Control Number: 49421

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SOAH DOCKET NO. 473-19-3974
PUC DOCKET NO. 49421

2019 JUN 10 PM 1:54

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR AUTHORITY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

OFFICE OF PUBLIC UTILITY COUNSEL'S RESPONSE TO CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC'S FIRST REQUEST FOR INFORMATION

The Office of Public Utility Counsel ("OPUC") submits this response to CenterPoint Energy Houston Electric, LLC's ("CenterPoint Houston") First Request for Information that was received on June 6, 2019. Pursuant to State Office of Administrative Hearings Order No. 2, OPUC's response is timely filed within four calendar days of receipt of CenterPoint Houston's discovery request. OPUC stipulates that all parties may treat this response as if it were filed under oath.

Dated: June 10, 2019

Respectfully submitted,

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Chief Executive & Public Counsel
State Bar No. 24042276

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Assistant Public Counsel
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SOAH DOCKET 473-19-3864
PUC DOCKET NO. 49421
OPUC's Response to CenterPoint Energy Houston Electric LLC's
First Request for Information

1-1. If not provided with your direct testimony in this case, please provide, in native format, all workpapers and documents supporting the testimony of each witness filing testimony on your behalf in this proceeding.

RESPONSE:

Please see the Direct Testimony and Workpapers of June M. Dively, Direct Testimony and Workpapers of Karl Nalepa, and Direct Testimony and Workpapers of Anjuli Winker.

Prepared By: Counsel
Sponsored By: June Dively, Karl Nalepa, and Anjuli Winker

1-2. For each testifying expert that has (or will) provided testimony for you in this case, please provide (to the extent not provided earlier):

1-2.1. A list of all cases in which the testifying expert has submitted testimony, from 2014 to the present;

1-2.2. Copies of all prior testimony, articles, speeches, published materials and peer review materials written by the testifying expert, from 2014 to the present;

1-2.3. The testifying expert's billing rate for this proceeding; and

1-2.4. All documents provided to, reviewed by, or prepared by or for the testifying expert in anticipation of the testifying expert filing testimony in this proceeding.

RESPONSE:

1-2.1 From 2014 to the present, OPUC witness June Dively has submitted testimony in the following cases:

PUC Docket No. 44941, *Application of El Paso Electric Company to Change Rates* (2015)

PUC Docket No. 45188, *Joint Report and Application of Oncor Electric Delivery Company LLC, Ovation Acquisition I, LLC, Ovation Acquisition II, LLC, and Shary Holdings, LLC for Regulatory Approvals pursuant to PURA §§14.101, 37.154, 39.262(I)-(m), and 39.915* (2015)

Gas Utilities Docket No. 10455, *Consolidated Complaints of TARGA Liquids Marketing and Trade, LLC, Pioneer Natural Resources USA, Inc., ConocoPhillips Company, and ELTM, LP, F/K/A Enbridge Liquids Transportation Marketing, LP, to Establish Common Carrier Rates for West Texas LPG Pipeline Limited Partnership* (2016)

PUC Docket No. 45414, *Review of the Rates of Sharyland Utilities, L.P., Establishment of Rates for Sharyland Distribution & Transmission Services, L.L.C., and Request for Grant of a Certificate of Convenience and Necessity and Transfer of Certificate Rights* (2017).

Gas Utilities Docket No. 10679, *Statement of Intent to Increase Gas Utility Rates Within the Unincorporated Areas Served by SiEnergy, LP in Central and South Texas* (2018)

PUC Docket No. 45979, *Review of Rate Case Expenses Incurred by Sharyland Utilities, L.P. Severed from Docket No. 45414* (2018)

PUC Docket No. 47141, *Review of Rate Case Expenses Incurred by Southwestern Electric Power Company and Municipalities in Docket No. 46449* (2018)

PUC Docket No. 48401, *Application of Texas-New Mexico Power Company for Authority to Change Rates* (2018)

For a list of all cases in which OPUC witness Karl Nalepa has submitted testimony from 2014 to the present, please see the Direct Testimony of Karl Nalepa at Appendix B (bates page 134).

For a list of all cases in which OPUC witness Anjuli Winker has submitted testimony from 2014 to the present, please see the Direct Testimony of Anjuli Winker at Attachment AW-B (bates page 48).

1-2.2 All responsive documents related to testimony before the Public Utility Commission of Texas ("PUCT" or the "Commission") are publicly available on the PUCT's Interchange, and all responsive documents related to testimony before the Railroad Commission of Texas ("Railroad Commission") can be obtained from the Railroad Commission. All responsive documents related to testimony before the Louisiana Public Service Commission and Colorado Public Utilities Commission are publicly available on each agency's website.

In addition, see Attachment CEHE-OPUC 1-2.2 for:

a. June Dively's report in American Arbitration Association Dispute Resolution No. 71 198 Y 00181 13 pertaining to Peregrine Pipeline Company, L.P. and Peregrine Field Services, L.P. v. XTO Energy Inc.; and
b. "Summary of the USAEE Central Texas Chapter's Workshop entitled EPA's Proposed Clean Power Plan Rules: Economic Modeling and Effects on the Electric Reliability of Texas Region," which was co-authored by Karl Nalepa.

1-2.3. Pursuant to agreement with Counsel for CenterPoint Houston, OPUC is not required to respond to this request for information.

1-2.4 Consistent with SOAH Order No. 2, this response does not include drafts of testimony or emails that include drafts of testimony as attachments. In addition, pursuant to agreement with Counsel for CenterPoint Houston, this response does not include administrative correspondence, such as emails forwarding case filings to testifying experts. Counsel for CenterPoint Houston also agreed to the redaction of OPUC witnesses' phone numbers and email addresses from this response.

SOAH DOCKET 473-18-4100
PUC DOCKET NO. 48439
OPUC's Response to CenterPoint Energy Houston Electric LLC's
First Request for Information

In anticipation of filing testimony in this proceeding, each OPUC testifying expert reviewed relevant portions of CenterPoint Houston's application, testimony, workpapers, responses to discovery, and errata. In addition, OPUC testifying experts June Dively, Karl Nalepa, and Anjuli Winker each reviewed the workpapers provided with their respective testimony and the items cited within their respective testimony. Mr. Nalepa also reviewed the Commission's orders in Docket Nos. 44572, 45747, 47032, and 48226, as well as settlement agreements that served as the basis for such orders. The correspondence included as Attachment CEHE-OPUC 1-2.4 was also provided to OPUC's testifying experts, as indicated on the specific correspondence.

Prepared By: Counsel
Sponsored By: June Dively, Karl Nalepa, and Anjuli Winker

Attachment 1-2.2a

EXPERT WITNESS REPORT OF

JUNE M. DIVELY, CPA, CFF, CR.FA, FABFA

PERTAINING TO

PEREGRINE PIPELINE COMPANY, L.P. AND PEREGRINE FIELD SERVICES, L.P.

V.

XTO ENERGY INC.

AMERICAN ARBITRATION ASSOCIATION

DISPUTE RESOLUTION NO. 71 198 Y 00181 13

OCTOBER 2, 2015

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Contents

Acronyms, Abbreviations and Defined Terms

AICPA – American Institute of Certified Public Accountants

CPA – Certified Public Accountant

CFF – Certified in Financial Forensics by the American Institute of Certified Public Accountants

CR.FA – Certified Forensic Accountant

Exchange Agreement – Agreement for Exchange of Dedicated Acreage executed June 1, 2008

FABFA – Fellow of the American Board of Forensic Accounts

Mcf – One thousand cubic feet

Natural Gas Contracts –

(a) Centralized Compression and Dehydration Contract between PFS and XTO dated October 3, 2007

(b) Natural Gas Transport Agreement between PPC and XTO dated October 3, 2007

(c) Meter Installation Agreement between PPC and XTO dated October 3, 2007

(d) Natural Gas Purchase Contract between PFS and XTO dated October 3, 2007

(e) Centralized Compression and Dehydration Contract between PFS and XTO dated March 31, 2008

(f) Natural Gas Transport Agreement between PPC and XTO dated March 31, 2008

(g) Meter Installation Agreement between PPC and XTO dated March 31, 2008

(h) Natural Gas Purchase Contract between PFS and XTO dated March 31, 2008

Peregrine – Collectively Peregrine Pipeline Company, L.P. and Peregrine Field Services, L.P.

PLLC – Professional Limited Liability Company

PPC – Peregrine Pipeline Company, L.P.

PFS – Peregrine Field Services, L.P.

RRC – Railroad Commission of Texas

Statement of Claim – Second Amended Statement of Claim, Peregrine Pipeline Company, L.P. and Peregrine Field Services, L.P., v. XTO Energy Inc., American Arbitration Association Dispute Resolution No. 71 198 Y 00181 13.

XTO – XTO Energy Inc.

Background

On March 20, 2015, Peregrine submitted its Statement of Claim against XTO to the American Arbitration Association. Therein, Peregrine pleads a cause of action for breach of Paragraphs 3 and 6 of the Centralized Compression and Dehydration Contract and the March 31, 2008 Centralized Compression and Dehydration Contract by failing to deliver gas and pay the required fees; breach of Article II, Paragraph 1; Article III, Paragraph 1; and Article V, Paragraphs 1 and 2 of the Natural Gas Transport Agreement and the March 31, 2008 Natural Gas Transport Agreement by failing to deliver all gas owned or controlled to PPC, failing to construct all gas gathering facilities to connect to PPC's system, and failing to pay the required fees; and breach of Paragraph 3 of the Meter Installation Agreement and the March 31, 2008 Meter Installation Agreement by failing to install the gas gathering lines, quality control facilities, and other required facilities at the interconnection between XTO's facilities and PPC's facilities (the "Breach"). The Breach is related to the Natural Gas Contracts covering certain assets that were sold by David H. Arrington Oil and Gas, Inc. to XTO. Because of the Breach, XTO has failed to deliver to PPC volumes under its control that were produced by the wells that would, absent the Breach, have been connected to PPC under the Exchange Agreement (collectively "Violation Wells" and individually "Violation Well").

Introduction and Assignment

I have compiled the information and formulated the opinions contained herein in connection with the Violation Wells. Specifically, I reviewed documents, volumetric data, and accounting records and have provided my opinion on the following items as they relate to the Violation Wells:

1. The methodology to calculate the net profits not received by Peregrine from the Violation wells.
2. The amount of net profits Peregrine would have received from the Violation Wells through June 2015 ("Net Profits").
3. The amounts paid by XTO to Peregrine that pertain to the Violation Wells through June 2015 production ("Payments").

Qualifications and Previous Testimony

I have been practicing as a CPA in the State of Texas since 1989, and as a CR.FA since 2006. I received the CFF credential from the AICPA in 2009. I have been a partner and the founding member of Dively & Associates, PLLC in Austin, Texas since 2003. I have a Bachelor of Business Administration in accounting and business data systems from the University of Texas at San Antonio. My curriculum vitae, which includes matters in which I have provided written or oral testimony, is presented in Exhibit A.

I established the predecessor firm to Dively & Associates, PLLC, Consulting Dynamics Group, LLC in 1996. In 2003, I established Dively & Associates, PLLC, a public accounting firm, and in 2011, I established Dively Energy Service, LLC, a consulting firm. During the 19 years I have practiced publicly, I have developed a specialization in accounting for regulated entities, cost of providing service, rate making, financial regulatory matters, and forensic accounting. I have provided services for both regulated entities and regulatory bodies.

Documents Reviewed

In order to render opinions on the questions asked of me, the following documents were reviewed:

1. The Statement of Claim; and,
2. The Natural Gas Contracts.

Data Acquired

In order to render opinions on the questions asked of me, following data was acquired:

Data	Source	Exhibit
1. List of the Violation Wells	Christopher Hall	B
2. Production volumes for each Violation Well	Specific Lease Query from the RRC online Production Data Query System	C
3. Btu Content of each Violation Well	Russell K. Hall and Associates, Inc.	D
4. XTO Owned or Controlled Percentage	Christopher Hall	B
5. PPC and PFS rates	Peregrine	F
6. Variable expense analysis	Dana Engelstad	H
7. XTO payment invoices and supporting files	Peregrine	K

Standards of Review

During my analysis, I complied with standards and utilized methodologies applicable to a Certified Public Accountant and a Certified Forensic Accountant. These standards and methodologies are generally accepted in my profession.

Executive Summary

In developing the methodology for calculating Net Profits, it was assumed that XTO would have delivered into PPC the percentage of production owned or controlled by XTO for the Violation Wells. Peregrine's witness, Christopher Hall, provided the list of Violation Wells. Using Mcf production data filed with the RRC, a database was created containing production data for all Violation Wells from the date of first production through June 2015. Btu factors derived from data received from Russell K. Hall and Associates, Inc. were then applied to convert the Mcf production for each well to MMBtu's. After determining the MMBtu's produced for each well, each well's MMBtu's produced were multiplied by the XTO Owned or Controlled Percentage provided by Peregrine's witness, Christopher Hall, to determine the XTO Owned or Controlled MMBtus for each Violation Well. A total of 42,652,681 MMBtus produced by the Violation Wells were Owned or Controlled by XTO ("Owned or Controlled Volumes").

To calculate Revenues, the Owned or Controlled Volumes, for each month, for each Violation Well, were multiplied by the PPC and PFS rates that were effective during that month. Total Revenues are $20,802,029 for PPC and $11,179,466 for PFS, for a total of $31,981,495.

Incremental expenses that would have been incurred had XTO delivered the Owned or Controlled Volumes ("Incremental Expenses") were calculated by applying variable expense rates per MMBtu, developed by Peregrine witness Dana Engelstad, to the Owned or Controlled Volumes. Incremental Expenses totaled $3,408,283 for PPC and $7,284,212 for PFS, for a total of $10,692,495.

Payments were compiled from invoices and supporting details received by Peregrine from XTO. Total Payments through June 2015 production are $5,844,832 for PPC and $0 for PFS, for a total of $5,844,832.

The Net Profits, Payments, and the remaining balance due Peregrine through June 2015 production follow:

	PPC	PFS	Total
Revenues	$ 20,802,029	$ 11,179,466	$ 31,981,495
Incremental Expenses	$ 3,408,283	$ 7,284,212	$ 10,692,495
Net Profits	$ 17,393,746	$ 3,895,254	$ 21,289,000
Payments Received from XTO	$ 5,844,832	$ 0	$ 5,844,832
Balance Due	$ 11,548,914	$ 3,895,254	$ 15,444,168

Methodology

The following page provides a flowchart of the methodology used to determine Net Profits. Owned or Controlled Volumes and Revenues were calculated by Violation Well. Revenue, Expenses, and Net Profits were summarized for PPC, PFS, and in total. This methodology is not intended to circumvent or in any way limit the application of professional judgement, standards or methods in determining the actual data inputs or underlying calculations. This report will describe deviations from the methodology presented.

Section	Purpose	Step	Description	Example	Source	Exhibit
		Methodology			**Data**	
		Step	Description	Example	Source	Exhibit
Volumes	Determine the Owned or Controlled Volumes produced by the Violation Wells	A	Obtain a list of the Violation Wells	Annetta Unit Dec-2010	Christopher Hall	B
		B	Obtain the Mcf Produced as reported to the RRC for each Violation Well	9,112	Specific Lease Query from the Railroad Commission of Texas online Production Data Query System	C
		C	Obtain the Btu content for each Violation Well	1.2180	Russell K. Hall and Associates, Inc.	D
		D = B x C	Calculate the MMBtu produced by each Violation Well	11,098		
		E	Obtain the XTO Owned or Controlled Percentage for each Violation Well	100%	Christopher Hall	B
		F = D x E	Calculate the Owned or Controlled Volumes Produced by each Violation Well	11,098		E
Revenues	Calculate revenues that would have been received	F	Previously calculated the Owned or Controlled Volumes Produced	11,098		E
		G	Obtain historical PPC and PFS Rates	$0.60	Peregrine	F
		H = F x G	Calculate the Revenues that would have been received had XTO delivered the Owned or Controlled Volumes	$6,659		G
Expenses	Calculate Incremental Expenses that would have been incurred	I	Obtain variable costs per Mmbtu	$ 0.2251	Dana Engelstad	H
		F	Previously calculated the Owned or Controlled Volumes Produced	11,098		E
		J = I x F	Calculate Incremental Expenses that would have been incurred had Peregrine received the Owned or Controlled Volumes	$2,498		I
Net Profits	Calculate Net Profits	K = H - J	Calculate the Net Profits that would have been received had Peregrine received the Owned or Controlled Volumes	$4,161		J

Calculation of Net Profits

The following procedures were applied and correlate with the alphanumeric steps provided in the methodology previously presented.

Step One - Volumes

The first step in the process is to determine the Owned or Controlled Volumes:

A. Obtain a list of the Violation Wells – Peregrine Witness Christopher Hall provided an Excel spreadsheet entitled *Wells Drilled on XTO Dedicated Acreage*. The list was limited to the Violation Wells using Mr. Hall's embedded filter. (Exhibit B) From the data provided by Mr. Hall, an Excel database was created for population with production data.

B. Obtain the Mcf produced by the Violation Wells – Using the Specific Lease Query of the online Production Data Query System in the website of the RRC, all available production volume data through June 2015 ("Mcf Production") was added to the database by year and month for each Violation Well identified in Exhibit B along with the RRC Lease Number.

   The following link provides quick access to the query system on the RRC's website: http://webapps.rrc.state.tx.us/PDQ/quickLeaseReportBuilderAction.do

   One well, Barone, required a deviation from these procedures. To obtain the production for Barone, it was necessary to use a "Pending" query because Barone was plugged prior to the completion reports being activated into the RRC database.

C. Obtain the Btu content for each Violation Well – Peregrine Witness Russell K. Hall, of Russell K. Hall and Associates, Inc., provided the Btu content for each Violation Well. (Exhibit D) The Btu content for each Violation Well was divided by 1000 to yield a "Btu Factor". The Btu Factors were added to the database.

D. Calculate the MMBtu produced by each Violation Well – Production volumes are reported to the RRC in Mcf, and must be converted to MMBtu because Peregrine's rates are applied to MMBtus. A field was added to the data base to calculate the MMBtu Produced by multiplying the Mcf Production by the Btu Factor. (Exhibit E)

   The volumes reported to the RRC do not contain all volumes produced by the Violation Wells because volumes used as lift gas are not included in the production reported to the RRC. Lift gas volumes related to wells that deliver to PPC typically incur transportation charges, but not compression and dehydration charges. By omitting an adder for lift gas volumes, all volumes resulting from this calculation would have been subject to both transportation and compression and dehydration charges.

E. Obtain XTO's Owned or Controlled Percentage for each Violation Well – Peregrine Witness Christopher Hall provided an Excel spreadsheet entitled *Wells Drilled on XTO Dedicated Acreage*. (Exhibit B) The list contained an XTO Owned or Controlled Percentage that represents the portion of the produced volumes that XTO would have delivered to Peregrine from the Violation Wells. The XTO Owned or Controlled Percentages were added to the database.

F. Calculate the Owned or Controlled Volumes for each Violation Well – To calculate the Owned or Controlled Volumes for each Violation Well, a field was added to the database to multiply the MMBtu produced by each Violation Well by XTO's Owned or Controlled Percentage to yield the Owned or Controlled Volumes. The Owned or Controlled Volumes from the Violation Wells through June 2015 totaled 42,652,681 MMBtu. (Exhibit E)

Step Two - Revenues

The second step in the process is to calculate Revenues.

G. Obtain historical PPC and PFS rates – During the period beginning 2008 through 2015, Peregrine has had three different sets of rates. The following are Peregrine's rates during the periods presented.

Period	PPC Rate Per MMBtu	PFS Rate Per MMBtu	Consolidated Rate Per MMBtu
2008 through February 2013	$0.4000	$0.2000	$0.6000
March 2013 through February 2015	$0.6300	$0.3700	$1.0000
March 2015 through Present	$0.7621	$0.4075	$1.1696

H. Calculate Revenues – To calculate Revenues, the Owned or Controlled Volumes were multiplied by the appropriate historical PPC and PFS rates. Revenues for the Violation Wells through June 2015 would have been $20,802,029 for PPC and $11,179,466 for PFS, for a total of $31,981,495. (Exhibit G)

Step Three - Expenses

The third step in the process is to calculate the expected incremental increase in operating expenses ("OpEx") and general and administrative expenses ("G&A") had Peregrine received the Owned or Controlled Volumes. The expected incremental increase in OpEx and G&A expenses for each year would be based upon Peregrine's variable expenses. There would be no expected increase in fixed expenses. The following procedures were applied:

I. Obtain variable costs per MMBtu – The variable costs per MMBtu for both OpEx and G&A for the years 2008 through 2014 for PPC and PFS were obtained from Peregrine witness Dana Engelstad. (Exhibit H)

J. Calculate Incremental Expenses – To calculate Incremental Expenses, the variable rates provided by Mr. Engelstad were multiplied by the Owned or Controlled Volumes. The variable cost for 2014 was used for 2015. Peregrine's expenses would have increased by $3,408,283 for PPC and $7,284,212 for PFS, for a total of $10,692,495. (Exhibit I)

Step Four – Net Profits

The fourth step in the process is to calculate Net Profits.

K. Net Profits are calculated as follows:

	PPC	PFS	Total
Revenues	$ 20,802,029	$ 11,179,466	$ 31,981,495
Incremental Expenses	$ 3,408,283	$ 7,284,212	$ 10,692,495
Net Profits	$ 17,393,746	$ 3,895,254	$ 21,289,000

Exhibit J provides Net Profits by calendar year.

Payments

XTO has made the following payments to Peregrine totaling $ 5,844,832 related to the Violation wells. Payments were compiled from supporting files and invoices received by Peregrine from XTO. (Exhibit K)

Summary of Payments made by XTO
for XTO Dedicated Acreage
All Periods through June 2015

Invoice/Last-Update Date	Period Covered	Total MMBtu	Total Payment	PPC	PFS
07/18/12	Nov 2007 - Jan 2011	2,971,011	$ 1,188,404	$ 1,188,404	$ -
07/18/12	Feb 2011 - Jul 2011	1,230,010	492,004	492,004	-
05/29/12	May 2011 - Jul 2011	70,059	28,023	28,023	-
05/29/12	Aug 2011 - Feb 2012	1,423,585	569,434	569,434	-
05/21/12	Mar 2013	173,179	69,272	69,272	-
08/24/12	Apr 2012 - Jun 2012	455,586	182,234	182,234	-
11/20/12	Jul 2012 - Sep 2012	402,737	161,095	161,095	-
02/22/13	Oct 2012 - Dec 2012	408,277	163,311	163,311	-
03/06/13	Mar 2012 - Sep 2012	273,725	109,490	109,490	-
05/31/13	Jan 2013 - Mar 2013	340,819	162,785	162,785	-
08/31/13	Apr 2013 - Jun 2013	336,096	211,740	211,740	-
11/30/13	Jul 2013 - Sep 2013	375,865	236,795	236,795	-
02/28/14	Oct 2013 - Dec 2013	687,637	433,211	433,211	-
05/28/14	Jan 2014 - Mar 2014	587,269	369,979	369,979	-
08/31/14	Apr 2014 - Jun 2014	482,783	304,153	304,153	-
11/30/14	Jul 2014 - Sep 2014	460,130	289,882	289,882	-
02/28/15	Oct 2014 - Dec 2014	446,471	281,277	281,277	-
05/31/14	Jan 2015 - Mar 2015	408,544	276,353	276,353	-
08/31/15	Apr 2014 - Jun 2015	413,840	315,387	315,387	-
		11,947,623	$ 5,844,832	$ 5,844,832	$ -

Summary

In summary, the remaining Net Profits due to Peregrine from XTO are as follows:

	PPC	PFS	Total
Net Profits	$ 17,393,746	$ 3,895,254	$ 21,289,000
Payments received from XTO	$ 5,844,832	$ 0	$ 5,844,832
Balance of Net Profits due to Peregrine	$ 11,548,914	$ 3,895,254	$ 15,444,168

Attachment 1-2.2b

EPA's Proposed Clean Power Plan Rules: Economic Modeling and Effects On the Electric Reliability of Texas Region

On April 8, 2015, the Central Texas Chapter of the USAEE (CTAEE) co-sponsored with the Energy Institute at the University of Texas at Austin a Workshop entitled ***EPA's Proposed Clean Power Plan Rules: Economic Modeling and Effects on the Electric Reliability of Texas Region***. The proposed new rules will limit greenhouse gas emissions from existing fossil fuel power plants under Section 111(d) of the Clean Air Act. If enacted, the proposed rules will have significant implications for the economy and the environment, both in Texas and across the country. The Workshop provided a forum for understanding the impact of, and options for, implementing the proposed rules that would be useful to policy makers. It attracted more than 100 registered attendees, representing a broad range of industry stakeholders.

The Workshop opened with introductory remarks by Dr. Mina Dioun, President of the CTAEE and Professor Thomas Edgar, Director of the Energy Institute. The program then highlighted five distinguished speakers, beginning with an overview of the proposed rule and followed by presentations of four experts on the results of their modeling work on the rule.

Professor David Spence of ***The University of Texas at Austin McCombs School of Business and Law School*** provided an overview of the proposed EPA rule and its legal aspects. He highlighted the four "building blocks" for compliance, including 1) heat rate improvements at coal-fired power plants, 2) increased dispatch of gas-fired generation, 3) greater use of zero-carbon sources such as renewables and nuclear, and 4) demand reduction programs. Professor Spence also outlined some of the key legal vulnerabilities, including 1) how the proposed rule might be perceived as "commandeering" state institutions for federal purposes, 2) possible inequities among the states in its impacts, 3) the proposed rule's consistency with the statute, and 4) consistency with other EPA rules. The merits and likely success in the courts of some of these arguments in opposition to the proposed rule were discussed.

The first session was moderated by Dr. Jay Zarnikau of ***Frontier Associates***. The speakers included Mr. Jack Moore of ***Energy + Environmental Economics Consulting (E3)*** and Mr. Trevor Houser of ***Rhodium Consulting*** who presented the results of Rhodium's joint research with the ***Center for Strategic and International Studies (CSIS)***.

Mr. Moore concluded that it was technically feasible for the U.S. to achieve an 80% reduction in greenhouse gas emissions from 1990 levels by the year 2050. He presented four scenarios which would take us there, relying on various combinations of renewables, nuclear energy, and carbon capture and storage, supplemented with energy efficiency and fuel switching. There is considerable uncertainty of the cost, with a midrange of 1% of GDP. The net cost to the average household to achieve this level of emissions would rise to about $25 per month. To achieve these reductions, some of the attractive short-term measures such as fuel switching or converting electric space heating to natural gas may make it more challenging to meet deep reductions in the long-term. And new infrastructure such as power plants that have a 30+ year life may have a different role in the generation mix in later years. Alternatively, the integration of hydrogen fuel would be a sustainable approach to de-carbonization.

Mr. Trevor Houser described how Rhodium and CSIS used the US DOE's National Energy Modeling System (NEMS) to analyze the proposed Clean Power Plan. The natural gas industry could be among the winners, and the coal industry among the losers. And this, in turn, suggests very disparate regional impacts from the Plan. Wyoming, a major coal producer, would get hit hard. Texas and neighboring states – large producers of natural gas – would realize net benefits. The more that other states relied upon fuel switching to meet the targets (as opposed to energy efficiency or renewables), the greater the demand for natural gas, and the greater the net benefits to Texas. The modeling also found that cooperation between states in meeting the goals dramatically lowers consumer costs.

The second session was moderated by Mr. Neil McAndrews of ***Neil McAndrews & Associates***. The speakers included Mr. Warren Lasher of ***ERCOT***, and Dr. Yingxia Yang of the ***Brattle Group***.

Mr. Lasher noted that the Clean Power Plan was one among many federal air quality actions affecting the Texas electricity market. Coal represented over 22% of the generation capacity in 2014, and the Cross State Air Pollution Rule (CSAPR), Mercury and Air Toxics Standards (MATS), Ash Disposal Rule, Regional Haze Federal Plan, Clean Water Act Section 316(b), and now the Clean Power Plan could all reduce the state's future reliance on coal generation, potentially affecting resource adequacy, transmission reliability, and renewable integration efforts. Because many of the coal plants within ERCOT are old and lack some form of environmental controls, a number of coal units will be retired because it will not be cost effective to retrofit and bring them into compliance. Natural gas, wind, and solar will be added instead.

