PUBLIC



INFORMATION SHEET

PRESIDING: Commissioner Duffley, Presiding; Chair Mitchell, and Commissioners Brown-Bland, Clodfelter, Hughes, McKissick, Jr., and Kemerait
PLACE: Raleigh, NC
DATE: Thursday, August 31, 2023
TIME: 2:00 p.m. to 4:58 p.m.
DOCKET NO.: E-7, Sub 1134 and E-7 Sub 1276
COMPANY: Duke Energy Carolinas, LLC
DESCRIPTION: In the Matter of Duke Energy Carolinas, LLC Application for Approval to Construct a 402 MW Natural Gas-Fired Combustion Turbine Electric Generating Facility in Lincoln County, and for an Application for Adjustment of Rates and Charges Applicable toElectric Service in North Carolina and for Performance-BasedRegulation

VOLUME NUMBER: 13

APPEARANCES
See attached

WITNESSES
See attached

EXHIBITS

None attached

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| | |
|---|---|
| REPORTED BY: Renee Habrack | TRANSCRIPT PAGES: 124 |
| TRANSCRIBED BY: Renee Habrack | PREFILED PAGES 158 |
| DATE FILED: September 8, 2023 | TOTAL PAGES 282 |

PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Thursday, August 31, 2023

TIME: 2:03 p.m. - 4:37 p.m.

DOCKET NO: E-7, Sub 1134 and E-7, Sub 1276

BEFORE: Commissioner Kimberly W. Duffley, Presiding
Chair Charlotte A. Mitchell
Commissioner ToNola D. Brown-Bland
Commissioner Daniel G. Clodfelter
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.
Commissioner Karen M. Kemerait

IN THE MATTER OF:

Duke Energy Carolinas, LLC

Application for Approval to Construct a 402 MW Natural Gas-Fired Combustion Turbine Electric Generating Facility in Lincoln County

and

Application For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and for Performance-Based Regulation

VOLUME 13

Noteworthy Reporting Services, LLC

A P P E A R A N C E S:

FOR DUKE ENERGY CAROLINAS, LLC:

Jack E. Jirak, Esq., Deputy General Counsel
Duke Energy Corporation
410 South Wilmington Street, NCRH 20
Raleigh, North Carolina 27602

Jason A. Higginbotham, Esq.
Associate General Counsel
Duke Energy Corporation
525 South Tryon Street/ECA3
Charlotte, North Carolina 28202

James H. Jeffries, IV, Esq., Partner
McGuireWoods LLP
201 North Tryon Street, Suite 3000
Charlotte, North Carolina 28202

Andrea Kells, Esq.
Kristin M. Athens, Esq.
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

A P P E A R A N C E S (Cont'd.):

Brandon F. Marzo, Esq., Partner
Melissa Oellerich Butler, Esq., Associate
Joshua Warren Combs, Esq., Associate
Troutman Pepper Hamilton Sanders LLP
600 Peachtree Street Northeast, Suite 3000
Atlanta, Georgia 30308

Kiran H. Mehta, Esq., Partner
Molly McIntosh Jagannathan, Esq., Partner
Melinda L. McGrath, Esq., Partner
Troutman Pepper Hamilton Sanders LLP
301 South College Street, Suite 3400
Charlotte, North Carolina 28202

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION:

Marcus W. Trathen, Esq.
Matthew Tynan, Esq.
Christopher B. Dodd, Esq.
Brooks Pierce McLendon Humphrey & Leonard, LLP
150 Fayetteville Street, Suite 1700
Raleigh, North Carolina 27601

A P P E A R A N C E S (Cont'd.):

FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES III:

Christina D. Cress, Esq., Partner
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Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

Chris S. Edwards, Esq., Partner
Ward and Smith, P.A.
127 Racine Drive
Wilmington, North Carolina 28403

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:

Ethan Blumenthal, Esq., Regulatory Counsel
Cassie Gavin, Esq., Director of Policy
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

A P P E A R A N C E S (Cont'd.):

HAYWOOD EMC, BLUE RIDGE EMC, PIEDMONT EMC, and
RUTHERFORD EMC:

Christina D. Cress, Esq., Partner
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

Chris S. Edwards, Esq., Partner
Ward and Smith, P.A.
127 Racine Drive
Wilmington, North Carolina 28403

FOR NORTH CAROLINA LEAGUE OF MUNICIPALITIES:
Ben Snowden, Esq., Partner
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

FOR THE COMMERCIAL GROUP:
Alan Jenkins, Esq.
Jenkins at Law, LLC
2950 Yellowtail Avenue
Marathon, Florida 33050

A P P E A R A N C E S (Cont'd.):

FOR THE SIERRA CLUB:
Catherine Cralle Jones, Esq.
Andrea Bonvecchio, Esq.
Law Offices of F. Bryan Brice, Jr.
130 South Salisbury Street
Raleigh, North Carolina 27601

FOR NORTH CAROLINA JUSTICE CENTER, NORTH CAROLINA HOUSING COALITION, NATURAL RESOURCES DEFENSE COUNCIL, SOUTHERN ALLIANCE FOR CLEAN ENERGY, AND VOTE SOLAR:
David L. Neal, Esq., Senior Attorney
Munashe Magarira, Esq., Staff Attorney
Thomas Gooding, Esq., Associate Attorney
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

FOR NC WARN:
Matthew D. Quinn, Esq., Partner
Lewis & Roberts, PLLC
Post Office Box 17529
Raleigh, North Carolina 27619

A P P E A R A N C E S (Cont'd.):

FOR THE KROGER CO. AND HARRIS TEETER, LLC:

Kurt J. Boehm, Esq.
Jody Kyler Cohn, Esq.
Boehm, Kurtz & Lowry
36 East 7th Street, Suite 1510
Cincinnati, Ohio 45202

Ben Royster, Esq.
Royster & Royster, PLLC
851 Marshall Street
Mount Airy, North Carolina 27030

FOR ANDALE, LLC:

Marcus W. Trathen, Esq.
Brooks Pierce McLendon Humphrey & Leonard, LLP
150 Fayetteville Street, Suite 1700
Raleigh, North Carolina 27601

A P P E A R A N C E S (Cont'd.)

FOR THE USING AND CONSUMING PUBLIC PURSUANT TO N.C.G.S. § 62-20 AND ON BEHALF OF THE STATE AND ITS CITIZENS PURSUANT TO N.C.G.S. § 114-2(8):

Tirrill Moore, Esq., Assistant Attorney General
Derrick C. Mertz, Esq.,
Special Deputy Attorney General
North Carolina Department of Justice
114 West Edenton Street
Raleigh, North Carolina 27603

FOR THE USING AND CONSUMING PUBLIC:

Lucy E. Edmondson, Esq., Chief Counsel
Robert B. Josey, Esq.
Nadia L. Luhr, Esq.
Anne M. Keyworth, Esq.
William S.F. Freeman, Esq.
William E.H. Creech, Esq.
Thomas Felling, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

T A B L E   O F   C O N T E N T S

E X A M I N A T I O N S

# E X H I B I T S

# NORTH CAROLINA UTILITIES COMMISSION
## APPEARANCE SLIP

DATE: 8-28-23 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: JACK E. JIRAK, DEPUTY GENERAL COUNSEL

FIRM NAME: DUKE ENERGY

ADDRESS: 410 S. WILMINGTON ST.

CITY: RALEIGH STATE: NC ZIP CODE: 27602

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

**Non-confidential transcripts are located on the Commission's website**. To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

_____ **Yes, I have signed the Confidentiality Agreement.**

Email: JACK.JIRAK@DUKE-ENERGY.COM

SIGNATURE: ______________________

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: 6/21/2023 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: Jason Higginbotham

Associate General Counsel

FIRM NAME: Duke Energy

ADDRESS: ______

CITY: ______ STATE: ______ ZIP CODE: ______

APPEARANCE ON BEHALF OF: Duke Energy Carolinas LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

**Non-confidential transcripts are located on the Commission's website.** To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

**ONLY** fill out this portion if you have signed an NDA to receive **CONFIDENTIAL** transcripts and/or exhibits:

☑ **Yes, I have signed the Confidentiality Agreement.**

Email: jason.higginbotham@duke-energy.com

SIGNATURE: ______

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: 8-28-23 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: JAMES H. JEFFRIES IV, PARTNER

FIRM NAME: MCGUIREWOODS LLP

ADDRESS: 201 N. TRYON STREET, SUITE 3000

CITY: CHARLOTTE STATE: NC ZIP CODE: 28202

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

**Non-confidential transcripts are located on the Commission's website**. To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

X **Yes, I have signed the Confidentiality Agreement.**

Email: JJEFFRIES@MCGUIREWOODS.COM

SIGNATURE: ______

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: 8/23/2023 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: Andrea R. Kells, Counsel

FIRM NAME: McGuireWoods, LLP

ADDRESS: 501 Fayetteville St. Suite 500

CITY: Raleigh STATE: NC ZIP CODE: 27601

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

**Non-confidential transcripts are located on the Commission's website.** To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

---

ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

X **Yes, I have signed the Confidentiality Agreement.**

Email: akells@mcguirewoods.com

SIGNATURE: Andrea R. Kells Digitally signed by Andrea R. Kells Date: 2023.08.23 09:43:52 -04'00'

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: August 28, 2023 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: Kristin M. Athens, Esquire

FIRM NAME: McGuireWoods LLP

ADDRESS: 501 Fayetteville St. Suite 500

CITY: Raleigh STATE: NC ZIP CODE: ______

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: x COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

**Non-confidential transcripts are located on the Commission's website.** To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

---

ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

x **Yes, I have signed the Confidentiality Agreement.**

Email: kathens@mcguirewoods.com

SIGNATURE: Kristin M. Athens Digitally signed by Kristin M. Athens Date: 2023.08.22 11:24:07 -04'00'

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

**DATE:** August 22, 2023 **DOCKET NO.:** E-7, Sub 1276

**ATTORNEY NAME and TITLE:** Brandon F. Marzo, Partner

**FIRM NAME:** Troutman Pepper Hamilton and Sanders LLP

**ADDRESS:** 600 Peachtree Street NE, Suite 3000

**CITY:** Atlanta **STATE:** GA **ZIP CODE:** 30308

**APPEARANCE ON BEHALF OF:** Duke Energy Carolinas, LLC

**APPLICANT:** X **COMPLAINANT:** ___ **INTERVENOR:** ___

**PROTESTANT:** ___ **RESPONDENT:** ___ **DEFENDANT:** ___

**Non-confidential transcripts are located on the Commission's website.** To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

---

ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

X **Yes, I have signed the Confidentiality Agreement.**

**Email:** brandon.marzo@troutman. com

**SIGNATURE:** [signature]

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

**DATE:** 8/22/23 **DOCKET NO.:** E-7, Sub 1276

**ATTORNEY NAME and TITLE:** Melissa Oellerich Butler, Associate

**FIRM NAME:** Troutman Pepper Hamilton Sanders LLP

**ADDRESS:** 600 Peachtreet St. NE Suite 3000

**CITY:** Atlanta **STATE:** GA **ZIP CODE:** 30308

**APPEARANCE ON BEHALF OF:** Duke Energy Carolinas, LLC

**APPLICANT:** X **COMPLAINANT:** ___ **INTERVENOR:** ___

**PROTESTANT:** ___ **RESPONDENT:** ___ **DEFENDANT:** ___

**Non-confidential transcripts are located on the Commission's website.** To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

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ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

X **Yes, I have signed the Confidentiality Agreement.**

**Email:** melissa.butler2@duke-energy.com

**SIGNATURE:** Melissa Oellerich Butler Digitally signed by Melissa Oellerich Butler Date: 2023.08.22 09:57:11 -04'00'

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: 8/22/23 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Joshua Warren Combs, Associate Attorney

FIRM NAME: Troutman Pepper Hamilton Sanders LLP

ADDRESS: 600 Peachtree Street, NE, Suite 3000

CITY: Atlanta STATE: GA ZIP CODE: 30308

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

**Non-confidential transcripts are located on the Commission's website.** To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

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X **Yes, I have signed the Confidentiality Agreement.**

Email: Josh.Combs@troutman.com

SIGNATURE: ______________________

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION
## APPEARANCE SLIP

DATE: 8/22/2023 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Kiran H. Mehta, Partner

FIRM NAME: Troutman Pepper Hamilton Sanders LLP

ADDRESS: 301 S. College St., Suite 3400

CITY: Charlotte STATE: NC ZIP CODE: 28202

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

**Non-confidential transcripts are located on the Commission's website.** To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

---

ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

X **Yes, I have signed the Confidentiality Agreement.**

Email: kiran.mehta@troutman.com

SIGNATURE: Kiran H. Mehta

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

**DATE:** August 22, 2023 **DOCKET NO.:** Docket No. E-7, Sub 1276

**ATTORNEY NAME and TITLE:** Molly McIntosh Jagannathan, Partner

**FIRM NAME:** Troutman Pepper Hamilton Sanders LLP

**ADDRESS:** 301 South College Street, Suite 3400

**CITY:** ~~Charlotte~~ **STATE:** NC **ZIP CODE:** 28202

**APPEARANCE ON BEHALF OF:** Duke Energy Carolinas, LLC

**APPLICANT:** X **COMPLAINANT:** ___ **INTERVENOR:** ___

**PROTESTANT:** ___ **RESPONDENT:** ___ **DEFENDANT:** ___

**Non-confidential transcripts are located on the Commission's website.** To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

---

ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

X **Yes, I have signed the Confidentiality Agreement.**

**Email:** molly.jagannathan@troutman.com

**SIGNATURE:** Molly M. Jagannathan Digitally signed by: Molly M. Jagannathan

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

**DATE:** August 23, 2023 **DOCKET NO.:** E-7, SUB 1276

**ATTORNEY NAME and TITLE:** MELINDA L. MCGRATH, PARTNER

**FIRM NAME:** TROUTMAN PEPPER HAMILTON SANDERS LLP

**ADDRESS:** 301 S. COLLEGE STREET; 34TH FLOOR

**CITY:** CHARLOTTE **STATE:** NC **ZIP CODE:** 28202

**APPEARANCE ON BEHALF OF:** DUKE ENERGY CAROLINAS, LLC

**APPLICANT:** XX **COMPLAINANT:** ___ **INTERVENOR:** ___

**PROTESTANT:** ___ **RESPONDENT:** ___ **DEFENDANT:** ___

**Non-confidential transcripts are located on the Commission's website.** To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

---

ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

XX **Yes, I have signed the Confidentiality Agreement.**

**Email:** Mindy.McGrath@troutman.com

**SIGNATURE:** MMcGrath

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: 8-28-23 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Marcus W. Trathen

FIRM NAME: Brooks Pierce McLendon Humphrey & Leonard, LLP

ADDRESS: 1700 Wells Fargo Capitol Center, 150 Fayetteville St.

CITY: Raleigh STATE: NC ZIP CODE: 27601

APPEARANCE ON BEHALF OF: CUCA

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

**Non-confidential transcripts are located on the Commission's website.** To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab and select Docket Search, enter the docket number and click search, select the highlighted docket number and select Documents for a list of all documents filed.

To receive an electronic **CONFIDENTIAL** transcript, please complete the following:

☒ **Yes, I have signed the Confidentiality Agreement.**

**Email:** mtrathen@brookspierce.com

**SIGNATURE:** /s/ Marcus Trathen

**(Required for distribution of CONFIDENTIAL transcript)**

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

**DATE:** 8/23/2023 **DOCKET NO.:** E-7 Sub 1276

**ATTORNEY NAME and TITLE:** Matthew B. Tynan

**FIRM NAME:** Brooks Pierce LLP

**ADDRESS:** P.O. Box 26000

**CITY:** Greensboro **STATE:** NC **ZIP CODE:** 27420

**APPEARANCE ON BEHALF OF:** Carolina Utility Customers Association

**APPLICANT:** ___ **COMPLAINANT:** ___ **INTERVENOR:** x

**PROTESTANT:** ___ **RESPONDENT:** ___ **DEFENDANT:** ___

**Non-confidential transcripts are located on the Commission's website.** To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

---

ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

x **Yes, I have signed the Confidentiality Agreement.**

**Email:** mtynan@brookspierce.com

**SIGNATURE:** Matthew B. Tynan

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

# APPEARANCE SLIP

DATE: 8-28-23 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Christopher B. Dodd

FIRM NAME: Brooks Pierce McLendon Humphrey & Leonard, LLP

ADDRESS: 115 N. 3rd St #301

CITY: Wilmington STATE: NC ZIP CODE: 28401

APPEARANCE ON BEHALF OF: CUCA

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

**Non-confidential transcripts are located on the Commission's website.** To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

---

ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

X **Yes, I have signed the Confidentiality Agreement.**

Email: cdodd@brookspierce.com

SIGNATURE: /s/ Christopher Dodd

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP



**DATE:** August 22, 2023 **DOCKET NO.:** E-7, Sub 1276; E-7, Sub 1134

**ATTORNEY NAME and TITLE:** Christina Cress, Partner; Douglas "D.C." Conant, Associate (Bailey & Dixon, LLP)

Chris S. Edwards, Partner (Ward & Smith, LLP)

**FIRM NAME:** Bailey & Dixon, LLP (CDC & DC); Ward & Smith, LLP (CSE)

**ADDRESS:** 434 Fayetteville St., Ste. 2500 (Bailey & Dixon); 127 Racine Drive (Ward & Smith)

**CITY:** Raleigh (B&D); Wilmington (W&S) **STATE:** NC **ZIP CODE:** 27601 (B&D); 28403 (W&S)

**APPEARANCE ON BEHALF OF:** CIGFUR III, Haywood EMC, Blue Ridge EMC, Piedmont EMC, and Rutherford EMC

**APPLICANT:** ___ **COMPLAINANT:** ___ **INTERVENOR:** X

**PROTESTANT:** ___ **RESPONDENT:** ___ **DEFENDANT:** ___

**Non-confidential transcripts are located on the Commission's website.** To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

---

ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

X **Yes, I have signed the Confidentiality Agreement.**

**Email:** ccress@bdixon.com

**SIGNATURE:** Christina D. Cress Digitally signed by Christina D. Cress Date: 2023.08.22 13:33:10 -04'00'

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION
## APPEARANCE SLIP

DATE: 8/28/23 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: Ethan Blumenthal, Regulatory Counsel

FIRM NAME: North Carolina Sustainable Energy Association

ADDRESS: 4800 Six Forks Rd., Suite 300

CITY: Raleigh STATE: NC ZIP CODE: 27609

APPEARANCE ON BEHALF OF: North Carolina Sustainable Energy Association

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X__

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

**Non-confidential transcripts are located on the Commission's website.** To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

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ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

_____ **Yes, I have signed the Confidentiality Agreement.**

Email: ethan@energync.org

SIGNATURE: Ethan Blumenthal Digitally signed by Ethan Blumenthal Date: 2023.08.21 21:17:22 -04'00'

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: 8-28-23 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Cassie Gavin, Director of Policy

FIRM NAME: NCSEA

ADDRESS: 4800 Six Forks Rd, Suite 300

CITY: Raleigh STATE: NC ZIP CODE: 27609

APPEARANCE ON BEHALF OF: NCSEA

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

**Non-confidential transcripts are located on the Commission's website.** To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

---

ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

☐ **Yes, I have signed the Confidentiality Agreement.**

Email: cassie@energync.org

SIGNATURE: /s/ by KJM: Cassie Gavin

**(Signature Required for distribution of CONFIDENTIAL information)**

OFFICIAL COPY

May 26 2023

OFFICIAL COPY

Oct 04 2023

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: 8/28/23 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Ben Snowden, Partner

FIRM NAME: Fox Rothschild LLP

ADDRESS: 434 Fayetteville St., Suite 2800

CITY: Raleigh STATE: NC ZIP CODE: 27601

APPEARANCE ON BEHALF OF: North Carolina League of Municipalities

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: x__

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

**Non-confidential transcripts are located on the Commission's website**. To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

x____ **Yes, I have signed the Confidentiality Agreement.**

Email: bsnowden@foxrothschild.com

SIGNATURE: BSnowden Digitally signed by BSnowden Date: 2023.04.27 16:52:04 -04'00'

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: 8/25/2023 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE:

Alan Jenkins

FIRM NAME: Jenkins at Law, LLC

ADDRESS: 2950 Yellowtail Ave

CITY: Marathon STATE: FL ZIP CODE: 33050

APPEARANCE ON BEHALF OF: The Commercial Group

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: x__

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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Email: aj@jenkinsatlaw.com

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# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: August 22, 2023 DOCKET NO.: E-7, SUb 1276

ATTORNEY NAME and TITLE: Catherine Cralle Jones

FIRM NAME: Law Offices of F. Bryan Brice, Jr.

ADDRESS: 130 S. Salisbury Street

CITY: Raleigh STATE: NC ZIP CODE: 27601

APPEARANCE ON BEHALF OF: Sierra Club

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X__

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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Email: cathy@attybryanbrice.com

SIGNATURE: Catherine Cralle Jones

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# NORTH CAROLINA UTILITIES COMMISSION
## APPEARANCE SLIP

DATE: August 22, 2023 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Andrea C. Bonvecchio

FIRM NAME: Law Offices of F. Bryan Brice, Jr.

ADDRESS: 130 S. Salisbury Street

CITY: Raleigh STATE: NC ZIP CODE: 27601

APPEARANCE ON BEHALF OF: Sierra Club

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X__

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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Email: andrea@attybryanbrice.com

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# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: August 28, 2023 DOCKET NO.: E-7, Sub 1276 ,

ATTORNEY NAME and TITLE: David L. Neal, Senior Attorney

FIRM NAME: Southern Environmental Law Center

ADDRESS: 601 West Rosemary Street, Suite 220

CITY: Chapel Hill STATE: North Carolina ZIP CODE: 27516

APPEARANCE ON BEHALF OF:

North Carolina Justice Center, North Carolina Housing Coalition, Southern Alliance for Clean Energy, Natural Resources Defense Council, and Vote Solar (NCJC, et al.)

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: x

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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Email: dneal@selcnc.org

SIGNATURE: 2023.08.23 12:33:09 -04'00'

**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: 08/28/2023 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Munaashe Magarira, Staff Attorney

FIRM NAME: Southern Environmental Law Center

ADDRESS: 601 W Rosemary Street, Suite 220

CITY: Chapel Hill STATE: NC ZIP CODE: 27516

APPEARANCE ON BEHALF OF: North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, Southern Alliance for Clean Energy, and Vote Solar

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: x__

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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Email: mmagarira@selcnc.org

SIGNATURE: Digitally signed by Munashe Magarira Date: 2023.08.22 09:28:18 -04'00'

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# NORTH CAROLINA UTILITIES COMMISSION
## APPEARANCE SLIP



**DATE:** 05/04/2023 **DOCKET NO.:** E-2 Sub 1300

**ATTORNEY NAME and TITLE:** Thomas Gooding, Associate Attorney

**FIRM NAME:** Southern Environmental Law Center

**ADDRESS:** 601 W. Rosemary Street, Suite 220

**CITY:** Chapel Hill **STATE:** NC **ZIP CODE:** 27516

**APPEARANCE ON BEHALF OF:** North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, Southern Alliance for Clean Energy, and Vote Solar

**APPLICANT:** ___ **COMPLAINANT:** ___ **INTERVENOR:** X__

**PROTESTANT:** ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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**Email:** tgooding@selcnc.org

**SIGNATURE:** Thomas Gooding Digitally signed by Thomas Gooding Date: 2023.04.29 12:46:36 -04'00'

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# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

**DATE:** 08/22/2023 **DOCKET NO.:** E-7, Sub 1276

**ATTORNEY NAME and TITLE:** Matthew D. Quinn, Partner

**FIRM NAME:** Lewis & Roberts, PLLC

**ADDRESS:** P. O. Box 17529

**CITY:** Raleigh **STATE:** NC **ZIP CODE:** 27619

**APPEARANCE ON BEHALF OF:** NC WARN

**APPLICANT:** ___ **COMPLAINANT:** ___ **INTERVENOR:** X

**PROTESTANT:** ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: 8-28-2023 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: Kurt Boehm

FIRM NAME: Boehm, Kurtz & Lowry

ADDRESS: 36 East Seventh Street, Suite 1510

CITY: Cincinnati STATE: Ohio ZIP CODE: 45202

APPEARANCE ON BEHALF OF: Kroger Co. and Harris Teeter

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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Email: kboehm@bkllawfirm.com

SIGNATURE: KB

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OFFICIAL COPY

Oct 04 2023

# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: August 25, 2023 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: Jody Kyler Cohn, Esq.

FIRM NAME: Boehm, Kurtz & Lowry

ADDRESS: 36 East 7th Street, Suite 1510

CITY: Cincinnati STATE: Ohio ZIP CODE: 45202

APPEARANCE ON BEHALF OF: The Kroger Company

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: 08/25/2023 DOCKET NO.: E-2 Sub1300

ATTORNEY NAME and TITLE: Benjamin M. Royster, Attorney

FIRM NAME: Royster & Royster PLLC

ADDRESS: 851 Marshall St.

CITY: Mt. Airy STATE: NC ZIP CODE: 27030

APPEARANCE ON BEHALF OF: Kroger Co. and Harris Teeter

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: x__

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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# NORTH CAROLINA UTILITIES COMMISSION
## APPEARANCE SLIP

DATE: 8-28-23 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Marcus W. Trathen

FIRM NAME: Brooks Pierce McLendon Humphrey & Leonard, LLP

ADDRESS: 1700 Wells Fargo Capitol Center, 150 Fayetteville St.

CITY: Raleigh STATE: NC ZIP CODE: 27601

APPEARANCE ON BEHALF OF: Andale, LLC

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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**Email:** mtrathen@brookspierce.com

SIGNATURE: /s/ Marcus Trathen

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# NORTH CAROLINA UTILITIES COMMISSION
## APPEARANCE SLIP

DATE: 8/28/2023 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Tirrill Moore

Assistant Attorney General

FIRM NAME: North Carolina Attorney General's Office

ADDRESS: 114 West Edenton Street

CITY: Raleigh STATE: NC ZIP CODE: 27602

APPEARANCE ON BEHALF OF: The using and consuming public; the State and its citizens

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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Email: temoore@ncdoj.gov

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# NORTH CAROLINA UTILITIES COMMISSION
## APPEARANCE SLIP

DATE: August 28, 2023 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Derrick C. Mertz, Special Deputy Attorney General;

FIRM NAME: North Carolina Department of Justice

ADDRESS: 114 W. Edenton Steet

CITY: Raleigh STATE: NC ZIP CODE: 27603

APPEARANCE ON BEHALF OF: The using and consuming public pursuant to N.C.G.S. sec. 62-20, and on behalf of the State of North Carolina and its citizens pursuant to N.C.G.S. sec. 114-2(8)

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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Email: dmertz@ncdoj.gov

SIGNATURE: Derrick Mertz Digitally signed by Derrick Mertz Date: 2023.08.23 15:26:03 -04'00'

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# NORTH CAROLINA UTILITIES COMMISSION

## PUBLIC STAFF - APPEARANCE SLIP

DATE August 28, 2023 DOCKET #: E-7, Sub 1276

PUBLIC STAFF ATTORNEY Lucy E. Edmondson; Robert B. Josey; Nadia L. Luhr; Thomas J. Felling; William E. H. Creech; William S.F. Freeman; Anne M. Keyworth

TO REQUEST A **CONFIDENTIAL** TRANSCRIPT, PLEASE PROVIDE YOUR EMAIL ADDRESS BELOW:

ACCOUNTING

CONSUMER SERVICES

COMMUNICATIONS

ENERGY

ECONOMICS

LEGAL lucy.edmondson@psncuc.nc.gov; robert.josey@psncuc.nc.gov; nadia.luhr@psncuc.nc.gov; thomas.felling@psncuc.nc.gov; zeke.creech@psncuc.nc.gov; william.freeman@psncuc.nc.gov; anne.keyworth@psncuc.nc.gov

TRANSPORTATION

WATER

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COUNSEL/MEMBER(s) REQUESTING A **CONFIDENTIAL** TRANSCRIPT WHO HAS SIGNED A CONFIDENTIALITY AGREEMENT WILL NEED TO SIGN BELOW.

/s/ Lucy E. Edmondson

/s/ Robert B. Josey

/s/ Nadia L. Luhr

/s/ Thomas J. Felling

/s/ William E. H. Creech

/s/ William Freeman /s/ Anne M. Keyworth

**Duke Energy Carolinas**
**Response to**
**Carolina Industrial Group for Fair Utility Rates III's**
**Second Set of Data Requests**

**Docket No. E-7, Sub 1276**

**Date of Request: June 19, 2023**
**Date of Response: June 30, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

***Confidential Responses are provided pursuant to Confidentiality Agreement***

The attached response to CIGFUR III's Second Data Request No.2-12, was provided to me by the following individual(s): Keva Hibbert, Lead Rates & Regulatory Strategy Analyst, and was provided to CIGFUR III under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

CIGFUR III
Data Request No. 2
DEP Docket No. E-7, Sub 1276
Item No. 2-12
Page 1 of 2

**Request:**

2-12. For the Company's last four (4) general rate cases filed with the NC Utilities Commission, please provide the following information:
(a) The sub-docket number;
(b) The date (month, date, year) upon which the Company filed its application for general rate case;
(c) The date (month, date, year) upon which new permanent rates took effect;
(d) The percentage of interclass cross-subsidy reduction proposed by the Company;
(e) The percentage of interclass cross-subsidy reduction approved by the Commission;
(f) The Basic Customer Charge increase (in both nominal dollars and percentage) proposed by the Company for residential customers; and
(g) The Basic Customer Charge increase (in both nominal dollars and percentage) approved by the Commission for residential customers.

**Response:**

(a) - (g)

- Docket No. E-7, Sub 1026
- Filed 2/4/2013
- Permanent Rates effective 9/25/2013
- Percentage of interclass cross-subsidy reduction proposed by the Company: 25%
- Percentage of interclass cross-subsidy reduction approved by the Commission: 15%
- Basic customer charge increase proposed: $4.47 (45.1%)
- Basic customer charge increase approved: $2.29 (23.1%)

- Docket No. E-7, Sub 1146
- Filed 8/25/2017
- Permanent Rates effective 8/1/2018
- Percentage of interclass cross-subsidy reduction proposed by the Company: 25%
- Percentage of interclass cross-subsidy reduction approved by the Commission: 25%
- Basic customer charge increase proposed: $5.99 (50.76%)
- Basic customer charge increase approved: $2.20 (18.64%)

- Docket No. E-7 Sub 1214
- Filed 9/30/2019
- Permanent Rates effective 6/1/2021
- Percentage of interclass cross-subsidy reduction proposed by the Company: 25%
- Percentage of interclass cross-subsidy reduction approved by the Commission: 25%

CIGFUR III
Data Request No. 2
DEP Docket No. E-7, Sub 1276
Item No. 2-12
Page 2 of 2

- Basic customer charge increase proposed: $0 (0%)
- Basic customer charge increase approved: $0 (0%)

- Docket E-7 Sub 1276
- Filed 1/19/2023
- Permanent Rates effective: TBD
- Percentage of interclass cross-subsidy reduction proposed by the Company: 10%
- Percentage of interclass cross-subsidy reduction approved by the Commission: TBD
- Basic customer charge increase proposed: $0 (0%)
- Basic customer charge increase approved: TBD

# Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives

**Ken Costello, Principal Researcher**

**National Regulatory Research Institute**

**Report No. 14-03**

**April 2014**


8611 Second Avenue, Suite 2C
Silver Spring, MD 20910
Tel: 301-588-5385
www.nrri.org

# National Regulatory Research Institute



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**About the Author**

**Mr. Ken Costello** is Principal Researcher, Energy and Environment, at the National Regulatory Research Institute. Mr. Costello previously worked for the Illinois Commerce Commission, the Argonne National Laboratory, Commonwealth Edison Company, and as an independent consultant. Mr. Costello has conducted extensive research and written widely on topics related to the energy industries and public utility regulation. His research has appeared in numerous books, technical reports and monographs, and scholarly and trade publications. Mr. Costello has also provided training and consulting services to several foreign countries. He received B.S. and M.A. degrees from Marquette University and completed two years of doctoral work at the University of Chicago.

# Acknowledgments

The author wishes to thank **Eric Ackerman**, Edison Electric Institute; **Emeritus Professor Sanford Berg**, University of Florida; **Professor Larry Blank**, New Mexico State University; **Mark Jamison**, Public Utility Research Center; **Professor Douglas N. Jones**, The Ohio State University; **Cynthia J. Marple**, Marple Strategies LLC; **Professor Karl McDermott**, University of Illinois Springfield; **Dr. Eddie Roberson**, Regulatory Partners Consulting; and NRRI colleague **Dr. Rajnish Barua**. Any errors in the paper remain the responsibility of the author.

# Executive Summary

Ratemaking is a major regulatory function that touches all aspects of utility operations. It also has wide-ranging ramifications for the different objectives that state utility regulators try to achieve. In pursuing these objectives, regulators attempt to promote the public interest. As this paper contends, good ratemaking is difficult, requiring both good analytics and sound judgment on the part of regulators.

Rate of return (ROR) ratemaking, or what this paper also refers to as "traditional ratemaking," has been a mainstay of state public utility regulation since its inception. It has allowed utilities to be financially healthy and invest in needed new capital, while at the same time protecting customers from the natural-monopoly power of utilities. The rationale for regulation is the need to assure adequate, reliable electric service at rates that are just and reasonable. Thus, regulation recognizes that financially healthy utilities are necessary for the long-term economic welfare of customers. At the same time, customer protection against the exercise of utility monopoly power is a core principle of ratemaking.

Over several decades, state utility commissions have modified ROR ratemaking to accommodate new technologies—as well as economic, operating, and market conditions, in addition to new policy mandates—for the purpose of preserving the implicit regulatory bargain. During that time, pressures from different quarters have raised fundamental questions on the necessary conditions for effective ROR ratemaking, including stable market conditions and well-informed regulators. Utilities generally have initiated calls for alternative ratemaking approaches, but other stakeholders have done so as well. For example, conservationists and environmentalists have pushed for revenue decoupling and net energy metering rates to advance the development of energy efficiency and renewable energy. In the coming years, revenue decoupling in particular may become increasingly attractive to electric utilities as their sales growth flattens and distributed generation proliferates. State utility commissions have begun to reconsider the merits of existing net metering rates, as adverse effects have become more transparent.

As another example of non-utility stakeholders pushing for alternative rate mechanisms, since the 1980s large customers have pushed for special contracts, economic development, and flexible rates in general, which are discriminatory in nature although under certain conditions in the public interest. These rates arguably are a response to the legacy of utility ratemaking favoring small utility customers relative to large customers.

These pressures from different stakeholders have provoked state legislatures and public utility commissions to modify utility ratemaking, sometimes fundamentally. Whether these changes, or what some observers call "reforms," have improved utility performance and long-term customer welfare awaits empirical analysis. There is also the question of whether state legislatures, given their lack of expertise in technical and often complex utility matters, should have any role in reforming ratemaking practices. We observe, in particular, alarmingly more intrusive state legislation in ratemaking matters that regularly promotes the interests of a single stakeholder while damaging the interests of others. These actions, in other words, often violate the "balancing act" principle that lies at the heart of state public utility regulation.

This paper takes on the more modest task of identifying and reviewing alternative rate mechanisms that have come to the forefront in state utility regulation over the past several years. It focuses on how each mechanism affects different regulatory objectives, including core and secondary objectives. After all, rate mechanisms are desirable only if they are compatible with the objectives set out by regulators, assuming they satisfy statutory and other legal requirements. The reader can skip to Part V to get the gist of this paper.

This paper excludes endorsing specific rate mechanisms, since it argues that their efficacy is case-specific and depends essentially on the weights commissioners place on the different objectives ascribed to ratemaking. The challenge for commissions, then, is to weigh these objectives and measure (if possible) the effect of a rate mechanism on each one, as well as on the overall public interest. Assigning weights requires judgment by commissions, while examining the effect demands data and other unbiased information derived from sound analytical methods. This paper addresses the latter task. If a commission assigns a top priority to economic efficiency, for example, it would tend to favor mechanisms that set prices compatible with marginal-cost principles and provide utilities with strong incentives for technological advances and productivity.

All rate mechanisms have mixed effects on the public interest. The presumption is that when a rate mechanism impedes some regulatory objective it sets back the public interest, while improving the public interest when it advances an objective. One example is cost trackers or riders in which the tradeoff exists between timely utility recovery of costs and robust incentives: Trackers and riders allow utilities to recover their costs more quickly and with more certainty, but they also can create incentive problems when (1) regulators fail to adequately scrutinize those costs and (2) cost recovery methods differ across different utility functional areas.

