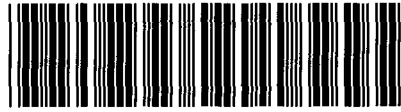

Control Number: 45570

Item Number: 285

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SOAH DOCKET NO. 473-16-2873.WS
PUC DOCKET NO. 45570

APPLICATION OF MONARCH UTILITIES I, L.P. TO CHANGE RATES FOR WATER AND SEWER SERVICE	§ § § § § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

THE STATE OF TEXAS

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DIRECT TESTIMONY OF

DEBI LOOCKERMAN

WATER UTILITY REGULATION

PUBLIC UTILITY COMMISSION OF TEXAS

August 24, 2016

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1

2 **I. INTRODUCTION OF WITNESS**

3 **Q. Please state your name and business address.**

4 A. Debi Loockerman, 1701 North Congress Avenue, Austin, Texas 78711.

5 **Q. By whom are you employed and in what capacity?**

6 A. I am employed by the Public Utility Commission of Texas (PUC or Commission) as the
7 director of water rates analysis in the Water Utilities Division.

8 **Q. What are your principal responsibilities?**

9 A. My responsibilities include managing the water and wastewater rates program and
10 accounting/finance personnel, analyzing rate applications appeals, reviewing annual
11 report filings, preparing written or oral testimony, making recommendations on
12 regulatory issues with respect to the financial regulation of water and sewer utilities, and
13 managing new rules and forms creation in the division for rate related matters. I also
14 review financial/managerial recommendations on certificate of convenience and necessity
15 applications and sale, merger, transfer applications.

16 **Q. Please state briefly your educational background and professional experience.**

17 A. I received a Bachelor of Business Administration degree with a major in accounting from
18 the University of Texas at Austin in 1984. I have worked in water and sewer rate
19 regulation for over 20 years in Texas. I am a Certified Public Accountant (CPA) licensed
20 in the State of Texas. I have accounting experience in public practice, industry and state
21 government. Attachment DL-1 is a copy of my resume.

1 **Q. Have you previously testified before the Commission?**

2 A. Yes. Attachment DL-2 is a list of my previous testimonies.

3 **II. PURPOSE OF TESTIMONY**

4 **Q. What is the purpose of your testimony in this proceeding?**

5 A. The purpose of my testimony is to present the Commission Staff's recommendations with
6 regard to Monarch Utilities I, LP's (Monarch) rate/tariff change request and associated
7 information provided therein with regard to the following issues: treatment and
8 determination of revenues held in abeyance; and treatment of the gain on sale by Monarch
9 of the City of Blue Mound (Blue Mound) and Midway public water system (PWS) assets.

10 **Q. What is the scope of your review?**

11 A. I reviewed the portions of the application relating to my testimony, the discovery
12 responses related to my testimony, and the pre-filed testimonies of Robert L. Kelly,
13 Charles W. Profilet, Jr. and Chris Ekrut.

14 **Q. Have you prepared any exhibits in connection with your testimony in this**
15 **proceeding?**

16 A. Yes, Exhibits DL-1 through DL-4.

17 **Q. Were these exhibits prepared by you or under your supervision?**

18 A. Yes.

19 **Q. On whose behalf are you testifying?**

20 A. I am testifying on behalf of the Commission Staff.

21 **III. SUMMARY OF RECOMMENDATIONS**

22 **Q. Please summarize your recommendations.**

23

24 A. I am recommending that:

1. There are no (zero) revenues held in abeyance by Monarch and thus, no recording or recovery of revenues held in abeyance should be allowed by Monarch.
2. The net gain resulting from the sale of Blue Mound's assets should be allocated 71.2% to ratepayers and 28.4% to shareholders.
3. The net gain resulting from the sale of Midway's assets should be allocated 76.6% to ratepayers and 23.4% to shareholders.
4. The net gain on the sales to be shared with ratepayers should be distributed to ratepayers through a rate rider over a one year period.
5. The rider for the sharing of the gain should be addressed in a future docket to be filed within one month of the final order date in this case.
6. I recommend the Commission order Monarch to coordinate with number-running staff to calculate the federal income tax effects, accumulated federal income tax effects, and the per connection dollar figure for the rider as a result of treatment of the gains in the future docket.

IV. REVENUES HELD IN ABEYANCE

Q. Did Monarch define revenues held in abeyance?

A. Not specifically. However, Monarch stated that 'This voluntary absorption of needed rate increases by Monarch's shareholder has benefited customers and has been called 'Revenue Held in Abeyance' in previous rate applications. Through the end of 2015, Monarch's cumulative Revenue Held in Abeyance benefit to customers is $46.8 million.'[1]

Q. What is the definition of "revenues held in abeyance"?

1 A. I reviewed the National Association of Regulatory Utility Commissioners'[1] (NARUC)
2 website and found no definition of this term. I also reviewed the glossary of *Principles of*
3 *Water Rates, Fees, and Charges, Manual of Water Supply Practices* (Manual M1) and
4 found no definition.

5 My understanding of Monarch's use of the term "revenue held in abeyance' in the
6 testimony is that it is comprised of the difference between revenues proposed to be
7 collected in Monarch's previous applications and the revenues produced by the stipulated
8 rates in the settlements.

9 However, if one dissects the term, 'revenues' would be recognized by Generally
10 Accepted Accounting Principles (GAAP) when they are, (a) realized or realizable; and (b)
11 earned. 'Abeyance' is also defined in the same dictionary as 'a condition of being
12 temporarily set aside'

13 By using the term "revenues held in abeyance' Monarch appears to claim that (1) $46.8
14 million has been realized or is realizable, (2) has been earned, and (3) has been
15 temporarily set aside.

16 **Q. Please explain your position with regard to your understanding of the term**
17 **"revenues held in abeyance" used by Monarch.**

18 A. The apparent presumption is false. First, Monarch's audited financial statements prepared
19 in accordance with GAAP for 2015 reflect no revenues held in abeyance or any
20 acknowledgement of an asset associated with revenues held in abeyance. Therefore, the
21 $46.8 discussed by Mr. Profilet and Mr. Kelly are not revenues because they have never
22 been realized, realizable or earned. In fact, one would expect that the only way they could

[1] Direct Testimony of Charles W. Profilet, Jr., p. 9, lines 11-14.

1 have been recorded on the balance sheet as an asset would be if an order previously
2 issued by the regulatory authority authorized them as revenues. There is no such order.[2]
3 Furthermore, there is no settlement agreement that supports any Monarch right to
4 property with regard to 'revenues held in abeyance. In other words, no revenues are
5 being held in abeyance by Monarch. Monarch is not expecting to receive any revenues
6 held in abeyance.[3] Lastly, there is no temporary halt to receiving any revenues. The
7 previous rates were set by order based on a settlement agreement with no temporary halt
8 to receiving any revenues mentioned in any order or settlement agreement.

9 **Q. What is your recommendation for the total amount of revenues held in abeyance by**
10 **Monarch?**

11 A. I recommend that the total revenues held in abeyance is zero.

12 **Q. What is your recommendation with regard to treatment of revenues held in**
13 **abeyance?**

14 A. I recommend that no amount be recorded as revenues held in abeyance for Monarch. I
15 recommend no recording of revenues and no recovery. This conclusion is consistent with
16 past rate case settlements, Monarch's audited financial statements, and Monarch's
17 assertions that Monarch is not requesting this amount.[4] Customers have received no
18 benefit from revenues held in abeyance, because revenues held in abeyance do not exist in
19 this case. Acknowledging revenues held in abeyance in this case would imply that past
20 settlements created a right to revenues that have not been collected. The settlements are

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[2] Attachment DL-4
[3] Attachment DL-5
[4] Attachment DL-5

1 silent on this issue. Thus, to incorporate revenues held in abeyance would be to practice
2 retroactive ratemaking.

3 **Q. Do you believe that there was a "voluntary absorption of needed rate increases by**
4 **Monarch's shareholder" in the amount of $46.8 million?**

5 A. No.

6 **Q. Why not?**

7 A. The previous Monarch cases were all resolved by agreed settlements. No rate base or cost
8 of service was ever established. Monarch's estimates of the $46.8 million are based on a
9 requested revenue requirement that was never established by Monarch as reasonable and
10 necessary. Expenses in the cost of service, rate base, and invested capital have not been
11 approved for Monarch in the settled cases. Therefore, I do not agree with Monarch's
12 claim that $46.8 million was "voluntarily" absorbed by the shareholders.

13 **V. TREATMENT OF GAIN ON BLUE MOUND AND MIDWAY SALES**

14 **Q. Please explain Monarch's requested treatment of the gain on the sale of the assets**
15 **associated with Blue Mound and Midway.**

16 A. According to Robert L. Kelly's testimony, Monarch is proposing that 100% of the gain
17 should be allocated to the shareholders. Mr. Kelly's testimony states that in *Public Utility*
18 *Commission of Texas v. Gulf States Utilities Company*, 809 S.W.2d 201 (Tex. 1991)
19 ("GSU Case"), the Supreme Court of Texas established nine principles that must be
20 weight in allocating gains on sales. Mr. Kelly generally addresses each 'criteria.'[5] The
21 main argument of Mr. Kelly to support the 100% allocation to shareholders appears to be
22 the existence of "revenues held in abeyance."

[5] Direct Testimony of Robert L. Kelly, p. 9-12

1 **Q. What is your recommendation regarding the regulatory treatment of the gain to be**
2 **recognized by Monarch?**
3 A. My recommendation is that the net gain on the sale of the Blue Mound assets should be
4 allocated 71.8% to the ratepayers and 28.2% to the shareholders. I further recommend
5 that the gain on the sale of the Midway assets be allocated 76.6% to the ratepayers and
6 23.4% to shareholders. The Commission should initially allocate the percentage of the
7 assets that have been depreciated to the ratepayers because this is the portion of the assets
8 that have 'paid' through depreciation expense. The remaining percentages should be
9 allocated equally between the ratepayers and shareholders. Table 1 reflects my
10 calculations.
11 **TABLE 1**

Allocation of Gains on Sale	Blue Mound	Customers	Share-holders	Midway	Customers	Share-holders
Original Cost of Assets	$2,801,825			$1,218,154		
Accumulated Depreciation (AD)	$1,210,573			$ 648,271		
Percentage of AD to Original Cost -100% allocation to ratepayers	43.2%	43.2%		53.2?	53.2?	
Net Book Value (NBV)	$1,591,252			$569,883		
Percentage of NBV to Original Cost-50%Allocated to Ratepayers/50? allocated to Shareholders	56.8%	28.4?	28.4%	46.8%	23.4?	23.4?
Total % recommendation-Blue Mound		**71.6%**	**28.4%**		**76.6%**	**23.4%**

12
13 **Q. Please summarize the rationale that leads you to this recommendation?**
14 **A.** The following is a summary of the main points that support my result.
15 1. The GSU Case that Monarch is relying on generally determined that the allocation
16 of gain should be determined by determining the burden of the assets and the risk

1 of loss associated with the assets, although that the case is based on a different set
2 of facts and circumstances from the present one.
3 2. The Commission should initially allocate the percentage of gain associated with
4 depreciation expense included in prior proposed costs of service because the
5 ratepayers have 'paid' for the assets through depreciation expense. The
6 Commission allocated the gain of un-depreciated property (land) 50% to
7 ratepayers and 50% to shareholders in the CenterPoint case, Docket No. 38339.[6] It
8 is illogical to assume that the Commission would award the ratepayers less in this
9 present case for depreciable property that they have partially paid for through
10 depreciation expense than it did in the CenterPoint case where ratepayers had paid
11 0% for the assets through depreciation expense. The percentage of assets sold in
12 this present case that are undepreciated can be likened to land that is not
13 depreciable property because Monarch will not recognize any depreciation from
14 the assets in the future. The Commission should follow its CenterPoint precedent
15 on this undepreciated portion of the assets sold by Monarch and allocate that
16 portion of the gain equally between ratepayers and shareholders.
17 3. Furthermore, the risk of increased rates in the future is born by the ratepayers who
18 continue to absorb increases to rates because of the loss in connection counts
19 associated with the sales. Monarch's ratepayers have clearly shared the financial
20 burden of the assets sold, and continue to be affected by the sale through higher
21 percentages of allocated expenses included in the cost of service. Although a
22 portion of the cost of service was affected by removing the related assets which

decreased depreciation, return, and taxes, the loss of connection count actually caused an increase in allocated expenses and ultimately in the total cost of service, according to Monarch's errata filing number 8 on June 2, 2016. Furthermore, the assets were included in previous cases with associated depreciation, maintenance, and tax expenses included in the costs of service.

4. One factor that the GSU Case stated could be considered when allocating the gain on sale of assets between ratepayers and shareholders is the financial condition of the utility. Monarch is facing financial pressure because of extensive improvements recently in process or completed. This supports allocation of a portion of the gain to the stockholders.

5. The recommended ratepayer/shareholder allocation is a reasonable sharing that acknowledges the fact that the assets sold are depreciable assets that were included in proposed rate base and cost of service calculations in prior filed cases, while also recognizing that there should be some incentive to negotiate reasonably for value received; and that Monarch's current financial condition should be considered.

Q. Why does the "voluntary absorption of needed rate increases" ("rates held in abeyance") not affect your recommendation?

A. Because I believe, based on my previous discussion, that the amount put forth by Monarch for the 'rates held in abeyance' is overstated and inaccurate. Furthermore, the amount is unrelated to the first Gulf State factor: the group that has borne the financial

[6] Attachment DL-3, *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates,* Docket 38339, Order at 29, FOF 139B.