Dr. Yang explained how Brattle was retained by the Texas Clean Energy Coalition to model future expansion of the ERCOT system under expanded roles for natural gas, renewables, and demand side resources, including demand response, energy efficiency, and combined heat & power (CHP) opportunities. The model was developed and results issued prior to EPA's proposed CPP rule and therefore do not reflect the EPA's four "building blocks" approach. However, the results include scenarios that are similar to the mass-based targets provided for under the rule. The results show moderate fuel switching to natural gas, but just 3.8 GW reduction in coal-fired capacity due to derates for carbon capture and sequestration (CCS). The results also show moderate increases for renewables, and significant increases in energy efficiency. Finally, the results suggest a large technical potential for CHP in Texas.

The Workshop presentations are available on the Central Texas Chapter page of the USAEE website: https://usaee.org/chapters/centraltexas.aspx

Contributors: Karl J. Nalepa, ReSolved Energy Consulting; Jay Zarnikau; and Neil McAndrews

Attachment 1-2.4

DAmbrosio, Eleanor

From: DAmbrosio, Eleanor
Sent: Wednesday, May 08, 2019 11:38 AM
To: June Dively
Cc: Quinn, Cassandra
Subject: 49421 Rate-Case Expenses

June,

Just a quick update to let you know that we have inquired as to whether CenterPoint plans to severe the rate-case expense issue, and it looks like the answer is no. They are going to talk to the client, but they framed it as though their decision rests on whether there would be settlement talks before testimony is due. We communicated that from OPUC's perspective, the schedule doesn't really have room for settlement talks before testimony is due.

I will keep you posted if they change their mind.

Thank you,
Eleanor

Eleanor D'Ambrosio | Assistant Public Counsel
Office of Public Utility Counsel
(512) 936-7506
Eleanor.Dambrosio@opuc.texas.gov

Quinn, Cassandra

From:	Quinn, Cassandra
Sent:	Thursday, May 09, 2019 10:23 AM
To:	Karl Nalepa; June Dively; Winker, Anjuli
Cc:	DAmbrosio, Eleanor
Subject:	49421 - Update on issues to be addressed

All,

I think this will primarily affect the issues that Karl is looking at, but I wanted to keep everyone in the loop.

At the open meeting this morning, the Commission determined that the following two issues should <u>not</u> be addressed:

(1) request for voltage regulation batteries, and

(2) request for a line extension allowance for electric vehicles.

There were also some other interesting takeaways:

- On Vectren, there was an issue added to the preliminary order to consider whether there are any protections that are appropriate to protect CenterPoint's financial integrity.
- The Chairman urged folks, especially Staff, to be sure to review prudence of substations.
- The Chairman noted that while they were not specifically addressing a lost revenue adjustment mechanism in the preliminary order, if what CenterPoint is proposing is energy efficiency related, then it should not be in base rates.

The actual preliminary order, as modified at today's meeting, should come out soon. If anyone has any questions, please just let us know.

Thank you,
Cassandra

Cassandra Quinn
Office of Public Utility Counsel
1701 Congress Avenue, Suite 9-180
P.O. Box 12397
Austin, Texas 78711-2397
(512) 936-7534 (Direct)
(512) 936-7525 (Fax)
cassandra.quinn@opuc.texas.gov

Quinn, Cassandra

From: Quinn, Cassandra
Sent: Monday, May 13, 2019 2:17 PM
To: Karl Nalepa
Subject: CenterPoint vegetation management report

Karl,
Below is a link to CenterPoint's current vegetation management report. CQ

From: noreply@puc.texas.gov [mailto:noreply@puc.texas.gov]
Sent: Wednesday, May 01, 2019 3:59 PM
To: Quinn, Cassandra
Subject: Interchange Notification: 41381-62

Filing Alert! A new document has been filed under 41381-62

Filing	41381-62
Item Type	PRJ
Date Filed	5/1/2019
Party	CENTERPOINT ENERGY HOUSTON ELECTRIC , LLC
Utility Type	E
Category	P, REG, SUBM
Date Sent	5/1/2019
User	Cassandra Quinn (sequin1218)
Document Link:	Get Document 41381-62

Master Description:

ANNUAL VEGETATION MANAGEMENT PLANS AND REPORTS PURSUANT TO PUC SUBST. R. §25.96

Filing Description:

VEGETATION MANAGEMENT REPORT

Public Utility Commission

www.puc.texas.gov

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END OF FILING

Quinn, Cassandra

From: Quinn, Cassandra
Sent: Monday, May 13, 2019 2:20 PM
To: Karl Nalepa
Subject: Lost revenue adjustment court case
Attachments: CenterPoint Energy Houston Elec LLC v Public Utility Comn.pdf

Karl,
As discussed, attached is the court case addressing LRAMs. CQ

Cassandra Quinn
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354 S.W.3d 899
Court of Appeals of Texas,
Austin.

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC, Appellant,
v.
PUBLIC UTILITY COMMISSION of Texas, Appellee.

No. 03-10-00633-CV.
|
Nov. 10, 2011.

Synopsis
Background: Electric utility company filed petition challenging rule promulgated by Public Utility Commission, which governed electric utilities' implementation of statutorily mandated energy-efficiency programs designed to reduce electricity consumption, on allegation that rule was invalid for failing to include a lost-revenue adjustment mechanism (LRAM).

[Holding:] The Court of Appeals, J. Woodfin Jones, C.J., held that under the governing statute, Commission was not required to promulgate a rule that included an LRAM.

Affirmed.

West Headnotes (6)

[1] **Administrative Law and Procedure**
Compliance with constitution or law in general
Administrative Law and Procedure
Compliance with rulemaking procedures or other process
A validity challenge tests a rule on procedural and constitutional grounds.

1 Cases that cite this headnote

[2] **Administrative Law and Procedure**
Effect of agency's authority or lack thereof
The scope of a validity challenge includes whether the agency had statutory authority to promulgate the rule.

1 Cases that cite this headnote

[3] **Administrative Law and Procedure**
Presumptions and burden of proof
Courts presume that an agency rule is valid, and the party challenging the rule has the burden of demonstrating its invalidity.

2 Cases that cite this headnote

[4] **Administrative Law and Procedure**
Effect of agency's authority or lack thereof
An agency's rules must comport with the agency's authorizing statute.

1 Cases that cite this headnote

[5] **Administrative Law and Procedure**
Facial invalidity
To establish an agency rule's facial invalidity, the challenger must show that the rule: (1) contravenes specific statutory language; (2) is counter to the statute's general objectives; or (3) imposes additional burdens, conditions, or restrictions in excess of or inconsistent with the relevant statutory provisions.

1 Cases that cite this headnote

[6] **Electricity**
Operating expenses
Under Public Utilities Regulation Act (PURA), which governed energy-efficiency programs designed to reduce electricity consumption, and which mandated that the Public Utility Commission establish energy efficiency cost recovery factor (EECRF) for utility expenditures made to satisfy the goal of programs, a utility's "costs" referred to actual expenditures associated with its energy-

efficiency programs, which could be recovered from a utility's customers through application of an EECRF that did not include a lost-revenue adjustment mechanism (LRAM). V.T.C.A., Utilities Code § 39.905(b)(1).

1 Cases that cite this headnote

Attorneys and Law Firms

***900** Christian J. Ward, April Farris, Ryan P. Bates, Yetter Coleman, LLP, Christopher D. Sileo, Jane M.N. Webre, Scott, Douglass & McConnico, LLP, Austin, TX, Jason M. Ryan, Assistant General Counsel, CenterPoint Energy, Inc., Houston, TX, for Appellant.

Philip G. Oldham, Tammy Cooper, Andrews Kurth, LLP, John R. Hulme, Assistant Attorney General, Environmental Protection & Administrative Law Division, Austin, TX, for Appellee.

James K. Rourke Jr., Sheri Sander Givens, Sara J. Ferris, Assistant Public Counsel, Office of Public Utility Counsel, Lino Mendiola III, Katherine Coleman, Andrews Kurth, LLP, Austin, TX, Melba T. Pourteau, Senior Assistant City Attorney, City of Houston, Legal Department, Houston, TX, for Intervenor.

Before Chief Justice JONES, Justices PEMBERTON and HENSON.

OPINION

J. WOODFIN JONES, Chief Justice.

In this direct appeal, we consider a challenge to the validity of a rule promulgated by the Public Utility Commission governing electric utilities' implementation of statutorily mandated energy-efficiency ***901** programs designed to reduce electricity consumption. *See* 16 Tex. Admin. Code § 25.181 (2011) (Pub. Util. Comm'n, Energy Efficiency Goal).[1] Appellant, CenterPoint Energy Houston Electric, LLC ("CenterPoint"), contends that section 39.905 of the Public Utilities Regulation Act ("PURA") requires that the Commission include a "lost-revenue adjustment mechanism" ("LRAM") in rule 25.181 and that the Commission's failure to do so renders the rule invalid. *See* Tex. Util.Code Ann. § 39.905 (West Supp.2010). CenterPoint alternatively contends that rule 25.181 is invalid because the Commission's failure to include an LRAM as part of rule 25.181 resulted from the Commission's erroneous interpretation of its own authority to do so under PURA. We will affirm.

1 In addition to the Commission, three intervenors argue in support of the rule. They are the Office of Public Utility Counsel, the City of Houston, and Texas Industrial Energy Consumers.

BACKGROUND

In 1999 the legislature enacted PURA section 39.905, which established energy-efficiency goals designed to reduce Texas customers' energy consumption. *See id.* § 39.905. The goals consisted of specified reductions—i.e., a slowing—in the anticipated growth in demand for electricity in the service areas of electric utilities. *See id.* § 39.905(a)(3). Since then, CenterPoint has offered energy-efficiency programs designed to meet these goals. In 2007, the legislature amended PURA section 39.905 to establish additional energy-efficiency goals. The amended statute also directed the Commission to adopt rules to establish "an energy efficiency cost recovery factor for ensuring timely and reasonable cost recovery for utility expenditures made to satisfy the goal of this section." *See id.* § 39.905(b)(1). Thus, the purpose of the "cost-recovery factor"—essentially a surcharge on customers' bills—was to facilitate the prompt recovery of "expenditures" made to achieve the goals of section 39.905.

The amended statute further provides:

> The energy efficiency cost recovery factor under Subsection (b)(1) may not result in an over-recovery of costs but may be adjusted each year to change rates to enable utilities to match revenues against energy efficiency costs and any incentives to which they are granted. The factor shall be adjusted to reflect any over-collection or under-collection of energy efficiency cost recovery revenues in previous years.

Id. § 39.905(b–1). Thus, this provision establishes an annual "true-up" procedure so that revenues produced by the "energy efficiency cost recovery factor" ("EECRF") stay reasonably close to the actual energy efficiency costs. In response to this legislation, in 2008 the Commission replaced its existing energy-efficiency rule with an amended rule that added provisions establishing the newly mandated EECRF. *See* 33 Tex. Reg. 3622 (2008) (former 16 Tex. Admin. Code § 25.181). As amended in 2008, rule 25.181 stated that a utility must establish an EECRF that "complies with this section to timely recover the reasonable costs of providing energy efficiency programs pursuant to this section." 16 Tex. Admin. Code § 25.181(f)(6).

In 2010, the Commission commenced a rulemaking proceeding, Project No. 37623, to again amend rule 25.181. In that proceeding, the Commission proposed amendments to the rule that would establish energy-efficiency goals for 2012 and 2013, add a cost cap, update the rule's cost- ***902** effectiveness standard, and modify calculation of the rule's performance bonus for utilities exceeding the stated energy-efficiency goals. The Commission also sought comments on whether it should adopt an LRAM that would provide a method for utilities to recover, through the EECRF, any *revenues* that could be shown to have been lost as a result of implementing the mandated energy efficiency programs. Numerous interested entities provided comments both for and against including an LRAM in rule 25.181. CenterPoint supported adoption of an LRAM, maintaining that, pursuant to PURA section 39.905, the Commission "clearly has the authority" to do so and that an LRAM "is a better solution than the filing of a costly base rate case—the utility's only other method of addressing an inability to adjust rates." In its Order in Project No. 37623, the Commission ultimately declined to include an LRAM provision in rule 25.181, stating that its decision was consistent with the conclusion it had reached in an earlier proceeding that "lost revenues" are not "energy-efficiency costs" that could be recovered through an EECRF under PURA section 39.905. [2] CenterPoint filed this direct appeal challenging the validity of rule 25.181. *See* Tex. Util.Code Ann. § 39.001(f) (West 2007).

2 The earlier proceeding had addressed—and rejected—CenterPoint's application for approval of an EECRF that would allow it to recover $1,436,550 of revenue losses it claimed were attributable to its 2009 energy-efficiency programs.

DISCUSSION

[1] [2] [3] [4] [5] This proceeding is a direct challenge to the validity of a chapter 39 "competition rule." *See id.* § 39.001(e). A validity challenge tests a rule on procedural and constitutional grounds. *Office of Pub. Util. Counsel v. Public Util. Comm'n,* 104 S.W.3d 225, 232 (Tex.App.-Austin 2003, no pet.). The scope of a validity challenge also includes whether the agency had statutory authority to promulgate the rule. *City of Alvin v. Public Util. Comm'n,* 143 S.W.3d 872, 878 (Tex.App.-Austin 2004, no pet.). We presume that an agency rule is valid, and the party challenging the rule has the burden of demonstrating its invalidity. *See McCarty v. Texas Parks & Wildlife Dep't,* 919 S.W.2d 853, 854 (Tex.App.-Austin 1996, no pet.). An agency's rules must comport with the agency's authorizing statute. *See Office of Pub. Util. Counsel v. Public Util. Comm'n,* 131 S.W.3d 314, 321 (Tex.App.-Austin 2004, pet. denied). To establish a rule's facial invalidity, the challenger must show that the rule (1) contravenes specific statutory language; (2) is counter to the statute's general objectives; or (3) imposes additional burdens, conditions, or restrictions in excess of or inconsistent with the relevant statutory provisions. *See id.* (citing *Office of Pub. Util. Counsel,* 104 S.W.3d at 232).

CenterPoint contends that PURA section 39.905 requires that the Commission include a provision for an LRAM in rule 25.181 and that its failure to do so contravenes the statute and renders the rule invalid. CenterPoint argues that when the legislature enacted PURA section 39.905(b–1) and directed the Commission to establish an EECRF to "enable utilities to match revenues against energy efficiency costs and any incentives to which they are granted," it divested the Commission of any discretion to decline to adopt an LRAM "as part of its efforts to enable utilities to meet the legislature's energy efficiency goals." *See* Tex. Util.Code Ann. § 39.905(b–1). The Commission counters that section 39.905 authorizes only compensation for a utility's *expenditures* associated with energy-efficiency programs, ***903** not for any *revenues* lost as a result of implementing those programs. The dispute, therefore, turns principally on the construction of a statute, a question of law that we review de novo. *See First Am. Title Ins. Co. v. Combs,* 258 S.W.3d 627, 632 (Tex.2008).

Our primary objective in construing statutes is to give effect to the legislature's intent. *Galbraith Eng'g Consultants, Inc. v. Pochucha,* 290 S.W.3d 863, 867 (Tex.2009). The plain meaning of the text is the best expression of legislative intent unless a different meaning is supplied by legislative definition or is apparent from the context, or unless the plain meaning would lead to absurd or nonsensical results that the legislature could not have intended. *City of Rockwall v. Hughes,* 246 S.W.3d 621, 625–26 (Tex.2008); *see* Tex. Gov't Code Ann. § 311.011 (West 2005) ("Words and phrases shall be read in context and construed according to the rules of grammar and common usage."). We look to the entire act in determining the legislature's intent with respect to a specific provision. *Upjohn Co. v. Rylander,* 38 S.W.3d 600, 607 (Tex.App.-Austin 2000, pet. denied). When a statute is ambiguous, we are required to give "serious consideration" to the construction of the statute by the administrative agency charged with its enforcement, *Railroad Comm'n v. Texas Citizens for a Safe Future & Clean Water,* 336 S.W.3d 619, 624 (Tex.2011), and uphold the agency's interpretation if it is reasonable, *First Am. Title Ins. Co.,* 258 S.W.3d at 632 (quoting *Tarrant Appraisal Dist. v. Moore,* 845 S.W.2d 820, 823 (Tex.1993)). We do not defer to an agency interpretation when a statute is unambiguous. *See Texas Citizens,* 336 S.W.3d at 624 & n. 6. We also " 'do not defer to administrative interpretation in regard to questions which do not lie within administrative expertise, or [which] deal with a nontechnical question of law.' " *Rylander v. Fisher Controls Int'l Inc.,* 45 S.W.3d 291, 302 (Tex.App.-Austin 2001, no pet.) (quoting 2B Singer, *Sutherland Statutory Construction* § 49.04, at 23–24 (6th ed. 2000)).

[6] CenterPoint contends that the plain language of PURA section 39.905 requires the inclusion of an LRAM because the statute mandates that a utility be compensated for revenues lost as a result of its energy-efficiency programs. CenterPoint's position depends on construing the term "costs" as used in PURA section 39.905 to include such lost revenues. CenterPoint asserts that the plain meaning of the term "includes the losses or sacrifices sustained as a result of an endeavor." Considered in context, however, we do not believe the statute permits such a broad reading of the term "costs." *See Continental Cas. Co. v. Downs,* 81 S.W.3d 803, 805 (Tex.2002) (courts must consider statute as whole and not words or provisions in isolation). Rather, PURA section 39.905(b)(1) directs the Commission to establish an EECRF "for ensuring timely and reasonable *cost recovery for utility expenditures* made to satisfy the goal of this section." Tex. Util.Code Ann. § 39.905(b)(1) (emphasis added). The statute thus provides that the "costs" the legislature intended for a utility to recover through the EECRF are its "expenditures" associated with its attempts to comply with the energy-efficiency mandate. *See id.* The ordinary meaning of the term "expenditure" is: (1) the act or process of paying out; disbursement; (2) a sum paid out. Black's Law Dictionary 658 (9th ed. 2009). In this context, the term "expenditures" does not contemplate lost revenues.

In at least two other provisions of PURA, the legislature expressly distinguishes "costs" from "revenues," indicating that its use of the term "costs" by itself ***904** does not encompass lost revenues. For example, PURA section 55.024(b) provides that a telecommunications utility may recover "all costs incurred *and all loss of revenue* " resulting from imposition of charges for providing mandatory two-way extended area service to customers. *See* Tex. Util.Code Ann. § 55.024(b) (West 2007) (emphasis added). In PURA section 56.025(e), the legislature directed the Commission to "implement a mechanism to replace the reasonably projected increase in costs *or decrease in revenue* " caused by a governmental agency's order, rule, or policy. *See id.* § 56.025(e) (West 2007) (emphasis added). These provisions further support our conclusion that the term "costs," as used by the legislature in PURA, is not intended to include lost revenues. The legislature's failure in PURA section 39.905 to specifically provide for recovery of "lost revenues," in addition to "costs," indicates that it intended for the EECRF to serve as a mechanism for a utility to recover out-of-pocket expenditures associated with its implementation of energy-efficiency programs, not to compensate a utility for any associated lost revenues attributable to those programs.

CenterPoint asserts that this interpretation of the term "costs" is inconsistent with PURA section 39.905(b–1), which provides that the EECRF may be adjusted each year to "enable utilities to match revenues against energy efficiency costs and any incentives to which they are granted." *See id.* § 39.905(b–1). CenterPoint interprets the term "revenues" to means revenues from its overall operations and contends that the EECRF is designed to match the utility's actual revenues with the total revenues it would have earned absent the energy-efficiency programs. We do not believe this is a reasonable interpretation of the relevant provisions. The second sentence of PURA section 39.905(b–1) states: "The [cost-recovery] factor shall be adjusted to reflect any over-collection or under-collection of *energy efficiency cost recovery revenues* in previous years." *Id.* (emphasis added). From the context, it is clear that the matching contemplated by the statute is between the actual revenues the utility collects *through its EECRF*—i.e., energy efficiency cost recovery revenues—and the expenditures made by the utility for the energy efficiency program—i.e., energy efficiency costs. The matching is not intended to address any lost revenues attributable to a general decrease in energy consumption resulting from energy-efficiency programs. Rather, the purpose of this provision is to ensure that a utility neither over-recovers nor under-recovers its actual energy-efficiency program expenditures.

CenterPoint also argues that the Commission's failure to include an LRAM in rule 25.181 renders the rule invalid because it runs counter to a legislative mandate contained in PURA section 39.905(b)(4), which requires that the Commission ensure that "the costs associated with [energy-efficiency] programs provided under [section 39.905] are borne by the customer classes that receive the services under the programs." *See id.* § 39.905(b)(4). Again, this argument depends on interpreting the term "costs" in this section to include lost revenues. However, there is nothing in the statute to indicate that the term "costs" in this section should be read more expansively than in section (b)(1). *See Sheshunoff v. Sheshunoff,* 172 S.W.3d 686, 690 (Tex.App.-Austin 2005, pet. denied) (when same or similar term is used in same connection in different statutes, term will be given same meaning in one as in other, unless there is something to indicate that different meaning was intended). We hold that the term "costs" in both 39.905(b)(1) and (b)(4) means a utility's actual expenditures associated ***905** with its energy-efficiency programs. These costs can be recovered from a utility's customers through application of an EECRF that does not include an LRAM.

We conclude that the text of the statute is clear and unambiguous and evidences the legislature's intent that the Commission ensure that a utility recovers only its energy-efficiency program expenditures through an EECRF. The EECRF is not intended to be used as a mechanism to compensate a utility for any lost revenues that may result from implementation of these programs. CenterPoint's first appellate issue is overruled.

In its second issue, CenterPoint contends that rule 25.181 is invalid because the Commission's failure to include an LRAM resulted from an erroneous interpretation of its authority under PURA section 39.905. However, an agency has only the authority expressly provided by statute or necessarily implied to carry out the powers the legislature has given it. *See Public Util. Comm'n v. City Pub. Serv. Bd.,* 53 S.W.3d 310, 315–16 (Tex.2001); *Public Util. Comm'n v. GTE–Southwest,* 901 S.W.2d 401, 407 (Tex.1995). As we have held above, PURA section 39.905 authorizes the Commission to allow utilities to recover their energy-efficiency program expenditures; it does not authorize the Commission to adopt a rule or procedure that allows utilities to use an EECRF to charge customers for any claimed "lost revenues" resulting from the energy-efficiency programs they are required to implement. The Commission properly exercised its authority under PURA section 39.905 and correctly concluded that including an LRAM in rule 25.181 would contravene the statute and exceed its statutory authority. We overrule CenterPoint's second appellate issue.

CONCLUSION

Because PURA section 39.905 does not permit, much less require, the Commission to adopt a lost-revenue adjustment mechanism as part of the authorized energy efficiency cost recovery factor, we overrule CenterPoint's two appellate issues challenging the validity of rule 25.181, find the rule be valid, and affirm it as enacted.

All Citations

354 S.W.3d 899, Util. L. Rep. P 27,172

End of Document

DAmbrosio, Eleanor

From:	DAmbrosio, Eleanor
Sent:	Monday, May 20, 2019 10:05 AM
To:	June Dively
Subject:	RE: TAC 25.107(f)(3)(B)

Sure. 512-936-7506

From: June Dively [redacted]
Sent: Monday, May 20, 2019 10:04 AM
To: DAmbrosio, Eleanor
Subject: RE: TAC 25.107(f)(3)(B)

Could we visit for a moment over the phone? What is your direct number?

June M. Dively, CPA, CFF, Cr.FA, FABFA

SiEnergy
SiEnergy | 3 Lakeway Centre Ct. | Suite 110 | Lakeway, TX 78734

[redacted]

From: DAmbrosio, Eleanor <eleanor.dambrosio@opuc.texas.gov>
Sent: Monday, May 20, 2019 9:58 AM
To: June Dively [redacted]
Subject: RE: TAC 25.107(f)(3)(B)

Here is what I have found so far. 16 TAC § 25.107(f)(3)(B) was first adopted in 2009 and has remained unchanged since then. In its order adopting the rule the Commission wrote:

The commission agrees with Joint TDUs' recommended language to satisfy audit standards and make it clear that the regulatory asset is to be reviewed for reasonableness before it is included in rates. The commission modifies rule language in subsection (f)(3)(B) consistent with Joint TDUs recommendation. The commission also agrees with ARM and Reliant that the rule should be clear that the regulatory asset must be adjusted for bad debt charges that are already being recovered through the TDU's rate, and has modified subsection (f)(3)(B) accordingly. Finally, the commission notes that cost recovery of a regulatory asset related to bad debt will be subject to review in a rate case pursuant to PURA §36.051.

So, it looks like there is no barrier to going all the way back to 2011 other than the "reasonable and necessary" inquiry. I also looked at Commission decisions issued after 2009, and the only decisions referencing bad debt were for vertically integrated utilities – I couldn't find any discussion of 25.107(f)(3)(B) or bad debt expense in a case involving a T&D only utility.

Can we turn your Option 2 into an argument about reasonableness and necessity? Or, since there was no actual bad debt expense in the test year, can we propose that it is reasonable and necessary for them to recover a 3-yr average since the bad debt "expense" approved in 38339 was a credit? (Careful, don't let the lawyer do accounting.)

Feel free to give me a call if you want to discuss further.

From: June Dively [redacted]
Sent: Monday, May 20, 2019 9:02 AM
To: DAmbrosio, Eleanor
Subject: RE: TAC 25.107(f)(3)(B)

Excellent!

June M. Dively, CPA, CFF, Cr.FA, FABFA

SfEnergy
SfEnergy | 3 Lakeway Centre Ct. | Suite 110 | Lakeway, TX 78734

[redacted]

From: DAmbrosio, Eleanor <eleanor.dambrosio@opuc.texas.gov>
Sent: Monday, May 20, 2019 8:29 AM
To: June Dively [redacted]
Subject: RE: TAC 25.107(f)(3)(B)

June,

I did a little looking last night and am about to start a more earnest review of this rule and the bad debt issue in general after I get you and Karl the updated RFI Index.

The 5/13/18 date denotes the last time the rule was amended, but it doesn't mean that was the last time subsection (f) was amended. So, I need to go back and see when subsection (f) was first adopted/last amended.

I will be in touch as soon as I have a better answer for you.

-Eleanor

From: June Dively [redacted]
Sent: Monday, May 20, 2019 8:26 AM
To: DAmbrosio, Eleanor
Subject: RE: TAC 25.107(f)(3)(B)

Eleanor,

Have been thinking about this all night and think we have 2 options:

1. The Rule says it's effective 5/13/18, and if that's true, and we believe it cannot be applied retroactively, then we can throw out all the bad debt that was deferred for 2011 through 2017 ($511,290) and all the bogus adjustment for bad debt in rates through that point ($962,050) for a total of $1,473,340.35 out of the $1,569,545.39 requested.
2. If the Rule can't be applied retroactively, then we can throw out all the bogus adjustment for bad debt in rates based upon the fact that the credit was not bad debt but an out-of-period recovery or some other accounting error. This would throw out $1,058,255.44 out of the $1,569,545.39 requested. If you like this approach, we can also use it in combination with one above to throw out 100% of the request.

Talk to you soon!

June

June M. Dively, CPA, CFF, Cr.FA, FABFA

SiEnergy
SiEnergy | 3 Lakeway Centre Ct. | Suite 110 | Lakeway, TX 78734

[redacted]

From: June Dively
Sent: Sunday, May 19, 2019 5:14 PM
To: DAmbrosio, Eleanor <eleanor.dambrosio@opuc.texas.gov>
Subject: TAC 25.107(f)(3)(B)

Eleanor,

I am hoping you can take a look at TAC 25.107(f)(3)(B). Here's why –

Centerpoint has included REP Bad Debt in its cost of service. The total is $1.6 million; however, $1.1 million relates to the amount of REP Bad Debt included in their last rate case 38339. The problem is that the last rate case had a $144,000 credit in it, not expense. The rule says you can defer REP Bad Debt, net of bad debt already included in your rates. So, they took their $500K in bad debt and subtract 7 years of credit from it, which results in a positive number.

So, the rule contemplated, for example $500,000 of REP Bad Debt minus $250,000 included in rates, leaves $250,000 to recover.
What they have done is $500,000 of REP Bad Debt minus a credit of $1.1 million to get $1.6 million.

Technically the math is correct. However, they go all the way back to 2011. When was this rule supposed to start?

See the attachment to COH 03-41, "Competitive Retailer Bad Debt in Rates".

If you look at the response, absent this rule, they would have had zero in the test year. Are we really going to refund that entire credit? Can we avoid it? Can you make a call to Staff and find out what they're thinking?

I was going to leave it in bad debt expense at the 3-year amortization but I'm thinking that since there is no test year expense, maybe it should be moved to a Rider? Other Riders are at 5 years. Your thoughts?