Before reviewing alternative rate mechanisms, this paper outlines a theoretical framework for decision making by commissions. This framework, in addition to identifying the cardinal objectives and core principles of utility ratemaking, describes conceptually how a commission can (1) take the available information and (2) process it using its subjective values for decision making that intends to advance the public interest. These values can include relevant regulatory objectives and the relative weights of each in affecting the public interest. The public interest, as argued in this paper, relates closely to the aggregation of objectives that regulatory actions try to achieve.

This paper concentrates on alternative rate mechanisms that affect regulatory objectives both positively and negatively. Good ratemaking decisions involve three distinct considerations. As expressed in a previous NRRI paper,

> In reviewing different ratemaking proposals, state commissions should have access to unbiased information for helping them better understand and evaluate the consequences of a decision. To make an assessment of ratemaking proposals,

commissions should follow three steps. First, commissions need to define the public interest by identifying the multiple objectives that comprise the public interest, assigning weights to those objectives and resolving the tradeoffs among them. Second, commissions need to understand each ratemaking proposal fully in terms of how it advances or impedes the multiple objectives that comprise the public interest. Third, commissions need to use a logical, transparent decision-making process that selects or modifies ratemaking proposals that come closest to achieving the public interest, as defined by a commission.[1]

Ratemaking requires attention to statutes and legal rules, economic principles, precedent, public acceptability, and the tradeoffs among different regulatory objectives, among other things. An essential part of the regulator's job is to exercise judgment on (1) what objectives ratemaking should achieve, (2) the relative significance of each objective, and (3) the willingness to impede certain objectives to advance others (e.g., rates that diminish economic efficiency but make electricity more affordable to low-income households).

This paper addresses several questions:

1. **What do we mean by traditional and alternative ratemaking?**
   This paper defines ROR (traditional) ratemaking to include a general rate case supplemented by trackers or riders under exceptional circumstances. Historical examples of these trackers are fuel adjustment and purchased gas adjustment mechanisms. Traditional ratemaking allows a utility to earn abnormally high or low earnings temporarily (i.e., between rate cases). Its contrast with ratemaking approaches—such as British-style price-cap regulation—is, therefore, not as distinct as it first appears. In one sense, traditional ratemaking represents a hybrid that shares features of different rate mechanisms that have evolved over time.

2. **Why is NRRI doing this study now?**
   All state utility commissions have had, and will continue to have, to evaluate a wide array of alternative rate mechanisms across the electricity, natural gas, and water utility industries. The widespread proposals for alternative ratemaking stem from common market and utility-operation developments across utilities and states, in addition to similar legal structures, constituents, and regulatory objectives. Commissions have had to grapple with sorting out the information provided by various stakeholders. Stakeholders, which extend beyond utilities, neglect to "tell the whole story," as they deliberately omit some of the effects of an alternative rate mechanism that would be contrary to their interests if they become transparent to the commission. Commissions readily know that advancing some vested interests may not be in the public interest. Allowing lower rates to certain customers because they

[1] Ken Costello, "Decision-Making Strategies for Assessing Ratemaking Methods: The Case of Natural Gas," NRRI 07-10, September 2007, iii.

petition for it, for example, may not be fair to other customers and, overall, not in the public interest.

3. **How can state commissions define "the public interest"?**
"The public interest" is a nebulous term devoid of any definite metric. Generically, it refers to the "common well-being" or "general welfare." It is central to policy debates, politics, democracy, and the purpose of government itself. One definition of "the public interest" is the composite indicator of the public well-being that combines the individual effects of an action on stakeholders and other societal interests. Another definition relates the public interest to the stakeholders' collective acceptance of a regulatory action. While nearly everyone would agree that advancing the common good or general welfare is an admirable goal, there is little consensus on what exactly constitutes the public interest. Some state utility commissions might associate the public interest with meeting minimum fairness requirements—for example, (a) fair treatment of utility investors and (b) protection of core customers. Even though "fairness" is a subjective term, commissions must establish bounds and rules to distinguish between fair and unfair actions.

4. **Why is it important to address the topic of this paper objectively and comprehensively?**
Commissions listen to the positions of different stakeholders, whose views often diverge and reflect opposing positions on individual rate mechanisms; besides, to be blunt, stakeholders have their own agenda to pursue. Commissions are in the unique position of trying to do what is best from the public's perspective, which is a most difficult task. After all, special interests do not represent the broad public interest. Because the public interest is diffused and not well-organized, it is crucial that commissions act as its proxy in regulatory matters.

5. **How should state commissions evaluate different rate mechanisms?**
By statute, state utility commissions must take a broad societal perspective, whether for ratemaking, planning, or other matters, in decision making. Regulators should, therefore, look at the totality or aggregative effects rather than just the outcome on the utility's financial condition, consumer short-term economic welfare, energy efficiency, social goals, or fairness to one party. Although advancing energy efficiency is a desirable goal, for example, it involves a cost that regulators must balance with the benefits. Excessive energy efficiency (e.g., energy efficiency that fails to pass a cost-effective test) can jeopardize economic efficiency and "fairness." In their duties, commissions must acknowledge the interests of individual groups by avoiding actions that would have a devastating effect on any one group. Since commissions assign objectives to ratemaking, logically they should evaluate mechanisms on how they advance certain objectives while not seriously impeding others that are at the core of ratemaking.

6. **What are the major alternative rate mechanisms currently under discussion?** They include those mechanisms presented before state commissions over the past several years by different interest groups, most prominently utilities. Alternative rate mechanisms vary considerably as to their objectives and outcomes; their support derives from different stakeholders with different agendas. All of these rate mechanisms, not surprisingly, have their good and bad features, which makes it difficult for regulators to evaluate them in terms of advancing the public interest. This paper identifies those mechanisms and enumerates their positive and negative features in the confines of regulatory objectives.

7. **What are the expected outcomes of alternative rate mechanisms in terms of advancing and impeding different regulatory objectives?** The analysis done for this study relies on economic theory and empirical evidence from real-world mechanisms. Uncertainty inevitably exists over some of the outcomes, especially about their magnitudes; the analyst is, in effect, making a prediction of the outcomes with a margin of error. This paper evaluates alternative rate mechanisms in terms of their effects on regulatory objectives.

8. **How can state commissions use the information in this study for decision making?** Ratemaking must take into account several factors, including what regulatory objectives to consider, the tradeoffs among objectives, and the weights that commissions place on each objective. It is understandable, then, why the ideal state of ratemaking (however defined) remains elusive and always will. Although regulators assign varied objectives to ratemaking and weigh them differently, they all should agree that achieving a particular objective at the lowest cost is in the public interest. One of the alleged legacies of public utility regulation is its spotty performance in achieving specific objectives at least cost. In striving for utility-service affordability to low-income households, for example, some rate mechanisms produce more benefits per dollar funded by general ratepayers than other mechanisms. Frequently, we observe non-optimal mechanisms that are excessive in costs relative to the gains to low-income households. Good ratemaking would attempt to control these wastes.

One major concern discussed in this paper is identifying the socially preferred outcome—that is, maximizing the public interest—when deviations from this state involve making tradeoffs amid conflicting objectives. Who, for example, decides on making these tradeoffs (within the context of this paper, the regulators do) and on how decision makers measure their consequences? Furthermore, what objectives should be included in ratemaking? Should they encompass the number of jobs created, the accelerated penetration of renewable energy, a cleaner environment, faster growth in energy efficiency, and the affordability of utility service to low-income households?

Adding to the complexity in decision making, much of the information, especially relating to risks and the relative importance of individual ratemaking objectives, is non-quantifiable. This information gap demands that regulators assess subjectively the outcomes from different choices. In short, the judgment of regulators becomes final when choosing among different ratemaking approaches. That is the tough part of their job. For this reason, this paper makes no recommendations as to the "goodness" or "badness" of individual rate mechanisms. It hopes, instead, to aid regulators by identifying the inevitable tradeoffs that they must make with all rate mechanisms to advance the public interest.

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# Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives

Utilities and other parties have continuously proposed alternative rate mechanisms over the past several decades. These mechanisms reflect a direction away from traditional ratemaking practices. As some readers may recall, similar attacks on traditional ratemaking occurred about 20 years ago. Before then, one can go as far back as the late 1960s and early 1970s to see that utilities, as well as some environmental groups,[2] also pushed for alternative rate mechanisms because of technological developments, as well as a changing market and operating environment.[3] This time, the alternative ratemaking mechanisms have encompassed a wider umbrella. Electric, natural gas, and water utilities in recent years, for example, have expanded their interest in nontraditional rate mechanisms to include different cost trackers for an increasing number of utility activities, time-of-use rates, performance incentives for energy efficiency, revenue decoupling, formula rates, and surcharges for new investments.

Commissions have always been open to non-traditional ratemaking mechanisms[4] but the recent onslaught is unprecedented in terms of intensity and the variety of such rate mechanisms. To no surprise, their primary motivation is to promote the self-interest of those proposing them. As this paper emphasizes, alternative rate mechanisms inevitably involve a cost in terms of impeding one or more regulatory objectives. In other words, commissions must make decisions that balance the different objectives. These decisions then implicitly represent commissions' relative preferences for achieving different objectives. Commissions tend to make policy, for example, that favors those regulatory objectives to which they assign a high weight.

Each stakeholder group expectedly takes positions and makes arguments that it regards as economically beneficial to itself; the regulator's job is to sift these arguments in identifying those that arise only from self-interest, and in discovering those arguments

[2] Some environmentalist groups pushed hard for marginal cost pricing as a way to reduce peak demand and defer new electricity generating capacity.

[3] Prior to that time, electric utilities were earning high rates of return because of regulatory lag that allowed then to retain, for several years, the benefits of high sales growth and stable or even declining costs. There was little public or commission opposition since prices did not rise. The problem was that these high profits probably should have benefited utility customers earlier in time by adjusting prices downward. On the other hand, high profits gave utilities more incentive to innovate and adopt new technologies that would benefit their customers in the longer term.

[4] Recently commissions have especially been responsive to alternative rate mechanisms that mitigate utility revenue erosion and the frequency of rate cases, reduce utility risks from large and unexpected costs, and promote energy efficiency and renewable energy.

that arise from self-interest but promote the public interest.[5] Any commission assessment on rate mechanisms is complex, requiring a combination of analytics, unbiased information, and judgment by commissioners to make decisions that are best for the public interest.

Historically, rate design in the utility sector has evolved to accommodate market and other changes—for example, phase-out of declining block rates, the shift from fixed bills, and the shift from one-part tariffs to two-part tariffs. We have seen this evolution not only in the public utility industries but in non-regulated industries as well. Good examples are Internet service and long-distance telephone service. Rate methodology changes take longer in the regulated sector, partially because of inertia and required due-process procedures. For example, entrenched bureaucratic inertia may resist change, especially when it triggers opposition by some stakeholders. Inertia can afflict regulators, utilities, and consumer advocates alike to the extent that they are risk averse toward change. This adversity can stem from uncertainty over the outcomes of change—for example, the effect of real-time pricing on residential customers who don't shift load between periods—in addition to the more obvious effects that would fall on certain stakeholders.[6] State utility commissions tend to undertake major reforms, including ratemaking ones, only when continuation of the *status quo* would bring disastrous results that disrupt the political equilibrium. These results can include: (1) utilities losing customers to competitors and suffering serious financial problems and (2) the suppression of a social objective (e.g., advancing energy efficiency) to which a commission gives high priority.

## I. The Legacy of Public Utility Regulation: The "Balancing Act"

State utility commissions have consistently subscribed, over the years, to what regulatory observers call the "balancing act" of regulation. Table 1 outlines features of the balancing act and how commissions have applied it.

State utility regulators balance the rights of utilities and their customers by considering three major factors: (1) *legal constraints*—for example, utilities have a right to be given a reasonable opportunity to be financially viable, and customers have a right to just and reasonable prices; (2) *the regulator's perception of fairness*; and (3) *compatibility with a broader interest.* Regulators attempt to balance the interests of the different stakeholders with the overall objective of promoting the general good; at least,

[5] The last condition might include a utility proposing a modification of rate design that would help it to avoid serious financial problems. The regulator can conclude that even though the proposal would directly benefit the utility and its shareholders, it would prevent the utility from having a higher cost of capital or difficulty in attracting funds for new investments that would benefit its customers in the long run.

[6] This adversity by regulators may stem from the expected effects of a change on politically powerful stakeholders (e.g., industrial customers) rather than on the public interest, however they define it.

that is the premise behind the public-interest theory of regulation. This paper assumes that good regulation requires commissions to make decisions that are in the public interest. It performs no analysis on whether commissions actually attempt to pursue this objective. The economic literature is replete with theoretical and empirical studies showing that state utility commissions tend to more fully serve politically powerful interest groups than the general public. The author leaves it up to reader to judge the validity of these studies. Terms like "fairness" and "just and reasonable prices" have subjective connotations that challenge regulators, for example, to balance the dual objectives of fairness and economic efficiency and other objectives.

Legal precedent dictates that commissions must set reasonable rates that allow a prudent utility to operate successfully, maintain its financial integrity, attract capital, and compensate its investors in line with actual risks.[7] "Fair and reasonable" rates: (1) provide affordable service to the vast majority of customers, (2) include only the prudent costs of a utility, (3) reflect the utility's cost of serving different classes of customers and of providing different services, (4) allow the utility to receive sufficient revenues to attract new capital and satisfy minimum financial standards,[8] (5) prohibit undue discrimination against any customer class or service (e.g., rates should never fall below short-run marginal cost), and (6) in competitive markets, are any price that is voluntarily transacted between a buyer and a seller.[9]

Commission actions, in accordance with the balancing act, attempt to ensure that customers receive safe and reliable service at just and reasonable rates. In today's environment, balancing involves the recognition of (1) utility competitors wanting a "level playing field," (2) customers wanting lower prices and reliable service, (3) utilities wanting rates that allow them to be financially healthy, and (4) environmentalists wanting clean energy and energy efficiency. Trying to accommodate these varied and somewhat conflicting objectives poses a tough task for commissions. Historically, commissions have tended to emphasize the longer-term consequences of their actions, rather than trying to appease the immediate demands of stakeholders. As this paper stresses, commissions are uniquely responsible for looking out for the long-term interest of the general public.

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[7] The U.S. Supreme Court outlined these conditions in its 1944 order for *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944). The Court recognized that regulators should have discretion to choose among various ratemaking methods to preserve (a) "just and reasonable" rates and (b) the right balance between different stakeholders under changed market and utility operational conditions. The decision, for example, allows regulators to modify ratemaking methods when conditions change.

[8] Rather than maximizing profits, utilities focus more on attaining targets for a set of financial variables that reflect their overall financial health.

[9] In workably competitive markets, removing any pricing constraints on the utility would allow it to better compete on a level playing field with unregulated providers.

One illustration of the "balancing act" is achieving fairness[10] without severely violating other, especially core, regulatory objectives. (Often regulators will consider secondary objectives, such as when they allow discriminatory pricing to promote economic development or discourage uneconomic bypass.) It is consistent with what analysts call "conjunctive decision making." The rule underlying this decision process requires that for any single option to receive approval it must meet a minimum threshold for each criterion.[11] A regulator might reject outright a declining-block rate structure just because it violates a primary objective, such as the encouragement of price-driven energy efficiency. A seasonal rate structure might also fail a threshold test because of higher utility bills during peak periods.

Regulators also seem guided by what analysts call *bounded rationality*; they may decide that a specific rate mechanism is acceptable, if not optimal. Regulators may use the rule of thumb that a rate mechanism warrants serious consideration when it meets or surpasses a threshold for the most important regulatory objectives. Assume that regulators deemed equity and revenue sufficiency as the only critical objectives. As long as a rate mechanism does not seriously violate "fairness" standards and allows the utility a reasonable opportunity to earn its authorized rate of return, regulators can find the option acceptable, if not the superior choice. Another test for acceptability is whether any major stakeholder vigorously opposes a rate mechanism; if none does, regulation is said to be in equilibrium, or a state of minimum conflict (i.e., a balanced outcome) that elicits minimal complaints.

Commissions also recognize that part of their ratemaking duties includes allowing utilities a good opportunity to recover their prudent costs, including a fair return on their investment, so that they are financially viable to provide customers with adequate service. Overall, balancing of investor and the consumer interests is a key element of commission decisions. Often it requires commissions to balance the allocation of risks and benefits primarily between utility investors and customers.[12]

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[10] The term "fairness" and its derivative, "fair," appear commonly in the regulatory arena. We often hear of a "fair rate of return," "fair and reasonable rates," "fair value," and a "fair process." Because fairness is elusive and enters the realm of philosophy, it becomes difficult to know what is fair and to say that one policy is fairer than another is. Stakeholders' perceptions of fairness differ; therefore, regulators must balance them to decide what is in the public interest. [*See* Doug N. Jones and Patrick C. Mann, "The Fairness Criterion in Public Utility Regulation: Does Fairness Still Matter?" *Journal of Economic Issues*, *35*(1) (March 2001): 153-72.]

[11] The conjunctive decision rule recognizes that when a particular stakeholder's interest becomes seriously violated, regulation departs from an equilibrium condition in which no one group places intense political and other pressures on regulators to change their practices or policies.

[12] Risk-allocation questions on cost recovery also arise between customer classes. When a new technology benefits only a portion of a utility's customers, for example, the regulator may have to consider the cost-recovery responsibility of separate customer classes. Should all

**Table 1: Elements of the Balancing Act**

1. **Symmetry of utility customer and investor interests**
   - Customers want fair and reasonable prices
   - Investors want an opportunity to earn a return commensurate with risk
2. **Balancing can involve regulatory objectives rather than stakeholder interests, although both tend to overlap**
3. **For example, commissions identify the objectives of ratemaking, weigh those objectives, and make the inevitable tradeoffs**
4. **Fairness to different stakeholders achieved by expert, disinterested regulatory bodies acting solely in the "public interest"**
   - Commissions balance the interests of different stakeholders, given their legal mandates and the political environment, so as to advance the public interest
5. **Commissions reject those positions and arguments of stakeholders deemed not to be in the public interest**
6. **The public interest reflects the composite indicator of the public well-being combining the individual effects of an action**
7. **The challenge for commissions is to identify the public interest amid the chorus of self-seeking arguments**
   - Are the positions taken by special interest (a) representative of the general public interest and (b) intellectually and analytically well founded?

Most state utility commissions operate under rather imprecise statutes that establish only boundary conditions for ratemaking.[13] For example, they may express the mandate that commissions set "just and reasonable" rates and provide universal service, without specifying how utilities should achieve those goals.[14] Constitutional law prohibits confiscation of utility investors' property. Some statutes prohibit excessive or undue price discrimination. Other than these broad conditions, commissions have wide discretion in selecting ratemaking methods and applications.

New regulatory objectives and expanded regulatory agendas have made ratemaking more complicated, especially in satisfying the core objectives underlying "just and reasonable" rates. Commissions must make additional tradeoffs, as new objectives often conflict with the core objectives.

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customers bear the risk of a new technology that benefits only residential customers? Should all residential customers pay the same costs for the technology even though some benefit more than others?

[13] Besides state statutes, the U.S. Constitution also places bounds on regulatory actions with regard to confiscation of utility investors' property.

[14] One interpretation of this mandate is that a utility charges customers no more than necessary to give it a reasonable opportunity to recover efficiently incurred costs, including a fair rate of return on its investments.

Many of the alternative rate mechanisms tend to lower risk to utility investors. Although they have the intent of making utilities more financially healthy, their benefits to customers are less obvious. In fact, regulators frequently struggle to discern how some rate mechanisms actually benefit utility customers.[15] While financially healthy utilities are desirable, state utility commissions have a duty to take a broader and more balanced perspective by considering whether an alternative rate mechanism would serve the public interest. What best serves utility interests, or any stakeholder interests for that matter, might violate the public interest. A challenge for commissions in reviewing rate mechanisms is to determine whether customers will benefit enough to offset the potential negative effects that might burden them.[16]

Changed economic, market, operating, and policy conditions justify regulators revisiting the "public interest" effects of existing ratemaking practices. Although these practices might have succeeded in balancing interests throughout the years, they may fail to do so in the future. Staying with the status quo, in short, can diminish utility performance and thus jeopardize the public interest.[17]

## II. Features of Traditional Ratemaking

Traditional ratemaking is the default method that state utility regulators use for setting utility rates. It is also the benchmark used by regulators to assess other ratemaking practices. Even though some industry observers have written off traditional ratemaking as an anachronism, it still retains the status of the core ratemaking paradigm in state utility regulation, notwithstanding the onslaught of alternative rate mechanisms proposed by diverse interest groups throughout the history of state public utility regulation. Typically, the onus is on utilities and other stakeholders to demonstrate the

[15] Several commissions have addressed the question of whether customers should benefit from lower utility risk by reducing a utility's authorized rate of return. Such an action could better balance the gains between utility investors and customers. Utilities have rejoined by contending that a more financially healthy utility by itself would make it more attractive to investors and in the process drive down its cost of capital. Thus, commissions should not "artificially" adjust the utility's authorized rate of return to compensate customers for lower utility risk.

[16] Some rate mechanisms diminish the incentive of utilities to control their costs, which eventually translates into higher rates for customers over time. The risk to customers derives from increasing the probability that they will have to shoulder excessive or imprudent utility costs because of the diminished incentive of the utility to control costs.

[17] Alternative ratemaking practices can not only rebalance stakeholder interests in a satisfactorily manner, they could also minimize what economists call "deadweight losses." These losses represent a decline in aggregate economic welfare. Rigid pricing, for example, could result in uneconomic bypass under competitive conditions that could shift output to firms that have higher costs (but lower prices) than the local utility.

superiority of an alternate approach over traditional ratemaking. A proactive regulator would initiate, or at least consider, alternative rate mechanisms on its own when conditions change to cast doubt on the efficacy of existing ratemaking methods.[18]

Four factors explain the popularity of traditional ratemaking over time: (1) its perceived fairness to all parties under most market and business conditions; (2) its ease of understanding; (3) the public's general acceptance of average-cost pricing that relates prices to costs, even if not the correct costs from an economic perspective; and (4) its attempt to achieve a balanced outcome that avoids, in most circumstances, extreme discontent by individual stakeholders.

## A. Six attributes

### 1. Opportunity for utilities to earn a reasonable return

Traditional ratemaking has several features, some of which are subject to severe criticism, forming the basis for alternative rate mechanisms. The first feature is the objective of allowing utilities the opportunity to earn a reasonable return on prudent costs. As a general practice, regulators set rates so that utilities have the opportunity to recover prudently incurred costs plus a reasonable (or "fair") return on equity. At the conclusion of a rate case, for example, the regulator considers the utility's new rates to be "just and reasonable" on a forward-going basis. The regulator determines the new rates to be sufficient for allowing a utility to attract capital necessary so that it can finance its operations in order to provide the services consumers demand, while at the same time charging consumers a fair price for the services purchased.[19]

According to most state statutes, regulators must assure the public that utility rates are "just and reasonable" and not unduly discriminatory. These requirements mean that customers are charged no more than necessary to give a utility a reasonable opportunity to recover efficiently incurred costs, including a fair return of and on their investments. Regulators often refer to "just and reasonable" rates in their decisions, but rarely do they say what criteria (e.g., the acceptable degree of price discrimination, the proper allocation of business risk between shareholders and consumers) would support such rates. "Just and reasonable" thus becomes a mantra, or a *post-hoc* justification, rather than a continuous workable criterion for regulatory decision making.

The predominant venue for rates setting is a general rate case, which addresses the three major parts of ratemaking: the revenue requirement, cost allocation, and rate

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[18] The regulator might rightly believe that a utility would not propose an action, such as an alternative rate mechanism that would be in the public interest but not in its interest.

[19] If a utility constantly earns below its authorized rate of return (i.e., its cost of capital), it could discourage utility investments that jeopardizes the quality of utility service or, in the worst case, cause severe financial problems that could lead to bankruptcy. The fact that the history of state utility regulation has seem few bankruptcies shows that one of its long-term objectives is to avoid utilities from experiencing severe financial problems.

design. A general rate case also typically covers a multimonth review period in which several parties participate. It almost always initiates at the utility's request, involves large sums of dollars, encompasses all rates, and includes a scrutiny of a utility's costs and revenues by different parties. In a general rate case, the regulator determines what rates a utility could charge its customers for a future period. It uses a test year that matches revenues with costs, at least over the first year of new rates. The approved rates reflect what a commission deems to be prudent utility management in controlling costs and other functions. That determination is based on a "test year" estimate of utility expenses, sales, and investment, as well as the cost of debt (interest on loans) and the cost of equity (the cost of attracting shareholders), with debt and equity being the sources that fund the capital projects necessary to fulfill the utility's service obligation.

### 2. Fixed rates between rate cases

A second feature of traditional ratemaking is that utility rates remain constant between rate cases, except for riders and trackers, surcharges, and indexing. The trend in recent years is to allow more rate changes between rate cases to account for unexpected costs or revenue changes that are difficult to predict in a general rate case or that fall outside the test period. Cost recovery for new capital projects outside of a general rate case is an example of this trend.[20]

### 3. Actual returns can deviate from the authorized return

A third feature is that commissions do not guarantee that utilities will earn their authorized rate of return. Almost always, a utility will not earn exactly its authorized rate of return. It can expect actual sales and costs to deviate from test-year levels. The gap depends on the accuracy of test-year parameters in representing sales and costs over the period of new rates.[21] The regulatory obligation is only to provide the utility with a reasonable opportunity to earn the authorized level.

### 4. Strong utility incentive to manage costs between rate cases

A fourth feature is that a utility has a strong incentive to control costs between rate cases. This motivation derives from the mechanics of traditional ratemaking in setting the price, not the actual earnings of a utility. To the extent that the utility is better

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[20] Since traditional ratemaking requires a general rate case for utilities to recover their capital costs for new projects, utilities may have to wait several years before they can recover those costs. Such regulatory lag can cause financial problems for utilities, at least that is what some utilities and Wall Street investors have argued.

[21] Assume that a utility's actual costs are 3 percent below test-year costs and that its profits or margins are 20 percent of costs. The utility's margins or ROR would increase by 15 percent. If the authorized ROR on equity is 10 percent, the actual ROR would then increase to 11.5 percent.

able to hold down costs, its earnings and rate of return increase.[22] If a utility, for example, enjoyed an unexpected growth in productivity resulting in lower costs between rate cases, it benefits for a time.[23] In this instance, regulatory lag works in favor of the utility—a utility's rates remain constant while its actual average cost falls below the test-year estimate. Customers do not see the benefits of lower utility costs until regulators reflect them in new rates. This outcome is known in regulatory circles as the "ratchet effect," which says, in effect, that utilities eventually would have to turn over any past cost savings to customers.[24] Analysts sometimes refer to this turnover, especially when rate cases occur frequently (i.e., with a shortened regulatory lag), as the antecedent of the cost-plus nature of traditional ratemaking.

### 5. The balancing of interests

As a fifth feature, as discussed earlier in this section, traditional ratemaking attempts to balance the interests of different stakeholders. Regulators face the challenge of translating individual groups' interests into a broader public or general interest. Utility regulation exhibits a "balancing act" approach.[25]

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[22] Because utilities initiate rate cases under traditional ratemaking, they can file for new rates, for example, when their costs rise because of lax management. This ability to control the timing of rate cases would somewhat weaken utilities' incentive to control costs. S*ee*, for example, Ellen M. Pint, "Price-Cap versus Rate-of-Return Regulation in a Stochastic-Cost Model," *RAND Journal of Economics*, Vol. 23, No. 4 (Winter 1992): 564-578.

[23] It is assumed that expected growth in productivity is built into existing rates.

[24] The "ratchet effect" may derive from the commission's adjustment of future forecasts based on past forecasting errors. The commission observes the utility's past actual costs to reset a future price. The "ratchet effect" reflects dynamic strategic behavior that could motivate a utility to intentionally inflate its costs so as to increase the price that a commission will allow in a future rate case. See Ken Costello, "Future Test Years: Challenges Posed for State Utility Commissions," NRRI 13-08, July 2013.

[25] Balancing interests may satisfy the regulator's own interests (e.g., achieving political equilibrium), rather than the public interest. Achieving this goal may result in regulatory approval of a ratemaking mechanism that share features of different mechanisms. One article expressed this view:

> Models of public utility regulation are often framed, alternatively, as rate-of-return or price-cap regulation. In practice, however, regulators have increasingly adopted a variety of hybrid regulatory constraints that embody elements of both these, and other, regulatory forms. In this paper, we draw upon elements of both the positive economic theory of regulation and standard efficiency-based economic analysis of regulation to develop a model that endogenously yields hybrid regulatory constraints as a regulatory optimum. In this context, the paper further demonstrates that a commonly observed side payment–profit sharing–enhances regulator welfare. The results provide a plausible basis for understanding the pattern of modern regulatory constraints.

### 6. Mixed outcomes from regulatory lag

A sixth feature is that regulatory lag can either benefit or harm utilities, depending on whether average cost is decreasing or increasing (relative to average revenue). Over the history of state utility regulation, regulatory lag has benefited utilities during some periods while hurting them in other periods. For example, utilities generally benefit when prices remain fixed over several years while their average cost is declining.[26]

Much discussion in the regulatory arena has focused on regulatory lag as it relates to the timing of cost recovery. On the plus side, a lag between cost incurrence by a utility and its recovery of those costs can provide additional incentives for efficient management and cost control.[27] Commissions rely on regulatory lag as an important tool in motivating utilities to act efficiently and prudently, as it can have a positive effect on utility performance. Regulatory lag can also encourage innovation.[28] In periods before the late 1960s, for example, when electric utilities had declining costs, infrequent rate cases allowed utilities to retain the benefits of new technologies over several years.[29] Retrospective reviews of utility activities were also rare during this time. Not

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[Larry Blank and John W. Mayo, "Endogenous Regulatory Constraints and the Emergence of Hybrid Regulation," *Review of Industrial Organization*, Vol. 35, Issue 3 (November 2009), 233.]

[26] Historical experiences have shown that state utility commissions have less concern with utilities earning above their authorized rate of return when rates remain fixed than when they increase. *See,* for example, Paul L. Joskow, "Inflation and Environmental Concern: Structural Changes in the Process of Public Utility Regulation," *Journal of Law and Economics*, Vol. 17 (1974): 291-327; and Larry Blank and John W. Mayo, "Endogenous Regulatory Constraints and the Emergence of Hybrid Regulation."

[27] As economist and regulator Alfred Kahn once remarked:

> Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites; companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one.

[Alfred E. Kahn, *Economics of Regulation, Vol. 2* (New York: John Wiley & Sons, 1971), 48.]

[28] *See*, for example, Paul Joskow, "Productivity Growth and Technical Change in the Generation of Electricity," *The Energy Journal*, vol. 8, (1987): 17-38. Some analysts believe that there was actually too much investment in new technologies because of excessive expected returns relative to risk.

[29] *See* Ken Costello, "New Technologies: Challenges for State Utility Regulators and What They Should Ask," NRRI 12-01, January 2012.

surprisingly, during this period the electric industry actively engaged in new technologies and other innovative activities.[30]

On the negative side, regulatory lag can cause severe cash-flow problems for a utility. If the costs are substantial and utility recovery of those costs occurs several years after incurrence, they can weaken a utility's financial condition to increase its cost of capital or make it more difficult to attract capital.

### B. Major regulatory principles for cost recovery

Two overriding principles determine cost recovery. The first is that costs should reflect efficient and prudent utility management. The second is that a utility should have a reasonable opportunity to recover its prudent costs and to earn its market-required return on capital expenditures.

Determination of cost recovery usually occurs within the confines of a rate case. Special conditions can warrant recovery of costs outside a rate case; cost trackers are an exception to the general rule of rate-case cost recovery. Until the last several years, a commission would require three "special" conditions for cost recovery outside of a general rate case. They are: (1) large cost component, (2) costs over which a utility's management has little control, and (3) unpredictable and highly volatile costs. Disagreements exist to this day over the interpretation of "special conditions" and when they exist. State commissions have exhibited acceptance, in recent years, of cost trackers for more utility functions.

What follows is a summary of the major principles for cost recovery applied by state utility commissions over the years:

1. *Cost recovery should reflect, in a reasonable way, the prudent costs of a utility, either incurred in the past or projected for the future.*

2. *Cost recovery should avoid dramatic price volatility to utility customers*. Customers prefer some price stability so that they can better budget their expenditures that include utility bills.

3. *Cost recovery should avoid jeopardizing a prudent utility's financial condition.* A commission may want, in special circumstances, to mitigate cash flow problems by allowing a utility quicker cost recovery.

4. *Cost recovery should avoid placing onerous burdens on either utility customers or shareholders.* This balance may require a tradeoff between immediate cost recovery and delay of cost recovery until after the next rate case.

[30] Ibid., 13-15.

5. *Where a utility has much discretion over costs, regulation would tend to (a) provide the utility with either robust incentives to control them or (b) establish performance standards.* Allowing for "automatic" cost recovery or recovery with minimal scrutiny weakens utility accountability to manage costs, leading to excessive risk for utility customers.

How regulators frame cost recovery is critical in examining (1) what costs they should allow utilities to recover, (2) how utilities should recover them, and (3) when they should recover them. Utilities sometimes convey the false assertion that they have a right to recover any costs they incurred, even before the regulator has assessed their reasonableness. Their position seems to be that "we expend money to satisfy mandates or serve our customers, so regulators should allow us recovery of this money in rates with little scrutiny." It presumes that regulators should trust that utilities will always act in the public interest. Good regulation would question the prudence and legitimacy of any costs; it owes that much to utility customers. As in other situations, regulators should not expect utility interests to coexist with the public interest.

# III. Reasons for Consideration of Alternative Rate Mechanisms

## A. Displeasure with traditional ratemaking

### 1. The need to periodically revisit ratemaking practices

This section identifies the major factors that have triggered the recent unprecedented interest in alternative rate mechanisms. A revisiting of the merits of existing ratemaking practices and their underlying premises has occurred periodically throughout the 100-plus years of public utility regulation. One lesson learned over this time is that commissions should consider the merits of alternative rate mechanisms when market, economic, operating, technological, and other conditions change.[31] If in fact the underlying assumptions of traditional ratemaking no longer hold, it becomes less likely that regulation will serve the public interest. One outcome might be the utility failing to recover its prudent costs. Another outcome might be the utility earning excessive profits and customers paying for imprudent costs. Regulators should then consider ratemaking alternatives to the status quo by either (1) revamping traditional ratemaking or (2) supplementing it with alternative rate mechanisms, in order to maintain the implicit "regulatory bargain."[32]

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[31] *See,* for example, Paul L. Joskow, "Inflation and Environmental Concern: Structural Changes in the Process of Public Utility Regulation"; Karl McDermott, *Cost of Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaptation* (Washington D.C.: Edison Electric Institute, June 2102); and Kenneth W. Costello and Douglas N. Jones, "Lessons Learned in State Electric Utility Regulation," in *Reinventing Electric Utility Regulation*, eds. Gregory B. Enholm and J. Robert Malko (Vienna,VA: Public Utilities Report, 1995): 69-92.

[32] This bargain is two-sided: (a) prudent utilities have a reasonable opportunity to recover operations and capital costs and (b) utility customers pay no more than required to

### 2. Criticisms from different sources

Sources of discontent with traditional ratemaking through the years have come from different quarters: economic theory, real-world experiences, recent market and other developments triggering a revisit of "old" ratemaking practices. Some critics consider traditional ratemaking as old-fashion and out of touch with today's environment.

Some stakeholders have expressed frustration with the rigid features of traditional ratemaking. As an example, ROR ratemaking can provide utilities with inadequate incentives to invest in new technologies that are cost-beneficial (e.g., provide customers with new services, address new environmental regulations at least cost). Specifically, it may remove many of the profit opportunities that induce unregulated firms to make technological improvements.[33] On the other hand, ROR ratemaking also limits utility risk for unsuccessful new technologies, which at least partially, if not perfectly, compensates for the absence of potentially high profit. Overall, ROR ratemaking tends to socialize both the benefits and the risks of new technologies.[34]

### 3. New conditions may warrant alternative ratemaking practices

According to some industry observers, traditional ratemaking works best in an era of high sales growth and declining average costs from increasing economies of scale and

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recover those costs. The traditional regulatory bargain equates "just and reasonable" rates with cost-based rates.