1 burdens (e.g. depreciation, maintenance, taxes) of the assets sold' [7] Monarch has
2 repeatedly used this amount to assess the other Gulf State factors in Robert Kelly's
3 testimony. If there were a 'voluntary absorption of needed rate increases' it stemmed
4 from previous settled cases, not the sales transactions between Monarch, Blue Mound,
5 and Midway. The two issues are unrelated.

6 I have already stated that 'revenues held in abeyance' should not be used as a criterion
7 for making decisions in this case. The amount was calculated using unsubstantiated data.
8 The rates agreed upon by all parties in the past three rate cases for Monarch were
9 supported as reasonable by Monarch. Monarch's decision to settle the past three rate
10 cases does not support the fact that Monarch bore the financial burdens of the Blue
11 Mound assets sold. In fact, there is no document in this case that would indicate Blue
12 Mound assets and related expenses were not included in setting prior rates. Indeed, in this
13 case, Monarch filed corrections to its rate case to remove such expenses from its cost of
14 service according to Monarch's errata filing number 8 on June 2, 2016. Therefore, it is
15 reasonable to assume that the depreciation, maintenance, and taxes would have been
16 included in the costs of service for the prior rate cases and Monarch's customers would
17 have been responsible for such expenses through paying the rates. Furthermore, any
18 sharing of the gain between Monarch and its customers cannot be characterized as
19 'effectively penalizing Monarch for its efforts to avoid rate shock' because there is no
20 established relationship between the settlements, avoidance of rate shock, and the sale of
21 the Blue Mound assets. There were no conclusions in the settlement agreements that
22 Monarch settled to avoid rate shock.

[7] Direct Testimony, Robert Kelly, page 9.

1 **Q. Do you have any policy concerns regarding Monarch's arguments?**

2 A. Yes. Monarch's arguments regarding the reasonableness of its settled rates will tend to
3 discourage settlement. It is not in the public interest for Monarch to use its settlements at
4 rates lower than its proposed rates to justify allocating unrelated gains on sales of assets
5 to shareholders.

6 **Q. Does this conclude your direct testimony?**

7 A. Yes. I reserve the right to supplement this testimony during the course of the proceeding
8 as new evidence is presented.

ATTACHMENT DL-1

Monarch Utilities I, L.P. 1 to Change Rates for Water and Sewer Service

SOAH Docket No. 473-16-2873.WS

PUC Docket No. 45570

Debi Loockerman, CPA
Professional Experience

Director, Water Rates Analysis (5/1/15 to current)
Public Utility Commission of Texas

- Manage programs and activities related to water and sewer rate program. Oversee staff engaged in rulemaking projects and contest cases.
- Recommend changes to program area and develop procedures for new law and rule implementation.
- Perform highly advanced rate making, financial, and managerial work including reviews of rate and tariff change applications, rate appeals, and financial and managerial reviews of water and sewer utility providers.

Financial Examiner IV
Public Utility Commission of Texas (1/14-5/15)

Provided expert witness testimony for electric utility rate making proceedings.
Reviewed, analyze, and make recommendations on cost of service issues and rate treatment issues in electric rate proceedings.

- Provided guidance and knowledge for the transfer of water utility rate regulation from the TCEQ to the PUC.
- Managed rule making projects and revise forms for rate case submissions.

Auditor V – Financial Review and Rate Analysis
Texas Commission on Environmental Quality (6/10-12/13)

Reviewed, analyzed and prepared comprehensive reports of complex business plans and/or financial, managerial and technical capacity information for public water systems and retail public water or sewer utilities.

- Provided customer service and utility assistance for public water systems and retail public water or sewer utilities in developing business plans; financial, managerial, and technical information; and in following the stategies set forth in the plans.
- Assisted in the development of program policies, procedures, and rules for the review of complex business plans or financial and managerial information submitted by public water systems and/or retail public water or sewer utilities.
- Provided assistance, gave professional advice and/or review and process rate/tariff change applications submitted by utilities for approval.
- Assisted with staff training, staff development and coordination of work assignments regarding business plans and financial, managerial and technical review for public water systems and/or retail water or sewer utilities.

Provided expert oral and written testimony and present information on the financial and managerial position of utilities and retail public water and/or sewer systems
Participated in the capacity development program and prepare financial, managerial, and technical assessments for the Texas Water Development Borad's Drinking Water State Revolving Fund and Economically Distressed Areas Program.

Auditor V
Texas Commission on Environmental Quality (11/08 through 6/10)

- Reviewed and analyzed audited financial statements of Districts for regulatory compliance and preparation in accordance with generally accepted accounting principles.

Prepared and implemented procedures for audit processing.

- Special projects, including assistance with legislative questions and analysis in the districts arena.

Owner, Debi Loockerman CPA dba Debi Carlson CPA(7/97 through 6/08)

- Provided consulting services and expert witness testimony in the rate making arena.
  Implemented accounting systems, including utility billing systems for privately owned water systems in Texas.
- Reviewed and analyzed financial statements of water utility companies to determine internal control issues and sufficiency of accounting procedures and ratemaking procedures.
- Income tax and monthly accounting services.

B & D Environmental, Inc. (7/97 through 06/08)
Partner/Controller

Prepared and defended costs of service for clients through the regulatory process for privately owned utilities.

- Worked with clients to negotiate the regulatory process to successfully obtain rate increases.
- Provided expert witness testimony in several cases and assisted in negotiation settlements for rate cases throughout this period.
- Prepared internal financial statements and tax returns.
  Managed cash flow and all tax reporting requirements including payroll.

Senior Rate Analyst, Texas Natural Resource Conservation Commission (11/89 through 7/97)

- Analyzed rate filings by private and publicly owned utilities to determine the cost of providing retail and wholesale water and sewer service.
  Prepared written and oral expert witness testimonies on wholesale and retail water and sewer rate methodologies in administrative hearings proceedings.
- Assisted in mediating informal rate hearings using effective oral and written communication skills, and negotiated agreements. Most agreements included utility rate increases and improved utility service issues.
- Designed a regulatory accounting system for small public water and wastewater utilities to enhance uniformity in accounting, viability determination, and compliance with regulatory requirements.

Accounting Manager, Service Life and Casualty Insurance (11/87 through 8/89)

- Assisted the chief financial officer in the supervision of four staff members.
  Interviewed, selected and trained new personnel.
- Prepared reconciliations between cash accounts, payroll accounts, and pension plan accounts and the general ledger.
  Prepared month end adjusting entries and year end adjusting entries for general ledger.
  Prepared and analyzed internal financial statements under supervision of the chief financial officer.
- Reviewed annual regulatory filings.

Senior Accountant, Eugene McCartt, C.P.A. (3/85 through 11/87)

Prepared monthly financial statements for all write up clients.
Prepared individual, corporate, not for profit, and partnership tax returns.
Communicated extensively with clients during all phases of work.

Education

Bachelor of Business Administration issued from the University of Texas at Austin in 1984, major in Accounting.

ATTACHMENT DL-2

Monarch Utilities I, L.P. 1 to Change Rates for Water and Sewer Service

SOAH Docket No. 473-16-2873.WS

PUC Docket No. 45570

Attachment DL-2
PUC Docket 45570
SOAH Docket 473-16-2873.WS

Debi Loockerman CPA
Public Utility Commission of Texas (PUC)
List of Previous Testimonies and filings

Written Testimony

Docket	Company	Subject
PUC Docket 44809	Quadvest, LP	Cost of Service
PUC Docket 44657	Interim La Ventana	Financial/Managerial capability
SOAH 473-15-1556	Southwestern Public Service Company	Property tax
SOAH 473-14-3659	Lone Star Transmission	Support of Stipulation
SOAH 582-12-6250	BFE Water Company	Cost of Service
SOAH 582-08-2863	Lower Colorado River Authority	Cost of Service
SOAH 582-08-4353	Interim-La Ventana acquisition	Financial/Managerial ability
TCEQ 30077-R	Highsaw Water Corp	Cost of Service
TCEQ 30089-R	Technology/Hydraulics	Cost of Service
TCEQ 9152-A	City of Point Blank	Cost of Service
TCEQ 8819-R	Oakridge Water Co.	Cost of Service
TCEQ 9271-A	City of Lewisville,	Cost of Service
TCEQ 9300-W	Evant Water Supply Corp	Cost of Service
TCEQ 8496-W	City of Winters	Cost of Service
TCEQ 8479-R	Engel Utility Company	Cost of Service

Memoranda in Lieu of Testimony

PUC Docket	Company	Subject
42104	AEP Texas Central Company	Interim Wholesale Trans. Rate
42133	Sharyland Utilities	Interim Wholesale Trans. Rate
42134	Electric Transmission Texas	Interim Wholesale Trans. Rate
42181	Texas-New Mexico Power	Interim Wholesale Trans. Rate
42200	Cross Texas Transmission	Interim Wholesale Trans. Rate

Other testimony and applications

While affiliated with B & D Environmental, Inc. I prepared cost of service studies and revenue requirements for the following entities and submitted rate/tariff change applications, along with my partners, to the TCEQ or predecessor agencies:

Patrick C. King, Receiver for Lamar Water Supply Corp
Greenwood Water Corporation (written testimony)
Brighton Water Systems, Inc. dba Wise Service Company
Country Terrace Water Company, Inc.
Midway Water Utilities, Inc.
Cindy Riley
North Orange Water & Sewer, LLC (written testimony)
Tapatio Springs Services Company & Kendall County Utility Company
P & B Water Corporation
Decker Utilities (written testimony)
Bret W. Fenner, Receiver for Twin Creek Park Water System
Bret W. Fenner, Receiver for Bertram Woods Water System
Bret Fenner, Receiver for High Sierra Water System

ATTACHMENT DL-3

Monarch Utilities I, L.P. l to Change Rates for Water and Sewer Service

SOAH Docket No. 473-16-2873.WS

PUC Docket No. 45570

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PUC DOCKET NO. 38339
SOAH DOCKET NO. 473-10-5001

APPLICATION OF CENTERPOINT ELECTRIC DELIVERY COMPANY, LLC, FOR AUTHORITY TO CHANGE RATES	§ § § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

This Order addresses the application of CenterPoint Electric Delivery Company, LLC for authority to change its rates. On June 30, 2010, CenterPoint filed its application with the Public Utility Commission of Texas requesting authority to increase its transmission and distribution rates and to reconcile costs related to its advanced metering system (AMS) deployment. CenterPoint originally requested a total net increase of $110 million: $18 million represented the net increase associated with transmission service and $92 million associated with retail delivery service. CenterPoint requested a rate of return on investment of 9.0%, based on a proposed capital structure having 50-50 ratio of debt to equity; a 6.74% cost of debt; and a return on equity of 11.25%.

On December 3, 2010, the State Office of Administrative Hearings (SOAH) administrative law judges (ALJs) issued a proposal for decision in which they recommended an overall rate increase for CenterPoint of $21.483 million.[1] For the reasons discussed in this Order, the Commission adopts in part and rejects in part the proposal for decision, including findings of fact and conclusions of law, and determines that CenterPoint's appropriate system-wide adjusted rates will lead to a revenue increase of $14.65 million.[2]

[1] Proposal for Decision (PFD), Attachment ALJ-3 at 1, line 10, column 2 "Difference between ALJs' Rec. and CNP. current revenues." (Dec. 3, 2010).

[2] Revised Number Runs and Associated Workpapers, Attachment Comm-3 AFTER Postage Stamp Update, at 1, line 10, column 2 (Feb. 18, 2011).

I. Procedural History

On June 30, 2010, CenterPoint made two filings: (1) a petition and rate-filing package and (2) a motion requesting the Commission to bifurcate the legal, policy, and fact issues relating to CenterPoint's distribution cost recovery factor (DCRF) rider—an alternative ratemaking mechanism that was proposed in the rate-filing package. The motion requested that the Commission refrain from issuing an order referring this case to SOAH until the legal, policy, and fact issues were decided.

The Commission referred this case to SOAH on June 30, 2010. The SOAH ALJs issued an order on July 8, 2010 suspending the effective date of tariff changes and setting a prehearing conference.

The Commission issued on July 8, 2010 an order requesting briefing on legal and policy issues related to the DCRF rider. Parties filed briefs on July 19, 2010. The Commission issued a preliminary order on July 30, 2010 listing issues to be addressed and not to be addressed in this proceeding. The order identified CenterPoint's proposed DCRF rider as an issue not to be addressed in this proceeding and noted that the Commission and all other industry participants are working towards a DCRF rule that would apply uniformly to all utilities.[3]

The hearing on the merits convened before the SOAH ALJs on October 11, 2010 and continued until October 15, 2010. Parties filed post-hearing and reply briefs, and the record was closed. Commission Staff filed the workpapers for the ALJs' requested number runs on December 20, 2010. The proposal for decision (PFD) was filed on December 3, 2010, exceptions to the PFD were filed on December 20, 2010, and replies to exceptions were filed on January 5, 2011. The ALJs filed on January 13, 2011 a letter recommending corrections to the PFD.

The Commission considered the matter at two open meetings: January 20, 2010 and February 3, 2011. At the January 20, 2010 open meeting, CenterPoint agreed to extend the

[3] *Rulemaking Related to Recovery by Electric Utilities Distribution Costs*, Project No. 38298, Proposal for Publication of New § 25.243 as Approved at the June 11, 2010 Open Meeting (June 11, 2010).

jurisdictional deadline to provide the Commission sufficient time to consider the issues in this proceeding.[4]

At the February 3, 2011 open meeting, the Commission voted to sever parties' requests for recovery of rate-case expenses in this proceeding into a separate docket. On February 28, 2011, a Commission ALJ issued Order No. 17 severing rate-case expenses associated with this proceeding into a new proceeding.[5]

New finding of fact 30A is added to reflect CenterPoint's agreement to extend the jurisdictional deadline and new finding of fact 30B is added to reflect severance of rate-case expenses.