June

June M. Dively, CPA, CFF, Cr.FA, FABFA
3 Lakeway Centre CT, Suite 110
Lakeway, TX 78734
[redacted]

DAmbrosio, Eleanor

From:	DAmbrosio, Eleanor
Sent:	Monday, May 20, 2019 2:55 PM
To:	June Dively
Cc:	Quinn, Cassandra
Subject:	49421 Rate-Case Expenses

June,

CenterPoint just filed a motion to sever the rate-case expenses for the current rate case only. They are asking to leave all of the expenses incurred in Docket Nos. 38339, 45747, 47032, 47364,
and 48226 at issue because all of the invoices supporting these expenses were included with the application. I may file a response requesting to sever all rate-case expenses but need to think about it for a moment.

Thank you,
Eleanor

Eleanor D'Ambrosio | Assistant Public Counsel
Office of Public Utility Counsel
(512) 936-7506
Eleanor.Dambrosio@opuc.texas.gov

DAmbrosio, Eleanor

From: DAmbrosio, Eleanor
Sent: Monday, May 20, 2019 2:25 PM
To: June Dively; Ferris, Sara
Subject: RE: Incentive Comp

Were either of these what you were thinking of?

"The Commission has repeatedly ruled that a utility cannot recover the cost of financially-based incentive compensation because financial measures are of more immediate benefit to shareholders and financial measures are not necessary or reasonable to provide utility services."

Application of Entergy Texas, Inc. for Rate Case Expenses Pertaining to PUC Docket No. 39896, Docket No. 40295, Order at 2 (May 21, 2013)

Also, the Commission discussed incentive compensation in the Order it issued in Docket No. 43695 as follows:

"It is well-established that a utility may not include in its rates the costs of incentives that are tied to financial-performance measures.21 The Commission agrees with the SOAH ALJs' characterization of the annual incentive plan as "complicated" and notes that when a utility elects to adopt a compensation plan that involves both financially-based and performance-based metrics, the utility still must show it has removed all aspects of the financially-based goals from its requested expense.22 Based on the testimony of the experts offered by AXM and OPUC, the Commission is not convinced SPS's adjustment fully captured the financial aspects of the annual incentive plan. Yet, SPS has sufficiently demonstrated that some portion of the plan is tied to performance-based objectives and is part of the necessary expense of attracting and retaining qualified Xcel employees. Therefore, removing all the expense of the plan would likewise be improper. Ultimately, the Commission adopts the amount of plan expense that OPUC recommended as an alternative. This amount better reflects that the plan has a financially-based, earnings-per-share trigger and requires Xcel employees to meet metrics that include financial goals, in addition to performance-related goals. Accordingly, the Commission deletes proposed findings of fact 83 through 85 and instead adopts new findings of fact 83A, 83B, 84A, and 85A."

From: June Dively [redacted]
Sent: Monday, May 20, 2019 1:54 PM
To: DAmbrosio, Eleanor; Ferris, Sara
Subject: Incentive Comp

Eleanor and Sara,

I am trying to remember which docket order had the finding regarding financially-based incentive compensation. I would like to refer to it in my testimony. Can one of you help?

Thanks so much!

June

June M. Dively, CPA, CFF, Cr.FA, FABFA

Si Energy

DAmbrosio, Eleanor

From: DAmbrosio, Eleanor
Sent: Wednesday, May 22, 2019 9:22 AM
To: June Dively
Subject: RE: Riders

I will check, but I don't think there is a rule that addresses the use of Riders. As I am sure you know, the overarching principle is that Riders should be used for non-recurring expenses.

From: June Dively [redacted]
Sent: Wednesday, May 22, 2019 9:01 AM
To: DAmbrosio, Eleanor
Subject: Riders

Eleanor,

I am recommending a Rider HCRF, consistent with the TNMP case, as well as one for the SMT costs. Am thinking of doing that for Medicare Part D. My question – Is there any Commission guidance on when a Rider is appropriate? I am arguing that short-term recoveries, 5 years or less, should be in Riders . . .

June M. Dively, CPA, CFF, Cr.FA, FABFA

SīEnergy
SīEnergy | 3 Lakeway Centre Ct. | Suite 110 | Lakeway, TX 78734

[redacted]

SiEnergy | 3 Lakeway Centre Ct. | Suite 110 | Lakeway, TX 78734

[redacted]

DAmbrosio, Eleanor

From:	DAmbrosio, Eleanor
Sent:	Wednesday, May 29, 2019 3:56 PM
To:	June Dively
Subject:	49421 Hurrican Harvey Carrying Costs
Attachments:	49421 CEHE Response to PUC08-14.pdf; PUC08-14e Attachment 1.xlsx

June,

Attached is CenterPoint's response to Staff 8-14. I am wondering if this is what you were after with your RFIs on the hurricane Harvey carrying cost issue? I filed those RFIs today, but wanted to make sure you saw this.

Thank you,
Eleanor

Eleanor D'Ambrosio | Assistant Public Counsel
Office of Public Utility Counsel
(512) 936-7506
Eleanor.Dambrosio@opuc.texas.gov

DAmbrosio, Eleanor

From: DAmbrosio, Eleanor
Sent: Tuesday, May 28, 2019 3:04 PM
To: June Dively
Subject: 49421 Workpapers
Attachments: 45747 Excerpt from Mary Kirk Direct.pdf; 45747 Excerpt from Ruth Stark Direct.pdf

June,

Now that your testimony includes a Q&A on the DCRF docket where the margin tax issue arose (D-45747), I am sending you the relevant portions of Staff's and CenterPoint's testimony so you can review them and add them to your workpapers.

Thank you,
Eleanor

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Eleanor.Dambrosio@opuc.texas.gov

DOCKET NO. 45747

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR APPROVAL TO AMEND ITS DISTRIBUTION COST RECOVERY FACTOR PURSUANT TO 16 TEX ADMIN. CODE §25.243 AND TO RECONCILE DOCKET NO. 44572 REVENUES	§ § § § § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY OF

MARY A. KIRK

FOR

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC

April 04, 2016

> period of the calendar year in which the payment is made and the report is due, regardless of when the accounting accrual for the cost occurs."

At page 19, the PFD notes,

> "The evidence further demonstrates that it is not unusual for a franchise to have a period for the tax base that is different than the service period, as is the case with SFT[52]."

The privilege year/service period decision in Docket No. 38339 is critical when calculating the correct incremental margin tax number in this case. As the Company explained in Docket No. 38339, its Texas margin tax payment on May 15 of any given year relates to the service provided during that calendar year (*i.e.,* the May 15, 2009 test year payment in Docket No. 38339 relates to the 2009 privilege or service period). The ***tax base*** is the taxable entity's margin on the year prior to the service period year. Therefore, the payment on May 15 of any given year relates to the tax base from the prior calendar year (*i.e.,* in Docket No. 38339, the May 15, 2009 test year payment relates to 2009 service, but is based on the tax base from 2008).

In Docket No. 38339, the Commission approved this methodology for calculating Texas margin tax and, thus, Company's current rates were set using this formula.[7]

Q. APPLYING THE DOCKET NO. 38339 METHODOLOGY, WHAT IS THE CORRECT SERVICE PERIOD AND TAX BASE TO USE IN THE DCRF TEXAS MARGIN TAX CALCULATION?

A. As discussed previously, the rule specifically states to use the methodology from the last comprehensive base-rate proceeding. The application of the Docket No.

[7] Commission Docket No. 38339, Order on Rehearing, June 23, 2011, FOF 161-165.

38339 methodology results in the use of a 2015 service period based on the tax base from 2014.

Q. WHAT IS THE CORRECT TAX RATE FOR THIS DCRF PROCEEDING CONSIDERING THE PRIVILEGE YEAR AND TAX BASE AS NOTED ABOVE?

A. 16 TAC §25.243(d), requires the use of the current tax rate. The current tax rate for the 2015 payment is 0.95%. The calculation of the Texas margin tax uses the tax base margin from the prior year (2014) to calculate the amount due in the service period (2015). The tax rate applicable to the service period is the correct tax rate to be used in the DCRF filing. Thus for the 2015 service period, the applicable tax rate was 0.95%.

Q. LEGISLATION WAS PASSED IN 2015 THAT ADJUSTED THE TAX RATE FOR THE MARGIN TAX CALCULATION. SHOULD THE MARGIN TAX CALCULATION BE ADJUSTED TO REFLECT THE NEW LEGISLATION?

A. No. House Bill No. 32 of the 2015 Texas Legislature set the rate of franchise tax at 0.75% for returns filed *after* January 1, 2016. This change in the tax rate is for a future service period, not the service period that is applicable to this DCRF filing. Consequently, this tax rate cannot and should not be used to calculate the Texas margin tax because doing so will result in a mismatch between the actual amount that will be owed and that recovered in the DCRF rates. The Company acknowledges that under current law the 0.75% tax rate would be used in its DCRF application filed in 2017 for the 2016 service year.

Q. WAS THE TEMPORARY PERMISSIVE ALTERNATIVE RATE FOR TEXAS MARGIN TAX REPORTS FILED IN 2015 USED BY THE COMPANY IN ITS MARGIN TAX CALCULATION?

A. Yes. The temporary permissive rate is the rate applicable in the year the Texas margin tax is paid (*e.g.,* the service period). The payment made in 2015 was at the temporary permissive rate of 0.95% as authorized under Chapter 171 of the Tax Code[8] and House Bill 500 of the 2013 Texas Legislature.[9]

Q. WHAT IS THE CORRECT TOTAL REVENUE FOR THIS DCRF PROCEEDING CONSIDERING THE PRIVILEGE YEAR AND TAX BASE AS NOTED ABOVE?

A. 16 TAC §25.243(d), requires the use of the methodology from the last comprehensive base-rate proceeding. The methodology from the Company's last base-rate proceeding requires that the total revenues be used in the calculation of the DCRF Margin Tax. The calculation of the Texas margin tax uses the tax base margin from the prior year (2014) to calculate the amount due in the service period (2015). The total revenue from the tax base year of 2014 is the appropriate total revenue to use in this DCRF filing. Thus for the 2015 service period, the applicable total revenue is $2.264 billion as shown on WP/Schedule E-2.2/1.

[8] Texas Tax Code Title 2 Subtitle F Chapter 171 Subchapter A §171.0023.
[9] Texas Legislature by Acts 213, Leg., R.S., Ch. 1232 (H.B. 500), Sec 2

Q. USING THE CALCULATION AS OUTLINED BY 16 TAC §25.243(d), WHAT ARE THE CORRECT AMOUNTS FOR TEXAS MARGIN TAX TAKING INTO CONSIDERATION THE CURRENT METHODOLOGY FROM DOCKET NO. 38339 (SERVICE PERIOD AND TAX BASE) AND CURRENT RATE AS NOTED ABOVE?

A. As shown in W/P E-2.2/1, the Company's Texas Margin Tax reflects the methodology approved in Docket No. 38339. The correct current tax margin rate used for 2015 service year is 0.95%, which is the tax rate for 2014 revenues when margin tax payment is made in 2015. The correct total revenue used for the 2015 service year is $2.264 billion, which is the tax base for 2014. An apportionment factor is applied to total revenues in the Margin Tax calculation to eliminate any revenues not subject to Texas Margin Tax. The current tax rate for the 2015 service year of 0.95% is then applied to calculate the Texas Margin Tax before adjustments. Adjustments are then made to remove any tax related to capital not related to distribution invested capital as stated in 16 TAC §25.243(b)(3). As shown on WP/Schedule E-2.2/1, the Texas Margin Tax in 2015 related to distribution invested capital is $14,396,368, or an incremental increase compared to Docket No. 38339 of $3,037,718.

Q. HOW DOES THE COMPANY ACCOUNT FOR TEXAS MARGIN TAX ON ITS BOOKS AND RECORDS?

A. The Company carries a regulatory asset reflecting the one year lag between the taxable year and the payment year. This accounting practice and regulatory asset was approved as filed in Docket No. 38339 and dates back to Docket No. 29526[10].

Q. WOULD THERE BE AN ACCOUNTING IMPACT TO THE COMPANY IF A DIFFERENT METHODOLOGY FROM THAT USED IN DOCKET NO. 38339 WAS USED TO CALCULATE TEXAS MARGIN TAX IN THIS DCRF FILING?

A. Yes. Because the Company carries a regulatory asset reflecting the one year lag between the taxable year and the payment year, any change to this approved methodology would strand this regulatory asset. This is contrary to the intent of the Commission given the approval of the deferral in Docket No. 29526, Findings of Fact 227-237. *See* Exhibit MAK-04 for illustrative purposes.

Q. PLEASE SUMMARIZE THE COMPANY'S POSITION WITH REGARD TO THE TEXAS MARGIN TAX CALCULATION?

A. The Texas margin tax should be calculated in accordance with the DCRF Statues, which support the use of total revenues. With regard to the methodology used to calculate Texas Margin Tax, the Commission's Rule clearly requires the use of the same methodology approved in Docket No. 38339 – that methodology dictates that ***tax base*** is the taxable entity's margin on the year prior to the service period year.

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[10] *Application of CenterPoint Energy Houston Electric LLC., Texas Genco, LP, and Reliant Energy Retail Services, LLC to Determine Stranded Costs and Other Balances*, Order on Rehearing, December 17, 2004.

SOAH DOCKET NO. 473-16-3581
PUC DOCKET NO. 45747

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC TO AMEND ITS DISTRIBUTION COST RECOVERY FACTOR AND TO RECONCILE DOCKET NO. 44572 REVENUES	§ § § § § § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

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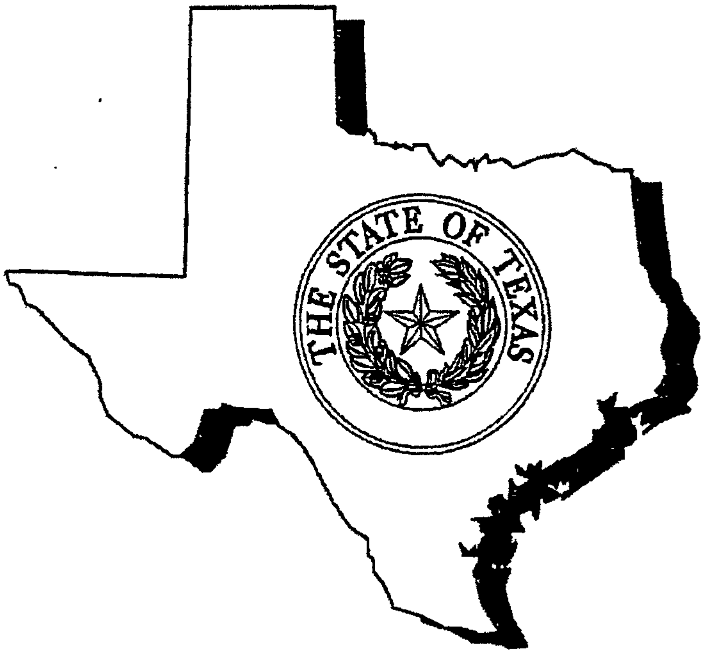

DIRECT TESTIMONY OF

RUTH STARK

RATE REGULATION DIVISION

PUBLIC UTILITY COMMISSION OF TEXAS

JUNE 3, 2016

0000001

97

Company's request. Staff witness Grant Gervais utilizes this revenue requirement to develop Staff's revenue requirement adjusted for load growth.

Q. Are you sponsoring any of the adjustments to CenterPoint's requested distribution revenue requirement?

A. Yes. Based on my review of 16 TAC § 25.243, the Company's application and responses to RFIs, I am proposing an adjustment to the Texas gross margins tax expense. I also propose adjustments to distribution invested capital and depreciation expense, as well as an adjustment to federal income taxes that are an attendant impact of the adjustment to invested capital and its associated return.

V. ADJUSTMENTS TO CENTERPOINT'S REQUEST

A. Taxes Other Than Income Taxes – Texas Margins Tax

Q. Please explain CenterPoint's request related to the Texas margins tax.

A. According to Schedule E-2, the Company is requesting an increase of $3,037,718 to the $11,358,650 in Texas margins tax approved in Docket No. 38339 for a total requested margins tax amount of $14,396,368. According to CenterPoint witness Mary Kirk, the Company's request is based on 16 TAC § 25.243(d) which requires other taxes to be calculated using current tax rates and the methodology from its last comprehensive base rate case.[3] Ms. Kirk explains that CenterPoint uses the cost of goods sold ("COGS") method.[4] In CenterPoint's last base rate case, the amount included in its calendar year 2009 test year revenue requirement for the Texas margins tax using the COGS method

[3] Direct Testimony of Mary Kirk at 23:7-18.

was based on a tax base of 2008 revenues for the 2009 privilege or service period. As explained by the testimony of Ms. Kirk, "in Docket No. 38339, the May 15, 2009 test year payment related to 2009 service, but is based on the tax base from 2008."[5]

Q. Please continue.

A. CenterPoint's Ms. Kirk asserts that this means that the Texas margins tax for purposes of this DCRF proceeding must use the amount of the tax paid during calendar year 2015 that was based on revenues received in calendar year 2014. Ms. Kirk goes on to say that not only must the Commission use 2014 revenues to determine the Texas margins tax, but that it must also use the tax rate of .95% because "the current tax rate for the 2015 payment is 0.95%."[6] Finally, Ms. Kirk testifies that total revenues must be used to determine the DCRF because that is consistent with the methodology used in Docket No. 38339[7].

Q. Do you agree with CenterPoint's interpretation of 16 TAC § 243(d)?

A. No, I do not for several reasons. First, 16 TAC § 243(d) defines OT_C as Current Other Taxes as related to Current Net Distribution Invested Capital, calculated using current tax rates and the methodology from the last comprehensive base-rate proceeding. The testimony of Ms. Kirk describes the methodology used in its last comprehensive base-rate case:

> **Q. WHAT <u>METHOD</u> DOES THE COMPANY UTILIZE FOR THE MARGIN TAX?**

---

[4] Kirk at 12:16.
[5] Kirk at 24:14-16.
[6] Kirk at 25: 6-7.
[7] Kirk at 14: 3-5.

> A. Under the Texas Margin Tax statutes, an entity is allowed to reduce its taxable revenues by the greater of: (1) its allowable Cost of Goods Sold ("COGS") deduction under Texas Margin Tax statutes; (2) certain employee compensation; or (3) 30% of total revenues. The Company utilizes the COGS **method**.
>
> **Q. WHY DID THE COMPANY CHOOSE THE COGS METHODOLOGY IN THE CALCULATION OF ITS MARGIN TAX?**
>
> A. Under the Texas Margin Tax statutes, the Company is required to be included in the consolidated Texas Margin Tax return with its parent and other member companies of the affiliated group. Each member company included in the consolidated group is required to use the same **method** of reducing its taxable revenues. CNP, the parent, elected to reduce its consolidated taxable revenues by COGS. This annual election was the most beneficial **method** for the CNP affiliated group and was, therefore, applied to all companies in the affiliated group, as required by statute.[8] (emphasis added)

Thus, the Cost of Goods Sold method is the methodology used by the Company in its last rate case and I concur that that is the method that should be used in this proceeding. I do not agree that the Company has used the correct taxable margin (revenues) in applying that method in this case nor do I agree that it has used the current tax rate as required by the rule.

Q. Please explain.

A. Ms. Kirk maintains that because the Commission used the amount of Texas Margin tax paid by the Company during the test year of its last rate case (calendar year 2009) which was based on revenues from the previous year (calendar year 2008), that the Commission must now use revenues from calendar year 2014 to determine the amount of margin tax included in the DCRF rates determined in this proceeding for rates to be collected starting in late 2016. CenterPoint filed a DCRF case in April of 2015 in order to update its

[8] Kirk at 12:11-23 and 13:1-3.

distribution investment for the period 2010 through the end of 2014. The present proceeding, filed in April of 2016, requests inclusion of distribution investment for the period January 1, 2015 through December 31, 2015. As noted above, TAC § 243(d) defines OT_C as Current Other Taxes as **related to Current Net Distribution Invested Capital.** It is illogical that a tax calculated using revenues from 2014 can be deemed **related** to the distribution invested capital added during the subsequent year, calendar year 2015, which is the subject of this proceeding. The DCRF proceeding is not a comprehensive base-rate proceeding and does not serve the same purpose as a full rate case. The purpose of the DCRF proceeding is to avoid having to file a full rate case with a full test year cost of service in order for the Company to be able to begin recovering incremental distribution investment. It, therefore, makes sense that using the same methodology to determine Texas margin tax from the last comprehensive base-rate proceeding (COGS) applied to a tax base (revenues) **related to Current Net Distribution Invested Capital** at the current tax rate is the appropriate manner to determine the margin tax for DCRF purposes.

Q. You indicated that there are several reasons you disagree with the Company's interpretation of 16 TAC § 243(d). What are the other reasons for your disagreement?

A. As noted above, CenterPoint is interpreting "current tax rate" to mean "the current tax rate for the 2015 payment" which is a distortion the meaning of "current tax rate." According to the Oxford dictionary, the definition of current is "belonging to the present time; happening or **being used or done now**." Merriam-Webster defines "current" in a similar fashion, "presently elapsing; occurring in or existing at the present time; most recent." According to the Texas Comptroller of Public Accounts, the rate applicable to CenterPoint for report years 2016 and 2017 is 0.75%.[9] This is the rate **being used now** and the rate that will be applied to the revenues collected under the DCRF approved in this proceeding. As Commissioner Anderson noted in his memo dated May 3, 2016 related to the Texas margins tax rate that should be used in determining Entergy Texas Inc.'s TCRF, "application of the reduced tax rate is appropriate because the TCRF rule contemplates use of the tax rates that apply during the period when revenues from the TCRF will be recovered."[10]

Q. Commissioner Anderson's memo relates to a different rule, 16 TAC § 25.239. Why are you using it as support for use of the 0.75% current tax rate in this proceeding?

A. I am relying on his reasoning from application of that rule because the DCRF rule, 16 TAC § 25.243(d) is even clearer and more proscriptive in its language than the TCRF rule that the current rate (the rate in effect when the DCRF revenues are collected) is to be used. The rate of 0.75% is the current rate that will be in effect when the revenues from CenterPoint's DCRF will be recovered.

Q. Ms. Kirk indicates, "The Company acknowledges that under current law, the .75% tax rate would be used in its DCRF application filed in 2017 for the 2016 service year."[11] Do you have any comments on this assertion?

---

[9] Texas Comptroller of Public Accounts: http://www.cpa.texas.gov/taxinfo/franchise/rates.html. Please note that the term "Texas Franchise Tax" is used interchangeably with the term "Texas Margin Tax."

[10] *Application of Entergy Texas, Inc. for Approval of a Transmission Cost Recovery Factor,* Docket No. 45084, May 3, 2016 Memo of Commissioner Anderson.

[11] Kirk at 25:21-23.

A. Yes. The Company may choose not to file or may be prohibited from filing a DCRF in 2017 due to excess earnings. Given that the Commission may deny the use of the DCRF mechanism in future years, it makes no sense that it would allow a utility to collect an amount of margin tax in the DCRF that would contribute to excess earnings. Additionally, two Commissioners have recently expressed concerns about utilities collecting amounts for taxes in rates that are in excess of what the utility is expected to pay.[12]

Q. What is your recommendation for the appropriate amount of Texas margin tax to include in this proceeding?

A. The appropriate amount of Texas margin tax is $12,236,219 which represents a decrease of $2,160,149 to the Company's request of $14,396,368. My calculation is shown on Attachment RS-3.

Q. Please explain how you arrived at your recommended Texas margin tax.

A. As noted above, the amount of current other taxes to be included in the DCRF is the amount **<u>related to the current net distribution</u>** invested capital using **<u>current tax rates</u>** and the methodology from the last comprehensive base-rate proceeding. The revenues collected in 2015 are more appropriate to use in this proceeding because they are more closely related to the current net distribution invested capital at December 31, 2015 than are the 2014 revenues. A review of the Company's estimated Texas margin tax due in calendar year 2016 based on 2015 revenues shows that of the $18,191,355 tax accrued on

[12] *Joint Report and Application of Oncor Electric Delivery Company, LLC, Ovation Acquisition I, LLC, Ovation Acquisition II, LLC, and Shary Holdings, LLC for Regulatory Approvals Pursuant to PURA §§ 14.101, 37.154, 39.262(l)-(m) and 39.915,* Docket No, 45188 (Mar. 24, 2016).

its books at the end of 2015, the total revenue amount of $2,365,217,619 used in the calculation ties to the earnings monitoring report submitted in this proceeding.[13] The Company then adds other revenues and book/tax adjustments to that amount in reaching the total taxable margin amount of $2,433,852,513 prior to application of the **0.75% current tax rate.** I used the same $2,433,852,513 taxable margin amount that the Company used in accruing its December 31, 2015 margin tax expense. As explained previously, the current Texas margin tax rate is 0.75% and is the rate that is required to be used pursuant to 16 TAC § 25.243. My calculation follows the same methodology used by CenterPoint with the exception of the revenue amount and the tax rate applied.

Q. How do you address CenterPoint's contention that using a method that is different from its requested method will cause an accounting impact to the Company?

A. Ms. Kirk testifies,

> "Because the Company carries a regulatory asset reflecting the one year lag between the taxable year and the payment year, any change to this approved methodology would strand this regulatory asset. This is contrary to the intent of the Commission given the approval of the deferral in Docket No. 29526, Findings of Fact 227-237."[14]

First, I would note that it was the Company's choice to account for the margin tax in the manner that it does and that it is the only Texas TDU that I am aware of that carries a regulatory asset on its books related to the tax. Second, I have reviewed the findings of fact from Docket No. 29526[15] noted above and believe that not only did the Commission

[13] CenterPoint's Response to Staff's Second Request for Information, Question Staff 2-3, Attachment RS-4.
[14] Kirk at 28:7-11.
[15] *Application of CenterPoint Energy Houston Electric LLC, Reliant Energy Retail Services, LLC and Texas Genco, LP to Determine Stranded Costs and Other Balances Pursuant to PURA § 39.262,* Docket No. 29526, Findings of Fact Nos. 227-237 (Dec. 17, 2004).

not "approve" any deferrals for the regulated CenterPoint TDU going forward in that proceeding, I believe that it is presumptuous and incorrect to testify as to the Commission's intent based on the discussion in the order and language of the cited findings of fact. A review of the Order on Rehearing in that proceeding reveals that the Commission was approving stranded cost recovery of a margin tax deferred debit related to the generation portion of the Company's operations recorded during regulation that it would not be able to recover post-regulation. The Commission noted that "the state franchise taxes are properly considered a deferred debit related to the discontinuance of the application of SFAS No. 71."[16] The Findings of Fact cited by Ms. Kirk discuss deferred debits in the context of discontinuance of SFAS 71 and stranded cost recovery pursuant to PURA § 39.251(7). The Findings of Fact discuss how the joint applicants' predecessor accounted for state franchise taxes as a deferred debit **prior to deregulation.** The Findings of Fact do not address how the margin tax is to be accounted for by CenterPoint going forward, as Ms. Kirk suggests.

Q. **Do you have any other comments regarding Ms. Kirk's contention that the Company will have a stranded regulatory asset related to the margin tax if the tax in this proceeding is not determined consistent with its request?**

A. Yes. The Company's Texas margin tax calculation in this proceeding appears at WP/Schedule E-2.2/1 and indicates that it is calculating its request based on the $21.5 million regulatory asset it recorded at the end of 2014. (See Attachment RS-5 which is a page from the Company's 2014 FERC Form 1 reflecting this regulatory asset). A review of CenterPoint's FERC Form 1 for the year ending December 31, 2015 as well as the

[16] Docket No. 29526 at 46-67.

earnings monitoring report included in its application in this proceeding shows that the Company currently has an amount of deferred Texas margin tax on its books of only \$18.2 million.[17] CenterPoint has already reduced the amount of Texas margin tax recorded on its books, yet alleges that it will have stranded costs if not allowed to recover the \$21.5 million amount on its books **at the end of 2014**. Additionally, as seen on Attachment RS-8 (a compilation of Texas margin tax amounts reported on CenterPoint's FERC Form 1s for the period 2002 through 2015), it is not unusual for the Company to make adjustments to the margin tax amounts carried on its books.

Q. Do you have an alternative recommendation should the Commission determine that the 2014 revenues should be used to determine the Texas margins tax?