[33] Regulatory policies can discourage or stimulate utility investments in innovations, thereby affecting the amount that utilities spend on innovation, the speed at which they innovate, and the nature of the innovations. The regulatory tools that affect innovation are ratemaking, mandates, and performance standards. By placing bounds on utility profits and risk, regulation can either constrain or stimulate innovation. Regulated utilities face more severe profit constraints than their unregulated counterparts, which by itself diminishes their willingness to innovate. Analysts have criticized traditional ROR ratemaking for providing utilities with weak incentives to innovate. *See*, for example, GE Digital Energy and Analysis Group, "Results-Based Regulation: A Modern Approach to Modernize the Grid," White Paper, October 2013.

Yet, regulatory policies can also encourage innovation, sometimes with poor results. Electric utilities, for example, historically invested aggressively in new technologies when their economic incentives were strong (i.e., the expected return was high relative to the risk). In the past, some of those new technologies have performed poorly, burdening utility customers with recovery of excessive costs. *See*, for example, H. Stuart Burness, W. David Montgomery, and James Quirk, "Capital Contracting and the Regulated Firm," *American Economic Review*, Vol. 70 (June 1980): 342-54. During the 1960s to the mid-1970s, for example, utilities found nuclear power attractive because of the potential to earn high rates of return and the low risks involved during this period of rare retrospective review. *See also* Paul Joskow, "Productivity Growth and Technical Change in the Generation of Electricity."

[34] *See* Ken Costello, "New Technologies: Challenges for State Utility Regulators and What They Should Ask."

productivity growth.[35] It is also more appropriate when regulatory objectives are more narrowly focused and confined to the setting of "just and reasonable" rates in conjunction with reliable and safe utility service. The expansion of regulatory objectives has pulled ratemaking in various directions, complicating the tradeoffs that regulators must make in their decisions.

Because conditions have changed, as argued by critics, traditional ratemaking fails to serve the public interest when compared with alternate rate mechanisms. This paper views this assertion as a hypothesis rather than as fact, since the public interest is a subjective concept that lacks a precise definition allowing for an objective conclusion comparing two states of affairs: a world with traditional ratemaking and a world with alternative rate mechanisms.[36] Typically, one state does not dominate by having superior outcomes for all of the regulatory objectives. For example, while an alternative rate mechanism may improve a utility's financial condition, it may shift risk to customers and diminish the incentive of the utility to manage its costs between rate cases.

### B. Three reasons for interest in alternative rate mechanisms

#### 1. New regulatory objectives

Three reasons explain the recent interest in alternative rate mechanisms. First, traditional ratemaking gives inadequate attention to new regulatory objectives. Promoting socially desirable renewable energy or energy efficiency, for example, may require a departure from cost-of-service rates, which is a feature of traditional ratemaking.[37] It may call for special incentives or subsidies funded by general ratepayers or surcharges that induce utilities to incur expenditures between rate cases.

#### 2. Declining sales growth

Second, declining sales growth and declining sales per customer have caused revenue erosion.[38] The standard two-part tariff has contributed to this problem.[39]

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[35] If cost changes over time are manageable, as the traditional ratemaking model assumes, utilities that operate under normal conditions will, on average, have the opportunity to recover their allowed costs.

[36] Critics are often special interests that seek to increase their economic gains from alternative rate mechanisms. As such, they have little credibility in asserting that traditional ratemaking has failed to serve the public interest.

[37] The smart grid and the emergence of distributed resources change the services that electricity customers demand, requiring utilities to offer them new unbundled services at "just and reasonable" rates.

[38] For the electric sector, five factors account for lower growth in sales: (a) a weak economy, (b) demand-side management programs, (c) building and appliance codes and standards, (d) distributed generation and (e) fuel switching. Many analysts now see a drop in annual sales growth to less than one percent as a long-term phenomenon. *See* Ahmad Faruqui,

The following expression represents the standard two-part tariff for base rates set by utilities:

$$B_i = C + p \cdot q_i$$

The base rate for customer i, $B_i$, equals the sum of the customer charge (C)[40] applicable to all customers, and the volumetric charge (p) times the quantity of utility service consumed by customer i ($q_i$).[41] It excludes purchased gas, fuel, and other costs recovered by a utility through a tracker or other rate mechanism outside of a general rate case.

The base rate recovers those costs related to investment in, and operation of, a utility system. The customer charge typically includes the direct cost of serving a customer, including the cost for meters, meter reading, billing and collection, servicing an account, call centers, and other costs independent of usage.[42] The volumetric recovers

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"The Future of Demand Growth: How Five Forces Are Creating a New Normal," presentation at the Goldman Sachs 11th Annual Power and Utility Conference, August 14, 2012.

Falling sales per customer has triggered interest in revenue decoupling, straight fixed-variable rates, formula rates, multiyear rate plans and lost revenue adjustment mechanisms. As discussed later, which of these is preferable from a public interest perspective requires a judgment call by regulators.

39 Non-linear pricing (with two-part tariff) has been used in the pricing of utility services since early in the 20th century. Early proponents such as Samuel Insull viewed this pricing method as a way to expand demand and lower average costs while satisfying a break-even constraint. Prior to that time, an unmetered rate was the earliest type of rate used by utilities: a customer is billed a fixed sum for service during a specified period regardless of usage; this billing practice was used prior to the introduction of meters; this rate structure was simple and easy to administer, but was both highly uneconomical and inequitable, since two customers with different levels of gas consumption would have the same monthly bill. Flat rates (i.e., one-part volumetric tariff) were the next rate structure, where the utility bills a customer based on a constant price per gas consumed and registered by a meter; this is simplest of all metered rate methods; it posed serious problems as well, including revenue instability, poor price signals, and subsidization of low-usage customers by high-usage ones.

40 Some utilities label this rate element the monthly service charge or some other name that represents the minimum charge to customers when they consume no utility service.

41 The formula above assumes a uniform volumetric distribution charge. Many utilities have block pricing where the volumetric distribution charge varies between blocks of consumption. These rate designs include increasing and declining block structures.

42 The monthly customer charge equals the allocated annual customer costs divided by the number of customer months.

the remaining costs of a utility. It includes both operating costs and capital costs not recovered in the customer charge.[43]

Using a numerical example, assume that the monthly customer charge is $10, the volumetric charge is $1.50 per thousand cubic feet (Mcf), and monthly usage is 10 Mcf. Under this tariff structure, the customer's bill (excluding purchased gas cost) would be $10 + ($1.50·10), or $25. If the customer did not consume any gas during the month, she would be charged $10. The marginal price to the customer (i.e., the cost to the customer of consuming one additional Mcf of local distribution service) would be $1.50. Under typical rate structures, the marginal price exceeds the marginal cost to the utility, since the marginal price includes fixed costs. When sales increase, for example, the utility's revenues grow by more than its costs, resulting in higher earnings. Obversely, with lower sales, the utility loses more revenues than it saves in costs, resulting in decreased earnings.

A secondary outcome is that the average price of gas to the customer (i.e., the customer's bill divided by monthly usage) decreases as the customer consumes more gas. In our example, the average price to a customer using 10 Mcf would be $2.50 per Mcf, while the average price at a usage level of 15 Mcf would be $2.17 per Mcf. This decline in average price reflects the decrease in a utility's average costs as monthly consumption increases, because the fixed costs of the system (to the extent that the utility recovers them through the non-varying customer charge[44]) are divided by more units of sale.

The utility's ability to recover its authorized rate of return depends on the level of sales. The utility would, therefore, have an incentive to promote sales, as additional sales would increase earnings as long as additional revenues exceed incremental costs.[45] This has negative ramifications for a policy objective that encourages utilities to promote energy efficiency.

### 3. Non-revenue-producing investments

Large capital expenditures, some of which are non-revenue producing (e.g., natural gas pipe replacement), are a third reason for interest in alternative rate mechanisms. Many utilities, as well as an increasing number of commissions, feel that

[43] The volumetric charge equals the total costs (minus the costs recovered in the customer charge) divided by the annual sales as determined at the last rate case.

[44] As discussed later, over the past several years commissions have tended to move more of the fixed costs out of the volumetric charge and into the fixed monthly charge. The problems created by the prevailing rate structure have also led to alternative rate mechanisms, such as revenue decoupling and straight fixed-variable rates. These mechanisms in part intend to overcome the utility's resistance to energy efficiency caused by the standard two-part tariff.

[45] Another outcome, when the utility recovers fixed costs recovered through a volumetric charge, is customers receiving inefficient price signals. Specifically, including non-variable costs in the marginal price would motivate customers to under-consume.

waiting for the utility to recover these costs until the completion of a new project or the next rate case could lead to serious cash-flow problems and, ultimately, "rate shock." As one consulting report for the electric industry has expressed:

> Under traditional regulation, we have seen that [intensifying cost pressures and general business turbulence] can lead to rate shock, frequent rate cases, and investment risk that is not commensurate with the rate of return.[46]

### C. Objectives of alternative rate mechanisms

Although utilities are the most frequent proposers of alternative rate mechanisms, other stakeholders have also advocated them to advance their agenda. The intent behind these mechanisms varies. They include:

1. Reducing risk to utilities and improve their financial condition by mitigating regulatory lag and offering them more certainty in cost recovery (e.g., future test years, regulatory preapproval of large capital projects)

2. Promoting certain social goals (e.g., infrastructure surcharges for gas pipeline replacement, discount rates to low-income households[47])

3. Facilitating new investments, especially those that do not generate additional utility revenues

4. Fostering new technologies (e.g., net metering of rooftop solar PV systems, regulatory preapproval of smart meters)

5. Encouraging utility energy efficiency (e.g., revenue decoupling, straight fixed-variable rates[48])

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[46] Mark Lowry Newton et al., *Forward Test Years for U.S. Electric Utilities*, prepared for the Edison Electric Institute, August 2010, 39.

[47] One example is targeted subsidized rates, where the utility offers a price discount to advance some social objective such as universal service and service affordability to low-income households. The rate offered to achieve these objectives might fall below short-run marginal cost, resulting in a burden on either utility shareholders or non-targeted customers, or sharing by both. A preferential rate directed at low-income households, for example, can include (a) a straight rate discount (e.g., a 20 percent discount from the cost-of-service rate), (b) a percentage-of-income payment plan (PIPP) where a utility bills an eligible customer based on a specified percentage of the household's income, or (c) crediting their bills by a specified lump-sum amount. As discussed later, alternative rate mechanisms should not only advance some regulatory objective, they should also do so most cost-effectively and with minimal waste.

[48] These rate mechanisms can also remove the disincentive of electric utilities to promote distributive generation, such as combined heat and power (CHP) and rooftop solar PV systems.

6. Increasing public benefits from utility investments and other activities (e.g., rolled-in pricing[49] for gas line extensions)

7. Reducing the frequency of rate cases (e.g., multiyear rate plans)[50]

8. Mitigating regulatory lag[51] (e.g., future test year, cost trackers)

# IV. A Framework for Commission Decision Making: Factors to Consider in Evaluating Alternative Rate Mechanisms

## A. Support for a proactive commission

As a rule, commissions make ratemaking decisions by responding to the positions of stakeholders, who present conflicting information, in the absence of pre-existing commission statements enunciating ratemaking principles,[52] which can include the weights assigned to the various regulatory objectives. Assuming a defensive stance makes commissions more vulnerable to political pressures from individual special interests. Excessively assuaging individual stakeholders would ostensibly, more times than not, fail to advance the public interest.

In taking a proactive stance, a commission might want to consider taking the initiative by laying out ratemaking principles and by identifying the objectives and

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[49] Under rolled-in pricing, the utility adds the costs of new investments to existing costs with prices to all customers based on this sum. New and existing customers face the same price. Analysts often refer to rolled-in prices as average or embedded cost prices. Under an alternate pricing method, namely, incremental pricing, the utility's price for sales to new customers differs from the price for sales to existing customers. It relates closely to the economist's notion of marginal cost. Rolled-in pricing is synonymous with the term "socializing the costs" whereby all customers pay for a utility investment or other activity even if a relatively few customers receive a disproportional share of the benefits.

[50] The downside to fewer rate cases is conditions might warrant regulators to frequently revise cost allocations, rate design and the utility's cost of capital.

[51] This outcome could, as mentioned earlier, weaken utility incentives for cost management, justifying at least consideration of conditioning a mechanism on predetermined performance benchmarks for different functional areas. There are at least three perspectives on regulatory lag, each with a positive or negative connotation: (a) it can create cash flow problems for a utility, (b) it can strengthen a utility's incentives to control costs, and (c) it can cause a utility to receive windfalls or losses for factors beyond its control, inferring a "fairness" problem.

[52] Regulatory decisions should hinge on principles rather than stakeholder and political pressures. This advice is not always easy to implement, but it is a requirement for good regulation directed at serving the public interest.

features that a ratemaking proposal should follow. Often, utilities and other stakeholders make proposals that are not in the public interest. Less evident, they may also *fail* to make proposals that would be in the public interest but contrary to their interests.[53]

The core principles of ratemaking tend to be immutable over time, as they represent a general guide to good ratemaking under a wide array of market, economic, technological, and political conditions. Less primary objectives, on the other hand, can vary as markets evolve and the economic and political landscape changes. New ratemaking objectives can surface, with some old ones discarded or relegated to a lower status. The regulatory weighing of these objectives can vary over time and between utilities, as conditions change and differ across utilities. In other words, regulators might find some rate mechanisms non-robust as market, technological, and operating conditions change.

### B. Utility performance is the key criterion

Utility performance is the litmus test for evaluating different rate mechanisms. After all, a main goal of public utility regulation is to improve the performance of utilities from their unregulated levels. Specifically, regulation is all about steering utility actions toward the public interest.

A relevant question in today's environment is then: Should regulators condition cost trackers, rate-stabilization plans, infrastructure surcharges, and other mechanisms that shift risks to customers on predetermined benchmarks or performance targets?[54] These mechanisms make cost recovery more timely, certain, and predictable for utilities.

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[53] A commission should almost always expect stakeholders to promote their self-interest and only propose an action that is in the public interest when it is in their interest as well.

[54] A dubious practice is to hold a utility to a predetermined benchmark or hard target, based on a peer group of utilities or even on the utility's previous performance. It is presumptuous to conclude that anytime a utility fails to achieve its target, it has acted imprudently. For many functional areas, penalizing or rewarding a utility based solely on this comparison would be inappropriate and unfair to the utility or customers; it is infeasible, for example, to control for all the factors that affect the performance of a particular functional area and explain the differences across utilities. The analyst would find it challenging to identify the factors, let alone try to measure their effects with reasonable precision. On the other hand, commissions should assume that utilities have some control over its performance. A perception to the contrary inevitably leads to an open-ended invitation for the utility to pass through all costs to customers with minimal regulatory oversight. Both of these extreme policies  a hard target and a *laissez faire* approach  make false assumptions that can lead to inefficient and inequitable outcomes. Some readers may disagree by asserting that hard targets can best motivate utilities to satisfy a commission's standard, no matter how less-than-perfect it is. A commission, for example, can reward a utility for reaching a target, instead of penalizing it for falling short.

Performance targets would help to compensate for the tendency of these mechanisms to create a "moral hazard" problem that could lead to less efficient utilities over time.[55]

### C. Meaning of "the public interest"

The term "social welfare" or "the public interest" is multidimensional in nature. A regulatory review of alternative rate mechanisms, therefore, requires consideration of fairness, economic, utility, financial, and other outcomes.

A narrow definition of "the public interest," more in line with traditional regulation, is the long-term interests of utility customers. After all, the original rationale for public utility regulation was to protect customers from the monopoly power of utilities. The "long-term" aspect means that holding rates down in a pending rate case may jeopardize the ability of the utility to fund new investments benefiting customers.

Long-term customer welfare, arguably, is one of the least represented interests in the regulatory and political arena. Utilities look out for their financial interests,[56] and consumer advocates tend to take a short-term view. A gap in adequate representation for the long-term interests of customers becomes evident. The job of regulators is to fill that void, notwithstanding the intense pressure they face to appease individual stakeholders with the most clout.

### D. Conflicting objectives and the public interest

Some of the elements of social welfare may be conflicting—for example, discounted rates to low-income households may diminish economic efficiency[57] and fairness from the perspective of the general ratepayers. A second example of conflicting outcomes relates to seasonal pricing. Under this pricing, a gas utility would charge

[55] A "moral hazard" problem occurs when a party faces little accountability for its actions, thus tending to act indifferently to the outcome.

[56] Utility management could have different interest than the shareholders. Management might place greater emphasis, for example, on immediate or short-term financial performance whereas shareholders might have a longer-term horizon (e.g., the average rate of return over a ten-year period).

[57] Economic efficiency takes into account: (1) the cost to society from satisfying the demands of utility consumers (i.e., productive efficiency) and (2) the value that consumers place on utility service (i.e., allocative efficiency). Key actions for achieving economic efficiency are to (a) set rates based on marginal cost principles and (b) give utilities strong incentives to operate efficiently. Economic efficiency helps to avoid the waste of resources from both consumption and production. Economic efficiency involves maximizing total net economic value, while equity or fairness involves the distribution of net value among producers and consumers. Another way to look at the two concepts is that what matters to economic efficiency is maximizing the size of the pie, while equity or fairness cares about the slicing of the pie. Ratemaking involves treating these two concepts interdependently as maximizing the size of the pie requires efficient pricing to consumers, which encompasses slicing the pie at the same time.

higher rates during the winter months, when demand and marginal cost are the highest. For an electric utility, rates would typically be the highest during winter and summer peak periods. Seasonal pricing gives utility customers better price signals, results in a more efficient use of a distribution system's facilities, promotes customer energy conservation during the highest-cost periods for utilities, and requires no special meters. Yet some stakeholders have vigorously opposed, and some state commissions have rejected, seasonal pricing, because it would cause rates to be higher during periods of peak consumption. In a few jurisdictions, the higher utility bill during peak periods has met with public scorn and negative media coverage. That is, seasonal pricing has sometimes failed the "public acceptability" test for ratemaking.

Another illustration of a particular pricing mechanism with conflicting objectives is special contracts to a large industrial customer. These contracts, which are in response to competition, can mitigate uneconomic bypass. It is uneconomic because a customer turns to a non-utility provider for one or more services when the alternative provider (e.g., retail marketer) has higher total costs but lower prices. Society incurs higher costs in meeting the demands of a customer. One major cause of uneconomic bypass is the inability of the utility to lower its rates below fully allocated embedded costs, which under certain circumstances (e.g., a utility has a high level of surplus capacity) could far exceed its marginal cost. Another cause of uneconomic bypass is faulty rate design, specifically an excessive usage charge, where certain customers within a group (e.g., high-usage customers within the industrial class) pay more than the utility's cost of serving them, and perhaps at a higher rate than the price of competitive providers. Special contracts or discounted tariffs, which can head off uneconomic bypass, are discriminatory, however: They can result in other customers "funding" them through higher rates, as the utility recovers less of its fixed costs from targeted customers than the amount the last rate case assigned to them.

Other examples abound in which a particular rate mechanism advances some regulatory objectives while hindering others. They include real-time pricing in which the tradeoff is between economic efficiency and price stability; and price caps in which the regulator must weigh the benefits of pricing flexibility and increased incentives for productive efficiency against profit variability, which could lead to "excessive" utility profits. This paper contends that these conflicts require regulators to make value judgments on the desirability of a rate mechanism.

## E. The "public interest" curve

### 1. Graphical analysis of regulatory trade-offs and the public interest

The "public interest" curve (PIC) in the context of utility ratemaking represents the combination of regulatory-objective levels that result in the same public interest, as judged by regulators. In simple terms, it says that advancing (impeding) regulatory objectives has a positive (negative) effect on the public interest. For example, a higher level of economic efficiency and affordability of utility service, other things remaining the same, promote the public interest. Theoretically, regulators can achieve the same public interest by impeding one or more regulatory objectives, so long as it advances others. As another example, regulators can offset the negative effect of passing risks to utility customers by making the utility more financially healthy. The desirability of this tradeoff inevitably requires judgment by regulators. Overall, regulators can select among different mixes of objectives to arrive at what they deem to be the "same" public interest. They essentially place an implicit value on achieving different objectives and must then consider tradeoffs in arriving at their preferred decision. For this reason, regulatory ratemaking involves a combination of the evidence and judgment.

Figure 1 shows the "bliss point" and inferior outcomes that depend on both (1) the willingness of regulators to tradeoff some objectives to advance others and (2) the capability of society to achieve different levels of objectives. One interpretation of the "bliss point" is that it represents the optimum state, or the highest level of social welfare that regulators can achieve given society's resource constraints and their relative preferences for different objectives.

The figure depicts this capability as the "objective" or empirically based possibility XY frontier and the regulatory preference curve as the public interest curve "PIC."[58] All points on the XY frontier are Pareto efficient in the sense that it is impossible to effect a change that makes anyone better off without making someone worse off.[59] This concept of efficiency is an absolute one and assumes no additional societal gains from resource reallocation.[60] A variation of Pareto efficiency expressed in relative terms, and more useful for evaluating public policies, is whether a policy change (e.g., regulatory action) would increase or reduce efficiency. In Figure 1, Point D would be Pareto inefficient, since moving toward the XY frontier could promote both objectives simultaneously, or at least one objective without compromising any other objective. We can then assume an improvement in the public interest when society moves closer to the XY frontier.

One observation is the independence of the XY frontier and the PIC. The former curve represents society's capability to achieve different levels of "public interest"; the

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[58] In a different context, PIC would be analogous to what economists call the social welfare curve or social indifference curve. Figure 1 represents a simple two-dimensional construct assuming a regulator has only two objectives. In reality, regulators have several objectives that would make the diagram multidimensional and the regulatory tradeoffs more complex.

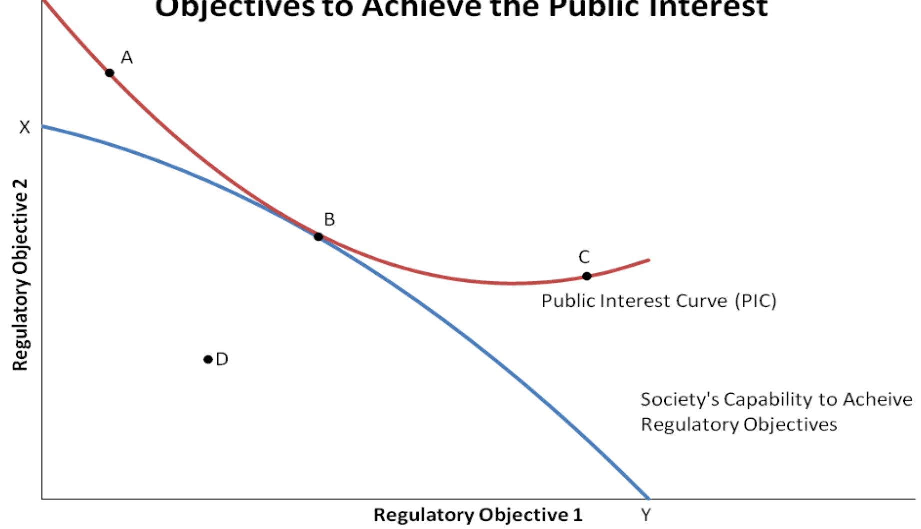
[59] One implication is that a reallocation of society's limited resources cannot increase efficiency. The assumptions underlying this condition include perfect competition, full information, no externalities, and no transaction costs. Pursuit of self-interest by market participants would, therefore, yield maximum aggregate economic welfare. Under the previous (admittedly stringent) assumptions, society cannot improve upon this outcome without making at least one person worse off. Thus, it represents a Pareto-efficient condition.

[60] *See* Lee S. Friedman, *The Microeconomics of Public Policy Analysis* (Princeton, NJ: Princeton University Press, 2002), 54-7.

latter curve reflects the preferences of the decision maker for different objectives. Just as an individual's ability to purchase goods and services depends on her income, her mix of actual purchases relies on her willingness to trade off one good or service for another. Those households who express the highest preference for education, for example, would spend a larger portion of their income on schooling their children, in the process forging the purchase of a larger house and other goods and services. In the same way, a regulator who emphasizes energy efficiency and renewable energy would tend to support subsidies for these "resources," even if it results in lower economic efficiency and higher rates.[61]

The concavity of the "XY" frontier shows the limitations of society when it comes to achieving different combinations of "objective" levels. Assume, for example, that *objective 1* is the inverse of the rate level and *objective 2* is the reliability level of utility service. As we achieve higher reliability (i.e., move upward on the XY curve), regulators would need to increase rates to pay for the additional cost. The concavity of the curve assumes that the incremental cost of reliability increases at higher reliability levels.[62] More generally, it says that as regulators pursue a particular objective to an "extreme" level, they may have to sacrifice other objectives at a substantial cost.

**Figure 1: Trading of Regulatory Objectives to Achieve the Public Interest**

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[61] Another analogous feature is the need for households to spend on essentials items, such as food, housing and energy, while regulators need to satisfy core principles dictated by the U.S. Constitution, and state statutes and rules. Both have discretion beyond these minimum requirements: households can purchase nonessential items just as regulators can pursue non-mandatory policy and other objectives.

[62] The assumption is that the utility would sequence its spending on reliability in descending order of cost effectiveness. That is, it will initially undertake those actions that improve reliability the most per dollar expended.

The convexity of PIC means that regulators are less willing to trade off one objective when less of it exists. In Figure 1, using our previous example and comparing point A with point B, at the margin regulators would be willing to accept a smaller decrease in rates (objective 1) to compensate for less reliability at point A than at point B. One explanation is that any decrease in reliability would have greater consequences at lower levels of reliability.

An upward shift in PIC means that public interest has improved but would be beyond the realm of possibility since the position of the XY frontier prohibits society from attaining that level. It is similar to saying that households would find their "utility" increasing as they consume more goods and services. Yet their incomes may fall short of allowing them to purchase additional levels.

The "bliss point" or point of maximum attainable public interest is at point B; that is at the point where the XY frontier and PIC are tangent. While points A and C would achieve the same public interest (since by definition they are alternate points on the PIC), they are unattainable since they lie above the XY frontier. As an illustration, attaining the combination of reliability and rate levels at point A is infeasible. It would require lower rates than are possible to achieve at the given level of reliability. Productivity improvements that would shift the XY frontier to the right can make point A feasible.[63] The attainment of point C would also require an improvement in productivity.

The balancing act of regulation, with the goal of trading off stakeholder interests or objectives, would tend to avoid a "corner solution" wherein regulators neglect certain objectives. In our example, a regulatory decision near point Y would reflect a low level of reliability that could jeopardize the public interest.[64] At the other extreme, achieving high levels of reliability may result in excessive rates that fail the tests of public acceptability and economic efficiency.

### 2. Insights from the public interest curve

The following observations depict the challenges commissions face in deciding on various rate mechanisms, applying the previous analysis. Although the "PIC-XY frontier" framework is conceptual, devoid of quantifiable evidence, it can provide several insights to regulators:

1. **The public interest (PI) relates the aggregate effect of a ratemaking decision to individual regulatory objectives.** For example, we can express "the public interest" as:

[63] Productivity here refers to the ratio of reliability levels to costs. An improvement would allow a utility to achieve different levels of reliability at lower cost.

[64] Although points near Y could result in low rates, most regulators would disfavor this outcome if the reliability is intolerably low.

*PI = f(economic efficiency, service reliability, utility-service affordability, financial health of the utility),*

with $\Delta PI / \Delta O_i > 0$ and the objectives acting as parameters; PI is multidimensional. The shape of the PIC (as defined earlier) depends on the tradeoffs among the different specified objectives. Making inter-objective comparisons requires regulators to impute dollar values or some common metric on the different objectives. Since regulators are unable to do that, they need to exercise judgment in placing a value on different objectives and trading-off objectives. Although ratemaking is both an art and a science—some compare it to sausage making—it should start with a strong foundation (specified objectives, compatible with economic principles, such as cost causation).[65] The PIC helps to demonstrate conceptually the optimal balancing of competing objectives. The shape of the curve describes the tradeoff among objectives, or the preferences placed on different objectives by regulators, who act as agents to society's interests. Two regulators having the same information and objectives for ratemaking, for example, can easily arrive at different decisions because of the different weights they assign to the objectives.[66]

2. **The major constraints for regulators are twofold. First, individual objectives, as well as their contribution to the overall public interest, are difficult or impossible to quantify. Second, there exists no consensus on the specification of the "proper" PIC—what parameters to include, as well as its shape (i.e., the tradeoffs).** How much does a more financially healthy utility promote the public interest? Does lowering the financial risk of a utility, for example, increase risks to ratepayers, thereby creating a "fairness" and "moral hazard" problem? Other than core objectives, what other objectives should regulators consider in ratemaking?

3. **There are inevitable tradeoffs and difficulties in combining different "objectives" mixes into a PIC.** Public utility regulation has always involved compromising different objectives. For example, to improve economic efficiency, how much higher would rates become for certain customers? Are these two outcomes, taken together, fair to all customers and in the public interest? How much would economic efficiency have to increase to

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[65] In terms of Figure 1, analysis of available quantifiable information can help to map out the XY curve.

[66] Another possible reason for dissimilar decisions is the regulators' different interpretations of the information that is equally available to both. This is probably not an uncommon occurrence, since much of the information presented in a rate case is adversarial in nature. Information may also be speculative and subject to other uncertainties, so a regulator must judge its veracity for decision making.

compensate for the higher rates?[67] As shown later, no single rate mechanism is superior to other mechanisms in advancing all of the regulatory objectives. Thus, regulators need to prioritize the objectives and implicitly assign weights to them in reaching ratemaking decisions.

4. **Regulators can improve the public interest by adopting policies that manage utility waste and inefficiency.** As shown in Figure 1, more efficient utility behavior would increase the opportunities for regulators to advance their objectives. Moving from point D toward the XY frontier means that regulators could advance one objective without compromising others. For regulators and society, the outcome is a non-zero-sum game in which everyone can benefit. This outcome speaks to the importance of regulation placing a high priority on managing the waste and inefficiencies of utility operations.[68]

5. **Traditional ratemaking places primary emphasis on reasonable rates, along with reliable and safe service.** These outcomes are core objectives of public utility regulation, so regulators are less willing to trade off these objectives to advance others.[69] These objectives, in other words, represent thresholds that regulators are unwilling to trade off.

6. **Non-core objectives have grown over time or moved up in importance, implying that regulators might be willing to trade off some core objectives.** For example, advancing energy efficiency or renewable energy may lead to subsidies, higher rates, or worsening of a utility's financial position. Net energy metering is a prime example: Some regulators are beginning to question whether fostering the development of rooftop solar PV systems is worth the price of higher rates to general ratepayers and worsening utility financial health.

7. **While analytics can help regulators to make informed decisions, their preferences for specific objectives, as well as tolerances for setting back other objectives, are key factors in their decisions.** Ratemaking requires more than just having good information on the outcomes of a rate mechanism, including their effects on individual stakeholders; it must also involve the regulator placing an implicit value on those outcomes to the general public.

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[67] As another example, how much would rates have to increase to general ratepayers to make utility service more affordable to low-income households? Would the increased rates more than offset the benefits of lower-priced utility service to needy households?

[68] Eliminating waste, while seemingly an admirable goal, may not be a good policy as the costs in achieving it may exceed the benefits.

[69] Regulators may also be legally bound to not trade off core objectives.

8. **A major obstacle in regulatory decisions is making the various objectives comparable (e.g., measuring in dollars) and scaling up individual objectives to arrive at a "public interest" metric.** As an example, assume two states: one in which electricity is affordable to all customers but requires subsidies funded by some customers to assist low-income customers; a second in which all customers pay for electricity based on the utility's cost of service. If the regulator is unable to impute a dollar value to affordability or economic efficiency, how can she conclude that one state is more in the public interest than the other state, unless she makes a value judgment?

9. **Another major problem is more conceptual: the absence of an agreement or consensus on the proper PIC, as each regulator may have her own view.** There can be many possible curve mappings of how society would trade off different objectives (e.g., economic efficiency and affordability). The shape of the PIC depends on the relative values regulators place on different objectives—for example, giving up some economic efficiency to achieve more affordability to low-income households. As noted earlier, the PIC by definition is an indifference curve mapping out various combinations of objective "levels" for which the public interest is the same.

## F. A process for effective ratemaking

### 1. Three essential steps

A rational process for ratemaking decisions involves regulators ordering and interpreting the information they have available to best advance the public interest. This approach requires that regulators: (1) define the public interest in terms of the objectives they assign to ratemaking, (2) understand the effect of each ratemaking proposal on advancing and impeding the different objectives, and (3) process all the information logically and systematically. An idealized vision of regulation is as a social institution that makes reasoned (i.e., rational and systematic) decisions based on expert and objective assessment of all the relevant information, and driven to advancing the public interest. Still, as emphasized in the last section, regulators inevitably need to exercise judgment by processing the information for decision making.

Suboptimal decision making leads to outcomes that fall short of maximizing the public interest. For example, in Figure 1, points on the XY frontier other than at B would be suboptimal: At these points, the public interest suffers relative to the public interest at B. Suboptimal decisions could also lead to utilities operating inside the XY frontier (e.g., at point D). Poor decisions can come from (1) lack of objective information, (2) regulators' goals incompatible with the public interest, and (3) the regulators' inability to process the available information.

One requisite for good decision making is for the regulator to have some notion of the public interest: What are the underlying regulatory objectives and what is the relative importance of each? Regulators should have access to unbiased information[70] for making informed decisions; otherwise, they will react to biased information by making incorrect decisions (i.e., decisions not in the public interest) even when they are fair-minded. Regulators also should be open to considering alternative ratemaking concepts and methods when they have the capability to improve matters in a changing world. What worked best in the past may not work well in the future. In the context of Figure 1, staying with existing ratemaking practices can cause utilities to operate inside the XY frontier.

Regulators also need to process the information logically, as well as interpret the information correctly, to arrive at a good decision. For example, they have to account for the inevitable tradeoffs in addition to assessing the public-interest effect of individual rate mechanisms. A regulator's decision is akin to purchasing a car, where a person must balance power, safety, fuel economy, appearance, maintenance costs, purchase price, reliability, and other features to reach a decision that is most satisfactory.

Similarly, the regulator needs to make decisions that account for multiple objectives, some of which are conflicting and non-quantifiable.[71] This task is admittedly difficult, requiring the combination of unbiased information and good judgment to make good decisions.

One prime example relates to marginal cost pricing.[72] (Marginal cost pricing sets prices equal to the cost to the utility of the last unit of service.) This pricing rule promotes economic efficiency by providing consumers with proper price signals while, as some stakeholders have argued, clashing with the objectives of equity and gradualism.[73] New regulatory objectives or expanded regulatory agenda have made ratemaking more complicated, especially in satisfying the core objectives underlying "just and reasonable" rates.

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[70] This information can come from advisory staff or staff testifying on behalf of the public interest, rather than from a narrow interest.

[71] A regulator's decision is more difficult than that of the prospective car owner in the sense that the latter has more precise quantifiable information that is less conjectural.

[72] Although not an elusive concept, marginal cost is difficult to measure and subject to much controversy. When this paper refers to marginal-cost pricing, it generally means the practice of setting rates relying more on forward-looking costs rather than embedded costs. As an example, discount pricing to industrial customers for a utility with surplus capacity would tend to lower rates below embedded cost that includes a utility's past capital expenditures and closer to the utility's marginal cost. A regulator may approve a discount rate to a specific customer, however, to avoid the utility from losing the load, rather than to improve economic efficiency.

Most often, utilities apply marginal cost principles to allocate costs. Once a utility determines the relative marginal costs of serving various customer classes, for example, marginal costs are then scaled to the utility's total revenue requirements. Thus, the actual marginal cost

To summarize, evaluating different rate mechanisms is complex, but it is one of the state utility commission's most important duties. First, rate mechanisms have differing effects on regulatory objectives, with most advancing some objectives while impeding others. Objectives can include a financially healthy utility and "moderate" shifting of business risk to customers. As public utility regulation branches out to address a larger number of social problems, conflicting objectives for individual rate mechanisms become more likely. Second, quantifying or evaluating the tradeoff in terms of the public interest is difficult. As an example, is price discrimination that makes utility service more affordable to low-income households in the public interest? Even after quantifying the expected outcomes for each rate mechanism, commissions will still have to process this information for determining what is in the public interest.

### 2. Attributes of acceptable rates

#### a. The core principles of "just and reasonable" rates

"Just and reasonable" rates reflect a balancing of different objectives. The core objectives applied by state utility commissions over several decades include:

1. Rates reflect the costs of an efficient and prudent utility.

2. Rates reflect the cost of serving different customers and providing different services and different levels of service.

