HINCKLEY ALLEN

100 Westminster Street, Suite 1500
Providence, RI 02903-2319
p: 401-274-2000 f: 401-277-9600
hinckleyallen.com

Adam M. Ramos
aramos@hinckleyallen.com
Direct Dial: 401-457-5164

September 21, 2021

VIA ELECTRONIC MAIL AND HAND DELIVERY

Luly E. Massaro, Commission Clerk
Rhode Island Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

Re: Petition of PPL Corporation, PPL Rhode Island Holdings, LLC, National Grid USA, and The Narragansett Electric Company for Authority to Transfer Ownership of The Narragansett Electric Company to PPL Rhode Island Holdings, LLC and Related Approvals; Docket No. D-21-09

Dear Ms. Massaro:

Enclosed please find an original and four copies of PPL Corporation ("PPL") and PPL Rhode Island Holdings, LLC's ("PPL RI") Responses and Objections to the Division of Public Utilities and Carriers' Advocacy Section's Seventh Set of Data Requests, issued on August 31, 2021 (the "Seventh Set of Data Requests").

This filing includes PPL and PPL RI's partial responses to the Seventh Set of Data Requests, specifically 7-1 through 7-5, 7-7 through 7-18, 7-22 through 7-28, 7-33, 7-39, 7-42, 7-44, 7-47, 7-49, 7-53, 7-54, 7-57, 7-60 and 7-61. On September 21, 2021, the Division Advocacy Section granted an extension to September 28, 2021 as to the remaining requests, which will be provided on a rolling basis as they are complete.

This filing includes a Motion for Protective Treatment of Confidential Information in accordance with Division Rules of Practice and Procedure 1.3(D)(2) and R.I. Gen. Laws § 38-2-2(4) for portions of PPL and PPL RI's response to Request 7-5, Confidential Attachment PPL-DIV 7-5-3, and Confidential Attachment PPL-DIV 7-5-4, which contain confidential and proprietary business information. For the reasons stated in the Motion for Protective Treatment, PPL and PPL RI seek protection from public disclosure for select portions of their response to Request 7-5 and Attachments PPL-DIV 7-5-3 and 7-5-4. Accordingly, PPL and PPL RI have provided the Division with an original and two complete, unredacted copies of the confidential documents in a sealed envelope marked "**Contains Privileged and Confidential Information – Do Not**

Release," and have included a slipsheet identifying the confidential attachment for the public filing.

Thank you for your attention to this matter. Please do not hesitate to contact me should you have any questions.

Very truly yours,

Adam M. Ramos

AMR:cw
Enclosures

cc: Service List D-21-09 (via e-mail only)

Docket No. D-21-09 PPL Corp., PPL RI Holdings, LLC, National Grid USA and The Narragansett Electric Co. (collectively, Applicants) – Petition to Transfer Ownership and Related Approvals

Service List Updated 8/18/2021

Name/Address	**E-mail**	**Phone**
PPL RI Holdings Adam M. Ramos, Esq. Gerald J. Petros, Esq. Hinckley, Allen & Snyder LLP 100 Westminster St., Suite 1500 Providence, RI 02903-2319	gpetros@hinckleyallen.com; aramos@hinckleyallen.com; amillinger@hinckleyallen.com; cwhaley@hinckleyallen.com; rjreybitz@pplweb.com; KKlock@pplweb.com; MJShafer@pplweb.com; MLBartolomei@pplweb.com; cdieter@hinckleyallen.com; rnerney@hinckleyallen.com;	401-274-2000
Narragansett Electric Co. Cheryl M. Kimball, Esq. Robert J. Humm, Eq. Keegan Werlin LLC 99 High St., Suite 2900 Boston, MA 02110	ckimball@keeganwerlin.com; rhumm@keeganwerlin.com; JCalitri@keeganwerlin.com;	617-951-1400
Jennifer Books Hutchinson, Esq. National Grid 280 Melrose St. Providence, RI 02907	jennifer.hutchinson@nationalgrid.com; Frances.Matte@nationalgrid.com; Joanne.Scanlon@nationalgrid.com; Brooke.Skulley@nationalgrid.com; Kathleen.Hitt@nationalgrid.com;	401-784-7288
Office of Energy Resources (OER) Albert Vitali, Esq. Dept. of Administration Dept. of Legal Services One Capitol Hill, 4th Floor Providence, RI 02908-5890	Albert.Vitali@doa.ri.gov; nancy.russolino@doa.ri.gov; Nicholas.Ucci@energy.ri.gov; Carrie.Gill@energy.ri.gov; Becca.Trietch@energy.ri.gov;	401-222-8880
Office of Attorney General (AG) Tiffany Parenteau, Esq. Nicholas Vaz, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	TParenteau@riag.ri.gov; NVaz@riag.ri.gov; eullucci@riag.ri.gov;	401-274-4400
Division Advocacy Section Christy Hetherington, Esq. Leo Wold, Esq. Division of Public Utilities & Carriers	Christy.hetherington@dpuc.ri.gov; Leo.wold@dpuc.ri.gov; John.bell@dpuc.ri.gov;	401-780-2140

Advocacy Section	Al.mancini@dpuc.ri.gov; Joel.munoz@dpuc.ri.gov;	
Latif Nurani Amber Stone Scott Strauss Anree G. Little David Effron Gregory Booth Linda Kushner Michael Ballaban D. Littell Matthew Kahal Bruce Oliver Tim Oliver	Latif.Nurani@spiegelmcd.com; Amber.Martin@spiegelmcd.com; scott.strauss@spiegelmcd.com; anree.little@spiegelmcd.com; Djeffron@aol.com; gboothpe@gmail.com; lkushner33@gmail.com; michael_ballaban@yahoo.com; dlittell@bernsteinshur.com; mkahal@exeterassociates.com; revilohill@verizon.net; Tim.b.oliver@gmail.com;	
Acadia Center Hank Webster, Director, Acadia Center 144 Westminster Street, Suite 203 Providence, RI 02903-2216	hwebster@acadiacenter.org;	401-276-0600 x401
Green Energy Consumers Alliance James G. Rhodes Esq. Rhodes Consulting 160 Woonsocket Hill Rd. North Smithfield, RI 02896	james@jrhodeslegal.com;	401-225-3441

Conservation Law Foundation (CFL) Margaret Curran, Esq. James Crowley, Esq. Conservation Law Foundation 235 Promenade Street Suite 560, Mailbox 28 Providence, RI 02908	mcurran@clf.org; jcrowley@clf.org;	401-228-1904
Luly E. Massaro, Clerk Division of Public Utilities 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; John.spirito@dpuc.ri.gov; Linda.george@dpuc.ri.gov; Thomas.kogut@dpuc.ri.gov;	

HINCKLEY ALLEN

100 Westminster Street, Suite 1500
Providence, RI 02903-2319
p: 401-274-2000 f: 401-277-9600
hinckleyallen.com

Adam M. Ramos
aramos@hinckleyallen.com
Direct Dial: 401-457-5164

September 28, 2021

VIA ELECTRONIC MAIL AND HAND DELIVERY

Luly E. Massaro, Commission Clerk
Rhode Island Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

Re: Petition of PPL Corporation, PPL Rhode Island Holdings, LLC, National Grid USA, and The Narragansett Electric Company for Authority to Transfer Ownership of The Narragansett Electric Company to PPL Rhode Island Holdings, LLC and Related Approvals; Docket No. D-21-09

Dear Ms. Massaro:

Enclosed please find an original and four copies of PPL Corporation ("PPL") and PPL Rhode Island Holdings, LLC's ("PPL RI") Responses and Objections to the Division of Public Utilities and Carriers' Advocacy Section's Seventh Set of Data Requests, issued on August 31, 2021 (the "Seventh Set of Data Requests").

This filing includes PPL and PPL RI's partial responses to the Seventh Set of Data Requests, specifically 7-6, 7-19 through 7-21, 7-29 through 7-32, 7-34 through 7-38, 7-40, 7-41, 7-43, 7-45, 7-46, 7-48, 7-50 through 7-52, 7-55, 7-56, 7-58 and 7-59. On September 21, 2021, the Division Advocacy Section granted an extension to September 28, 2021 as to the remaining requests. This completes PPL and PPL RI's responses to the Seventh Set of Data Requests.

Thank you for your attention to this matter. Please do not hesitate to contact me should you have any questions.

Very truly yours,

Adam M. Ramos

Enclosures

cc: Service List D-21-09 (via e-mail only)

Docket No. D-21-09 PPL Corp., PPL RI Holdings, LLC, National Grid USA and The Narragansett Electric Co. (collectively, Applicants) – Petition to Transfer Ownership and Related Approvals

Service List Updated 8/18/2021

Name/Address	E-mail	Phone
PPL RI Holdings Adam M. Ramos, Esq. Gerald J. Petros, Esq. Hinckley, Allen & Snyder LLP 100 Westminster St., Suite 1500 Providence, RI 02903-2319	gpetros@hinckleyallen.com; aramos@hinckleyallen.com; amillinger@hinckleyallen.com; cwhaley@hinckleyallen.com; rjreybitz@pplweb.com; KKlock@pplweb.com; MJShafer@pplweb.com; MLBartolomei@pplweb.com; cdieter@hinckleyallen.com; rnerney@hinckleyallen.com;	401-274-2000
Narragansett Electric Co. Cheryl M. Kimball, Esq. Robert J. Humm, Eq. Keegan Werlin LLC 99 High St., Suite 2900 Boston, MA 02110	ckimball@keeganwerlin.com; rhumm@keeganwerlin.com; JCalitri@keeganwerlin.com;	617-951-1400
Jennifer Books Hutchinson, Esq. National Grid 280 Melrose St. Providence, RI 02907	jennifer.hutchinson@nationalgrid.com; Frances.Matte@nationalgrid.com; Joanne.Scanlon@nationalgrid.com; Brooke.Skulley@nationalgrid.com; Kathleen.Hitt@nationalgrid.com;	401-784-7288
Office of Energy Resources (OER) Albert Vitali, Esq. Dept. of Administration Dept. of Legal Services One Capitol Hill, 4th Floor Providence, RI 02908-5890	Albert.Vitali@doa.ri.gov; nancy.russolino@doa.ri.gov; Nicholas.Ucci@energy.ri.gov; Carrie.Gill@energy.ri.gov; Becca.Trietch@energy.ri.gov;	401-222-8880
Office of Attorney General (AG) Tiffany Parenteau, Esq. Nicholas Vaz, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	TParenteau@riag.ri.gov; NVaz@riag.ri.gov; eullucci@riag.ri.gov;	401-274-4400
Division Advocacy Section Christy Hetherington, Esq. Leo Wold, Esq. Division of Public Utilities & Carriers	Christy.hetherington@dpuc.ri.gov; Leo.wold@dpuc.ri.gov; John.bell@dpuc.ri.gov;	401-780-2140

Advocacy Section	Al.mancini@dpuc.ri.gov; Joel.munoz@dpuc.ri.gov;	
Latif Nurani Amber Stone Scott Strauss Anree G. Little David Effron Gregory Booth Linda Kushner Michael Ballaban D. Littell Matthew Kahal Bruce Oliver Tim Oliver	Latif.Nurani@spiegelmcd.com; Amber.Martin@spiegelmcd.com; scott.strauss@spiegelmcd.com; anree.little@spiegelmcd.com; Djeffron@aol.com; gboothpe@gmail.com; lkushner33@gmail.com; michael_ballaban@yahoo.com; dlittell@bernsteinshur.com; mkahal@exeterassociates.com; revilohill@verizon.net; Tim.b.oliver@gmail.com;	
Acadia Center Hank Webster, Director, Acadia Center 144 Westminster Street, Suite 203 Providence, RI 02903-2216	hwebster@acadiacenter.org;	401-276-0600 x401
Green Energy Consumers Alliance James G. Rhodes Esq. Rhodes Consulting 160 Woonsocket Hill Rd. North Smithfield, RI 02896	james@jrhodeslegal.com;	401-225-3441

Conservation Law Foundation (CFL) Margaret Curran, Esq. James Crowley, Esq. Conservation Law Foundation 235 Promenade Street Suite 560, Mailbox 28 Providence, RI 02908	mcurran@clf.org; jcrowley@clf.org;	401-228-1904
Luly E. Massaro, Clerk Division of Public Utilities 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; John.spirito@dpuc.ri.gov; Linda.george@dpuc.ri.gov; Thomas.kogut@dpuc.ri.gov;	

STATE OF RHODE ISLAND
DIVISION OF PUBLIC UTILITIES AND CARRIERS

In Re: Petition of PPL Corporation, PPL Rhode Island Holdings, LLC, National Grid USA, and The Narragansett Electric Company for Authority to Transfer Ownership of The Narragansett Electric Company to PPL Rhode Island Holdings, LLC and Related Approvals	)	Docket No. 2021-09

MOTION OF PPL CORPORATION AND PPL RHODE ISLAND HOLDINGS, LLC FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION PRODUCED IN RESPONSE TO SEVENTH SET OF DATA REQUESTS DATED AUGUST 31, 2021

PPL Corporation ("PPL") and PPL Rhode Island Holdings, LLC ("PPL RI") (collectively "PPL") request that the Division of Public Utilities and Carriers (the "Division"), pursuant to Division Rules of Practice and Procedure 1.3(D)(2) and 1.21(E), 815-RICR-00-00-1 *et seq.*, grant protection from public disclosure to certain confidential and proprietary information and documents submitted by PPL in response to the Division Advocacy Section's Seventh Set of Data Requests ("Seventh Data Requests"), dated August 31, 2021.

Specifically, PPL seeks an order from the Division to protect from public disclosure portions of PPL's response to data request Division 7-5, Attachment PPL-DIV 7-5-3, and Attachment PPL-DIV 7-5-4. PPL requests protective treatment of the redacted portions of this response and these two attachments and seeks a determination that the information contained therein is not a public record, in accordance with R.I. Gen. Laws § 38-2-2(4)(B). PPL also requests that, pending entry of that ruling, the Division preliminarily grant PPL's request for confidential treatment.

I. BACKGROUND

On May 4, 2021, PPL and PPL RI, along with National Grid USA ("National Grid"), and The Narragansett Electric Company ("Narragansett") (with PPL and PPL RI, collectively, the "Applicants"), filed a petition with the Division for approval of PPL RI's purchase from National Grid of 100% of the common stock of Narragansett and related approvals.

On August 31, 2021, the Division Advocacy Section served the Seventh Data Requests, consisting of 61 requests. PPL provided certain responses to the Seventh Data Requests on September 21, 2021. This contemporaneous motion seeks confidential treatment and protection from public disclosure for portions of the response to data request Division 7-5, Attachment PPL-DIV 7-5-3, and Attachment PPL-DIV 7-5-4, which implicate the confidential and competitively sensitive internal strategy information of PPL and the proprietary information of Itron, a non-party to this proceeding.

II. LEGAL STANDARD

The Access to Public Records Act, R.I. Gen. Laws § 38-2-1 *et seq.* ("APRA"), establishes the proper balance between "public access to public records" and protection "from disclosure [of] information about particular individuals maintained in the files of public bodies when disclosure would constitute an unwarranted invasion of personal privacy." Gen. Laws § 38-2-1. Per APRA, "all records maintained or kept on file by any public body" are "public records" to which the public has a right of inspection unless a statutory exception applies. *Id.* § 38-2-3.