A. Yes. If the Commission determines that it is appropriate to use the 2014 revenues to determine the amount of Texas margin tax related to rates going into effect at the end of 2016, the rule (16 TAC § 25.243) still requires the use of the current tax rate in the calculation. The result of using the 2014 revenues and the 0.75% current tax rate is shown on Attachment RS-9 and results in a total margin tax of \$11,393,254 which is a decrease of \$3,003,114 to the Company's request.

B. Distribution Invested Capital and Depreciation Expense

Q. Do you have a recommendation regarding CenterPoint's requested distribution invested capital and depreciation expense?

[17] CenterPoint's 2015 FERC Form 1, Other Regulatory Assets at 232 and CenterPoint's 2015 Earnings Monitoring Report, Supplemental Schedule III-1. Please see Attachments RS-6 and RS-7, respectively.

DAmbrosio, Eleanor

From: DAmbrosio, Eleanor
Sent: Tuesday, May 28, 2019 12:56 PM
To: Winker, Anjuli
Subject: 49421 S&P report from LK 1-4
Attachments: S&P Global - Utility Impact of the TCJA.pdf

Here you go!

Eleanor D'Ambrosio | Assistant Public Counsel
Office of Public Utility Counsel
(512) 936-7506
Eleanor.Dambrosio@opuc.texas.gov

RRA Financial Focus
Utility Impact of the Tax Cuts and Jobs Act

- Investor-owned gas and electric utilities are preparing to return billions to ratepayers nationwide as provided for in the Tax Cuts and Jobs Act of 2017. Some $91.4 billion could be flowed back as utilities' excess deferred income tax liabilities are normalized in state regulatory proceedings, according to our latest analysis of Regulatory Research Associates' utility universe.
- Utility cash flows are expected to be reduced due to the return of excess deferred taxes and refunding of over-collections that occur until new rates are in place and because the lower tax rate reduces revenue requirements on an ongoing basis.
- Credit rating agencies have warned that utility credit metrics will be strained as a result of decreasing cash flows. Several utility holding companies and diversified utilities with competitive generation segments have announced plans to raise capital through equity and debt issuances or plans to reduce capital expenditures to maintain credit metrics.
- Our analysis concludes the average RRA utility decreased its total deferred income tax liability at Dec. 31, 2017 by 43%, compared to the year before. This follows several years of escalating balances.
- Rate base growth is expected across the sector as a result of the Tax Act, as lower deferred income tax liabilities reduces the offset to rate base in most states. Based on our analysis, utilities, including Edison International, Eversource Energy, OGE Energy, Pinnacle West Capital and ONE Gas are likely to benefit the most from tax-reform-related rate base growth.

Coincident with the completion of year-end 2017 accounting, the utility industry has written down billions in deferred tax liabilities associated with the reduction in the corporate income tax rate to 21% from 35%, and adjusted earnings guidance based on tax law changes. Investors now are focused on further implications of the Tax Cuts and Jobs Act of 2017, or TCJA, including credit ratings and near-term cash flow impacts. Also being evaluated are longer-term earnings expansion prospects given expected growth in utility rate base from lower deferred taxes.

Overall, tax reform — as RRA sees it — is near-term negative, but longer-term positive for regulated utilities. Longer-term, the reduction in deferred federal income taxes is expected to lead to increased rate base growth among electric and gas utilities, given that most states deduct accumulated deferred income taxes, or ADIT, in calculating rate base. Therefore, carrying a smaller ADIT balance should, all else being equal, increases rate base. Utilities should also have more "headroom" in proceedings seeking added capital investment before state regulators as customer rates decline nationwide, all else equal, due to the lower corporate tax rate. For our earlier analysis on tax reform read: Tax reform bill promises big changes for utilities, power producers.

Credit rating agencies have cautioned that the lower corporate tax rate could pressure utility credit metrics, as the reduction in deferred tax liabilities resulting from their revaluation to reflect the lower tax rate, together with the loss of bonus depreciation, will impact operational cash flows. S&P Global Ratings suggests that holding companies taxed on a consolidated basis are

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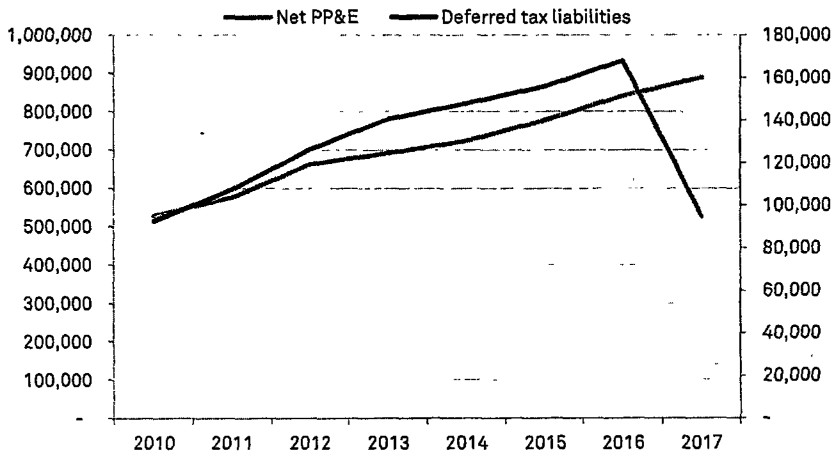
more likely to experience credit pressure than standalone utilities. Several utility holding companies and diversified utilities with unregulated generation segments have recently disclosed plans to issue new equity or debt or reduce capital investment in order to offset impacts to capital structures and improve cash flow.

Utilities re-measured ADIT given the lower tax rate and recorded excess ADIT as a regulatory liability on their balance sheets at the end of 2017. In rate making proceedings, excess deferred tax balances are classified as either protected by the Internal Revenue Code or unprotected. Protected excess ADITs are subject to normalization procedures, whereby they are subtracted from rate base and returned to ratepayers over an agreed upon amortization schedule, typically the remaining life of the assets. Unprotected excess deferred income taxes are not subject to normalization and their treatment is subject to determination of the governing regulatory agency. Most state regulatory commissions and FERC have opened proceedings into tax reform impacts and treatment of utility jurisdictional rate bases and rates. See map below to see tax reform proceedings by state.

Tax act causes write-off of tax liabilities ($M)



As of Dec. 31, 2017.
Note: Includes data for 43 investor-owned utility holding companies. IOUs that did not have deferred tax liability data available excluded.
Source: S&P Global Market Intelligence

Looking at the entire utility sector as represented by the RRA universe, the chart at the left shows the steep drop in deferred tax liabilities at Dec. 31, 2017, following years of accumulation made possible with the help of bonus depreciation and intensive capital investment.

The average RRA utility decreased its total deferred income tax liability at Dec. 31, 2017 by 43%, compared to the year before. Utilities that slashed their deferred income tax liability most included South Jersey Industries, FirstEnergy and ALLETE. Those that decreased the liability the least include Sempra Energy, UGI Corp and Spire Inc. See table at end of report for a company-by-company breakdown.

Regulatory liabilities up $1.7 billion on average

In an effort to benchmark RRA-covered gas and electric utilities against potential cash flow and rate base impacts, RRA has compiled data that addresses regulatory liabilities specifically resulting from re-measurement of deferred taxes required by the TCJA. This data was typically disclosed in corporate Form 10-Ks and 10-Qs. Of the 54 investor-owned utilities that had made those filings as of March 16, the total increase in regulatory liabilities resulting from the re-measurement, which could be returned to ratepayers nationwide was $91.4 billion. The average amount of increase in regulatory liabilities per company for the Tax Act was about $1.7 billion.

The Tax Cuts and Jobs Act of 2017, enacted in December 2017, represents the first major overhaul of the U.S. tax code in 30 years. Many ramifications of the new law will have far reaching impacts on the utility sector and the energy industry. Under SEC guidelines, companies are required to finalize and record the tax effects of the TCJA by Dec. 31, 2018. Many issues addressed in this report are complex and impact accounting from financial and regulatory perspectives. RRA expects clarifications and revisions to be ongoing regarding the outlook for the sector. Additionally, state regulatory investigations are under way nationwide, and RRA recommends that clients pay careful attention to those developments as they unfold. The assumptions and projections made in this report are intended to provide clarity for clients on these complicated issues; however, in some instances data may be incomplete and the conclusions drawn are a "best estimate."

In the table below, RRA benchmarked the sector based on tax-related regulatory liabilities, cash flow and net property, plant and equipment, or PP&E, in service at year-end 2017. Potential cash flow impacts are estimated using a ratio of regulatory liabilities to operating cash flow. The lower the ratio, the less corporate cash flow is expected to decline relative to the sector by the normalization of excess ADIT, in our view. The higher the ratio, the more cash flow is expected to decrease by the return of excess ADIT over time. Utilities with the highest ratio of regulatory liabilities to operating cash flow include NiSource Inc. and ONE Gas Inc. Those with the lowest ratios include AES Corp., National Fuel Gas Co. and UGI Corp.

Potential rate base impacts are calculated using a ratio of regulatory liabilities to net PP&E in service at Dec. 31, 2017. In this context, RRA uses net PP&E as a proxy for rate base, although rate base can only be determined by state regulatory commissions and typically includes items besides net PP&E. The higher the ratio, the more likely rate base will be favorably impacted by the reduction in ADIT, based on our analysis. The lower the ratio, the less likely rate base will benefit relative to the sector. Utilities with the highest ratio include Edison International, Eversource Energy, OGE Energy, Pinnacle West Capital and ONE Gas. Utilities with the lowest ratio include, UGI Corp., Unitil Corp., IDACORP Inc. and AES Corp.

RRA notes that operating cash flow and net PP&E in service data from S&P Global Market Intelligence are corporate consolidated results and not reflective exclusively of the results of regulated utility segments. Diversified utility holding companies may have unregulated merchant generation operations that are also included. More broadly-diversified utility holding companies might have non-utility operations, i.e., construction services or banking segments, also reflected in the data. Excluding these operations would typically have the effect of reducing both cash flow from operating activities and net PP&E in service and increase both ratios.

Potential cash flow and rate base impacts of Tax Act on Utilities

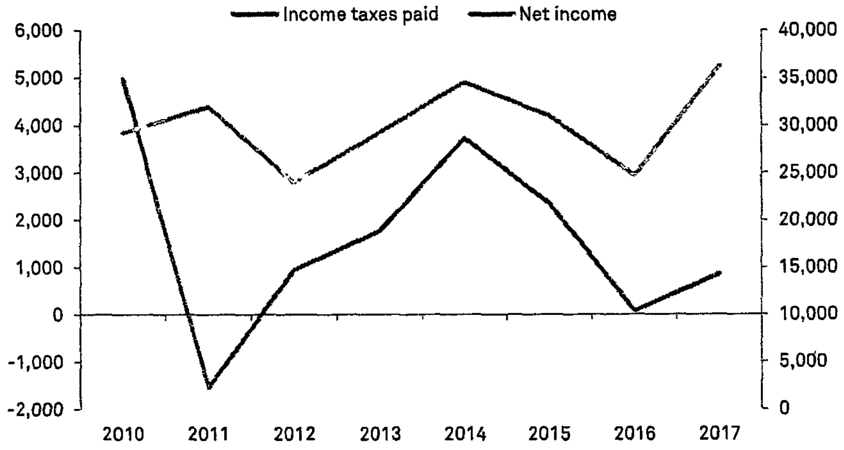
Company	Ticker	Increase in regulatory liabilities ($M)[1]	Cash flow from operations (2016) ($M)[2]	Regulatory liabilities to cash flow ratio (x)	Net utility plant (2016) ($M)[2]	Regulatory liabilities to net utility plant ratio (x)	Disclosed need for additional capital as a result of the tax act
AES Corp.	AES	253.0	593.4	0.43	4,504.0	0.06	
ALLETE Inc.	ALE	393.6	199.3	1.97	3,123.5	0.13	
Alliant Energy Corp.	LNT	885.9	841.0	1.05	9,419.5	0.09	
Ameren Corp.	AEE	2,204.0	2,093.1	1.05	18,059.1	0.12	Y
American Electric Power Co. Inc.	AEP	4,400.0	2,931.8	1.50	37,988.3	0.12	
Atmos Energy Corp.	ATO	746.2	798.4	0.93	7,980.2	0.09	
Avangrid Inc.	AGR	NA	798.5	NA	8,725.1	NA	Y
Avista Corp.	AVA	442.0	337.8	1.31	3,678.5	0.12	Y
Black Hills Corp.	BKH	301.0	214.2	1.41	2,567.0	0.12	
CenterPoint Energy Inc.	CNP	1,300.0	638.4	2.04	7,051.6	0.18	
Chesapeake Utilities Corp.	CPK	98.5	104.1	0.95	313.1	0.31	Y
CMS Energy Corp.	CMS	1,500.0	1,673.4	0.90	13,785.4	0.11	
Consolidated Edison Inc.	ED	3,700.0	3,201.0	1.16	32,065.1	0.12	Y
Dominion Energy Inc.	D	3,600.0	3,271.5	1.10	26,412.2	0.14	
DTE Energy Co.	DTE	1,700.0	1,689.8	1.01	14,340.8	0.12	
Duke Energy Corp.	DUK	8,313.0	6,999.6	1.19	66,401.7	0.13	Y
Edison International	EIX	5,000.0	3,523.7	1.42	33,834.9	0.15	
El Paso Electric Co.	EE	275.3	232.3	1.19	2,713.4	0.10	
Entergy Corp.	ETR	2,900.0	2,112.3	1.37	24,296.5	0.12	Y
Eversource Energy	ES	575.0	1,975.4	0.29	18,025.4	0.03	
Exelon Corp.	EXC	4,734.0	5,716.1	0.83	46,763.5	0.10	
FirstEnergy Corp.	FE	2,300.0	2,579.1	0.89	25,682.4	0.09	
Great Plains Energy Inc.	GXP	794.6	795.8	1.00	8,849.5	0.09	
Hawaiian Electric Industries Inc.	HE	285.0	417.7	0.68	4,081.9	0.07	
IDACORP Inc.	IDA	194.0	309.9	0.63	3,969.5	0.05	
MDU Resources Group Inc.	MDU	285.5	240.8	1.19	1,607.5	0.18	
MGE Energy Inc.	MGEE	103.5	146.5	0.71	1,009.8	0.10	
National Fuel Gas Co.	NFG	337.0	86.1	3.92	1,265.8	0.27	
New Jersey Resources Corp.	NJR	228.0	172.3	1.32	1,757.5	0.13	
NextEra Energy Inc.	NEE	4,500.0	4,152.3	1.08	32,886.9	0.14	
NiSource Inc.	NI	1,500.0	423.3	3.54	5,120.1	0.29	Y
Northwest Natural Gas Co.	NWN	213.3	201.4	1.06	1,648.4	0.13	
NorthWestern Corp.	NWE	231.7	320.2	0.72	3,898.4	0.06	
OGE Energy Corp.	OGE	955.5	568.1	1.68	7,415.2	0.13	Y
ONE Gas Inc.	OGS	519.4	168.0	3.09	3,742.3	0.14	
Otter Tail Corp.	OTTR	149.1	129.4	1.15	1,307.3	0.11	
PG&E Corp.	PCG	3,859.0	4,313.9	0.89	45,102.3	0.09	Y
Pinnacle West Capital Corp.	PNW	1,500.0	987.2	1.52	12,262.2	0.12	
PNM Resources Inc.	PNM	549.0	384.3	1.43	4,419.0	0.12	
Portland General Electric Co.	POR	357.0	548.8	0.65	5,547.1	0.06	
PPL Corp.	PPL	3,350.0	1,930.0	1.74	18,915.5	0.18	
Public Service Enterprise Group Inc.	PEG	2,100.0	1,918.8	1.09	20,782.7	0.10	
SCANA Corp.	SCG	1,076.0	920.8	1.17	11,802.9	0.09	
Sempra Energy	SE	2,402.0	1,296.1	1.85	12,057.5	0.20	
South Jersey Industries Inc.	SJI	264.0	143.0	1.85	1,952.9	0.14	
Southern Co.	SO	6,900.0	5,032.5	1.37	54,001.4	0.13	Y
Southwest Gas Holdings Inc.	SWX	430.0	598.4	0.72	3,680.0	0.12	
Spire Inc.	SR	264.1	380.5	0.69	5,767.5	0.05	Y
UGI Corp.	UGI	303.9	106.6	2.85	1,246.9	0.24	
Unitil Corp.	UTL	48.9	42.5	1.15	386.0	0.13	
Vectren Corp.	VVC	333.4	183.0	1.82	1,791.6	0.19	
WEC Energy Group Inc.	WEC	2,450.0	1,244.2	1.97	12,323.6	0.20	
Westar Energy Inc.	WR	845.2	951.8	0.89	8,978.6	0.09	
WGL Holdings Inc.	WGL	NA	211.5	NA	3,286.8	NA	
Xcel Energy Inc.	XEL	3,800.0	3,059.0	1.24	31,172.3	0.12	Y

[1] Increase in regulatory liabilities at Dec. 31, 2017, resulting from remeasurement of deferred taxes requred by the Tax Cuts and Jobs Act of 2017.
[2] Includes only cash flow, assets net of depreciation of regulated utility operations if FERC data provided by utility
Data excludes results of non utility/power businesses or non-U.S. utility operations
Sources: Form 10-Ks; investor presentations; earnings call transcripts; FERC

Most utilities have not paid cash taxes for several years using a build-up of deferred tax liabilities generated by bonus depreciation and similar incentives to shield cash flow. But the end of bonus depreciation following 2019 and the drop in deferred tax liabilities is expected to reduce utility cash flow and make them cash taxpayers sooner than previously forecast.

Shielded from paying taxes for years, utilities have been reporting net operating losses, or NOLs, that can continue to be carried forward, albeit under less favorable terms pursuant to the new tax law. Companies in the RRA coverage universe paid $864 million in cash income taxes in 2017, according to available S&P Global Market Intelligence data, and posted net income of $36.2 billion.

Utility sector income taxes paid remains low ($M)



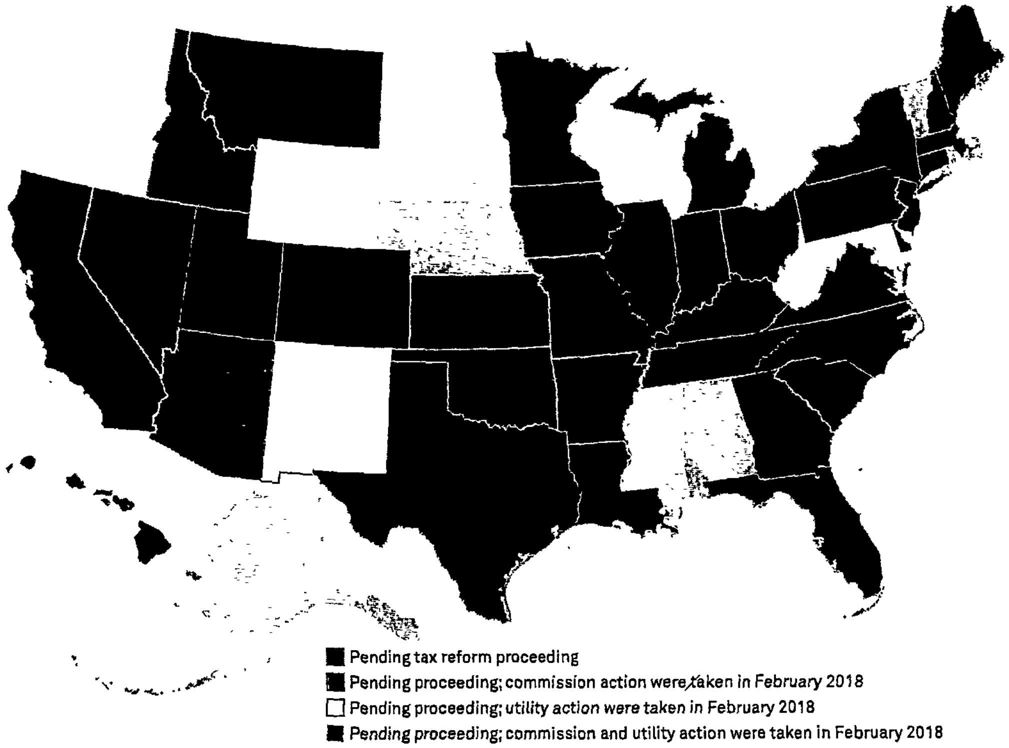
Note: Represents consolidated results of 55 public utilities and utility holding companies.
Source: S&P Global Market Intelligence

Income taxes paid by RRA utilities took a steep dive in 2011 as net operating losses were generated primarily from the bonus depreciation deduction allowed under the Tax Relief Act of 2010. The act provided for 100% depreciation deduction for qualified property placed into service in late 2010 and through 2011. Income taxes paid accelerated the following few years and then took another steep dive after bonus depreciation was extended through the Protecting Americans from Tax Hikes Act of 2015, or PATH Act.

Taxes paid rose slightly in 2017 and should accelerate further as bonus depreciation is phased out at the end of 2019. Still, many utility holding companies have NOL balances that can allow them to remain non-cash-paying taxpayers for several years. Edison International management indicated in its latest earnings call that the company expects not to be a cash taxpayer until 2025. NiSource management indicated the company has a federal NOL carryforward that will preclude the company from paying cash taxes beyond 2025. PG&E management disclosed that the TCJA will likely require the company to become a federal taxpayer in 2020, a year earlier than its previous expectation. Sempra Energy does not expect to be a federal taxpayer for the next five years. AES management indicated that the company will move toward a taxable position over the next two to three years, as its NOL balance decreases.

The following is company-specific commentary on tax reform impacts taken from earnings calls, annual reports and presentations. We expect that these plans will be subject to change in coming months depending on the outcome of state regulatory matters as well as from final determinations of certain tax issues.

Tax reform proceedings



Data as of Feb. 28, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Regulated electric/gas utilities:

ALE: The re-measurement of deferred taxes required by the TCJA increased regulatory liabilities by about $394 million. The provisional amount may change as ALE receives additional clarification and implementation guidance. The Minnesota and Wisconsin utility commissions both opened dockets to address ratemaking treatment and mechanisms to pass benefits of tax reform to ALE utility ratepayers. ALE's unregulated operations, which accounting for less than 10% of consolidated revenue, will benefit from lower income tax expense going forward. ALE boosted 2018 earnings guidance by 10 cent per share, or $5.1 million, due to anticipated benefits of TCJA.

ATO: TCJA resulted in the re-measurement of the net deferred tax liability included in ATO's rate base. The excess deferred tax balance, estimated at $746 million, will be returned to utility customers in accordance with regulatory requirements. ATO anticipates the reduction in operating cash flow from lower customer bills, combined with the return of regulatory liabilities establishing connection with implementing tax reform, will increase estimated financing needs through fiscal 2022 by approximately $500 million to $600 million.

EE: El Paso recorded an increase in regulatory liabilities of $275 million as a result of the TCJA. Following the enactment of the TCJA and the reduction of the federal corporate income tax rate, revenues collected from EE customers in 2018 will be reduced by an amount that approximates the savings in tax expense. This reduction in revenues is expected to negatively impact EE cash flows by about $26 million to $31 million during 2018.

NWN: The utility's deferred tax liability re-measurement resulted in a $213.3 million regulatory liability as tax reform is expected to benefit customers. The utility is "working closely with the Oregon commission and other stakeholders on several significant dockets, including the best way to return TCJA benefits to customers through an Oregon general rate case, which we filed in December 2017." NWN expects to see a net increase in cash flows as a result of TCJA over the longer term, as taxes are a pass through to customers and lower deferred tax liabilities and no bonus depreciation are expected to increase regulatory returns.

POR: POR's net regulatory liability was increased by $357 million, as the company deferred the impact of re-measuring accumulated deferred income taxes pursuant to enactment of the TCJA. POR plans to use the average-rate-assumption-method to account for the refund to customers. The unprotected portion of the re-measurement is not subject to tax normalization rules and will be amortized over time. POR proposes to defer for future refund the 2018 expected net benefits as part of an application filed with the Oregon Public Utilities Commission on Dec. 29, 2017. If approved as requested, any refund to customers of the net benefits associated with the TCJA in 2018 would be subject to an earnings test and limited by the company's previously authorized regulated ROE.

WR: Regulatory liabilities increased $845 million primarily due to the TCJA. WR indicates amortization of the liability will lower prices for customers over a period generally corresponding to the life of WR plant assets. The TCJA, including elimination of bonus depreciation and a lower accumulated deferred income tax, results in approximately 4% compounded annual rate base growth through 2022. Management indicates cash flow "headwinds" are expected, which may decrease WR's FFO-to-debt ratio by 100 to 200 basis points. WR indicates that in its pending rate case it proposes to implement a $1.6 million first-step rate decrease in September to reflect the tax change.

Holding company with regulated utilities:

LNT: The TCJA reduced deferred tax liabilities and increased regulatory liabilities by $885.9 million. Tax reform is not forecasted to have a material impact on LNT's 2018 earnings. LNT utilities are working with state utilities commissions to determine the amount and appropriate mechanism to provide these benefits to their customers. LNT currently is unable to quantify cash flow from operations, credit ratings, liquidity, and capital needs impacts.

AEE: AEE booked a $2.2 billion increase in noncurrent regulatory liabilities as result of TCJA at its two operating utilities. AEE expects a decrease in operating cash flows of approximately $1 billion from 2018 through 2022 — Ameren Missouri, $0.3 billion and Ameren Illinois, $0.4 billion— as a result of the TCJA, and expects an increase in rate base of approximately $1 billion over the same time period —Ameren Missouri, $0.3 billion and Ameren Illinois, $0.5 billion. Over the next five years, AEE may be required to issue incremental debt and/or equity to fund this reduction in operating cash flows, with the long-term intent to maintain strong financial metrics and an equity ratio around 50%, as calculated in accordance with ratemaking frameworks.

AVA: Recorded a $442 million liability to be returned to customers. AVA expects to report an annual reduction in earnings of $0.05 to $0.06 per share and a reduction in operating cash flows from the loss of bonus depreciation and the return of excess deferred taxes to customers. As a result, AVA indicates it may need to raise additional capital.

BKH: Recorded a $301 million regulatory liability that will generally be amortized over the remaining life of the related assets using the normalization principles as specifically prescribed in the TCJA. From a cash flow perspective, BKH expects cash flows to be negatively impacted by $35 million to $45 million annually, due to the lower revenue collection as tax reform benefits flow to customers through the regulatory process. BKH expects tax reform to impact 2018 earnings minimally, as the reduced tax benefit on holding company debt will be largely, but not completely, offset by the reduced tax expense on the company's nonutility earnings

CNP: CNP recorded $1.3 billion in excess deferred taxes at its regulated utilities, as a result of the TCJA. Changes in tax depreciation at the lower federal rate are expected to increase forecasted year-end 2019 average rate base by about $300 million. The change in tax depreciation expense at the lower tax rate reduces the tax shield, thereby reducing near-term cash flows, and the timing of the return of excess deferred taxes may reduce near-term cash flows. CNP's unregulated business is expected to benefit from the lower tax rate, boosting earnings by $0.10 per share, or $43 million, in 2018.

CMS: For CMS, excess deferred tax liabilities related to the TCJA are estimated at $1.5 billion. The repeal of the alternative minimum tax, or AMT, allows CMS to monetize substantial AMT credits over the next four years to the tune of about $125 million in the first year, which partially offsets the likely near-term operating cash flow reduction at the utility. CMS parent interest expense will be largely offset by the interest income generated by EnerBank, its industrial bank subsidiary.

DTE: DTE estimates that, as a result of the TCJA, $1.7 billion of excess deferred tax liabilities will need to flow back to ratepayers. DTE management estimates two-third of this balance is protected vs unprotected. DTE's earnings guidance was increased by $0.10 per share tied to the lower tax rate on nonutility business. DTE's utilities are expected to begin to contribute to EPS growth in the latter part of the next five-years, as the utilities transition from funding rate base growth through cash generated by deferred taxes to a higher mix of equity relative to debt. DTE expects to issue incremental equity of $300 million 2018-2020 as a result of tax reform impacts. Consequently, in the latter portion of the five-year period, EPS accretion from tax reform actually grows to — in the range of 13 cent per share ($23 million).

ED: Excess deferred income taxes of approximately $3.7billion, including $3.5 billion for subsidiary Consolidated Edison of New York, were recorded as regulatory liability related to the TCJA. The TCJA is expected to result in decreased cash flows from operating activities, and require increased cash flows.

