Commission's PCRF Rule and recovered those costs without the need to demonstrate special circumstances. And each year thereafter, ETI would file annual PCRF applications to reflect additional increases *or decreases* in third party capacity costs.

Q. DID ETI FILE A PCRF APPLICATION WHEN ETI HAD AN OPPORTUNITY?

A. No.

Q. HAVE YOU DETERMINED WHAT AMOUNT OF THIRD PARTY CAPACITY COSTS ETI COULD HAVE REQUESTED AS NOT RECOVERED IN THE FIRST YEAR RATES WERE EFFECTIVE FOLLOWING DOCKET NO. 39896?

A. Yes. ETI could have requested the recovery of $6.75 million of third party capacity costs. This potential PCRF recovery would recover all third party capacity costs incurred by ETI, not just the select two contracts ETI is requesting recovery of through special circumstances. Moreover, ETI would then make annual PCRF filings to reflect the annual under-recovery or over-recovery of third party capacity costs through base rates.

As I testified earlier, ETI's third party and affiliate capacity costs will decrease by approximately $9.1 million going forward. So if ETI had filed to recover third party capacity cost increases through a PCRF for the first year rates were in effect from Docket No. 39896, ETI would have to reflect the subsequent cost decreases through revenue credits to customers in subsequent PCRF applications.

Q. DOES ETI'S SPECIAL CIRCUMSTANCES REQUEST INCLUDE CAPACITY COSTS INCURRED PRIOR TO JULY 2012 THAT COULD NOT BE INCLUDED IN A PCRF APPLICATION?

A. Yes. ETI requests the recovery of Frontier capacity costs incurred between July 2011 and June 2012. The majority of those capacity costs would likely not fall within a historical 12 month cost-year that could have been requested in a PCRF application filed after the effective date of the PCRF Rule. Moreover, the base rates in effect at that time were established by the Commission in Docket No. 37744 based upon a black box settlement that did not establish a baseline level of capacity costs or establish other parameters that could be used in the PCRF formula.

Q. DOES THE FACT THAT ETI COULD NOT HAVE FILED A PCRF APPLICATION TO RECOVER CAPACITY COSTS INCURRED PRIOR TO JULY 2012 CHANGE YOUR OPINION AS TO WHETHER ETI SHOULD BE

GRANTED A SPECIAL CIRCUMSTANCE REQUEST TO RECOVER THOSE COSTS?

A. No. The base rates in effect at that time were approved by the Commission based upon the agreement of ETI and the parties to Docket No. 37744. The settlement involved a give and take that is typical of any settlement of base rate cases. The settlement was also a black box settlement where the level of third party capacity costs, or any capacity costs for that matter, was unspecified. As such, it is impossible to determine if the third party capacity costs embedded in rates were sufficient or if there were any offsetting decreases in other cost of service items that would have permitted ETI to recover additional revenues that could be used to offset any cost increases.

In my opinion, the Commission should not permit a utility that has agreed to the sufficiency of base rates to follow up the settlement with a case stating that the rates did not recover certain cost of service items such as capacity. If parties could not have certainty that a base rate settlement was definitive of the cost recovery contemplated by the base rate settlement, then parties may be reluctant to enter into such settlements.

Q. DOES ETI CLAIM THAT THE CARVILLE AND FRONTIER CAPACITY COSTS WERE UNRECOVERED THROUGH BASE RATES?

A. Yes. ETI witness Robert Cooper testifies that the base rates set in Docket No. 37744 and the current base rates set in Docket No. 39896 are insufficient to recover the Carville and Frontier capacity costs.[74]

Q. WHAT IS THE BASIS FOR MR. COOPER'S CLAIM?

A. Mr. Cooper's claim that the Carville and Frontier costs are not recovered through base rates is based on the fact that the Carville contract began after the test year in Docket No. 39896 and the Frontier contract began on May 1, 2011, two months prior to the test-year-end in Docket No. 39896.[75] Mr. Cooper asserts that because the Frontier 150 MW Step-up capacity costs were not recognized in Docket No. 37744 to set rates, the rates established by the Commission in Docket No. 37744 could not be sufficient to recover the Frontier capacity costs.[76] Mr. Cooper also asserts that because the Carville capacity costs were not incurred during the test year and only two months of the Frontier capacity costs were incurred in the test year used to set rates in Docket No. 39896, the base rates set by the Commission in Docket No. 39896 cannot be sufficient to recover the Carville capacity costs and the full amount of the Frontier 150 MW Step-up capacity costs.[77]

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[74] Direct Testimony of Robert Cooper at 28.

[75] Id., at 30-31.

[76] *Id.*

[77] *Id.*

Q. DOES MR. COOPER'S ANALYSIS TAKE INTO CONSIDERATION THE PARAMETERS APPROVED BY THE COMMISSION IN THE PCRF RULE FOR DETERMINING WHETHER BASE RATES ARE INSUFFICIENT TO RECOVER THIRD PARTY CAPACITY PURCHASES?

A. No, it does not. Mr. Cooper takes two third party purchase power capacity contracts in isolation and does not consider any other changes in the level of third party or affiliate capacity costs as would be done under the technical parameters and formula in the PCRF Rule. Mr. Cooper also does not offset any cost increases with the increased revenues from load growth as is required by the PCRF Rule.

Q. EVEN THOUGH MR. COOPER'S ANALYSIS DOES NOT COMPLY WITH THE PCRF RULE, DO YOU CONSIDER MR. COOPER'S ANALYSIS TO PROPERLY DETERMINE THE SUFFICIENCY OF RATES TO RECOVER CAPACITY COSTS UNDER OTHER ACCEPTED METHODS OF RATEMAKING ANALYSIS?

A. No. Claims that base rate costs are not recovered through base rates are generally not accepted to permit a utility to recover historical costs. Base rates are set on a prospective basis based upon a historical test year adjusted for known and measurable changes. Base rates are not set to recover past costs. There have been very limited exceptions to the base rate recovery model. And in those exceptions where historical costs have been permitted for recovery, there is typically an analysis as to whether the costs were otherwise recovered through base rates.