II. Discussion

A. Uncertain Tax Positions

Financial Accounting Standards Board Interpretation No. 48 (FIN 48) requires CenterPoint to identify uncertain tax positions (UTPs) that may have to be paid to a taxing authority. This FIN-48 liability must, for financial reporting purposes, be excluded from accumulated deferred federal income taxes (ADFIT) and accrue interest and penalties.[6] The ALJs' recommended that CenterPoint's FIN-48 liabilities, in the amount of $164,314,000, be added to CenterPoint's accumulated deferred federal income taxes (ADFIT) and reduce CenterPoint's rate base by that amount.[7] The Commission agrees with the ALJs recommendation, but also agrees with CenterPoint that it should be able to track the amount it actually has to pay on UTPs and recover a return on that amount.

The Commission has previously determined that a FIN-48 liability should be included in ADFIT and the ALJs recommended the same treatment in this case.[8] The ALJs found that the

[4] Open Meeting Tr. at 174 (Jan. 20, 2010).

[5] Order No. 17 (Feb 28, 2011), memorializing Commission decision to sever rate-case expenses into new Docket 39127.

[6] PFD at 11.

[7] *Id.* at 16.

[8] *Id.* at 15-16.

new tax schedule UTP—on which companies must describe, list, and rank each UTP—only marginally increased the likelihood of an audit by the Internal Revenue Service. The Commission is persuaded that the release of the IRS's new schedule UTP to account for UTPs will provide the IRS auditors sufficient information to quickly determine which UTPs are of a magnitude worth investigating. Therefore, an IRS audit is more likely to occur on some UTPs. The Commission further agrees with CenterPoint that if an IRS audit of a FIN-48 UTP results in an unfavorable outcome, CenterPoint will not be able to earn a return on the amount paid to the IRS until CenterPoint's next rate case.

Accordingly, the Commission authorizes CenterPoint to establish a deferred tax account tracker—Rider DTA—to recover on a *prospective* basis an after-tax return of 8.21% on the amounts paid to the IRS that result from an unfavorable FIN-48 UTP audit. The Rider DTA will track unfavorable IRS FIN-48 rulings and the return will be applied prospectively to FIN-48 amounts disallowed by an IRS audit after such amounts are actually paid. If CenterPoint prevails in an appeal of an unfavorable FIN-48 UTP decision, then any amounts collected under Rider DTA related to that overturned decision should be credited back to ratepayers.

Finding of fact 45 is deleted and new findings of fact 45A to 45F are added to reflect the Commission's decision on this issue.

B. Rate Base – Cost of Debt Return on Equity

The ALJs recommended that CenterPoint's return on equity should be set at 10.41%. The Commission disagrees and finds that, based on CenterPoint's proposed capital structure and financial risk, a 10% return on equity will permit CenterPoint a reasonable opportunity to earn a return on its invested capital that is used and useful in providing service to the public in excess of CenterPoint's reasonable and necessary operating expenses. Findings of fact 70, 71, 72, 73 and 75 are deleted and new findings of fact 70A, 71A, 72A, 73A, and 75A are added to give effect to the Commission's decision on this point.

C. Gain on the Sale of Land

CenterPoint sold a number of properties over the last few years and recorded the gain on those sales for the benefit of shareholders. The ALJs agreed with CenterPoint that—because it

does not recover depreciation on land, only two sales occurred during the test year, and there is no authority to include transactions outside of the test year—its proposed treatment was appropriate.[9]

The Commission disagrees with the ALJs, in part, and reverses the ALJs' recommendation to the extent it applies to the gains from the sale of land that occurred within the test year. Ratepayers pay a return on the investment and expenses associated with land, such as taxes. The Commission concludes that customers should benefit through a 50% share of the gain on any land sold during the test year.

Finding of fact 137 is modified, finding of fact 139 is deleted, and new findings of fact 139A and 139B are added to reflect the Commission's decision.

D. Gross-Up of Consolidated Tax Savings Adjustment

PURA § 36.060 requires CenterPoint to calculate a consolidated tax savings adjustment (CTSA) and the Commission agrees with the ALJs that the CTSA in this case is $9,800,000. The ALJs also recommend that the CTSA be grossed-up to $15,076,923. The Commission disagrees with that recommendation although it notes that the application of a gross up to CTSAs has not been consistently applied.

In Docket No. 14965,[10] the Commission acknowledged that it had struggled with the appropriate treatment of CTSAs, and viewed that docket as an opportunity to take a fresh look at the issue.[11] The current methodology to calculate CTSAs—sometimes referred to as the interest shield method or the interest credit method—was developed by the Commission in that docket. The method was not a rate-base approach, but resulted in an amount that would be a credit against operating expenses.[12] In that docket, the Commission squarely addressed the gross-up issue and determined that the use of a gross-up factor was not appropriate.[13] The final order in

[9] *Id.* at 111-12.

[10] *Application of Central Power and Light Company for Authority to Change Rates*, Docket No. 14965, Second Order Rehearing at 7 (Oct. 16, 1997).

[11] Open Meeting Tr. At 76, 78-80, 84 (Mar. 5, 1997).

[12] Open Meeting Tr. at 71-87 (Mar. 18, 1997).

[13] Open Meeting Tr. at 49-51 (June 18, 1997).

that docket demonstrates that the approximately $6.1 million CTSA was not grossed up.[14] That order was overturned, but on remand, the matter settled leaving the Commission's order unchanged.

Less than a year later, in Docket No. 16705,[15] the ALJs recommended including a CTSA based on Commission Staff's methodology, but made no mention of a gross-up factor.[16] The Commission accepted that recommendation and also made no mention of a gross-up factor. Commission Staff testified that its method to calculate the CTSA 'conform[ed] to the Commission's decision in Docket No. 14965, except that a different time period was used.[17] There was no mention of a gross-up factor in this testimony and the supporting calculations of the amount of the CTSA ($877,000) do not include a gross-up factor.[18] However, there is testimony that a CTSA decreases the return[19] and in the accompanying tax schedule to the Commission's order, the CTSA was included not only to directly reduce the tax expense, but to also reduce the amount of the return component on which the tax expense was computed.[20] This amounted to a gross up of the CTSA. This deviation from Docket No. 14965 is not mentioned in any pleading, testimony, the PFD, or the Commission's order. The Commission's order is also silent about a gross-up factor; the gross up is shown only on Schedule V to the order. It is difficult to reconcile that deviation given the absence in the record of any indication outside of the single line on Schedule V, the testimony that the methodology conformed to Docket No. 14965, and the Commission's instruction to Entergy to calculate a CTSA using the method established in Docket No. 14965,[21] which did not gross up the CTSA.

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[14] Docket No.14965, Second Order on Rehearing, Schedule V.

[15] *Application of Entergy Texas for Approval of its Transition to Competition Plan and the Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors, and to Recovery a Surcharge for Under Recovered Fuel Cost*, Docket No. 16705, Order on Rehearing, (Sept. 4, 1998).

[16] *Id.* at 300, 303 (citing to GC [Commission Staff] Ex. 44, Errata Attachment CR-TAX-9).

[17] Docket No. 16705. Direct Testimony of Candice Romines, GC [Commission Staff] Ex. 44 at 18.

[18] Docket No. 16705, GC [Commission Staff] Ex. 44, Errata Attachment CR-TAX-9).

[19] Docket No. 16705. Direct Testimony of Candice Romines, GC [Commission Staff] Ex. 44 at 19.

[20] *Id.* Schedule V.

[21] *Id.* Order on Rehearing, Finding of Fact No. 35 (Sept. 4, 1998).

Nevertheless, a gross up of CTSAs has been authorized in subsequent proceedings. In the Reliant UCOS case, the ALJ recommended against including a CTSA given the nature of that case.[22] The Commission rejected that recommendation and approved a CTSA with a gross up,[23] but just mentioned the gross up in passing during its deliberation,[24] and didn't mention gross up in its order.[25] In Docket No. 28840[26] the gross-up issue was remanded to SOAH and was fully vetted. The ALJ there recommended a CTSA and that it be grossed up. The ALJ relied on the Commission's decision to gross up the CTSA in Docket Nos. 16705 and 22355[27] and concluded that a gross up must be made to reflect the proper revenue requirement of the adjustment.'[28] In its order, the Commission found that because a CTSA 'is a direct adjustment to federal income tax, it must be grossed up to reflect the full effect on revenue requirement of the adjustment,'[29] and provided both the CTSA amount and the grossed-up amount. In Docket No. 33309,[30] the Commission approved a CTSA with a gross up, but the gross up is barely mentioned in either the PFD[31] or the Commission's order.[32] Nearly a dozen other rate cases that settled do not mention a CTSA or a gross up, but in any event the methodologies used in a settled case have not been adopted by the Commission.

The disagreements on this issue seem to focus on whether the CTSA should be treated as an adjustment to taxes so that a gross up is appropriate, or whether it should be treated as an interest expense so that a gross up is not appropriate. The Commission does not find in this record an adequate basis upon which to apply a gross-up factor to CenterPoint's CTSA. The

[22] Docket No. 22355, PFD at 44 (Feb. 7, 2001).

[23] Docket No. 22355, Order at 58, 124, Findings of Fact Nos. 64-65B.

[24] Open Meeting Tr. at 335-47 (Apr. 25, 2001).

[25] Docket No. 22355, Order at 58, 124, Findings of Fact Nos. 64-65B.

[26] *Application of AEP Texas Central Company for Authority to Change Rates,* Docket No. 28840, Findings of Fact Nos. 194, R7, R8 (Aug. 15, 2005).

[27] Docket No. 22840, PFD on Remand at 10 (Nov. 16, 2004).

[28] *Id.*

[29] 28840, Order at 39, Findings of Fact Nos. R7, R8.

[30] *Application of AEP Central for Authority to Change Rates,* Docket No. 33309, Order on Remand, Findings of Fact Nos. 119 and 120 (Mar. 4, 2008).

[31] Docket No. 33309, PFD at 150-54 (Aug. 30, 2007).

[32] Docket No. 33309, Order on Rehearing at 16, Findings of Fact Nos. 119, 120 (Mar. 4, 2008).

Commission's original intent when it developed this methodology was to not gross up the CTSA, but to treat it as an offset against expenses. That is, it was not to be treated as either an interest expense or a direct adjustment to income taxes, rather it was a statutorily mandated adjustment made for rate-making purposes that should reduce expenses and should not be grossed up. While perhaps not perfect, the method adequately determines a utility's fair share of savings resulting from a consolidated return. The Commission agrees that not grossing up the CTSA will diminish the revenue impact, but it does not agree that the intended effect is not achieved.[33] Therefore, the Commission reverses the ALJs, returns to the origin methodology, and finds it is inappropriate to gross up CenterPoint's CTSA; the amount of the CTSA should not reduce the taxable portion of rate base.

To reflect the Commission's decisions regarding the gross up of the CTSA, finding of fact 145 is modified, finding of fact 146 is deleted, and new findings of fact 146A and 146B and new conclusion of law 16A are added.

E. Medicare Part D Subsidy Expense

The Medicare Prescription Drug Improvement and Modernization Act of 2003 expanded Medicare to include prescription drug benefits for retirees equivalent to Medicare Part D benefits. This Act also provides for a 28% non-taxable subsidy for an employer's cost for providing prescription drugs to its retirees and this subsidy did not diminish the tax deductibility of the subsidized prescription drug benefits paid by CenterPoint.[34] The Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010 will eliminate the non-taxable status of the subsidy beginning January 1, 2013.[35] The actual amounts of the Medicare Part D subsidy received prior to January 1, 2013 will continue to be nontaxable, while amounts received during 2013 and beyond will effectively become taxable.[36] Consequently, CenterPoint will experience a Medicare Part D subsidy expense increase January 1, 2013. The

[33] PFD at 126.

[34] *Id.* at 47.

[35] Direct Testimony of Alan Felsenthal, CEHE Ex. 26 at 47.

[36] *Id.*

ALJs recommend that CenterPoint's proposed increase of $6,520,000 to its test-year income tax expense to account for the increase to its tax expenses be approved.

GCCC, OPC and Staff argue that the changes to CenterPoint's Medicare Part D subsidy expense that will occur after December 31, 2012 are too far in the future to be included in the rates set in this proceeding. The Commission agrees. The termination date of the subsidy is December 31, 2012, nearly two years in the future. It is not in the public interest to approve expenses that will be incurred that far in the future in the rates set in this proceeding. The Commission rejects the ALJs' recommendation on this point.

Findings of fact 157 and 158 are deleted and new finding of fact 157A is added to reflect the Commission's decision on this point.

F. Medicare Part D Subsidy- ADFIT

CenterPoint proposed to amortize a $9.3 million (grossed up) ADFIT and income-tax-related regulatory asset over a three-year period to account for a Medicare Part D subsidy receivable as of December 31, 2009.[37] The receivable was reduced by the estimated Medicare Part D subsidy amounts that will be received in 2010, 2011 and 2012. The ALJs recommend the Commission approve and include CenterPoint's proposed three-year amortization in CenterPoint's rates set in this proceeding. The ALJs found that CenterPoint's proposed recovery of this regulatory asset more closely matches the recovery of the increased tax expense with the ratepayers who received the benefit of the nontaxable Medicare Part D subsidy in prior year and favors intergenerational equity.[38]

The Commission rejects the ALJs' recommendation on this point and does not allow recovery of the three-year amortization of the $9.3 million regulatory asset in the rates set in this proceeding. As with CenterPoint's proposal to increase its income tax expense to account for this future change, the health care legislation underlying CenterPoint's proposal to amortize this regulatory asset will not be effective until January 1, 2013, a change too far into the future to be included in the rates set in this proceeding. However, the Commission authorizes CenterPoint to

[37] PFD at 131-32.