3. Rates are not unduly discriminatory.

4. Rates must be fair among customer classes and between utility shareholders and customers as a group; fairness also relates to risk bearing.[74]

5. Rates allow a prudent utility a reasonable opportunity to receive sufficient revenues to attract new capital and not encounter serious financial difficulties.

Other, less universal, regulatory objectives can include: (1) public acceptability (e.g., no severe political backlash), (2) rate stability and gradualism (e.g., no rate shock), (3) affordable utility service (e.g., low-income households spending less than 15 percent

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would only equal the utility's cost of service by accident and would not constitute the determining factor in establishing the class revenue requirements used to set rates.

[73] For example, moving from embedded-cost to marginal-cost pricing could lead to much higher prices to some customers or much higher prices for all customers over specific periods (e.g., summer peak periods for electricity service). For other problems with marginal cost pricing, *see* R. H. Coase, " The Marginal Cost Controversy," *Economica*, Vol. 13 (August 1946): 169-82.

[74] For example, if utility shareholders bear the burden of subpar performance, what rewards do they receive when the utility performs exceptionally well? Symmetry seems imperative in achieving "fair" risk bearing.

of their incomes on gas service), (4) efficient consumption (e.g., prices based on marginal-cost principles), (5) efficient competition (e.g., creation of a level playing field), (6) moderate regulatory burden (e.g., streamlining of rate cases), and (7) promotion of specified social goals (e.g., subsidization of renewable energy). These objectives coincide with Bonbright's classic criteria for good ratemaking that most state utility commissions have relied on over the years. Bonbright identified the four primary functions of public utility rates as capital attraction, efficiency, demand rationing, and income distribution.[75]

### (1) Economic efficiency as only one goal

Economists sometimes forget that the main goal of regulation is not merely to promote *economic efficiency*: regulation originated and developed prior to the ideas of economic efficiency and the principles of welfare economics. Most enabling legislation mandates just, reasonable, and fair rates, not efficient rates per se. Throughout the history of state utility regulation, for example, "fairness" is a major consideration in ratemaking. Reasons for why regulators would not maximize economic welfare (i.e., take the most efficient actions to correct market failures), which, incidentally, some analysts associate with the public interest, include: (1) individuals have, besides economic objectives, non-economic objectives (e.g., due process) that are affected by regulation but not accounted for by welfare economics; and (2) political institutions and administrative processes influence regulatory actions. These two reasons can explain why a rational regulator would be unlikely to seek to maximize conventional measures of economic welfare (i.e., the sum of consumer and producer surplus).[76]

### (2) Mixed outcomes from discriminatory pricing

*Discriminatory pricing* occurs when price differences for the same service do not correspond to cost differences. It takes into account customers' willingness to pay, which depends on the ability of customers to find alternative suppliers or to engage in self-supply. A utility may establish a special rate, for example, based on the opportunities of an industrial customer to switch to another fuel. Specifically, it may have to offer a rate below fully allocated costs to customers facing competitive pressures. Discriminatory pricing may help a utility to improve its utilization of existing capacity by offering a lower rate to customers who would consequently increase their usage. It almost always

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[75] See James C. Bonbright et al., *Principles of Public Utility Rates*, 2nd Edition, Public Utilities Reports, Inc., 1988; the first edition, authored solely by Bonbright, was published in 1961.

[76] Societal institutions that govern economic transactions often arise and survive even though they are not economically efficient. They may, instead, focus on political and other noneconomic problems, just as state utility commissions do. *See*, for example, Sheilagh Ogilvie, "Whatever Is, Is Right"? Economic Institutions in Pre-Industrial Europe," *Economic History Review*, Vol. 60, Issue 4 (2007): 649-84.

raises a question of fairness, especially when a favorable rate falls outside a zone of reasonableness. When a rate falls short of a utility's short-run marginal cost or lies above the price that an unregulated monopolist would charge, for example, a commission would likely find the rate impermissible—that is, consider it "undue." There is also the question of who should bear the burden of a revenue shortfall from offering a lower than embedded-cost rate to certain customers.

#### (3) The consequences of risk bearing

*Risk bearing* refers to absorbing the consequences of an unexpected adverse outcome. Most commissions would probably consider undue discriminatory rates, and rates that shift all risks to customers (e.g., preapproval of all costs for a new project)[77] when the utility can better shoulder those risks and have some control over them, to violate a fairness standard. Utility cost recovery in the absence of regulatory oversight would ostensibly (1) be unfair to customers and (2) create a "moral hazard" problem from diminished utility incentives to manage costs.

## V. A Review of Alternative Rate Mechanisms

### A. Grouping alternative rate mechanisms by objective

Alternative rate mechanisms have objectives that supporters usually articulate. Our review turns up ten different objectives. We identify these objectives, along with the rate mechanisms that attempt to address them.[78]

#### 1. Reduce regulatory lag and utility financial risk for operational and investment activities: cost trackers, infrastructure surcharges, future test years, CWIP in rate base, multiyear rate plans, formula rates

Supporters of less regulatory lag contend that it has eroded utilities' rates of return on equity below their authorized returns. Some proponents have argued, for example, that a gap of a 100 basis point or more presents a serious financial problem for a utility. A counterargument is that the subpar rate of return may stem more from less-than-optimal management practices or other factors than from regulatory lag per se. To the extent that a utility's costs rise above test-year levels, a rate-of-return gap can occur.

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[77] As noted earlier, the risk to customers derives from an increase in the probability that they will bear the burden of excessive costs because of the weakened incentive of a utility to control its costs.

[78] *Appendix A* outlines samples of alternative rate mechanisms, highlighting a comparison between the competing revenue decoupling and straight fixed-variable mechanisms.

### a. Cost trackers

*Cost trackers* allow a utility to recover specific costs from customers outside of a general rate case. These costs deviate either from some baseline (e.g., the level of bad debt incorporated into existing base rates) or are zero-based. Utilities recover these costs contingent on some formula or predefined rule.[79]

Utilities have greatly expanded their use of cost trackers in recent years. The list of cost trackers is long.[80] Even though they have not supplanted traditional ROR ratemaking, over the last several years cost trackers have assumed a larger presence in utility ratemaking.

The "extraordinary circumstances" justifying most of the cost trackers that commissions have historically approved encompass costs that are: (a) largely outside the control of a utility, (b) unpredictable and volatile (e.g., unable to estimate the cost within a tolerance level in a general rate case), and (c) substantial and recurring (e.g., the difference between test-year cost and actual cost can materially affect a utility's rate of return). Until the last several years, commissions required that all three conditions exist if a utility hoped to have costs recovered through a tracker. Commissions, consequently, limited the use of cost trackers: The perception was that they created bad ("cost plus") incentives, shifted risk to customers, and were rarely consequential in improving a utility's financial health.

Many of the new cost trackers fail the "extraordinary circumstances" test.[81] Whether these so-called "marginal" cost trackers are in the public interest is hard to say when evaluated against the sphere of regulatory objectives. One concern is that, although they unequivocally benefit utilities and their shareholders, it is less clear how they benefit utility customers.[82] Cost trackers can improve a utility's cash-flow situation and reduce the number of rate cases, but they also can diminish a utility's incentive to efficiently manage its costs.[83]

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[79] Examples of cost trackers are fuel adjustment clauses, purchased gas adjustment clauses, riders for recovery of energy efficiency and environmental abatement costs, property taxes and bad debt.

[80] Some utilities, for example, have more than 20 cost trackers.

[81] *See,* for example, Ken Costello, "How Should Regulators View Cost Trackers?" NRRI 09-13, September 2009.

[82] Some industry analysts would argue that cost trackers are necessary to enable utilities to financially invest in new infrastructure that can substantially benefit customers. Another possible benefit to customers is the preservation of credit ratings that can allow utilities to access capital under the most favorable terms.

[83] Cost trackers can, in various ways, result in higher utility costs. First, they undercut the positive effects of regulatory lag on a utility's costs. Economic theory predicts that the longer

### b. Infrastructure surcharges

*Infrastructure surcharges*[84] allow for cost recovery for large capital projects prior to completion and spread over time, based often on the utility reaching specified milestones.[85] Surcharges can help to avoid drastic one-time rate increases from large projects and mitigate cash flow for utilities by reducing the accumulation of financing costs and regulatory lag.[86] Finally, they allow for more timely cost recovery during construction without a general rate case. On the downside, infrastructure surcharges have the potential for less-than-satisfactory cost performance by utility management when the commission exercises inadequate oversight. They also inherently shift risk to utility customers by requiring them to pay for new projects before completion and operation.

To elaborate, an important incentive for utility cost efficiency is the threat of cost disallowance from retrospective reviews. To the extent that infrastructure surcharges reduce the effectiveness of these reviews, they further erode incentives for cost management. That is, with less regulatory oversight and auditing, which often accompany rate cases, a rational utility might pay less attention to cost management.[87]

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the regulatory lag, the more incentive a utility has to control its costs. Second, when a utility is able to pass through (with little or no regulatory scrutiny) higher costs to customers with minimal financial consequences, it would tend to exert less-than-optimal effort toward controlling costs. An important incentive for cost control by utilities is the threat of cost disallowance from retrospective reviews. To the extent that cost trackers dilute the frequency and quality of these reviews, incentives for cost control further erode. Third, when cost trackers cover some functional areas and exclude others, perverse incentives can arise that would motivate the utility not to pursue cost-minimization of its overall operation.

[84] Infrastructure surcharges come under different labels, including distribution-system improvement charges and capital expenditures riders.

[85] Unlike new power plants or other facilities that have zero value to customers until fully completed, other projects such as gas pipeline replacement programs can benefit customers and public safety prior to full completion. These programs add increments of new pipes continuously over some specified time horizon. Even if it takes, say, the utility five years to finish the program, any new pipes laid prior to that time would have positive safety consequences and result in less lost gas. The "used and useful" standard would, therefore, have less relevance for new pipes replacing old pipes than for a new power plant or other projects that produce no benefits until fully completed.

[86] *See*, for example, Mark Newton Lowry, *Alternative Regulation for Infrastructure Cost Recovery*, prepared for the Edison Electric Institute, January 9, 2007; and the Brattle Group, *Alternative Regulation and Ratemaking Approaches for Water Companies: Supporting the Capital Investment Needs of 21st Century*, prepared for the National Association of Water Companies, September 23, 2013. The latter study showed that infrastructure surcharges, under the labels Distribution System Improvement Charges (DSIC) and Capital Expenditure (Capex) Riders, are almost as common for water utilities as they are for natural gas and electric utilities.

[87] Some infrastructure surcharges try to avoid these problems. The Pennsylvania DSIC Program, for example, places a annual cap (e.g., 5 percent of a utility's distribution revenue) on

Regulators have long recognized the importance of retrospective reviews as a management incentive. Many regulatory experts view retrospective reviews as dissuading a utility from poor decision making with the threat of a penalty—making the utility more diligent and careful in its planning and operations, for instance.

### c. Future test years

*Future test years* (FTYs) are not really new but in a sense are nontraditional, since only a minority of states use them for setting rates. Under a future test year, the utility calculates the required rate increase based on projections for costs and revenues.[88] Rising average cost gives more support for the use of an FTY for ratemaking, although it does not constitute a *sufficient* condition. An FTY mitigates regulatory lag when compared with an historical test year, as the new rates would account for conditions when the new rates go into effect. An FTY, in its purest form, forecasts all the costs and sales elements for the first 12 months of new rates. It would therefore begin after a rate case and normally at the time when new rates would go into effect.

Utility forecasts are, however, susceptible to bias and error.[89] Information asymmetry,[90] which is an acute problem in public utility regulation, complicates the

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the amount recovered, allows a commission audit of costs and construction progress, and requires a utility to submit a five-to-ten year infrastructure improvement plan that the commission must review at least once every five years.

As another example, the Washington Utilities and Transportation Commission approved an infrastructure surcharge for natural gas pipe replacement to address the concern that traditional cost recovery would act as a barrier to a utility's aggressive pipe replacement program. The Commission emphasized that utilities enjoying a surcharge must "meaningfully expedite and improve company performance in their pipe replacement programs." If a utility, for example, fails to meet construction milestones or other targets, it could lose its right to recover costs through the surcharge. *See* Washington Utilities and Transportation Commission, *Commission Policy on Accelerated Replacement of Pipeline Facilities with Elevated Risk, In the Matter of the Policy of the Washington Utilities and Transportation Commission Related to Replacing Pipeline Facilities with an Elevated Risk of Failure,* Docket UG-120715, December 31, 2012.

[88] *See* Mark Lowry Newton et al., *Forward Test Years for U.S. Electric Utilities*.

[89] An observer may ask why a commission should rely on anything other than an FTY, since good ratemaking requires that new rates reflect the utility's costs and sales, at least over the first several months that they are in effect. Ratemaking, after all, is prospective, and an FTY matches the test year with the effective period of new rates. Although in theory this argument seems hard to dispute, it ignores the reality that forecasts are susceptible to error and some costs and sales elements are inherently difficult to predict. Another factor is that utilities would have incentives to present biased forecasts that are not always easy for commission staff and interveners to uncover. A commission would, therefore, be presumptuous to assume that forecasted costs and sales are more accurate than historical test-year data accounting for "known and measurable" changes.

commission task of evaluating a utility's forecasts in terms of their accuracy and objectivity.[91] Without an adequate evaluation, a commission is hard pressed to know whether a utility's proposed rates are "just and reasonable."

### d. Construction work in progress

*Construction Work in Progress (CWIP) in rate base* allows a utility to recover its costs for large capital projects prior to in-service. Specifically, it permits capitalization of the financing cost of CWIP, or Allowance for Funds Used During Construction (AFUDC). Otherwise, AFUDC does not create cash-flow dollars for the utility. Opponents of a CWIP policy point to an intergenerational problem in which current and future ratepayers are not necessarily the same group.[92] Another concern is that ratepayers may not benefit: Even though the total dollar amount collected from ratepayers would decline in the long term, the fact that ratepayers are paying sooner may not reduce their financial obligations when expressed in present value terms.

### e. Multiyear rate plans

A consultant's report contains the following definition of *multiyear rate plans*:

> Multiyear rate plans ("MYRPs") are designed to compensate a utility for changing business conditions without frequent, full true-ups to its actual cost of service. Rate cases are held infrequently, most often at three to five year intervals. Any rate escalations that are made between rate cases are based in whole or in part on automatic attrition relief mechanisms ("ARMs"). The rate adjustments provided by ARMs are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* growth. The "externalization" of ratemaking that these two features of MYRPs achieve can strengthen utility performance incentives despite a reduction in regulatory cost. Benefits of better performance can be shared between the utility and its

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[90] Commissions are at a distinct disadvantage relative to the utility in interpreting and evaluating the utility's performance. Commissions generally lack the knowledge, for example, to detect when the utility is efficient or inefficient, and the opportunities for utilities to minimize their costs. As part of their duties, commissions need to evaluate whether the utility's projected costs reflect competent utility management, or imprudent management.

[91] *See* Ken Costello, "Future Test Years: Challenges Posed for State Utility Commissions."

[92] Current ratepayers who are paying for the plant may move or for some reason will not enjoy the benefits from the project when completed.

customers. Lower regulatory cost has special appeal in jurisdictions where numerous utilities must be regulated. [93]

Supporters of multiyear rate plans point to five benefits: (1) more predictable revenues for utilities, bolstering their financial condition,[94] (2) spreading rate increases over a longer period,[95] (3) more predictable rates for customers, (4) timely recovery of costs for new capital projects, and (5) fewer general rate cases over time. These benefits, although perhaps deemed by some readers to be minimal from the perspective of utility customers, may dominate any downsides, making multiyear rate plans worthwhile to consider.[96]

A potentially serious problem with multiyear rate plans is trying to derive reasonably accurate forecasts over a three- or five-year period. Poor forecasts can lead to extreme utility earnings, either on the high side or low side. These plans also require more time on the part of commission staff and other parties to evaluate them, in addition to increasing the complexity of rate cases.

Multiyear rate plans provide utilities with differing performance incentives, depending on whether allowed rate adjustments derive from forecasted costs for a utility or on indexes that are exogenous to an individual utility's actual costs.[97] The latter approach provides a utility with stronger performance incentives.[98] Most of the real-world plans have "stay out" provisions that provide an additional utility incentive for cost management.

Some plans specify the actual dollar amount of allowed revenue changes for each year, while others depend on a formula or indices to determine allowable annual

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[93] Pacific Economics Group Research, *Alternative Regulation for Evolving Utility Challenges: An Updated Survey*, prepared for the Edison Electric Institute, January 2013, 35.

[94] Supporters also contend that an MYRP prevents "earnings" attrition in that it prevent the erosion of a utility's rate of return that could occur under an historical test year with the past relationship between revenues, expenses and rate base changing in the future.

[95] A plan may call for levelizing rates over (say) the next three years to avoid raising rate drastically over a one-year period or rate shock. Because some of the utility revenues are deferred to a later year, a commission may allow the utility to impute a carrying charge on those revenues.

[96] Some proponents of multiyear rate plans contend that they ease the financial burden on utilities when they invest in new infrastructure that has potential large benefits to customers.

[97] One possible index would apply to O&M costs.

[98] Plans can also include performance standards for customer service, reliability and other functional areas. If a utility falls short of these standards, the commission can penalize it.

changes.[99] Multiyear plans may lessen the need for cost trackers and surcharges, given their automatic (usually annual) base-rate adjustments that mitigate the adverse effect of regulatory lag on a utility's earnings.

To avoid wide financial swings, multiyear rate plans can include an earnings-sharing component that confines the utility's actual rate of return within a narrower range.[100] This feature may diminish a utility's incentive for cost management, but it allows utility customers to reap the benefits of unexpected efficiency gains prior to the next general rate case.[101] It also tempers the extreme effects that could result from large forecasting errors (e.g., exorbitantly high or excessively low utility profits).

#### f. Formula rate plans

A previous NRRI paper defines *formula rate plans (FRPs)* as:

> A ratemaking method in which the utility adjusts its base rates outside of a general rate case, usually annually, based on an actual or projected rate of

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[99] A third group includes hybrid plans that combine features of the other two groups. *See*, for example, ScottMadden, Inc., "Innovative Ratemaking – Multiyear Rate Plans," White Paper, February 2014, 5.

[100] As an example, in 2013 the Washington Utilities and Transportation Commission approved an multiyear rate plan for Puget Sound Energy (PSE), reasoning that the plan will:

> …allow modest annual increases in PSE's rates while requiring that the Company not file a general rate increase before March 2016 at the earliest. This holds the promise of customers paying rates that are lower than might be the case under traditional approaches to ratemaking. The rate plan is designed to give an incentive to PSE to become more efficient and to implement cost-cutting measures that will promote its ability to earn its authorized overall rate of return. The rate plan includes important protections for customers, including an earnings test that requires PSE to share with customers on an equal basis any earnings that exceed its authorized return during the term of the plan. Annual rate increases also are capped at 3.0 percent.

(Washington Utilities and Transportation Commission, *In the Matter of the Petition of Puget Sound Energy, Inc, and Northwest Energy Coalition for an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and to Record Accounting Entities associated with the Mechanisms, Final Order Authorizing Rates*, Dockets UE-130137 and UG-130138, June 25, 2013, ii.)

[101] This feature exemplifies formula rate plans, which this paper discusses next. Both types of plans are comprehensive regulatory mechanisms allowing a utility to change its base rates outside of a general rate case.

return (ROR) on rate base or equity that falls outside some commission-defined band.[102]

FRPs have some advantages over traditional ratemaking, but these advantages rely on the details of design and execution.[103] For customers, they can offer benefits by reducing a utility's business risk, thereby reducing its cost of capital.[104] They can also allow the utility to share with customers prior to the next general rate case a portion of the benefits from cost efficiencies and favorable circumstances. High sales growth and productivity, for example, can produce unexpectedly high profits to a utility. Under traditional ratemaking, the utility would retain these profits until the next rate case. FRPs can distribute some of these profits to customers sooner. They can also moderate rate changes: Instead of a utility filing a rate case proposing a double-digit increase in rates, for example, an FRP could achieve the same increase more gradually over time. The adjustment of rates more frequently and at more moderate levels, however, might not necessarily benefit customers if a utility is able to pass through costs with less review by the regulator.

FRPs contain several features that affect a utility's performance: (1) setting of the initial base rate, (2) the band around the authorized rate of return, (3) sharing of the actual rate of return that lies outside the band, (4) performance standards,[105] (5) monitoring and other reporting requirements, (6) method of cost review (e.g., auditing of costs, determination of prudent costs), and (7) caps on rate adjustments (e.g., 2 percent annually).

One important requisite for FRPs to be compatible with "just and reasonable" rates is that the utility must demonstrate high performance in cost efficiency and non-cost areas of operation integral to consumer well-being. A badly structured plan can produce poor incentives for a utility.[106] For example, a plan should preclude a guaranteed earnings level to a utility, and the "dead band" should be broad enough to motivate a

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[102] Ken Costello, "Formula Rate Plans: Do They Promote the Public Interest?" NRRI 10-11, August 2010, ii.

[103] Examples of FRPs are the plans under different labels for utilities in Alabama, Louisiana, Mississippi, Oklahoma and South Carolina. The American Gas Association refers to these mechanisms as Rate Stabilization Plans.

[104] "Business risk" refers to the uncertainty associated with the operating cash flows of a business; it encompasses sales, cost, and operating risks.

[105] Regulators can establish performance standards for reliability, customer service, and other functional areas whose outcomes depend upon the actions of utility management. Standards address the concern that FRPS might cause a utility to become more lax in its performance.

[106] One concern is that a formula rate plan could increase the chances of a utility passing through imprudent cost to customers.

utility to perform optimally.[107] Critics of formula rates also have argued that they shift risks to customers.

### 2. Reduce the frequency of rate cases: formula rates, multiyear rate plans, future test years

Having fewer rate cases can save both utilities and the commission time and money. Spreading rate cases over too many years (e.g., one rate case every five years), on the other hand, may ignore the reality of changed conditions that warrant a revisit of existing cost allocations, the authorized rate of return and rate designs. Besides, if regulators specify no profit bounds, utilities' earnings could turn out abnormally high.

### 3. Eliminate disincentive for energy efficiency: revenue decoupling riders, declining block rates, straight fixed-variable rates

#### a. Revenue-decoupling riders

Under a *revenue-decoupling rider*, the utility adjusts its rates between rate cases for sales deviating from some baseline level; for example, periodic adjustment of rates for a gap between actual sales and test-year sales per customer. If a utility's actual sales per customer over a specific period fall below the level embedded in existing rates, the utility could increase its rates to compensate for the revenue shortfall.[108] This mechanism helps to stabilize a utility's revenues and earnings, making it more indifferent to the level of actual sales and thus removing any financial harm from energy efficiency.

Three conditions would support revenue decoupling: (a) the utility's limited ability to add new customers in growing sales; (b) the commission's reluctance to recognize declining consumption per customer in setting base rates because of statutory or commission restrictions on *pro forma* adjustments to include only "known and measurable changes" to a historical test year;[109] and (c) a commission's requirement for a utility to promote energy efficiency.

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[107] The band should be wide enough so that the utility can retain a higher ROR that could come from improved cost performance, or absorb a lower ROR that could come from lower cost performance. A wider band provides a utility with better incentives for cost performance. The incentives for a utility operating within the band are comparable to those incentives a utility faces between rate cases under traditional ROR ratemaking.

[108] Symmetrically, revenue decoupling could cause rates to declines when sales exceed the test-year level.

[109] In other words, the sales used in the test-year calculation may lack accuracy, other things held constant, resulting in the utility under-recovering or over-recovering its fixed costs that the commission previously deemed prudent.

Although revenue decoupling is not without controversy, it is arguably in line with the "balancing act" of regulation by not seriously violating any core regulatory objective: They do not create the incentive problems of cost trackers or the price discrimination of some other rate mechanisms. They also do not cause a utility to earn excessive returns or to pass along imprudent costs to customers. In fact, they reduce the possibility of the former outcome. Revenue decoupling also reduces the need to accurately calculate test-year sales in a general rate case. The major concern with revenue decoupling is that, while ostensibly beneficial to a utility, the gains to customers are less transparent.[110]

We should expect to see more proposals for revenue decoupling in the years ahead, especially by electric utilities. Two reasons are declining sales growth and even negative growth, and the expansion of distributed generation.

### b. Declining block rates

*Declining block rates* have been disfavored by most commissions and stakeholders for a number of years, mainly because they encourage more consumption. They can, however, overcome some of the problems with existing rate structures, avoiding the need for alternative rate mechanisms such as revenue decoupling.[111] For example, with shrinking consumption per customer, they can cause customers to shift to a higher rate block that would offset at least a portion of a utility's revenue losses.

When first introduced early last century, declining rate structures allowed utilities to recover their fixed costs in the initial blocks; the effective rates for later blocks closely correspond to commodity costs (i.e., short-run marginal cost). This rate structure allowed a utility to become more competitive with other energy sources and to promote its sales by giving larger users a lower marginal price. It is the last effect that has met with opposition by those who favor energy efficiency. Yet, because of the abundance of shale gas, reverting to a rate structure that encourages consumption, such as declining block rates, may have some merit for the natural gas sector.

### c. Straight fixed-variable rates

Under *straight fixed-variable (SFV) rates*, the utility recovers all of its fixed costs, both customer and demand related, through a fixed monthly charge that is independent of customer usage. The utility recovers all of its variable costs (i.e., costs that vary with the quantity of service) through a volumetric charge. In contrast, under the standard or

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[110] This is probably one reason why many consumer advocates have opposed revenue decoupling, sometimes with great vigor, in rate cases.

[111] *See*, for example, Stephen J. Brown and David S. Sibley, *The Theory of Public Utility Pricing* (Cambridge, UK: Cambridge University Press, 1986), 93-6.

typical two-part tariff, utilities recover a portion of their fixed costs in the volumetric charge.[112]

Similar to a revenue-decoupling rider, this rate design separates a utility's earnings from its actual sales. It provides customers with efficient price signals.[113] It also removes any utility disincentive to promote energy efficiency, since any revenue declines would equal avoided costs.[114]

Compared to the standard two-part tariff, this rate structure would increase the utility bills of low usage customers and decrease the bills of high usage customers; it would also tend to reduce winter gas bills and increase summer gas bills.[115] Finally, compared to the standard two-part tariff, this rate structure reduces the benefits to consumers from using less electricity or gas.

In sum, SFV rates have two image problems, which explain their rare use in real-world state-commission utility pricing. First, the perception is that they would disproportionally hurt low-income households.[116] The presumption is that low-income households are below-average users of energy, which empirical evidence does not unequivocally support.[117] Second, in some quarters, SFV rates are anti-conservation. The argument is that customers will see lower rates on the margin, discouraging some customer-initiated energy efficiency that would otherwise occur.[118] The counterargument is that the SFV rates give customers better price signals to make decisions on how much to invest in energy efficiency.

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[112] *See* the earlier discussion in Part III.B.2.

[113] The Federal Energy Regulatory Commission (FERC) has adopted SFV rates for gas pipelines for three reasons. They (a) induce maximum throughput, (b) allow pipelines and natural gas in general to better compete with alternate fuels, and (c) reduce peak demand and the need to expand pipeline capacity over time.

[114] For a variant of SFV rates that has sparked debate, *see* David Magnus Boonin, "A Rate Design to Increase Efficiency and Reduce Revenue Requirements," *The Electricity Journal*, Vol. 22 (May 2009): 68-78.

[115] This outcome would help to better balance monthly gas bills over the course of a year.

[116] Even if low-income customers consume below-average levels of utility service, a utility could offer them a discount on the fixed monthly charge to buffer any bill changes that would otherwise exit when switching to a SFV rate.

[117] Consumer advocates generally oppose SFV rates because they believe that small users would see higher utility bills.

[118] For this reason, conversationalists and environmentalists have publicly come out in opposition to SFV rates; they tend to favor revenue-decoupling riders as the preferred alternative to remove utility disincentive for promoting energy efficiency.

### 4. Make utility service affordable to low-income customers: inverted rates, rate discounts, percentage-of-income plans

#### a. Inverted rates

*Inverted rates* have two major objectives: (1) promote energy conservation by increasing rates for high usage, and (2) provide for affordable level of utility service to meet basic human needs, often referred to as lifeline rates. As shown later, they have dubious features that have hampered their acceptance by utilities and regulators. California is a case study in how inverted rates can have adverse consequences.[119] Few states have adopted inverted rates, for good reason.[120]

#### b. Rate discounts

An example of a *rate discount* is the utility giving eligible low-income households a discount of 30 percent off the rates the utility charges other residential customers. If other customers pay a price of 10 cents for each additional kWh consumed, for example, low-income households would pay 7 cents. One form of rate discounts might involve larger discounts for smaller energy use. A household could receive a discount of 40 percent if it consumes fewer than 500 kWhs per month, while its discount falls to 30 percent when it consumes higher amounts. One real-world example is California's Alternate Rates for Energy program (CARE). This program provides eligible low-income customers with a 20 percent rate discount on their electric and natural gas bills. All other utility customers fund the CARE program through a rate surcharge.

#### c. Percentage-of-income plans

*Percentage-of-income plans* limit the utility bills of eligible low-income households to a predetermined percentage of their income. The premise is that affordability inversely relates to how much households pay for energy relative to their incomes. Such a plan, for example, may require that eligible households pay no more than 15 percent of their income toward natural-gas service during the winter heating season. The benefits to customers would depend upon both their income and their unsubsidized utility bill. Both lower-income customers and customers with higher utility bills, in other words, benefit the most.[121]

### 5. Promote renewable energy: net metering rates

Some utilities are calling for a revisiting of the traditional utility rate model along with *net metering rates*, because of the penetration of rooftop solar PV systems as a form

[119] A later section of this paper describes these consequences.

[120] For a more thorough critique of inverted rates, *see* Part VI.G.

[121] *See* Ken Costello, "How to Determine the Effectiveness of Energy Assistance, and Why It's Important," NRRI 09-17, December 2009.

of distributed generation, for the following reasons[122]: (a) Many solar customers are paying higher than cost-based rates for utility electricity service—California is a prime example with its inverted rate structure; (b) most jurisdictions lack revenue decoupling or a straight-fixed variable rate design to break the link between sales and profits; (c) most jurisdictions lack a standby rate to pay for transmission and distribution costs for backup service; (d) no jurisdiction allows accelerated depreciation whereby a utility can more quickly recover stranded assets; (e) the net metering rate, in most instances, does not relate to a utility's actual avoided costs; and (f) lower-income customers tend to subsidize solar customers, who generally have higher incomes.

Net metering rates are a clear example of where regulators need to weigh the benefits of accelerating the development of PV solar systems against the costs of impeding other regulatory objectives. Some of these objectives lie at the core of utility ratemaking, including equity and utility financial stability.

### 6. Prevent uneconomic bypass and ease the ability of the utility to compete in certain markets: flexible rates, special contracts

#### a. Flexible rates

*Flexible rates* allow a utility to charge a price to certain customers within a specified range. A commission would designate a price ceiling and floor within which a ratemaking practice often follows competitive market conditions, compelling a utility to offer some customers a special rate that falls below the standard or fully allocated cost rate.[123]

A flexible rate can help deter uneconomic bypass where a customer switches to a competing fuel or retail marketer when the economic cost of the alternate provider is greater than the cost of local utility service. Flexible rates are similar to the long-standing value-of-service rates in taking into account the demand characteristics of customers.

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[122] Net metering rates can also apply to other technologies, such as gas-fired distributed generation.

[123] Assume that a utility provides service to two customers and its total cost is

$$TC = v_1q_1 + v_2q_2 + f_1 + f_2 + F$$

Where v = variable cost (i.e., short-run marginal cost), q = sales, f = assignable fixed costs (e.g., dedicated substation), 1 and 2 denote the two services offered by the utility, and F = common costs (e.g., distribution system).

The price for each service ($p_1$ and $p_2$) is set such that the revenue collected is $p_1q_1 + p_2q_2 = TC$, $p_1q_1 = v_1q_1 + f_1 + \alpha_1 F$, and $p_2q_2 = v_2q_2 + f_2 + \alpha_2 F$. The utility recovers its cost and the regulator fully allocates the common costs to each service, using some demand factor (e.g., coincident peak demand), measured by the shares $\alpha_1$ and $\alpha_2$. In offering a lower rate (say) to service 1, service 2 is responsible for recovering more of the common cost; that is, the actual share for service 2 is greater than $\alpha_2$ and the actual share for service 1 is less than $\alpha_1$.

One issue relates to eligibility for a discount rate: Establishing a broad set of customers who can qualify could lead to a "free rider" problem, in which some customers would receive a windfall gain from a lower rate for doing nothing differently than what they would otherwise have done. To avoid this problem, a utility should target discount rates to only those large customers who have demonstrated the need for rate relief to continue operating at the same site or, for example, to not self-generate their electricity.

Flexible rates are undoubtedly discriminatory in that the utility charges different rates to customers in the same class (within the zone of allowable rates). Flexible rates raise the question of who should bear the cost of discounts (i.e., revenue shortfalls relative to fully allocated cost revenues)—utility customers, utility shareholders, or both groups sharing the costs?[124]

#### b. Special contracts

Under a *special contract*, the utility negotiates with a large business or industrial customer for a favorable rate and other terms and conditions. Usually the customer has service alternatives and faces unique circumstances that may compel a utility to offer the customer a special deal (e.g., favorable non-price terms and conditions). The customer might otherwise leave the utility service area, not expand its business, or close its business. Special treatment to an individual customer represents a discriminatory action, but one that regulators can justify under certain conditions.

### 7. Optimize energy usage over different times or reduce a peaking problem: time-of-use pricing, critical peak pricing, real-time pricing, seasonal pricing

#### a. Time-of-use pricing

*Time-of-use pricing* differentiates prices by time periods, but the prices are predetermined and fixed between general rate cases. Prices are typically higher during peak periods and lower at off-peak periods. Although they can create capacity benefits, time-of-use prices largely focus on reducing a utility's energy cost. They can also promote certain technologies, such as distributed energy storage, plug-in electric vehicles, and rooftop solar PV systems.[125]

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[124] Utilities tend to support utility customers paying for shortfalls, arguing in part that the rate discount allows utilities to retain customers or at least to increase their sales over what they would otherwise. As long as utilities are recovering some of their fixed costs from these customers, other customers are better off. This argument presumes no "free riders"; that is, the rate discount actually avoids customers departing or lost sales from customers who stay on the utility system (e.g., a factory that added a shift because of a lower electricity rate).

[125] For example, a cost-based off-peak rate could improve the competitiveness of electric vehicles, inducing more consumers to switch from gasoline vehicles or not to switch to natural gas vehicles.

### b. Critical peak pricing

Under *critical peak pricing* (CPP), the utility substantially raises its prices during "critical peak periods," or certain hours during event days.[126] The goal is to reduce load during those few hours within which the utility has exceptionally high generating or power-purchasing costs.[127] The benefit to customers is that they receive lower prices during non-critical periods relative to the standard tariff. The utility usually notifies customers in advance of a critical peak event and caps the number of events per year. CPP is simple to implement, and customers pay high prices in only a small number of hours. It biggest drawback lies with resistance to the utility setting extremely high prices during "stress" periods, which can seriously burden some customers.

### c. Real-time pricing

*Real-time pricing* (RTP) sets rates at fine intervals (e.g., hour-to-hour) in line with a utility's marginal costs during those times.[128] It is the economist's ideal form of utility pricing. A major factor is the hourly change in wholesale cost.[129] Customers receive price signals from the utility in advance.[130] Many analysts consider RTP to be crucial in linking wholesale prices to the retail price of electricity, thus giving utility customers proper price signals. The consequence is an efficient level of total demand and efficient allocation of electric power across hourly periods. A utility benefits from a lowering of its energy and capacity costs. RTP can also help integrate renewable energy into an electric grid by creating load flexibility during all hours of the day.

Notwithstanding the strong theoretical appeal for RTP along with the generally positive empirical evidence, we have seen relatively little use of this pricing method at the state level.[131] Even in states that have open retail markets, there has been a resistance to RTP by state regulators, consumers, and even utilities.

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[126] For some CPP programs, prices during critical periods might be as much as five times higher than the average peak price.

[127] A major benefit to the utility is capacity deferral and the reduced probability of shortfalls.

[128] Real-time pricing is sometimes referred to as dynamic pricing.

[129] Controversy arises over the correct definition and measurement of marginal cost. Marginal cost can include the value of lost consumption from inadequate capacity during extreme conditions.

[130] Unlike early vintage time-of-use prices, which the regulator approves in a previous rate case, real-time prices better reflect a utility's actual costs across different periods.