ES: Tax reform is expected to increase ES rate base by $575 million by 2020. The refund of excess accumulated deferred federal income tax will slightly reduce cash flows, but ES does not expect to need to issue equity. ES recorded about $2.9 billion of regulatory liabilities related to the TCJA. New distribution rates that took effect recently in Massachusetts reflect about $56 million of annual benefits from the reduction of the federal corporate tax rate. Similarly, a three-year settlement reached recently in subsidiary Connecticut Light and Power's distribution rate case is expected to reflect between $45 million and $50 million of annual customer benefits from the lower tax rate.

EIX: The implementation of tax reform at Southern California Edison resulted in a reduction of deferred tax liabilities and a corresponding increase in regulatory liabilities of about $5 billion. The company expects that by 2020, the TCJA will effectively increase rate base $400 million. There will be a smaller tax shield from interest on EIX parent debt, but that will largely be offset with other items. In the near term, SCE expects tax reform to lower rates charged to customers, but not to have a meaningful impact to SCE's earnings. EIX expects to be a cash taxpayer in 2025.

GXP: GXP estimates that excess accumulate deferred tax liabilities refundable through future rates will amount to $795 million. GXP expects to return approximately $100 million in annual tax savings to Missouri and Kansas customers. The company anticipates an ongoing decrease in annual cash flow of about $100 million and 1% to 2% decrease in cash flow to debt metrics.

IDA: IDA calculates that, as a result of the TCJA, excess accumulated deferred income taxes of $194 million will need to be flowed back to customers. Proceedings are pending in Idaho and Oregon o address tax reform-related issues.

NI: The re-measurement of NI's deferred tax liabilities increased regulatory liabilities by about $1.5 billion, which will flow back to customers. The TCJA will cause near-term adjustments to cash flow that NI management indicated it will "need to navigate." NI expects its NOL carryforward will provide a cash tax benefit to NI that extends beyond 2025.

NWE: The company recorded an estimated regulatory liability of $320 million for the change in regulated utility deferred taxes as a result of the TCJA. NWE expects a $15 million to $20 million loss of cash from operations in 2018 and beyond due to the TCJA. NOLs are now anticipated to be available into 2020, versus 2021 expected previously.

OGE: OGE has recorded a $955.5 million non-current regulatory liability associated with income taxes will be refundable to customers. While interest expense deductibility remains at the utility, OGE has no significant holding company debt, making limitations on interest deductibility a non-factor. The company will see some impact from other provisions related to non-deductible expenses, but those items are not expected to be material with respect to 2018.

OGS: OGS is working to determine the amounts of regulatory liabilities arising from the TCJA that will be refunded each year, but expects to return approximately $400 million to customers over the next 25 to 30 years. OGS deferred $519 million as a regulatory liability for ratemaking purposes associated with TCJA. OGS expects its rate base will increase in 2018 on slightly higher capital spending and as a result of the effects of tax reform. OGS expects its ROE to improve in future years as it normalizes the impact of tax reform through regulatory filings. However, the reduction in operating cash flows, combined with the return of regulatory liabilities recorded in conjunction with tax reform, is expected to increase OGS' estimated financing needs through 2022 by about $150 million to $200 million.

PCG: PEG recorded an almost $3.9 billion regulatory liability to reflect the change in net deferred tax liabilities associated with the TCJA. The utility currently anticipates an annual reduction to revenue requirements of about $500 million starting in 2018, and increases to rate base of about $500 million in 2018 and $300 million in 2019, as a result of the Tax Act. Through 2019, PCG now expects rate base growth of approximately 7.5% to 8% annually compared to the 6.5% to 7% previously forecasted. Revenues collected from customers are expected to decline by $500 million annually, impacting cash flows. PG&E expects to become a federal cash taxpayer in 2020, a year earlier than previously forecasted.

PNW: PNW recorded a $1.5 billion regulatory liability related to excess accumulated deferred taxes flowing from the TCJA. The majority of these excess deferred taxes are subject to IRS normalization provisions. From a rate base perspective, PNW's preliminary estimates show incremental rate base of about $150 million per year in 2018 and 2019 as a result of both the lower tax rate and legislative changes related to tax depreciation.

PNM: The TCJA resulted in a $549 million net increase in regulatory liabilities at PNM's utilities. Cash flows will be reduced in the near term, as the benefits of the reduced corporate income tax rate are passed on to ratepayers, without a corresponding reduction in income taxes paid due to PNM having an NOL carryforward for income taxes purposes. In addition, the income tax benefit of net losses for the unregulated activities of PNM Resources, primarily interest expense on holding company debt, will be negatively impacted by the reduced rate.

SR: The adjustment to deferred tax liabilities as result of TCJA at Spire Missouri and Spire Alabama was $264 million combined. SR anticipates that the TCJA will reduce cash flows in the future as customers' bills are lowered, thus impacting credit metrics. SR does not expect restrictions on deductibility of interest at the holding company level to have a material impact on future earnings.

UTL: UTL recorded a regulatory liability in the amount of $48.9 million as a result of the TCJA. Subject to regulatory approval, UTL will pass back to ratepayers the excess accumulated deferred tax balance, using the average rate assumption method. UTL expects its distribution revenue to decrease by about $7.5 million across all regulated entities, offset by an equal amount of tax expense reductions. Consequently, there will be no material effect on net income. Cash flow will be negatively impacted, but UTL's credit metrics are expected to remain strong. Rate base growth is now expected near the high end of its previous 6%-8% range.

WEC: WEC recorded a $2.45 billion change in deferred taxes for its regulated utilities due to the enactment of the TCJA. Management now expects WEC's FFO-to-debt metric to be in the range of 16% to 18%. WEC does not expect the limitation on interest deductions to materially adversely impact earnings. WEC indicated revaluation of its deferred tax assets and liabilities is subject to further clarification of the new law and the ultimate impact cannot be estimated at this time.

XEL: Estimated accounting impacts of the TCJA at XEL included $2.7 billion, $3.8 billion grossed-up for taxes, of reclassifications of plant-related excess deferred taxes to regulatory liabilities. XEL expects tax reform to be mildly accretive to earnings over the next five years, adding $1.3 billion to rate base. The tax law changes will reduce cash from operations and adversely impact credit metrics. In response, XEL expects to scale back its five-year capital expenditure plan by $500 million and issue up to $300 million of additional equity.

Diversified utilities:

AEP: As a result of the TCJA, AEP recorded total excess regulated deferred federal income taxes to be returned to utility ratepayers of $4.4 billion, including a normalized or "protected" portion of excess accumulated deferred income tax of $3.2 billion and a non-depreciation portion of $1.2 billion. AEP raised its annualized rate base growth forecast for the years 2018 through 2020 to 9% vs. 8% previously. The impact of the new law's changes to interest deductibility should be marginal, as parent company debt is minimal. Reduced operating cash flow, from the flow-through of tax benefits to ratepayers, is not expected to require incremental issuances, but AEP has cut its capital spending forecast for 2018-2020 by $500 million.

AGR: AGR is still reviewing the impacts of the TCJA and the appropriate methodology for ensuring that benefits flow to ratepayers. AGR projects increased financing costs and a need to issue debt to offset the related reduction in cash flow. AGR's renewables business is expected to benefit from the lower tax rate. Overall, AGR expects a $0.05 per share, or $15 million, benefit from tax reform.

CPK: For CPK's regulated businesses, the TCJA-related change in deferred income taxes of $98.5 million was recorded as an offset to a regulatory liability, some portion of which may ultimately be subject to refund to customers. CPK indicates that it may need to access additional debt and equity capital to meet financing needs due to lower operating cash flows from its regulated energy businesses.

D: The company recorded a $3.6 billion increase in regulatory liabilities at its regulated operations — Virginia Electric and Power and Dominion Energy Gas — associated with TCJA. Dominion is awaiting guidance from the U.S. Treasury Department with respect to the deductibility of interest expense at its unregulated businesses. Regulated utilities continue to work with their respective regulatory commissions to determine the amount and timing of the flow-through of TCJA-related benefits to customers. The ultimate resolution with regulators could be material to D's operating cash flows.

DUK: Duke expects the revaluation of accumulated deferred taxes under the TCJA to add about $3.5 billion to its rate base by 2021, resulting in a 7% CAGR, a 1% increase compared to its previous forecast. The rate reductions resulting from tax reform are also expected to provide additional headroom in customer bills, allowing for increased capital investment. The company recorded a net regulatory liability related to income taxes of $8 billion at Dec. 31, 2017. In addition, the lower tax shield at the holding company level is expected to reduce earnings. In order to strengthen its balance sheet to mitigate the impact of lower expected cash flows, DUK plans to issue $2 billion in common stock during 2018, including its previous plan to issue $350 million annually beginning in 2018, and reduce its capital expenditures during 2018-2022 by about $1 billion.

ETR: The company recognized a regulatory liability of $2.9 billion due to a re-measurement of deferred tax assets and liabilities resulting from the income tax rate change. ETR estimates the unprotected portion of excess accumulated deferred income taxes at $1.4 billion, which will be returned to customers over time through refunds, cash investments in new assets, accelerated depreciation or other options approved by regulators. The protected portion of excess ADIT is subject to normalization, and will be amortized over the remaining lives of the associated assets. Over the next three years, ETR expects its rate base to grow a little over $1 billion due to TCJA. It plans to issue about $1 billion in equity before the end of 2019 to stabilize the balance sheet, and plans to counter reduced operating cash flow through a combination of utility company debt, parent debt, internal cash generation and external equity.

EXC: The company recorded $4.7 billion in net regulatory liabilities, including $3 billion subject to normalization rules and $1.7 billion that will be amortized over a time period set by state regulators. EXC projects rate base growth of 7.4% versus 6.5% previously, as a result of the TCJA-relate revaluation of accumulated deferred tax balances. Tax reform is estimated to increase rate base by about $1.7 billion by 2020, relative to previous expectations. EXC expects "much stronger free cash flow" from its merchant business, which will more than offset additional equity needs of the utilities. The lower tax rate and 100% expensing of depreciation at the merchant business will improve EPS by $0.10 per share, or $97 million.

FE: Almost all of the company's $2.3 billion in excess of accumulated deferred tax balance is considered protected and subject to normalization provisions; these amounts will be refunded to ratepayers over the life of its assets. FE forecasts a $400 million uplift in rate base with the elimination of bonus depreciation in two years. The company expects that the TCJA will reduce the FFO-to-debt ratio by between 1% and 1.5%, and that the FFO ratio will remain at 13% through 2021. FE also expects to lose some tax shield due to limitations on interest deductibility.

MGEE: MGEE recorded a $130.5 million increase in regulatory liabilities as a result of the TCJA. Tax reform is generally expected to result in lower operating cash inflows in future years, as a result of the elimination of bonus depreciation and lower customer rates as tax-related benefits are passed on to ratepayers

NFG: NFG recorder an approximate $337 million deferred regulatory liability as a result of the TCJA. NFG management is still awaiting details on certain aspects of tax reform, such as potential limitations on the deductibility of interest expense and executive compensation. NFG management indicates that the company still has a "decent-sized NOL that will offset any tax payments for this year."

NJR: NJR recorded $228 million as a noncurrent regulatory liability to be refunded to ratepayers as a result of the lower tax rate. The lower tax rate is expected to boost non-regulated net income by between $0.04 and $0.08 per share, or between $3.5 million and $7 million.

NEE: The company's Florida Power & Light, or FPL, subsidiary revalued deferred income tax liabilities to the new 21% corporate income tax rate. The majority of the reduction in income tax liability, totaling $4.5 billion, has been reclassified as a regulatory liability that is expected be amortized over the underlying assets' remaining useful lives. Tax reform is generally expected to result in lower operating cash flows for NEE, as FPL uses tax savings to recover the Irma storm surcharges, but NEE does not expect an impact on credit metrics. The impact to NEE's unregulated Energy Resources subsidiary is expected to be significantly accretive to earnings, increasing NEE's adjusted EPS by roughly $0.45 per share, or $212 million, in 2018.

PEG: For PEG, excess accumulated deferred taxes related to TCJA total about $2.1 billion. About 70% are deemed protected under the IRS normalization rules, which require that protected deferred tax balances be returned to customers over the remaining lives of the associated assets. The remaining 30%, or about $600 million, some of which were recognized in PEG's Jan. 12, 2018, distribution base rate filing, are to be returned to customers over a time frame that will be determined in discussions with the New Jersey Board of Public Utilities and with FERC. According to the company, TCJA impacts on cash flow and credit metrics are manageable given PEG's business mix and the strength of balance sheet. The earnings boost expected from the reduced tax burden for its unregulated businesses is expected to be $0.16 per share, or $81 million, in 2018.

SCG: SCG recorded accumulated deferred income taxes of about $1.1 billion, which includes excess deferred income taxes arising from re-measurement of deferred income taxes upon enactment of the Tax Act.

SRE: For SRE, regulatory liabilities recorded as result of the Tax Act were $2.4 billion. The one-time reparation of SRE's foreign subsidiary earnings partially mitigates the credit impact of the flow-through ratepayers of lower utility taxes. SRE plans to repatriate about $1.6 billion from 2018-2022. Tax reform is expected to decrease earnings per share by between $0.25 and $0.30 in 2018, as SRE is impacted by the lower tax shield on corporate interest, but long-term the impact is expected to be neutral.

SO: Southern recorded a nearly $7 billion deferred tax liability, of which $5.7 billion is protected and $1.3 billion is unprotected. Management has indicated that cash flow is expected to be adversely affected at SO's state-regulated utilities and, "absent mitigation, lower FFO to debt ratios" Will result. Southern Power, SO's unregulated business, is expected to benefit from the lower tax rate by $15 million to $20 million.

SJI: SJI expects experience a benefit at its South Jersey Gas subsidiary, due to a higher rate base, as accumulated deferred tax offsets are reduced, with the amount dependent upon regulatory action and timing of base rate cases. SJI reported excess accumulated deferred income taxes of $264 million. For its non-utility operations, SJI saw a $13.5 million one-time benefit associated with the revaluation of its net deferred tax liabilities, expects ongoing benefits beginning in 2018 that will rise to $10 million annually beginning in 2020. Cash flows are expected to decrease by between $20 million and $40 million per year due to the return of excess deferred taxes to ratepayers and the elimination of bonus depreciation.

UGI: UGI recorded $304 million in excess accumulated deferred income taxes resulting from the tax law, and a proceeding is pending in Pennsylvania to determine how this balance and other TCJA-related benefits will flow through to ratepayers. UGI has extensive non-regulated and foreign operations. The company indicated that the TCJA boosted EPS for the first quarter of fiscal 2018, i.e. the quarter ended Dec. 31, 2017, by $0.12 per share. The company expects a net full-year benefit related to tax policy of $0.15 to $0.25, including the negative impact of changes in French tax law.

Broadly-diversified utilities:

AES: The company's U.S. utilities recorded an increase in deferred income tax liabilities of $241 million, due to the revaluation of deferred taxes associated with the tax rate change. AES also repatriated foreign earnings under the reduced tax rate provided for in the Tax Act. AES expects a "meaningful limitation" on interest expense deductions. Also under new global intangible income rules, un-repatriated foreign earnings above a certain threshold can now be subject to U.S. tax. AES expects these issues will impact near-term earnings by between $0.05 and $0.08 per share annually, or $33 million to $53 million. Management indicates it has taken actions to offset these impacts and will continue to evaluate additional tax planning opportunities. AES continues to have a significant NOL position.

HE: The company reclassified $285 million in net excess accumulated deferred taxes as a regulatory liability that will be returned to customers through rates. While tax reform will result in higher financing needs in the future for HE's utility due to the loss of bonus depreciation, HE does not expect to need any additional external equity or equity from the company's dividend reinvestment program during 2018. Net interest income from HE's banking unit will "more than cover holding company interest expense. So interest expense deductibility will not be an issue," according to management. American Savings Bank is expected to see increased dividend and earnings capacity.

MDU: MDU continues to work with the various regulators on a plan flow TCJA-related savings to customers. This resulted in the creation of a regulatory liability refundable to customers of $285.5 million. MDU's non-regulated construction business is expected to benefit from the TCJA. MDU's construction materials businesses reported $46.2 million higher earnings in 2017 as result of tax reform.

OTTR: OTTR booked a $149 million increase in regulatory liabilities associated with excess accumulated deferred income taxes. OTTR expects its rate base to grow by about an additional $100 million over its five-year planning horizon as a result of the Tax Act. No material impact on equity needs foreseen and the company expects to no negative impact credit ratings. OTTR's 2018 guidance assumes an uplift of $0.05 per share, or $2 million, related to the tax reform impact on its manufacturing platform and corporate cost center.

PPL: PPL recorded a net increase in regulatory liabilities as a result of TCJA at its U.S. utilities of almost $3.4 billion. PPL now projects its combined regulated rate base to grow by 6.4% through 2020, increasing to $31 billion. PPL added an additional equity issuance into its financing plan for 2018 and expects increased cash distributions from its U.K. business to mitigate the impact of the lower corporate tax rate on earnings and cash flow. The company anticipates about $0.05 per share of incremental dilution from the planned issuance of an additional $650 million of equity relative to its prior assumptions.

SWX: SWX estimates that excess deferred taxes to be passed back to utility customers will total $430 million; related proceedings are underway in Arizona, California and Nevada. The Tax Act is expected to provide a direct benefit to SWX's non-regulated construction services business.

VVC: The TCJA resulted in $333 million in excess federal deferred income taxes for VCC's utility group. Statewide proceedings related to the Tax Act have begun in Indiana and Ohio. While tax reform reduces cash from operations, additional cash available from VVC's nonutility businesses help fund utility capital spending.

Independent Power Producers:

Independent power producers, or IPPs, including NRG Energy Inc., Vistra Energy Corp., and Dynegy Inc., continue to examine the TCJA, and its overall impact to the bottom line. Under SEC rules, companies are required to finalize and record the tax effects of the TCJA by Dec. 31, 2018. RRA expects the sector to be a net beneficiary of the law given the permanent lower tax rate and full expensing for certain capital investments, which could support cash flows.

With regard to net operating losses, or NOLs — created when operating expenses exceed operating revenues at a particular business unit, and are used to offset taxable income — existing NOLs can continue to be utilized at 100% of taxable income with a 20 year carryforward, while NOLs incurred after the 2017 tax year are limited to 80% of taxable income with an indefinite carryforward, potentially weakening IPPs' "tax shield" against future taxable income. The TCJA also repealed the alternative minimum tax, or AMT, and it also limits the deduction of net business interest expense to 30% of adjusted taxable income. For NRG and Dynegy, reductions to the companies' deferred tax asset balances due to the lower tax rate were offset through valuation allowances, a balance established when it is likely that all or a portion of net deferred tax assets will not be utilized.

DYN: DYN recorded a $394 million reduction to its net deferred tax assets, including the federal benefit of state deferred taxes, that was fully offset by a decrease in its valuation allowance for the year ended Dec.31, 2017. The Houston-based power generator and electric retailer also recorded a $223 million current tax benefit and long-term tax receivable in 2017 related to the expected refund of its existing AMT credits. DYN expects the related refunds to total $112 million in 2019; $56 million in 2020; $28 million in 2021; and the remainder in 2022. At year-end 2017, Dynegy had $4.6 billion of federal NOLs and $3.6 billion of state NOLs that can be used to offset future taxable income, with the federal NOLs expiring between 2024 and 2037. In the near-term, DYN expects greater utilization of its NOLs to offset the limit of net business interest expense.

NRG: NRG recorded a $733 million reduction to its net deferred tax assets that was offset by a valuation allowance of $660 million, and the company recorded a long-term receivable of $64 million related to the expected refund of its existing AMT credits, expected to be received between 2019 and 2020. At year-end 2017, the company had domestic federal NOL carryforwards of $2.8 billion, which begin expiring in 2026, and state NOL carryforwards of $2.2 billion. With more than $3 billion expected from asset sales and a leaner balance sheet as part of its broader strategic transformation plan announced in 2017, NRG's cash position and resultant financial flexibility appear to be on solid footing for the foreseeable future. The company expects cash flow from operations in 2018 in a range of approximately $2.02 billion to $2.2 billion, compared with $1.39 billion in 2017, and adjusted free cash flow in a range of $1.55 billion to $1.75 billion, compared with $1.30 billion in 2017.

VST: VST recorded an approximately $451 million reduction to its deferred tax asset balance for the year ended Dec. 31, 2017; however, considering its expectation that its deferred tax assets will be fully utilized to offset future taxable income, the company did not recognize a valuation allowance. At year-end 2017, the company had no federal NOL carryforwards, and no AMT credit carryforwards. Excluding the impacts from its pending acquisition of Dynegy, VST expects 2018 adjusted free cash flow in a range of $600 million to $750 million. The company expects to update guidance upon closing of the Dynegy acquisition.

Change in deferred income tax liabilities ($000)

	2017	2016	
South Jersey Industries Inc.	86,884	343,549	-75%
FirstEnergy Corp.	1,359,000	3,765,000	-64%
ALLETE Inc.	197,700	521,300	-62%
Otter Tail Corp.	100,501	226,591	-56%
Westar Energy Inc.	815,743	1,752,776	-53%
Great Plains Energy Inc.	621,700	1,329,700	-53%
Southern Co.	6,842,000	14,092,000	-51%
NiSource Inc.	1,292,900	2,528,000	-49%
NextEra Energy Inc.	5,754,000	11,101,000	-48%
OGE Energy Corp.	1,227,800	2,334,500	-47%
IDACORP Inc.	660,940	1,244,250	-47%
Hawaiian Electric Industries Inc.	388,430	728,806	-47%
Vectren Corp.	491,300	905,700	-46%
Avista Corp.	466,630	840,928	-45%
PNM Resources Inc.	491,479	884,633	-44%
Portland General Electric Co.	376,000	669,000	-44%
Xcel Energy Inc.	3,845,000	6,784,319	-43%
PG&E Corp.	5,822,000	10,213,000	-43%
Pinnacle West Capital Corp.	1,690,805	2,945,232	-43%
ONE Gas Inc.	599,945	1,038,568	-42%
WEC Energy Group Inc.	2,999,800	5,146,600	-42%
MGE Energy Inc.	225,130	383,813	-41%
Eversource Energy	3,297,518	5,607,207	-41%
NorthWestern Corp.	340,729	575,582	-41%
Chesapeake Utilities Corp.	135,850	222,894	-39%
PPL Corp.	2,462,000	3,889,000	-37%
Sempra Energy	2,767,000	3,745,000	-26%
National Fuel Gas Co.	891,287	823,795	8%
New Jersey Resources Corp.	514,708	473,847	9%
UGI Corp.	1,357,000	1,212,400	12%
Spire Inc.	707,500	607,300	16%
WGL Holdings Inc.	868,067	726,763	19%
AES Corp.	1,006,000	804,000	25%

As of Dec. 31, 2017.
Note: Nine utilities or utility holding companies without data available excluded.
Source: S&P Global Market Intelligence

DAmbrosio, Eleanor

From: DAmbrosio, Eleanor
Sent: Wednesday, May 29, 2019 2:21 PM
To: Winker, Anjuli
Subject: TNMP Response to LK 1-4
Attachments: TNMP Response to RFI LK 1-4.pdf

Here you go! It is now a single document with the RFI question as the first page.

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TEXASNEW MEXICO POWER COMPANY'S RESPONSES TO COMMISSION CITIES' - LK 1-1 THROUGH LK 1-10

LK 1-4 Please provide copies of all articles, regulatory commission orders, rating agency reports, and other supporting documentation cited and relied upon by Mr. Hevert in his Direct Testimony and exhibits. Include copies of all articles, reports, and other documents cited in the footnotes.

Prepared by: Joshua Kaushansky

Sponsored by: Robert Hevert

Attachment: TNMP 48401_LK 1-4 Attachment A Index.xls; TNMP 48401 LK 1-4 Attachment B (Voluminous).pdf; TNMP 48401 LK 1-4 Attachment C.pdf; TNMP 48401 LK 1-4 Attachment D.pdf; TNMP 48401 LK 1-4 Attachment E.pdf; TNMP 48401 LK 1-4 Attachment F.pdf; TNMP 48401 LK 1-4 Attachment G.pdf; TNMP 48401 LK 1-4 Attachment H.pdf; TNMP 48401 LK 1-4 Attachment I.pdf; TNMP 48401 LK 1-4 Attachment J.pdf; TNMP 48401 LK 1-4 Attachment K (Voluminous).pdf

RESPONSE:

Attachments LK 1-4 B and LK 1-4 K responsive to this request are voluminous and are available for inspection at TNMP's Voluminous Room, Jackson Walker L.L.P., 100 Congress Avenue, Suite 1100, Austin, Texas 78701, during normal business hours, by making arrangements with Pamela Collins, (214) 953-5973.

Please see attachments TNMP 48401_LK 1-4 Attachments A through K for Mr. Hevert's cited material.

Tax Reform Impact on the U.S. Utilities, Power & Gas Sector

Tax Reform Creates Near-Term Credit Pressure for Regulated Utilities and Holding Companies

Regulatory Support Key to Mitigating Downward Migration in Ratings

Near-Term Pressure on Credit Metrics: The Tax Cuts and Jobs Act signed into law on Dec. 22, 2017 has negative credit implications for regulated utilities and utility holding companies over the short to medium term. A reduction in customer bills to reflect lower federal income taxes and return of excess accumulated deferred income taxes (ADIT) is expected to lower revenues and FFO across the sector. Absent mitigating strategies on the regulatory front, this is expected to lead to weaker credit metrics and negative rating actions for issuers with limited headroom to absorb the leverage creep.

Significant Hit to FFO: To analyse the impact of the tax reform bill across our utility coverage, Fitch Ratings studied a sample of 140 regulated operating subsidiaries and utility holding companies. We estimate that regulated utility subsidiaries will, on average, see an approximately 6% reduction in net revenues if tax changes are reflected in customer bills right away. Fitch has assumed that a substantial portion of the excess ADIT will be returned to customers over the life of the utility property. The lower revenue translates to an approximately 15% reduction in FFO that drives an approximately 45 basis point increase in FFO-adjusted leverage across our sample.

Regulatory Response and Financial Policy Key: State regulators have begun to examine the impact of tax reform on regulated utilities in their states. While most state regulators will seek to provide some sort of rate relief to customers, they may be open to a negotiated outcome that also preserves the creditworthiness of the utilities. Management actions to defend their credit profiles are also important in assessing the future rating trajectory of an issuer. Overall, Fitch expects rating actions to be limited and on a case-by-case basis. Holding companies are more vulnerable given the elevated leverage profile for many, driven by past debt-funded acquisitions.

Longer-Term Positive: Over a longer-term perspective, Fitch views tax reform as modestly positive for utilities. The sector retained the deductibility of interest expense, which would have otherwise significantly impacted cost of capital for this capital-intensive sector. The exemption from 100% capex expensing is also welcome news for the sector, which has seen years of bonus depreciation inflate ADIT, which is netted from the rate base in most state regulatory jurisdictions. The excess ADIT will be recorded as a regulatory liability, which will amortize over time, leading to rate base and earnings growth. Finally, the reduction in federal income taxes lowers cost of service to customers, providing utilities headroom to increase rates for capital investments.

In this report, Fitch Ratings addresses the following frequently asked questions from investors:

- How does tax reform affect regulated utilities?
- What is the impact of tax reform on utility holding companies and nonregulated businesses?
- What is the magnitude of FFO reduction and leverage increase for the sector?
- Does Fitch expect to take widespread rating actions driven by tax law changes?
- Which issuers does Fitch consider most at risk for negative rating actions?

How Does Tax Reform Affect Regulated Utilities?

The Tax Cuts and Jobs Act has negative credit implications for the regulated utilities and several utility holding companies over the short to medium term. A reduction in customer bills to reflect lower federal income taxes and return of excess ADIT to customers is expected to lower revenues and FFO across the sector. Absent mitigating strategies on the regulatory front, this is expected to lead to weaker credit metrics and negative rating actions for those issuers that have limited headroom to absorb the leverage creep. The end of bonus depreciation or the "interest-free loan" from the federal government and reduced FFO at a time when capex budgets are elevated will necessitate greater reliance on equity and debt funding for the utility subsidiaries. This could lead to higher costs of capital for the sector, especially if regulators require an immediate reduction in customer bills to reflect the tax law changes.

It is important to note that the negative impact on cash flows and leverage metrics is primarily being driven by timing-related differences. Due to availability of 100% and 50% bonus depreciation on qualified property in recent years, most utilities have not been paying cash taxes and have seen a sharp buildup in ADIT. This situation would have reversed over time, and our financial forecasts did reflect a hit to FFO for most utilities as they returned to full cash taxpaying status by 2020–2021. With tax reform, utilities cannot claim bonus depreciation anymore, the ADIT has to be recalculated at the new 21% rate, the future ADIT also builds at the 21% rate, and the excess ADIT has to be refunded to customers, leading to lower FFO expectation compared to prior Fitch estimates. Since federal income taxes are included in a utility's cost of service, this is typically a straight pass-through cost. With most utilities not paying cash taxes, the reduction in revenue requirement due to lower federal taxes does not have an equivalent offset. Hence, past bonus depreciation benefits have exacerbated the situation for utilities, leading to unanticipated near-term pressure on FFO.