The definition of "public record" under APRA specifically excludes "trade secrets and commercial or financial information obtained from a person, firm, or corporation that is of a privileged or confidential nature." *Id.* § 38-2-2(4)(B). The statute provides that such records "shall not be deemed public." *Id.* Moreover, Division Rule of Practice and Procedure 1.3(D)(2) states that, "Any party submitting documents to the Division may request a preliminary finding that some or all of the information is exempt from the mandatory public disclosure requirements of the Access to Public Records Act. A preliminary finding that some documents are privileged shall not preclude the Division from releasing those documents pursuant to public request in accordance with R.I. Gen. Laws § 32-2-1 *et seq*."

The Rhode Island Supreme Court has held that when documents fall within a specific APRA exemption, they "are not considered to be public records," and "the act does not apply to them." *Providence Journal Co. v. Kane*, 577 A.2d 661, 663 (R.I. 1990). Further, the court has held that the exemption for "financial or commercial information" under APRA includes information "whose disclosure would be likely . . . to cause substantial harm to the competitive position of the person from whom the information was obtained." *Providence Journal Co. v. Convention Ctr. Auth.*, 774 A.2d 40, 47 (R.I. 2001).

III. BASIS FOR CONFIDENTIALITY

The redacted portion of the response to data request Division 7-5 discusses Louisville Gas & Electric Company's ("LG&E") confidential process for estimating and planning four categories of gas supply volumes for its customers. Disclosure of this information would, therefore, disclose confidential information of LG&E – a subsidiary of PPL.

Similarly, Attachment PPL-DIV 7-5-3 is a document entitled "Appendix A, Residential SAE Modeling Framework," and Attachment PPL-DIV 7-5-4 is a document entitled "Appendix B, Commercial Statistically Adjusted End-Use Model." These documents reflect Itron's confidential and proprietary gas supply planning process and, specifically, the formulas used by

Itron to assist with long-term supply planning process for residential and commercial gas supply. Itron is not a party to this proceeding, and LG&E, a subsidiary of PPL, owes Itron confidentiality obligations. Disclosure of this information would, therefore, disclose confidential and proprietary information of Itron – a non-party to this proceeding to which LG&E owes confidentiality requirements.

Further, LG&E and Itron both treat this information as confidential and commercially sensitive. Disclosing this proprietary business information as part of the Division's review process could "cause substantial harm" to LG&E's and Itron's respective "competitive positions." *See* Gen. Laws § 38-2-1; *Convention Ctr. Auth.*, 774 A.2d at 47. Accordingly, the redacted portion of the response to data request Division 7-5, Attachment PPL-DIV 7-5-3, and Attachment PPL-DIV 7-5-4 contain "commercial or financial information" to which the APRA public disclosure requirements do not apply. *See* Gen. Laws § 38-2-2(4)(B); *Kane*, 577 A.2d at 663.

PPL therefore respectfully requests that the Division grant protective treatment to the redacted portion of the response to data request Division 7-5, Attachment PPL-DIV 7-5-3, and Attachment PPL-DIV 7-5-4 and take the following actions to preserve their confidentiality: (1) maintain the redacted portion of the response to data request Division 7-5, Attachment PPL-DIV 7-5-3, and Attachment PPL-DIV 7-5-4 as confidential indefinitely; (2) not place the redacted portion of the response to data request Division 7-5, Attachment PPL-DIV 7-5-3, and Attachment PPL-DIV 7-5-4 on the public docket; (3) disclose the redacted portion of the response to data request Division 7-5, Attachment PPL-DIV 7-5-3, and Attachment PPL-DIV 7-5-4 only to the Division, its attorneys, and staff as necessary to review the Applicants' application; and (4) pending entry of a final ruling on this motion, preliminarily grant PPL's request for confidential treatment.

WHEREFORE, PPL Corporation and PPL Rhode Island Holdings, LLC respectfully request that the Division grant their Motion for Protective Treatment.

Date: September 21, 2021

Respectfully submitted,

PPL Corporation and PPL Rhode Island Holdings, LLC
By its attorneys,

Gerald Petros (#2931)
Adam Ramos (#7591)
Hinckley Allen & Snyder
100 Westminster Street, Suite 1500
Providence, RI 02903-2319
(401) 457-5278
(401) 277-9600 (fax)
gpetros@hinckleyallen.com
aramos@hinckleyallen.com

CERTIFICATE OF SERVICE

I hereby certify that on September 21, 2021, I sent a copy of the foregoing to the Service List by electronic mail.

/s/ Adam M. Ramos

Division 7-1

Request:

Please identify each gas supply agreement through which Narragansett expects to receive natural gas and/or LNG supplies over the next five years and for each agreement identified, please:

a. Specify the term of the agreement;

b. Specify the daily, monthly, seasonal and annual limits on the volumes of natural gas and/or LNG purchased under the agreement;

c. Specify the provisions for extension or renewal of the agreement; and

d. Specify all known opportunities for Narragansett to:

    i. Increase natural gas and/or LNG purchases under the terms of the agreement; and

    ii. Reduce natural gas and/or LNG purchases under the terms of the agreement.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-1.

Division 7-2

Request:

Please identify each interstate and/or international pipeline agreement through which Narragansett expects to receive natural gas supplies over the next five years and for each agreement identified, please:

a. Specify the term of the agreement;

b. Specify the daily, monthly, seasonal and annual limits on the volumes of natural gas volumes delivered under the agreement;

c. Specify the provisions for extension or renewal of the agreement; and

d. Specify all known opportunities for Narragansett to:

   i. Increase natural gas deliveries under the terms of the agreement; and

   ii. Reduce natural gas deliveries under the terms of the agreement.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-2.

Division 7-3

Request:

Please identify each natural gas storage agreement under which Narragansett expects to receive natural gas storage services over the next five years and for each agreement identified, please:

a. Specify the term of the agreement;

b. Specify the daily, monthly, seasonal and annual limits on the volumes of natural gas Narragansett injected into storage;

c. Specify the daily, monthly, seasonal and annual limits on the volumes of natural gas Narragansett withdrawals from storage;

d. Specify the provisions for extension or renewal of the agreement; and

e. Specify all known opportunities for Narragansett to:

   i. Increase the natural gas storage capacity available under the terms of the agreement; and

   ii. Reduce the natural gas storage capacity to which Narragansett is financially committed under the terms of the agreement.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-3.

Division 7-4

Request:

Please specify the changes, if any, PPL expects to make in the planning criteria that Narragansett/National Grid currently employ in long-range gas supply planning criteria and methods. The response to this request should include, but should not be limited to, the criteria that PPL would use to determine Design Day and Design Winter gas service requirements.

Response:

PPL does not have access to National Grid's non-public forecasting and planning information. Some of this information is confidential and is not expected to be shared with PPL until PPL owns Narragansett. However, based the information provided to PPL by National Grid and information that is publicly available[1], PPL has no reason to believe that National Grid is not performing forecasting and planning activities well on behalf of Narragansett. During the transition period, PPL will work with National Grid to fully understand their current processes and then determine what, if any, changes in planning criteria are necessary.

[1] A summary of National Grid's gas forecasting and planning process is available here: http://www.ripuc.ri.gov/eventsactions/docket/5043-NGrid-LRGas%20Plan-2020-21%20to%202024-25%20(6-30-20).pdf. The assumed likelihood of design weather is similar to LG&E's assumption, which is described in the response to 7-5.

REDACTED

Division 7-5

Request:

Please specify the methods and criteria used by LG&E to estimate:

a. Normal Annual Gas Supply volumes;

b. Design Annual Gas Supply volumes;

c. Design Winter Gas Supply volumes; and

d. Design Day Gas Supply volumes.

Response:

a. LG&E's Sales Analysis and Forecasting group provides a 5-year forecast to LG&E's Gas Management, Planning, and Supply group to use in its long-term supply planning process. This forecast is provided by customer class (rate schedule) for each month in the form of a Daily Sendout Formula. The forecast is updated annually in May of each year. Please see Attachment PPL-DIV 7-5-1 and Attachment PPL-DIV 7-5-2, which describe the development of the Annual Forecast and Daily Sendout Formulas. Please also see CONFIDENTIAL Attachment PPL-DIV 7-5-3, Appendix A, Residential SAE Modeling Framework, and CONFIDENTIAL Attachment PPL-DIV 7-5-4, Appendix B, Commercial Statistically Adjusted End-Use Model.

LG&E's Gas Management, Planning, and Supply group uses the Hitachi ABB SENDOUT gas supply planning model to apply daily weather patterns to Daily Sendout Formulas to determine daily, monthly, seasonal, and annual supply requirements. Normal annual gas supply requirements are determined using actual daily weather for Louisville, KY for a year that closely resembles the National Oceanic and Atmospheric Administration (NOAA) 30-year Normal weather pattern for Louisville, KY. The actual weather pattern is used instead of the NOAA normal weather pattern because it includes more daily weather variability.

b. - d. [redacted]

Prepared by or under the supervision of: Lonnie E. Bellar

REDACTED

[redacted]

Prepared by or under the supervision of: Lonnie E. Bellar

Annual Natural Gas Sendout Process

Sales Analysis & Forecasting
May 2021

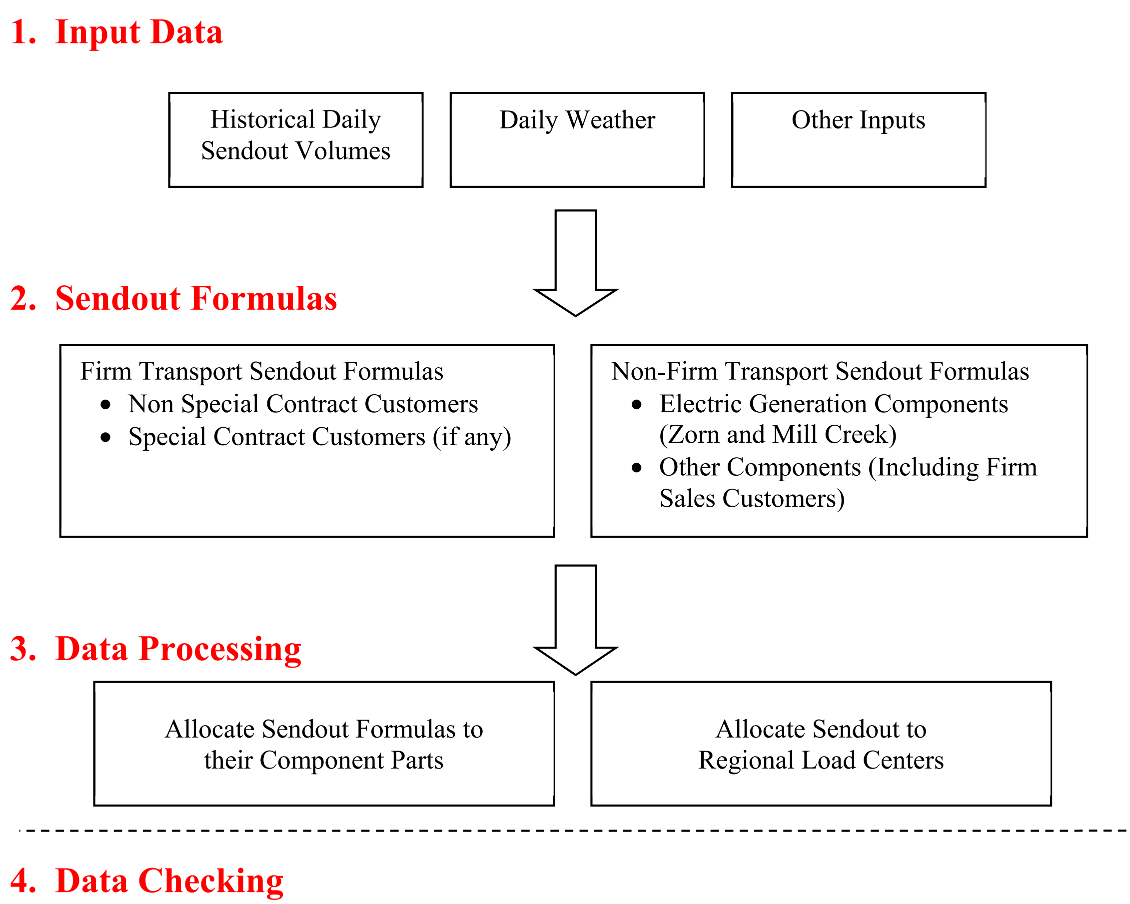
Table of Contents

1 Introduction

The Gas Supply Department forecasts daily sendout (DSO) as a part of its gas supply planning process. Each year, Sales Analysis & Forecasting provides daily sendout formulas to the Gas Supply Department. Like the volume forecast, the production of the sendout formulas can be divided into four parts (see Figure 1). In the first part of the process, input data is gathered and prepared for use in the subsequent parts. The following data items are key inputs to the production of the daily sendout formulas:

- Historical daily gas sendout volumes
- Daily weather data
- Other data including gas used by company-owned facilities and Generation Planning's forecast of gas used by Zorn and Mill Creek.

Figure 1 –Sendout Formula Process Diagram



DSO is recorded for the total system and for Firm Transportation (FT) customers. The difference between total DSO and FT sendout is "NonFT" sendout. NonFT sendout includes sales to retail customers, electric generation uses, other company uses, and losses. Electric generation uses include gas used by Zorn and Mill Creek. In the second part of the process, sendout formulas are produced for NonFT and FT sendout. Then, in the third part of the process, the NonFT and FT sendout formula parameters are allocated to their component parts.

The final part of the process is data checking. Every step in the production of the sendout formulas is checked before proceeding to the next step.

2 Input Data

Table 1 provides a summary of the data inputs used to produce the sendout formulas. The sections to follow describe the key processes used to prepare the data for use in this process.

Table 1 – Data Inputs for Production of DSO Formulas

Data	Source	Format
Historical DSO Volumes	Gas Supply (Monthly DSO Variance Report)	Daily Volumes (Total Sendout Excluding Gas Used by Electric Generating Stations and FT Sendout)
Historical Daily Average Temperatures	Gas Supply (Monthly DSO Variance Report)	Daily Temperatures
Other Company Uses	Louisville Gas & Electric Company Distribution of MCF Sendout	Monthly Reports
Forecasted Volumes for Zorn and Mill Creek Generation Units	Generation Planning	Monthly
Monthly Normal Weather Forecast	Sales Analysis & Forecasting	Monthly HDD/CDDs
Daily Normal Weather Forecast	Sales Analysis & Forecasting	Daily HDD/CDDs
Design Weather	Gas Supply	Daily HDDs

2.1 Historical DSO Volumes

LG&E delivers natural gas to customers each day by re-delivering natural gas received from interstate pipelines. Additionally, gas may be withdrawn from company-owned storage facilities to meet system requirements. The total amount of gas delivered into the system on a daily basis is the total daily sendout (DSO).

DSO is recorded for the total system and for Firm Transportation (FT) customers. As previously mentioned, FT customers currently include only non-special contract customers. If there were any special contract FT customers, the DSO would be recorded separately for such customers and they would have their own, separate DSO formulas. The difference between the total system DSO and FT sendout is “NonFT” sendout. In addition to sales to retail customers, NonFT sendout includes gas used by company-owned generating assets, other company uses, and losses.

Electric generation uses include gas used by Zorn and Mill Creek. Table 2 contains a complete list of the FT and NonFT sendout components.

Table 2 – FT, NonFT, and Special Contract Sendout Components

NonFT Sendout	FT Sendout	Special Contracts (if applicable)
Company Uses – Zorn Company Uses – Other Gas Lost and Unaccounted For Firm-Sales Mill Creek (Electric Generation Special Contract) Distributed Generation Gas Service Residential Gas Service Commercial Gas Service Industrial Gas Service Substitute Gas Sales Service Standby Transportation Sales Commercial TS-2 Industrial TS-2 As-Available Gas Service Sales As-Available Gas Service Transport	Firm-Transportation	Currently N/A

2.2 Historical Daily Weather Data

The historical daily weather series used in the production of the DSO formulas is supplied by the Gas Supply Department and is based on a Gas Day that begins and ends at 10:00 AM (vs. 12:00 AM).