[131] Pilot programs for RTP have shown that customers do respond to price and that the benefits exceed metering and other incremental costs associated with RTP. For example, RTP

One possible barrier to RTP is the wide acceptance of average-cost pricing in public utility regulation. A hallmark of state regulation is the setting of prices based on embedded historical cost. This pricing methodology precludes customers from having to pay fluctuating prices—for example, higher prices during peak periods and other periods of tight supplies.[132] Regulators have also expressed concern that some consumers would not shift load to lower-priced periods and thereby drive up the average price of electricity they pay and their utility bill. Even if consumers do shift their load, regulators may conclude that the benefits would still fall short of metering and other costs.

#### d. Seasonal pricing

Under *seasonal pricing*, a gas utility would charge higher rates during the winter months when demand and marginal cost are at their maximum. For an electric utility, rates would typically be higher during the summer months. This pricing (1) gives consumers better price signals (relative to uniform rates), (2) results in a more efficient use of a utility system's facilities, and (3) requires no special meters. Yet some stakeholders have opposed, and some state commissions have rejected, seasonal pricing because of rates being at their maximum during periods of peak consumption. Higher utility bills during peak periods have met with public scorn and negative media coverage.

### 8. Lessen the price rigidity of regulation and promote cost efficiency: price caps

*Price caps* establish allowable price changes, usually annually, based on the change in some specified price index (e.g., consumer price index) minus the change in expected or targeted productivity.[133] They permit utilities to price below the cap when

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requires electricity smart meters that can send and receive information about electricity costs and give consumers more timely information about their own usage.

[132] Depending on the specific design, such pricing can result in highly volatile prices that a commission may believe would lead to widespread public opposition. *See*, for example, Ken Costello, "An Observation on Real-Time Pricing: Why Practice Lags Theory," *The Electricity Journal*, Vol. 17, No.1 (January-February 2004): 21-25.

[133] A generic price-cap formula subtracts from a specified price index (PI) a productivity measure (X) or offset:

$$\%\Delta P = \%\Delta\ PI - \%\Delta\ X$$

The allowed percentage increase in price ($\%\Delta$ P) equals the percentage increase in some specified price index ($\%\Delta$ PI) minus the percentage increase in productivity ($\%\Delta$ X). Productivity growth, for example, could reflect the average historical gains for a peer group of utilities. Alternatively, it could measure technological improvements for an industry or for the economy as a whole. The price index could encompass a broad range of commodities that are either regional or national in scope. One candidate is the Consumer Price Index. For a discussion of price caps, *see* Janice A. Hauge and David E. M. Sappington, "Pricing in Network Industries," In *The Oxford Handbook of Regulation*, ed. Robert Baldwin, Martin Cave, and Martin Lodge, 462-499 (Oxford, UK: Oxford University Press, 2010).

warranted by market conditions (e.g., retaining a large customer with a lower rate who would otherwise self-generate or switch to another provider).[134]

Compared with traditional ratemaking, a utility would have a stronger incentive for cost efficiency since (1) price changes do not depend on the actual costs of a utility and (2) rate reviews take place at predetermined multiyear intervals prescribed by regulators.[135] The focus shifts from "inputs" to "output," which should improve the utility's incentive to be more efficient.[136]

In its pure form, price caps regulate a utility's prices but not its profits. They represent a fundamental break from traditional ROR regulation.[137] In practice, however, many price-cap plans include an earnings-sharing component. One reason is that regulators are reluctant to make a full commitment to allow unconstrained profits between general rate reviews.[138]

Because price caps give utilities robust incentives to manage costs, in many real-world plans the regulator sets reliability/customer-service standards. One common approach taken by regulators is to penalize a utility for falling short of the pre-specified standards, but not to reward it for superior performance. The presumption is that a utility should not earn a reward for fulfilling a primary obligation, namely, providing high service quality.

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[134] One criticism of ROR regulation is its price rigidity, which may prevent a utility from responding in a timely manner to changing market conditions, thereby losing customers or sales.

[135] In effect, prices caps involves commission-determined regulatory lag; for example, once the commission sets the initial rate, the utility cannot file another rate case for five years. Under ROR regulation, utilities control the timing of rate cases.

[136] For a general discussion of price caps, *see* Wayne P. Olson and Kenneth W. Costello, "Electricity Matters: New Incentives in a Changing Electric Services Industry," *The Electricity Journal*, Vol. 8 (January-February 1995): 28-40; and Mark Newton Lowry and Lawrence Kaufmann, *Price Cap Regulation of Power Distribution*, report prepared for the Edison Electric Institute, June 1998.

[137] As a rule, the "ratchet effect" would affect utility behavior under price caps any time the utility expects the current benefits from increased efficiency to be "taken away" in the form of lower future prices. If so, utility incentives to control costs would closely resemble those under rate-of-return regulation.

[138] *See*, for example, Larry Blank and John W. Mayo, "Endogenous Regulatory Constraints and the Emergence of Hybrid Regulation." The authors argue that, partially because of political and stakeholder pressures, utility regulators will lean toward hybrid forms of regulation that combine elements of price caps and ROR regulation.

### 9. Avoid rate shock: infrastructure surcharges, CWIP, phase-in

*Phase-in plans* involve a gradual or delayed inclusion of capital costs in rate base, relative to cost recovery under traditional ratemaking. Although they provide high certainty that a utility will eventually recover all of its allowable costs and return on investment, phase-in plans require deferral of those costs to future periods. Thus, they pose something of a risk for utility shareholders, especially if the magnitude of costs is large.[139] On the positive side for utilities, deferring certain costs as a regulatory asset avoids the utility's having to write-off these costs in the current period, which would harm investors.

### 10. Promote specific activities: focused performance-based ratemaking, special pricing

#### a. Focused performance-based ratemaking

*Focused performance-based ratemaking* (or "incentive mechanisms") aims to provide utilities with strong incentives, properly aligned with customers' interests, to perform exceptionally well a particular function. One desirable outcome is less need for detailed regulatory review of utility decisions. A well-structured incentive mechanism awards and penalizes a utility appropriately for consequences that reflect superior or subpar performance.

Incentive mechanisms have three basic components: (1) the target or standard, (2) the sizes of the rewards and penalties (e.g., the share of "gains" and "losses" allocated to utility shareholders and customers), and (3) the maximum rewards and penalties to the utility. Incentive mechanisms sometimes include a "dead band." A "dead band" recognizes the inherent uncertainty over identifying a correct benchmark. Incentive mechanisms can also include waivers or exceptions for certain events beyond the control of a utility.[140]

A poorly structured incentive mechanism can lead to unintended consequences. Specifically, strategic behavior or gaming by a utility can result in a zero-sum outcome or, worse, distortive utility behavior. The former outcome allocates all the benefits to the utility while producing no real gains for its customers. Distortive utility behavior reduces efficiency as the utility devotes excessive resources to the targeted area, which decreases the overall performance of the utility. An incentive mechanism can also unfairly harm the utility when the benchmark is set at a value that makes it highly difficult for the utility to surpass or even achieve.[141]

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[139] This is a reason why Wall Street has always expressed trepidation toward phase-in plans.

[140] Such exceptions can weaken the incentives underpinning a mechanism.

[141] *See* Ken Costello and James F. Wilson, "A Hard Look at Incentive Mechanisms for Natural Gas Procurement," NRRI 06-15, November 2006.

### b. Special pricing

*Special pricing* involves deviating from normal ratemaking practices to bolster a particular activity or regulatory objective. One recent example is rolled-in pricing to encourage the expansion of natural gas service to unserved areas. Traditional regulatory policy requires that new customers pay for the uneconomical costs associated with gas-line expansions, not only to protect existing customers but also to prevent the utility from suffering any financial harm.[142] This policy coincides with the principle of incremental cost pricing that allocates additional costs to those customers who directly benefit. The general perception is that since new customers are the major beneficiaries of gas-line extensions, they should pay the bulk of the costs.[143] With the abundance of shale gas, however, some commissions and other policymakers are contemplating whether rolled-in pricing[144] is justifiable, since energy consumers' switching to natural gas could have potentially large public benefits (e.g., economic development, cleaner environment).[145]

## B. How each rate mechanism affects regulatory objectives

The evidence on the effects of individual rate mechanisms can derive from various sources, namely, economic theory, real-world experiences, and other empirical evidence. Some effects are more transparent and obvious than others. Many of the more recent alternative rate mechanisms have difficulties in quantifying, or even conceptualizing, the benefits to utility customers. Some mechanisms definitely improve the financial health of utilities, and others benefit specific customers and advance, for example, energy efficiency and renewable energy. Commissions often know the

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142 This policy passes what economists call the "no burden test" to protect existing customers. That is why, for example, most utility tariffs require new customer contributions and specific economic tests for assessing proposals to extend gas lines. As a rule, when a utility receives revenues from new customers greater than the incremental cost, existing customers are better off. The revenues from new customers can filter through rates and a separate surcharge.

143 State utility commissions generally approve rolled-in pricing when a new investment benefits all customers or when demand by all customers creates the need for a new investment. When the utility expands its system dedicated to serving new customers, on the other hand, rolled-in pricing becomes less defensible and incremental pricing more valid. The addition of new customers, at least in theory, can benefit existing customers. A concept called "economies of scope" says that by providing another service—for example, service to new customers—a firm might more efficiently use its internal resources. As an illustration, with added customers, a utility might lower its average cost for information technology activities, general personnel, billing, and metering. The result is a lowering of the utility's average cost, which benefits all customers, both new and existing. For new gas distribution lines, these broad benefits are probably small.

144 For a definition of rolled-in pricing, *see* footnote 45.

145 *See* Kenneth W. Costello, "Exploiting the Abundance of U.S. Shale Gas: Overcoming Obstacles to Fuel Switching and Expanding the Gas Distribution System," *Energy Law Journal*, Vol. 34, No. 2 (2013): 541-87.

positives and negatives of different rate mechanisms, in general if not precise terms, as they relate to individual ratemaking objectives, but they grapple with knowing which ones are preferable from a public-interest perspective.

Four basic questions confront state utility commissions in their ratemaking duties:

- *What are the objectives of ratemaking and their relative importance?* Objectives are desirable outcomes, such as strong utility incentives for cost control, high probability of utility receiving sufficient revenues, and prices based on marginal-cost principles.

- *What rate mechanism or group of mechanisms would be most effective in achieving those objectives?* Good regulation requires that rate mechanisms achieve specific objectives with minimum impediments to other objectives. For example, cost trackers should minimize the risk to customers from paying for imprudent utility costs.

- *Perhaps most fundamental, what rate mechanism would be both fair to the utility and most beneficial to customers?* How can a formula rate plan or a cost tracker, for example, produce a non-zero-sum outcome (i.e., result in benefits to both the utility and its customers)? As its primary objective, a rate mechanism should promote the long-term interests of utility customers.

- *What are the expected outcomes from individual rate mechanisms, especially in terms of economic efficiency?*[146] Improvements in economic efficiency are important because potentially all stakeholders can benefit.

Table 2 lists different rate mechanisms, along with their positive and negative features in advancing different regulatory objectives. The right-hand column contains general comments that summarize each rate mechanism. Table 3 identifies those rate mechanisms that seem to best advance and impede individual regulatory objectives.

The two tables reflect the author's perception of the disparate effects of individual rate mechanisms on regulatory objectives. The reader may take issue with some of the author's statements, and that is valid, as many of them are inconclusive and subject to a degree of conjecture. Equally knowledgeable people can have different views on individual rate mechanisms, just as regulators do. It is for this reason that ratemaking is as much art as science. Whether ratemaking changes, or what some observers call "reforms," have improved overall utility performance and long-term customer welfare

[146] Utility rate structures are inefficient perhaps not so much as a result of the low weight that regulators place on economic efficiency relative to other objectives, but because of failure of regulators to understand what is inefficient and socially harmful about existing rate structures. It seems plausible that regulators fail to understand well the negative consequences of inefficient pricing, or if they do, they do not consider them that important, at least relative to other regulatory objectives, such as utility financial security, fairness, and risk allocation between the utility and its customers.

lies outside the scope of this paper. There is presently a high ratio of hypothesis to empirical evidence on the effects of different rate mechanisms.

This paper excludes the advocacy of individual rate mechanisms. It, instead, assumes the less ambitious task of identifying and examining alternative rate mechanisms that have surfaced in state utility-regulation proceedings over the past several years. It focuses on how each mechanism affects the various regulatory objectives, including core and secondary objectives. This paper takes the position that rate mechanisms are desirable only if they satisfy the objectives set out by regulators.

As Table 2 shows, all rate mechanisms have mixed effects on the public interest. We presume that when a rate mechanism impedes a particular regulatory objective, it sets back the public interest, while advancing an objective improves the public interest. One example is cost trackers or riders in which the tradeoff exists between timely utility cost recovery and tolerable customer risk: Trackers and riders allow utilities to recover their costs more quickly and with more certainty (i.e., to become more financially healthy), but as mentioned earlier in this paper, they also can create incentive problems that could drive up the cost of utility service. Since this document is not advocacy-oriented in nature, the author takes no position on whether cost trackers or other rate mechanisms are in the public interest. It highlights the fact that regulators must make trade-offs when deciding on rate mechanisms such as cost trackers.

**Table 2: Different Effects of Rate Mechanisms on Regulatory Objectives**

| Rate Mechanism | Positive | Negative | General Comments |
|---|---|---|---|
| **Traditional ROR ratemaking** | Emphasis on due process<br>Focus on utility prudence<br>Simple for public to understand<br>Perception of fairness<br>Avoidance of undue price discrimination<br>Strong utility incentive for cost management between rate cases<br>Long-standing core ratemaking paradigm | Pricing rigidity<br>Disincentives for promoting certain social goals, such as utility-initiated energy efficiency<br>Excessive regulatory lag under high inflation and stagnant sales growth<br>Inefficient average-cost pricing<br>Weak long-term utility incentives for cost management<br>Weak utility incentive for innovations (assuming rigid profit controls) | Strongest justification under stable market and utility operating conditions<br>Many “negatives” have minimal consequences under stable conditions<br>Problems arise in a dynamic environment<br>Throughout its history, traditional ROR ratemaking has endured attacks from different stakeholders<br>Although modified over time, traditional ROR ratemaking still dominates state utility ratemaking<br>Most other countries reject U.S.-style traditional ROR |

| Rate Mechanism | Positive | Negative | General Comments |
|---|---|---|---|
| | | Frequent rate cases in a dynamic environment<br>Incentive for excessive capital investments<br>High regulatory costs | ratemaking |
| **Future test year** | Representative of costs and sales in a rate year<br>Mitigation of utility financial problems under dynamic conditions<br>Efficient price signals<br>Less frequent rate cases<br>Fairness to utilities in a dynamic market environment<br>Mitigation of rate shock from annual levelized revenue increases | Forecasts susceptible to error and some costs and sales elements inherently difficult to predict<br>Burden for parties to validate the accuracy and reasonableness of utility forecasts<br>Utility exploitation of information asymmetry problem, resulting in biased forecasts<br>Reduced regulatory lag for incenting utility cost efficiency | Justification increases in the absence of other regulatory-lag mitigating ratemaking mechanisms (e.g., CWIP in rate base, revenue decoupling, trackers)<br>The appropriate test year requires an assessment of the unique risks associated with each one (Type I and II errors)<br>The majority of states do not use a future test year, but more states have allowed it in recent years<br>There remains deep opposition to future test years by some commissions and consumer advocates<br>Information asymmetry is a serious problem |
| **Infrastructure surcharge** | Avoidance of rate shock or large one-time rate increases<br>Mitigation of cash flow and other utility financial problems<br>More timely cost recovery without a rate case<br>Well-suited for non revenue-creating investments | Potential for imprudent utility performance and risk shifting to utility customers | Surcharges have proliferated in recent years<br>Increasingly, state legislatures have allowed or mandated commissions to use surcharges<br>They are more appropriate for new projects, such as gas pipeline replacement programs, that do not create additional utility revenues<br>Commissions generally, and rightly so, require audits, the meeting of milestones and other benchmarks for early cost recovery |
| **Cost tracker** | Reduced utility financial risk<br>Reduced frequency of rate | Potential for imprudent utility performance and risk shifting to utility | Trackers have proliferated over the past several years, even for |

| Rate Mechanism | Positive | Negative | General Comments |
|---|---|---|---|
| | cases | customers<br><br>Perverse utility incentives for cost management | minor cost items<br><br>Commissions have approved them, for example, even if they fail to meet the traditional three-pronged test<br><br>Commissions staff and other parties may find it difficult to evaluate costs when given a short time for review |
| **Formula rate plan** | Reduced utility financial risk<br><br>Sharing of abnormal profits between rate cases<br><br>Less frequent general rate cases<br><br>Avoidance of single-issue ratemaking and perverse incentive problems with cost trackers<br><br>More moderate rate changes compared with traditional ROR ratemaking | Questionable incentives for utility cost management because of (a) reduced regulatory lag and (b) less scrutiny of utility costs<br><br>Downsides of less frequent general rate cases<br><br>Additional reporting and monitoring requirements | Formula rates are concentrated in the Southeast for setting rates for both electric and gas utilities<br><br>Existing plans have generally met with satisfaction from stakeholders as well as the commissions<br><br>It is somewhat surprising that we don’t observe more formula rate plans to replace the large number of cost trackers that many utilities have<br><br>Some economists favor price caps and multiyear rate plans (with indexing) over formula rates, largely because of the incentive effect |
| **Multiyear rate plan** | Reduced frequency of rate cases<br><br>More predictable rates<br><br>Strong performance incentives with industry or economy-wide indexes to adjust annual rates<br><br>Utility recovery of capital costs for new projects without filing a separate rate case | Potentially wide profit variability<br><br>Reliance on multiyear forecasts of costs and sales | Some new interest in a few states<br><br>The performance incentives depend on whether annual rate changes relate to actual utility costs or to an “exogenous” index<br><br>Earnings-sharing component can reduce profit variability caused by erroneous forecasts |
| **Price cap** | Robust incentives for utility cost management<br><br>Increased pricing flexibility<br><br>Regularized commission-determined general rate cases<br><br>Decline in real prices, | Potentially wide profit variability<br><br>Skeptical public<br><br>Potential for excessive price discrimination<br><br>Incentive to cut costs | Since the 1990s, price caps have received little interest<br><br>Much more popular in other countries, which have found them preferable to U.S.-style ROR regulation<br><br>Maine has, by most accounts, |

| Rate Mechanism | Positive | Negative | General Comments |
|---|---|---|---|
| | assuming productivity growth | jeopardizing utility service quality | successfully applied price caps for electricity regulation since the mid 1990s<br>Price caps typically include service quality standards and often a earnings-sharing component<br>The "ratchet effect" reduces the incentives for cost efficiency under price caps resembling those for ROR regulation |
| **Revenue decoupling rider** | Enhanced utility earnings stability<br>Reduced frequency of general rate cases<br>Mitigation of utility disincentive for energy efficiency initiatives<br>Fairness to utility in recovering prudent fixed costs<br>Lessened importance of sales calculations in a general rate case | Skeptical public<br>Second best approach to addressing utility disincentives for energy efficiency<br>Weakened incentive for sales growth when warranted by market and utility operating conditions | Most popular in the natural gas sector but increasing in number for electric utilities<br>Most commissions prefer revenue decoupling riders over its closest rivals, straight fixed-variable rate design and lost revenue adjustment mechanisms<br>Revenue decoupling seems to not seriously violate any core regulatory principles and is compatible with the "balancing act" aspect of public utility regulation<br>Empirical evidence have shown typically small annual rate adjustments, with many decoupling plans adjusting rates downward as well as upward |
| **Performance incentive for energy efficiency** | Level playing field for utility energy-efficiency initiatives compared with supply side alternatives<br>Increased utility motivation for promoting energy efficiency | Potential for perverse incentives<br>Motivation for non-cost effective utility energy-efficiency initiatives<br>Difficult to construct an appropriate benchmark | Incentives for energy efficiency have increased in recent years<br>As energy efficiency grows and becomes a core function, utilities will likely propose incentives in addition to revenue decoupling and cost trackers<br>Some evidence that utilities with performance incentives tend to be more proactive in promoting energy efficiency |
| **Flexible rate** | Avoidance of uneconomic | Potential "free rider" problem allowing | Several utilities have special contracts or rates to |

| Rate Mechanism | Positive | Negative | General Comments |
|---|---|---|---|
| | bypass<br><br>Increased utility competitiveness in non-captive markets<br><br>Potentially higher total utility profits in the absence of "free riders" | recipient "windfall"<br><br>Price discrimination that allocates more of the utility's fixed costs to small customers<br><br>Poor substitute for more efficient rate design | accommodate the needs of industrial customers<br><br>Commissions usually specify conditions for utilities to offer flexible rates that include (1) rates must not fall below short-run marginal cost and (2) the customer financially needs a special rate to not relocate or close down |
| **Inverted rate** | Promotion of energy efficiency<br><br>Assistance to low-usage, low income households<br><br>Promotion of economic efficiency assuming<br><br>cost-based tiers | Increased revenue risk for the utility<br><br>Uneconomically inefficient with non cost-based tiers<br><br>Problematic to charge two customers different rates at any one time when the utility incurs the same marginal cost in serving both | Inverted rates are not widespread in the U.S.; they have been most popular in California<br><br>They have led to unintended consequences in California with net metering rates designed to benefit solar PV systems |
| **Discounted service to low-income households** | Affordability of utility service to more customers<br><br>Improvement of utility arrearage/bad debt problem<br><br>Reduced utility costs for disconnections<br><br>Increased reconnections | Higher rates for general ratepayers<br><br>Excessive consumption by targeted customers<br><br>Price discrimination based on the ability-to-pay principle | Several states have special rates for eligible low-income households<br><br>They vary considerably across states, with some having percentage-of-income plans while others have a fixed discounts off the normal tariff<br><br>Some rate structures are more effective in managing waste or producing higher benefits per dollar funded by general ratepayers |

| Rate Mechanism | Positive | Negative | General Comments |
|---|---|---|---|
| **Time-of-use rate** | Economically efficient<br>Need for less utility capacity additions over time<br>Avoidance of subsidies to high peak-use utility customers<br>Promotion of demand-side actions to allocate utility costs | Aggravation of high utility bills during peak periods<br>Skeptical public<br>Potentially large adverse effect on utility non price-responsive customers<br>Revenue instability for utilities | Strong economic rationale for them but uncommonly applied, especially for residential customers<br>Several obstacles to time-of-use rates from three perspectives: (1) regulatory, (2) utilities, and (3) consumers<br>Regulatory concern about some consumers being worse off – e.g., losers would include consumers not shifting their load to lower-cost periods<br>A hallmark of public utility regulation is average cost pricing and resistance to unstable prices |
| **CWIP in rate base** | Improved utility cash flow<br>More timely cost recovery<br>Avoidance of rate shock | Risk shifting to utility customers assuming inadequate regulatory cost review<br>Potential intergenerational-equity problem | Infrastructure surcharges have tended to replace CWIP in rate base as a cost-recovery mechanism to mitigate utility cash flow problems<br>CWIP/phase in mechanisms became popular in the 1970s and 1980s when utilities were building large new capital projects |
| **Straight fixed-variable rate** | Efficient rate structure that gives utility customers good price signals<br>Enhanced utility-earnings stability<br>More levelized utility bills across seasons<br>Positive hedging effect on utility customers during extreme weather conditions<br>Removal of utility disincentives for energy efficiency<br>Removal of inequities caused by intra-class subsidies<br>Consistent with the pricing of many other goods and | Adverse effect on low-usage customers, some of whom may be low-income households<br>Reduced incentive for price-induced energy efficiency<br>Widening of gap between marginal price for customers and full marginal social cost<br>Skeptical public | SFV is less popular than revenue decoupling in removing utility disincentives for energy efficiency<br>SFV has a definite image problem<br>Generally, SFV faces intense opposition by consumer groups, environmentalists and commission staff<br>Instead of accepting a pure SFV rate design, over the past several years many commissions have allowed utilities to reallocate more of their fixed costs to the customer or service charge<br>SFV can have an "rate shock" problem in that it could cause |

| Rate Mechanism | Positive | Negative | General Comments |
|---|---|---|---|
| | services | | some customers to see dramatically higher bills<br>Although SFV has a number of favorite traits, the negative traits have dominated the debate in regulatory proceedings |
| **Net metering rate** | Improved economics of solar PV technologies<br>Improved competition between utilities and non-utility suppliers<br>Avoidance of certain utility costs | Utility revenue erosion<br>Potential for stranded utility assets<br>Higher rates to general ratepayers<br>Potential subsidy to solar users | Commissions have begun to revisit existing net metering rates<br>Success of rooftop solar PV systems has worried electric utilities enough to begin questioning net metering rates and advocate their elimination or redesign |
| **Focused performance-based ratemaking** | Enhanced performance in focused area of utility operation<br>Potential win-win outcome for both utility shareholders and customers<br>Potential for reduced regulatory costs from fewer prudence reviews | Potential for distorted incentives<br>Gaming by stakeholders in setting benchmarks | Special incentives for electricity reliability have grown in popularity<br>Commissions seem more receptive to partial incentive mechanisms than to more comprehensive measures, such as price caps and formula rates |
| **Standard two-part tariff** | Public acceptability<br>Protection of low-usage utility customers<br>Utility incentive for managing costs to increase sales<br>Strong price-driven incentives for energy efficiency | No guarantee of utilities recovering their prudent fixed costs<br>Disincentive for utilities to advance energy efficiency<br>Cross-subsidy of low-usage customers by high-usage customers<br>Economically inefficient<br>Lessened utility competitiveness in certain markets because of higher marginal price<br>Negative hedging effect on utility customers | Utilities and conservationists alike have questioned (for different reasons) the merits of the standard two-part tariff<br>The reason for interest in modifying the rate structure is that it conflicts with other regulatory objectives<br>Some headway in recent years in gradually shifting more of the fixed costs out of the volumetric charge<br>Much resistance to make a wholesale shifting of fixed costs to a customer or service charge<br>A few cases where gas and electric utilities have gone to SFV rates |

| Rate Mechanism | Positive | Negative | General Comments |
|---|---|---|---|
| **Declining block rate** | Utility earnings stability<br>Economically efficient with cost-based tiers<br>Improved utility system utilization<br>Promotion of sales in a period of abundant utility supply | Contrary to energy-efficiency goals<br>Price discrimination with non cost-based tiers | Commissions have phased-out declining block rates over the years, largely because of energy efficiency goals<br>It is unlikely that they will make a comeback, although they can achieve the same objectives as revenue decoupling and SFV rates |

**Table 3: Aligning Regulatory Objectives with Individual Rate Mechanisms**

| Regulatory Objective | Rate Mechanisms with Tendency toward Positive Effect | Rate Mechanisms with Tendency toward Negative Effect |
|---|---|---|
| **Revenue sufficiency** | Revenue decoupling, straight fixed-variable rates, formula rates, future test year, declining-block rates | Inverted rate, standard two-part rates, subsidized rates, historical test year |
| **Profit stability** | Revenue decoupling, straight fixed-variable rates, formula rates, declining-block rates | Inverted rates, standard two-part rates |
| **Public acceptability** | Standard two-part rates, subsidized rates | Revenue decoupling, straight fixed-variable rates, discriminatory rates, time-of-use rates |
| **Proper price signals** | Marginal-cost rates, straight fixed-variable rates | Standard two-part rates, subsidized rates |
| **Fair sharing of fixed costs** | Embedded-cost rates | Special contracts, discriminatory prices |
| **Fair sharing of risk** | Standard two-part rates, formula rates | Cost trackers, infrastructure surcharges, CWIP in rate base |
| **Promotion of utility innovations** | Targeted incentives, preapproval of project and costs, regulatory lag (for utility retention of cost savings), upfront regulatory commitment, accelerated depreciation, infrastructure surcharges, prompt and certain cost recovery | Traditional ratemaking, cost-based rates, regulatory lag (for utility recovery of investment costs), retrospective reviews, book depreciation, entry restrictions for new firms |
| **Encouragement of new investments** | CWIP in rate base, future test year, infrastructure surcharges, formula rates, multiyear rate plans, subsidies, preapproval of project and costs, accelerated depreciation | "Used and useful" standard, 20-20 hindsight reviews, cost recovery only in general rate cases |

| Regulatory Objective | Rate Mechanisms with Tendency toward Positive Effect | Rate Mechanisms with Tendency toward Negative Effect |
|---|---|---|
| **Efficient competition ("level playing field")** | Flexible rates special contracts, value of service rates, unbundled pricing | Rigid embedded-cost rates, non-cost based rates |
| **Efficient consumption** | Marginal-cost rates, time-of-use rates | Rate subsidies, standard two-part rates, average-cost rates |
| **Promotion of energy efficiency** | Inverted rates, revenue decoupling, straight fixed-variable rates (utility initiated), performance incentives | Standard two-part rates, straight fixed-variable rates (customer-initiated), declining-block rates (customer initiated) |
| **Affordability** | Inverted rates, rate discounts, percentage-of-income plans, low-income weatherization programs | Strictly cost-based rates, high customer charge, straight fixed-variable rates |
| **Promotion of social objectives (e.g., electric generation diversity)** | Infrastructure surcharges or system benefits charges, above-cost rates to some customers | Strictly cost-based prices, no rate subsidies |

## C. Two illustrations of challenges posed by multi-objectives

### 1. Rate mechanisms to promote energy efficiency

Good ratemaking harmonizes a utility's financial interests with cost-effective, energy-efficiency initiatives. This principle relates to what analysts call the "principal/agent problem"; namely, how to motivate a utility to achieve the objectives set out by the regulator.[147] Assume that a regulator wants a utility to commit itself to promoting energy efficiency. At the minimum, the utility hopes to avoid any negative financial consequences; this outcome might require a future test year, a revenue-decoupling rider, a lost revenue adjustment mechanism, or a rate design that protects the utility against unexpected sales declines (e.g., straight fixed-variable rates). The regulator could further incent utilities by allowing them to profit from cost-effective initiatives comparable to profits earned from supply side alternatives.[148] Profits can

[147] The assumption is that the objectives align with promoting only cost-effective energy efficiency or energy efficiency that passes some other well-grounded benefit-cost test. Energy efficiency is a physical concept, devoid of economics. Since it also has a cost, society can overspend on energy efficiency when its costs exceed the benefits.

[148] The regulator may view energy-efficiency activities as a core function that warrants a utility to earn a profit, rather than simply recovering lost revenues and expenses dollar-for-dollar. A current issue before some state utility commissions is whether utilities should have the opportunity to profit (e.g., earn a rate of return) from their energy-efficiency activities.

derive from shared savings, performance target incentives, and a rate-of-return adder. Without financial inducements, the regulator would need to more closely monitor the utility to ensure compliance with the predetermined energy-efficiency goals.

### a. Grouping of rate mechanisms

Many state utility commissions have applied at least one of four distinct kinds of rate mechanisms to stimulate energy efficiency. Each of them affects differently a utility's earnings and financial risk from promoting energy efficiency. The four classes of rate mechanisms and specific examples are:

1. *Timely cost recovery for the utility outside of a general rate case* (cost-recovery rider or tracker, system benefits charge[149])

2. *Proper pricing signals to consumers* (inverted and non-declining rate structure, real-time or dynamic pricing, critical peak pricing, long-run marginal cost pricing)

3. *Earnings stabilization for the utility* (revenue decoupling rider, lost revenue adjustment mechanism, straight fixed-variable rate, formula rate plan[150])

4. *Performance incentive for the utility* that aligns the utility interests with the public interest (shared savings incentive, performance target incentive, rate-of-return adder[151])

Some state utility commissions have recently become more proactive in approving alternative rate mechanisms that foster energy-efficiency initiatives. They have gone beyond cost riders and lost revenue mechanisms (e.g., revenue decoupling) to performance incentives.[152] Over time, commissions have become increasingly cognizant of the conflicts between utility profits and energy efficiency. These rate mechanisms

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[149] The system benefits charge is a surcharge added to customer bills in support of energy efficiency. Utilities have imposed surcharges to fund other activities, such as low-income programs and the procurement of renewable energy.

[150] The rationale for these mechanisms is the disincentive for promoting energy efficiency by utilities under the standard two-part tariffs that is prevalent in the utility sectors (*see* the earlier discussion in Part III.B.2).

[151] Performance incentives can involve the utility receiving a predetermined share of the benefits from energy-efficiency initiatives (e.g., the utility's avoided cost), or the utility placing some of its expenditures in rate base or earning a bonus on its rate of return for surpassing a commission energy-savings target.

[152] As energy efficiency has become a more prominent utility activity, revenue stabilization and performance incentive mechanisms have received greater support from state commissions.

attempt to address past problems of low motivation by utilities to aggressively pursue energy efficiency.

#### b. Discordant objectives

Relevant to this paper, conflicts exist between promoting energy efficiency and other regulatory objectives. Energy efficiency can impede, for example: (1) utility financial stability when lost revenues exceed avoided costs,[153] (2) minimum short-term rates,[154] (3) strong incentives for holding down costs,[155] (4) moderate risk to customers,[156] and (5) minimum customer-funded subsidies.[157] In taking a balanced position, a commission would consider the tradeoffs involved in promoting energy efficiency. Energy efficiency, although seemingly desirable in many circumstances, is not immune from clashes with other regulatory objectives. That is why, for example, commissions hesitate to give utilities a blank check in expanding their energy-efficiency activities. Like almost everything else, society can overspend on energy efficiency.

In sum, the $64,000 question for regulators is how to select a portfolio of ratemaking mechanisms that best advances simultaneously the goals of energy efficiency and the public interest. The differing adverse effect of each mechanism on other regulatory objectives makes their task difficult.

### 2. Energy assistance programs

#### a. "Affordability" as a regulatory objective

One hallmark of public utility regulation is its commitment to the universal availability of utility service. While economic efficiency focuses on the aggregated

[153] The outcome is typically given that most energy utilities recover a substantial portion of their fixed costs in the volumetric component of rates.

[154] When energy-efficiency initiatives fail what some analysts call the "no loser" test, a utility's rates would tend to be higher than in the absence of these initiatives. The reason is that revenue losses are greater than the decline in revenue requirements.

[155] Trackers, for example, can cause a utility to overspend on energy efficiency if the commission inadequately scrutinizes the costs in terms of their prudence by allowing "automatic" pass-through.

[156] Shifting too much risk to customers might violate the regulator‘s sense of fairness and create a "moral hazard" problem in which the utility lacks adequate incentive to behave prudently. Achieving the proper allocation of risk between utilities and ratepayers is a difficult but critical task for regulators.

[157] To the extent that energy-efficiency initiatives expand, the net benefits of marginal actions could decline, requiring general customers to absorb a higher dollar amount per unit of energy saved.

effect of utility activities, fairness or equity factors are a chief concern of public policy.[158] "Affordability" goes beyond whether a physical service is available; it includes whether households are able to pay for their utility services without jeopardizing their ability to purchase other essential goods and services, such as food, medicine and housing.

To say differently, access to utility service includes the economic ability of customers to buy utility services. One generally acceptable "affordability" metric is the ratio of utility bills to income.

Several states have special rates for low-income consumers, as well as special tariffs for particular groups of customers, reflecting income distribution and political economy considerations. We refer to them here as "energy assistance" programs.

Some utilities believe that requiring general ratepayers and even shareholders to fund energy assistance programs is preferable to struggling with the problem of low-income households continuously falling behind in their utility bills and being vulnerable to service disconnections. Utilities are able to reduce their costs when they have a lower number of delinquent customers, some with severe payment problems that inevitably will lead to service disconnections.[159]

In advancing the public interest, regulators would want to achieve the "affordability" goal with minimal impediment to other objectives such as economic efficiency and utility financial health. A regretful regulatory legacy is the achievement of specific regulatory objectives at higher than least cost. One goal of energy assistance, in addition to making utility service more affordable to low-income households, should be to achieve a target at the lowest cost to the utility and the other customers.

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[158] Many analysts have identified inadequate income as the real culprit of unaffordable utility service. They contend that state and federal legislatures, or other governmental entities, are best able to address poverty by (a) supplementing the income of poor households (e.g., via cash subsidies with no strings attached), (b) in-kind assistance funded through general revenues (e.g., "energy stamps") or (c) offering them financial support for energy-efficiency improvements. Specifically, they argue that these actions are more effective and efficient than subsidized utility rates. Political pressures and legislative mandates, however, have led to energy utilities' offering of programs to insulate low-income households from unaffordable utility bills. These initiatives, described by some analysts as "taxation by regulation," require higher rates to the majority of customers to pay for energy subsidies targeted at a smaller group of customers. The "tariff effect" that makes funding customers minimally worse off in return for making low-income recipients better off has political appeal.