Over a longer-term perspective, Fitch views tax reform as modestly positive for utilities. The sector retained the deductibility of interest expense, which would have otherwise significantly impacted cost of capital for this capital-intensive sector. The exemption from 100% capex expensing is also welcome news for the sector, which has seen years of bonus depreciation benefits supress rate base (for most states, ADIT reduces the rate base on which a utility earns a return). Finally, the reduction in federal income taxes lowers cost of service to customers, providing utilities headroom to increase rates for capital investments. Fitch estimates that electric utility customers could, on average, see approximately 3%–5% reduction in their bills due to tax law changes.

What Is the Impact of Tax Reform on Utility Holding Companies and Nonregulated Businesses?

At the holding company level, the reduction in utility subsidiaries' cash flows will weaken the consolidated cash flow profile, leading to higher leverage unless mitigated by holdco debt reduction. In addition, there continues to be limited clarity surrounding the deductibility of holding company interest, in particular the methodology to allocate consolidated interest expense between regulated and nonregulated businesses. Until resolved, these issues will continue to weigh on the financial policies of holding companies.

There is no ambiguity in how interest expense will be treated for regulated and nonregulated entities. Regulated subsidiaries will be able to fully deduct interest expense for tax purposes, and nonregulated businesses, similar to other corporations, will be subject to the 30% of EBITDA limitation (which changes to 30% of EBIT in 2022). Calculating interest deductibility for holding companies gets complicated. For holdcos such as NextEra Energy, Inc., which has distinct regulated and nonregulated debt issuing entities, the analysis is straightforward. However, for other holdcos such as Dominion Energy, Inc., which issues debt for nonregulated businesses at the holdco level, or even for holdcos such as Exelon Corporation and FirstEnergy Corporation, which issue debt at their nonregulated entities, it is not clear how the consolidated interest expense will be allocated between regulated and nonregulated businesses. Several managements we spoke to seem to believe that asset-based allocation, such as that used for allocation of interest for foreign corporations, will be applicable. As a broader issue, we are most concerned with allocation of holdco interest expense to regulated businesses to claim full deductibility of interest expense, since regulated subsidiaries already meet their prescribed capital structure. We expect uncertainty to prevail until the U.S. Treasury department issues guidance in this regard.

For nonregulated businesses, the reduction in federal income taxes is positive because the benefit accrues straight to the bottom line. Fitch expects renewable business to be negatively impacted since the federal renewable tax credits are less valuable at the lower tax rate, thus making renewable economics less favorable. Fitch also expects less tax equity to be available as a source of financing, which is likely to hit the small renewable developers disproportionately. In this regard, solar developers may be more significantly impacted than wind developers due to the large upfront solar investment tax credit (ITC) that needs to be absorbed versus a 10-year life of wind production tax credits (PTCs). A lower tax rate also lowers the net present value of accumulated renewable tax credits and accumulated net operating losses by extending the time period over which these will be used.

What Is the Magnitude of FFO Reduction and Leverage Increase for the Sector?

We have analyzed the cash flow impact for the sector while admitting that tax and accounting nuances overlaid by the complexity of regulatory accounting makes the exercise challenging. After analyzing a sample of 140 regulated operating subsidiaries and utility holding companies, we estimate that regulated utility subsidiaries will, on average, see an approximately 6% reduction in net revenues if the tax reform changes are reflected in rates right away. This reduction in revenues translates to an approximately 15% reduction in FFO and an approximately 45 basis point increase in FFO-adjusted leverage across our sample.

Key inputs and assumptions incorporated in our analysis include:

- **Immediate reduction in customer bills to reflect the cut in federal tax rate to 21% from 35%:** Under cost-of-service regulation, federal and state income taxes are treated as an expense that is recoverable in regulatory tariffs. The reduction in federal income tax rate will lower the income tax expense, thus leading to lower revenue requirement for a regulated utility. As highlighted above, due to prior bonus depreciation benefits, most utilities are not paying cash taxes. As a result, immediate reduction in customer bills to reflect the lower revenue requirement will lead to lower FFO.
- **95% of ADIT, as reported on LTM basis, was assumed to be protected:** Based on our survey of regulated utilities, it appears a vast majority of the ADIT reported on the balance sheet pertain to public utility property and arise from accelerated federal tax depreciation and investment tax credits on that property, and, therefore, are protected by IRS normalization requirements. As a rough rule of thumb for our sample, we assumed that 95% of ADIT is protected and 5% unprotected, while recognizing that actual amounts may vary by utility.
- **Return of the excess protected ADIT over 30 years and excess unprotected ADIT over five years:** Section 203(e) of the Tax Reform Act of 1986, also known as the Average Rate Assumption Method (ARAM), provided for the reduction in protected ADIT due to the reduction in the tax rate to be spread over the life of the related property. Fitch has assumed that similar ARAM will be applicable for the Tax Cuts and Jobs Act, which seems consistent with the approach that most utilities are taking. The average life of utility property varies by utility, but 30 years serves as a good approximation. The return of unprotected ADIT is not subject to IRS normalization rules and, hence, will be subject to discretion of the regulators. While the regulatory approach with respect to unprotected ADIT varied across states in 1986, for the purpose of our exercise, we have assumed that regulators will require excess unprotected ADIT to be returned to customers over a five-year period.
- **Net PPE-based allocation methodology for holding company interest:** For the purpose of our exercise, we have allocated the consolidated interest expense between regulated and nonregulated businesses using net PPE as a proxy.
- **No adjustments made for bonus depreciation:** We have not made adjustments for the loss in bonus depreciation for years 2018 and 2019 (versus prior benefits at 40% and 30% for property placed in service in 2018 and 2019, respectively). The negative impact will be partially offset by bonus depreciation on capex incurred until Sept. 29, 2017 for property placed in service in 2018.

Does Fitch Expect to Take Widespread Rating Actions Driven by Tax Law Changes?

Fitch's rating actions will be guided by both the regulatory and management responses. A majority of states have opened dockets or requested all utilities in the state to submit an analysis on the implications of the tax reform. While regulators will be keen to provide some sort of rate relief for customers, such actions could take many forms and vary in time frame. Some jurisdictions may be open to a negotiated outcome that focuses more on benefits of rate stability and creditworthy utilities rather than immediate rate reductions. In the former, many tools could be employed, including the following:

- Deferral of lower tax expense to use as an offset to expected future rate increases either from the recovery of regulatory deferrals or rate base growth
- Return of excess unprotected ADIT over a longer-term horizon
- Increase in authorized equity ratio and/or return on equity
- Accelerated depreciation on some assets
- Lower capex

The time frame for regulatory action is an important consideration and will be varied. Some jurisdictions have asked for tax savings to be returned to customers immediately, thereby creating a decline in cash flow on day one. Some jurisdictions have directed utilities to segregate the effect of lower taxes to consider in future ratemaking procedures, and therefore result in no near-term change to cash flow. Some companies are in the middle of multiyear rate plans or rate settlements that do not provide for changes in tax rate, while other rate arrangements have incorporated mechanisms for lower taxes. Lastly, managements' responses to defend their credit profiles in the face of prospective lower cash flow will be key. If Fitch sees a credible path for credit metrics to be restored commensurate with the existing rating level, no rating actions may be warranted.

Holding companies are more vulnerable to negative rating actions given the elevated leverage profile for many, driven by past debt-funded acquisitions. The cash flow profile of holdcos will be weaker than prior expectations due to regulated utility subsidiaries bearing the brunt of tax law changes, leading to lower cash tax and possibly lower dividend distributions to parent holding companies. Moreover, funding needs at regulated subsidiaries will increase with the elimination of bonus depreciation. Conversely, the nonregulated subsidiaries will benefit from tax reform, which will be positive for parent holding companies.

Which Issuers Does Fitch Consider Most at Risk for Negative Rating Actions?

Issuers with limited headroom at the current rating level that are close to their negative rating triggers as established by Fitch are more vulnerable to negative rating actions. The most susceptible issuers are those that already have a Negative Outlook or are on Negative Rating Watch.

Key Rating Triggers for Select Issuers on Negative Outlook or Rating Watch

Issuer	IDR	Outlook/ Watch	Pre-Tax Reform FFO-Adjusted Leverage 2018F (x)	Key Downgrade Trigger	Key Upgrade Trigger
DTE Energy Co.	BBB+	Negative Outlook	4.6	Material delays associated with permitting and constructing the NEXUS pipeline, along with FFO-adjusted leverage sustaining > 4.5x.	Sustained FFO-adjusted leverage to 4.0x or better.
Duke Energy Corp.	BBB+	Negative Outlook	5.4	Inability to recover coal ash costs and sustained FFO-adjusted leverage > 5.1x by 2019.	Unlikely in medium term.
Georgia Power Co.	A	Negative Rating Watch	4.4	Proceeding with construction of new nuclear units while retaining material exposure to further costs and schedule overruns, and FFO-adjusted leverage > 4.3x on a sustained basis.	Unlikely in medium term.
SCANA Corp.	BB+	Negative Rating Watch	8.1	Material unrecoverable costs for the abandoned new nuclear project, constrained liquidity and adjusted debt/EBITDAR > 5.5x.	Constructive resolution of the stranded new nuclear project and adjusted debt/EBITDAR < 4.5x.
Southern Company	A–	Negative Rating Watch	5.2	Downgrade of Georgia Power Co. and FFO-adjusted leverage sustaining > 4.7x by 2019.	Unlikely in medium term.
WGL Holdings, Inc.	A–	Negative Rating Watch	4.2	Ownership by a weaker parent after acquisition is completed, and FFO-adjusted leverage > 4.0x.	Unlikely in medium term.

Source: Fitch

Related Research

Fitch 2018 Outlook: U.S. Utilities, Power & Gas (Supportive Regulation and Low Commodity Costs Support Stable Outlook) (November 2017)
U.S. Utility Parent Companies Handbook (A Detailed Review of Utility Parent Companies — Third Edition) (November 2017)
U.S. Competitive Generators Handbook (A Detailed Review of Competitive Generation Companies) (October 2017)
U.S. Regulated Utility Parent Holding Companies Peer Comparison (October 2017)
U.S. Integrated Electric Utilities Handbook (A Detailed Review of Integrated Electric Utilities) (August 2017)
U.S. Transmission and Distribution Utilities Handbook (Detailed Review of Electric and Gas T&D Utilities — Third Edition) (May 2017)

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S&P Global
Market Intelligence

March 19, 2018
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RRA Financial Focus
Utility Impact of the Tax Cuts and Jobs Act

- Investor-owned gas and electric utilities are preparing to return billions to ratepayers nationwide as provided for in the Tax Cuts and Jobs Act of 2017. Some $91.4 billion could be flowed back as utilities' excess deferred income tax liabilities are normalized in state regulatory proceedings, according to our latest analysis of Regulatory Research Associates' utility universe.
- Utility cash flows are expected to be reduced due to the return of excess deferred taxes and refunding of over-collections that occur until new rates are in place and because the lower tax rate reduces revenue requirements on an ongoing basis.
- Credit rating agencies have warned that utility credit metrics will be strained as a result of decreasing cash flows. Several utility holding companies and diversified utilities with competitive generation segments have announced plans to raise capital through equity and debt issuances or plans to reduce capital expenditures to maintain credit metrics.
- Our analysis concludes the average RRA utility decreased its total deferred income tax liability at Dec. 31, 2017 by 43%, compared to the year before. This follows several years of escalating balances.
- Rate base growth is expected across the sector as a result of the Tax Act, as lower deferred income tax liabilities reduces the offset to rate base in most states. Based on our analysis, utilities, including Edison International, Eversource Energy, OGE Energy, Pinnacle West Capital and ONE Gas are likely to benefit the most from tax-reform-related rate base growth.

Coincident with the completion of year-end 2017 accounting, the utility industry has written down billions in deferred tax liabilities associated with the reduction in the corporate income tax rate to 21% from 35%, and adjusted earnings guidance based on tax law changes. Investors now are focused on further implications of the Tax Cuts and Jobs Act of 2017, or TCJA, including credit ratings and near-term cash flow impacts. Also being evaluated are longer-term earnings expansion prospects given expected growth in utility rate base from lower deferred taxes.

Overall, tax reform — as RRA sees it — is near-term negative, but longer-term positive for regulated utilities. Longer-term, the reduction in deferred federal income taxes is expected to lead to increased rate base growth among electric and gas utilities, given that most states deduct accumulated deferred income taxes, or ADIT, in calculating rate base. Therefore, carrying a smaller ADIT balance should, all else being equal, increases rate base. Utilities should also have more "headroom" in proceedings seeking added capital investment before state regulators as customer rates decline nationwide, all else equal, due to the lower corporate tax rate. For our earlier analysis on tax reform read: Tax reform bill promises big changes for utilities, power producers.

Credit rating agencies have cautioned that the lower corporate tax rate could pressure utility credit metrics, as the reduction in deferred tax liabilities resulting from their revaluation to reflect the lower tax rate, together with the loss of bonus depreciation, will impact operational cash flows. S&P Global Ratings suggests that holding companies taxed on a consolidated basis are

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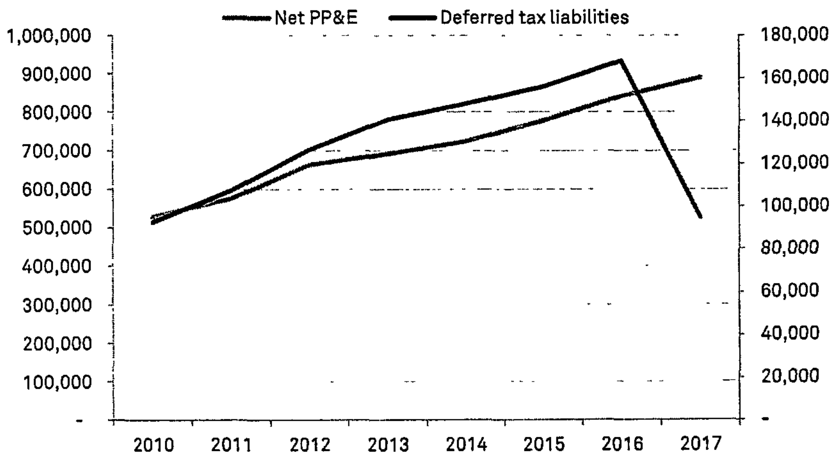
more likely to experience credit pressure than standalone utilities. Several utility holding companies and diversified utilities with unregulated generation segments have recently disclosed plans to issue new equity or debt or reduce capital investment in order to offset impacts to capital structures and improve cash flow.

Utilities re-measured ADIT given the lower tax rate and recorded excess ADIT as a regulatory liability on their balance sheets at the end of 2017. In rate making proceedings, excess deferred tax balances are classified as either protected by the Internal Revenue Code or unprotected. Protected excess ADITs are subject to normalization procedures, whereby they are subtracted from rate base and returned to ratepayers over an agreed upon amortization schedule, typically the remaining life of the assets. Unprotected excess deferred income taxes are not subject to normalization and their treatment is subject to determination of the governing regulatory agency. Most state regulatory commissions and FERC have opened proceedings into tax reform impacts and treatment of utility jurisdictional rate bases and rates. See map below to see tax reform proceedings by state.

Tax act causes write-off of tax liabilities ($M)



As of Dec. 31, 2017,
Note: Includes data for 43 investor-owned utility holding companies. IOUs that did not have deferred tax liability data available excluded.
Source: S&P Global Market Intelligence

Looking at the entire utility sector as represented by the RRA universe, the chart at the left shows the steep drop in deferred tax liabilities at Dec. 31, 2017, following years of accumulation made possible with the help of bonus depreciation and intensive capital investment.

The average RRA utility decreased its total deferred income tax liability at Dec. 31, 2017 by 43%, compared to the year before. Utilities that slashed their deferred income tax liability most included South Jersey Industries, FirstEnergy and ALLETE. Those that decreased the liability the least include Sempra Energy, UGI Corp and Spire Inc. See table at end of report for a company-by-company breakdown.

Regulatory liabilities up $1.7 billion on average

In an effort to benchmark RRA-covered gas and electric utilities against potential cash flow and rate base impacts, RRA has compiled data that addresses regulatory liabilities specifically resulting from re-measurement of deferred taxes required by the TCJA. This data was typically disclosed in corporate Form 10-Ks and 10-Qs. Of the 54 investor-owned utilities that had made those filings as of March 16, the total increase in regulatory liabilities resulting from the re-measurement, which could be returned to ratepayers nationwide was $91.4 billion. The average amount of increase in regulatory liabilities per company for the Tax Act was about $1.7 billion.

The Tax Cuts and Jobs Act of 2017, enacted in December 2017, represents the first major overhaul of the U.S. tax code in 30 years. Many ramifications of the new law will have far reaching impacts on the utility sector and the energy industry. Under SEC guidelines, companies are required to finalize and record the tax effects of the TCJA by Dec. 31, 2018. Many issues addressed in this report are complex and impact accounting from financial and regulatory perspectives. RRA expects clarifications and revisions to be ongoing regarding the outlook for the sector. Additionally, state regulatory investigations are under way nationwide, and RRA recommends that clients pay careful attention to those developments as they unfold. The assumptions and projections made in this report are intended to provide clarity for clients on these complicated issues; however, in some instances data may be incomplete and the conclusions drawn are a "best estimate."

In the table below, RRA benchmarked the sector based on tax-related regulatory liabilities, cash flow and net property, plant and equipment, or PP&E, in service at year-end 2017. Potential cash flow impacts are estimated using a ratio of regulatory liabilities to operating cash flow. The lower the ratio, the less corporate cash flow is expected to decline relative to the sector by the normalization of excess ADIT, in our view. The higher the ratio, the more cash flow is expected to decrease by the return of excess ADIT over time. Utilities with the highest ratio of regulatory liabilities to operating cash flow include NiSource Inc. and ONE Gas Inc. Those with the lowest ratios include AES Corp., National Fuel Gas Co. and UGI Corp.

Potential rate base impacts are calculated using a ratio of regulatory liabilities to net PP&E in service at Dec. 31, 2017. In this context, RRA uses net PP&E as a proxy for rate base, although rate base can only be determined by state regulatory commissions and typically includes items besides net PP&E. The higher the ratio, the more likely rate base will be favorably impacted by the reduction in ADIT, based on our analysis. The lower the ratio, the less likely rate base will benefit relative to the sector. Utilities with the highest ratio include Edison International, Eversource Energy, OGE Energy, Pinnacle West Capital and ONE Gas. Utilities with the lowest ratio include, UGI Corp., Unitil Corp., IDACORP Inc. and AES Corp.

RRA notes that operating cash flow and net PP&E in service data from S&P Global Market Intelligence are corporate consolidated results and not reflective exclusively of the results of regulated utility segments. Diversified utility holding companies may have unregulated merchant generation operations that are also included. More broadly-diversified utility holding companies might have non-utility operations, i.e., construction services or banking segments, also reflected in the data. Excluding these operations would typically have the effect of reducing both cash flow from operating activities and net PP&E in service and increase both ratios.

Potential cash flow and rate base impacts of Tax Act on Utilities

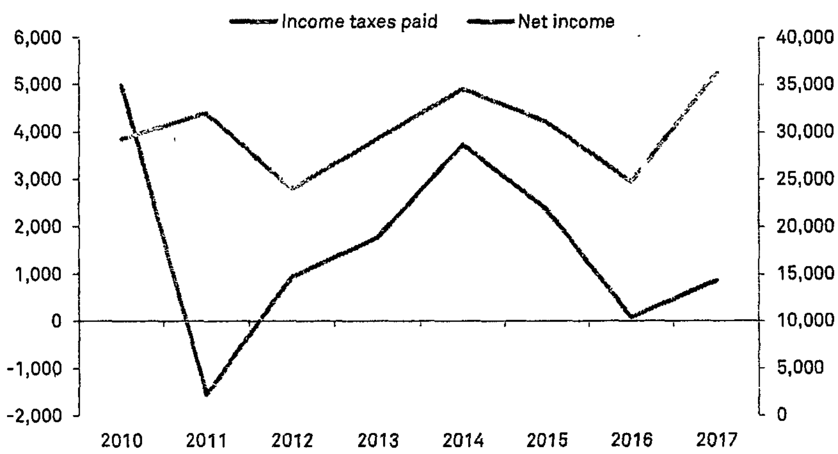
Company	Ticker	Increase in regulatory liabilities ($M)[1]	Cash flow from operations (2016) ($M)[2]	Regulatory liabilities to cash flow ratio (x)	Net utility plant (2016) ($M)[2]	Regulatory liabilities to net utility plant ratio (x)	Disclosed need for additional capital as a result of the tax act
AES Corp.	AES	253.0	593.4	0.43	4,504.0	0.06	
ALLETE Inc.	ALE	393.6	199.3	1.97	3,123.5	0.13	
Alliant Energy Corp.	LNT	885.9	841.0	1.05	9,419.5	0.09	
Ameren Corp.	AEE	2,204.0	2,093.1	1.05	18,059.1	0.12	Y
American Electric Power Co. Inc.	AEP	4,400.0	2,931.8	1.50	37,988.3	0.12	
Atmos Energy Corp.	ATO	746.2	798.4	0.93	7,980.2	0.09	
Avangrid Inc.	AGR	NA	798.5	NA	8,725.1	NA	Y
Avista Corp.	AVA	442.0	337.8	1.31	3,678.5	0.12	Y
Black Hills Corp.	BKH	301.0	214.2	1.41	2,567.0	0.12	
CenterPoint Energy Inc.	CNP	1,300.0	638.4	2.04	7,051.6	0.18	
Chesapeake Utilities Corp.	CPK	98.5	104.1	0.95	313.1	0.31	Y
CMS Energy Corp.	CMS	1,500.0	1,673.4	0.90	13,785.4	0.11	
Consolidated Edison Inc.	ED	3,700.0	3,201.0	1.16	32,065.1	0.12	Y
Dominion Energy Inc.	D	3,600.0	3,271.5	1.10	26,412.2	0.14	
DTE Energy Co.	DTE	1,700.0	1,689.8	1.01	14,340.8	0.12	
Duke Energy Corp.	DUK	8,313.0	6,999.6	1.19	66,401.7	0.13	Y
Edison International	EIX	5,000.0	3,523.7	1.42	33,834.9	0.15	
El Paso Electric Co.	EE	275.3	232.3	1.19	2,713.4	0.10	
Entergy Corp.	ETR	2,900.0	2,112.3	1.37	24,296.5	0.12	Y
Eversource Energy	ES	575.0	1,975.4	0.29	18,025.4	0.03	
Exelon Corp.	EXC	4,734.0	5,716.1	0.83	46,763.5	0.10	
FirstEnergy Corp.	FE	2,300.0	2,579.1	0.89	25,682.4	0.09	
Great Plains Energy Inc.	GXP	794.6	795.8	1.00	8,849.5	0.09	
Hawaiian Electric Industries Inc.	HE	285.0	417.7	0.68	4,081.9	0.07	
IDACORP Inc.	IDA	194.0	309.9	0.63	3,969.5	0.05	
MDU Resources Group Inc.	MDU	285.5	240.8	1.19	1,607.5	0.18	
MGE Energy Inc.	MGEE	103.5	146.5	0.71	1,009.8	0.10	
National Fuel Gas Co.	NFG	337.0	86.1	3.92	1,265.8	0.27	
New Jersey Resources Corp.	NJR	228.0	172.3	1.32	1,757.5	0.13	
NextEra Energy Inc.	NEE	4,500.0	4,152.3	1.08	32,886.9	0.14	
NiSource Inc.	NI	1,500.0	423.3	3.54	5,120.1	0.29	Y
Northwest Natural Gas Co.	NWN	213.3	201.4	1.06	1,648.4	0.13	
NorthWestern Corp.	NWE	231.7	320.2	0.72	3,898.4	0.06	
OGE Energy Corp.	OGE	955.5	568.1	1.68	7,415.2	0.13	Y
ONE Gas Inc.	OGS	519.4	168.0	3.09	3,742.3	0.14	
Otter Tail Corp.	OTTR	149.1	129.4	1.15	1,307.3	0.11	
PG&E Corp.	PCG	3,859.0	4,313.9	0.89	45,102.3	0.09	Y
Pinnacle West Capital Corp.	PNW	1,500.0	987.2	1.52	12,262.2	0.12	
PNM Resources Inc.	PNM	549.0	384.3	1.43	4,419.0	0.12	
Portland General Electric Co.	POR	357.0	548.8	0.65	5,547.1	0.06	
PPL Corp.	PPL	3,350.0	1,930.0	1.74	18,915.5	0.18	
Public Service Enterprise Group Inc.	PEG	2,100.0	1,918.8	1.09	20,782.7	0.10	
SCANA Corp.	SCG	1,076.0	920.8	1.17	11,802.9	0.09	
Sempra Energy	SE	2,402.0	1,296.1	1.85	12,057.5	0.20	
South Jersey Industries Inc.	SJI	264.0	143.0	1.85	1,952.9	0.14	
Southern Co.	SO	6,900.0	5,032.5	1.37	54,001.4	0.13	Y
Southwest Gas Holdings Inc.	SWX	430.0	598.4	0.72	3,680.0	0.12	
Spire Inc.	SR	264.1	380.5	0.69	5,767.5	0.05	Y
UGI Corp.	UGI	303.9	106.6	2.85	1,246.9	0.24	
Unitil Corp.	UTL	48.9	42.5	1.15	386.0	0.13	
Vectren Corp.	VVC	333.4	183.0	1.82	1,791.6	0.19	
WEC Energy Group Inc.	WEC	2,450.0	1,244.2	1.97	12,323.6	0.20	
Westar Energy Inc.	WR	845.2	951.8	0.89	8,978.6	0.09	
WGL Holdings Inc.	WGL	NA	211.5	NA	3,286.8	NA	
Xcel Energy Inc.	XEL	3,800.0	3,059.0	1.24	31,172.3	0.12	Y

[1] Increase in regulatory liabilities at Dec. 31, 2017, resulting from remeasurement of deferred taxes requred by the Tax Cuts and Jobs Act of 2017.
[2] Includes only cash flow, assets net of depreciation of regulated utility operations if FERC data provided by utility
Data excludes results of non utility/power businesses or non-U.S. utility operations
Sources: Form 10-Ks; investor presentations; earnings call transcripts; FERC

Most utilities have not paid cash taxes for several years using a build-up of deferred tax liabilities generated by bonus depreciation and similar incentives to shield cash flow. But the end of bonus depreciation following 2019 and the drop in deferred tax liabilities is expected to reduce utility cash flow and make them cash taxpayers sooner than previously forecast.

Shielded from paying taxes for years, utilities have been reporting net operating losses, or NOLs, that can continue to be carried forward, albeit under less favorable terms pursuant to the new tax law. Companies in the RRA coverage universe paid $864 million in cash income taxes in 2017, according to available S&P Global Market Intelligence data, and posted net income of $36.2 billion.