2.3 Daily Normal Weather Forecast

A daily normal weather forecast is used to produce a forecast of DSO under normal weather conditions. The daily normal weather forecast is based on thirty years of historical weather data.

3 Sendout Formulas

The monthly sendout formulas provided to the Gas Supply Department are in the format requested by the Gas Supply Department and include the following parameters:

Table 3 – Sendout Formula Parameters

Parameter	Description
BL_{wknd}	Weekend base load usage (Mcf).
BL_{wkdy}	Weekday base load usage (Mcf).
BP_1	1st HDD breakpoint.
BP_2	2nd HDD breakpoint.
BP_3	3rd HDD breakpoint.
BP_4*	4th HDD breakpoint.
T_1	1st temperature coefficient.
T_2	2nd temperature coefficient.
T_3	3rd temperature coefficient.
T_4*	4th temperature coefficient.

*Applicable for the January sendout formula only.

The 4th breakpoint and coefficient was added to the January formula to account for extreme temperatures experienced during 2014. The following equations are used to compute DSO for a given month and usage type. The "max" function returns the largest value in a set of values (e.g., max(20, 0) = 20).

If the current day is a weekend day,

$$DSO = BL_{wknd} + \max(HDD-BP_1, 0)*T_1 + \max(HDD-BP_2, 0)*T_2 + \max(HDD-BP_3, 0)*T_3 + \max(HDD-BP_4, 0)*T_4$$

Else,

$$DSO = BL_{wkdy} + \max(HDD-BP_1, 0)*T_1 + \max(HDD-BP_2, 0)*T_2 + \max(HDD-BP_3, 0)*T_3 + \max(HDD-BP_4, 0)*T_4$$

$$HDD = \max(65\text{-Average Gas Day Temperature}, 0)$$

The weekend and weekday base load parameters include gas used for water heating, which is a function of ground water temperatures. As ground water temperatures decrease, the monthly base load parameters would be expected to increase. The HDD breakpoint parameters are points along the DSO line where the slope changes. The temperature coefficients define the slope of the DSO line between breakpoints.

An important decision in the formula specification process is selecting the period of history over which the sendout formulas are specified. The primary objective in making this decision is to select a period of history with a representative set of high and low temperatures. Generally, daily observations from three or four historical months (for example, the past 3 Aprils) – approximately 90 to 120 daily observations in total – are used to estimate the DSO coefficients for each month. Daily observations from other months are incorporated when temperatures in more recent months are not representative.

The following sections summarize the processes used to specify the NonFT and FT sendout formulas. Formula parameters are ultimately developed for every component of NonFT and FT sendout in Table 2 and every month in the 5-year forecast period.

3.1 DSO Formula Specification

The process used to specify NonFT and FT sendout formula coefficients differs for the winter and summer months.

3.1.1 Winter DSO Formula Specification

For the winter months, R software was used to optimize the formula coefficients based on historical DSO volumes and historical daily average temperatures. DSO formulas are used in inventory planning. Optimizing formula coefficients is an iterative process with feedback from other groups aimed at minimizing forecast errors, particularly under extreme weather scenarios.

3.1.2 Summer DSO Formula Specification

Since there is little, if any, weather-sensitive load in the summer months, the summer formula coefficients are specified by simply averaging weekday and weekend loads by month with adjustments to reflect customer growth and system planning risks.

3.2 Reasonability Checks

Once the summer and winter formulas are specified, the formulas are reviewed to make sure the following criteria are met:

1. The relationships between the weekend and weekday base load parameters in the winter months and the differences between base load parameters from one month to the next should be consistent with history. The latter is somewhat subjective for the winter months due to the lack of historical sendout observations under zero HDD weather conditions. Some insights about these relationships can be obtained by comparing historical weekend and weekday loads by month and HDD.
2. For a winter month, the forecasted usage in the DSO formula should be upward sloping. In theory, the heating response during the winter months should resemble an “S” curve. The heating response is staggered as temperatures initially begin to get cooler. Then, the response becomes consistent as all customers are heating their homes. At some point, however, the heating response begins to taper off as some customers reach their maximum heating capacity.

3.3 Formula Specification Under Design Weather Conditions

Specifying the sendout formulas under design weather conditions with an “ordinary least squares” approach may not be possible due to the lack of recent historical sendout observations under peak design weather conditions. If recent sendout data under peak design weather conditions is not available, an analysis would be conducted using historical sendout data to produce reasonable estimates for peak sendout. The following guidelines were followed when estimating these values:

1. Ideally, the peak estimate for a given month should be based on previous observations in that month under peak weather conditions.
2. More recent observations are better than less recent observations. However, due to special circumstances, some historical observations should not be incorporated in the analysis. For example, the observed sendout on New Year’s Day of 2018 – which was very cold – may not be a good reference point because the day was a holiday.

3. In the absence of comparable historical data for a given month, a reasonable peak estimate may be derived by continuing the slope of the coldest historical observations for that month (similar to point 4 below) or basing it upon historical observations in an adjacent month.
4. In some cases, it may make sense to use the assumed base load usage to compute an implied use-per-HDD value for a historical observation. Then, an estimate of peak sendout can be computed based on the peak HDD value (i.e., peak sendout = base load + use-per-HDD*peak HDD).

Once the peak estimates are determined, the final temperature coefficient may need to be adjusted so that the formula's sendout prediction under peak weather conditions will match the estimate.

4 Data Processing

After the NonFT and FT DSO formulas are specified, the formula parameters are allocated to their component parts and to regional load centers.

4.1 Allocate Sendout Formulas to their Component Parts

The FT sendout formulas are only allocated to FT customers.

The process used to allocate NonFT sendout to its component parts considers gas used for electric generation, company uses, and losses differently from the other NonFT components. Each of these items is discussed in the following sections.

4.1.1 Gas Used for Electric Generation

A separate set of NonFT sendout formulas is developed for (a) Zorn and (b) Mill Creek. Consumption at each of these generation stations is assumed to be constant throughout the month (with no variations based on weather or the day of week).

4.1.2 Company Uses

Company uses – as a component of the NonFT sendout formula – include compressor station usage, city gate usage, and gas used by company-owned facilities. In the non-winter months, these company uses are only reported on a quarterly basis. Since the gas is actually used throughout the year, the quarterly usage was reallocated to its component months per the guidance of the Gas Control department. This redistribution results in use that is more likely during normal weather.

4.1.3 Gas Lost and Unaccounted For

"Lost and unaccounted for gas" (LAUF) includes fixed gas losses (resulting from leaks on the gas distribution system) and metering losses. Metering losses exist because the gas meters for residential and commercial customers are designed to measure gas at a constant temperature of 60 degrees Fahrenheit. In the winter months – when the temperature is less than 60 degrees and the density of gas is greater – metering losses are positive (i.e., customers actually consume more gas than the meter indicates). In the summer months, metering losses are negative.

The forecast of fixed losses – as the name suggests – is constant at 65,000 Mcf per month or 2,137 Mcf per day. The forecast of LAUF is based on a model developed by the Prime Group ("Prime Model"). This model estimates the temperature of gas – and ultimately the density of gas – for a given month as a function of the current and previous two months temperatures. Then, the model computes the percentage difference between the density of gas at the estimated temperature and the density of gas at 60 degrees.

Metering losses are computed by multiplying the base load and weather-sensitive portions of "net sendout" by this percentage. Net sendout is the gas delivered to customers without temperature-compensating meters. The base load portion of net sendout is computed by subtracting the sum of company uses and fixed losses from the base load portion of NonFT sendout. The weather-sensitive portion of net sendout is equal to the weather-sensitive portion of NonFT sendout.

4.1.4 Other NonFT Components

NonFT sendout (like FT sendout) is comprised of base load and weather-sensitive volumes. Gas used for electric generation, company uses, fixed losses, and the base load portion of metering losses make up a portion of the NonFT base load volumes. The weather-sensitive portion of metering losses makes up a portion of the NonFT weather-sensitive volumes. The remaining portions of the NonFT base load and weather-sensitive volumes must be allocated to the sales components of sendout (RGS, CGS, IGS, AAGS, SGSS, Commercial TS-2, and Industrial TS-2 sales). To complete this process, the volume forecast for each sales class and month is broken into base load and weather-sensitive sales components. These components provide the basis for allocating the NonFT formula parameters to their component parts and are derived based on class-specific assumptions regarding the class's sensitivity to ground water temperatures and ambient air temperatures. The Distributed Generation (DGGS) component of NonFT is based on contracted volumes.

4.2 Regional Load Center Allocation

NonFT and FT sendout formula parameters are also allocated to two regional load centers: East and West. Each regional spreadsheet has the flexibility to define months by season (winter or summer) and to allow a change in the allocation percent by season.

5 Data Checking

The production of the sendout formula parameters involves a large amount of data and calculations. For this reason, every aspect of the process must be checked for errors. The criteria for checking the key aspects of the process have been discussed in each section of this report.

Natural Gas Volume Forecast Process

Sales Analysis & Forecasting

July 2021

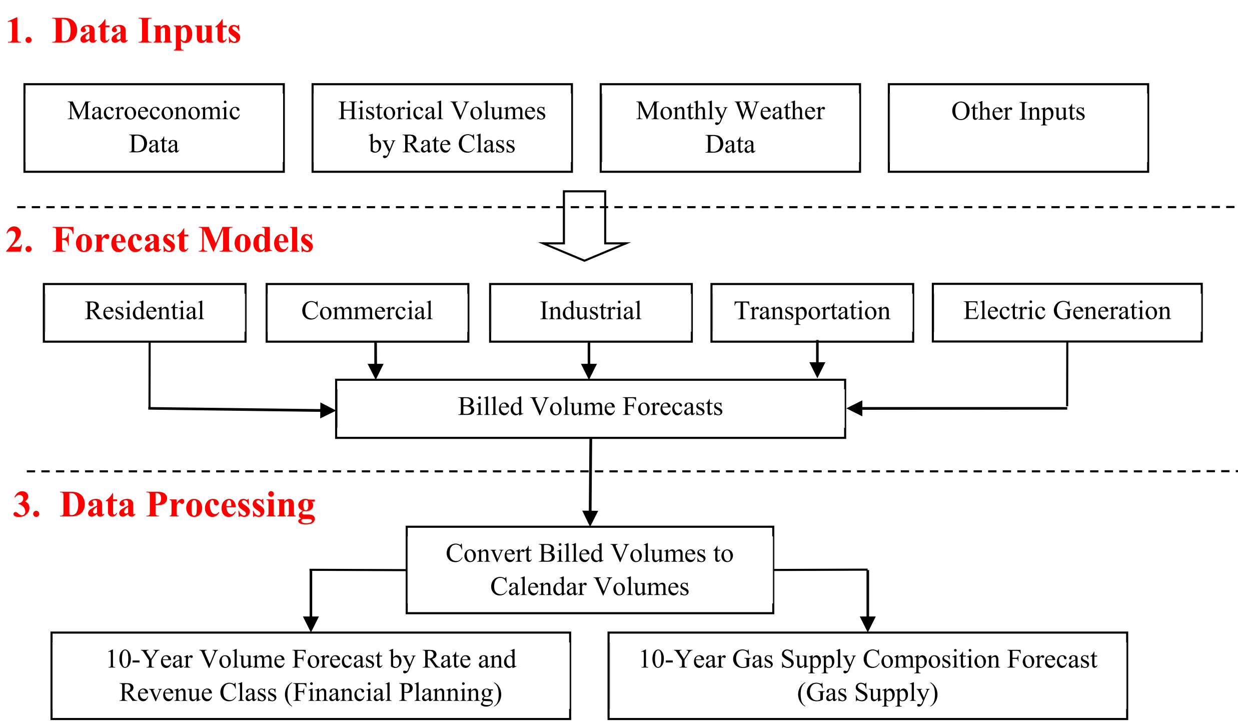
Table of Contents

1 Introduction

The Sales Analysis & Forecasting group annually develops the natural gas sales and transportation forecasts for the Louisville Gas & Electric Company (LG&E). LG&E natural gas customers can broadly be classified as either sales customers or transportation customers, and sales customers can be further divided into firm and interruptible customers. LG&E must procure gas for firm sales customers, but it has no obligation to procure gas for interruptible sales customers or transportation customers. LG&E provides gas service to sales customers on residential, industrial, and commercial rates. Transportation customers are large industrial and commercial customers on LG&E's distribution system who contract for their own gas supply and use the company's pipeline system to deliver gas from an interstate pipeline to their facilities. The gas sales and transportation forecasts are an input to the company's revenue and gas supply expense forecast. This document describes the processes used to produce these forecasts.

The forecast process can be divided into three parts (see Figure 1). The first part of the forecast process involves gathering and processing input data. Key inputs to the forecast process include macroeconomic data, historical gas sales and customer data, weather data, and other data such as residential heating appliance shares and efficiencies.

Figure 1 – Natural Gas Volume Forecast Process Diagram



In the second part of the forecast process, input data is used to specify various forecast models. LG&E's natural gas volumes are forecasted by rate class. Most of the forecast models produce volume forecasts on a monthly billed basis.[1] In the third part of the forecast process, gas volume data from the forecast models is processed to meet the needs of the forecast end users. The monthly billed sales forecasts must first be converted to calendar month forecasts. The billed and calendar sales forecasts are allocated by rate and revenue class for the Financial Planning department.[2] In addition, the calendar forecasts are used to produce the Gas Supply Composition Forecast.

Throughout the forecast process, the forecast results are reviewed to ensure they are reasonable. For example, the new forecast is compared to (i) the previous forecast and (ii) weather-normalized actual sales for the comparable period in prior years. Each of these parts and the software tools used to produce the forecast are discussed in more detail in the following sections.

2 Software Tools

The following software packages are used in the forecast process:

- SAS, R
- Itron Metrix ND
- Microsoft Office: Excel, PowerPoint, Access

SAS, R, and Metrix ND are used to specify forecast models. The Microsoft Office tools are primarily used for analysis and presentations.

[1] All customers are assigned to one of 20 billing portions. A billing portion determines what day of the month a customer's meter is read. Because most billing portions do not coincide precisely with the boundaries of calendar months, most customers' monthly bills will include sales that were consumed in multiple calendar months. The sales on customers' bills are referred to as "billed" sales.

[2] Rate class defines the tariff assigned to each customer meter while Revenue class is a higher-level grouping; a Revenue class consists of one or more rate classes.

3 Input Data

Table 1 provides a summary of the data inputs. The sections that follow describe key processes used to prepare the data for use in the forecast process.