[38] *Id.* at 136.

continue to monitor and accrue the difference between what their rates assume the Medicare Part B subsidy tax expense would be and the reality of what CenterPoint is required to pay as a regulatory asset to be addressed in CenterPoint's next rate case.[39]

Findings of fact 64 and 159 are deleted and new finding of fact 159A is added to reflect the Commission's decision.

G. Classification of Transformer Investment

The ALJs recommended revising the classification of transformer-investment costs from 100% demand related as proposed by CenterPoint to a classification of 18% energy related and 82% demand related. This recommendation is based on GCCC's recommendation that investment costs for transformers have been and will be incurred to reduce customers' wholesale energy costs and the benefits of such investment should reflect less energy use. Therefore, energy reductions should be classified on an energy basis.[40] The ALJs' recommendation is based on their apparent misunderstanding that GCCC's position was undisputed.[41] The record reflects that TIEC and CenterPoint did dispute GCCC's recommendation. TIEC's rate design witness filed cross-rebuttal testimony that addressed at length why GCCC's proposal should be rejected.[42] CenterPoint's rate design expert testified that CenterPoint has already assigned non-minimum plant transformer investment based on a study utilizing energy usage by the rate classes using the transformers.[43] The Commission finds that CenterPoint's proposal appropriately assigns these costs.

New finding of fact 170A is added to reflect the Commission's decision.

H. Rate Case Expenses

The ALJs recommended approval of certain actual and estimated rate-case expenses incurred in this proceeding by CenterPoint, COH, GCCC and TCUC. Additionally, on

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[39] Open Meeting Tr. 154-156 (Feb 3, 2011).

[40] Direct Testimony of Clarence Johnson, GCCC Ex. 2 at 27-31.

[41] PFD at 148.

[42] Cross Rebuttal Testimony of Jeffrey Pollock, TIEC Ex. 3 at 13-16.

[43] Rebuttal Testimony of Mathew Troxle, CenterPoint Ex. 61 at 51.

January 6, 2011, Commission Staff, TCUC, GCCC, and COH/HCOC filed a joint motion requesting approval of an unopposed stipulation and settlement agreement of rate-case expenses incurred in this proceeding. The Commission concludes that all rate-case expense issues should be severed from this proceeding and parties should seek recovery of rate-case expenses incurred in this proceeding in a separate docket.[44]

To give effect to the Commission's decision regarding rate-case expenses, findings of fact 246, 247, 248, 249 and 250 are deleted and new finding of fact 246A is added.

I. Municipal Franchise Fees

Commission Staff sought a $24.1 million reduction to CenterPoint's requested $138.6 million municipal franchise-fee expense because it does not meet the requirements of Tax Code § 182.025 or PURA § 33.008(b).[45] They also asserted that amounts in excess of a franchise fee calculated under PURA § 33.008(b) can only be recovered if they are paid in exchange for additional benefits that must be explicitly identified and quantified in the franchise ordinance.[46] The ALJs rejected Commission Staff's arguments and relied on PURA § 33.008(f) that allows, on expiration of a franchise agreement existing on September 1, 1999, utilities and municipalities to agree to a different level of compensation.[47] Further, the ALJs concluded that under PURA § 33.008(c) such agreed-to amounts are reasonable and necessary operating expenses of the utility.[48] The ALJs specifically noted that "the increase in franchise fees in this case is the result of negotiations between cities and [CenterPoint] on *expiration of the previously existing franchise fees.*"[49] Because the ALJs concluded that the franchise fees were appropriately established under PURA, they are a reasonable and necessary operating expense.

The Commission agrees with the ALJs. This case is different than the recent Oncor rate case in which the Commission disallowed a portion of Oncor's franchise-fee expense. In that

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[44] Open Meeting Tr. 75-78 (Feb. 3, 2011).

[45] PFD at 138.

[46] *Id.* at 141.

[47] *Id.* at 139-40.

[48] *Id.* at 140.

[49] *Id.* at 142 (emphasis added).

case, there were no findings that a franchise fee had expired, and Oncor did not challenge the lack of such a finding in its motions for rehearing. Thus, it did not show that it was entitled to rely on PURA § 33.008(f) and was limited to the formula in PURA § 33.008(b). In this case, CenterPoint brought forth evidence to support the ALJs' finding that existing franchise fees had expired, that PURA § 33.008(f) was the applicable provision, and that CenterPoint's franchise fees were reasonable and necessary.[50]

The Commission adds new finding of fact 167A to properly reflect this decision.

J. Number-Running Issues

On February 7, 2011, Commission Advising and Docket Management (CADM) filed a memorandum in this proceeding requesting that Commission Staff update the number running schedules to reflect the Commission's decisions. Commission Staff filed updated number-running schedules on February 18, 2011 that included Commission-ordered changes to the ALJs' PFD and also included an update to the ERCOT postage-stamp rate due to increasing the transmission service provider (TSP) access fees that were approved by the Commission after CenterPoint filed its application.

Findings of fact 76 through 80 and 171 are modified to reflect amounts produced in the new number runs.

The Commission adopts the following findings of fact and conclusions of law:

III. Findings of Fact

Procedural History

1. CenterPoint Energy Houston Electric, LLC is an investor-owned electric utility within the Electric Reliability Council of Texas (ERCOT) system.

2. CenterPoint is the legal entity that includes the regulated transmission and distribution utility (TDU), various true-up items related to competition transition charge recovery, three transition bond subsidiaries, and one storm restoration transition bond subsidiary.

[50] Direct Testimony of Judy Liu, CEHE Ex. 15 at 19-21; Rebuttal Testimony of Monty Akers, COH/HCOC Ex. 8 at 5-6; Cross-rebuttal Testimony of Lane Kollen, GCCC Ex. 3 at 7.

3. CenterPoint provides transmission and distribution (T&D) electric services in a roughly 5,000-square-mile territory of the southeast coastal region of Texas, including the Houston area. CenterPoint delivers electricity to over two million meters in 95 cities in Texas.

4. As part of the unbundled cost of service (UCOS) hearing in 2001, CenterPoint's cost of service was separated for accounting purposes between its transmission and distribution functions, and its rates were set among various classifications.

5. Pursuant to the settlement agreement reached as part of its 2006 rate case in *Petition by Commission Staff for a Review of the Rates of CenterPoint Energy Houston Electric, LLC Pursuant to PURA § 36.151*, Docket No. 32093 (Sept. 5, 2006), CenterPoint filed a 2009 earnings monitoring report (EMR) in March 2010 for review by the Commission Staff, the City of Houston, and the Gulf Coast Coalition of Cities (GCCC).

6. The 2009 EMR showed that the CenterPoint earned a weather-adjusted return on equity of 9.81%. The 2009 EMR showed that CenterPoint earned a non-weather-adjusted return on equity of 11.13%.

7. On June 30, 2010, CenterPoint filed its application with the Commission for authority to increase its T&D rates and a reconciliation of costs incurred related to its advanced metering-system (AMS) deployment.

8. CenterPoint filed this application at the directive of Commission Staff, the City of Houston, and GCCC, who chose to exercise their right under the order in Docket No. 32093 to require CenterPoint to initiate a general rate case.

9. Under CenterPoint's proposed rates, retail distribution service revenues would increase by approximately $92 million, and transmission revenues would increase by approximately $18 million.

10. CenterPoint's application was served on Commission Staff and the Office of Public Utility Counsel (OPC) on June 30, 2010.

11. On September 16, 2010, CenterPoint filed an affidavit attesting to the completion of the publication of notice as required by P.U.C. Subst. R. 22.51(a)(1).

12. CenterPoint served a copy of its statement of intent to each municipality within CenterPoint's service area and a copy of its petition to each municipality within CenterPoint's service area with original jurisdiction.

13. CenterPoint timely served by mail notice of the application to each of the ERCOT wholesale transmission customers on the service list in Commission Staff's Application to Set 2010 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas, Docket No. 37680 (Apr. 16, 2010).

14. CenterPoint timely served notice by mail of the application to each retail electric provider listed on the Commission's website as of the date on which notice was sent.

15. CenterPoint timely served notice by mail of the application to each party in *Application of CenterPoint Energy Houston Electric, LLC for Approval of Deployment Plan and Request for Surcharge for an Advanced Metering System*, Docket No. 35639 (Dec. 22, 2008).

16. CenterPoint timely served notice and a copy of the application and rate-filing package to each party in *Petition by Commission Staff for a Review of the Rates of CenterPoint Energy Houston Electric, LLC Pursuant to PURA § 36.151*, Docket No. 32093 (Sept. 5, 2006), the CenterPoint's last general rate case.

17. The Commission referred this proceeding to SOAH on June 30, 2010.

18. The following entities were granted intervenor status in this case: the City of Houston and the Houston Coalition of Cities (COH/HCOC); GCCC; Texas Coast Utilities Coalition (TCUC); Texas Industrial Energy Consumers (TIEC); State of Texas; OPC; Alliance for Retail Markets (ARM); Reliant Energy Retail Services, LLC; TXU Energy Retail Company LLC; Texas Energy Association for Marketers (TEAM); Direct Energy; Texas Legal Services Center and Texas Ratepayers' Organization to Save Energy (TLSC/Texas ROSE), and Oncor Electric Delivery Company LLC.

19. On June 30, 2010, CenterPoint filed a motion to bifurcate issues related to its requested alternative ratemaking mechanism, the rider distribution cost recovery factor (DCRF), for an initial, Commissioner-held hearing.

20. On July 8, 2010, the Commission issued an order requesting briefing on threshold legal or policy issues on whether the Commission should consider CenterPoint's proposed rider DCRF as an alternative ratemaking mechanism, and if so, whether the Commission should bifurcate the rider DCRF issues for an initial, Commission-held hearing on the merits. CenterPoint, the State of Texas, TCUC, OPUC, GCCC, TIEC, and ARM filed briefs.

21. On July 30, 2010, the Commission issued its preliminary order setting forth 37 issues to be addressed in this proceeding. The Order stated that the following issues would not be addressed in this proceeding: whether to permit a lost revenue adjustment through an energy-efficiency cost recovery factor (EECRF), whether CenterPoint may include money spent pursuant to the settlement in Docket No. 32093 in its calculation of its performance bonus, and whether CenterPoint should be authorized to implement a DCRF.

22. CenterPoint corrected the public notice to be published in the Houston Chronicle pursuant to its errata filed on August 9, 2010.

23. Once a week for four consecutive weeks, CenterPoint provided notice by publication using the corrected public notice of the proposed rate change in the Houston Chronicle, a newspaper having general circulation in each county in CenterPoint's service territory.

24. Subsequent to its June 30 filing, CenterPoint timely filed appeals with the Commission of the municipal ordinances denying the Company's requested rate change.

25. The Commission consolidated all of CenterPoint's appeals from municipal rate ordinances denying the rate request for determination in this proceeding.

26. On October 12, 2010 and November 12, 2010, CenterPoint timely filed additional appeals with the Commission of the rate ordinances of the municipalities within its service territory, and the appeals and the request to consolidate were granted.

27. CenterPoint's application is based on a test year ended December 31, 2009.

28. The hearing on the merits began on October 11, 2010, and lasted five hearing days, concluding on October 15, 2010.

29. The record closed on October 29, 2010, with the filing of reply briefs by the parties.

30. Consistent with the Public Utility Regulatory Act (PURA), CenterPoint's proposed effective date for the proposed rates is no later than 185 days from the initial filing date of June 30, 2010.

30A. At the January 20, 2010 open meeting CenterPoint agreed to extend the jurisdictional deadline to provide the Commission sufficient time to consider the issues in this proceeding.

Rate Base

31. CenterPoint's total capital investment in transmission and substation facilities of $651.6 million incurred between January 1, 2003, and December 31, 2009, is used and useful in providing service to the public and reasonable and necessary.

32. CenterPoint's investment of $802.5 million in distribution plant additions, including investments from January 1, 2006 through December 31, 2009 is used and useful in providing service to the public and is reasonable and necessary.

33. CenterPoint's $3.4 million of post-test-year adjustments for the cost of meeting new Department of Energy (DOE) efficiency requirements that became effective January 1, 2010 is reasonable and necessary.

34. CenterPoint properly made an adjustment to the test year costs for $52.6 million in AMS capital costs incurred from January 1, 2010 through March 31, 2010, consistent with the Commission's order in *Application of CenterPoint Energy Houston Electric, LLC for Approval of Deployment Plan and Request for Surcharge for an Advanced Metering System*, Docket No. 35639 (Dec. 22, 2008).

35. Before the adoption of Financial Accounting Standards Board (FASB) Interpretation No. 48 (FIN 48), companies required to issue financial statements in accordance with generally accepted accounting principles (GAAP) lacked specific guidance about how to treat uncertain tax positions (UTPs) for financial reporting purposes.

36. For UTPs that relate only to a question of when a tax deduction may be claimed, FIN 48 requires a company to measure the probable tax benefit that it will recognize for the tax

position and then record for financial reporting purposes the largest amount of tax benefit that is more likely than not to be realized upon settlement with the taxing authority, assuming the authority's full knowledge of all relevant facts and law.

37. The portion of the UTP that would be less likely than not to be realized upon settlement with the taxing authority is recorded as a FIN 48 liability and excluded from ADFIT for financial reporting purposes.

38. FIN 48 is designed to achieve an accurate and objective assessment of the ultimate treatment of a taxpayer's UTPs.

39. FIN 48 requires the accrual of interest and penalties (if appropriate) on the amounts recorded as FIN 48 liabilities beginning in the first period the interest would accrue under the relevant tax law, in the case of interest, or when the tax position is taken on a tax return, in the case of penalties.