[159] Assistance should result in reduced utility collection costs, service disconnections, arrearages, and debt write-offs. These cost reductions can more than offset the lost revenues from rate discounting and thereby increase the utility's net revenues. Such an outcome explains why some public utilities support energy assistance to low-income households. These utilities might find it easier to receive regulatory approval for recovering revenue shortfalls when they support energy assistance programs.

### b. Managing waste from energy assistance

Waste is a byproduct that has afflicted energy assistance, energy efficiency, reliability-improvement activities and renewable energy programs. Good regulation not only involves achieving different goals but to pursue them at least cost. Otherwise, society faces less potential gains from utility activities that turn into lost opportunities. Efficiency losses from energy assistance can stem from: (1) recipients over-consuming energy when the subsidized price lies below the utility's marginal cost, and (2) an excessive gap between the actual benefits to targeted participants and the subsidy cost funded by the utility or general ratepayers (e.g., utility customers pay $15 million to subsidize low-income households who benefit by only $10 million). If eligible customers receive a certain dollar of benefits from energy assistance, as good public policy the dollars funded by other customers should be at the lowest possible level. Equivalently, for a fixed number of dollars funded by general ratepayers, the benefits to low-income customers should be at the highest possible level.

Wasteful actions in providing energy assistance reduce benefits to targeted utility customers. One source of waste is non-poor households benefiting from energy assistance, thereby deducting the assistance given to the most financially needy households. A non-targeted lifeline rate or a discounted rate with broad eligibility rules that include non-needy customers can lead to such a distortive outcome.

Although compromising some regulatory goals (e.g., cost-based prices), the fostering of energy affordability to a greater number of households can advance other regulatory goals. No-cost weatherization to low-income households, for example, not only makes energy more affordable but it also promotes energy efficiency. It can, in addition, reduce collection costs, service disconnections, debt write-offs ("uncollectibles"), and arrearages ("past due bills"). Other energy assistance actions can also mitigate collection problems that financially affect utilities and their non-poor customers. Overall, weatherization to poor households has a number of appealing features that warrant serious consideration by policymakers, including state utility commissions.[160]

### c. Balancing regulatory objectives

Regulators need to consider various regulatory goals in determining the preferred level of affordable utility service to low-income households. The conflicting nature of some objectives requires a value judgment when it comes to weighing the tradeoffs. As an illustration, regulators should consider the compromising effects that advancing affordability has on economic efficiency and discriminatory-free rates.[161] To what extent

[160] *See*, for example, Ken Costello, "How to Determine the Effectiveness of Energy Assistance, and Why It's Important".

[161] Energy assistance funded by general ratepayers is a form of subsidy for which one group of customers (namely, general ratepayers) subsidizes service to another group of customers (namely, low-income households) by paying more than the cost to serve them while the other group pays less.

do regulators want to diminish economic efficiency or require general ratepayers to subsidize a group of low-income households? How much discriminatory pricing will they tolerate?

What primary objectives should energy assistance have? One objective is to keep existing low-income households on the utility system and reconnect service for others. Affordability means that low-income households are able to enjoy the comforts of space heating and other energy services without fear of disconnection by the utility.

**d. Differing outcomes from alternate rate mechanisms**

Specific energy assistance options include a change in rate design, a rate discount, a bill cap based on income, a lump-sum payment, a cost waiver, and no-cost weatherization and other forms of energy efficiency. These options have unique effects on low-income households, other customers, and the utility. Which of these initiatives would provide "most bang for the buck"? What should be the dollar amount of assistance? Regulators should review whether a utility's energy-assistance actions are achieving the regulatory goal of utility-service affordability (1) most effectively and (2) with minimal adverse effects on other regulatory objectives. For example, many economists consider inverted ("lifeline") rates an inefficient and wasteful approach for assisting poor households.

A major problem with energy assistance is that they can cause rates charged to low-income households to fall below cost and rates charged to other customers to increase above cost. Economic efficiency diminishes, and low-income households would tend to consume more energy.[162] The latter effect by itself runs counter to reducing the energy burden of low-income households, as well as advancing energy efficiency.

Energy assistance is a form of discriminatory pricing that some regulators might consider undesirable. Its rationale is that customers with a low ability to pay for utility services should receive favorable rate treatment. Discriminatory pricing almost always raises a question of fairness, especially when a favorable rate falls outside a "zone of reasonableness." When a rate falls short of a utility's short-run marginal cost or lies above the price that an unregulated monopolist would charge, a regulator would likely find the rate impermissible. We see examples in unregulated sectors in which a firm offers discounts, say, to seniors and students because of their low incomes. Firms do not favor these groups for altruistic reason. Instead, they offer discounts to increase their profits by attracting more customers and sales from price-sensitive customers. As long as the price lies above variable costs, firms can grow their profits from additional sales.

[162] If these households face below-cost rates, they would tend to consume more energy. Some observers would contend that even if they do, that is desirable since presumably they were under-consuming energy previously when utility service was less affordable.

# VI. Experiences with Seven Alternative Rate Mechanisms

The real test of any rate mechanism is how it performs in practice over several years. After all, *ex ante* predictions based on economic theory or "blackboard' analysis, although useful in reviewing the potential merits of a rate mechanism, are not good substitutes for empirical evidence. An assessment of whether a mechanism has achieved its objectives, surpassed them, or fallen short is an important but difficult task: The analyst must predict outcomes in the absence of the alternative mechanism and compare them with what actually occurred.[163] Important "outcome" metrics include price, cost, the utility's financial condition, and fairness. In effect, the test reduces to the effectiveness of a rate mechanism to achieve "just and reasonable" rates, as defined by a commission.

Summaries of seven rate mechanisms lying outside the mainstream follow. All of them have been operating for several years. The evidence derives from different sources, including commission staff responses to eight questions sent by the author of this paper,[164] discussions with stakeholders, and third-party documents. For the majority of mechanisms, the rate mechanisms have performed positively in line with expectations. Some of them, however, needed modifications, and questions still remain over whether on net they have advanced the public interest. One mechanism, inverted rates, was the exception in which events have caused it to have negative consequences triggering strong opposition from various stakeholders.

## A. Alabama's rate stabilization plan

Since 1982, Alabama's electric and gas utilities have relied on a formula-ratemaking mechanism called the Rate Stabilization and Equalization (RSE) mechanism to make quarterly rate adjustments outside of a general rate case.[165] Other states, especially in the Southeast, also use formula rates to regulate utilities.

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[163] Economists and statisticians call this "counterfactual analysis."

[164] The author sent out the questions at the beginning of December 2013. The eight questions are: (a) when was the mechanism first instituted, (b) who first proposed it, (c) What was the rationale for it, (d) which parties supported and opposed it, (e) what modifications have utilities made to it since its inception, (f) has the mechanism encountered any problems and if so what were they and did the commission reconcile them, (g) has your commission done a retrospective review of the mechanism highlighting, for example, the benefits achieved and whether the mechanism has performed as expected, and (h) what has been your commission's overall experience with the mechanism? Most commissions responded fully to the questions.

[165] Alabama Power Company has operated under the RSE since 1982. Alabama Gas Co.'s current rate stabilization plan, which has undergone modification over time, is similar to the plan for Mobile Gas Service and was originally implemented in 1983. Mobile Gas Service's plan initiated in 2002.

Under RSE, the Alabama Public Service Commission annually compares a utility's expected ROE with the authorized range to determine any needed base rate adjustments to move the ROE toward a prespecified dead band. Starting in 2005, gas utilities could use forecasted costs and sales data based upon budget data.[166] Along with this change, the Commission allowed customers to receive refunds when the actual ROE rises above the "dead band" range but did not permit utilities to recoup ROE shortfalls.

Supporters of RSE point to three favorable features:

1. *More thorough cost reviews:* the Commission oversees a utility's cost on both an annual and ongoing basis.

2. *Rate smoothing:* traditional ratemaking is susceptible to rate shock under inflationary and slow sales-growth conditions. Because RSE adjusts rates more often, it mitigates against large step increases.

3. *Lessening of regulatory lag:* Because RSE uses forecasted data and involves annual reviews, it reduces the negative effects of regulatory lag on a utility's financial health.

RSE for Alabama Power Company (APCO) has had positive outcomes, at least as reported by the Edison Electric Institute:

> The constructive regulatory environment that has developed in Alabama brings benefits to customers in a number of ways…[E]lectric rates in Alabama have consistently been below the national average. In addition, the smoothing effects of RSE have been attractive to all customers, particularly large industrial customers. As a result, Alabama has enjoyed a period of strong economic development, which contributed to a growth of employment in the 1990's and 2000's (and which shielded the state from some of the more severe consequences attributable to the recession). RSE also has allowed APCO to restore its credit rating to the high level that it maintains today, thus leading to lower interest costs that put downward pressure on rates. In Alabama's experience, the formula rate methodology under RSE has been a winning approach for the commission, the consumers, and the utilities alike.[167]

Since RSE was adopted in November 1982, Alabama Power has had 12 upward rate adjustments, 3 downward rate adjustments, and no rate adjustments in 15 of the years.

The Edison Electric Institute also concluded that:

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[166] Previously, there were erratic movements of utility rates and earnings; setting rates based on future data helped to stabilize these parameters.

[167] Edison Electric Institute, "Case Study of Alabama Stabilization and Equalization Mechanism," EEI paper, June 2011, 7.

> The story of RSE is a story of successful regulatory innovation. RSE has changed the regulatory environment in Alabama, from one of distrust and confrontation, to one of communication and cooperation. This constructive relationship has produced substantial benefits for customers and shareholders alike. RSE has enabled Alabama, a comparatively small state, to become a leader in economic development. Companies such as ThyssenKrupp, EADS, Hyundai, Honda, Toyota and Mercedes have moved to Alabama in recent years. When asked why they chose to locate in Alabama, they consistently rank low cost, reliable energy, and a stable regulatory climate, as among the top reasons.[168]

Since these glowing comments came from an industry trade association, the reader might interpret then with some skepticism.[169] Different parties in Alabama have, however, indicated to the author the positive outcomes that have derived from the RSE. A 2013 NRRI survey of Commission staff indicated that the RSE has worked well and staff is confident in its review of utilities' costs, earnings and other parameters in determining the reasonableness of any rate adjustments.[170] One less positive response was that staff said that the burden is generally on the staff or the Attorney General to demonstrate that the utility's budget numbers are unreasonable. One interpretation is that a utility can present its budget numbers without defending them, which places the onus on other parties to show that they are inappropriate.

### B. Central Maine Power's Alternative Rate Plan

Since 1995, Maine electric utilities have operated under an Alternative Rate Plan (ARP). The Public Utilities Commission encouraged this ratemaking mechanism, and it was agreed to by all the parties to the case, including the utility, Central Maine Power Company (CMP).[171] The Commission considered an ARP as an improvement over cost-of-service ratemaking, for setting prices. Before the ARP, price changes would require several months of litigation, with the number, amount and timing of resulting price changes difficult to predict. Stakeholders consider this uncertainty untenable, demanding at least Commission consideration of a new ratemaking paradigm.

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[168] Edison Electric Institute, "Case Study of Alabama Stabilization and Equalization Mechanism," 1.

[169] Inferring that the RSE was a major contributor to Alabama's economic development may be a stretch. A sound analysis would have to control for other factors of economic development (e.g., favorable taxes, low cost of living) to isolate the effect of the RSE.

[170] Ken Costello, "Future Test Years: Evidence from State Utility Commissions," Report No. 13-10, October 2013.

[171] The Commission first articulated the objectives and benefits of an ARP in Docket No. 1992-345.

Other states have adopted indexed price-cap plans like the ARP to regulate telephone-utility prices.[172] Maine was the first state to apply such a plan to electric utilities.

The ARP replaced traditional ROR regulation with a multiyear price cap approach. Under price caps, changes in a utility's rates rely on a formula that allows for automatic rate adjustments based largely on the difference between the inflation and a productivity offset.[173] Price caps are usually set for a predetermined number of years (e.g., five years), with no rate cases filed in the interim.

The plan limits the utility's rate increases, while allowing it to retain cost savings attained from improved cost efficiencies.[174] It shifts risk from customers to utility shareholders. The plan also gives CMP pricing flexibility: For example, it is able to offer reduced or re-designed rates to customers who would otherwise fuel switch or leave the utility's service area. The rationale for pricing flexibility is that it allows the utility to recover its fixed costs that it would otherwise lose, thereby avoiding a reallocation of those costs to remaining customers.[175] Other positive features of an ARP include rate predictability and stability, reduced regulatory costs, and stronger incentives for utilities to minimize their costs. Regularized regulatory lag (e.g., five years), for example, would increase the expected time that a utility would reap the benefits from improvement in cost efficiency.

Since 1995, CMP has operated under a five-year ARP.[176] The Commission has made several modifications to the plan over time.[177] One change is the adoption of flow-through treatment of certain costs, most notably storm-related expenses.

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[172] The Central Maine Power plan represents a hybrid plan with price caps as the primary component supplemented by earnings-sharing and service-quality factors. A decline in service quality, which is measured as an index combining customer service and reliability, results in a penalty based on a predetermined formula.

[173] The plan also allows for pass-through of mandated costs and net capital gains or losses. For example, the K factor allows a utility to receive additional revenues for projected capital spending. The K factor substitutes for other mechanisms, such as a capital cost tracker that recovers expenditures for large non-revenue producing projects. One criticism of the K factor is that it diminishes incentives for cost efficiency.

[174] It would hold price changes below the rate of inflation, assuming positive productivity growth. In its latest proposal, however, CMP includes a productivity offset of negative 1.46 percent in its ARP formula. This translates into an annual proposed rate increase of 1.46 percent higher then the rate of inflation.

[175] The presumption is that rigid rates could induce certain customers, especially industrial firms, to close down their facilities, self-generate or relocate.

[176] In 2013, another utility (Northern Utilities) proposed an ARP that would allow it to adjust its distribution rates without a general rate case until 2017.

The Commission sets annual targets for service quality, responsiveness and outage duration, among other things. The reason for these targets is to ensure that the strong utility incentive to manage costs under the plan does not sacrifice reliability or service quality in general. CMP receives a penalty when it performs poorly.[178]

The large revenue increase proposed by CMP in its latest filing raised questions on whether the ARP has performed well.[179] Staff asked whether an ARP is appropriate given projections of substantial capital expenditures.[180] Previously, the Commission expressed concern that CMP had underinvested during the ARP regime.[181] In fact, in the latest CMP filing the staff recommended suspending the ARP and replacing it with traditional cost-of-service regulation:

> Given the issues/concerns with CMP's performance under prior ARPs, as well as the concern that a new ARP cannot adequately address CMP's projected capital plans in a way that meaningfully protects ratepayers, the Staff's recommendation at this time would be that the Commission take an ARP 'hiatus' for CMP and allow CMP to operate under cost of service ratemaking for a period of time. This would allow CMP to address its system and spending needs consistent with the interests of both shareholders and ratepayers. In the future, an ARP form of regulation can be revisited and, as appropriate, adopted in a way that meets the Commission's objectives and concerns.[182]

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[177] Change also derived from the Commission's mandate for CMP to divest its generating facilities by 2000. CMP thus went from a vertically integrated utility to a distribution-only utility

[178] A Service Quality Index (SQI) measures CMP's service quality composed of seven parts. The SQI has a total potential annual penalty of $5 million.

[179] Unlike previous ARPs, CMP's index formula calculates allowed revenue increases, rather than allowed rate increases. The utility also proposed a revenue decoupling mechanism in conjunction with the ARP.

[180] Maine Public Utilities Commission, *Central Maine Power Company Request for New Alternative Rate Plan ("ARP 2014"), Bench Analysis*, Docket No. 2013-00168, December 12, 2013 at https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId={168485BE-732A-4E4F-A4DD-ACD068CE9F7B}&DocExt=pdf.

[181] Specifically, staff's concern is the following:

> A question certainly exists as to whether the ARP has provided the correct incentives for capital spending or, alternatively, whether sequential ARPs have promoted a pattern of spending driven by the cycle of ARP terminations and rate resettings.

[182] Maine Public Utilities Commission, *Bench Analysis*, 20.

Commission staff contended that a reversal to cost-of-service regulation would not necessarily increase regulatory burdens, lead to continuous rate filings, or diminish the utility's incentive to control costs. Staff alluded to the recent positive experiences of two other in-state electric utilities, Bangor Hydro-Electric Company and Maine Public Service Company. The first utility operated under an ARP until 2008 and the latter utility never operated under an ARP. As stated in the *Bench Analysis*:

> …the normal "regulatory lag" between rates [under cost-of-cost regulation] was sufficient to promote the Commission's objectives of management efficiency, cost containment and rate stability (at 21).

Based on the views of different parties, the overall results from the ARP are mixed but, on net, positive. First, price increases under an ARP generally have been modest with no reporting of service-quality problems. In the initial years, CMP's earnings were held down by the unexpected closing of a nuclear power plant,[183] but the utility has improved its earnings since then by reducing its costs and becoming more efficient. Second, soon after the plan was in place, CMP increased the number of special, discounted rates offered to customers, partly because of the streamlined process. These discounts have helped some large industrial firms to remain competitive. Third, the plan has reduced the number of contentious hearings over time, allowing both the commission and utility personnel to devote more time to other activities.

### C. Atlanta Gas Light's STRIDE program

In 1998, The Georgia Public Service Commission approved a surcharge for Atlanta Gas Light (AGL) that allowed the utility to recover prudently incurred costs under a 13-year pipe replacement program (PRP) that would replace more than 2,600 miles of bare steel and cast iron distribution pipes. The Commission Order for Docket 8516 adopted a Stipulation allowing AGL to replace its corroded pipes in 10 years and establish a surcharge[184] to recover its costs. The genesis of the program was a "show cause" Order. Previously Commission staff found the utility in probable violation of Part 192 of the Minimum Federal Safety Standards and Georgia State Law. The utility extended the PRP to 2013 as part of a settlement.[185]

In 2010, AGL received Commission approval to rename the program the Strategic Infrastructure Development and Enhancement (STRIDE) Program so that it could include as part of the surcharge costs the Integrated System Reinforcement Program (i-SRP), which expanded the distribution system, and the Integrated Customer Growth Program (i-CGP). AGL estimates that improvements under i-SRP will cost $400 million over ten

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[183] Because the utility had no fuel adjustment clause, it was unable to pass along to consumers the cost of replacement power.

[184] The utility recovers the surcharge from all firm customers in its service area.

[185] The residential surcharge increased from $1.29 per month in years 7-9 to $1.95 in years 10-13.

years, including an upgrade of the backbone of the utility's distribution system to improve reliability and branch out the distribution system to meet future growth. In 2010, AGL further expanded the program to include i-CGP for the purpose of extending its pipeline facilities to serve customers without pipeline access. Most recently under the i-VPR, AGL plans to charge customers a fixed monthly fee for replacing 756 miles of the oldest plastic pipes that are susceptible to cracking.[186]

As recently as December 2013, the Commission approved two agreements: (1) the 2013-2017 Integrated System Reinforcement Program (i-SRP 2.0) Plan and (2) the 2013-2017 Integrated Customer Growth Program (i-CGP 2.0) Plan. These programs will involve a $261-million investment in distribution improvements over the following four years. The agreements, among other things, give the Commission final authority over all projects, require AGL to file quarterly, semi-annual and annual reports with the Commission on expenditures and the progress of all projects. The agreements also allow Commission staff to conduct prudence audits of the projects.[187] One of the Commissioners commented that:

> This Commission realizes that extending and improving the natural gas distribution system is vital to Georgia's economic development…[Our] decision will allow Atlanta Gas Light Company to extend service to unserved and underserved customers and will promote economic development across our state.[188]

AGL must file, every three years, its plan before the Commission for the following three years. Some parties have questioned the merits of AGL's aggressive pipeline replacement program. AGL has contended that a large-scale replacement program lowers the chances of a major pipeline failure and allows it to acquire piping and labor at a lower cost.

In the early years of the program the Commission annually reviewed the utility's eligible costs from the previous year before approving a new surcharge amount. Later, the Commission set a fixed dollar amount that AGL could recover annually under the program. According to AGL, it has expended more than $2 billion on replacement and new pipes since 1998. The average residential bill has increased by $4.38 to fund these investments.

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[186] AGL has over 3,300 miles of vintage plastic pipe, which is about 10 percent of the total pipe mileage of its distribution system. AGL plans to replace all of these plastic pipes over the next 10-15 years.

[187] The Commission staff can file interrogatories, conduct quarterly prudence audits for all the programs and issue annual reports. Any staff complaints get resolved either through discussion with the utility or by the Commission.

[188] National Association of Regulatory Utility Commissioners, "State News: Georgia Approves AGL Improvement Program," *The Bulletin*, Issue 1 (January 6, 2014).

Overall, the Commission favors the use of surcharges for AGL to recover its costs under the STRIDE program. According to the Commission, the program has achieved its purpose of replacing and expanding pipes partly because AGL is able to recover its costs in a timely manner outside of a general rate case. AGL probably would have had to file several additional rate cases over the timeframe of the program in the absence of the STRIDE program. The Commission also supports the program because it is project specific and allows AGL to recover only those costs that it approves. The Commission has the discretion to modify the surcharge mechanism if deemed appropriate.

Infrastructure charges for gas pipeline replacement have soared in popularity across the country over the past few years.[189] Some commissions have rationalized them as an incentive for utilities to retire old pipes that pose a safety threat. Since pipe replacements do not lead to increased utility revenues, many commissions have recognized the potential adverse financial effect on utilities if they have to wait to recover their costs until the following general rate case. Pressure has come from Wall Street, environmentalists, the Federal Safety Agency, and the utilities themselves for state utility commissions to encourage pipe replacement and expedited cost recovery via infrastructure surcharges. This "iron quadrangle" has made it difficult for commissions to oppose both accelerated pipe replacement and not allowing utilities prompt recovery of their costs, even if the evidence on their merits is inconclusive.

Some commissions have tied cost recovery for pipe replacement to utility performance in terms of cost and construction milestones. They have also required a utility to have a comprehensive strategy for replacing pipes, as well as a short-term action plan. Some commissions also conduct a retrospective review to assure, for example, that the previous year's costs are consistent with the utility's replacement plan and prudent construction practices.[190] Some commissions also cap the amount that the utility can recover through the surcharge. Finally, it is common for utilities to convert cost recovery from the "surcharge" account to base rates in the next general rate case.

### D. Wisconsin's future test year

The Public Service Commission has used a future test years for ratemaking over the past 35 years. It mandates a future test year for large utilities. These utilities file a rate case every year unless they are under a rate freeze.

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[189] *See*, for example, U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, *White Paper on State Pipeline Infrastructure Replacement Programs*, December 2011.

[190] The intent is to assure that the surcharge charge passed through to customers equals only the prudent portion of the costs incurred by the utility.

The Commission has a large staff to audit a utility's filing and has refined its procedures over the years. It has developed a filing format for utilities that requires extensive documentation of their forecasts.[191]

In a 2013 NRRI survey on future test years,[192] the Commission responded to several questions as follows:

1. The greatest difficulty with FTYs lies with the inherent differences of opinion between staff, utilities and intervenors as to forecasted revenues and expenses.

2. The Commission has many years of experience with FTYs and is comfortable with them. The Commission has an overall positive experience with FTYs.

3. Independent forecasts are often used for sales. Commission staff normally adjusts the utility's forecasts for O&M expenses, net investment rate base, capital structure, working capital, and taxes.

4. The burden is on the utility to support its rate-filing application. Intervenors and staff provide additional information to build a complete record for the Commission.

5. The Commission requires the filing of historical information for sales, O&M expenses, rate base (e.g., expenditures, timing of additions), and working capital balances. This information acts as a benchmark for evaluating forecasts.

6. The utilities are subject to external audits of their financial statements.

7. Some utilities have a propensity to forecast their costs and revenues conservatively in order to increase the chances of meeting or exceeding its authorized ROE. Staff has seen differing tendencies among the state's utilities. For example, there is some evidence that some utilities have consistently under-forecasted sales.

8. The Commission has made adjustments to subsequent cost forecasts reflecting past forecasting errors, usually in the form of budget-to-actual adjustments.

9. The Commission compares actual weather-normalized sales to the utility's filed forecast over several years (i.e., it retrospectively compares the utility's forecasted sales allowed in rates with actual sales).

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[191] *See* Wisconsin Public Service Commission, "Investor Owned Utility Rate Cases Data Submittal Requirements Request for Change in Rates," Commission staff correspondence, April 6, 1995.

[192] Ken Costello, "Future Test Years: Evidence from State Utility Commissions."

10. The Commission authorizes a true-up or post-adjustment to rates only when it orders a utility to defer costs or revenues associated with a specified activity. Without such an order, such adjustments would be considered retroactive ratemaking, which is illegal in Wisconsin.

11. The Commission can always bring a utility in for a rate review if earnings are too high or low with the option, when earnings appear too high, to make rates subject to refund from that time on, pending review of financial information. Conversely, a utility has the ability to file a rate review at any time.

The Commission has strict filing requirements for an FTY.[193] It identified four key factors in assuring the public that rates based on an FTY are "just and reasonable":

- Commission staff audits a utility's rate applications.
- Commission staff compares estimates to historical experience.
- Commission staff compares the ongoing actual return on equity over time with the authorized return.
- Good, professional communication between Commission staff, the utilities, and intervenors greatly enhances the process.

As mentioned earlier, the Commission has a large number of staff members, which allows it to thoroughly audit utilities' FTY filing. Other commissions with much fewer staff resources might find it difficult to expend the same effort on auditing and overseeing the utility's costs and sales filings as the Commission does.

One general finding from the NRRI survey[194] was that most commissions using an FTY have had an overall positive experience, with no thought to discard an FTY in later rate cases. Although in some instances commissions underwent initial difficulties—including the broad one of evaluating the reasonableness of a utility's forecasts—they were able to eventually overcome them. A few commissions reported continuing challenges with (1) evaluating utility forecasts and (2) addressing utility incentives for biasing their forecasts to favor a larger rate increase. A number of commissions emphasized the importance of auditing, detailed reviews, and reliance on evidence presented during a rate case as crucial to determining the appropriate test-year costs.

### E. Utah's (Questar's) Conservation Enabling Tariff

In October 2006 the Public Service Commission approved the proposed Questar Gas Conservation Enabling Tariff (CET) as a three-year pilot program. The Commission

[193] Wisconsin Public Service Commission, "Investor Owned Utility Rate Cases Data Submittal Requirements Request for Change in Rates."

[194] Ken Costello, "Future Test Years: Evidence from State Utility Commissions."

made CET permanent in June 2010.[195] The rationale for the tariff was to: (1) address the downward trend of gas usage per customer and (2) remove the disincentive for Questar to promote energy efficiency.[196] The former phenomenon made it difficult for Questar to recover its authorized rate of return. The tariff intended to align the utility's interests with customer interests in expanding energy efficiency.

This revenue-decoupling tariff received wide support, including from the Utah Division of Public Utilities, after initial opposition by consumer advocates.[197] A Division witness testified that the CET would "protect Questar's revenues from shortfalls due to price shocks and economic downturns."[198] Questar Gas estimated that, adjusting for weather, its typical residential customer decreased gas usage by around 35 percent during 1980-2005.[199] Parties agreed that the CET would remove a major obstacle to Questar's energy-efficiency efforts.[200]

In getting Commission approval for the tariff, Questar agreed to institute (1) customer energy efficiency programs, (2) demand-side management programs, and (3) a low-income assistance program. The tariff applies to only general service customers.

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[195] The Commission has reviewed the CET on several occasions. Its initial review led to the Commission approval of the initial pilot for the last two years. A later review resulted in the CET becoming permanent. The Commission monitors the program monthly and less frequently for the performance of Questar's energy efficiency programs. The Commission also reviews the utility's actual rate of return semi-annually and annually.

Unlike some other states, incidentally, the Utah Commission does not adjust the utility's authorized rate of return downward for the risk-shifting aspect of revenue decoupling. For example, the Oregon Public Utilities Commission and the Vermont Public Service Board reduce the utility's ROE because of risk shifting. The rationale for a lower ROE is that customers should receive some form of compensation for lower utility risk.

[196] Commissions in other states have typically given these same reasons for approving revenue decoupling.

[197] One concern was that Questar would be protected from any decline in revenue, regardless of whether it resulted from energy conservation, higher natural gas prices, or a recession. Opponents and skeptics of revenue decoupling have leveled this criticism in other jurisdictions as well.

[198] *See* the testimony of Dr. George R. Compton, Docket No. 05-057-T01, January 23, 2006, at 11.

[199] Two identified sources of the decline are more energy efficient appliances and homes, and higher natural gas prices. Gas usage per residential customers has declined nationally and in most states, in parallel with Questar's experience.

[200] Parties in Utah indicated to the author that the CET has motivated Questar to be proactive in supporting energy efficiency.

The tariff specifies a weather-adjusted margin per customer for each month[201] with differences to be deferred and recovered from customers or refunded to customers through periodic rate adjustments.[202] In other words, the utility recovers "margin" shortfalls from customers and refunds "margin" surpluses to customers in future rate changes. The Commission caps accruals to the balancing account at 5 percent of gross revenues and amortizations at 2.5 percent. The CET has had small annual percent changes in the base rate, either upward or downward.

The decoupling experience in Utah parallels that in other states. One national study[203] makes two major conclusions, which apply to revenue-decoupling mechanisms such as the CET. First, revenue-decoupling rate adjustments are mostly small—within plus or minus 2 percent of retail rates. Specifically, the study said that:

> Across the total of all utilities and rate adjustment frequencies, 64% of all adjustments are within plus or minus 2% of the retail rate. This amounts to about $2.30 per month for the average electric customer and about $1.40 per month for the average natural gas customer.[204]

For the CET, annual rate increases adjustments have never exceeded 0.54 percent.

Second, the study shows that revenue decoupling mechanism has involved both refunds and surcharges: The study found that across all electric and gas utilities and all adjustment frequencies, 63 percent were surcharges and 37 percent were refunds. Since its inception, the CET has triggered nine upward rate adjustments and five downward rate adjustments, close to the national average of rate increases being less than twice the frequency of rate decreases.

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[201] Measurement of the base revenue per customers has changed from a historical level, a three-year average, to a proposed (as of this writing) forecasted level.

[202] The CET divorces Questar's non-gas revenues from the temperature-adjusted sales per customer. The utility has a weather-normalization adjustment that offsets the revenue effect of temperature variations.

[203] Pamela Morgan, "A Decade of Decoupling for U.S. Energy Utilities: Rate Impacts, Designs, and Observations," Revised February 2013 at http://switchboard.nrdc.org/blogs/rcavanagh/Decoupling%20report%20Final%20Feb%202013%20-%20pdf%20(2).pdf.

[204] Ibid., 3.

### F. Ohio gas utilities' straight fixed-variable (SFV) rates

Under SFV rates, the utility recovers all distribution costs (base rates) in the fixed component.[205] In describing SFV rates, Ohio Supreme Court remarked that:

> Under traditional natural-gas rate design, a small portion of the utility's fixed delivery costs is recovered through a low fixed monthly customer charge with the remaining fixed distribution costs recovered through a rate that varies with gas usage. The SFV rate design separates or "decouples" the utility's recovery of its costs of delivering gas (which are predominantly fixed) from the amount of gas that customers actually use (which varies from month to month). Under the modified SFV rate structure approved in the Duke and Dominion cases, most fixed costs of delivering gas are collected through a higher flat customer charge, with the remaining fixed costs recovered through a correspondingly lower variable gas-usage component.[206]

SFV rates recognize that a gas utility's non-gas costs are independent of throughput; thus, all residential customers pay the same amount for distribution service, no matter how much gas they consume. The rates would eliminate subsidies from high-usage customers to low-use customers.

Three Ohio gas utilities during 2007–2008 proposed revenue decoupling with true-ups in the form of surcharges for delivery cost recovery. In all instances, instead, the Public Utilities Commission of Ohio ruled in favor of SFV rates. Commission staff was a major driver in supporting SFV rates. In its Order for the Duke Energy docket, the Commission stated that:

> Staff maintains that the evidence of record clearly indicates that Duke's revenue erosion problem is real and that the levelized rate design is the better way to balance the utility's desire for recovery of its authorized return with promotion of energy efficiency as a customer and societal benefit through control of energy bills…Staff asserts that, as long as the bulk of a utility's distribution costs are recovered through the volumetric component of base rates, this decline in per-customer usage threatens the utility's recovery of its fixed costs of providing service. Staff contends that the levelized rate design best addresses this issue while

[205] A modified SFV rate would allocate most, but not all, of the fixed costs of delivering gas to a flat monthly charge. For Duke Energy, the change to a modified SFV rate increased the flat charge for residential customers from $6 to around $20-$25, offset by a lower volumetric charge to recover the remaining fixed distribution costs.

[206] *Ohio Consumers' Counsel v. Pub. Util. Comm.*, 127 Ohio St.3d 524, 2010-Ohio-6239, Ohio Supreme Court, Decision, December 23, 2010, 1-2.

> simultaneously removing the disincentives to utility-sponsored energy efficiency programs that exist with the traditional rate design.[207]

In its decision for the Duke Energy case, the Commission ruled in favor of SFV rates over a revenue-decoupling rider:

> On balance, the Commission finds the levelized rate design advocated by Duke and Staff to be preferable to a decoupling rider. Both methods would address revenue and earnings stability issues in that the fixed costs of delivering gas to the home will be recovered regardless of consumption. Each would also remove any disincentive by the company to promote conservation and energy efficiency. The levelized rate design…has the added benefit of producing more stable customer bills throughout all seasons because fixed costs will be recovered evenly throughout the year. In contrast, with a decoupling rider, as favored by [the Office of the Ohio Consumers' Counsel], customers would still pay a higher portion of their fixed costs during the heating season when their bills are already the highest, and the rates would be less predictable since they could be adjusted each year to make up for lower-than-expected sales… A levelized rate design also has the advantage of being easier for customers to understand. Customers will transparently see most of the costs that do not vary with usage recovered through a flat monthly fee. Customers are accustomed to fixed monthly bills for numerous other services, such as telephone, water, trash, internet, and cable services. A decoupling rider, on the other hand, is much more complicated and harder to explain to customers.[208]

One utility gradually transformed its rate design to SFV over the course of two rate cases. Making the transition smoother helps to avoid a large bill impact for some customers. The lesson here is that any radical change in rate design or rates in general requires politically that they gradually, over a multiyear period, affect those who become worse off. Imposing an immediate and large burden on the losers would likely meet with

[207] The Public Utilities Commission of Ohio, *In the Matter of the Application of Duke Energy Ohio, Inc. for an Increase in Rates et al., Opinion and Order,* Case No. 07-589-GA-AIR et al., May 28, 2008, 13.

[208] Ibid., 18.

strong opposition, undermining ratemaking reforms.[209] In other words, it would fail the critical public-acceptability criterion.[210]

Commission staff found that, on average, low-income customers are not low-usage customers. This evidence helped to dispose of the general perception that moving to a SFV rate would disproportionally harm poor households. In fact, it suggests that poor households would (1) see lower winter gas bills under a SFV rate and (2) no longer subsidize higher-income customers.

In the Duke and Dominion rate cases, the Office of the Ohio Consumers' Counsel and the Ohio Partners for Affordable Energy opposed the SFV rate.[211] They favored a revenue decoupling rider in conjunction with the traditional rate design that recovers a portion of the utility's fixed costs in the volumetric charge. They have two major concerns with SFV rates: (1) They discourage customers to conserve, since at the margin they would see lower prices; and (2) they would harm low-usage customers, including poor households. Groups have also raised these concerns in other states where utilities have proposed SFV rates.

Staff indicated to the author that education was crucial in gaining customer acceptance of SFV rates. Although the Commission initially had to answer questions from many customers about the new rate design, they have subsided over time with apparent little opposition to SFV rates, at least by the vast majority of customers. SFV rates so far have taken a back seat to revenue decoupling across the country as a mechanism to protect utilities from revenue erosion. Utilities have, however, become more aggressive in proposing SFV rates to their state commissions.[212]

### G. California's inverted rates

California statutes require the Public Utilities Commission to set inverted rates. Legislation passed in 2001 initiated a five-tier inverted rate structure in addition to

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[209] Staff indicated to the author that the distribution charge constitutes only about 20 percent of an average customer's total gas bill. Thus, even if the distribution charge increased substantially for some customers, namely, low-usage customers, the percent change in their total bill would be one-fifth of the percent change in the distribution charge.