Table 1 – Volume Forecast Data Inputs

Data	Source	Format
State Macroeconomic Data (Employment, Wages)	IHS Markit	Annual or Quarterly by County – History and Forecast
State Demographic Data (Households, Personal Income, Population)	IHS Markit, Kentucky Data Center	Annual or Quarterly – History and Forecast
National Macroeconomic Data (Industrial Production Index)	IHS Markit	Annual or Quarterly – History and Forecast
Weather	National Oceanic and Atmospheric Administration ("NOAA")	Daily HDD/CDD by Weather Station – History
Historical Gas Supply Cost	State Regulation and Rates	Monthly
Henry Hub Gas Price Forecast	Corporate Long-term Planning Process	Monthly
Gas Supply Cost Forecast	Gas Supply (based on Henry Hub Gas Price Forecast)	Monthly
Historical Billing Portion Meter Reading Schedule	Revenue Accounting	Billing Portion Read Dates
Heating Appliance Efficiencies	Energy Information Administration ("EIA")	Annual Efficiencies by Appliance (Furnace, Water Heater)
Residential End-Use Data	EIA, LG&E Residential End-Use Survey	Appliance Saturations
Commercial End-Use Data	EIA, LG&E Commercial End-Use Survey	Appliance Saturations
Billed Sales History by Rate Class	CCS Billing System	Monthly
Number of Customers History by Rate Class	CCS Billing System	Monthly
Forecasts of Gas Used by Electric Generation	Generation Planning	Monthly

3.1 Billed Usage History

Historical billed usage volumes for all retail customers are taken from the LG&E Customer Care System (CCS). The LG&E Billed Transport Report contains historical usage volumes for all transportation customers. Transportation customers nominate – on a daily basis – the amount of gas they expect to consume. A daily or monthly "imbalance" is computed as the difference between the amount of natural gas actually consumed and the amount of natural gas nominated.

For several classes, a significant portion of the total gas usage is made up of gas consumed by heating appliances (e.g., gas furnaces and gas water heaters). Heating appliance usage is a function of appliance efficiencies and weather. As appliance efficiencies improve over time, the average use-per-customer will decline in the absence of customer behavioral changes.

The heating appliances that consume the most natural gas are the gas furnace and gas water heater. Total usage and efficiency data for these appliances are provided by the US Energy Information Administration (EIA) and are used as inputs into some of the forecast models.

3.2 Processing of Weather Data

Weather is a key explanatory variable in the gas forecast models. The weather dataset from the National Oceanic & Atmospheric Administration (NOAA) contains temperatures (maximum, minimum, and average), heating degree days (HDD), and cooling degree days (CDD) for each day and weather station over the past 30 years. This data and the Company's meter reading schedule are used to create (a) a historical weather series by billing period and (b) a forecast of "normal" weather by billing period.[3] Each of these processes is summarized below.

3.2.1 Historical Weather by Billing Period

The methodology used to create the historical weather series by billing period consists of the following steps:

1. Using the historical daily weather data from NOAA, sum the HDD and CDD values by billing portion.[4] Each historical billing period consists of 20 portions. The Company's historical meter reading schedule contains the beginning and ending date for each billing portion.
2. Average the billing portion total HDDs and CDDs by billing period.

3.2.2 Normal Weather Forecast by Billing Period

The methodology used to produce the forecast of normal weather by billing period includes the production of a daily forecast of normal weather. The methodology used to develop the daily forecast (summarized in Steps 2-5) is consistent with the methodology used by NOAA to create

[3] "Normal" weather is defined as the average weather over a historical period. The Companies do not attempt to forecast any trends in weather.

[4] Weather data in the gas forecast is taken from the weather station at Standiford Field Airport (SDF) in Louisville.

its daily normal weather forecast.[5] The following steps are used to create the forecast of normal weather by billing period:

1. Compute the forecast of monthly weather by *calendar* month by averaging the monthly degree-day values over the period of history upon which the normal forecast is based. The normal weather forecast is based on the most recent 30-year historical period. Therefore, the normal HDD value for January is the average of the 30 January HDD values in this period.
2. Compute "unsmoothed" daily normal weather values by averaging temperature, HDDs, and CDDs by calendar day. The unsmoothed normal temperature for January 1, for example, is computed as the average of the 30 January 1 temperatures in the historical period. This process excludes February 29.
3. Smooth the daily values using a 30-day moving average centered about the desired day. The "smoothed" normal temperature for January 1, for example, is computed as the average of the unsmoothed daily normal temperatures between December 16 and January 15.
4. Manually adjust the values in Step 3 so that the following criteria are met:
    a. The sum of the daily HDDs and CDDs by month should match the normal monthly HDDs and CDDs in Step 1.
    b. The daily temperatures and CDDs should be monotonically increasing from winter to summer and monotonically decreasing from summer to winter. The daily HDD series should follow a reverse trend.

    These criteria ensure the daily normal series is consistent with the monthly normal series.
5. The Company's forecasted meter reading schedule contains the beginning and ending date for each billing portion through the end of the forecast period. In this step, sum the HDD and CDD values by billing portion. Use the February 28 weather data as a proxy for February 29 when billing portions include leap days.
6. Average the billing portion totals by billing period.

3.3 Forecasts of Gas Used by Electric Generation

LG&E's gas distribution business provides firm gas service to the Mill Creek generating station via a special contract ("Electric Generation Special Contract"). The forecast of natural gas used by the Mill Creek station is provided by the Generation Planning group. In addition, the Generation Planning group provides a forecast of gas used by the Zorn generating station, which is also served by the LG&E gas distribution system (but not as a part of the Electric Generation Special Contract).

From a revenue accounting perspective, the gas consumed by the Mill Creek station is accounted for in a separate Interdepartmental Sales revenue class. The gas consumed by the Zorn station is

[5] NOAA derives daily normal values by applying a cubic spline to a specially prepared series of the monthly normal values.

considered Company Use and is recorded in the utility financial reports as part of gas 'Used in Electric Generation.'

4 Forecast Models

LG&E's gas sales forecasts are developed through econometric modeling of gas sales by rate class, but also incorporate specific intelligence on the prospective gas consumptions of the utilities' largest customers. Econometric modeling captures the (observed) statistical relationship between gas consumption – the dependent variable – and one or more independent explanatory variables such as the number of households or the level of economic activity in the service territory. Forecasts of gas sales are then derived from a projection of the independent variable(s).

This widely accepted approach can readily accommodate the influences of national, regional and local (service territory) drivers of electricity sales. This approach may be applied to forecast the number of customers, gas sales, or use-per-customer. The statistical relationships will vary depending upon the jurisdiction being modeled and the class of service.

LG&E natural gas customers can broadly be classified as either sales customers or transportation customers. Sales customers include customers on the residential, industrial, and commercial gas service rates. Transportation customers are large industrial and commercial customers on LG&E's distribution system who contract for their own gas supply.

The econometric models used to produce the forecast pass two critical tests. First, the explanatory variables of the models must be theoretically appropriate and widely used in gas sales forecasting. Second, the inclusion of these explanatory variables must produce statistically significant results that lead to an intuitively reasonable forecast. In other words, the models must be theoretically and empirically robust to explain the historical behavior of the Companies' customers. Each forecast is discussed in detail in the following sections.

4.1 Residential Forecast

The residential forecast consists of all customers on the Residential Gas Service (RGS) rate schedule. The RGS class accounts for approximately half of the total volume forecast. RGS sales are forecasted as the product of a customer forecast and a use-per-customer forecast. Consumption on the Volunteer Fire Department (VFD) rate schedule is included in the residential forecast.

4.1.1 Residential Gas Service (RGS) Customer Forecast

The RGS customer forecast is modeled as a function of the number of forecasted households in the LG&E service territory. Historical and forecasted households by county and Metropolitan Statistical Area (MSA) are provided by IHS Markit.

4.1.2 Residential Gas Service (RGS) Use-per-Customer Forecast

The RGS use-per-customer forecast is developed using a Statistically-Adjusted End-Use (SAE) model (similar to what is used to forecast residential electric sales). Such a model combines an econometric model – that relates monthly sales to various explanatory variables such as weather and economic conditions – with traditional end-use modeling. For natural gas, the SAE approach defines energy use as a function of energy used by heating equipment and other natural-gas fueled equipment.

$$\text{Use-per-Customer} = a_1 * XHeat + a_2 * XOther$$

The heating and other components (the X variables) are based on various input variables including weather (heating and cooling degree days), appliance saturations, efficiencies, and economic and demographic variables such as income, population, members per household and the gas supply cost. In addition, certain binary variables may be added to compensate for anomalies in the data or other events. Once the historical profile of these explanatory variables has been established, a regression model is specified to identify the statistical relationship between changes in these variables and changes in the dependent variable, use-per-customer. A discussion of each of these components and the methodology used to develop them is contained in Appendix A.

4.2 Commercial Forecast

The commercial forecast comprises customers on the Firm Commercial Gas Service (CGS) and Commercial As-Available Gas Service (CAAGS) rate schedules. Given the unique characteristics of these classes, each class is modeled separately.

4.2.1 Firm Commercial Gas Service (CGS) Sales Forecast

Similar to the RGS use-per-customer forecast, the CGS sales volume forecast is developed using an SAE model. A key difference between the RGS and CGS forecasts is RGS sales are forecasted using a UPC forecast times a customer forecast, while CGS is directly a sales forecast. For CGS, customers are forecasted separately and UPC is implied. A discussion of the heating and other components utilized in the CGS SAE model is contained in Appendix B.

4.2.2 Commercial As-Available Gas Service (CAAGS) Forecast

There are a small number of CAAGS customers so each customer is forecasted separately. The forecasts are developed with input from Major Account representatives when necessary to make sure the underlying assumptions and forecasted volumes are reasonable.

4.3 Industrial Forecast

The industrial revenue class comprises customers on the Firm Industrial Gas Service (IGS) and Industrial As-Available Gas Service (IAAGS) rate schedules.

4.3.1 Firm Industrial Gas Service (IGS) Forecast

IGS volumes are forecasted in total as a function of weather variables, number of customers, and recent usage.

4.3.2 Industrial As-Available Gas Service (IAAGS) Forecast

There are a small number of IAAGS customers so each customer is forecasted separately. The forecasts are developed with input from Major Account representatives when necessary to make sure the underlying assumptions and forecasted volumes are reasonable.

4.4 Substitute Gas Sales Service (SGGS)

There are a small number of SGGS customers so each customer is forecasted separately. The forecasts are developed with input from Major Account representatives when necessary to make sure the underlying assumptions and forecasted volumes are reasonable.

4.5 Distributed Generation Gas Service (DGGS)

There are a small number of DGGS customers so each customer is forecasted separately. The forecasts are developed with input from the Gas Supply group based on usage over the last twelve months.

4.6 Electric Generation Sales Forecast

As mentioned in section 3.3, the interdepartmental sales forecast consists of gas used by the Mill Creek generating station and is developed with input from the Generation Planning group based on usage over the last twelve months.

4.7 Firm Transportation Forecast

The firm transportation forecast consists of special contract customers and customers on the Firm Transportation Service (FT) rate schedule. A limited number of the company's largest FT customers make up approximately two-thirds of the class's total usage. Forecasts for these customers are developed individually with input from Major Account representatives. Volumes for the other customers are forecasted in total as a function of number of customers, recent usage, and binary variables to account for anomalies in the data.

4.8 Rider TS-2 Transportation Forecast

The TS-2 transportation forecast consists of commercial and industrial customers with a Gas Transportation Service (TS-2) rider. The forecast is the sum of projections for individual customers that are expected to be on the rate in any given period.

4.9 Customer Forecasts

Customer forecasts for each rate are used in the company's revenue forecast to compute revenue from customer charges. The customer charge for the CGS and IGS rate plans varies based on the capacity of the customer's meter (i.e., whether it's less than or greater than 5,000 cf/hr). Therefore, information from CCS is used to segment the total number of CGS and IGS customers into these two meter-capacity categories.

5 Data Processing

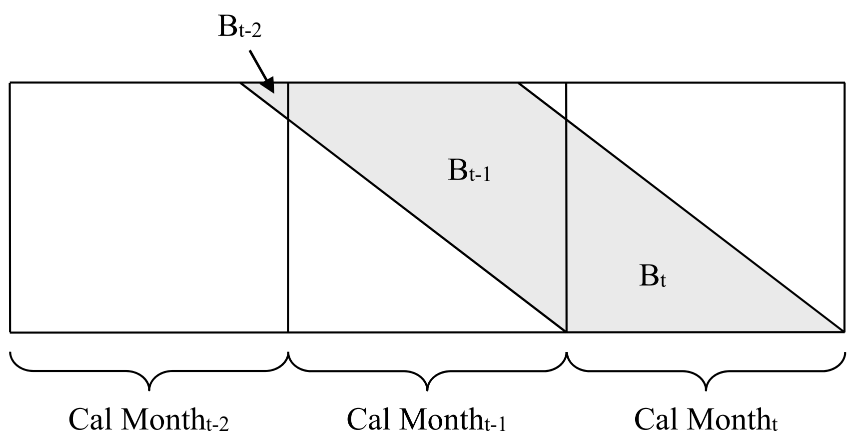
The models discussed in the preceding section produce forecasts on a "billed" basis. All customers are assigned to one of 20 billing portions. A billing portion determines what day of the month, generally, a customer's meter is read. The volumes on customers' bills are referred to as "billed" volumes. If a customer's billing portion does not coincide directly with the boundaries of calendar months, that customer's bill will include volumes from multiple calendar months.

In this part of the forecast process, the billed forecast data is processed to meet the needs of the forecast's end users. First, the billed forecasts are converted from a billed basis to a calendar-month basis. Then, the calendar forecasts are allocated by rate and revenue class for use by the Financial Planning Department. In addition, the calendar forecasts are used – along with forecasts of gas losses and gas used by company-owned facilities and generating assets – to produce the Gas Supply Composition Forecast. Each of these processes is discussed in the following sections.

5.1 Billed-to-Calendar Conversion

The majority of forecast volumes, which are primarily in the RGS and CGS rates, must be converted from a billed to calendar basis to meet the needs of the Financial Planning department. The shaded area in Figure 2 represents a typical billing period (B). Area B_t represents the portion of billed sales consumed in the current calendar month (Cal $Month_t$). Area B_{t-1} represents the portion of billed sales consumed in the previous calendar month (Cal $Month_{t-1}$). Area B_{t-2} represents the portion of billed sales consumed in the calendar month two months prior to the current month (Cal $Month_{t-2}$). Not all billing periods include volumes that were consumed in the calendar month two months prior to the current month.

Figure 2 – Billed and Calendar Sales



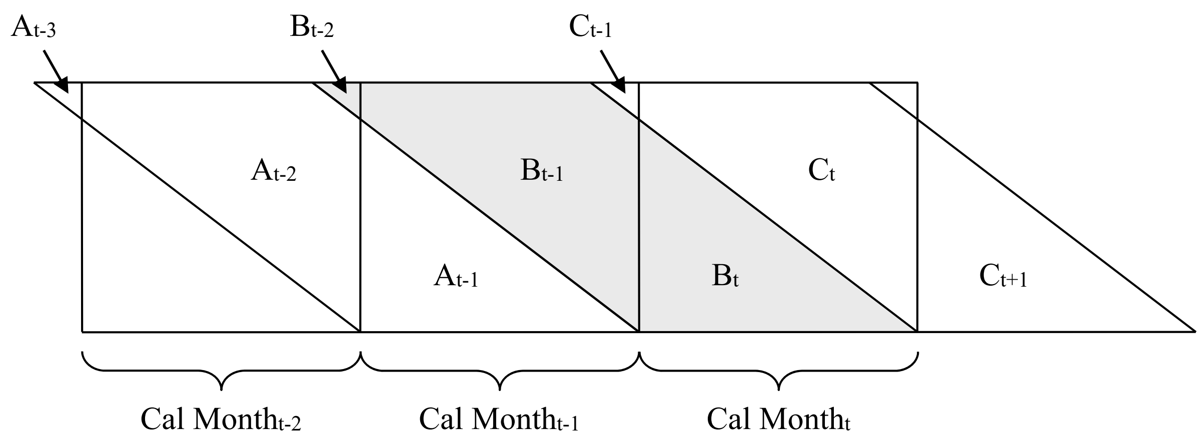
In this process, billed sales are allocated to calendar months based on when they are consumed. Furthermore, the weather-sensitive portion of the billed sales forecast is allocated to calendar months based on heating degree days (HDDs) and the non-weather-sensitive portion is allocated based on billing days.[6] For example, the January billing period includes portions of January, December, and possibly November. Under normal weather conditions, January will have more

[6] For a given billing period, the number of degree days and billing days in each calendar month is computed as an average over the 20 billing portions.