40. ADFIT liabilities represent cost-free capital and, accordingly, are deducted from rate base.

41. FIN 48 liabilities represent cost-free capital and should be deducted from rate base.

42. FIN 48 was issued in June 2006 and adopted by CenterPoint in 2007.

43. While CenterPoint is responsible for carefully analyzing its tax positions and recording appropriate adjustments for any UTPs based on the requirements of FIN 48, CenterPoint's independent external auditors examine the UTP liabilities as part of their annual financial statement audit and they review the UTP liabilities on a quarterly basis in connection with CenterPoint's Securities and Exchange Commission quarterly reporting responsibilities.

44. The IRS has finalized schedule UTP pursuant to which all corporations with assets in excess of $100 million are required to (i) provide the primary Internal Revenue Code sections relating to each UTP. (ii) indicate whether each UTP relates to temporary or permanent differences, (iii) rank their UTPs from highest to lowest based on size, and (iv) provide a concise description of each UTP including information that reasonably can

be expected to apprise the IRS of the identity of the tax position and the nature of the issue.

45. [DELETED]

45A. Schedule UTP will increase the likelihood that CenterPoint's UTP will become IRS audit issues.

45B. Unfavorable outcomes of IRS audits of a CenterPoint's UTPs will result in CenterPoint paying taxes to the IRS.

45C. Amounts paid to the IRS that result from an unfavorable IRS audit do not represent cost-free capital.

45D. CenterPoint's deferred tax-account tracker rider (Rider DTA) provides CenterPoint with a method of prospectively tracking amounts paid to the IRS that result from an unfavorable FIN-48 UTP audit that no longer represent a source of cost free capital.

45E. Amounts paid to the IRS as a result of an unfavorable FIN-48 UTP audit should earn an 8.21% after-tax return on investment.

45F. If CenterPoint prevails on an appeal of an unfavorable FIN-48 UTP decision, then amounts collected under Rider DTA related to that decision should be credited back to ratepayers.

46. CenterPoint properly included in its ADFIT balance ADFIT on the PURA § 36.065 pension-and-other-post-employment-benefits regulatory asset.

47. Investor-owned electric utilities may include a reasonable allowance for cash working capital (CWC) in rate base as determined by a lead-lag study conducted in accordance with the Commission's rules.

48. CWC represents the amount of working capital, not specifically addressed in other rate base items, that is necessary to fund the gap between the time expenditures are made and the time corresponding revenues are received.

49. The lead-lag study conducted by the Company considered the actual operations of CenterPoint, adjusted for known and measurable changes, and is consistent with P.U.C. Subst. R. 25.231(c)(2)(B)(iii).

50. A 48.50-day Texas state franchise tax expense lag is reasonable and accurate.

51. A 45.21-day affiliate operations and maintenance expense lead is reasonable and accurate.

52. A 254.30 day employee bonus expense lead is reasonable and accurate.

53. CenterPoint properly included in its rate base $68.4 million as the cost of materials and supplies.

54. CenterPoint's total electric plant in service (EPIS) for the test year was $7.231 billion less accumulated depreciation of $2.987 billion, for a net EPIS of $4.244 billion.

55. CenterPoint properly included in EPIS storm restoration costs, related to Hurricane Ike based on the findings in *Application of CenterPoint Energy Houston Electric, LLC, for Determination of Hurricane Restoration Costs*, Docket No. 36918 (Aug. 14, 2009) and properly calculated carrying costs related and in addition to the storm restoration costs, through September 1, 2010.

56. Commission precedent authorizes inclusion of plant held for future use (PHFU) in rate base when the utility has a definitive plan to put the property into service within the next ten years. CenterPoint's request for PHFU meets the Commission's standard for inclusion in rate base and should be approved.

57. CenterPoint's total electric PHFU is $44.04 million, but only $41,257,135 of that amount relates to property CenterPoint expects to be used and useful in the next ten years.

58. CenterPoint properly included $10.1 million in rate base for the total injuries and damages reserve.

59. CenterPoint's prepayments of $4.4 million are reasonable and should be included in its rate base.

60. CenterPoint's PURA § 36.065(b) reserve account in the amount of $58.7 million for deferred expenses for pension and other-post-employment-benefits (OPEB) was properly determined in accordance with actuarial or other similar studies, and it is reasonable, necessary, and recoverable as part of CenterPoint's rate base in accordance with PURA § 36.065.

61. For purposes of PURA § 36.065(b)(1), the base year is 2007, because that is the first year that rates from CenterPoint's last general rate proceeding were in effect.

62. For purposes of PURA § 36.065(b)(2), CenterPoint by actuarial or other similar studies correctly measured the annual amounts of pension and OPEB expenses that is chargeable to the CenterPoint's operating expense. The annual accrued-expense amounts included in this reserve account are for the years 2008, 2009, and 2010. The amount of pension and OPEB expense for 2010 is known and measurable because this amount is actuarially determined as of December 31, 2009.

63. The PURA §36.065(b) reserve account properly includes pension and OPEB expenses assigned to CenterPoint from CenterPoint Energy Service Company, LLC (Service Company) for the years 2008, 2009, and 2010. These expenses are no different than other operating expenses that have been assigned to CenterPoint. The amount of Service Company's pension and OPEB expenses has been actuarially determined in accordance with PURA § 36.065.

64. [DELETED]

65. CenterPoint's regulatory asset in the amount of $453,000 for expenses associated with the cost of performing expedited switches was properly determined and is reasonable and necessary.

66. CenterPoint's three-year amortization period is appropriate for the CenterPoint's regulatory asset for costs for performing expedited switches.

Rate of Return and Cost of Capital

67. The appropriate capital structure for CenterPoint is 55% long-term debt and 45% common equity.

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68. A capital structure composed of 55% debt and 45% equity is reasonable in light of CenterPoint's business and regulatory risks.

69. A capital structure composed of 55% debt and 45% equity will help CenterPoint attract capital from investors.

70. [DELETED]

70A. A return on common equity (ROE) of 10.00% will allow CenterPoint a reasonable opportunity to earn a reasonable return on its invested capital.

71. [DELETED]

71A. CenterPoint's energy conservation efforts, the quality of its services, the efficiency of its operations, and the quality of its management support a 10.00% ROE.

72. [DELETED]

72A. The results of the discounted cash flow model, capital asset pricing model, and risk premium approach support a ROE of 10.00%.

73. [DELETED]

73A. A 10.00% ROE is consistent with CenterPoint's business and regulatory risk.

74. CenterPoint's proposed embedded cost of debt 6.74% is reasonable.

75. [DELETED]

75A. CenterPoint's overall rate of return is as follows:

Component	Capital Structure	Cost of Capital	Weighted Avg Cost of Capital
Long-Term Debt	55.00%	6.74%	3.71%
Common Equity	45.00%	10.00%	4.50%
Total	100.00%		8.21%

Cost of Service

76. CenterPoint's test-year total transmission operations and maintenance (O&M) expense in FERC accounts 560 through 573 as adjusted by the Commission in the amount of $202,978 million is reasonable and necessary.

77. CenterPoint's test-year total-distribution O&M expense in FERC accounts 580 through 598 as adjusted by the Commission in the amount of $188.128 million is reasonable and necessary.

78. CenterPoint's proposed $7.15 million O&M expenditure related to storm hardening is reasonable and necessary.

79. CenterPoint's requested total-customer-services-and-information expense of $35.54 million is reasonable and necessary.

80. CenterPoint's requested administrative-and-general-expense of $178.067 million is reasonable and necessary.

81. The evidence demonstrates that CenterPoint's short-term incentive compensation plan (STI) is a reasonable and necessary component of a total compensation package required to recruit, retain, and motivate employees.

82. CenterPoint's long-term incentive-compensation plan (LTI) is not a reasonable and necessary component of CenterPoint's total compensation package.

83. The corporate and financial goals of STI are directly tied to metrics such as customer service and safety.

84. CenterPoint reasonably calculated overtime expenses for the test year that are representative of its current and future work demands.

85. The amount of pension and OPEB expenses CenterPoint requested is consistent with the requirement of PURA § 36.065(a), was determined by actuarial and other similar studies in accordance with GAAP. and is reasonable and necessary.

86. For purposes of calculating the annual base amount of pension and OPEB expenses approved as an operating expense in this rate proceeding, for purposes of PURA § 36.065 (b) and for use in the next CenterPoint rate proceeding, the annual amount of

pension and OPEB approved as an operating expense, which includes financial accounting standard (FAS) pension expense (FAS 87), OPEB (FAS 106), and other post-employment expense (FAS 112), is $39.8 million, based on the amount of such expense for CenterPoint ($31.2 million) and for the amount assigned by Service Company to CenterPoint ($8.6 million).

87. The amount of post retirement benefits included in rates as part of FERC account 926, which is to be funded to the irrevocable, external trust dedicated to the payment of OPEB expenses in accordance with P.U.C. SUBST. R. 25.231(b)(1)(H)(v), is $8.813 million.

88. For purposes of the calculation of pension and OPEB expense under PURA § 36.065(a), the amount of pension and OPEB expenses for 2010 is known and measurable because this amount is actuarially determined as of December 31, 2009.

89. The Monte Carlo simulation used to calculate the amount of the accrual is a reasonable program for estimating loss experience over a long period of time.

90. The Handy-Whitman Index is a standard type of database used to measure cost changes for utility companies, and is a reasonable method for adjusting historic O&M costs to current dollar levels.

91. The Company shall annually accrue $4.15 million to the self-insurance reserve to account for annual expected O&M losses from storm damage in excess of $100,000 and build towards a target reserve of $13.38 million.

92. Consistent with PURA § 36.064, $4.15 million annually for the self-insurance reserve is in the public interest, reasonable, and a lower-cost alternative to purchasing commercial insurance and ratepayers will receive benefits from the savings associated with this reserve.

93. CenterPoint's request for the self-insurance reserve is not intended to provide a reserve for losses caused by storms where the total loss is in excess of at least $100 million, nor are the findings in this Order intended to preempt CenterPoint or the Commission from considering other methods of recovering losses caused by future catastrophic storm or other events.

94. PURA § 36.058 allows a utility to recover costs paid by a utility to an affiliate entity if it demonstrates that its payments are reasonable and necessary for each item or class of items as determined by the Commission and if the price charged by the affiliate to the utility is no higher than the price charged by the affiliate to other purchasers.

95. CenterPoint's affiliated entities, specifically Service Company, and the natural gas distribution operations (gas operations) of CenterPoint Energy Resource Corp. (Resource Corp), provided services to CenterPoint during the test year.

96. Service Company and Resources Corp. are subsidiaries of CenterPoint Energy, Inc. (CNP) and affiliates of CenterPoint.

97. Service Company provides corporate services to CenterPoint including executive management, regulated operations management, human resources, procurement, information technology, regulatory services, administrative services, real estate services, legal services, accounting, environmental services, internal audit, community relations, corporate communications, financial services, financial planning and management support, corporate services, corporate secretary, corporate planning, and research and development unrelated to marketing activity and/or business development for the competitive affiliate regarding its services and products.

98. Resources Corp's gas operations provide underground-line locating services to CenterPoint.

99. Each of these classes of services is prudent, necessary, reasonable, and not duplicative of services otherwise provided by CenterPoint. If it were not affiliated with Service Company, CenterPoint would have to incur similar types of costs, which would be equal to or greater than those charged by the affiliates.

100. CenterPoint does not share with its competitive affiliates those services prohibited by the Commission's rules, such as engineering, purchasing of electric transmission facilities and service, T&D system operations, and marketing, unless Service Company provides such services exclusively to affiliated regulated utilities and only for the provision of regulated utility services.

101. CenterPoint and its affiliates follow a number of processes to ensure that affiliate charges are reasonable and necessary and that CenterPoint and its affiliates are charged the same rate for similar services. These processes include (1) the use of service-level agreements (SLAs) to define the level of service required and the cost of those services, (2) direct billing of affiliate expenses where possible, (3) reasonable allocation methodologies for costs that cannot be directly billed, (4) budgeting processes and controls to provide budgeted costs that are reasonable and necessary to ensure appropriate levels of service to its customers, (5) financial system controls to ensure that billings are accurate and timely, (6) accounting controls, (7) oversight controls such as the Commitment Review Team, the Risk Oversight Committee, and the Executive Committee that provide control over business unit and Service Company expenditures and activities, and (8) labor-cost controls that evaluate and price each job.

102. The evidence establishes that the four main categories of allocation factors used by Service Company–composite ratio, assets, operating expense, and headcount–are reasonable.

103. The Company's assignment methodologies are appropriate to further ensure that its affiliate charges are reasonable and necessary. These assignment methodologies are described in the following publications: *CenterPoint Corporate Cost Center Assignment Manual* (2009), *Information Technology Cost Center Assignment Manual* (2009), *Business Support Services Cost Center Assignment Manual* (2009), and *Regulated Operations Cost Center Assignment Manual* (2009) (collectively, the manuals). These manuals provide appropriate and reasonable methodologies for assigning affiliate costs, including the composite ratio that considers assets, gross margin, and head count in the allocation of those costs.

104. Total net affiliate billings to CenterPoint, as adjusted, are $194.7 million.

105. CenterPoint's net affiliate-related costs of $194.7 million are not higher than charges to a third party or other affiliate for the same class of items.

106. There is no preferential treatment among, or cross subsidization of, affiliates by Service Company.

107. Service Company has complied with Commission rules requiring that affiliate costs be fully allocated. These costs are fully assigned, and otherwise comport with the applicable requirements of P.U.C. SUBST. R. 25.272 and PURA § 36.058.

108. CenterPoint provides affiliate services to Service Company, CenterPoint Energy Properties, LLC, and Gas Operations.

109. CenterPoint services to its affiliates include meter reading, fleet services, shop services, geographic information services, surveying and right-of-way, underground-line locating, radio communications, data-circuit management, field operations, community relations, and other incidental and intermittent services.