[210] As one analyst has put it, changes of any kind must strive to cushion the effect on the losers or "the train will never leave the station."

[211] Other parties in these cases did not take a position on SFV rates.

[212] In early January, for example, PacifiCorp proposed a hike in fixed charges for its Utah residential customers, including $4.25 per month for net-metered solar customers. In its rate case, PacifiCorp contended that it needs to recover more revenue from the fixed portion of residential bills in view of declining electricity use per customer. Without higher fixed fees, the utility argued that it would have a disincentive to promote energy efficiency. Customers with renewable generation would pay an additional $4.25 net metering facilities charge.

freezing rate changes for the first two tiers.[213] Since that time, higher tiers have had to shoulder utility cost increases, which have led to higher-tier rates deviating farther from cost. Legislation in 2009 allowed for modest increases in tier one and two rates.

The passage of new legislation in October 2013 reflected the intent of the lawmakers in California to have the Commission modify existing rate design, including revamping or eliminating inverted rates.[214] One reason for this recent skepticism toward inverted rates is the strong incentive they have given high-usage electricity customers to install solar PV systems and avail themselves of the generous net energy-metering rates in the state. The legislation allows the Commission to redesign rates to become more equitable and reflective of cost of service. It also gives the Commission authority to increase the monthly fixed charge (at a cap of $10, except for distributed-generation customers).[215]

California has the steepest inverted rate design in the country, with marginal consumption on higher tiers costing three times or more the level of baseline consumption. Compared to most inverted rates, California has more tiers and, according to some analysts, the most distorted prices. Currently, the state's three largest utilities have either three, four, or five tiers.

Some policymakers favor inverted rates because they encourage energy efficiency. They can also promote economic efficiency when the utility's marginal cost is greater at higher tiers. Higher-tier rates above marginal costs like in California, however, would tend to lead to deficient usage of electricity.[216] Net metering in conjunction with technologies such as rooftop solar PV systems has excessively stimulated customers who pay above-cost top tier electricity prices to invest in distributed generation.[217] This outcome is evident in California, where the Public Utilities Commission is investigating the future of inverted rates. One alternative for mitigating this problem is to (1) impose a fixed customer charge on customers who install a rooftop solar system and (2) increase the customer charge for other customers. The utility can then lower the rates in the higher tiers closer to marginal cost. Evidence for California

[213] The first two tiers included usage not exceeding 130 percent of the baseline. Thus, customers with higher usage (in tiers 3-5) had to bear the full brunt of any utility rate increases.

[214] At the time of this writing, the Commission is considering new electric rate structures in Rulemaking R.12-06-013.

[215] Other rate topics to be addressed by the Commission are: (a) real-time and critical peak pricing, (b) demand charges, (c) low-income subsidies, and (d) net energy metering tariffs.

[216] This condition can easily occur. The marginal cost for a utility at any particular time depends on coincident demand. High-demand periods for the utility system as a whole may not coincide with high-demand periods for individual customers. Thus, the high-tier rates are unlikely to correlate well with the system marginal cost.

[217] Much larger increases in rates for the highest tiers compared to the lower tiers over the past several years have caused this problem.

has shown that top-tier utility-electricity customers are subsidizing lower tier customers.[218]

Another argument against inverted rates is that many low-income customers consume above-average amounts of electricity and natural gas.[219] Many wealthy households also consume a relatively small amount of energy. Using inverted rates to assist the poor may, therefore, be counterproductive in assisting poor households. Non-targeted inverted rates (i.e., eligibility for inverted rates does not depend on a household's income) inadvertently can benefit high-income, low-energy-use customers.

To elaborate, if the policy objective is to subsidize low-income customers, more cost-effective ways exist.[220] Giving a lump-sum credit or rate discounts to eligible households could achieve the same goals at lower cost than "subsidizing" utility customers. Some non-poor customers inevitably benefit when inverted rates do not require that customers paying the first-tier rate have low incomes. Under this rate, benefits could accrue randomly across households with wide-ranging incomes. Energy usage varies widely across households, not necessarily because of income differences but because of other factors such as household size and consumer preferences. Some higher-income households might consume smaller amounts of energy because of their financial ability to make investments in energy efficiency.[221]

Regulators approving inverted rates argue that they encourage energy efficiency and provide customers with lower marginal prices for "essential" electricity and gas use. A simple example of inverted rates is when a customer pays 8 cents per kilowatt-hour (kWh) for the first 500 kWhs consumed in a month, and 12 cents for all additional kWhs.

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[218] Analysts have shown three sources of intra-class subsidies in California: (a) inverted rates, (b) the absence of time-of-use rates and (c) low-income energy assistance.

[219] One reason is that poor households are less able to afford energy efficiency, especially those initiatives that require large investments (i.e., high upfront costs).

[220] *See* the previous discussion in Part V.C.2, and Severin Borenstein, "Regional and Income Distribution Effects of Alternative Retail Electricity Tariffs," Working Paper EI@Haas WP 225, October 2011.

[221] On the other hand, one could argue that income and energy consumption have a fairly strong correlation, e.g., wealthier households tend to own larger homes and have more discretionary energy-consuming appliances. The correlation also might substantially differ between electricity and natural gas. Since the early 1980s, national statistics show that the difference in energy consumption between households eligible for federal assistance and other households slightly declined. *See*, for example, U.S. Energy Information Administration, *Residential Energy Consumption Survey*, various issues, at http://www.eia.doe.gov/emeu/consumption/index.htm.

These rates provide benefits to low-income households only when they consume low amounts of energy relative to other customers.[222]

In sum, when inverted rates fail to reflect marginal cost, they are discriminatory against the largest users and economically inefficient.[223] They also make a utility's revenues and earnings more volatile and less predictable.[224] Perhaps most damaging, they can harm those customers, namely low-income households, that they are supposed to help. The real lesson here is that using rate design to advance a social agenda—namely, assisting low-income households while at the same time promoting energy efficiency—can create new problems and conflict with core regulatory objectives. To say it differently, the experience of inverted rates in California is a good example of unintended consequences with apparent adverse effects on the public interest.

## VII. Final Thoughts

After all is said and done, three major questions face regulators in deciding on the merits of different rate mechanisms: (1) What are the objectives of ratemaking? (2) What effective their relative importance in advancing the public interest? (2) What rate mechanisms are most effective in achieving those objectives? (3) What rate mechanisms would benefit both utilities and their customers?

The last question is compatible with the "balancing act" wherein any regulatory action, including ratemaking, should produce a non-zero-sum game, with both utility investors and customers benefiting. Some of the alternative rate mechanisms violate this condition by leaving out utility customers as beneficiaries. They either shift risk to customers or allocate no direct benefits to them. Many of the alternative rate mechanisms are more transparent in benefiting individual stakeholders (notably, utility shareholders and environmentalists) and not the public interest.

Commissions should consider, for decision making, grouping their objectives into core and non-core. Frequently, interest groups pressure commissions to promote new objectives at the expense of core principles. Although core principles differ by

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[222] As some studies have shown, however, many low-income households are above-average usage customers.

[223] There is the real problem, for example, of charging two customers different rates at any one time when they impose the same marginal cost on a utility. The only logical conclusion is that the customer being charged the higher rate (e.g., the customer on the higher-rate tier) is being discriminated against.

[224] Inverted rates, like volumetric rates that include fixed costs, increase the risk that a utility will under-recover its fixed cost, because it disproportionately collects those costs through the higher rate tiers where the greatest amount of usage volatility occurs. This is one reason why utilities tend to oppose inverted rates.

jurisdiction, they all call for a financially healthy utility that provides reliable and safe service at a cost reflecting prudent utility management.

One message conveyed by this paper is that ratemaking is as much an art as a science, requiring regulators to impute their subjective values and judgment in decision making. Analysts can play an important role, however, by providing regulators with vital information on the inevitable tradeoffs among the various objectives that they assign to ratemaking.

Some alternative rate mechanisms might result in all stakeholders being better off. At least in theory, if they result in a net efficiency gain, all parties can benefit, although in practice, politically and administratively, it may be difficult to prevent losers.

As part of their duties, commissions take into consideration the positions of different stakeholders, whose views often diverge and reflect opposing positions on individual rate mechanisms. To be blunt, stakeholders have their own agenda to pursue; commissions are in the unique position of doing what is best from the public's perspective, which is a most challenging task. After all, special interests do not represent the broad public interest. The public interest is diffused and not well-organized, so commissions should act as its advocate in the regulatory arena.

In conclusion, pressures from different stakeholders for ratemaking changes have provoked state legislatures and public utility commissions to modify utility ratemaking, sometimes fundamentally. Whether these changes, or what some observers call "reforms," have improved utility performance and long-term customer welfare awaits empirical analysis. There is also the question of whether state legislatures, given their lack of expertise in technical and often complex utility matters, should have any role in reforming ratemaking practices. We observe, in particular, alarmingly more intrusive state legislation in ratemaking matters that regularly promote the interests of a single stakeholder while damaging the interests of others. These actions, in other words, often violate the "balancing act" principle that lies at the heart of state public utility regulation.

# Appendix: Examples of Alternative Rate Mechanisms

**A.** **Incremental changes to traditional ROR regulation**

**1.** CWIP in rate base

**2.** Phase-in plan

**3.** Future test year

**4.** Accelerated depreciation[225]

**5.** Interim rate relief

**B.** **Multiyear plans**

**1.** UK-style price caps (e.g., Central Maine Power)

**a.** Has strong incentives for cost efficiency as allowed price changes depend on exogenous factors (e.g., industry cost index)

**b.** Has potential for high profit volatility

**c.** Avoids frequent (e.g., annual) general rate cases

**d.** Often combined with performance standards for service quality and an earnings sharing mechanism

**2.** Multiyear test period (e.g., New York and California utilities, Xcel)

**a.** Uses forecasted revenue and cost parameters, e.g. over the next three years

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[225] *Accelerated depreciation* allows the utility to improve its cash flow in the early years of an asset's life, which can help to finance a new technology. It increases, however, the burden on customers by increasing their rates in the near term. Book depreciation, in comparison, can delay retirements of obsolete plant. To retire an asset not yet fully depreciated can result in the old capital asset becoming "stranded," leaving the utility with the potential to lose future cost recovery from the asset. The utility may then decide not to invest in a new technology or other innovation until the old asset has fully depreciated. Most state utility commissions use book depreciation, which relates annual depreciation to three factors: (1) the original cost of property plus the cost of removal less estimated salvage value; (2) the estimated service life over which the utility writes off the asset property; and (3) the method used to distribute value over this life, usually straight-line depreciation.

**b.** Uses cost forecasts for an individual utility or an exogenous index (which provides stronger incentives for cost efficiency)

**c.** Specifies annual dollar amounts of revenue increases or uses a formula

**d.** Sometimes applies earnings sharing mechanism when ROE falls outside a predefined band

**e.** Avoids frequent (e.g., annual) general rate cases

**f.** Frequency has a **"**stay out**"** provision

**C. A comparison of a revenue decoupling (RD) rider with a straight fixed-variable (SFV) rate**

**1.** Definition of RD

**a.** Outside of rate-case price adjustments based on the difference between actual revenues and some specified revenue baseline—e.g., the revenues per customer a utility expects to receive at the time of the last rate case

**b.** "True-up" mechanism that adjusts base rates between rate cases based upon differences between actual revenues and baseline revenues

**c.** Revenue shortfalls or surpluses placed in an account balance for later recovery by the utility or reimbursement to customers; recovery or reimbursement done monthly, quarterly, or at some other regular interval

**d.** Recovery of fixed costs based on baseline revenues, not actual sales, hence the term "decoupling"

**e.** A (hard or soft) revenue cap, on either a per-customer basis or total customer-class basis

**2.** The rationales for RD

**a.** It eliminates the disincentive for utilities to promote energy efficiency.

**b.** Standard rate design places the utility at risk for recovering its fixed costs, with the risk increasing in recent years because of declining usage per customer.

**c.** RD is superior to alternative rate designs in achieving revenue stability and promoting energy efficiency.

**d.** RD represents an incremental change in ratemaking practices that would advance some regulatory objectives at little cost to other objectives.

**e.** It would result in small annual rate adjustments, either upward or downward.

**3.** Analysis of RD compared with SFV rates

**a.** Arguments in support of RD

**(1)** It avoids the poor and sometimes distorted incentives of cost trackers.[226]

**(2)** It does not diminish the incentive, like SFV, for price-driven energy efficiency.

**(3)** It does not cause a utility to earn excessive returns.

**(4)** It avoids the problem of determining test-year sales.

**(5)** It would seem to coincide better with the "gradualism" and "public acceptability" objectives of regulation than (say) SFV rates

**b.** On the other hand, SFV has attractive features:

**(1)** It is compatible with sound economic (e.g., marginal cost) principles

**(2)** It increases the competitiveness of the utility for high-usage customers from a lower volumetric charge.

**(3)** It eliminates intra-class subsidies favoring low-usage customers.

**(4)** It is simple to implement and for customers to understand.

**(5)** It is a common pricing method for capital-intensive services.

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[226] This is not really an argument for RD but an explanation for why not to lump RD with cost trackers, which some stakeholders have done.

**(6)** It involves no periodic true-up or price changes between rate cases, resulting in longer regulatory lag.

**(7)** It results in more stable utility bills during the peak months; thus, it is a better bill hedge than the typical rate design (e.g., it allocates more of the fixed costs from high-usage periods to low-usage periods).

## D. Alternative rate designs departing from average-cost pricing and the standard two-part tariff

**1.** Straight fixed-variable rate

**2.** Real-time pricing

**3.** Time-of-use pricing

**4.** Critical peak pricing

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# Making Utility Assistance to Low-Income Households More Effective

**Kenneth W. Costello**

*Regulators can engage in smart policymaking to make utility services affordable for low-income households.*

Affordability has become a greater concern for regulators, utilities, and consumer groups, especially due to the COVID-19 pandemic and the expectation in some jurisdictions that electric rates will rise rapidly over the next several years. Households affordability of electricity and natural gas demands some form of special utility assistance or subsidy. State utility regulators must put forward smart initiatives to subsidize utilities for low-income houses.

Affordability by one definition entails households being able to pay for their utility services without jeopardizing their ability to purchase other essential goods and services, such as food, medicine, and housing. A commonly used "affordability" metric is the ratio of utility bills to income. The real culprit of unaffordable utility service is inadequate income.

The U.S. government operates special utility assistance initiatives—or SUAs. But whether regulated utilities should themselves assure the affordability of their service for low-income customers is a question that has occupied policymakers for several decades.

Political pressures and legislative mandates have ultimately compelled utilities, with approval by their regulators, to protect low-income households from unaffordable utility bills. Some observers view these actions as "taxation by regulation" that require slightly higher rates to the majority of customers to pay for an SUA benefitting a smaller, target group of customers. This "tariff effect," which makes the majority minimally worse off to make a small minority materially better off, has definite political appeal in a wide range of government activities.

Public utility regulators are on the front lines in evaluating and approving these initiatives in the public interest, conditioned on legal, economic, and other constraints. Increased effectiveness of these programs means that more dollars are going to eligible low-income households—not wasted on excessive administrative costs or benefitting non-needy households.

Smart regulation requires that an SUA funded by utility ratepayers provide adequate benefits to the intended targets, namely, eligible low-income households. But because funding for an SUA typically falls short of meeting the needs of *all* low-income households, regulators should try to ensure that each dollar expended returns the highest possible dividend.

In dealing with an "affordability" problem, policymakers can apply one of three broad approaches: increasing the incomes of poor households; lowering the share of the utility bill for which the customer is responsible for paying; or reducing the customer's utility usage.

SUA initiatives focus on the latter two approaches, while cash supplements fall under the first approach. With each approach, utility services become more affordable, either by increasing a household's income or by reducing the amount a household must spend on utility services.

Various kinds of SUAs have differing effects on recipients, funding utility customers, and utility shareholders, as well as on society in general. Most SUA initiatives reduce energy bills for eligible households either by lowering the effective price of utility service or by reducing energy consumption through, for example, weatherization programs. These initiatives leave households with more discretionary money to purchase other goods and services, some of which are as essential as utility service.

Regulators and other policymakers should identify the criteria for socially desirable SUAs. No single initiative comes out favorably in meeting all criteria, but some of them satisfy certain criteria while satisfying others less well. Six primary criteria indicate socially desirable SUAs:

- the recipients of an SUA should receive maximum benefits relative to the dollars funded by utility customers;
- consumer education should make eligible households aware of available assistance and how to reduce their energy bills;
- an SUA should avoid large efficiency losses or cross-subsidization;
- an SUA should have reasonable administrative costs;
- funding should have a tolerable financial effect on individual subsidizing customers; and
- an SUA should lower collection costs, service disconnections, arrearages, and debt write-offs.

The principle of "spreading the burden" across many utility customers reduces the financial cost on individual utility customers. But questions arise as to which utility customers should fund the subsidies and at what point does the "subsidy" cost becomes excessive. A well-intentioned objective that attempts to reduce low-income households' energy burden to the level of other households could lead to an excessive increase in general rates that violates equity and other regulatory goals.



Rate relief to low-income households could also benefit all customers if in its absence the utility would have disconnected low-income households, or those customers would have accumulated large debt or costs associated with service reconnection.

Some utilities consider an SUA a good business strategy when it increases their net revenues. Without subsidies, a utility is likely to receive only partial bill payments from some low-income households—and collecting unpaid amounts incur additional costs. If the unpaid amount becomes uncollectible, the utility would likely write off this amount as bad debt.

Alternatively, the utility might be able to avoid those costs by discounting customers' bills. These cost reductions can more than offset the lost revenues from discounting and thereby increase the utility's net revenues or reduce the burden on subsidizing customers.

Such outcomes probably explain why some utilities have initiated SUAs to help low-income households: Utilities might find it easier to garner regulatory favors, such as approval for recovery of revenue shortfalls, when they champion an SUA.

The most important message to take here is that an SUA should maximize the benefits to targeted households relative to the funding provided by other utility customers, and it should minimize adverse effects. In funding and executing an SUA, regulators should control for distortions in subsidy pricing and recipient behavior from moral hazard incentives that cause customers to not pay their utility bills on time or at all with little consequences.

Regulators should review current SUA initiatives to determine whether they operate most effectively and with minimal adverse effects on other regulatory goals. This balance is rarely achieved and prevents an SUA from being as effective as it can be. Regulators can do better.

*Kenneth W. Costello is a regulatory economist.*

Tagged: electric grid, Electricity, Energy, low-income communities, utility regulation

I/A

E-7. Sub 1276
Public Staff
Lucas Exhibit 1




| Site | Physical address | Nomenclature to identify CCR storage area | | Years during which CCR storage area was in operation (receiving or storing CCR) | Amount of CCR disposed of cumulatively (tons) | Amount of CCR disposed of cumulatively (cubic yards) | Status |
|---|---|---|---|---|---|---|---|
| Allen | 253 Plant Allen Rd., Belmont, NC 28012 | Pond | Retired Ash Basin | 1957-1973 | 6,152,310 | 5,126,925 | Landfilling |
| | | Pond | Active Ash Basin | 1972-2018 | 10,479,837 | 8,733,198 | Landfilling |
| | | Fill | Ash Fill 1 | 2004-2009 | 428,400 | 357,000 | Landfilling |
| | | Fill | Ash Fill 2 | 2004-2009 | 562,800 | 469,000 | Landfilling |
| | | Fill | Subgrade for Landfill | 2010-2010 | 600,000 | 500,000 | Closed |
| | | Landfill | RAB Landfill | 2010 - present | 1,140,508 | 950,423 | Landfilling |
| Belews Creek | 3195 Pine Hall Rd., Belews Creek, NC 27009 | Pond | Active Ash Basin | 1972-2018 | 11,971,315 | 9,976,096 | Landfilling |
| | | Fill | Structural Fill | 2004-2009 | 986,400 | 822,000 | Closed |
| | | Landfill | Pine Hall Rd. Landfill | 1984-2014 | 3,616,800 | 3,014,000 | Closed |
| | | Landfill | Craig Road Landfill | 2007 - present | 1,995,653 | 1,663,044 | Final disposal |
| | | Landfill | Gypsum (FGD) Landfill | 2008 - present | 961,701 | 801,418 | Final disposal |
| Buck | 1385 Dukeville Rd., Salisbury, NC 28146 | Pond | Ash Basin 1 (additional primary pond) | 1982-2013 | 3,550,800 | 2,959,000 | Active Beneficiation Site |
| | | Pond | Ash Basin 2 (Primary Pond) | 1957-2013 | 1,998,000 | 1,665,000 | |
| | | Pond | Ash Basin 3 (Secondary pond | 1977-2013 | 864,000 | 720,000 | |
| | | Fill | Ash fill area | 2009-2010 | 235,200 | 196,000 | |
| Cliffside | 573 Duke Power Rd., Mooresboro, NC 28114 | Pond | Units 1-4 Inactive Ash Basin | 1957-1977 | 455,259 | 379,383 | Closed |
| | | Pond | Unit 5 Inactive Ash Basin | 1970-1980 | 2,352,000 | 1,960,000 | Landfilling |
| | | Pond | Active Ash Basin | 1980-2018 | 5,038,467 | 4,198,723 | Landfilling |
| | | Fill | Ash Storage 1 (part of active ash basin) | early 1980's | 204,000 | 170,000 | Landfilling |
| | | Landfill | CCP Landfill | 2010 - present | 2,065,703 | 1,721,419 | Final disposal |
| Dan River | 864 S Edgewood Rd., Eden, NC 27288 | Pond | Primary Ash Basin | 1956 - 2012 | 1,288,292 | 1,073,577 | Closed |
| | | Pond | Secondary Ash Basin | 1977 - 2012 | 494,360 | 411,967 | Closed |
| | | Fill | Ash Fill 1 | 1980 - unknown | 954,500 | 795,417 | Closed |
| | | Fill | Ash Fill 2 | 1980 - unknown | 115,626 | 96,355 | Closed |
| | | Landfill | Dan River Landfill | 2017-present | 2,073,096 | 1,727,580 | Closed |
| Marshall | 8320 NC Hwy. 150 E, Terrell, NC 28682 | Pond | Active Ash Basin | 1965 - 2018 | 16,835,839 | 14,029,866 | Landfilling |
| | | Fill | Structural Fill (solar panels) | 2000 - 2013 | 6,492,000 | 5,410,000 | Closure in process |
| | | Fill | Subgrade fill (Cells 1&2) | 2010 - 2011 | 462,000 | 385,000 | |
| | | Fill | Subgrade fill (Cells 3&4) | 2011 - 2012 | 409,200 | 341,000 | |
| | | Landfill | Old Ash Fill (part of retired landfill) | 1984 - 1986 | 626,400 | 522,000 | |
| | | Landfill | Retired Landfill (permit 18-04) | 1986 - 1999 | 4,876,800 | 4,064,000 | Landfilling |
| | | Landfill | Industrial Landfill (Permit 18-12) | 2011 - present | 2,053,990 | 1,711,658 | |
| | | Landfill | FGD Landfill (permit 18-09) | 2006 - 2019 | 1,068,728 | 890,607 | |

| Site | Physical address | Nomenclature to identify CCR storage area | | Years during which CCR storage area was in operation (receiving or storing CCR) | Amount of CCR disposed of cumulatively (tons) | Amount of CCR disposed of cumulatively (cubic yards) | Status |
|---|---|---|---|---|---|---|---|
| Riverbend | 175 Steam Plant Road, Mt. Holly, NC 28120 | Pond | Primary Ash Basin | 1957-2014 | 2,619,350 | 2,182,792 | Closed |
| | | Pond | Secondary Ash Basin | 1957-2014 | 995,400 | 829,500 | Closed |
| | | Fill | Ash fill area | 1979 - 2007 | 1,361,400 | 1,134,500 | Closed |
| | | Fill | Cinder Pit | 1929-1957 | 202,700 | 168,917 | Closed |
| WS Lee | 205 Lee Steam Plant Rd., Belton, SC 29627 | Pond | Primary Ash Basin | 1974-2014 | 2,247,003 | 1,872,503 | |
| | | Pond | Secondary Ash Basin | 1978-2014 | 46,203 | 38,503 | |
| | | Fill | Ash Fill Area (Old ash fill area) | 1951 - 1974 | 378,989 | 315,824 | |
| | | Pond | 1951/1959 Inactive Ash Basin | 1951-1974 | 1,178,337 | 981,948 | |
| | | Fill | Structural Fill | 2000 - 2007 | 859,200 | 716,000 | |

**§ 130A-309.216. Ash beneficiation projects.**

(a) On or before January 1, 2017, an impoundment owner shall (i) identify, at a minimum, impoundments at two sites located within the State with ash stored in the impoundments on that date that is suitable for processing for cementitious purposes and (ii) enter into a binding agreement for the installation and operation of an ash beneficiation project at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all ash processed to be removed from the impoundment(s) located at the sites. As soon as legally practicable thereafter, the impoundment owner shall apply for all permits necessary for the ash beneficiation projects from the Department. The Department shall expedite any State permits and approvals required for such projects. No later than 24 months after issuance of all necessary permits, operation of both ash beneficiation projects shall be commenced. An impoundment owner shall use commercially reasonable efforts to produce 300,000 tons of ash to specifications appropriate for cementitious products from each project.

(b) On or before July 1, 2017, an impoundment owner shall (i) identify an impoundment at an additional site located within the State with ash stored in the impoundment on that date that is suitable for processing for cementitious purposes and (ii) enter into a binding agreement for the installation and operation of an ash beneficiation project capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all ash processed to be removed from the impoundment(s) located at the site. As soon as legally practicable thereafter, the impoundment owner shall apply for all permits necessary for the ash beneficiation project from the Department. The Department shall expedite any State permits and approvals required for such projects. No later than 24 months after issuance of all necessary permits, operation of the ash beneficiation project shall be commenced. An impoundment owner shall use commercially reasonable efforts to produce 300,000 tons of ash to specifications appropriate for cementitious products from the project.

(c) Notwithstanding any deadline for closure provided by G.S. 130A-309.214, any impoundment classified as intermediate- or low-risk that is located at a site at which an ash beneficiation project is installed, operating, and processing at least 300,000 tons of ash annually from the impoundment, shall be closed no later than December 31, 2029. (2016-95, s. 1.)

## Reclaimed STAR® Ash Plant

### News

- The SEFA Group, is building a $40 million facility to recycle high carbon fly ash produced by the power company Santee Cooper at its Winyah generating station in Georgetown, S.C.
- SEFA also will take in coal fly ash from other Santee Cooper electric generating stations, where the material will be processed into a marketable product.
- The new facility is expected to recycle up to 400,000 tons of fly ash per year. SEFA will use the material as a primary ingredient for its STAR process to produce a pure mineral product, free of organic contaminants.

THE SEFA GROUP

www.sefagroup.com

## Reclaimed STAR® Ash Plant

### News

- Santee Cooper has worked to recycle as much of its ash as possible (90%). ...with EPA regulations spurring the closure of coal-fired generating stations around the country, there has become greater demand for ash and the development of new technology that increases the viability of pond ash.

  R.M. Singletary, executive vice president of corporate services, says "This is a triple win. It is cost effective, which means it is responsive to our customers' best interests. It utilizes innovative technology to help an important South Carolina industry be sustainable. And it is an EPA-approved use of ash."

THE SEFA GROUP

www.sefagroup.com

**G. Coal ash insurance litigation proceeds.** The Settling Parties agree that Customers will receive one hundred percent (100%) of the first **[BEGIN CONFIDENTIAL]** $ [redacted] **[END CONFIDENTIAL]** in NC retail allocable proceeds the Companies receive from any coal ash insurance litigation, without reduction for any attorneys' fees incurred. This amount shall be kept confidential, and redacted in any publicly filed or publicly available copy of this CCR Settlement Agreement. Any coal ash litigation proceeds received above this amount will be shared equally between Customers and the Companies without reduction for any attorneys' fees incurred. Any such proceeds due to Customers under this provision will be applied by the Companies in the form of an offset to CCR Costs. In any proceeding before the Commission, or in any appeals therefrom, the Settling Parties further agree not to oppose any request by the Companies to seek approval to defer their legal costs associated with the coal ash insurance litigation. The Intervenor Settling Parties reserve their respective rights to review and object to the recovery of such legal costs in future rate cases.

North Carolina Public Staff
Data Request No. 97
DEC Docket No. E-7, Sub 1276
Item No. 97-6


**Request:**

6. Please provide copies of any asbestos studies that show the presence of asbestos that DEC has not removed.

**Response:**

There have been no additional studies, outside of the estimates provided in the Decommissioning Cost Estimate Study, required to support asbestos removal or abatement for DEC sites.

North Carolina Public Staff
Data Request No. 97
DEC Docket No. E-7, Sub 1276
Item No. 97-8

**Request:**

8. Page 15, item 39, states: "A 20 percent contingency was included on the direct costs in the estimates prepared as part of this Study to cover unknowns." Please explain how "1898 & Co." determined this percentage.

**Response:**

1898 & Co. provided the following response:

"The percentage of contingency applied to any cost estimate is directly related to the level of unknowns associated with the project. We would apply higher contingency at early stages of planning when there are more potential unknowns. For instance, when preparing construction cost estimates for a new fossil-fuel generation facility on a greenfield site, we would typically determine the level of contingency based on the stage of planning or execution that we are in, which impacts the level of unknowns, which would include potential scope changes as well as weather delays and other factors.

As engineering design progresses and some of these unknowns can be reduced through subsurface investigations, engineering design drawings, and engineering specifications, the amount of contingency may be reduced, and a lower level of contingency would be applied. However, contingency would never be completely eliminated, even after full detailed design is completed, because some unknowns, like weather delays, cannot be completely eliminated.

The dismantlement cost estimates prepared as part of this filing are similar to the types of cost estimates made in the early stages of planning for a new fossil-fuel generation facility on a greenfield site. However, a dismantlement cost estimate presents additional risks that must be accounted for in the contingency. Dismantlement activities occur on sites where power generation has been ongoing for many years and environmental contamination is more likely than on a greenfield site. In addition, no on-site testing for hazardous materials and potential environmental contamination has been performed during these planning stages to fully identify all of these items. No subsurface investigations or groundwater sampling has been performed to identify and define remediation requirements. And some unknowns, such as below grade storage tanks or piping, which may contain hazardous materials, may not be uncovered until the dismantlement process is underway.

In general, it is reasonably expected that changes to the scope of decommissioning that could occur at the time of execution of the decommissioning project would result in cost increases, over the base cost estimates. For example, 1898 & Co.'s cost estimates include minimal levels of environmental remediation, so contingency is required to cover the risk that additional contamination exists.

In addition, other factors that impact risk include changes to market conditions, weather delays, scrap price changes, etc. The further out in the future that the decommissioning activities will occur, the greater the risk that pricing could exceed the current baseline estimates. In conclusion, a 20 percent contingency on these costs is reasonable and warranted based on the level of risk associated with the decommissioning projects.

For all of these reasons, our experience with actual dismantlement costs relative to dismantlement cost estimates, and our professional judgment, we recommend and apply a 20% contingency to dismantlement cost studies, consistent with the studies we have prepared for various utility clients throughout the United States. A 20% contingency on site dismantlement estimates has been accepted by many public service commissions."