HDDs than December. Therefore, a greater portion of the weather-sensitive sales in the January billing period will be allocated to the calendar month of January.

Figure 3 contains two additional billing periods (A & C). Calendar sales for Cal Month$_{t-1}$ is equal to the sum of sales in in billing period segments A_{t-1}, B_{t-1}, and C_{t-1}.

Figure 3 – Billed and Calendar Sales



5.2 Rate-to-Revenue Class Allocation

To meet revenue forecasting requirements, the billed and calendar volume forecasts, which are initially developed by rate class, must be allocated to revenue classes. Revenue class is a higher level grouping; all rate classes are allocated to one or more of the following revenue classes:

- Residential
- Commercial
- Industrial
- Interdepartmental
- Transport

This information is used by the Financial Planning department to develop a forecast of revenues for the planning period. Billed and calendar forecasts are allocated to revenue classes using a set of allocation ratios. These ratios are derived based on historical sales data from CCS for gas volumes and customers.

Attachments PPL-DIV 7-5-3 to 7-5-4

Confidential Attachments PPL-DIV 7-5-3 to 7-5-4 contain confidential information. PPL and PPL RI have requested protective treatment of these confidential attachments in their entirety.

Division 7-6

Request:

Please provide Narragansett's best available assessment of the impacts that Rhode Island's decarbonization will have on its gas system requirements over the next five years for:

a. Normal Annual Gas Supply volumes;

b. Design Annual Gas Supply volumes;

c. Design Winter Gas Supply volumes; and

d. Design Day Gas Supply volumes.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-6.

Prepared by or under the supervision of: Legal Department

Division 7-7

Request:

Please detail Narragansett's plan by year for replacing the remaining Cast Iron gas mains on its Rhode Island system and provide the Company's estimated costs per mile for Cast Iron main replacement.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-7.

Division 7-8

Request:

Please detail Narragansett's plan for replacing the remaining Bare Steel and Unprotected Steel gas mains on its Rhode Island system and provide the Company's estimated costs per mile for replacing Bare Steel and Unprotected Steel gas mains.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-8.

Division 7-9

Request:

Please detail by year for the period 2010 to 2020 LG&E's average costs per mile for replacing:

a. Cast Iron gas mains;

b. Bare Steel gas mains; and

c. Unprotected Steel gas mains.

Response:

LG&E's main replacement program began in 1996 and was completed in 2017. The program consisted of replacing cast iron, wrought iron, bare steel and unprotected mains and services on the primarily low pressure gas distribution system. In total, the miles of mains and services replaced are as follows:

- Miles of Main Installed: 650
- Miles of Main Retired: 540
- Miles of Main Uprated: 65
- Services Replaced: >70,000

The total program cost was approximately $287 million. The annual costs from 2010-2017 are shown below. The main replacement program was not performed on a segment by segment basis and thus not tracked by main or service type. LG&E does not have the information of the average costs per mile or per foot.

Prepared by or under the supervision of: Lonnie E. Bellar

	Main Replacement Program		
Year	Capital Cost	Miles of Main	No. of Services
2010	$ 16,909,841	40.3	4,049
2011	$ 21,190,164	50.0	5,649
2012	$ 19,941,202	27.7	2,853
2013	$ 21,510,657	32.6	1,739
2014	$ 22,582,801	32.3	2,644
2015	$ 23,129,783	29.2	2,090
2016	$ 23,829,616	11.5	2,429
2017	$ 14,318,339	1.2	698
2018	$ 3,101,723	0	-
2019	$ 270,210	0	-
2020	$ 1,004	0	-
Total	$ 166,785,339	224.8	22,151

Notes: No pipeline installed in 2018-2020. Costs are for restoration and administrative labor activities.

Since 2016, LG&E has initiated a vintage plastic pipeline (Aldyl-A) replacement program, an elevated pressure reinforcement program and a steel gas service line replacement program. The vintage plastic pipeline replacement program which has been completed replaced all known Aldyl-A plastic pipelines and services. The elevated pressure reinforcement program which began in 2018 consists of replacing and/or converting portions of the elevated (3 psi) system to a medium pressure system. Where replacement occurs, existing elevated pressure steel pipelines and services are replaced with polyethylene piping. The steel gas service line replacement program which began in 2018 consists of replacing steel services and retiring curbed steel services.

	Aldyl-A Replacement Program		
Year	Capital	Miles of Main	No. of Services
2016	$ 2,342,873	6.1	362
2017	$ 3,332,659	8.9	325
2018	$ 48,697	0	0
Total	$ 5,724,229	14.9	687

Notes: No pipeline installed in 2018. Costs are for restoration and administrative labor activities.

Prepared by or under the supervision of: Lonnie E. Bellar

	Elevated Pressure Reinforcement Program		
Year	Capital	Miles of Main	No. of Services
2018	$ 430,212	0.41	0
2019	$ 2,753,144	3.1	128
2020	$ 4,167,929	2.7	260
Total	$ 7,351,284	6.3	388

	Steel Service Line Replacement Program		Curb Service Removal	
Year	Capital	No. of Services	Capital	No. of Services
2018	$ 4,991,446	1,841	$ 720,055	253
2019	$ 9,108,846	2,763	$ 2,496,620	1,239
2020	$ 7,160,139	1,983	$ 3,628,600	1,180
Total	$ 21,260,431	6,587	$ 6,845,275	2,672

Prepared by or under the supervision of: Lonnie E. Bellar

Division 7-10

Request:

Please detail Narragansett's plans for replacing the remaining Base Steel, Unprotected Steel, Cast Iron, Ductile Iron, and Copper services on its Rhode Island system and provide the Company's estimated costs per service for replacing each type of service line referenced

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-10.

Division 7-11

Request:

Please detail by year for the period 2010 to 2020 LG&E's average costs per foot for replacing:

a. Bare Steel gas service lines;

b. Cast Iron gas service lines; and

c. Copper service lines.

Response:

PPL and PPL RI refer to their response to PPL-DIV 7-9.

Prepared by or under the supervision of: Lonnie E. Bellar

Division 7-12

Request:

Please provide by decade the number of services installed on the Narragansett Gas system in Rhode Island as of the time of the most recent Annual Report to the Pipeline and Hazardous Materials Safety Administration (PHMSA).

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-12.

Prepared by or under the supervision of: Legal Department

Division 7-13

Request:

Please provide by decade installed the number of services installed on the Narragansett Gas system in Rhode Island as of the time of the most recent PHMSA Annual Report by type of service line.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-13.

Prepared by or under the supervision of: Legal Department

Division 7-14

Request:

For each of the last five calendar years, please provide the number of services on the Narragansett Gas system in Rhode Island that were replaced by type of service line and by decade installed.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-14.

Division 7-15

Request:

Based on data submitted to PHMSA for each of the last ten years, it appears that the number of hazardous leaks on service lines on the LG&E gas system have generally been two to three times the numbers of hazardous leaks on service lines for Narragansett's gas system. Please verify the accuracy of this assessment and provide PPL's explanation of the greater number of hazardous gas leaks on service lines reported for its LG&E gas system when compared to Narragansett's gas system.

Response:

While the data does show a greater number of hazardous leaks for the LG&E gas system than the Narragansett gas system, there are a number of reasons why this is the case. First, LG&E has approximately 50,000 more customers and over 100,000 more gas services than Narragansett. Second, LG&E's annual excavating (line locating) ticket volume is more than double the Narragansett excavation ticket over a ten year average and thus results in a higher volume of excavation damages by comparison. Approximately 86% of LG&E's excavation damages are on gas services.

Further, material, weld, and joint failures contain the highest number of total leaks on an annual basis. These leak codes are used commonly when a leak occurs, but a true cause cannot readily be determined. For example, they are used frequently when there is a leak on a service and the entire service is replaced without determining the root cause of the leak. LG&E's ongoing service replacement program will continue to help drive down the number of these type of leaks.

Leaks on equipment, such as valves, regulators, and control/relief equipment, can also be a threat to the distribution system. Overall, equipment failure leaks on LG&E's system have decreased 50% since 2010. This decrease can be attributed to the removal of aging equipment being replaced by newer more reliable equipment.

For incorrect operations, historically one of the most reoccurring events in improper installation was the installation of a riser/service head adaptor by a plumber (cross-threading). Now that the gas service riser replacement project is complete, there should be a decrease in this event. The Distribution Integrity Management group has noted an increase in electrofusion leaks and will continue to monitor electrofusion failures and address any noticeable trends for both manufacturing issues and incorrect operations.

Prepared by or under the supervision of: Lonnie E. Bellar

Division 7-16

Request:

Please identify each program and/or technology for improvement of end-use gas consumption by customers that has been employed by LG&E but is not currently used by Narragansett's gas system in Rhode Island.

Response:

PPL and PPL RI are not aware of any gas DSM programs or technologies for improvement of end-use gas consumption by customers that LG&E has employed, but are not currently implemented by the Narragansett gas system in Rhode Island.

Prepared by or under the supervision of: Lonnie E. Bellar

Division 7-17

Request:

Please identify each best practice for gas system operations, maintenance, and/or customer service that is presently employed by LG&E but that is not presently used by Narragansett's gas system in Rhode Island.

Response:

PPL has not participated in or undertaken a "best practice" benchmarking exercise with National Grid for the Narragansett gas system in Rhode Island.

LG&E has employed numerous practices that have helped improve safety, productivity, and customer satisfaction, including those listed below. Based on PPL's discussions with National Grid and Narragansett, PPL has noted where National Grid and Narragansett have or have not employed such practices for the gas distribution operations in Rhode Island and any distinctions.

- Gas Operation Reliability and Safety Programs
  - Large scale main replacement program - completed (bare steel, cast iron, wrought iron). Narragansett operates a large-scale main replacement program in Rhode Island, which is still in progress.
  - Vintage plastic main replacement program - completed (Aldyl-A pipe). Narragansett considers Aldyl-A pipe as leak-prone pipe, and it is included in Narragansett's leak-prone pipe replacement program.
  - Gas service riser replacement program - completed (gas service head adapters). Narragansett does not employ a similar program.
  - Steel gas service replacement program (protected steel). Narragansett employs a proactive bare steel service replacement program. Protected steel services are replaced in conjunction with leak-prone pipe replacement, if necessary, based on the condition of the service.
  - Elevated pressure main replacement program (3 psi protected steel). Narragansett employs a low-pressure to high-pressure program.

- Gas Distribution Integrity Management – New probabilistic risk modeling software. Narragansett uses the Copperleaf software for risk ranking capital investments. The parties have not yet compared the details of their respective risk modeling software, so do not yet know whether the respective modeling systems provide significantly different benefits.

Prepared by or under the supervision of: Lonnie E. Bellar

- Material Standardization – Standardization of design, fabrication, and installation of residential and commercial gas meter sets, gas regulation, and city gate facilities. Narragansett operates a similar program.

- Technology – Systems and Applications
    - Core/Central – ESRI GIS, work management and design, dispatch, and outage management systems. Narragansett uses similar systems for GIS and Dispatch; however, Narragansett does not have an outage management system for its gas distribution system.
    - Mobile – mapping, inspection, field services, and emergency response systems. Narragansett employs or is developing similar systems.

- Corrosion Control – Enhanced AC monitoring and mitigation program. Narragansett employs similar programs.

- Damage Prevention – Enhanced excavator training and corporate communication initiatives. Narragansett employs similar programs.

- Construction – Joint trench standardized construction of gas, electric, and telecom facilities. Narragansett uses a standardized trench program for gas, electric, and telecom facilities.

- Gas Training – Expansion and renovation of the training center with new laboratories and outside field pipeline training facilities. National Grid has similar training facilities located in Massachusetts; however, National Grid does not have a Rhode Island-based training facility.

- Operator Qualification ("OQ") – Mobile OQ and drug & alcohol daily field verification application (OQ Verify). Narragansett employs a field verification program for OQ; however, Narragansett does not use a mobile drug & alcohol daily field verification program.

- Pipeline Safety Management – Voluntary implementation of API 1173. Narragansett has adopted API 1173 and has an extensive program to implement and monitor pipe maturity.

- Customer Satisfaction – New business cycle time under 9 work days. Narragansett does not measure or monitor metrics related to new business cycle time; however, National Grid conducts a survey for customers who have recently completed a conversion to natural gas, including for Narragansett customers.

Prepared by or under the supervision of: Lonnie E. Bellar

- Emergency Response – 90%+ response time success rate under 60 minutes. Under Narragansett's current regulatory requirements, it meets or exceeds a threshold target response time of 95.18% within 30 minutes for "Business Hours" (Monday through Friday, 8:00 a.m. to 4:00 p.m.) and 94.38% within 45 minutes for "Non-Business Hours" (anything outside of Monday through Friday, 8:00 a.m. to 4:00 p.m.).

Division 7-18

Request:

Please document PPL's experience with Advanced Leak Detection (ALD) methods and technology and explain how and to what extent PPL proposes to use ALD on Narragansett's gas system in Rhode Island. If PPL does not have a plan for the use of ALD in Rhode Island, please explain why and indicate whether it would consider the use of such technology going forward.

Response:

PPL's only significant experience with ALD has been associated with aerial leak surveys on its gas transmission system using Light Detection and Ranging ("LiDAR") technology. LiDAR has been in use since 2019 on the gas transmission system. Functionally, the LiDAR system has been effective detecting leaks via the aerial surveys covering the gas transmission right-of-ways and gas storage fields.

PPL has tested the use of ALD in the form of mobile leak survey technology to gain a better understanding of the technology and its practical use. Mobile leak survey technology presents opportunities for improvement, but the current processes designed to satisfy various inspection requirements make the transition difficult.

It is PPL's intention to continue evaluating various forms of ALD and to determine appropriate steps forward. Factors it will consider include financial implications, process changes, practical application, and personnel impacts.

Division 7-19

Request:

After the transfer of ownership of the Narragansett gas system to PPL, please identify the individuals and procedures that will be utilized to:

a. Optimize Narragansett's gas supply portfolio;

b. Manage Off-System Sales; and

c. Manage capacity release transactions.

For each individual identified in response to parts a, b, and c above, please provide a resume for the individual and document their experience with respect to the activities for which they will be responsible.

Response:

a) through c):

PPL Rhode Island Holdings, LLC ("PPL Rhode Island") will be responsible for activities related to the optimization of the gas supply portfolio including off-system sales, capacity release transactions, as well the administration of the Natural Gas Portfolio Management Plan. On Day 1, the parties anticipate that National Grid USA will support PPL Rhode Island with the optimization services under the Transition Services Agreement. The parties expect that there will be considerable continuity of resources and personnel that have undertaken this activity in the past, mainly from National Grid USA's Energy Procurement organization following existing processes. At this time, PPL does not know who specifically will perform the work; therefore, PPL cannot identify the individuals expected to be involved in these activities.

Division 7-20

Request:

Forecasting of gas supply requirements for Narragansett's gas system has generally been provided by National Grid personnel. Please identify the entity who will provide gas supply requirement forecasting for Narragansett:

a. During the transition period; and

b. After the transition period.