110. Services provided by CenterPoint to its affiliates and by Service Company and other affiliates to CenterPoint are billed at cost.

111. CenterPoint billed its affiliates $33.7 million for the test year, and such costs are reasonable.

112. Each item or class of items included within CenterPoint's requested net affiliate-related costs of $194.7 million for the test year are reasonable and necessary and satisfy the standard set forth in PURA § 36.058.

113. CenterPoint has established that the test-year O&M expenses of $7.9 million for customer services are reasonable, necessary, and representative of the costs necessary to provide service to customers of CenterPoint.

114. CenterPoint's electric market operations organization O&M expense of $7.1 million is reasonable and necessary and should be included in the CenterPoint's rates.

115. The Commission has previously ordered a seven-year amortization period for CenterPoint's Hurricane Rita storm costs in Docket 32093. CenterPoint's request to include an annual amortization expense of $4.1 million over each of the next three years is consistent with the order in Docket 32093 because three years remain from the seven-year amortization period, is reasonable and should be approved.

116. CenterPoint has received $22.625 million in insurance proceeds related to Hurricane Ike. The appropriate amortization period for the Hurricane Ike insurance proceeds is five years.

117. P.U.C. SUBST. R. 25.231(c)(2)(ii) states that the reserve for depreciation is the accumulation of recognized allocations of original cost, representing the recovery of initial investment over the estimated useful life of the asset.

118. The use of the remaining-life depreciation method to recover differences between theoretical and actual depreciation reserves is the most appropriate method and should be continued.

119. It is reasonable for CenterPoint to calculate depreciation-reserve allocations on a straight-line basis over the remaining, expected useful life of the item or facility.

120. Except as described below, the service lives and net salvage rates proposed by CenterPoint are reasonable, and the Commission should use these service lives and net salvage rates in calculating depreciation rates for CenterPoint's transmission, distribution, and general plant assets.

121. The appropriate service life for CenterPoint's transmission-station equipment (FERC account 353) is 47 years with a dispersion curve of R1.

122. The appropriate service life for CenterPoint's distribution poles and fixtures (FERC account 364) is 35 years with a dispersion curve of R0.5.

123. The service lives proposed by CenterPoint for transmission, distribution, and general plant assets are reasonable and should be adopted.

124. The net salvage rate of negative 15% for CenterPoint's transmission towers and fixtures (FERC account 354) is the most reasonable of those proposed and should be adopted.

125. The net salvage rate of negative 35% for CenterPoint's transmission poles and fixtures (FERC account 355) is the most reasonable of those proposed and should be adopted.

126. The net salvage rate of negative 74% for CenterPoint's transmission overhead conductor (FERC account 356) is the most reasonable of those proposed and should be adopted.

127. The net salvage rate of negative 2% for CenterPoint's transmission underground conduit (FERC account 358) is the most reasonable of those proposed and should be adopted.

128. The net salvage rate of 0% for CenterPoint's station equipment (FERC account 362) is the most reasonable of those proposed and should be adopted.

129. The net salvage rate of negative 45% for CenterPoint's distribution poles and fixtures (FERC account 364) is the most reasonable of those proposed and should be adopted.

130. The net salvage rate of negative 13% for CenterPoint's distribution underground conductors (FERC account 367) is the most reasonable of those proposed and should be adopted.

131. The net salvage rate of negative 2% for CenterPoint's line transformers (FERC account 368) is the most reasonable of those proposed and should be adopted.

132. The net salvage rate of negative 20% for CenterPoint's distribution services (FERC account 369) is the most reasonable of those proposed and should be adopted.

133. The net salvage rate of 0% for CenterPoint's general structures and improvements (FERC account 390) is the most reasonable of those proposed and should be adopted.

134. CenterPoint's proposed net salvage rates for transmission, distribution, and general plant assets are reasonable and should be adopted.

135. CenterPoint's request to establish depreciation rates applicable to a general depreciated functional group and general amortized function group is reasonable.

136. The burden or financial risk associated with the ownership of land has been borne by shareholders who provided the funds to purchase the land.

137. Land is not a depreciable asset, and customers have not paid any depreciation expense associated with the land. This does not mean ratepayers have no claim on any gain or loss resulting from the sale of land.

138. Only two of the land sales at issue, resulting in a gain of only $187,000, were within the test year, and approximately $23 million of the total $47 million of gain occurred prior to the test year in CenterPoint's last base-rate filing.

139. [DELETED]

139A. CenterPoint has properly accounted for the gain and loss on the sale of land that occurred outside the 2009 test year for this rate case.

139B. It is reasonable for CenterPoint to return 50% of the $187,000 gain on the sale of land that occurred within the test year.

140. For federal income tax purposes, CenterPoint is part of an affiliated group of companies that files a consolidated federal income tax return.

141. CenterPoint's corporate parent filed a consolidated federal tax return for both 2008 and 2009.

142. If a utility was a member of an affiliated group eligible to file a consolidated income tax return and it was advantageous for the utility to do so, and unless the Commission determines it was reasonable not to consolidate returns, PURA § 36.060 requires the Commission to compute the utility's taxes as though a consolidated return had been filed and the utility had realized its fair share of the savings resulting from the consolidated return.

143. CenterPoint is not ring fenced from its corporate parent and affiliates in a manner that exempts the Company from a consolidated-tax-savings adjustment.

144. In Application of Central Power and Light Company for Authority to Change Rates, Docket No. 14965 (Oct. 16, 1997) and every docket in which a consolidated tax savings adjustment was applied thereafter, the tax benefit produced by the loss affiliates was attributed to all members of the affiliated group that had income (including the utility) on a pro-rata basis.

145. CenterPoint is a member of an affiliated group eligible to file consolidated income taxes and a consolidated tax savings adjustment should be applied to CenterPoint's federal tax expense.

146. [DELETED]

146A. The methodology developed by the Commission to determine the consolidated tax savings adjustment did not gross up the resulting amount.

146B The consolidated tax savings adjustment applied to CenterPoint should not be grossed-up.

147. The Medicare Prescription Drug, Improvement and Modernization Act of 2003 expanded Medicare to include prescription drug coverage.

148. CenterPoint began receiving a subsidy from the federal government equal to 28% of the cost of providing such coverage (the Medicare Part D subsidy).

149. Under the 2003 Medicare Act, CenterPoint could deduct for tax purposes the full cost of providing such coverage and was not required to reduce its deduction for the Medicare Part D subsidy.

150. The Medicare Part D subsidy created a permanent difference of $28.6 million from 2004 through 2009, as calculated pursuant to FASB Statement No. 109.

151. Only $5.4 million of the $28.6 million Medicare Part D subsidy was actually received from 2004 through 2009 while the $23.2 million of the permanent difference related to amounts that were anticipated to be received in 2010 and afterwards but nevertheless was required to be accrued under FASB Statement No. 106.

152. In 2010, Congress passed comprehensive health care legislation–the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (collectively with the health care acts)–that caused the Medicare Part D subsidy to be effectively taxable for tax years beginning after December 31, 2012.

153. The amount of Medicare Part D subsidy receipts that CenterPoint will receive in 2010, 2011, and 2012, which will continue to be non-taxable under the health care legislation, has already been fully reflected in the income tax calculations CenterPoint has recorded in its financial statements in years prior to 2010.

154. The health care acts effectively changed the tax rate applicable to the Medicare Part D subsidy from 0% to 35%.

155. The Commission has permitted the effects of changes in tax rates or tax laws to be recovered in rates charged to customers.

156. The effects of the health care acts have been reflected in CenterPoint's financial statements for the three months ended March 31, 2010, in accordance with GAAP.

157. [DELETED]

157A. The health care acts do not become effective until January 1, 2013; therefore, it is unreasonable for CenterPoint to include in the rates set in this proceeding a future increase to CenterPoint's federal income tax expense caused by that legislation.

158. [DELETED]

159. [DELETED]

159A. It is appropriate for CenterPoint to monitor and accrue the difference between what its rates assume the Medicare Part B subsidy tax expense will be and what CenterPoint is required to pay as a regulatory asset to be addressed in CenterPoint's next rate case.

160. Ad valorem property taxes of $68.45 million are reasonable and necessary expenses.

161. CenterPoint is part of a combined group (the CenterPoint state group) for purposes of calculating and reporting the Texas franchise (margin) tax.

162. The CenterPoint state group calculates its margin by subtracting cost of goods sold from revenue, which produces the lowest margin for the CenterPoint state group, and each CenterPoint group member computes the amount it pays to CenterPoint Energy, Inc. based on this method.

163. Under Texas law, all entities in the CenterPoint state group must use the same method to calculate their margin.

164. CenterPoint was required to use the cost-of-goods-sold method and has utilized this method applied to the stand-alone revenues and expenses reflected in its financial statements to determine its Texas franchise tax for the test year.

165. Texas state franchise taxes in the amount of $16.338 million are reasonable and necessary expenses.

166. Payroll taxes in the amount of $10.440 million are reasonable and necessary expenses.

167. Municipal franchise fees in the amount of $138.6 million are reasonable and necessary expenses.

167A. CenterPoint renegotiated franchise fee agreements with cities when the existing agreements expired.

168. Agreeing to pay a city municipal franchise fees above the statutory default formula amount in PURA § 33.008(b) provides CenterPoint and its ratepayers with significant benefits, including the right not to be charged additional fees or to be required to obtain additional permits for work performed within the public rights of way; clearly defined rules about indemnity, audit rights, and the circumstances when the company must bear the cost of relocating its physical infrastructure; and a two-year limitation on the time cities have to challenge franchise-fee payments.

Cost Allocation and Rate Design

169. To fully recover its retail transmission costs, CenterPoint calculates a retail component, which includes CenterPoint's wholesale charge, to calculate its retail transmission revenue requirement.

170. Pursuant to P.U.C. Subst. R. 25.192(b)(1), CenterPoint's wholesale transmission rate is calculated by dividing its Commission-approved wholesale transmission cost of service (TCOS) by the average of the ERCOT coincident peak demand for the months of June, July, August, and September, known as the 4CP.

170A. CenterPoint's proposal to classify 100% of its transmission investment cost as demand related is reasonable.

171. The wholesale TCOS, which is collected from distribution service providers (DSPs) in ERCOT for their proportional use of CenterPoint's transmission grid, is calculated to be $232.04 million. When the requested wholesale TCOS is divided by the ERCOT 4CP and then divided again by 12, a transmission-service monthly rate of $0.317734 per kilowatt (kW) per month is the result and is appropriate.

172. Rider UCOS Wholesale Credit (RUWC) is a credit that, pursuant to the settlement in Docket No. 32093, is to be returned to DSPs that were assessed a transmission service charge under Rate Schedule Wholesale Transmission Service and will expire in November 2010.

173. The RUWC credit will remain in effect until $19.2 million has been returned, which is November 2010.

174. CenterPoint's proposal to return the insurance-proceeds credit over a three-year period or until the funds are fully returned through Rider Insurance Proceeds Credit (Rider IPC), at which point the rider and credit would terminate, is reasonable.

175. In allocating costs, CenterPoint followed the principles of cost causation. Each of the retail delivery classes has been allocated revenues in line with the costs those classes generate.

176. The use of 4CP is consistent with cost causation.

177. CenterPoint's proposal to use adjusted 4CP is inappropriate and should not be adopted.

178. The Commission should continue to use 15-minute data for allocation of transmission costs on 4CP as it most accurately reflects the conditions that will prevail when the proposed rates go into effect.

179. CenterPoint's allocation of municipal franchise fees to the customer classes based upon in-city kilowatt-hour (kWh) sales and collection of the fees from all customers within the customer class is reasonable and consistent with Commission precedent.

180. CenterPoint's proposal to extend its street light replacement standard from 48 hours to 72 hours is reasonable.

181. CenterPoint's rolling 30-year interval for establishing normal weather follows the precedent consistently established for CenterPoint by the Commission. It is appropriate for the Commission to continue to rely on its past practice and adopt a weather adjustment based on the 30-year interval.

182. As modified by the requirements of the Commission's preliminary order, CenterPoint's proposed Rider EECRF is uncontested.

183. A utility may earn a performance bonus if it exceeds its demand reduction pursuant to P.U.C. Subst. R. 25.181(h).

184. CenterPoint needs to collect $30.784 million to fulfill its statutory energy-efficiency obligations. Further, under the parameters set in the preliminary order, the approved performance bonus for Company's 2009 energy-efficiency programs is $3,007,344.

185. CenterPoint shall use the $504,858 originally earmarked for assistance to low income customers and never spent for bill assistance for low-income customers.

186. Accordingly, rider EECRF. and the uncontested $33,286,486 in expense and performance bonus to be collected pursuant to its operation, are reasonable and should be approved.

187. CenterPoint will file its storm-hardening plan with the Commission in May 2011.

188. P.U.C. Subst. R. 25.95 did not require any utility to undertake any specific storm-hardening initiatives.

189. Storm-hardening costs should be treated as part of a utility's historical test year costs in a future rate case.

190. There is no special legislation authorizing CenterPoint to recover its extraordinary storm-hardening costs through a rider.

191. CenterPoint's proposed storm-hardening rider (Rider SH) is not based on whether CenterPoint, as a whole, is fully recovering its overall costs and allowed return on investment through its existing rates, and over recovery could be exacerbated by CenterPoint's proposed annual true-up.

192. CenterPoint's proposed allocation factor for Rider SH could assign costs to customer classes in a manner that is inconsistent with the principles of cost causation.

193. Rider SH is not in the public interest. CenterPoint has other means of recovering these expenses.

194. Rider State Colleges and Universities Discount (SCUD)–which provides a 20% discount from base rates for electric service provided to state institutions of higher learning pursuant to PURA § 36.351–should be removed from CenterPoint's tariff consistent with the Commission's decision in Application of Oncor Electric Delivery Company, LLC, for Authority to Change Rates, Docket No. 35717 (Nov. 30, 2009).