Utility sector income taxes paid remains low ($M)



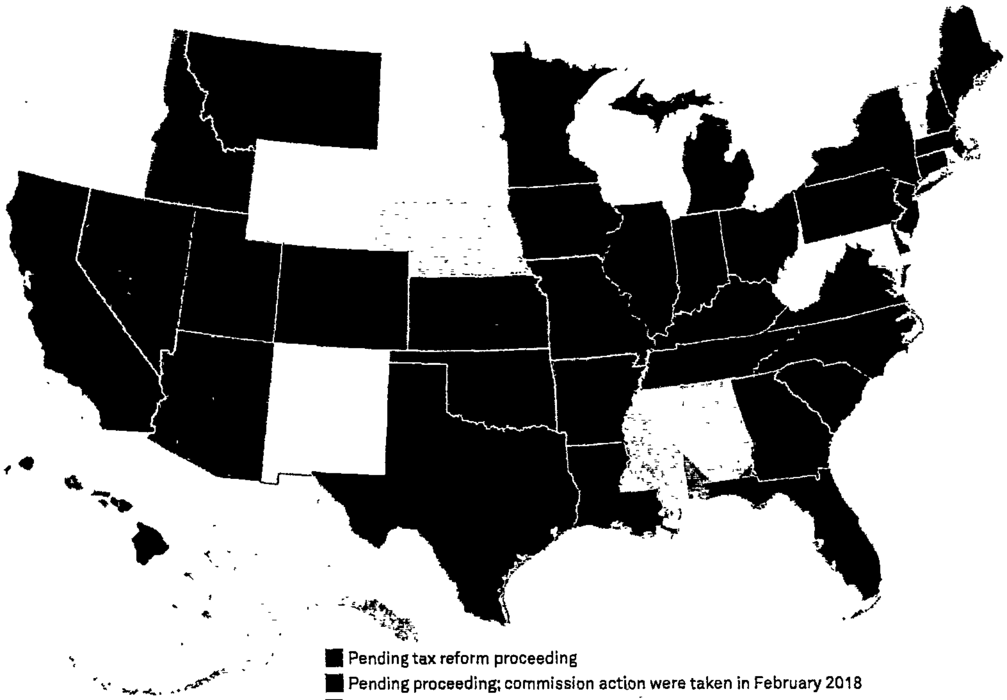
Note: Represents consolidated results of 55 public utilities and utility holding companies.
Source: S&P Global Market Intelligence

Income taxes paid by RRA utilities took a steep dive in 2011 as net operating losses were generated primarily from the bonus depreciation deduction allowed under the Tax Relief Act of 2010. The act provided for 100% depreciation deduction for qualified property placed into service in late 2010 and through 2011. Income taxes paid accelerated the following few years and then took another steep dive after bonus depreciation was extended through the Protecting Americans from Tax Hikes Act of 2015, or PATH Act.

Taxes paid rose slightly in 2017 and should accelerate further as bonus depreciation is phased out at the end of 2019. Still, many utility holding companies have NOL balances that can allow them to remain non-cash-paying taxpayers for several years. Edison International management indicated in its latest earnings call that the company expects not to be a cash taxpayer until 2025. NiSource management indicated the company has a federal NOL carryforward that will preclude the company from paying cash taxes beyond 2025. PG&E management disclosed that the TCJA will likely require the company to become a federal taxpayer in 2020, a year earlier than its previous expectation. Sempra Energy does not expect to be a federal taxpayer for the next five years. AES management indicated that the company will move toward a taxable position over the next two to three years, as its NOL balance decreases.

The following is company-specific commentary on tax reform impacts taken from earnings calls, annual reports and presentations. We expect that these plans will be subject to change in coming months depending on the outcome of state regulatory matters as well as from final determinations of certain tax issues.

Tax reform proceedings



■ Pending tax reform proceeding
■ Pending proceeding; commission action were taken in February 2018
□ Pending proceeding; utility action were taken in February 2018
■ Pending proceeding; commission and utility action were taken in February 2018

Data as of Feb. 28, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Regulated electric/gas utilities:

ALE: The re-measurement of deferred taxes required by the TCJA increased regulatory liabilities by about $394 million. The provisional amount may change as ALE receives additional clarification and implementation guidance. The Minnesota and Wisconsin utility commissions both opened dockets to address ratemaking treatment and mechanisms to pass benefits of tax reform to ALE utility ratepayers. ALE's unregulated operations, which accounting for less than 10% of consolidated revenue, will benefit from lower income tax expense going forward. ALE boosted 2018 earnings guidance by 10 cent per share, or $5.1 million, due to anticipated benefits of TCJA.

ATO: TCJA resulted in the re-measurement of the net deferred tax liability included in ATO's rate base. The excess deferred tax balance, estimated at $746 million, will be returned to utility customers in accordance with regulatory requirements. ATO anticipates the reduction in operating cash flow from lower customer bills, combined with the return of regulatory liabilities establishing connection with implementing tax reform, will increase estimated financing needs through fiscal 2022 by approximately $500 million to $600 million.

EE: El Paso recorded an increase in regulatory liabilities of $275 million as a result of the TCJA. Following the enactment of the TCJA and the reduction of the federal corporate income tax rate, revenues collected from EE customers in 2018 will be reduced by an amount that approximates the savings in tax expense. This reduction in revenues is expected to negatively impact EE cash flows by about $26 million to $31 million during 2018.

NWN: The utility's deferred tax liability re-measurement resulted in a $213.3 million regulatory liability as tax reform is expected to benefit customers. The utility is "working closely with the Oregon commission and other stakeholders on several significant dockets, including the best way to return TCJA benefits to customers through an Oregon general rate case, which we filed in December 2017." NWN expects to see a net increase in cash flows as a result of TCJA over the longer term, as taxes are a pass through to customers and lower deferred tax liabilities and no bonus depreciation are expected to increase regulatory returns.

POR: POR's net regulatory liability was increased by $357 million, as the company deferred the impact of re-measuring accumulated deferred income taxes pursuant to enactment of the TCJA. POR plans to use the average-rate-assumption-method to account for the refund to customers. The unprotected portion of the re-measurement is not subject to tax normalization rules and will be amortized over time. POR proposes to defer for future refund the 2018 expected net benefits as part of an application filed with the Oregon Public Utilities Commission on Dec. 29, 2017. If approved as requested, any refund to customers of the net benefits associated with the TCJA in 2018 would be subject to an earnings test and limited by the company's previously authorized regulated ROE.

WR: Regulatory liabilities increased $845 million primarily due to the TCJA. WR indicates amortization of the liability will lower prices for customers over a period generally corresponding to the life of WR plant assets. The TCJA, including elimination of bonus depreciation and a lower accumulated deferred income tax, results in approximately 4% compounded annual rate base growth through 2022. Management indicates cash flow "headwinds" are expected, which may decrease WR's FFO-to-debt ratio by 100 to 200 basis points. WR indicates that in its pending rate case it proposes to implement a $1.6 million first-step rate decrease in September to reflect the tax change.

Holding company with regulated utilities:

LNT: The TCJA reduced deferred tax liabilities and increased regulatory liabilities by $885.9 million. Tax reform is not forecasted to have a material impact on LNT's 2018 earnings. LNT utilities are working with state utilities commissions to determine the amount and appropriate mechanism to provide these benefits to their customers. LNT currently is unable to quantify cash flow from operations, credit ratings, liquidity, and capital needs impacts.

AEE: AEE booked a $2.2 billion increase in noncurrent regulatory liabilities as result of TCJA at its two operating utilities. AEE expects a decrease in operating cash flows of approximately $1 billion from 2018 through 2022 — Ameren Missouri, $0.3 billion and Ameren Illinois, $0.4 billion— as a result of the TCJA, and expects an increase in rate base of approximately $1 billion over the same time period —Ameren Missouri, $0.3 billion and Ameren Illinois, $0.5 billion. Over the next five years, AEE may be required to issue incremental debt and/or equity to fund this reduction in operating cash flows, with the long-term intent to maintain strong financial metrics and an equity ratio around 50%, as calculated in accordance with ratemaking frameworks.

AVA: Recorded a $442 million liability to be returned to customers. AVA expects to report an annual reduction in earnings of $0.05 to $0.06 per share and a reduction in operating cash flows from the loss of bonus depreciation and the return of excess deferred taxes to customers. As a result, AVA indicates it may need to raise additional capital.

BKH: Recorded a $301 million regulatory liability that will generally be amortized over the remaining life of the related assets using the normalization principles as specifically prescribed in the TCJA. From a cash flow perspective, BKH expects cash flows to be negatively impacted by $35 million to $45 million annually, due to the lower revenue collection as tax reform benefits flow to customers through the regulatory process. BKH expects tax reform to impact 2018 earnings minimally, as the reduced tax benefit on holding company debt will be largely, but not completely, offset by the reduced tax expense on the company's nonutility earnings

CNP: CNP recorded $1.3 billion in excess deferred taxes at its regulated utilities, as a result of the TCJA. Changes in tax depreciation at the lower federal rate are expected to increase forecasted year-end 2019 average rate base by about $300 million. The change in tax depreciation expense at the lower tax rate reduces the tax shield, thereby reducing near-term cash flows, and the timing of the return of excess deferred taxes may reduce near-term cash flows. CNP's unregulated business is expected to benefit from the lower tax rate, boosting earnings by $0.10 per share, or $43 million, in 2018.

CMS: For CMS, excess deferred tax liabilities related to the TCJA are estimated at $1.5 billion. The repeal of the alternative minimum tax, or AMT, allows CMS to monetize substantial AMT credits over the next four years to the tune of about $125 million in the first year, which partially offsets the likely near-term operating cash flow reduction at the utility. CMS parent interest expense will be largely offset by the interest income generated by EnerBank, its industrial bank subsidiary.

DTE: DTE estimates that, as a result of the TCJA, $1.7 billion of excess deferred tax liabilities will need to flow back to ratepayers. DTE management estimates two-third of this balance is protected vs unprotected. DTE's earnings guidance was increased by $0.10 per share tied to the lower tax rate on nonutility business. DTE's utilities are expected to begin to contribute to EPS growth in the latter part of the next five-years, as the utilities transition from funding rate base growth through cash generated by deferred taxes to a higher mix of equity relative to debt. DTE expects to issue incremental equity of $300 million 2018-2020 as a result of tax reform impacts. Consequently, in the latter portion of the five-year period, EPS accretion from tax reform actually grows to — in the range of 13 cent per share ($23 million).

ED: Excess deferred income taxes of approximately $3.7billion, including $3.5 billion for subsidiary Consolidated Edison of New York, were recorded as regulatory liability related to the TCJA. The TCJA is expected to result in decreased cash flows from operating activities, and require increased cash flows.

ES: Tax reform is expected to increase ES rate base by $575 million by 2020. The refund of excess accumulated deferred federal income tax will slightly reduce cash flows, but ES does not expect to need to issue equity. ES recorded about $2.9 billion of regulatory liabilities related to the TCJA. New distribution rates that took effect recently in Massachusetts reflect about $56 million of annual benefits from the reduction of the federal corporate tax rate. Similarly, a three-year settlement reached recently in subsidiary Connecticut Light and Power's distribution rate case is expected to reflect between $45 million and $50 million of annual customer benefits from the lower tax rate.

EIX: The implementation of tax reform at Southern California Edison resulted in a reduction of deferred tax liabilities and a corresponding increase in regulatory liabilities of about $5 billion. The company expects that by 2020, the TCJA will effectively increase rate base $400 million. There will be a smaller tax shield from interest on EIX parent debt, but that will largely be offset with other items. In the near term, SCE expects tax reform to lower rates charged to customers, but not to have a meaningful impact to SCE's earnings. EIX expects to be a cash taxpayer in 2025.

GXP: GXP estimates that excess accumulate deferred tax liabilities refundable through future rates will amount to $795 million. GXP expects to return approximately $100 million in annual tax savings to Missouri and Kansas customers. The company anticipates an ongoing decrease in annual cash flow of about $100 million and 1% to 2% decrease in cash flow to debt metrics.

IDA: IDA calculates that, as a result of the TCJA, excess accumulated deferred income taxes of $194 million will need to be flowed back to customers. Proceedings are pending in Idaho and Oregon o address tax reform-related issues.

NI: The re-measurement of NI's deferred tax liabilities increased regulatory liabilities by about $1.5 billion, which will flow back to customers. The TCJA will cause near-term adjustments to cash flow that NI management indicated it will "need to navigate." NI expects its NOL carryforward will provide a cash tax benefit to NI that extends beyond 2025.

NWE: The company recorded an estimated regulatory liability of $320 million for the change in regulated utility deferred taxes as a result of the TCJA. NWE expects a $15 million to $20 million loss of cash from operations in 2018 and beyond due to the TCJA. NOLs are now anticipated to be available into 2020, versus 2021 expected previously.

OGE: OGE has recorded a $955.5 million non-current regulatory liability associated with income taxes will be refundable to customers. While interest expense deductibility remains at the utility, OGE has no significant holding company debt, making limitations on interest deductibility a non-factor. The company will see some impact from other provisions related to non-deductible expenses, but those items are not expected to be material with respect to 2018.

OGS: OGS is working to determine the amounts of regulatory liabilities arising from the TCJA that will be refunded each year, but expects to return approximately $400 million to customers over the next 25 to 30 years. OGS deferred $519 million as a regulatory liability for ratemaking purposes associated with TCJA. OGS expects its rate base will increase in 2018 on slightly higher capital spending and as a result of the effects of tax reform. OGS expects its ROE to improve in future years as it normalizes the impact of tax reform through regulatory filings. However, the reduction in operating cash flows, combined with the return of regulatory liabilities recorded in conjunction with tax reform, is expected to increase OGS' estimated financing needs through 2022 by about $150 million to $200 million.

PCG: PEG recorded an almost $3.9 billion regulatory liability to reflect the change in net deferred tax liabilities associated with the TCJA. The utility currently anticipates an annual reduction to revenue requirements of about $500 million starting in 2018, and increases to rate base of about $500 million in 2018 and $300 million in 2019, as a result of the Tax Act. Through 2019, PCG now expects rate base growth of approximately 7.5% to 8% annually compared to the 6.5% to 7% previously forecasted. Revenues collected from customers are expected to decline by $500 million annually, impacting cash flows. PG&E expects to become a federal cash taxpayer in 2020, a year earlier than previously forecasted.

PNW: PNW recorded a $1.5 billion regulatory liability related to excess accumulated deferred taxes flowing from the TCJA. The majority of these excess deferred taxes are subject to IRS normalization provisions. From a rate base perspective, PNW's preliminary estimates show incremental rate base of about $150 million per year in 2018 and 2019 as a result of both the lower tax rate and legislative changes related to tax depreciation.

PNM: The TCJA resulted in a $549 million net increase in regulatory liabilities at PNM's utilities. Cash flows will be reduced in the near term, as the benefits of the reduced corporate income tax rate are passed on to ratepayers, without a corresponding reduction in income taxes paid due to PNM having an NOL carryforward for income taxes purposes. In addition, the income tax benefit of net losses for the unregulated activities of PNM Resources, primarily interest expense on holding company debt, will be negatively impacted by the reduced rate.

SR: The adjustment to deferred tax liabilities as result of TCJA at Spire Missouri and Spire Alabama was $264 million combined. SR anticipates that the TCJA will reduce cash flows in the future as customers' bills are lowered, thus impacting credit metrics. SR does not expect restrictions on deductibility of interest at the holding company level to have a material impact on future earnings.

UTL: UTL recorded a regulatory liability in the amount of $48.9 million as a result of the TCJA. Subject to regulatory approval, UTL will pass back to ratepayers the excess accumulated deferred tax balance, using the average rate assumption method. UTL expects its distribution revenue to decrease by about $7.5 million across all regulated entities, offset by an equal amount of tax expense reductions. Consequently, there will be no material effect on net income. Cash flow will be negatively impacted, but UTL's credit metrics are expected to remain strong. Rate base growth is now expected near the high end of its previous 6%-8% range.

WEC: WEC recorded a $2.45 billion change in deferred taxes for its regulated utilities due to the enactment of the TCJA. Management now expects WEC's FFO-to-debt metric to be in the range of 16% to 18%. WEC does not expect the limitation on interest deductions to materially adversely impact earnings. WEC indicated revaluation of its deferred tax assets and liabilities is subject to further clarification of the new law and the ultimate impact cannot be estimated at this time.

XEL: Estimated accounting impacts of the TCJA at XEL included $2.7 billion, $3.8 billion grossed-up for taxes, of reclassifications of plant-related excess deferred taxes to regulatory liabilities. XEL expects tax reform to be mildly accretive to earnings over the next five years, adding $1.3 billion to rate base. The tax law changes will reduce cash from operations and adversely impact credit metrics. In response, XEL expects to scale back its five-year capital expenditure plan by $500 million and issue up to $300 million of additional equity.

Diversified utilities:

AEP: As a result of the TCJA, AEP recorded total excess regulated deferred federal income taxes to be returned to utility ratepayers of $4.4 billion, including a normalized or "protected" portion of excess accumulated deferred income tax of $3.2 billion and a non-depreciation portion of $1.2 billion. AEP raised its annualized rate base growth forecast for the years 2018 through 2020 to 9% vs. 8% previously. The impact of the new law's changes to interest deductibility should be marginal, as parent company debt is minimal. Reduced operating cash flow, from the flow-through of tax benefits to ratepayers, is not expected to require incremental issuances, but AEP has cut its capital spending forecast for 2018-2020 by $500 million.

AGR: AGR is still reviewing the impacts of the TCJA and the appropriate methodology for ensuring that benefits flow to ratepayers. AGR projects increased financing costs and a need to issue debt to offset the related reduction in cash flow. AGR's renewables business is expected to benefit from the lower tax rate. Overall, AGR expects a $0.05 per share, or $15 million, benefit from tax reform.

CPK: For CPK's regulated businesses, the TCJA-related change in deferred income taxes of $98.5 million was recorded as an offset to a regulatory liability, some portion of which may ultimately be subject to refund to customers. CPK indicates that it may need to access additional debt and equity capital to meet financing needs due to lower operating cash flows from its regulated energy businesses.

D: The company recorded a $3.6 billion increase in regulatory liabilities at its regulated operations — Virginia Electric and Power and Dominion Energy Gas — associated with TCJA. Dominion is awaiting guidance from the U.S. Treasury Department with respect to the deductibility of interest expense at its unregulated businesses. Regulated utilities continue to work with their respective regulatory commissions to determine the amount and timing of the flow-through of TCJA-related benefits to customers. The ultimate resolution with regulators could be material to D's operating cash flows.

DUK: Duke expects the revaluation of accumulated deferred taxes under the TCJA to add about $3.5 billion to its rate base by 2021, resulting in a 7% CAGR, a 1% increase compared to its previous forecast. The rate reductions resulting from tax reform are also expected to provide additional headroom in customer bills, allowing for increased capital investment. The company recorded a net regulatory liability related to income taxes of $8 billion at Dec. 31, 2017. In addition, the lower tax shield at the holding company level is expected to reduce earnings. In order to strengthen its balance sheet to mitigate the impact of lower expected cash flows, DUK plans to issue $2 billion in common stock during 2018, including its previous plan to issue $350 million annually beginning in 2018, and reduce its capital expenditures during 2018-2022 by about $1 billion.

ETR: The company recognized a regulatory liability of $2.9 billion due to a re-measurement of deferred tax assets and liabilities resulting from the income tax rate change. ETR estimates the unprotected portion of excess accumulated deferred income taxes at $1.4 billion, which will be returned to customers over time through refunds, cash investments in new assets, accelerated depreciation or other options approved by regulators. The protected portion of excess ADIT is subject to normalization, and will be amortized over the remaining lives of the associated assets. Over the next three years, ETR expects its rate base to grow a little over $1 billion due to TCJA. It plans to issue about $1 billion in equity before the end of 2019 to stabilize the balance sheet, and plans to counter reduced operating cash flow through a combination of utility company debt, parent debt, internal cash generation and external equity.

EXC: The company recorded $4.7 billion in net regulatory liabilities, including $3 billion subject to normalization rules and $1.7 billion that will be amortized over a time period set by state regulators. EXC projects rate base growth of 7.4% versus 6.5% previously, as a result of the TCJA-relate revaluation of accumulated deferred tax balances. Tax reform is estimated to increase rate base by about $1.7 billion by 2020, relative to previous expectations. EXC expects "much stronger free cash flow" from its merchant business, which will more than offset additional equity needs of the utilities. The lower tax rate and 100% expensing of depreciation at the merchant business will improve EPS by $0.10 per share, or $97 million.

FE: Almost all of the company's $2.3 billion in excess of accumulated deferred tax balance is considered protected and subject to normalization provisions; these amounts will be refunded to ratepayers over the life of its assets. FE forecasts a $400 million uplift in rate base with the elimination of bonus depreciation in two years. The company expects that the TCJA will reduce the FFO-to-debt ratio by between 1% and 1.5%, and that the FFO ratio will remain at 13% through 2021. FE also expects to lose some tax shield due to limitations on interest deductibility.

MGEE: MGEE recorded a $130.5 million increase in regulatory liabilities as a result of the TCJA. Tax reform is generally expected to result in lower operating cash inflows in future years, as a result of the elimination of bonus depreciation and lower customer rates as tax-related benefits are passed on to ratepayers

NFG: NFG recorder an approximate $337 million deferred regulatory liability as a result of the TCJA. NFG management is still awaiting details on certain aspects of tax reform, such as potential limitations on the deductibility of interest expense and executive compensation. NFG management indicates that the company still has a "decent-sized NOL that will offset any tax payments for this year."

NJR: NJR recorded $228 million as a noncurrent regulatory liability to be refunded to ratepayers as a result of the lower tax rate. The lower tax rate is expected to boost non-regulated net income by between $0.04 and $0.08 per share, or between $3.5 million and $7 million.

NEE: The company's Florida Power & Light, or FPL, subsidiary revalued deferred income tax liabilities to the new 21% corporate income tax rate. The majority of the reduction in income tax liability, totaling $4.5 billion, has been reclassified as a regulatory liability that is expected be amortized over the underlying assets' remaining useful lives. Tax reform is generally expected to result in lower operating cash flows for NEE, as FPL uses tax savings to recover the Irma storm surcharges, but NEE does not expect an impact on credit metrics. The impact to NEE's unregulated Energy Resources subsidiary is expected to be significantly accretive to earnings, increasing NEE's adjusted EPS by roughly $0.45 per share, or $212 million, in 2018.

PEG: For PEG, excess accumulated deferred taxes related to TCJA total about $2.1 billion. About 70% are deemed protected under the IRS normalization rules, which require that protected deferred tax balances be returned to customers over the remaining lives of the associated assets. The remaining 30%, or about $600 million, some of which were recognized in PEG's Jan. 12, 2018, distribution base rate filing, are to be returned to customers over a time frame that will be determined in discussions with the New Jersey Board of Public Utilities and with FERC. According to the company, TCJA impacts on cash flow and credit metrics are manageable given PEG's business mix and the strength of balance sheet. The earnings boost expected from the reduced tax burden for its unregulated businesses is expected to be $0.16 per share, or $81 million, in 2018.

SCG: SCG recorded accumulated deferred income taxes of about $1.1 billion, which includes excess deferred income taxes arising from re-measurement of deferred income taxes upon enactment of the Tax Act.

SRE: For SRE, regulatory liabilities recorded as result of the Tax Act were $2.4 billion. The one-time reparation of SRE's foreign subsidiary earnings partially mitigates the credit impact of the flow-through ratepayers of lower utility taxes. SRE plans to repatriate about $1.6 billion from 2018-2022. Tax reform is expected to decrease earnings per share by between $0.25 and $0.30 in 2018, as SRE is impacted by the lower tax shield on corporate interest, but long-term the impact is expected to be neutral.

SO: Southern recorded a nearly $7 billion deferred tax liability, of which $5.7 billion is protected and $1.3 billion is unprotected. Management has indicated that cash flow is expected to be adversely affected at SO's state-regulated utilities and, "absent mitigation, lower FFO to debt ratios" will result. Southern Power, SO's unregulated business, is expected to benefit from the lower tax rate by $15 million to $20 million.

SJI: SJI expects experience a benefit at its South Jersey Gas subsidiary, due to a higher rate base, as accumulated deferred tax offsets are reduced, with the amount dependent upon regulatory action and timing of base rate cases. SJI reported excess accumulated deferred income taxes of $264 million. For its non-utility operations, SJI saw a $13.5 million one-time benefit associated with the revaluation of its net deferred tax liabilities, expects ongoing benefits beginning in 2018 that will rise to $10 million annually beginning in 2020. Cash flows are expected to decrease by between $20 million and $40 million per year due to the return of excess deferred taxes to ratepayers and the elimination of bonus depreciation.

UGI: UGI recorded $304 million in excess accumulated deferred income taxes resulting from the tax law, and a proceeding is pending in Pennsylvania to determine how this balance and other TCJA-related benefits will flow through to ratepayers. UGI has extensive non-regulated and foreign operations. The company indicated that the TCJA boosted EPS for the first quarter of fiscal 2018, i.e. the quarter ended Dec. 31, 2017, by $0.12 per share. The company expects a net full-year benefit related to tax policy of $0.15 to $0.25, including the negative impact of changes in French tax law.

Broadly-diversified utilities:

AES: The company's U.S. utilities recorded an increase in deferred income tax liabilities of $241 million, due to the revaluation of deferred taxes associated with the tax rate change. AES also repatriated foreign earnings under the reduced tax rate provided for in the Tax Act. AES expects a "meaningful limitation" on interest expense deductions. Also under new global intangible income rules, un-repatriated foreign earnings above a certain threshold can now be subject to U.S. tax. AES expects these issues will impact near-term earnings by between $0.05 and $0.08 per share annually, or $33 million to $53 million. Management indicates it has taken actions to offset these impacts and will continue to evaluate additional tax planning opportunities. AES continues to have a significant NOL position.

HE: The company reclassified $285 million in net excess accumulated deferred taxes as a regulatory liability that will be returned to customers through rates. While tax reform will result in higher financing needs in the future for HE's utility due to the loss of bonus depreciation, HE does not expect to need any additional external equity or equity from the company's dividend reinvestment program during 2018. Net interest income from HE's banking unit will "more than cover holding company interest expense. So interest expense deductibility will not be an issue," according to management. American Savings Bank is expected to see increased dividend and earnings capacity.

MDU: MDU continues to work with the various regulators on a plan flow TCJA-related savings to customers. This resulted in the creation of a regulatory liability refundable to customers of $285.5 million. MDU's non-regulated construction business is expected to benefit from the TCJA. MDU's construction materials businesses reported $46.2 million higher earnings in 2017 as result of tax reform.

OTTR: OTTR booked a $149 million increase in regulatory liabilities associated with excess accumulated deferred income taxes. OTTR expects its rate base to grow by about an additional $100 million over its five-year planning horizon as a result of the Tax Act. No material impact on equity needs foreseen and the company expects to no negative impact credit ratings. OTTR's 2018 guidance assumes an uplift of $0.05 per share, or $2 million, related to the tax reform impact on its manufacturing platform and corporate cost center.

PPL: PPL recorded a net increase in regulatory liabilities as a result of TCJA at its U.S. utilities of almost $3.4 billion. PPL now projects its combined regulated rate base to grow by 6.4% through 2020, increasing to $31 billion. PPL added an additional equity issuance into its financing plan for 2018 and expects increased cash distributions from its U.K. business to mitigate the impact of the lower corporate tax rate on earnings and cash flow. The company anticipates about $0.05 per share of incremental dilution from the planned issuance of an additional $650 million of equity relative to its prior assumptions.

SWX: SWX estimates that excess deferred taxes to be passed back to utility customers will total $430 million; related proceedings are underway in Arizona, California and Nevada. The Tax Act is expected to provide a direct benefit to SWX's non-regulated construction services business.

VVC: The TCJA resulted in $333 million in excess federal deferred income taxes for VCC's utility group. Statewide proceedings related to the Tax Act have begun in Indiana and Ohio. While tax reform reduces cash from operations, additional cash available from VVC's nonutility businesses help fund utility capital spending.

Independent Power Producers:

Independent power producers, or IPPs, including NRG Energy Inc., Vistra Energy Corp., and Dynegy Inc., continue to examine the TCJA, and its overall impact to the bottom line. Under SEC rules, companies are required to finalize and record the tax effects of the TCJA by Dec. 31, 2018. RRA expects the sector to be a net beneficiary of the law given the permanent lower tax rate and full expensing for certain capital investments, which could support cash flows.

With regard to net operating losses, or NOLs — created when operating expenses exceed operating revenues at a particular business unit, and are used to offset taxable income — existing NOLs can continue to be utilized at 100% of taxable income with a 20 year carryforward, while NOLs incurred after the 2017 tax year are limited to 80% of taxable income with an indefinite carryforward, potentially weakening IPPs' "tax shield" against future taxable income. The TCJA also repealed the alternative minimum tax, or AMT, and it also limits the deduction of net business interest expense to 30% of adjusted taxable income. For NRG and Dynegy, reductions to the companies' deferred tax asset balances due to the lower tax rate were offset through valuation allowances, a balance established when it is likely that all or a portion of net deferred tax assets will not be utilized.

DYN: DYN recorded a $394 million reduction to its net deferred tax assets, including the federal benefit of state deferred taxes, that was fully offset by a decrease in its valuation allowance for the year ended Dec.31, 2017. The Houston-based power generator and electric retailer also recorded a $223 million current tax benefit and long-term tax receivable in 2017 related to the expected refund of its existing AMT credits. DYN expects the related refunds to total $112 million in 2019; $56 million in 2020; $28 million in 2021; and the remainder in 2022. At year-end 2017, Dynegy had $4.6 billion of federal NOLs and $3.6 billion of state NOLs that can be used to offset future taxable income, with the federal NOLs expiring between 2024 and 2037. In the near-term, DYN expects greater utilization of its NOLs to offset the limit of net business interest expense.