Response:

a. National Grid USA will provide gas supply requirement forecasting under a transition service agreement ("TSA") for a period of up to two years. During the transition period, PPL will work with National Grid and Narragansett to fully understand best practices they utilize in forecasting and planning for Narragansett system needs.

b. PPL and PPL RI currently plan to have personnel in Kentucky provide gas supply forecasting for Narragansett after the transition period. PPL and PPL RI have not yet determined the specific entity that will provide those gas supply forecasting services.

Prepared by or under the supervision of: David J. Bonenberger

Division 7-21

Request:

Forecasting of service requirements tends to be a data intensive activity that can require substantial reliance on historical data for customer, usage, pricing and other economic variables. Please identify:

a. The data sets presently used for forecasting gas supply requirements for Narragansett's gas system that will be fully transferred to PPL as part of the proposed transaction; and

b. The data sets, or portions thereof, presently used for forecasting gas supply requirements for Narragansett's gas system that will not be fully transferred to PPL as part of the proposed transaction

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-21.

Division 7-22

Request:

Please update Exhibit 12 of National Grid's June 30, 2020 Gas Long-Range Resource and Requirements Plan in Docket No. 5043.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-22.

Division 7-23

Request:

Please provide a diagram comparable to that provided in Exhibit 12 of National Grid's June 30, 2020 Gas Long-Range Resource and Requirements Plan in Docket No. 5043 for the LG&E gas system operated by PPL.

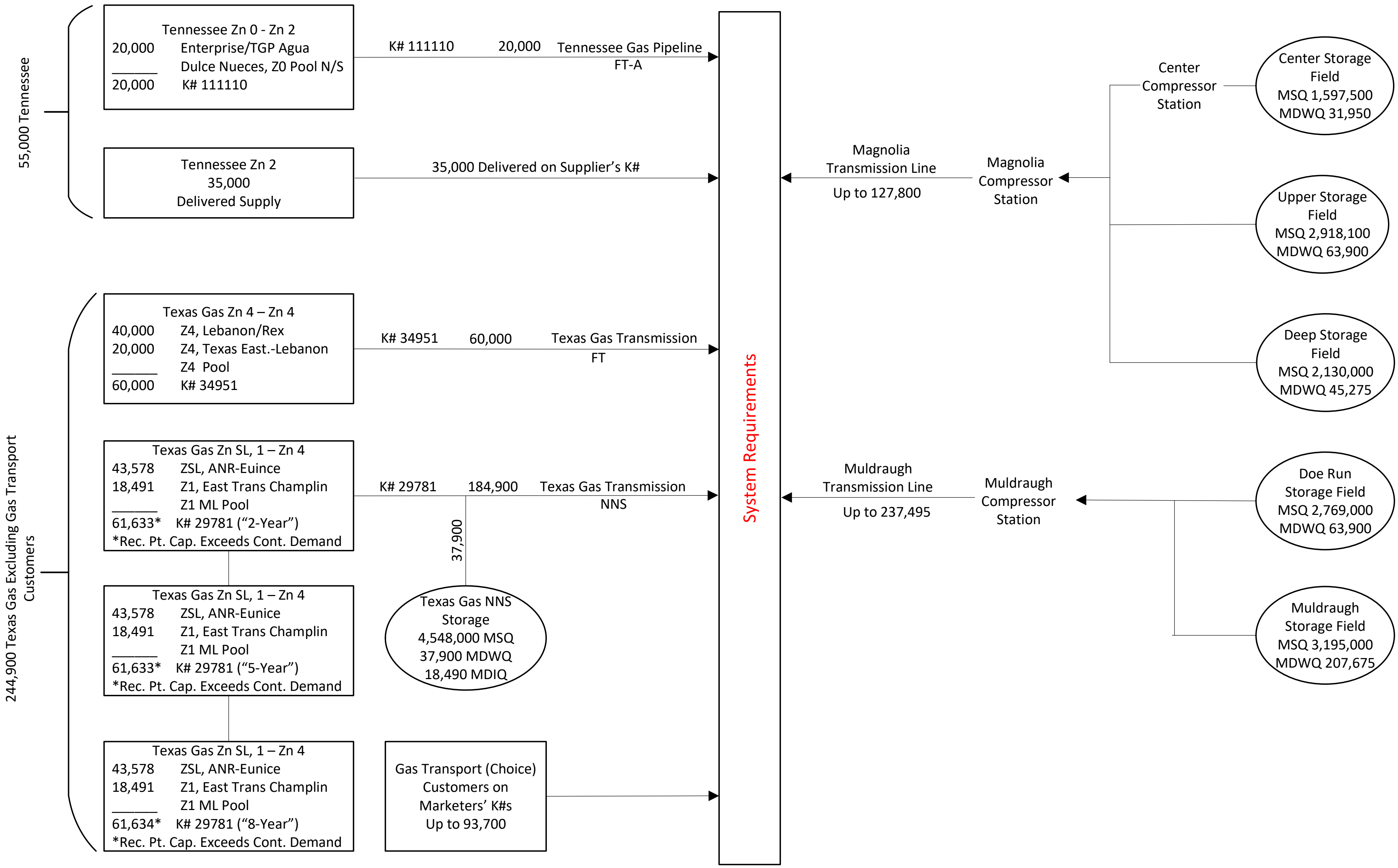
Response:

Please see Attachment PPL-DIV 7-23-1 Louisville Gas and Electric Company – Portfolio Schematic.

Prepared by or under the supervision of: Lonnie E. Bellar

Louisville Gas and Electric Company – Portfolio Schematic

Peak Season Volumes (MMBtu) as of November 1, 2021



Division 7-24

Request:

Exhibit 13 of National Grid's June 30, 2020 Gas Long-Range Resource and Requirements Plan in Docket No. 5043 lists a number of Transportation Contracts that expired, are scheduled to expire before the proposed transfer of ownership, or will expire within three years of the proposed transfer of ownership. For each such contract, please provide:

a. The manner in which National Grid has replaced or plans to replace the expiring contract.

b. The impact of the contract's expiration/replacement on:

   i. City Gate MDQ; and

   ii. Annual Quantity

c. The contract expiration date for the new or replacement contract; and

d. The impact of the contract's renewal or replacement on Narragansett's annual gas supply costs.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-24.

Division 7-25

Request:

PPL makes representations regarding how its costs of gas compare with costs of gas for other Kentucky utilities. Please provide all available comparisons of Narragansett's costs of gas for Rhode Island with those for other gas utilities in New England.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-25.

Division 7-26

Request:

Please provide all available customer satisfaction survey results for Narragansett's gas system in Rhode Island that have been compiled within the last three years.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-26.

Division 7-27

Request:

Provide a detailed list of each service provided by the Service Company across the National Grid operating companies.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-27.

Division 7-28

Request:

Provide a list of the Service Company anticipated staff reductions and how many of these employees are expected to be offered positions with PPL Rhode Island.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-28.

Division 7-29

Request:

National Grid indicates it has approximately 5,100 Service Company employees. Provide a list of each employee position which will be required in order for all the Service Company services to be continued for Narragansett after acquisition by PPL.

Response:

PPL and PPL Rhode Island's current understanding is that not all 5,100 National Grid USA Service Company, Inc. ("National Grid Service Company") employees provide services to Narragansett. PPL, PPL Rhode Island, and National Grid are in the process of identifying National Grid Service Company roles and individuals that will transfer to PPL Rhode Island upon close of the Transaction. It is anticipated that PPL Rhode Island will offer positions to as many as 350-400 National Grid Service Company employees. PPL and PPL Rhode Island also refer to and incorporate by reference their response to Division 7-55. The majority of National Grid Service Company employees who transfer to PPL Rhode Island will be in the Electric Operation, Gas Operations, Operations Support, Regulatory Support, and Legal functions.

Just as Narragansett currently receives support from National Grid Service Company, PPL Rhode Island will receive support from existing PPL organizations for functions such as Human Resources, Finance & Accounting, Information Technology, Legal, and Supply Chain. The process of identifying additional support for PPL Rhode Island from existing PPL organizations is ongoing.

Prepared by or under the supervision of: David J. Bonenberger

Division 7-30

Request:

How many years does National Grid anticipate it will provide Service Company services to PPL?

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-30.

Division 7-31

Request:

Provide the basis for PPL's position that the loss of Service Company expertise, including decades of institutional knowledge, will not result in a diminution in the quality of the services to be furnished to customers following approval of the acquisition.

Response:

As set forth in the testimony of Mr. Gregory N. Dudkin at page 5, PPL, like National Grid USA, is an experienced utility operator with an outstanding track record of achieving high levels of service, reliability and customer satisfaction. As further set forth in the testimony of Mr. Dudkin, PPL intends to continue to utilize best practices already established by National Grid USA.

Many of the current of National Grid employees (both directly employed by Narragansett and indirectly employed by National Grid USA Service Company, Inc. ("Service Company"), who currently deliver a high level of electric and gas distribution services in Rhode Island and have significant institutional knowledge of Rhode Island gas and electric operations, will continue to serve Narragansett's Rhode Island customers as employees under PPL RI ownership on Day 1. These employees currently perform the work for the Rhode Island service area and have detailed knowledge of the systems and processes in the functional areas that will be transferred on Day 1.

To the extent that any Service Company functions will not be performed by former employees of Narragansett or the Service Company on Day 1, such areas that are not transferred will gradually transition to PPL through the Transition Services Agreement ("TSA"). National Grid USA and PPL are jointly developing Knowledge Transfer agreements that will be built into the TSA schedules to help enable PPL to continue to access National Grid's subject matter experts after Day 1 to continue the ongoing knowledge transfer for the duration of the transition period. During the transition period the Service Company also will transfer historical data to PPL to ensure operational continuity for Narragansett. Please see National Grid USA and Narragansett's responses to data requests Division 7-35 and Division 7-36 for additional information regarding institutional knowledge transfer and training that National Grid USA anticipates providing to PPL during the transition period.

These measures will ensure that Narragansett customers continue to receive the same high-level quality of service previously employed by National Grid even after the conclusion of the TSA period, and will provide PPL with a smooth transition into operating a utility in the New England and Rhode Island area. As a result of PPL's extensive and successful experience as a utility operator with an outstanding track record of achieving high levels of service, reliability and customer satisfaction, plus the measures being taken above to transfer existing knowledge of Narragansett's electric and gas operations, PPL maintains that its acquisition of Narragansett from National Grid USA will not diminish the quality of electric and gas distribution services customers expect in Rhode Island.

Prepared by or under the supervision of: David J. Bonenberger

---

Division 7-32

Request:

On page 12 of Mr. Sobolewski's testimony, he states National Grid is confident that the Transaction will not diminish the high level of electric and gas distribution services customers expect in Rhode Island. Please explain in detail the basis for this statement, including how PPL intends to address its lack of experience with respect to utility matters in either New England or Rhode Island.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-32.

Division 7-33

Request:

Provide the service Company's schedule outlining the full duration of the transition, including all significant milestone dates.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-33.

Division 7-34

Request:

Provide a detailed list of each support function to be provided by the Service Company including the names, title and position of each Service Company employee who will be completely or partially assigned to support PPL during the transition.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-34.

Division 7-35

Request:

Provide a detailed explanation of what level of institutional knowledge will be transferred to PPL during the transition and detail the processes through which that institutional knowledge can and will be transferred.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-35.

Division 7-36

Request:

On page 14 of Mr. Sobolewski's testimony, he indicates National Grid will work very closely with PPL in the short and long-term to transition support. What is the anticipated duration for the short-term support and the duration for the long-term support? Provide a detailed list of each support function which will be provided during the short-term and each support function provided during the long-term.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-36.

Division 7-37

Request:

On page 14 and 15 of Mr. Sobolewski's testimony, he states National Grid will help PPL continue to advance uninterrupted ongoing initiatives, projects, and dockets in Rhode Island that are underway as of the closing of the Transaction. Provide a detailed list of each of these contemplated initiatives, projects and dockets. Provide a detailed explanation of how National Grid will assure these initiatives will be advanced uninterrupted and each provide National Grid employee and their title that will be assigned to assure these initiatives continue moving forward.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-37.

Division 7-38

Request:

On page 15 of Mr. Sobolewski's testimony, he states National Grid and PPL are taking a deliberate and programmatic approach to transitioning the various functional areas of the Narragansett business. Identify each functional area being transitioned, and describe in detail the programmatic approach.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-38.

Division 7-39

Request:

Provide a detailed list of the information and documentation being exchanged between National Grid and PPL as discussed on Page 15 of Mr. Sobolewski's testimony.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-39.

Division 7-40

Request:

Provide a detailed list of functional areas that can safely and efficiently be transferred to PPL on Day 1 as discussed on Page 15 of Mr. Sobolewski's testimony.

Response:

PPL is in the process of finalizing Day 1 organizational design and talent selection. The outcome of this process, and the ability to place required individuals into Day 1 roles will have a direct impact on which functions will be completely transferred to PPL on Day 1, and which functions will require full or partial Transition Service support from National Grid. As of August 16, 2021, the following functions are expected to transition safely and efficiently to PPL on Day 1, or shortly there-after (e.g. certain TSAs will be in place to manage large, inflight projects (such as capital construction projects) until they are completed or can be fully transitioned to PPL post Day 1).

Electric Operations:
Field Engineering
Protection, Control, Telecom, Meter Engineering & Operations
Distribution Design
Asset Management
Distribution Control Center
Regional Field Operations
Customer Meter Services
Project & Construction Management
Work & Resource Planning

Gas Operations:
Customer Meter Services
Meter Shop
Field Operations
Leak Survey & Damage Prevention
Construction & Inspection
Project & Construction Management
Work & Resource Planning
Engineering & Asset Management
LNG Operations
Instrumentation & Regulation
Pipeline Safety & Compliance

Prepared by or under the supervision of: Michael Caverly

Customer Service / Customer Operations:
Customer Connections
Customer Programs (Energy Efficiency, Low Income, Customer Assistance)
Marketing & Growth

Operations Support:
Fleet
Safety
Environmental

Reg. & Government Affairs:
Regulatory Affairs
Regulatory Strategy
Regulatory filling accountability

HR:
Recruitment
Talent management
Labor relations
Performance mgmt.

Legal & Compliance:
All activities transitioning to PPL

Finance & Accounting:
Overall financial planning including debt, cash management, tax filings, enterprise risk management, insurance, audit and internal controls

IT:
Required PPL IT equipment, systems access, and support

It should be noted that many of these functions will still be supported by underlying National Grid technology platforms until full migration to PPL technology and processes is complete. Employees taking roles in the PPL Rhode Island organization will maintain full access to National Grid technology and infrastructure required to perform their functions, and National Grid will maintain full support and maintenance of the required technology under the TSA.

Prepared by or under the supervision of: Michael Caverly

Division 7-41

Request:

Provide a copy of the PPL operating model discussed on page 17 of Mr. Sobolewski's testimony.

Response:

See Attachment PPL-DIV 7-41-1 for a chart depicting the current version of PPL's target Rhode Island operating model structure. Additionally, PPL has described its operating model in its response to data request Division 2-1, and described its operating philosophy in its response to data request Division 6-1.c.