DEC Decommissioning Study Tables 1-1 and 5-1 with Public Staff's Adjustments

| Plant Name | Gross Decom Cost | Inventory Cost | Salvage Credits | Inventory Credits | Net Project Cost |
|---|---|---|---|---|---|
| 99 Islands | $ 2,961,250 | $ 48,000 | $ (758,000) | $ (5,000) | $ 2,246,250 |
| Allen | $ 58,721,300 | $ 9,356,000 | $ (33,520,000) | $ (936,000) | $ 33,621,300 |
| Bad Creek | $ 6,377,900 | $ 5,719,000 | $ (11,072,000) | $ (572,000) | $ 452,900 |
| Bear Creek | $ 878,600 | - | $ (283,000) | - | $ 595,600 |
| Belews Creek | $ 72,047,500 | $ 33,156,000 | $ (35,814,000) | $ (3,316,000) | $ 66,073,500 |
| Bridgewater | $ 2,015,950 | $ 92,000 | $ (799,000) | $ (9,000) | $ 1,299,950 |
| Buck | $ 11,801,300 | $ 8,219,000 | $ (8,373,000) | $ (821,900) | $ 10,825,400 |
| Cedar Cliff | $ 1,175,300 | - | $ (308,000) | - | $ 867,300 |
| Cedar Creek | $ 1,937,750 | $ 107,000 | $ (945,000) | $ (11,000) | $ 1,088,750 |
| Clemson | $ 635,950 | $ 357,000 | $ (428,000) | $ (35,700) | $ 529,250 |
| Cliffside | $ 67,071,450 | $ 28,973,000 | $ (32,796,000) | $ (2,897,300) | $ 60,351,150 |
| Cowans Ford | $ 3,375,250 | $ 139,000 | $ (4,196,000) | $ (14,000) | $ (695,750) |
| Dan River | $ 12,308,450 | $ 9,857,000 | $ (7,355,000) | $ (986,000) | $ 13,824,450 |
| Dearborn | $ 1,903,250 | $ 25,000 | $ (1,135,000) | $ (3,000) | $ 790,250 |
| DEC Central Storeroom | - | $ 230,080 | $ (23,008) | - | $ 207,072 |
| Fishing Creek | $ 2,808,300 | $ 100,000 | $ (1,461,000) | $ (10,000) | $ 1,437,300 |
| Gaston | $ 3,854,800 | - | $ (2,110,400) | - | $ 1,744,400 |
| Gaston Shoals | $ 2,139,000 | - | $ (294,000) | - | $ 1,845,000 |
| Great Falls | $ 4,394,150 | $ 26,000 | $ (714,000) | $ (3,000) | $ 3,703,150 |
| Hydro Repair | - | $ 43,500 | $ (4,350) | - | $ 39,150 |
| Jocassee | $ 4,097,450 | - | $ (7,224,000) | - | $ (3,126,550) |
| Keowee | $ 3,010,700 | - | $ (2,871,000) | - | $ 139,700 |
| Lark | $ 1,845,750 | $ 62,259,000 | $ (198,000) | $ (6,226,000) | $ 57,680,750 |
| Lincoln | $ 14,927,000 | $ 1,761,000 | $ (16,527,000) | $ (440,000) | $ (279,000) |
| Lookout Shoals | $ 1,785,950 | $ 127,000 | $ (773,000) | $ (13,000) | $ 1,126,950 |
| Maiden Creek | $ 13,907,525 | $ 63,700 | $ (8,677,000) | $ (6,400) | $ 5,287,825 |
| Marshall | $ 52,454,950 | $ 20,743,000 | $ (38,051,000) | $ (2,074,000) | $ 33,072,950 |
| Mill Creek | $ 5,079,550 | $ 766,000 | $ (6,206,000) | $ (191,000) | $ (551,450) |
| Mocksville | $ 2,621,770 | - | $ (1,099,900) | - | $ 1,521,870 |
| Monroe | $ 11,005,845 | $ 45,100 | $ (4,512,500) | $ (4,500) | $ 6,533,945 |
| Mountain Island | $ 2,641,550 | $ 87,000 | $ (1,310,000) | $ (9,000) | $ 1,409,550 |
| Nantahala | $ 1,642,200 | $ 51,000 | $ (838,000) | $ (5,000) | $ 850,200 |

DEC Decommissioning Study Tables 1-1 and 5-1 with Public Staff's Adjustments

| Plant Name | Gross Decom Cost | Inventory Cost | Salvage Credits | Inventory Credits | Net Project Cost |
|---|---|---|---|---|---|
| Oxford | $ 1,536,400 | $ 96,000 | $ (898,000) | $ (10,000) | $ 724,400 |
| Queens Creek | $ 1,001,650 | - | $ (197,000) | - | $ 804,650 |
| Rhodhiss | $ 1,902,100 | $ 111,000 | $ (935,000) | $ (11,000) | $ 1,067,100 |
| Rockingham | $ 5,215,250 | $ 1,689,000 | $ (6,347,000) | $ (422,000) | $ 135,250 |
| Rocky Creek | $ 3,923,800 | $ 9,000 | $ (1,003,000) | $ (1,000) | $ 2,928,800 |
| Tennessee Creek | $ 1,841,150 | - | $ (386,000) | - | $ 1,455,150 |
| Thorpe | $ 3,156,750 | - | $ (527,000) | - | $ 2,629,750 |
| Tuckasegee | $ 1,721,700 | - | $ (154,000) | - | $ 1,567,700 |
| Wateree | $ 3,024,500 | $ 302,000 | $ (1,690,000) | $ (30,000) | $ 1,606,500 |
| Woodleaf | $ 1,140,340 | $ 9,700 | $ (407,500) | $ (1,000) | $ 741,540 |
| WS Lee CT | $ 1,635,300 | - | $ (1,062,000) | - | $ 573,300 |
| WS Lee Boiler | $ 12,165,850 | $ 1,652,000 | $ (4,614,000) | $ (165,000) | $ 9,038,850 |
| WS Lee CC | $ 12,150,900 | $ 4,411,000 | $ (8,428,000) | $ (441,000) | $ 7,692,900 |
| Wylie | $ 2,674,900 | $ 113,000 | $ (1,405,000) | $ (11,000) | $ 1,371,900 |
| TOTAL | $ 424,518,280 | $ 190,743,080 | $ (258,729,658) | $ (19,680,800) | $ 336,850,902 |

E-7, Sub 1276
Public Staff
Lucas Exhibit 8

**Customer Class Fuel Revenues for 2022, with and without the equal percentage change adjustment**

| | E-7, Sub 1250 Jan 2022 | E-7, Sub 1250 Feb 2022 | E-7, Sub 1250 Mar 2022 | E-7, Sub 1250 Apr 2022 | E-7, Sub 1250 May 2022 | E-7, Sub 1250 Jun 2022 | E-7, Sub 1250 Jul 2022 | E-7, Sub 1250 Aug 2022 | E-7, Sub 1263 Sep 2022 | E-7, Sub 1263 Oct 2022 | E-7, Sub 1263 Nov 2022 | E-7, Sub 1263 Dec 2022 | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues WITH the Equal Percent Method** | | | | | | | | | | | | | |
| NC Residential | 31,971,271 | 34,662,841 | 26,774,364 | 21,646,049 | 21,636,364 | 28,767,178 | 33,162,218 | 36,121,220 | 49,544,499 | 34,160,622 | 33,462,435 | 51,547,488 | 403,456,549 |
| NC General Service | 33,019,343 | 33,121,431 | 31,035,163 | 31,656,984 | 32,710,460 | 37,559,617 | 38,940,314 | 42,472,737 | 56,008,399 | 46,023,347 | 42,406,562 | 47,967,452 | 472,921,810 |
| NC Industrial | 17,474,050 | 17,764,649 | 19,575,011 | 18,657,689 | 18,918,796 | 20,933,734 | 20,337,515 | 21,196,918 | 25,751,156 | 24,467,468 | 23,648,667 | 22,412,256 | 251,137,908 |
| NC Public Street Lighting | 363,064 | 361,318 | 387,397 | 312,532 | 375,572 | 384,128 | 327,377 | 385,701 | 500,560 | 1,148,579 | 1,093,416 | 1,160,930 | 6,800,574 |
| NC Total Retail | 82,827,727 | 85,910,239 | 77,771,935 | 72,273,254 | 73,641,192 | 87,644,657 | 92,767,425 | 100,176,576 | 131,804,613 | 105,800,016 | 100,611,080 | 123,088,126 | 1,134,316,842 |
| **Revenues WITHOUT the Equal Percent Method** | | | | | | | | | | | | | |
| NC Residential | 34,417,986 | 37,315,539 | 28,823,368 | 23,302,590 | 23,292,165 | 30,968,689 | 35,700,075 | 38,885,526 | 47,671,587 | 32,869,261 | 32,197,467 | 49,598,858 | 415,043,111 |
| NC General Service | 32,044,216 | 32,143,290 | 30,118,633 | 30,722,091 | 31,744,456 | 36,450,407 | 37,790,330 | 41,218,433 | 57,782,193 | 47,480,913 | 43,749,584 | 49,486,588 | 470,731,134 |
| NC Industrial | 16,632,888 | 16,909,497 | 18,632,713 | 17,759,548 | 18,008,086 | 19,926,030 | 19,358,512 | 20,176,545 | 26,337,234 | 25,024,331 | 24,186,894 | 22,922,343 | 245,874,621 |
| NC Public Street Lighting | 352,342 | 350,648 | 375,956 | 303,302 | 364,481 | 372,784 | 317,709 | 374,311 | 516,412 | 1,184,954 | 1,128,045 | 1,197,697 | 6,838,641 |
| NC Total Retail | 83,447,432 | 86,718,974 | 77,950,671 | 72,087,531 | 73,409,187 | 87,717,910 | 93,166,626 | 100,654,814 | 132,307,427 | 106,559,459 | 101,261,989 | 123,205,486 | 1,138,487,507 |

E-7, Sub 1250 fuel rates in effect from January 2022 through August 2022
E-7, Sub 1263 fuel rates in effect from September 2022 through December 2022

| | |
|---|---|
| | 1,134,316,842 |
| | 1,138,487,507 |
| Rounding Error = | 0.368% |

| | Increase or (Decrease) | Total | Percent |
|---|---|---|---|
| NC Residential | 11,586,561 | 403,456,549 | 2.9% |
| NC General Service | (2,190,677) | 472,921,810 | -0.5% |
| NC Industrial | (5,263,287) | 251,137,908 | -2.1% |
| NC Public Street Lighting | 38,067 | 6,800,574 | 0.6% |

E-7, Sub 1276
Public Staff
Lucas Exhibit 9

**Duke Energy Carolinas, LLC**
**North Carolina Annual Fuel and Fuel Related Expense**
**Summary Comparison of Fuel and Fuel Related Cost Factors**
**Test Period Ended December 31, 2022**
**Billing Period September 2023 - August 2024**
**Docket E-7, Sub 1282**

**Modified Clark Exhibit 1**

**NOT FILED - IN RESPONSE TO PSDR 190**
This view represents the fuel cost increase based on kWh sales (removal of the equal change percentage) and inclusion of Voltage differential.

| Line # | Description | Reference | Residential cents/kWh | General cents/kWh | Industrial cents/kWh | Composite cents/kWh |
|---|---|---|---|---|---|---|
| | **Current Fuel and Fuel Related Cost Factors (Approved Fuel Rider Docket No. E-7, Sub 1263)** | | | | | |
| 1 | Approved Fuel and Fuel Related Costs Factors | Input | 2.0003 | 1.8217 | 1.8396 | 1.901 |
| 2 | EMF Increment (Decrement) cents/kWh | Input | 0.4863 | 0.6254 | 0.5726 | 0.5597 |
| 3 | EMF Interest Increment (Decrement) cents/kWh | Input | | | | |
| 4 | Approved Net Fuel and Fuel Related Costs Factors | Sum | **2.4866** | **2.4471** | **2.4122** | **2.4607** |
| [redacted] | | | | | | |
| | **Proposed Fuel and Fuel Related Cost Factors using Proposed Nuclear Capacity Factor of 93.52%** | | | | | |
| 7 | Fuel and Fuel Related Costs excluding Purchased Capacity cents/kWh | | 2.3014 | 2.3142 | 2.3112 | 2.3087 |
| 8 | REPS Compliance and QF Purchased Power - Capacity cents/kWh | | 0.0331 | 0.0245 | 0.0214 | 0.0272 |
| 9 | Total adjusted Fuel and Fuel Related Costs cents/kWh | Sum | 2.3345 | 2.3387 | 2.3326 | 2.3359 |
| 10 | EMF Increment (Decrement) cents/kWh | Exh 3 pg 2, 3, 4 | 1.2579 | 1.2342 | 1.3007 | 1.2568 |
| 11 | EMF Interest Increment (Decrement) cents/kWh | Exh 3 pg 2, 3, 4 | 0.0084 | 0.0082 | 0.0087 | 0.0084 |
| 12 | Net Fuel and Fuel Related Costs Factors cents/kWh | Sum | **3.6008** | **3.5811** | **3.642** | **3.6011** |

Note: Fuel factors exclude regulatory fee

I/A



# COMPREHENSIVE SETTLEMENT AGREEMENT

This Comprehensive Settlement Agreement is entered into this 3rd day of September, 2008 by and between Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. ("PEC"), Carolina Industrial Group for Fair Utility Rates II ("CIGFUR"), Carolina Utility Customers Association ("CUCA") and the North Carolina Utilities Commission Public Staff ("Public Staff").

WHEREAS, in Senate Bill 3, the North Carolina General Assembly removed the requirement that the electric utilities of North Carolina's fuel and fuel related costs be recovered using a uniform increment or decrement rate per kilowatt-hour;

WHEREAS, PEC's deferred under-recovered fuel and fuel related cost balance as of July 31, 2008 is estimated to be $203,363,040; and

WHEREAS, the entire fuel and fuel related cost increase requested by PEC to recover its forecasted fuel and fuel related costs for the rate review period of December 1, 2008 through November 30, 2009 and recover its deferred fuel and fuel related cost balance as of July 31, 2008 is $411 million; and

NOW THEREFORE, PEC, CIGFUR, CUCA and the Public Staff agree as follows:

1. In PEC's 2008, 2009 and 2010 fuel and fuel related cost recovery proceedings, PEC shall propose and all parties shall support the recovery of PEC's fuel and fuel-related costs using a uniform percent increase per average monthly bill per rate class methodology such that each rate class will, on average, experience the same average monthly percent bill increase based upon current rates and charges.

2. PEC's under-recovered deferred fuel and fuel related cost balance as of July 31, 2008 is $203,363,040. Of this amount, $78,465,290 represents under-recovered deferred fuel and fuel related costs from April 1, 2008, through July 31, 2008, the end of the test period in the 2008 fuel and fuel related cost recovery proceeding. Pursuant to G.S. 62-133.2(d), the reasonableness and prudence of these costs is subject to review in PEC's 2009 fuel and fuel related cost recovery proceeding. Subject to such review, PEC will recover this amount equally over three consecutive 12-month billing periods. Year One is the 12 months ending November 30, 2009; Year Two is the 12 months ending November 30, 2010; and Year 3 is the 12 months ending November 30, 2011. Interest on net of tax amounts outstanding as compared to full collection in the first year will bear interest at a rate equal to the five-year US Treasury Note, plus 150 basis points, adjusted quarterly. The rate in effect at the close of business on March 31, June 30, September 30 and December 31 shall be used for the three succeeding business months.

> Interest in Year One will be based upon 66.67% of the net of tax balance that remains at the end of Year One. However, under existing procedures for collecting deferred fuel costs, this amount would not have been completely received at the beginning of the billing period, but rather would have been received partially in all billing cycles throughout the year. Therefore, the proper assumption is that this 66.67% balance would have been received at mid-year. Interest will therefore apply only to 50% of the net of tax balance.

Year One Interest will be calculated as follows:

$203,363,040 x 60% x 66.67% x 50% x 5% (interest rate for example only) = approximately $2,034,000 million.

Interest in Year Two will be compounded on December 1, 2009 and will apply to the outstanding 66.67%. However, one-half of the 66.67% will be included in rates and therefore will be outstanding for only one-half of the year. Part One of Year Two below shows the compound effect, Part Two shows the interest on the amount being collected during Year Two and Part Three shows the interest on the amount to be collected in Year Three.

Part One: Compound - $2,034,000 x 5% = $102,000

Part Two: $203,363,040 x 60% x 33.33% x 50% x 5% = $1,017,000

Part Three: $203,363,040 x 60% x 33.34% x 5% = $2,034,000

Total Year Two interest will be the sum of Parts One, Two and Three of $3,153,000

Year Three interest compounds again on December 1, 2010 and further applies to one-half of the final 33.34% being collected in Year Three:

Part One: Compound - ($2,034,000 + $3,153,000) x 5% = $259,000

Part Two: $203,363,040 x 60% x 33.34% x 50% x 5% = $1,017,000.

Total Year Three interest will be $1,276,000

Total Interest will be the total of Years One, Two and Three of $6,463,000, assuming a 5% interest rate and a 60% net of tax rate. These rates will be updated quarterly as appropriate.

3. Any member of CIGFUR or CUCA may elect to pay their entire pro rata share of the July 31, 2008 deferred fuel cost balance during the rate review period December 1, 2008 through November 30, 2009, and thereby avoid paying any interest on the deferred balance as it exists on December 1, 2009.

4. PEC shall file with the Commission a new Supplementary and Non-Firm Standby Service Rider to be available to industrial customers that own and utilize electric generation facilities. This tariff will have no standby, backstand, or generation capacity reservation charge. Customers will pay an amount equal to 2% of the difference between the cost of (1) the transmission & distribution facilities requested and installed to serve Customer's total contract demand, and (2) the facilities required to serve the customer's supplementary contract demand. Customer shall also pay an amount equal to 2% of the cost of any protective equipment that may be required. Customers subscribing to this tariff are not guaranteed the provision of electric energy for the non-firm standby load normally served by the customer owned generation. Rather, PEC shall only be required to provide standby electric energy to such customer if PEC determines, in its sole discretion, using good faith efforts, that electric energy and transmission capacity are available to serve the customer's non-firm standby load. The rate for standby service provided from PEC owned resources shall be the applicable hourly rates in Schedule LGS-RTP. If PEC must purchase energy in order to provide standby service, PEC shall provide the customer 30 minutes notice of the need to make such purchase, and upon request by the

customer will make such purchase. The rate for the energy supplied by PEC when a purchase is made shall be the market price of the energy at the PJM existing prices at the time the energy is delivered plus 5%, plus all applicable transmission charges. PEC will collaborate with the Public Staff, CIGFUR and CUCA in the development of this new tariff. PEC shall not be obligated to provide firm service for the non-firm standby load served under the terms of such new Supplementary and Non-Firm Standby Service Rider as discussed herein. PEC will not construct or acquire long-term generating capacity or associated reserve capacity to serve such non-firm load, nor will it incorporate such non-firm load into future resource planning.

5. The Public Staff, CUCA and CIGFUR shall not oppose a request by PEC to eliminate any obligation to amortize any of its Clean Smokestacks Costs (costs incurred to meet the requirements of N.C. Gen. Stat. § 143-215.107D) above $569.1 million amortized at December 31, 2007 and instead place all such costs in PEC's rate base and allocate such costs between and among PEC's North Carolina, South Carolina and wholesale jurisdictions. PEC shall be allowed to accrue AFUDC on all Smokestacks costs above $813 million. The accrual of AFUDC will cease when the construction project is complete and associated facilities are placed in service. PEC shall be allowed to represent in its petition to eliminate such amortizations that the Public Staff, CIGFUR and CUCA do not oppose or object to PEC's request. In the ratemaking proceeding in which PEC seeks to adjust its rates to reflect inclusion of such Clean Smokestacks costs in its rate base, the Public Staff, CIGFUR and/or CUCA may challenge the reasonableness and prudence of such costs.

6. Pursuant to paragraph 12 of the Revised Alternate Settlement Agreement approved by the Commission in Docket No. E-2, Sub 889, PEC shall file a decremental rider applicable to Schedule LGS-RTP to be effective for service rendered from December 1, 2008 through November 30, 2009. The decremental rider is applicable to the actual energy consumed and billed in the month, including both the energy consumed in the Customer Baseline Load as well as incremental usage subject to the RTP hourly energy charge. Such credit shall be calculated as follows:

> Credit = the sum of the following for all coal units during the time period April 1 through March 31 [(the amount of coal burned by unit on a mmbtu basis to make excess generation sales) multiplied by (the replacement price of coal at the time of the sale minus the stockpile average price, both expressed on a $/mmbtu, for the respective coal unit used to make excess generation sales)], where:
>
> - The fuel burned to make excess generation sales will be extracted by unit from the routine fuel credit calculation process.
>
> - Replacement coal costs are based on the observed spot value of the commodity from an independent published source (currently Global Energy's Daily Coal Price Forecast), adjusted for applicable variable charges, to represent delivered cost. Exceptions may exist where the specific fuel type being utilized is not well represented by a published source. In such cases, quotes, market observations, or actual transactions may be used to arrive at the appropriate replacement price signal.
>
> - Stockpile average prices are based on the weighted average delivered coal costs as recorded at the end of the prior month in the fuel management system.

The credit shall be distributed to the individual RTP customers via a decremental rider to each RTP customer's bill. The decremental rider shall be calculated by dividing the aggregate credit calculated pursuant to the methodology described above by the annual kWh billed for the fuel case test year ended March 31 for Schedule LGS-RTP participants expected to receive service during the effective term of the rider. The decremental rider shall be rounded to the nearest thousands of a cent per kWh (i.e. $0.00XXX/kWh). No adjustment shall be made to actual sales for planned or past changes in consumption due to weather or other events. The decremental rider shall be applicable to the actual energy consumed and billed in the month, including both the energy consumed in the Customer Baseline Load as well as incremental usage subject to RTP hourly rates. The revenue associated with the Real Time Pricing

Energy Rider shall be separately stated on the monthly bill. Upon termination of the Rider, there will not be a true-up of any difference between the decremental rider revenue and the "revenue reduction target."

The wording of the actual Rider to be submitted for approval by the North Carolina Utilities Commission shall be as follows:

**REAL TIME PRICING ENERGY RIDER**

A decremental rider of 0.072¢/kWh* shall be added to the Monthly Rate applicable to the Large General Service (Experimental - Real Time Pricing) Schedule LGS-RTP effective for service rendered on and after December 1, 2008 through November 30, 2009. The decremental rider is applicable to the actual energy consumed and billed in the month, including both the energy consumed in the Customer Baseline Load as well as incremental usage subject to the RTP hourly energy charge.

* This decrement is not a part of the energy charges included in the energy prices stated in the LGS-RTP Schedule and should therefore be applied in addition to the rates stated in the Schedule.

7. In the event this Settlement Agreement is not approved by the Commission in its entirety, those portions of the Agreement that are approved shall survive and be implemented and all parties shall collaboratively, and in good faith attempt to negotiate revisions to the Agreement that restore to the disadvantaged party or parties the benefits of this Comprehensive Settlement Agreement to the greatest extent possible. If the Commission: A) rejects PEC's proposal to recover its fuel and fuel-related costs using a uniform percent increase per average monthly bill per rate class methodology such that each rate class will, on average, experience the same average monthly percent bill increase based upon current rates and charges; B) does not establish an alternative methodology acceptable to the Public Staff, CIGFUR and CUCA to recover such costs; and C) approves the elimination of all Clean Smokestacks cost amortizations by PEC in excess of $569.1 million, then, PEC agrees that unless another method is agreed to by the Public Staff, CIGFUR and CUCA to restore the lost benefit to CIGFUR and CUCA, in the ratemaking proceeding in which PEC seeks to adjust its rates

to reflect inclusion of such Clean Smokestacks costs in its ratebase it will propose rates for the Real Time Pricing Tariff Class that do not include the increased revenue requirement associated with including the North Carolina jurisdictional allocated portion of the $244 million of Clean Smokestacks costs that will be ratebased and depreciated rather than amortized if its petition to eliminate such amortizations is granted.

8. This Agreement constitutes the entire agreement between and among the parties and supersedes any and all previous agreements either written or oral.

Len S. Anthony, General Counsel
Progress Energy Carolinas, Inc.

Carolina Industrial Group for Fair Utility Rates II

Carolina Utility Customers Association

North Carolina Utilities Commission – Public Staff

Len S. Anthony, General Counsel
Progress Energy Carolinas, Inc.

Carolina Industrial Group for Fair Utility Rates II

Sharon C. Miller
Carolina Utility Customers Association

North Carolina Utilities Commission – Public Staff

Len S. Anthony, General Counsel
Progress Energy Carolinas, Inc.

Carolina Industrial Group for Fair Utility Rates II

Carolina Utility Customers Association

Antoinette R. Wike
North Carolina Utilities Commission – Public Staff

**REVISED**
**BARKLEY EXHIBIT No. 5B**

**CAROLINA POWER & LIGHT COMPANY**
**d/b/a PROGRESS ENERGY CAROLINAS, INC.**
**DOCKET NO. E-2, SUB 929**

**CALCULATION OF TOTAL NC RETAIL REVENUE INCREASE**

| Line # | Item | Amount | Data Source |
|---|---|---|---|
| (1) | Forecasted NC Retail Sales [KWH] | 38,746,072 | PEC Projection |
| (2) | Forecasted System Retail Sales [KWH] | 59,102,109 | PEC Projection |
| (3) | NC Retail Allocation of Forecasted Sales [KWH] | 65.56% | Line 1 / Line 2 |
| (4) | NC Non-Capacity Purchased Power | $139,370,127 | Exhibit 5A, Page 1 of 3, Line 11 |
| (5) | NC Cogen Capacity & Renewables | $15,539,260 | Exhibit 5A, Page 2 of 3, Line 11 |
| (6) | Total Other Fuel Costs | $1,673,489,378 | Exhibit 5A, Page 3 of 3, Line 19 |
| (7) | Other Fuel Costs From NC Retail | $1,097,103,661 | Line 6 X Line 3 |
| (8) | Total Costs From NC Retail | $1,252,013,048 | Line 4 + Line 5 + Line 7 |
| (9) | Calculated Fuel Rate | 3.231 | Line 8 / Line 1 |
| (10) | Proposed EMF Rate | 0.180 | Revised Exhibit 6, Line 28 |
| (11) | Total Calculated Fuel Rate | 3.411 | Line 9 + Line 10 |
| (12) | Current Fuel Rate | 2.679 | See Note 1 below |
| (13) | Increase in Fuel Rate | 0.732 | Line 11 - Line 12 |
| (14) | Test Year Normalized NC Retail Sales [KWH] | 37,619,054,066 | Exhibit 4, Page 1 of 2, Line 13, Column 6 |
| (15) | Proposed Total Dollar Increase | $275,371,476 | (Line 13 x Line 14) /100 |

| | |
|---|---|
| Note 1:<br>Fuel Rate per Order in E-2, Sub 903 | 2.675 |
| Adjusted fuel rate per Supplemental Barkley Exhibit No. 1, Page 2 of 1.280 less base factor established in E-2, Sub 537 of 1.276 | 0.004 |
| Adjusted factor for fuel rate increase calculation | 2.679 |

**CAROLINA POWER & LIGHT COMPANY**
***d/b/a PROGRESS ENERGY CAROLINAS, INC.***
**DOCKET NO. E-2, SUB 929**

**Derivation of Equal Percent Increases for All Rate Classes**

**Calculation of Total Fuel Rate**

| Line # | Rate Class | Normalized NC Test Year Sales | Average Rate Per KWH at Current Rates (2) | Annual Revenue at Current Rates | Increase in Fuel Revenues | Total Fuel Rate Increase (5) | Fuel Rate Sub 903 | Total Fuel Rate |
|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) = (b) x (c) | (e) = (d) x Line 9 | (f) = (e) / (b) | (g) | (h) = (f) + (g) |
| (1) | Residential | 14,801,402,259 | $0.09442 | $1,397,559,736 | $126,502,723 | $0.00855 | $0.02675 | $0.03530 |
| (2) | Small General Service | 1,499,942,558 | $0.10209 | $153,122,767 | $13,860,193 | $0.00924 | $0.02675 | $0.03599 |
| (3) | Medium General Service | 11,651,550,994 | $0.07277 | $847,935,377 | $76,752,450 | $0.00659 | $0.02675 | $0.03334 |
| (4) | Large General Service | 9,231,146,788 | $0.06023 | $555,951,242 | $50,322,962 | $0.00545 | $0.02675 | $0.03220 |
| (5) | Lighting (5) | 435,011,467 | $0.20147 | $87,642,763 | $7,933,148 | $0.01824 | $0.02675 | $0.04499 |
| (6) | *NC Retail* | *37,619,054,066 (1)* | | *$3,042,211,885* | *$275,371,476* | $0.00732 | | |

| | | |
|---|---|---|
| (7) | Incremental Change in Fuel Rates | $0.00732 |
| (8) | Increase in NC Retail Fuel Revenue (3) | $275,371,476 |
| (9) | Retail Percent Change in Annualized Revenue (4) | 9.05% |

(1) Exhibit 4, Page 1 of 2, Line 13, Column (6).
(2) Exhibit 5C, Page 3 of 3, Column 4.
(3) The increase in fuel revenue is provided in Revised Barkley Exhibit No. 5B, Line 15.
(4) The Retail Percent Change in revenues equals the fuel increase divided by the annual revenue at current rates.
(5) Fuel revenues exclude NC gross receipts taxes. These taxes are added after determination of class rates.

REVISED
BARKLEY EXHIBIT No. 5D

**CAROLINA POWER & LIGHT COMPANY**
**d/b/a PROGRESS ENERGY CAROLINAS, INC.**
**DOCKET NO. E-2, SUB 929**
**Rates for Period Ending November 2009**

**SUMMARY OF FUEL RATES**

cents/kWh

| Line # | Rate Class | Non-Capacity Purchased Power [1] | Cogen Capacity and Renewables [2] | All Other Fuel Costs [3] | EMF Factor [4] | Total Fuel Costs [5] |
|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| (1) | *Residential* | 0.356 | 0.049 | 2.945 | 0.180 | 3.530 |
| (2) | Small General Service | 0.307 | 0.050 | 3.062 | 0.180 | 3.599 |
| (3) | Medium General Service | 0.364 | 0.040 | 2.750 | 0.180 | 3.334 |
| (4) | Large General Service | 0.372 | 0.025 | 2.643 | 0.180 | 3.220 |
| (5) | Lighting | 0.352 | 0.000 | 3.967 | 0.180 | 4.499 |

[1] Exh. 5A, Page 1 of 3
[2] Exh. 5A, Page 2 of 3
[3] Column (e) - Column (a) - Column (b) - Column (d).
[4] Revised Exh. 6, Line 26.
[5] Revised Exh. 5C, page 1 of 3, Column (h).

REVISED
BARKLEY EXHIBIT No. 6

**CAROLINA POWER & LIGHT COMPANY**
**d/b/a PROGRESS ENERGY CAROLINAS, INC.**
**DOCKET NO. E-2, SUB 929**
**TEST PERIOD ENDING MARCH 31, 2008**

| Line # | | MONTHLY OVER / (UNDER) COLLECTION [$] (1) | CUMULATIVE OVER / (UNDER) COLLECTION [$] (2) | Data Source |
|---|---|---|---|---|
| (1) | April 2007 | (19,641,222) | (19,641,222) | EX8_Sch 4 |
| (2) | May | (10,497,197) | (30,138,419) | EX8_Sch 4 |
| (3) | June | (16,644,353) | (46,782,772) | EX8_Sch 4 |
| (4) | July | (16,622,727) | (63,405,499) | EX8_Sch 4 |
| (5) | August | (42,655,262) | (106,060,761) | EX8_Sch 4 |
| (6) | September | (12,993,943) | (119,054,704) | EX8_Sch 4 |
| (7) | Adj April through Aug Sub 889 | (1,526,329) | (120,581,033) | EX8_Sch 4 |
| (8) | October (Sub 889) | (8,223,358) | (128,804,391) | EX8_Sch 4 |
| (9) | October (Sub 903) | (2,544,380) | (131,348,771) | EX8_Sch 4 |
| (10) | November | 11,971,208 | (119,377,563) | EX8_Sch 4 |
| (11) | December | 4,010,556 | (115,367,007) | EX8_Sch 4 |
| (12) | January 2008 | (9,962,883) | (125,329,890) | EX8_Sch 4 |
| (13) | February | 13,442,722 | (111,887,168) | EX8_Sch 4 |
| (14) | March | (2,893,766) | (114,780,934) | EX8_Sch 4 |
| (15) | April | 2,048,473 | (112,732,461) | EX9 P51 |
| (16) | May | 1,759,833 | (110,972,628) | EX9 P51 |
| (17) | June | (45,445,323) | (156,417,951) | Revised EX9 P51 |
| (18) | July | (35,141,749) | (191,559,700) | Revised EX9 P51 |
| (19) | Total Recovery Period | | (191,559,700) | Line 18, Column (2) |
| (20) | Marketer Adjustment to 61% | | (188,735) | EX9 P49 |
| (21) | Interest | | (13,314,859) | Revised EX9 P50 |
| (22.) | Adjustments to Deferred Balance | | 1,700,254 | Supplemental Ex. 1, Page 1 |
| (23) | Total EMF Recovery | | (203,363,040) | Lines 19 + 20 + 21 + 22 |
| (24) | One third of EMF Recovery | | (67,787,680) | Line 23 / 3 |
| (25) | Normalized Test Year NC Retail Sales [KWH] | | 37,619,054,066 | Exhibit 4, Page 1 of 2, Line 13, Column (6) |
| (26) | EMF Factor [cents/KWH] | | 0.180 | Line 24 / Line 25 |

**PROGRESS ENERGY CAROLINAS, INC.**
***DEFERRED ACCOUNT INTEREST***

| Month | Sub 868 | Sub 889 | Total |
|---|---|---|---|
| Apr-07 | 560,090 | 264,513 | 824,603 |
| May-07 | 555,362 | 316,203 | 871,565 |
| Jun-07 | 513,175 | 350,477 | 863,652 |
| Jul-07 | 501,908 | 414,149 | 916,057 |
| Aug-07 | 471,303 | 470,228 | 941,531 |
| Sep-07 | 425,996 | 510,219 | 936,215 |
| Oct-07 | 444,464 | 581,331 | 1,025,795 |
| Nov-07 | 402,305 | 563,582 | 965,887 |
| Dec-07 | 384,753 | 562,852 | 947,605 |
| Jan-08 | 350,435 | 540,345 | 890,780 |
| Feb-08 | 294,641 | 484,566 | 779,207 |
| Mar-08 | 282,166 | 497,313 | 779,479 |
| Apr-08 | 244,593 | 463,325 | 707,918 |
| May-08 | 222,885 | 459,946 | 682,831 |
| Jun-08 | 184,397 | 425,381 | 609,778 |
| Jul-08 | 154,877 | 417,079 | 571,956 |
| Total | 5,993,350 | 7,321,509 | 13,314,859 |

**CAROLINA POWER & LIGHT COMPANY**
**d/b/a PROGRESS ENERGY CAROLINAS, INC.**
**DOCKET NO. E-2, SUB 929**
***FOR THE PERIOD FROM APRIL 1, 2008 to JULY 31, 2008***

**FINAL OVER/UNDER RECOVERY OF FUEL AND FUEL RELATED COSTS**

Over / (Under) Recovery

| Line # | Date | Actual NC Retail Sales MWHs | Actual Cost/kwh | Billed Rate/kwh | Actual Over/(Under) Recovery |
|---|---|---|---|---|---|
| (1) | April 2008 | 2,731,297 | 2.213 | 2.288 | 2,048,473 |
| (2) | May 2008 | 2,838,441 | 2.226 | 2.288 | 1,759,833 |
| (3) | June 2008 | 3,193,628 | 3.711 | 2.288 | (45,445,323) |
| (4) | July 2008 | 3,458,834 | 3.304 | 2.288 | (35,141,749) |

Note: This activity represents actual results.

Carolina Power & Light Company
d/b/a Progress Energy Carolinas, Inc.
(North Carolina Only)

ANNUAL BILLING ADJUSTMENTS
RIDER BA-1

APPLICABILITY – RATES INCLUDED IN TARIFF CHARGES

The rates shown below are included in the MONTHLY RATE provision in each schedule identified in the table below:

| Billing Adjustment Factors (¢/kWh)* | | | | | |
|---|---|---|---|---|---|
| Rate Class | Fuel Adjustment | | DSM/EE Adjustment | | Net Adjustment |
| | Rate(1) | EMF(2) | Rate(3) | EMF(4) | |
| Residential | 2.139 | 0.186 | | | |
| Applicable to Schedules: RES, R-TOUD & R-TOUE | | | | | |
| Small General Service | 2.210 | 0.186 | | | |
| Applicable to Schedules: SGS & TSS | | | | | |
| Medium General Service | 1.936 | 0.186 | | | |
| Applicable to Schedules: MGS, SGS-TOU, SI, CH-TOUE, GS-TES, APH-TES, CSG, CSE & Riders 66 & SS (less than 1 MW) | | | | | |
| Large General Service | 1.819 | 0.186 | | | |
| Applicable to Schedules: LGS, LGS-TOU, LGS-RTP and Riders 66 & SS (1 MW and greater) | | | | | |
| Lighting | 3.140 | 0.186 | | | |
| Applicable to Schedules: ALS, SLS, SLR & SFLS | | | | | |

* Billing Adjustment Factors, shown above, include North Carolina gross receipts taxes.

*Billing Adjustment Factors Description:*

(1) The Fuel Adjustment Rate is adjusted annually to reflect incremental changes in the costs of fuel and fuel-related costs from the rates approved in the last general rate case.

(2) The Fuel Adjustment Experience Modification Factor (EMF) is adjusted annually to reflect the difference between reasonable and prudently incurred fuel and fuel-related costs and the fuel and fuel-related revenues realized during a test period under review and shall remain in effect for a fixed 12 month period.

(3) The Demand Side Management/Energy Efficiency (DSM/EE) Rate is adjusted annually to reflect the costs and incentives associated with demand side management and energy efficiency measures and programs approved by the North Carolina Utilities Commission.

(4) The Demand Side Management/Energy Efficiency Experience Modification Factor (DSM/EE EMF) is adjusted annually to reflect the difference between reasonable and prudently incurred DSM/EE costs and incentives and DSM/EE revenues realized during the period under review and shall remain in effect for a fixed 12 month period.

**Duke Energy Carolinas**
**Response to**
**Carolina Industrial Group for Fair Utility Rates III's**
**Second Set of Data Requests**

**Docket No. E-7, Sub 1276**

**Date of Request: June 19, 2023**
**Date of Response: June 30, 2023**

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

***Confidential Responses are provided pursuant to Confidentiality Agreement***

The attached response to CIGFUR III's Second Data Request No.2-13, was provided to me by the following individual(s): Keva Hibbert, Lead Rates & Regulatory Strategy Analyst, and was provided to CIGFUR III under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

CIGFUR III
Data Request No. 2
DEP Docket No. E-7, Sub 1276
Item No. 2-13
Page 1 of 1

**Request:**

2-13. How many industrial facility closures or year-over-year demand reductions in DEC's North Carolina service territory is the Company aware of for each of the last five (5) years? Has the Company been made aware of any impending industrial facility closures or year-over-year demand reductions in DEC's North Carolina service territory in the coming year?

**Response:**

See attachment "DEC CIGFUR DR 2 1-13 NC Industrial Account Closings 2018-2023.xlsx" for a summary of industrial account closings since 2018 based on customer growth analysis from the current and previous general rate cases. The source data and process changed between 2020 and 2021 with the implementation of the SAP billing system, so there are differences in how account closings were defined, filtered and summarized.

The Company is aware of potential or pending demand reductions for 5 industrial facilities in 2023.

**NC Industrial Account Closings**

| | Non-TOU | TOU | TOTAL | Source |
|---|---|---|---|---|
| 2018 | 54 | N/A | N/A | 2019 Rate Case Customer Growth Ext. Dec 2019 |
| 2019 | 45 | N/A | N/A | 2019 Rate Case Customer Growth Ext. Dec 2019 |
| 2020 | 32 | N/A | N/A | 2019 Rate Case Customer Growth Ext. Dec 2019 |
| 2021 | 191 | 74 | 265 | 2023 Rate Case Customer Growth Ext. May 2023 |
| 2022 | 226 | 37 | 263 | 2023 Rate Case Customer Growth Ext. May 2023 |
| Jan-May 2023 | 66 | 24 | 90 | 2023 Rate Case Customer Growth Ext. May 2023 |

Note: New process implemented with SAP billing system beginning April 2021

**Duke Energy Carolinas**
**Response to**
**Carolina Industrial Group for Fair Utility Rates III's**
**Second Set of Data Requests**

**Docket No. E-7, Sub 1276**

**Date of Request: June 19, 2023**
**Date of Response: June 30, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

***Confidential Responses are provided pursuant to Confidentiality Agreement***

The attached response to CIGFUR III's Second Data Request No.2-2, was provided to me by the following individual(s): Kathryn Taylor, Rates & Regulatory Strategy Director, and was provided to CIGFUR III under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

CIGFUR III
Data Request No. 2
DEP Docket No. E-7, Sub 1276
Item No. 2-2
Page 1 of 1

**Request:**

2-2. Please confirm that the increment or decrement rider authorized by N.C.G.S. § 62-233.2 is a cost recovery mechanism that operates independently and is considered separately from riders or other cost recovery mechanisms authorized by the PBR Statute.

**Response:**

N.C.G.S. § 62-133.2 is for fuel and fuel-related charge adjustment cost recovery. The fuel rider operates independently and is considered separately from riders or other cost recovery mechanisms authorized by the PBR Statute.