195. CenterPoint should provide a waiver for the 80% demand ratchet for customers in the secondary greater than 10 kilovolt-ampere (kVA) and primary service class rate schedules that have less than the kVA equivalent of 20 kW of annual peak demand based on their non-coincident Peak (NCP) monthly usage.

196. Tariff sheets for SCUD, EMC, and RURC should be deleted from the tariff because they have expired.

197. The light-emitting-diode lamp type should be approved for inclusion in CenterPoint's street-lighting tariff.

198. Rider Transmission Cost Recovery Factor (TCRF) should be approved and include all CenterPoint ERCOT TCOS costs not included in CenterPoint's base rates and updated ERCOT 4CP allocators.

199. Rate Electric Service Switchovers (ESS) is based on cost to serve and should be approved.

200. Rate Competitive Metering Credit (CMC) is based on cost to serve and should be approved.

201. Rider RDE should be approved.

202. Rider IPC in the tariff for wholesale transmission service should be approved.

203. The retail rider DTA and wholesale Rider DT should not be approved.

204. Billing determinants adjusted for weather normalization as proposed by the Company more closely reflect those that will occur when rates go into effect and should be used to calculate rates.

AMS Reconciliation

205. The Commission approved CenterPoint's AMS deployment plan in *Application of CenterPoint Energy Houston Electric, LLC for Approval of Deployment Plan and Request for Surcharge for an Advanced Metering System*, Docket No. 35639 (Dec. 22, 2008).

206. CenterPoint's AMS deployment has been consistent with both the timing and functionality requirements of the deployment plan approved in Docket No. 35639.

207. CenterPoint has agreed to file an amendment to its deployment plan with an amended statement of functionality at least three months before 'hybrid pricing' functionality is available to retail electric providers.

208. If CenterPoint's provision of 'hybrid pricing' functionality requires enhancements to its communications systems beyond that which is described and agreed to in Docket No. 35639, CenterPoint may seek additional funding beyond what is currently included in the AMS surcharge.

209. The final order in Docket No. 35639 required CenterPoint to pursue AMS funding available under the Energy Independence & Security Act (EISA).

210. CenterPoint successfully fulfilled the requirement in the Final Order in Docket No. 35639 to pursue AMS funding under the EISA. The Department of Energy awarded CenterPoint a $200 million smart-grid investment grant (SGIG).

211. CenterPoint's decision to seek $50 million of the $200 million SGIG for its intelligent grid (IG) initiative was reasonable.

212. As a condition of the SGIG, CenterPoint is required to complete its AMS deployment in 2012 instead of 2014 as contemplated in the Final Order in Docket No. 35639.

213. CenterPoint's acceleration of AMS deployment, consistent with the terms of the SGIG, is reasonable.

214. With respect to CenterPoint's limited Phase I deployment of the IG, CenterPoint has agreed to include a deployment plan in the Monthly Progress Report on AMS currently filed with the Commission.

215. CenterPoint incurred $164,710,917 in reasonable and necessary capital and O&M costs associated with its AMS deployment during the period January 1, 2009, to March 31, 2010, (the Reconciliation Period).

216. CenterPoint properly included in reconcilable AMS costs an adjustment totaling $1,006,004 to reduce the salvage value of unutilized lock collars and increase pilot-project costs to reflect actual costs.

217. During the reconciliation period, CenterPoint realized $569,876 in O&M savings and increased revenue as a result of its AMS deployment.

218. CenterPoint's capital expenses, O&M expenses, O&M savings, and revenue increases yield a net revenue requirement for the reconciliation period of $45,541,989. Surcharge revenues through March 31, 2010, were $93,992,329. Together with interest and adjustments, these amounts yield an over-recovery balance of $51,640,849.

219. CenterPoint has properly tracked and recorded its AMS costs incurred during the Reconciliation Period.

220. CenterPoint's use of January 1, 2009, through March 31, 2010, as the reconciliation period is reasonable.

221. In this and all future AMS reconciliations, the savings categories to be evaluated and considered are those listed in Exhibit A appended to the PFD, which represents CenterPoint's adaptation of the McKinsey model as approved in Docket No. 35639.

222. It is reasonable for actual savings and benefits realized by CenterPoint during the Reconciliation Period to be lower than those estimated in Docket No. 35639 because the original estimates were based on a higher level of AMS deployment than that eventually agreed upon and approved in the final order in that docket.

223. CenterPoint accrued a receivable of $26,478,785 in March 2010 in connection with the SGIG award. The accrual was for the DOE's portion of the allowable project costs incurred during the last quarter of 2009 and the first quarter of 2010. CenterPoint properly accounted for this accrual by netting it against plant additions in the calculation of the Company's revenue requirement.

224. CenterPoint properly netted $20,453,907 in construction work in progress against $26,478,785 in SGIG revenues and applied the balance as a negative $6,024,877 beginning plant balance used in calculating the revised surcharge duration.

225. The Final Order in Docket No. 35639 permits CenterPoint to recover the undepreciated cost of the retired meters that are replaced by AMS meters.

226. CenterPoint properly identified the undepreciated cost of the retired meters, placed them in a regulatory asset account, and included them in net plant in the base-rate case.

227. CenterPoint has properly excluded from the surcharge calculations the reasonable and necessary costs of installed AMS equipment, included in the AMS reconciliation, and placed those costs in its proposed base rates.

228. CenterPoint has reasonably estimated the costs necessary to complete the AMS project, calculating projected capital costs from April 1, 2010 through December 31, 2017 of $462,480,243 and projected O&M expenses for the same period of $199,731,837.

229. CenterPoint properly subtracted future SGIG receipts ($4,741,868 in O&M and $119,402,302 in capital) from its estimates of the costs necessary to complete the AMS project.

230. CenterPoint has reasonably calculated surcharge over-recoveries received prior to March 31, 2010, and deducted them from the amounts needed for future cost recovery.

231. In finding of fact 21 in the final order in Docket No. 35639, the Commission approved CenterPoint's existing surcharge methodology.

232. In calculating the revised AMS surcharge, CenterPoint properly included a credit for the federal SGIG monies received after March 31, 2010.

233. Shortening the recovery period rather than reducing the dollar amount of the monthly surcharge is an appropriate and reasonable method to decrease the surcharge.

234. Shortening the surcharge recovery period benefits ratepayers by reducing the carrying costs for AMS and facilitates CenterPoint's efforts to implement AMS on an accelerated track by providing the Company with more up-front cash.

235. CenterPoint reasonably calculated an over-recovery during the Reconciliation Period in the amount of $51,640,849.

236. The $51,640,849 over-recovery is the beginning regulatory liability amount for calculating the revised AMS surcharge.

237. The terms, including pricing, of each contract, contract amendment, and change order listed in Exhibit B appended to the PFD (which included revisions to the IBM, Itron, and other contracts previously approved in Docket No. 35639, as well as new AMS-related contracts) are reasonable.

238. CenterPoint's existing depreciation rates do not include meter removal costs.

239. The removal costs associated with installing AMS meters are negligible and required only because CenterPoint is installing new advanced meters.

240. It is reasonable for CenterPoint to include removal costs as part of the AMS installation costs under the Itron contract.

241. CenterPoint's revised projected savings of $114,487,661 for the remainder of the surcharge period from April 1, 2010 through 2017 is reasonable.

242. CenterPoint's revised future-savings estimate takes into account results achieved to date, as well as the Company's acceleration of its deployment plan as required by the federal stimulus grant.

243. CenterPoint does not realize savings from any reduction in field service personnel, because the cost of services performed by field service personnel is recovered through a discretionary service charge (DSC). When the service is eliminated, CenterPoint avoids the expense, but also forgoes the associated revenue by not charging the DSC.

244. Where a DSC is in place to capture savings from AMS, it would be inappropriate to also credit the surcharge for those same savings.

245. CenterPoint anticipates receiving an additional $124,144,170 in SGIG funding for AMS deployment from the DOE, and this sum has been applied to reduce the estimated future costs of the project.

Rate Case Expenses

246. [DELETED]

246A. All rate case expenses associated with this proceeding were severed and placed into Docket No. 39127.

247. [DELETED]

248. [DELETED]

249. [DELETED]

250. [DELETED]

IV. Conclusions of Law

1. CenterPoint is an electric utility as defined by PURA § 31.002, and, therefore, it is subject to the Commission's jurisdiction under PURA §§ 14.001, 32.001, 33.001, 33.002, 33.051, 35.004, and 36.102.

2. CenterPoint is a transmission distribution utility as defined in PURA § 31.002(19).

3. Pursuant to PURA § 14.053 and TEX. GOV'T CODE § 2003.049(b), SOAH has jurisdiction over all matters relating to the conduct of the hearing in this case, including the preparation of a proposal for decision.

4. CenterPoint has the burden of proving that the rate change it is requesting is just and reasonable pursuant to PURA § 36.006.

5. This docket was processed in accordance with the requirements of PURA and Administrative Procedure Act, TEX. GOV'T CODE ANN. Chapter 2001 (Vernon 2008).

6. CenterPoint provided adequate notice of this proceeding in compliance with P.U.C. PROC. R. 22.51.

7. Pursuant to PURA § 33.001, each municipality in CenterPoint's service area that has not ceded jurisdiction to the Commission has jurisdiction over the Company's Application, which seeks to change rates for distribution services within each municipality.

8. Pursuant to PURA § 33.051, the Commission has jurisdiction over an appeal from a municipality's rate proceeding.

9. In compliance with PURA § 36.052, CenterPoint's overall revenues approved in this proceeding permit CenterPoint a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses.

10. Consistent with PURA § 36.053, the rates approved in this proceeding are based on original cost, less depreciation, of property used and useful to CenterPoint in providing service.

11. The ADFIT adjustments approved in this proceeding are consistent with PURA § 36.059 and P.U.C. SUBST. R. 25.231(c)(2)(C)(i).

12. PURA § 36.065(a) provides that electric utility rates shall include 'expenses for pensions and other postemployment benefits (OPEBs), as determined by actuarial or other similar studies in accordance with generally accepted accounting principles, in an amount the regulatory authority finds reasonable.

13. CenterPoint's requested ADFIT asset for its pension plan, OPEBs and FAS 112 ADFIT liabilities were properly included in its rate base in accordance with PURA § 36.065.

14. Including the cash working capital approved in this proceeding in CenterPoint's rate base is consistent with P.U.C. SUBST. R. 25.231(c)(2)(B)(iii)(IV), which allows a reasonable allowance for CWC to be included in rate base.

15. The return on equity and overall rate of return authorized in this proceeding are consistent with the requirements of PURA §§ 36.051 and 36.052.

16. The affiliate expenses approved in this proceeding and included in CenterPoint's rates meet the affiliate payment standards articulated in PURA §§ 36.051, 36.058, and *Railroad Commission of Texas v. Rio Grande Valley Gas Co.* 683 S.W.2d 783 (Tex. App.—Austin 1984, no writ).

16A. The consolidated tax savings adjustment approved in this Order appropriately implements PURA § 36.060.

17. PURA § 33.008(f) expressly permits a utility and a municipality in its service area to agree to a different level of compensation than the default formula amount in PURA § 33.008(b) upon the expiration of a franchise agreement existing on September 1, 1999, and PURA § 33.008(c) expressly provides for the recovery in rates of such agreed amounts.

18. The phrase 'municipal franchise charges authorized by this section shall be considered a reasonable and necessary operating expense of each. .transmission and distribution utility' contained in PURA § 33.008(c) applies to all subsections of PURA § 33.008 and is not limited in application to Subsection (b).

19. PURA § 36.064 permits a utility to self-insure against 'potential liability or catastrophic property loss, including windstorm, fire, and explosion losses, that could not have been reasonably anticipated and included under operating and maintenance expenses. The Commission shall approve a self-insurance plan under that section if it finds the coverage is in the public interest, the plan, considering all of its costs, is a lower cost alternative to purchasing commercial insurance, and ratepayers receive the benefits of the savings.

20. CenterPoint's liability or catastrophic property-loss self-insurance program accords with PURA § 36.064 and P.U.C. SUBST. R. 25.231(b)(1)(G).

21. CenterPoint's $164.314 million of temporary timing differences that are recorded as FIN 48 liabilities must be included in ADFIT.

22. The ADFIT adjustments approved in this proceeding are consistent with PURA § 36.059 and P.U.C. SUBST. R. 25.231(c)(2)(C)(i).

23. PURA § 39.905 does not provide a means by which an electric utility can raise customer's rates for the electricity they consume based in part on the reduction to load growth that results from the electric utility achieving its energy-efficiency goals.

24. CenterPoint's proposed storm-hardening expenses are neither mandated nor required by P.U.C. SUBST. R. 25.95.

25. CenterPoint's proposed storm-hardening expenses are not an allowed expense for purposes of P.U.C. SUBST. R. 25.231(b) because they are not a known and measureable change to CenterPoint's cost of service for the historical test year.

26. CenterPoint's proposed Rider SH is contrary to PURA § 36.201.

27. CenterPoint's proposed energy-efficiency cost recovery factor, modified in the manner described in the findings of fact, complies with PURA §39.905 and P.U.C. SUBST. R. 25.181.

28. CenterPoint's energy-efficiency programs adhere to the cost-effectiveness parameters CenterPoint has earned and correctly calculated its energy-efficiency performance bonus consistent with the requirements of PURA § 39.905 and P.U.C. SUBST. R. 25.181(h).

29. The EECRF calculations approved in this proceeding are appropriate and in accordance with PURA § 39.905 and P.U.C. SUBST. R. 25.181.

30. The EECRF assignments and allocations to the rate classes, as proposed by CenterPoint are approved and are consistent with PURA § 39.905 and P.U.C. SUBST. R. 25.181.