Target State RI Operating Model

Preliminary - Subject to Revisions

Physical Location Key
Rhode Island | Penn. | Kentucky

President, Rhode Island
David Bonenberger

Corporate Services
Finance & Accounting (1)
Security (2)
Remittance Processing
Legal

Customer
Kristin DeSousa, Senior Director
- Contact Center Operations
- Operations Support
- Business Services
- Programs (including energy efficiency)
- Cust Experience Strategy
- Meter Data Services

Gas Ops
Michele Leone, Vice President
- Gas Operations
- Engineering & Design
- Gas Control, I&R, Planning
- Scheduling, Dispatch, WOM
- Compliance & Pipeline Safety
- Capital Projects & Construction
- Gas Procurement, & Retail Choice
- Gas Forecasting

Electric Ops
Alan LaBarre, Senior Director
- Field Operations
- Planning & Engineering
- Distribution Operations
- Project & Const. Mgmt
- Meter Reading / AMI
- Centralized Electric Support (PA)

Regulatory & Gov't Affairs
Brian Schuster, Director
- State Regulatory Affairs
- External / Internal Communications
- RI State Gov't Relations
- RI Community & ED
- Regulatory Strategy

Business Services Lead
TBD
- Supply Chain (Local logistics)
- Fleet (Local management)
- HSE (health, safety, training)
- Emergency Preparedness
- Facilities / Real Estate

Finance
Kate Hearns, Director
- Bus. Planning/ KPI's
- Property Accounting

HR
Kathy Moar, Manager
- HR Specialist

(1) Includes Tax, Treasury, Gas Hedging; Risk

(2) Most RI Security Operations performed from PA, including giving directions to RI FTEs

Legal / Corp. Compliance
(Local regulatory & legal support)

Security

Direct Corporate staff embedded within Rhode Island

IT
(Direct PPL EU staff with minor presence in RI)

Regulatory Accounting & Reporting

Direct Rhode Island staff w/ support from PPL centrally managed functions

Electric Support
- Transmission Operations
- Electric Market Operations
- Advanced Grid Strategy
- Transmission Planning & Regulat.
- Compliance Training
- Standards: T&D + Substation
- Complex Engineering

Business Services
- Supply Chain
- Comms.
- HSE
- Emerg. Prep.
- HR
- Facilities
- Fleet

Division 7-42

Request:

Provide all documents that compare in detail PPL's proposed electric utility operational model in Rhode Island with National Grid's current operational model. Please include all documents that delineate functions and/or infrastructure that are the same as National Grid, that are in addition to National Grid, or that will be less than National Grid currently provides.

Response:

PPL's proposed electric utility operational model was designed leveraging current state information provided by National Grid, input from PPL's electric utility leadership, and input from the incoming PPL Rhode Island Electric Senior Director, who will be joining the Rhode Island leadership team from National Grid. There is currently no documentation that directly compares in detail the two organizations.

PPL reviewed and considered National Grid's current state electric operational model when designing the new PPL Rhode Island organization. The current National Grid operating model is broken down as follows:

- Electric Asset Management & Engineering
- Workplan Development & Resource Management
- Project Management & Construction
- Operations, Maintenance & Construction
- T&D Control
- Emergency Planning & Response

The proposed PPL Rhode Island electric utility operational model does not contemplate any significant changes to the types of functions already provided directly within Narragansett, or by National Grid USA Service Company, Inc. (the "Service Company"). The major differences in the Rhode Island operational model are where the functions will be based, and if the functions will be dedicated fully to Rhode Island, or support both Pennsylvania and Rhode Island.

In most cases, the PPL operational model has designed dedicated Rhode Island functions and organizations that currently support multiple jurisdictions at National Grid. These include the following, which will be based out of Rhode Island:

- Distribution Control
- Work & Resource Management

- Distribution Engineering & Asset Management
- Project Management & Construction

PPL plans to support certain functions out of PPL's existing Pennsylvania organizations for both Pennsylvania and Rhode Island operations and would operate similar to how National Grid provides those functions today from the Service Company. These include the following and would be based out of Pennsylvania:

- Transmission & Substation planning, engineering, and asset management
- Transmission Control

The following graphic depicts the high level functional operating model for Rhode Island electric operations.

Rhode Island Located & Managed

Division 7-43

Request:

Referencing the response to DIV 1-54 (c), PPL states that "[c]ertain functions that are currently provided by National Grid that are planned to be created in Rhode Island are Customer Contact and back office functions, Electric dispatch and control room operations, gas control and dispatch functions, gas and electric training operations and miscellaneous service company functions." PPL further states in DIV 1-54(d) that "[i]f the Transaction is approved, PPL expect to submit plans for approval that increases the amount of infrastructure investments in Rhode Island, which will have a direct impact on the Rhode Island economy through direct and indirect purchases, use of contractors and service providers. In addition, PPL plans to create certain functions in Rhode Island that will require investments in facilities, construction, professional services and purchases (see item c. above)."

a. Please provide details on the proposed infrastructure and cost, correlating the planned investment to the follow-up response to DIV 1-54(c). How will PPL fund the proposed infrastructure? Does PPL intend to recover the cost of the infrastructure in Rhode Island rates? If PPL has not identified the proposed infrastructure or cost, and cannot quantify the economic benefits that PPL asserts will occur in Rhode Island, how can PPL guarantee that Rhode Island ratepayers will not incur incremental costs for infrastructure without receiving commensurate benefits?

b. Regarding Customer Contact and back office functions, electric dispatch and control room operations, gas control and dispatch functions, gas and electric training operations and service company functions, please:

    i. Explain what functions are currently located in Rhode Island under National Grid's ownership;

    ii. State whether any function located in Rhode Island is designed to serve the full needs of all Rhode Island customers; and

    iii. State whether PPL has plans to create or expand any of the functions in Rhode Island in order to serve Rhode Island customers exclusively. If the answer is yes, please provide details on the plans including timing and proposed cost.

Response:

a. PPL is still in the process of determining proposed infrastructure investments to enhance the reliability and resiliency of the electric grid, as well as to enhance the grid's ability to integrate distributed energy resources ("DER"). As part of that process, PPL is reviewing, among other things, the Grid Modernization Plan (Docket 5114) (the "GMP") and Advanced Metering Functionality ("AMF") Plan (Docket 5113) filed by Narragansett with the Rhode Island Public Utilities Commission (the "PUC"). PPL has not yet identified any specific proposed infrastructure investments or quantified the costs associated with any such investments, nor has it quantified the benefits that these investments will provide to Narragansett customers.

   Notwithstanding the foregoing, PPL can be sure that Narragansett customers will not incur incremental costs for infrastructure improvements without receiving commensurate benefits because: (1) any infrastructure investments PPL makes while operating under the current approved base rates would not result in incremental costs because rates are already set and in effect; and (2) any infrastructure investments PPL proposed through other mechanisms, such as the Infrastructure, Safety, and Reliability Plan or in a future general rate case in Rhode Island will be subject to review and approval by the PUC.

b. PPL and PPL RI refer to National Grid USA and Narragansett's responses to subparts (b)(i) and (b)(ii) of this request.

   In response to subpart (b)(iii) of this request, PPL and PPL RI refer to their response to data request Division 7-42, their response to data request Division 7-41, and Attachment PPL DIV 7-41-1 for information regarding functions that PPL and PPL RI plan to create or expand to serve Rhode Island customers exclusively.

Prepared by or under the supervision of: David J. Bonenberger and Stephen K. Breininger

---

Division 7-44

Request:

Regarding the separation and reintegration of electric distribution facilities that serve customers across National Grid's Rhode Island and Massachusetts jurisdictions, National Grid states that "[i]t is expected that these facilities will remain the same immediately following completion of the transaction." Please explain in detail how National Grid currently operates and allocates costs regarding distribution facilities located in Rhode Island that serve Massachusetts Electric Company customers in Massachusetts, and distribution facilities located in Massachusetts that serve the Narragansett Electric Company customers in Rhode Island. The response should detail items including (but not limited to) wholesale power supply, customer billing, operations, maintenance, and storm restoration costs. Describe how each function will be managed on Day 1 if the facilities remain the same but are under PPL ownership.

Response:

See National Grid USA's ("National Grid") response to data request Division 7-44. PPL Corporation ("PPL") is purchasing 100 percent of the common stock of Narragansett, and Narragansett's existing borderline service arrangement with Massachusetts Electric Company ("Massachusetts Electric"), including, but not limited to, contracts and regulatory approvals, will not be substantially affected by the Transaction. PPL and PPL Rhode Island Holdings, LLC anticipate that they will maintain a borderline service arrangement with Massachusetts Electric in a substantially similar manner as has been described by National Grid in its response to Division 7-44, and, as of Day 1, PPL's management of the wholesale power supply, customer billing, operations, maintenance, and storm restoration functions will be the same as had been the case under National Grid ownership.

Prepared by or under the supervision of: David J. Bonenberger

---

Division 7-45

Request:

Referencing PPL's responses to DIV 2-8 and 2-47, please provide copies of grid modernization plans developed by PPL that demonstrate PPL's overall strategic investments and roadmap. Identify:

a. which portions of those plans have been implemented and provide the associated cost; and

b. which portions of those plans are anticipated to be implemented in the future and provide the anticipated cost and the recovery mechanism.

Response:

Pennsylvania

PPL and PPL RI refer to PPL Electric Utilities Corporation's ("PPL Electric") Long Term Infrastructure Improvement Plan ("LTIIP"), provided as Attachment PPL-DIV 2-14-1; PPL Electric's Biennial Inspection, Maintenance, Repair and Replacement Plan, provided as Attachment PPL-DIV 2-14-2; PPL Electric's Smart Meter Technology Procurement and Installation Plan, referenced in the response to data request Division 7-49, which can be found at https://www.puc.pa.gov/pcdocs/1296056.pdf; and PPL Electric's 2020 Annual Smart Meter Progress Report, provided as Attachment PPL_DIV 7-45-1. PPL Electric makes smart grid investments in the normal course of business and does not have grid modernization or equivalent plans for several of the initiatives referenced in PPL-DIV 2-8 and 2-47.

PPL's prior responses at Division 2-8 and 2-47 along with the attached and referenced plans and documents provide the costs and status of the implementation of the various initiatives referenced in the responses to Division 2-8 and 2-47.

PPL Electric anticipates recovering these costs, with the exception of AMI costs, through its Pennsylvania PUC approved base distribution rates, FERC approved transmission formula rate, or under Pennsylvania Act 11 Distribution System Improvement Charge. PPL Electric recovers the costs of the deployment of AMI meters through a Pennsylvania PUC approved Advanced Metering Rider recovery mechanism.

Kentucky

PPL and PPL RI refer to Louisville Gas & Electric Corporation ("LG&E") and Kentucky Utilities' ("KU") 2021-2025 Distribution Reliability Resiliency Plan, provided as PPL-DIV 2-14, which describes the specific strategic investments related to grid modernization.

PPL and PPL RI also refer to Attachment PPL-DIV 7-45-2, which is LG&E and KU's Distribution Automation ("DA") program included in the Certificate of Public Convenience and Necessity filing to the Kentucky Public Service Commission in 2016. This program started in 2017 and will complete by 12/31/2021. Anticipated capital expenditures for the full program are estimated to be approximately $105 million.

PPL and PPL RI also refer to LG&E and KU's KU SCADA Expansion investment proposal, provided as Attachment PPL-DIV 7-45-3. This program started in 2018 and to date (through August 2021) approximately $16 million has been spent with another $5 million planned over the next five-year business plan.

PPL and PPL RI also refer to LG&E and KU's Electro-Mechanical Relay Replacement investment proposal, provided as Attachment PPL-DIV 7-45-4. This program started in 2019 and to date (through August 2021) approximately $15.9 million has been spent with another $10 million planned over the next five-year business plan.

PPL and PPL RI also refer to LG&E and KU's current development of their forthcoming SCADA Voltage Controller Upgrades investment proposal, which they estimate will be completed by the end of 2021.

LG&E and KU anticipate recovering the costs for these programs through retail rates approved by the Kentucky Public Service Commission.

Division 7-46

Request:

Referencing PPL's response to DIV 2-38, please provide a detailed cost estimate for all transaction and transition costs that will be part of PPL revenue requirement and incorporated into the retail rates.

Response:

PPL has not yet developed an estimate for a revenue requirement to be incorporated in the retail rates of Narragansett. PPL will evaluate on a case-by-case basis what transition costs will be included in the revenue requirement of a future rate case. PPL, however, will not seek costs related to the Transaction for negotiating the Share Purchase Agreement with National Grid USA and obtaining the necessary approvals, including the costs associated with this proceeding.

Prepared by or under the supervision of: David J. Bonenberger and Stephen K. Breininger

---

Division 7-47

Request:

Referencing PPL's response to DIV 2-43, provide all documents that demonstrate PPL can produce a Long Range Plan and short term studies like the National Grid ISR Plan.

Response:

PPL has experience and expertise in preparing long and short term plans and studies similar to the National Grid ISR Plan. PPL has provided explanations and examples of these plans and studies in its response to Division 2-14 and 2-43. In addition, experienced National Grid system planners and engineering leadership will be joining PPL staff and will work in Rhode Island post-Transaction close. As such, distribution system planning work product will continue to be delivered in a manner that supports the ISR Plan and meets the Rhode Island Division of Public Utilities and Carriers and Rhode Island Public Utilities Commission's expectations.

Prepared by or under the supervision of: David J. Bonenberger

Division 7-48

Request:

Please provide any studies which PPL completed to support the programs listed in response to DIV 2-8 and any cost benefit analyses performed.

Response:

PPL and PPL RI refer to their response to data requests Division 7-45 and Division 2-47. The response to data request Division 2-8 discusses the benefits of the programs listed in the response to data request Division 2-47. Additionally, the response to data request Division 7-45 provides and references studies responsive to this request. Some of the programs implemented in Pennsylvania by PPL Electric Utilities Corporation were performed in the normal course of business, and, therefore, PPL Electric Utilities Corporation did not develop studies or perform cost benefit analyses specific to those programs.

Division 7-49

Request:

Provide the study (or studies) that supported the AMI deployment as it exists today on the PPL system. State whether AMI is fully deployed on all PPL systems.

Response:

Please see Attachment PPL-DIV 7-49-1 Analysis of Metering Alternatives.

PPL Electric Utilities Corporation's ("PPL Electric") Smart Meter Technology Procurement and Installation Plan can be found at the following link:

https://www.puc.pa.gov/pcdocs/1296056.pdf

PPL Electric has effectively fully deployed AMI meters to its entire system. There remain approximately 20 meters that need to be exchanged but which are the subject of pending PUC formal complaints preventing the exchange of those meters.

LGE KU has effectively deployed about 27,000 AMI meters primarily to opt-in program participants. There remain approximately 1.3 million meters and gas indices which the exchanges are planned to commence mid 2022 and continue until 2026.

Prepared by or under the supervision of: David J. Bonenberger and Lonnie E. Bellar

Analysis of Metering Alternatives

LG&E KU
PPL companies

October 2020

Contents

1. Executive Summary

The Companies' meter assets include approximately 1 million electric meters and 340,000 gas meters. Approximately 75% of electric meters are electromechanical meters and have an average age of 32 years. Electromechanical meters are no longer manufactured and annual meter replacements are forecasted to increase over time as longer-lived meters are replaced as they fail with shorter-lived non-communicating electronic meters. Each month, the Companies manually read most meters and manually provide meter-related services ("field services") such as connecting and disconnecting meters for service. Effective 2019, total annual contract costs for meter reading and field services increased by $5.8 million (45%). Prior contracts executed in 2014 did not allow for annual increases, so spending on these services was well under market at the end of the contract terms.

Given this increase and the forecasted increase in the number of annual meter replacements, the Companies completed an analysis of metering alternatives to determine the best alternative for reliably serving customers at the lowest reasonable cost. The analysis considered alternatives with Advanced Metering Infrastructure ("AMI") and Automatic Meter Reading ("AMR") metering technologies in addition to a "Status Quo" alternative where the Companies continue to replace existing meters as they fail with non-communicating electronic meters.