NRG: NRG recorded a $733 million reduction to its net deferred tax assets that was offset by a valuation allowance of $660 million, and the company recorded a long-term receivable of $64 million related to the expected refund of its existing AMT credits, expected to be received between 2019 and 2020. At year-end 2017, the company had domestic federal NOL carryforwards of $2.8 billion, which begin expiring in 2026, and state NOL carryforwards of $2.2 billion. With more than $3 billion expected from asset sales and a leaner balance sheet as part of its broader strategic transformation plan announced in 2017, NRG's cash position and resultant financial flexibility appear to be on solid footing for the foreseeable future. The company expects cash flow from operations in 2018 in a range of approximately $2.02 billion to $2.2 billion, compared with $1.39 billion in 2017, and adjusted free cash flow in a range of $1.55 billion to $1.75 billion, compared with $1.30 billion in 2017.

VST: VST recorded an approximately $451 million reduction to its deferred tax asset balance for the year ended Dec. 31, 2017; however, considering its expectation that its deferred tax assets will be fully utilized to offset future taxable income, the company did not recognize a valuation allowance. At year-end 2017, the company had no federal NOL carryforwards, and no AMT credit carryforwards. Excluding the impacts from its pending acquisition of Dynegy, VST expects 2018 adjusted free cash flow in a range of $600 million to $750 million. The company expects to update guidance upon closing of the Dynegy acquisition.

Change in deferred income tax liabilities ($000)

	2017	2016	
South Jersey Industries Inc.	86,884	343,549	-75%
FirstEnergy Corp.	1,359,000	3,765,000	-64%
ALLETE Inc.	197,700	521,300	-62%
Otter Tail Corp.	100,501	226,591	-56%
Westar Energy Inc.	815,743	1,752,776	-53%
Great Plains Energy Inc.	621,700	1,329,700	-53%
Southern Co.	6,842,000	14,092,000	-51%
NiSource Inc.	1,292,900	2,528,000	-49%
NextEra Energy Inc.	5,754,000	11,101,000	-48%
OGE Energy Corp.	1,227,800	2,334,500	-47%
IDACORP Inc.	660,940	1,244,250	-47%
Hawaiian Electric Industries Inc.	388,430	728,806	-47%
Vectren Corp.	491,300	905,700	-46%
Avista Corp.	466,630	840,928	-45%
PNM Resources Inc.	491,479	884,633	-44%
Portland General Electric Co.	376,000	669,000	-44%
Xcel Energy Inc.	3,845,000	6,784,319	-43%
PG&E Corp.	5,822,000	10,213,000	-43%
Pinnacle West Capital Corp.	1,690,805	2,945,232	-43%
ONE Gas Inc.	599,945	1,038,568	-42%
WEC Energy Group Inc.	2,999,800	5,146,600	-42%
MGE Energy Inc.	225,130	383,813	-41%
Eversource Energy	3,297,518	5,607,207	-41%
NorthWestern Corp.	340,729	575,582	-41%
Chesapeake Utilities Corp.	135,850	222,894	-39%
PPL Corp.	2,462,000	3,889,000	-37%
Sempra Energy	2,767,000	3,745,000	-26%
National Fuel Gas Co.	891,287	823,795	8%
New Jersey Resources Corp.	514,708	473,847	9%
UGI Corp.	1,357,000	1,212,400	12%
Spire Inc.	707,500	607,300	16%
WGL Holdings Inc.	868,067	726,763	19%
AES Corp.	1,006,000	804,000	25%

As of Dec. 31, 2017.
Note: Nine utilities or utility holding companies without data available excluded.
Source: S&P Global Market Intelligence

DAmbrosio, Eleanor

From: DAmbrosio, Eleanor
Sent: Wednesday, May 29, 2019 12:45 PM
To: June Dively
Subject: 49421 Margin Tax RFIs

June,
Do any of these look like the RFI you were thinking of that shows the change in the Gross Margin Tax accounting treatment?

Thank you,
Eleanor

GCCC 3-15 Refer to the Direct Testimony of Kristie Colvin at 39:19 through 40:6 wherein she describes the Company's present accounting for the Texas Margin Tax by accruing a regulatory asset in the year the liability is established and the reversal of the regulatory asset to expense in the following year when it is recovered in rates and paid.

a. Confirm that the offsetting credit to the regulatory asset when it is booked is a liability, e.g., Texas Margin Tax Payable. If confirmed, provide the FERC account/subaccount and the name of the account on the Company's accounting books.

b. Provide the actual journal entries to record the regulatory asset and the related liability by month in each year 2015 through 2018 and the reversal of the regulatory asset by month in each following year 2016 through 2019.

c. Confirm that the regulatory asset is not financed because it is offset by a liability that has not yet been paid and that will not be paid until the following year. If denied, then provide a corrected statement and all support for the corrected statement, including the journal entry showing the credit component of the journal entry to record the regulatory asset that shows a credit to cash or to some form of financing. If none, then so state.

GCCC 3-16 Refer to Schedule II-B-12, which shows that the Company included $19.627 million for the Texas Margin Tax Regulatory Asset in rate base.

a. Explain why this regulatory asset should be included in rate base. The explanation shown on Schedule II-B-12a merely describes the accounting under GAAP and then recites the Company's proposed ratemaking treatment. The explanation does not address why the regulatory asset should be included in rate base given that it was not paid in cash or financed, and given that the related liability amount is not subtracted from rate base.

b. Confirm that the amount shown on Schedule II-B-12 is the December 31, 2018 balance, not the 13-month average balance for the test year.

GCCC 3-17 Refer to Schedule II-B-12a, which provides a "narrative description of the Regulatory Asset — Texas Margin Tax. The narrative states in part: "Under Generally Accepted Accounting Principles (GAAP), Texas margin tax is considered an income tax. Per ASC 740-10-55-143, 'The portion of the current tax liability based on income is required to be accrued with a charge to income during the period in which the income is earned.'"

a. Confirm that the Company is required to record the Texas Margin Tax as an expense (charge to income) during the period in which the revenue (income) is earned, meaning the year in which the liability is accrued based on the revenues for that year, not the revenue (income) in the following year when the liability is paid.

b. Provide the GAAP provision that allows the Company to defer the income tax expense described in part (a) of this question until the following year when the liability is paid.
c. Under GAAP, does the Company incur the liability in the year when it is recorded or in the following year when it is paid? Cite and provide a copy of all authoritative sources reviewed and/or relied on for your response.

GCCC 3-18 Refer to the Direct Testimony of Kristie Colvin at 40:1-3 wherein she states that the Commission approved this accounting practice (recording of a regulatory asset for the deferral of Texas Margin Tax expense as regulatory asset until it is.paid in the following year when the liability is paid).

a. Describe the Company's accounting practice prior to the final order in Docket No. 29526.

b. Indicate whether the Company recorded a one-time increase to income (credit) to income when it first recorded a regulatory asset for the deferred Texas Margin Tax expense regardless of whether it was before or after the final order in Docket No. 29526. If so, provide the actual journal entry made to record this increase to income.

Staff 8-1 Please provide the adjustments to CenterPoint's request in this docket, by FERC account, that would be required to remove entirely CenterPoint's regulatory asset associated with Margin Tax. Include both the asset and expenses amounts by FERC account.

Eleanor D'Ambrosio | Assistant Public Counsel
Office of Public Utility Counsel
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Eleanor.Dambrosio@opuc.texas.gov

Quinn, Cassandra

From: June Dively [redacted]
Sent: Thursday, May 30, 2019 3:13 PM
To: Karl Nalepa
Cc: Quinn, Cassandra; DAmbrosio, Eleanor
Subject: WP - HCRF Carrying Costs.xlsx
Attachments: WP - HCRF Carrying Costs.xlsx

Karl,

I took a look at the attached, which is the response to PUC 08-14. This is what CP has provided to support its carrying costs. I spoke to Eleanor and I will have very limited availability next week but I told her I would take a look. On the highlighted tab you will see CP's calculations in columns A through J and my work is all the columns to the right. In order to think this through I recalculated their number using their compounded Monthly Interest calc (see the other tabs in the workbook) and then recalculated the number without compounding. You'll find that work in columns L through R. Removing the compounding reduces the carrying costs by $127.5K. Do you know any reason why we would approve a compounded interest rate? Looks like its even compounded monthly. We don't calculate compounded interest rates in our cost of debt calculations (not really my area but I've never seen that before).

My next step, was Columns T through AC. If all goes well, you should be able to drop your adjustments into column U by month and the spreadsheet should give you your adjustment to carrying costs. If you're quantifying adjustments separately, you might need to copy this section for each separate calculation. Feel free to trash my work and start from scratch but I wanted you to have this if it's useful to you and keeps us from having to duplicate efforts.

So, my last thoughts are, what about the Hurricane Ike credit balance? Those credits are not included in the calculation of the carrying costs. They've essentially had that free money for a while. Shouldn't they be included? However, the impact may be very, very small.

Since you are testifying as to the amount of the deferred HH carrying costs, could you please add this to your testimony?

Thank you!

June

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
HURRICANE HARVEY WITH CARRYING CHARGES

		[A]	[B]	[C]	[D]	[E]	[F]	[G]
		2017	2018					
1	Annual Interest Rate	10.630%	9.403%					
2	Monthly Interest Rate	0.008453961	0.007517123					
3				Cumulative	Insurance	Cumulative		Cumulative
4			Incurred O&M Costs	Incurred O&M Costs	Proceeds	Proceeds	Carrying Costs	Carrying Costs
5								
6	August-17		$ 12,029,774.27	$ 12,029,774.27		$ -	$ 22,034.84	$ 22,034.84
7	September-17		27,804,479.10	39,834,253.37		0.00	219,414.51	241,449.34
8	October-17		39,572,963.26	79,407,216.63		0.00	506,072.56	747,521.90
9	November-17		15,038,076.36	94,445,292.99	(3,732,379.36)	(3,732,379.36)	725,413.97	1,472,935.88
10	December-17		(21,332,097.05)	73,113,195.94	(115,434.41)	(3,847,813.78)	688,677.26	2,161,613.14
11	January-18		456,704.26	73,569,900.20		(3,847,813.78)	538,642.08	2,700,255.22
12	February-18		190,365.96	73,760,266.16		(3,847,813.78)	545,123.17	3,245,378.39
13	March-18		(133,309.08)	73,626,957.08		(3,847,813.78)	549,435.38	3,794,813.77
14	April-18		440,312.90	74,067,269.98		(3,847,813.78)	554,719.45	4,349,533.22
15	May-18		(58,425.90)	74,008,844.08	(1,218,987.40)	(5,066,801.18)	555,743.05	4,905,276.27
16	June-18		73,805.09	74,082,649.17	(1,551,438.51)	(6,618,239.69)	549,565.62	5,454,841.89
17	July-18		30,471.46	74,113,120.63		(6,618,239.69)	548,257.53	6,003,099.42
18	August-18		280,655.64	74,393,776.27		(6,618,239.69)	553,548.24	6,556,647.66
19	September-18		20,973.42	74,414,749.69		(6,618,239.69)	558,843.02	7,115,490.68
20	October-18		(462,086.52)	73,952,663.17	(2,731,178.22)	(9,349,417.91)	551,120.66	7,666,611.34
21	November-18		84,628.96	74,037,292.13	(1,937,502.50)	(11,286,920.41)	536,297.28	8,202,908.62
22	December-18		1,655,770.83	75,693,062.96		(11,286,920.41)	539,587.87	8,742,496.50
23								
24								
25		Total		$ 75,693,062.96		$ (11,286,920.41)		$ 8,742,496.50

[H] [C]+[E]+[G] Cumulative Overall Balance	Adjustment to remove Compounding Cumulative Total Costs	Additions with Half Year Convention	13 Days in August	Rate	CC on Change	CC on Beginning Balance	Total Carrying Costs	Requested Additions	Nalepa Adjustments
12,051,809.11	12,029,774.27	6,014,887.13	13/30	0.88584%	22,034.84		22,034.84	12,029,774.27	
40,075,702.71	39,834,253.37	13,902,239.55		0.88584%	123,151.56	106,564.52	229,716.08	27,804,479.10	
80,154,738.53	79,407,216.63	19,786,481.63		0.88584%	175,276.52	352,867.65	528,144.17	39,572,963.26	
92,185,849.50	90,712,913.63	5,652,848.50		0.88584%	50,075.18	703,420.68	753,495.86	11,305,697.00	
71,426,995.30	69,265,382.16	(10,723,765.73)		0.88584%	(94,995.38)	803,571.04	708,575.66	(21,447,531.46)	
72,422,341.64	69,722,086.42	228,352.13		0.78360%	1,789.37	542,763.68	544,553.05	456,704.26	
73,157,830.77	69,912,452.38	95,182.98		0.78360%	745.85	546,342.42	547,088.27	190,365.96	
73,573,957.07	69,779,143.30	(66,654.54)		0.78360%	(522.31)	547,834.12	547,311.82	(133,309.08)	
74,568,989.42	70,219,456.20	220,156.45		0.78360%	1,725.15	546,789.51	548,514.66	440,312.90	
73,847,319.17	68,942,042.90	(638,706.65)		0.78360%	(5,004.91)	550,239.81	545,234.90	(1,277,413.30)	
72,919,251.37	67,464,409.48	(738,816.71)		0.78360%	(5,789.37)	540,229.99	534,440.62	(1,477,633.42)	
73,497,980.36	67,494,880.94	15,235.73		0.78360%	119.39	528,651.25	528,770.64	30,471.46	
74,332,184.24	67,775,536.58	140,327.82		0.78360%	1,099.61	528,890.03	529,989.64	280,655.64	
74,912,000.68	67,796,510.00	10,486.71		0.78360%	82.17	531,089.25	531,171.42	20,973.42	
72,269,856.60	64,603,245.26	(1,596,632.37)		0.78360%	(12,511.21)	531,253.60	518,742.38	(3,193,264.74)	
70,953,280.34	62,750,371.72	(926,436.77)		0.78360%	(7,259.56)	506,231.17	498,971.61	(1,852,873.54)	
73,148,639.05	64,406,142.55	827,885.41		0.78360%	6,487.31	491,712.05	498,199.36	1,655,770.83	
		32,203,071.28					8,614,954.98	64,406,142.55	
		-				Requested	8,742,496.50	-	
						Adjustment	(127,541.52)		

99

Adjustment for Nalepa Disallowances

Adjusted Additions	Cumulative Total Costs	Additions with Half Year Convention	13 Days in August	Rate	CC on Change	CC on Beginning Balance	Total Carrying Costs
12,029,774.27	12,029,774.27	6,014,887.13	13/30	0.88584%	22,034.84		22,034.84
27,804,479.10	39,834,253.37	13,902,239.55		0.88584%	123,151.56	106,564.52	229,716.08
39,572,963.26	79,407,216.63	19,786,481.63		0.88584%	175,276.52	352,867.65	528,144.17
11,305,697.00	90,712,913.63	5,652,848.50		0.88584%	50,075.18	703,420.68	753,495.86
(21,447,531.46)	69,265,382.16	(10,723,765.73)		0.88584%	(94,995.38)	803,571.04	708,575.66
456,704.26	69,722,086.42	228,352.13		0.78360%	1,789.37	542,763.68	544,553.05
190,365.96	69,912,452.38	95,182.98		0.78360%	745.85	546,342.42	547,088.27
(133,309.08)	69,779,143.30	(66,654.54)		0.78360%	(522.31)	547,834.12	547,311.82
440,312.90	70,219,456.20	220,156.45		0.78360%	1,725.15	546,789.51	548,514.66
(1,277,413.30)	68,942,042.90	(638,706.65)		0.78360%	(5,004.91)	550,239.81	545,234.90
(1,477,633.42)	67,464,409.48	(738,816.71)		0.78360%	(5,789.37)	540,229.99	534,440.62
30,471.46	67,494,880.94	15,235.73		0.78360%	119.39	528,651.25	528,770.64
280,655.64	67,775,536.58	140,327.82		0.78360%	1,099.61	528,890.03	529,989.64
20,973.42	67,796,510.00	10,486.71		0.78360%	82.17	531,089.25	531,171.42
(3,193,264.74)	64,603,245.26	(1,596,632.37)		0.78360%	(12,511.21)	531,253.60	518,742.38
(1,852,873.54)	62,750,371.72	(926,436.77)		0.78360%	(7,259.56)	506,231.17	498,971.61
1,655,770.83	64,406,142.55	827,885.41		0.78360%	6,487.31	491,712.05	498,199.36
64,406,142.55		32,203,071.28					8,614,954.98
		-			After Adj for Compounding		8,614,954.98
						Adjustment	-

Quinn, Cassandra

From: Quinn, Cassandra
Sent: Friday, May 31, 2019 2:47 PM
To: Karl Nalepa
Subject: TNMP Hurricane Harvey compliance docket

The TNMP Hurricane Harvey compliance docket is 49122. Here is a link to the interchange filings:
http://interchange.puc.texas.gov/Search/Filings?UtilityType=A&ControlNumber=49122&ItemMatch=Equal&DocumentType=ALL&SortOrder=Ascending

It looks like TNMP and Staff have reached a settlement agreement that has not yet been ruled on by the Commission. However, it has some exhibits/workpapers that appear to show the interest amounts. Here is a link to the Stipulation:
http://interchange.puc.texas.gov/Documents/49122_15_1018203.PDF.

Cassandra Quinn
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(512) 936-7534 (Direct)
(512) 936-7525 (Fax)
cassandra.quinn@opuc.texas.gov

Quinn, Cassandra

From:	Quinn, Cassandra
Sent:	Monday, June 03, 2019 8:32 AM
To:	June Dively; Karl Nalepa
Cc:	DAmbrosio, Eleanor
Subject:	RE: WP - HCRF Carrying Costs.xlsx

June,
In TNMP, they opened a separate compliance docket on the HCRF calculation, and the parties have just filed a settlement agreement with their calculations. Do you have a few minutes to look at the calculations they are using? The docket is 49122. OPUC did not participate in that docket, so I'm not sure whether the calculations changed. CQ

From: June Dively [redacted]
Sent: Monday, June 03, 2019 8:20 AM
To: Karl Nalepa; Quinn, Cassandra
Cc: DAmbrosio, Eleanor
Subject: RE: WP - HCRF Carrying Costs.xlsx

Bad news – TNMP compounded monthly (Exhibit SRW-11). Each month they added the calculated carrying costs to the total amount due before calculating the next month's carrying costs. Frustration. So, we need to make the case without regard to TNMP's calculation even though we reference it for the amortization period.

June M. Dively, CPA, CFF, Cr.FA, FABFA

SiEnergy
SiEnergy | 3 Lakeway Centre Ct. | Suite 110 | Lakeway, TX 78734

[redacted]

From: Karl Nalepa [redacted]
Sent: Monday, June 3, 2019 8:03 AM
To: June Dively [redacted]; Quinn, Cassandra <Cassandra.Quinn@Opuc.texas.gov>
Cc: DAmbrosio, Eleanor <eleanor.dambrosio@opuc.texas.gov>
Subject: RE: WP - HCRF Carrying Costs.xlsx

OK, good. That would be consistent with the TNMP approach. It appears to me that the interest is calculated monthly but it is not compounded (not interest on interest).

Karl J. Nalepa

Partner
ReSolved Energy Consulting, LLC
11044 Research Blvd., Suite A-420
Austin, Texas 78759

[redacted]

email: [redacted]

From: June Dively [redacted]
Sent: Monday, June 03, 2019 7:58 AM
To: Karl Nalepa [redacted]; Quinn, Cassandra <Cassandra.Quinn@Opuc.texas.gov>
Cc: DAmbrosio, Eleanor <eleanor.dambrosio@opuc.texas.gov>
Subject: RE: WP - HCRF Carrying Costs.xlsx

Karl,

Thank you for this summary. In my testimony, I recommend removing the HH Reg Asset from rate base altogether, and a 5-year amortization of the balance through Rider HCRF.

Even though TNMP calculated it's carrying costs monthly, were you able to tell if it was compounded? There's no reference to compounding, correct? *I may poke around a bit in my file.*

June M. Dively, CPA, CFF, Cr.FA, FABFA

SIEnergy
SIEnergy | 3 Lakeway Centre Ct. | Suite 110 | Lakeway, TX 78734

[redacted]

From: Karl Nalepa [redacted]
Sent: Monday, June 3, 2019 7:38 AM
To: Quinn, Cassandra <Cassandra.Quinn@Opuc.texas.gov>; June Dively [redacted]
Cc: DAmbrosio, Eleanor <eleanor.dambrosio@opuc.texas.gov>
Subject: RE: WP - HCRF Carrying Costs.xlsx

All,

TNMP's rate case was settled, so whatever we decide for CEH I think we have some flexibility if it differs from what TNMP did. That said, TNMP will recover its Hurricane Harvey costs in a rider rather than in base rates. It did calculate carrying charges on a monthly basis at its pre-tax WACC. TNMP did not include a regulatory asset in rate base on the Harvey balance.

The carrying charges CEH is asking for in its errata are the carrying charges incurred since the hurricane restoration costs were incurred, and the return on the regulatory asset are carrying charges incurred after rates are set in this case, so mechanically there won't be any double counting of carrying charges if the regulatory asset in rate base includes only the restoration costs (no carrying charges). But, I agree with June that we don't calculate return on rate base on a monthly basis, so why would we calculate carrying charges on the regulatory asset differently. I also struggle with CEH including the entire Hurricane Harvey regulatory asset in rate base, while at the same time collecting the balance from ratepayers. Shouldn't the rate base component be the average balance, not the total balance? Otherwise, TNMP collects a return on costs it has already collected from ratepayers.

Karl J. Nalepa
Partner
ReSolved Energy Consulting, LLC
11044 Research Blvd., Suite A-420
Austin, Texas 78759

[redacted]

email: [redacted]

From: Quinn, Cassandra <Cassandra.Quinn@Opuc.texas.gov>
Sent: Friday, May 31, 2019 6:39 PM
To: June Dively [redacted]
Cc: Karl Nalepa [redacted]; DAmbrosio, Eleanor <eleanor.dambrosio@opuc.texas.gov>
Subject: Re: WP - HCRF Carrying Costs.xlsx

Thanks, June. Karl is looking at the TNMP HCRF proceeding, and I will try to find more solid precedent on the carrying charge issue this weekend.

Sent from my iPhone

On May 31, 2019, at 6:04 PM, June Dively [redacted] wrote:

> My thoughts – we don't compound rate of return. In fact, my staff doesn't compound AFUDC. If you compound, one could say you are earning more than the WACC. By adding uncompounded WACC, you are getting what you would get if the item had been in rate base, and I think your recovering the WACC on an annual basis. Since rates are set on recovering WACC on an annual basis, it seems unreasonable to compound monthly. It's good that your looking at precedent. Maybe we can look at TNMP's HCRF to see what they did.
>
> Karl, I'm interest in your thoughts.
>
> **June M. Dively, CPA, CFF, Cr.FA, FABFA**
> 3 Lakeway Centre CT, Suite 110
> Lakeway, TX 78734
> [redacted]

From: Quinn, Cassandra <Cassandra.Quinn@Opuc.texas.gov>
Sent: Friday, May 31, 2019 5:34 PM
To: Karl Nalepa [redacted] June Dively [redacted]
Cc: DAmbrosio, Eleanor <eleanor.dambrosio@opuc.texas.gov>
Subject: RE: WP - HCRF Carrying Costs.xlsx

I'm still looking into this further, but I wanted to raise two issues on the carrying charges.

1. Under PURA 36.402(b), system restoration costs *shall* include carrying costs at the electric utility's WACC. CenterPoint is proposing to include the costs in rate base and therefore would already recover its WACC on the costs. As a result, adding carrying costs on top appears to be inappropriate. I think I have found a case that supports this, but need to look at it closer.
    a. Given that, I think we need to add a sentence or two to June's testimony stating that if her recommendation is not adopted, the Company should not get to recover both a return on the Hurricane Harvey costs and carrying costs.

2. The various ways of calculating interest are not something I have much expertise in, so if I've got something wrong, please correct me. As I understand the issue that June raised below, it looks like the distinction is whether interest should be compounded monthly or compounded annually—is that correct? In doing some searches, I've come across the concept of "compounding monthly at the annual rate"—is that the concept we need to be looking at here?
    a. Also, the statute talks about including carrying costs at the utility's WACC. Rates are set based on recovering the WACC on an annual basis, so would that be justification for compounding annually for the carrying costs?

If you have any thoughts or concerns on these, please let me know.

Thank you,
Cassandra

From: Karl Nalepa [redacted]
Sent: Thursday, May 30, 2019 5:52 PM
To: June Dively
Cc: Quinn, Cassandra; DAmbrosio, Eleanor
Subject: RE: WP - HCRF Carrying Costs.xlsx

June, your analysis looks good. Let me look it over and see what I think.

Karl J. Nalepa
Partner
ReSolved Energy Consulting, LLC
11044 Research Blvd., Suite A-420
Austin, Texas 78759

[redacted]

email: [redacted]

From: June Dively [redacted]
Sent: Thursday, May 30, 2019 3:13 PM
To: Karl Nalepa [redacted]
Cc: Quinn, Cassandra <Cassandra.Quinn@Opuc.texas.gov>; DAmbrosio, Eleanor <eleanor.dambrosio@opuc.texas.gov>
Subject: WP - HCRF Carrying Costs.xlsx

Karl,

I took a look at the attached, which is the response to PUC 08-14. This is what CP has provided to support its carrying costs. I spoke to Eleanor and I will have very limited availability next week but I told her I would take a look. On the highlighted tab you will see CP's calculations in columns A through J and my work is all the columns to the right. In order to think this through I recalculated their number using their compounded Monthly Interest calc (see the other tabs in the workbook) and then recalculated the number without compounding. You'll find that work in columns L through R. Removing the compounding reduces the carrying costs by $127.5K. Do you know any reason why we would approve a compounded interest rate? Looks like its even compounded monthly. We don't calculate compounded interest rates in our cost of debt calculations (not really my area but I've never seen that before).

My next step, was Columns T through AC. If all goes well, you should be able to drop your adjustments into column U by month and the spreadsheet should give you your adjustment to carrying costs. If you're quantifying adjustments separately, you might need to copy this section for each separate calculation. Feel free to trash my work and start from scratch but I wanted you to have this if it's useful to you and keeps us from having to duplicate efforts.

So, my last thoughts are, what about the Hurricane Ike credit balance? Those credits are not included in the calculation of the carrying costs. They've essentially had that free money for a while. Shouldn't they be included? However, the impact may be very, very small.

Since you are testifying as to the amount of the deferred HH carrying costs, could you please add this to your testimony?

Thank you!

June

Quinn, Cassandra

From: Quinn, Cassandra
Sent: Wednesday, June 05, 2019 2:46 PM
To: Karl Nalepa
Subject: RE: 49421 CEH - Nalepa relied upons

Thanks! I just wanted to let you know I got three emails in total: this one, the one with EE and weather norm attachments, and the service quality reports. From a quick review, it looks like everything. I think these would all go in workpapers, but if you think differently on any of them, please just let me know.

From: Karl Nalepa [redacted]
Sent: Wednesday, June 05, 2019 1:47 PM
To: Quinn, Cassandra
Subject: 49421 CEH - Nalepa relied upons

Here are the rest...

Karl J. Nalepa
Partner
ReSolved Energy Consulting, LLC
11044 Research Blvd., Suite A-420
Austin, Texas 78759

[redacted]

email: [redacted]

SOAH DOCKET 473-18-4100
PUC DOCKET NO. 48439
OPUC's Response to CenterPoint Energy Houston Electric LLC's
First Request for Information

1-3. For each consulting expert whose mental impressions or opinions have been reviewed by one or more of your testifying experts in this case, please provide (to the extent not provided earlier):

1-3.1. A list of all cases in which the consulting expert has submitted testimony, from 2014 to the present;

1-3.2. Copies of all prior testimony, articles, speeches, published materials and peer review materials written by the consulting expert, from 2005 to the present;

1-3.3. The consulting expert's billing rate for this proceeding; and

1-3.4. All documents provided to, reviewed by, or prepared by or for the consulting expert in anticipation of the testifying expert filing testimony in this proceeding.

RESPONSE:

Not applicable.

Prepared By: Counsel
Sponsored By: Counsel

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing document was served on all parties of record in this proceeding on this 10th day of June 2019, by facsimile, electronic mail, and/or first class, U.S. Mail.

Cassandra Quinn