31. The proposed EECRF tariff schedule provided by CenterPoint is consistent with the Commission's Preliminary Order, complies with PURA § 39.905 and P.U.C. SUBST. R. 25.181.

32. The 20% discount in PURA § 36.351 applies to electric services provided by an electric utility to four-year state universities, upper-level institutions, Texas State Technical College, and colleges in areas of the state that are not open to competition.

33. The 20% discount in PURA § 36.351 does not apply to electric services provided by a TDU to REPs that in turn sell their electric services to four-year state universities, upper-level institutions, Texas State Technical College, and colleges in areas of the state that are open to competition.

34. PURA § 36.351 does not require CenterPoint to provide a 20% discount to four-year state universities, upper-level institutions, Texas State Technical College, and colleges.

35. PURA § 36.060 requires the use of a consolidated tax savings adjustment when computing an electric utility's federal income taxes.

36. PURA § 36.060 requires that a consolidated tax savings adjustment should be made in this proceeding.

37. CenterPoint's AMS deployment is consistent with the functionality requirements of P.U.C. SUBST. R. 25.130 and the Final Order in Docket No. 35639.

38. Pursuant to the Final Order in Docket No. 35639, CenterPoint has fulfilled its obligation to pursue AMS funding available under the EISA by obtaining a $200 million SGIG.

39. CenterPoint's acceleration of its AMS deployment plan in accordance with the terms of the SGIG and its designation of $50 million of the SGIG for an IG initiative are consistent with the final order in Docket No. 35639.

40. PURA § 39.107(h) entitles CenterPoint to impose a surcharge to recover its reasonable and necessary costs incurred in deploying AMS.

41. Pursuant to P.U.C. SUBST. R. 25.130(k)(4) and (6) and finding of fact 34 in Docket No. 35639, CenterPoint has excluded from the surcharge calculations the reasonable and necessary costs of installed AMS equipment, placing those costs in its proposed base rates.

42. CenterPoint's treatment of the cost of removing the electro-mechanical meters being replaced by advanced meters is consistent with the Commission's rules, the Final Order in Docket No. 35639, and the FERC Uniform System of Accounts.

43. CenterPoint's rates, as approved in this proceeding, are just and reasonable in accordance with PURA § 36.003.

V. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following orders:

1. The proposal for decision prepared by the SOAH ALJs is adopted to the extent consistent with this Order.

2. CenterPoint's application is granted to the extent consistent with this Order.

3. CenterPoint's implementation and administration of Rider DTA shall be consistent with this Order.

4. CenterPoint shall file tariffs consistent with this Order within 20 days of the date of this Order. No later than ten days after the date of the tariff filings, Staff shall file its comments recommending approval, modification, or rejection of the individual sheets of the tariff proposal. Responses to the Staff's recommendation shall be filed no later than 15 days after the filing of the tariff. The Commission shall by letter approve, modify, or reject each tariff sheet. The tariff sheets shall become effective 30 days after approval by the Commission letter or deemed approved pursuant to paragraph 4.

5. The tariff sheets shall become be deemed approved and shall be become effective on the expiration of 20 days from the date of filing, in the absence of written notification of modification or rejection by the Commission. If any sheets are modified or rejected, CenterPoint shall file proposed revisions of those sheets in accordance with the Commission's letter within ten days of the date of that letter, and the review procedure set out above shall apply to the revised sheets. The tariff sheets shall become effective 30 days after approval.

6. Copies of all tariff-related filings shall be served on all parties of record.

7. CenterPoint shall begin tracking its uncollectible expenses by customer class and include that result in its next base rate case.

8. CenterPoint shall make modifications to its approved AMS deployment plan to account for the accelerated deployment, and also to account for its plans to modify its pricing methodology, within 60 days of issuance of this Order. These changes shall be provided in CenterPoint's monthly compliance reporting, in Project No. 36699.

9. CenterPoint shall file a deployment plan with the Commission detailing its intelligent grid (IG) project, within 60 days of issuance of this Order.

10. When CenterPoint seeks cost recovery for the remaining costs of its IG project, it shall file a cost-benefit analysis of its IG project.

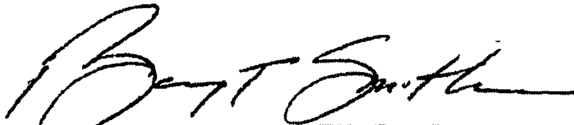
11. With regard to its IG project, CenterPoint shall file a report with the Commission on a quarterly basis with a summary of what it has deployed. This report shall include the monthly reports CenterPoint is required to file with the Department of Energy. The schedule for these reports shall commence no later than 60 days following the issuance of this Order.

12. CenterPoint shall implement a network operations center as soon as reasonably possible and report to the Commission when it is operational.

13. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted, are denied.

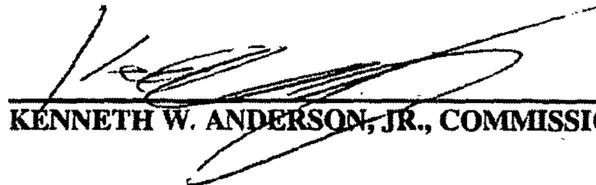
SIGNED AT AUSTIN, TEXAS the 12th day of May2011

PUBLIC UTILITY COMMISSION OF TEXAS



BARRY T. SMITHERMAN, CHAIRMAN

DONNA L. NELSON, COMMISSIONER



KENNETH W. ANDERSON, JR., COMMISSIONER

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ATTACHMENT DL-4

Monarch Utilities I, L.P. I to Change Rates for Water and Sewer Service

SOAH Docket No. 473-16-2873.WS

PUC Docket No. 45570

PUC DOCKET NO. 45570
SOAH DOCKET NO. 473-16-2873.WS

MONARCH'S RESPONSES TO OPUC'S SECOND REQUESTS FOR INFORMATION

OPUC RFI 2-18: **Please admit or deny that the Monarch Revenue Held in Abeyance amounts have not been granted to Monarch as a regulatory asset within any jurisdiction. If denied, provide the jurisdiction that approved of this type of adjustment.**

RESPONSE: In responding to this RFI we interpret the term 'regulatory asset" to mean authorization for future recovery in rates. Monarch admits that the Monarch Revenue Held in Abeyance amounts have not been authorized for future recovery in rates within any jurisdiction.

Prepared by: Robert Kelly
Sponsored by: Robert Kelly

ATTACHMENT DL-5

Monarch Utilities I, L.P. l to Change Rates for Water and Sewer Service

SOAH Docket No. 473-16-2873.WS

PUC Docket No. 45570

PUC DOCKET NO. 45570
SOAH DOCKET NO. 473-16-2873.WS

MONARCH'S SUPPLEMENTAL RESPONSES
TO STAFF'S EIGHTH REQUESTS FOR INFORMATION

STAFF RFI 8-11:	**Is it Monarch's contention that the customers and any regulatory authority agreed to Monarch collecting "revenues held in abeyance" in a future year? If so, provide the document reflecting such agreement.**
RESPONSE:	No.

Prepared by: Robert Kelly
Sponsored by: Robert Kelly

PUC DOCKET NO. 45570
SOAH DOCKET NO. 473-16-2873.WS

MONARCH'S SUPPLEMENTAL RESPONSES
TO STAFF'S EIGHTH REQUESTS FOR INFORMATION

STAFF RFI 8-12: **Has Monarch recorded "revenues held in abeyance" anywhere in its books and records? If so, please specify the account number and name where the amount is recorded and what year it was recorded in.**

RESPONSE: No.

Prepared by: Robert Kelly
Sponsored by: Robert Kelly

MONARCH'S SUPPLEMENTAL RESPONSES TO STAFF'S EIGHTH REQUESTS FOR INFORMATION

STAFF RFI 8-13: **Is it Monarch's intent to attempt to recover the "revenues held in abeyance" in any form or fashion from the customers of the utility? If so, please specify how Monarch intends to do so.**

RESPONSE: No.

Prepared by: Robert Kelly
Sponsored by: Robert Kelly

ATTACHMENT DL-6

Monarch Utilities I, L.P. 1 to Change Rates for Water and Sewer Service

SOAH Docket No. 473-16-2873.WS

PUC Docket No. 45570

to perform life and net salvage analysis.[476] CenterPoint contends that it used uniform data to perform its life and net salvage analyses and TCUC did not.[477]

The ALJs are persuaded that CenterPoint's analysis is the most appropriate for use in this case in that it uses uniform data to perform the analyses. Therefore, the ALJs recommend that the Commission adopt 0 percent for the net salvage value for this account.

4. Gain on Sale of Land

CenterPoint sold 23 properties since its last litigated rate case and recorded the gain on sale associated with the sales exclusively for the benefit of shareholders. TCUC recommends returning 100 percent of that gain, for all but three properties, to customers.[478]

TCUC contends that in evaluating who is entitled to the gain on this sale, the *Public Utility Comm'n of Texas v. Gulf State Utilities Co.* case is directly on point.[479] In that case the Texas Supreme Court needed to resolve whether the Commission properly allocated the gains from the sale of the plants between Gulf State Utilities' (GSU) ratepayers and its shareholders. The court reversed the Commission because it failed to take into consideration both of the equitable principles commonly used to resolve allocation problem, that the "benefits should follow the burdens' and that 'gain should follow risk of loss."[480] As the court went on to state:

> The gain should be allocated to that group (as between shareholders and ratepayers) that has borne the financial burdens (e.g. depreciation, maintenance, taxes) and risks of the asset sold. In addition to these two general equitable factors, courts have also considered numerous other factors, including whether the asset sold had been included in the rate base over the years, whether the asset was depreciable property, nondepreciable property, or a combination of the two types, the impact of the

[476] *Id.* at 34.

[477] CEHE Ex. 57 (Watson Rebuttal) at 44.

[478] TCUC Ex. 1 (Pous Direct) at 42.

[479] 809 S.W.2d 201, 211 (Tex. 1990).

[480] *Id.* at 211, *citing Democratic Cent. Comm'n. v. Washington Metro. Transit Comm'n,* 485 F.2d 786 (D.C. Cir. 1973) and *Washington Pub. Interest Org. v. Public Serv. Comm'n,* 393 A.2d 71 (D.C. 1978).

> proposed allocation on the financial strength of the utility, the reason for the asset's appreciation (e.g. inflation, a germinal increase in property value in the area), any advantages enjoyed by the shareholders because of the favored treatment accorded the asset, the dividends paid out to the shareholders over the years, and any extraordinary burdens borne by the ratepayers in connection with that asset.[481]

The court also made it clear that "the proper allocation of such proceeds is a complicated one that cannot be resolved simply by reference to who paid for the property."[482] TCUC stated that a review of the various factors that might impact the allocation of gain between customers and shareholders argues strongly that the gain should be allocated to customers. First, argues TCUC, land is not a depreciable asset and it is presumed it will gain value over time. TCUC contends that its review of the appreciation of the land revealed no special action taken by the Company that created the appreciation of the land. It is likely that system growth and inflation caused the land to gain in value and this is not due to actions taken by shareholders. TCUC further contends that customers had to pay the cost for property taxes, operations and maintenance expense, or any other type of expense would have been borne by customers as a component of the overall revenue requirements for the Company, which contributed to the overall return obtained by the Company and are factors in the timing of rate proceedings. As a consequence, argues TCUC, the customer has always been at risk for the gain or loss associated with the property and shareholders have not shouldered any financial harm associated with the property. TCUC contends that if the ownership of the land were causing any financial hardship, CenterPoint would have initiated a rate case to increase rates and that the record in this case is devoid of any evidence that identifies the prior actions of purchasing land was the reason for a rate filing. In addition, TCUC notes that the Company has continued to pay dividends over this period.[483]

CenterPoint responded to TCUC's arguments by asserting that CenterPoint does not recover depreciation expense on land, and consequently does not recover from ratepayers the money spent to acquire the land. Therefore, the investment in the property is shouldered solely by investors. Further, CenterPoint argued that only two of the land sales that form the basis of TCUC's proposed

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[481] 809 S.W.2d at 211.

[482] *Id.*

[483] TCUC Ex. 1 (Pous Direct) at 46.

adjustment occurred within the test year, and TCUC has failed to identify any statutory or regulatory authority that allows it to include transactions that occurred outside the test year, and in fact, prior to the Company's last rate case in its proposed adjustment.[484] Finally, CenterPoint contended that the fact that customers may have paid for the cost of property taxes and O&M expense, standing alone, is not sufficient reason to allocate the entire gain on sale of land to customers. These costs support the use of the land for the facilities that provide service; however, they do not maintain or enhance the property for capital appreciation purposes.

The ALJs find that CenterPoint's arguments are the more persuasive of those offered. The fact that CenterPoint did not recover depreciation on the assets that were sold is undisputed. The fact that customers may have borne some level of O&M expenses associated with the properties is, of course, relevant, but nothing indicates that the level borne by customers was significant. Accordingly, the ALJs recommend that the Commission adopt CenterPoint's proposed treatment of the gains from sales of these properties.

L. Federal Income Taxes [Germane to Preliminary Order Issue No. 23]

1. CTSA [Germane to Preliminary Order Issue No. 22]

(a) Applicabilty of PURA § 36.060

PURA § 36.060 provides in relevant part:

> (a) Unless it is shown to the satisfaction of the regulatory authority that it was reasonable to choose not to consolidate returns, an electric utility's income taxes shall be computed as though a consolidated return had been filed and the utility had realized its fair share of the savings resulting from that return, if:
>
> (1) the utility is a member of an affiliated group eligible to file a consolidated income tax return; and
>
> (2) it is advantageous to the utility to do so.

[484] CEHE Ex. 66 (Fitzgerald Rebuttal) at 24-25.