The long-term viability of AMR is a key uncertainty in this analysis. The Companies issued a request for information ("RFI") in March 2020 to gather information from meter vendors regarding the future availability and pricing for various meter types. The responses, which are summarized in Appendix B – Metering RFI Summary, indicate that only one vendor is committing to future AMR research and investment. Moving forward, AMR metering costs are more likely to escalate faster than other metering technologies, and the risk of obsolescence for AMR meters is high. For this reason, the Companies evaluated the metering alternatives under two AMR obsolescence scenarios: one where AMR becomes obsolete midway through the analysis period and one where AMR remains viable for the full 30-year analysis period.

The financial analysis is focused entirely on revenue requirements and sets aside difficult-to-quantify benefits for the AMI alternatives like improved customer experience, the reduction of non-technical losses, and the ability to offer programs like prepay that depend on AMI. In both AMR obsolescence scenarios, AMI is the least-cost metering technology for electric customers and most gas customers, and AMR is least-cost in portions of the LG&E gas service territory where neither LG&E nor KU provides electric service ("gas-only" service territory). As seen in Table 1, the present value of revenue requirements ("PVRR") for this metering alternative ("AMI + AMR in the Gas-Only Territory" or "AMI+AMR_GO") is $53.3 million favorable to the Status Quo when AMR is assumed to become obsolete and $50.4 favorable when AMR is assumed to remain viable. The major drivers of PVRR differences in this analysis are meter reading and field services costs, new meter costs, and two forms of fuel savings: (1) those resulting from the ability with AMI to reduce customers' energy requirements by incrementally lowering distribution voltages through Conservation Voltage Reduction ("CVR"); and (2) those resulting from customers choosing to reduce their energy usage due to access to enhanced usage data made available by AMI through the Companies' online ePortal system. The AMI+AMR_GO alternative has higher new meter costs than the Status Quo alternative but significantly lower meter reading and field services costs as well as fuel savings.

Table 1: PVRR Summary ($M, 2020 Dollars, 2021-2050)

	AMR Becomes Obsolete		AMR Remains Viable		
Alternative	**PVRR (A)**	**PVRR Delta to Status Quo**	**PVRR (B)**	**PVRR Delta to Status Quo**	**AMR Obsolescence Risk (A less B)**
Status Quo	734.2	0.0	729.9	0.0	4.3
Full AMI	683.0	-51.3	683.0	-47.0	0.0
AMI + AMR in Gas-Only Territory	680.9	-53.3	679.6	-50.4	1.3
Full AMR	749.3	15.0	687.8	-42.1	61.4

Unsurprisingly, the unfavorable impact of AMR obsolescence is greatest for the Full AMR alternative. The Companies currently read approximately 105,000 electric and gas meters by vehicle using AMR metering technology. This number is reduced to 19,000 in the AMI+AMR_GO alternative and zero in the Full AMI alternative. Based on this analysis and the forecasted increases in meter reading and field services costs, if the Companies installed AMR throughout the LG&E and KU service territories and then AMR became obsolete, the most economical solution would be to replace the AMR meters with AMI. While customers would ultimately see the cost savings and other benefits associated with AMI, the early replacement of AMR meters makes this scenario very costly. AMR obsolescence increases the PVRR of the Full AMR alternative by $61.4 million and the PVRR of the AMI+AMR_GO alternative by only $1.3 million. Based on the risk of obsolescence, deploying AMR throughout the Companies' service territories is not a prudent investment for customers.

The AMI+AMR_GO alternative reduces the Companies' exposure to AMR obsolescence risk compared to the Status Quo by reducing the total number of meters read by AMR. In addition, unlike the Full AMI alternative, the AMI+AMR_GO alternative enables the Companies to utilize existing gas meter assets in the gas-only service territory. Compared to the Full AMI alternative, the favorability of the AMI+AMR_GO alternative is relatively small but it is clearly the preferred alternative for these reasons.

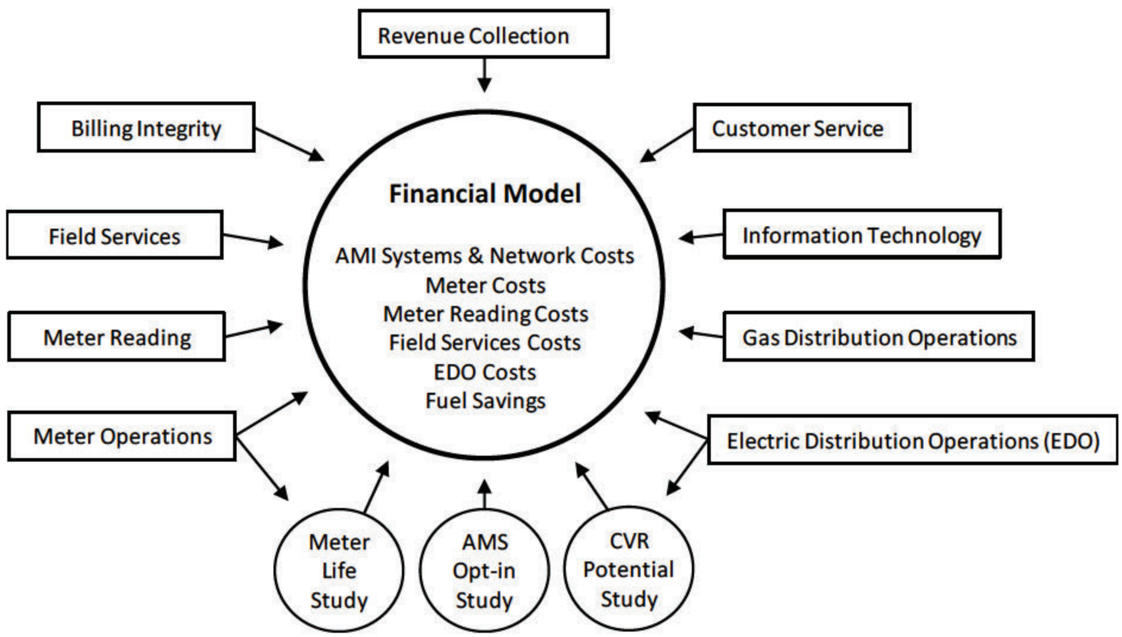
The Companies evaluated the PVRR difference between the AMI+AMR_GO and Status Quo alternatives over 243 cases created by varying input assumptions to which the analysis is most sensitive. The PVRR of the AMI+AMR_GO alternative is favorable to the Status Quo in 99.6% of the cases evaluated and ranges from only $4.2 million unfavorable to $115.4 million favorable. In addition, the favorability of the AMI+AMR_GO alternative does not depend on any single input assumption. These results demonstrate that the AMI+AMR_GO alternative has virtually no downside risk.

Finally, the timeline for implementing the AMI+AMR_GO alternative is 5 years and was developed to deliver savings as soon as possible and provide a good customer experience. In the final phase of the analysis, the Companies evaluated the AMI+AMR_GO alternative over different implementation timelines. Delaying the beginning of the 5-year implementation project or deferring AMI systems implementation so that more in-scope meters can be replaced as they fail increases the PVRR by postponing the project's benefits. This analysis shows that the AMI+AMR_GO alternative is least-cost and that the proposed 5-year implementation timeline beginning in October 2021 is optimal.

2. Analytical Framework

The Companies developed a collaborative process and analytical framework for evaluating all reasonable metering alternatives with input from all business areas impacted by the decision. This framework is illustrated in Figure 1. Annual capital and operating costs for each alternative are modeled in a financial analysis tool developed in Microsoft Excel ("Financial Model"). Section 3 contains an overview of the Status Quo alternative. Section 4 contains an overview of the other metering alternatives. The Financial Model computes annual revenue requirements and the PVRR for each alternative over a 30-year analysis period. Because electronic, AMI, and AMR meters have an average operating life of at least 15 years, the analysis period includes more than one meter replacement cycle.

Figure 1: Analytical Framework



The financial analysis is focused entirely on revenue requirements and sets aside benefits for the AMI alternatives that either have no impact on revenue requirements or are hard to quantify ("non-quantified benefits"). Non-quantified benefits include improved safety, improved reliability, improved customer experience, reduced non-technical losses, and the ability to offer additional customer programs or services like prepay. The Financial Model includes all revenue requirements for AMI systems and network, meters, meter reading, and field services costs.[1] Electric Distribution Operations ("EDO") savings and fuel

[1] Revenue requirements associated with the Companies' capital investments in existing meter assets are included in the Financial Model. The PVRR associated with this investment is assumed to be the same in all alternatives because the Companies assume in all scenarios they will recover the cost of their prudent investments, including their existing meter assets.

savings are modeled for the two AMI alternatives as differences from the Status Quo. A detailed discussion of model inputs is included in Appendix A – Model Inputs.

Three studies were completed to support key input assumptions to the financial analysis. The results of the Companies' Meter Life Study were used to forecast the need for new meters in each alternative. The results of the Companies' CVR Potential Study were used to compute the range of CVR-related fuel savings for the AMI alternatives. The results of Tetra Tech's AMS Opt-in Study were used to compute the range of fuel savings in the AMI alternatives associated with giving customers access to AMI interval data. Summaries of these studies are attached as appendices to this report. A complete summary of the financial analysis is provided in the following sections.

3. Status Quo Meter Operations

Table 2 provides a summary of the Companies' meter assets. In total, the Companies' meter assets include approximately 1 million electric meters and 340,000 gas meters. Electricity consumption for most customers with advanced meters is collected from AMI mesh meters using the RF mesh network developed for the AMS Opt-in program.[2] The Companies are not considering replacing these meters ("Existing AMI Mesh") or the roughly 2,000 specialized meters that measure consumption primarily for larger customers on time-of-day rates ("TOD Meters"). All other meters are labeled "in-scope" for the purpose of this analysis and are evaluated for replacement. In-scope meters include electromechanical and electronic meters that measure consumption for customers that are not on TOD rates as well as AMI cellular meters ("Existing AMI Cellular") for customers that require an AMI meter but are not on the RF mesh network.[3] About 98% of total electric meters are in scope, as are more than 99% of gas meters.

Table 2: Summary of Meter Assets[4]

	LG&E	KU	ODP	Total
Electric:				
TOD Meters	1,000	1,000	0	2,000
Existing AMI Mesh	11,000	8,000	0	19,000
Existing AMI Cellular*	1,000	2,000	0	3,000
Electronic Meters*	100,000	140,000	9,000	249,000
Electromechanical Meters*	318,000	395,000	21,000	734,000
Total Electric Meters	431,000	547,000	30,000	1,008,000
Total In-Scope Electric Meters*	419,000	538,000	30,000	987,000
Gas:				
Rotary Meters	2,000	0	0	2,000
Meters in Gas-Only Territory*	19,000	0	0	19,000
Other Gas Meters*	318,000	0	0	318,000
Total Gas Meters	339,000	0	0	339,000
Total In-Scope Gas Meters*	337,000	0	0	337,000
Total Meters	770,000	547,000	30,000	1,347,000
Total In-Scope Meters	756,000	538,000	30,000	1,324,000

*Denotes in-scope meters.

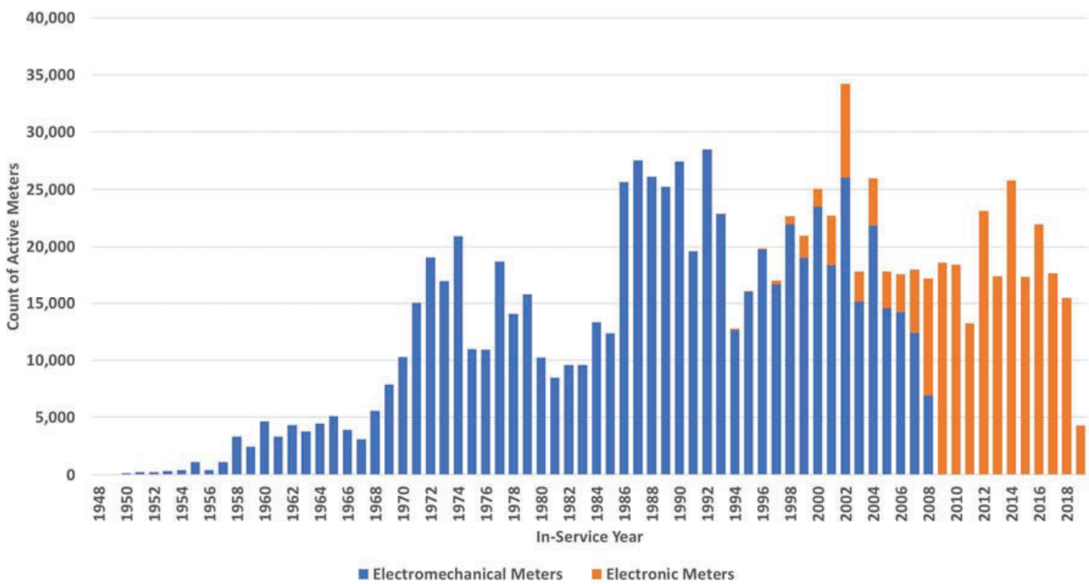
Approximately 2,000 gas meters are rotary meters that are used to measure gas consumption for large commercial and industrial customers ("Rotary Meters"). This analysis does not contemplate changes for these meters because these meters are not compatible with an AMI communications module and switching to AMI would require a full meter replacement with significant disruption to the customers'

[2] Information about the Companies' AMS Opt-In program can be found at https://lge-ku.com/advanced-meter.
[3] This analysis contemplates an expanded RF mesh network and AMI cellular meters would not be compatible with an expanded mesh network.
[4] Meter counts fluctuate over time based on customers being added or removed. This table shows approximate counts from the beginning of 2020 rounded to the nearest thousand.

operations. Of the remaining 337,000 gas meters that are in-scope, 19,000 meters are located in portions of the LG&E gas service territory where neither KU nor LG&E provides electric service ("gas-only service territory"). The analysis evaluates different metering alternatives for the gas-only service territory.

Figure 2 summarizes the age of the Companies' electromechanical and electronic meters. Approximately 75% of in-scope electric meters are electromechanical meters and have an average age of 32 years. Because electromechanical meters are no longer manufactured, they are replaced by non-communicating electronic meters ("electronic meters") when they fail.[5] The Companies' 249,000 electronic meters have an average age of 8 years.

Figure 2: Electric Meter Population by Type and In-Service Year



The Companies completed an analysis of meter failures over the past 10 years to develop failure curves for electromechanical and electronic meters ("2019 Meter Life Study").[6] Figure 3 and Figure 4 show the failure curves from this analysis. Unsurprisingly, the likelihood of failure increases with age for both meter types. Electronic meters have a shorter average operating life than electromechanical meters (20 years for electronic versus 46 years for electromechanical). A 20-year operating life for electronic meters is the same as the operating life for AMI meters according to two of the largest AMI meter manufacturers, [redacted].[7] Aside from the ability to communicate via the mesh network and remotely connect

[5] The Companies issued a request for information in March 2020 to gather information from meter vendors regarding the future availability and pricing for various meter types. All respondents stated that electromechanical meters are no longer manufactured (see Appendix B – Metering RFI Summary).
[6] This analysis is summarized in Appendix C – 2019 Meter Life Study.
[7] See Appendix B – Metering RFI Summary and Appendix F – [redacted] Meter Life Study.

and disconnect service, an AMI meter is no different than a non-communicating electronic meter; AMI and non-communicating electronic meters share the same meter platform.

Figure 3: Electromechanical Failure Rate by Age

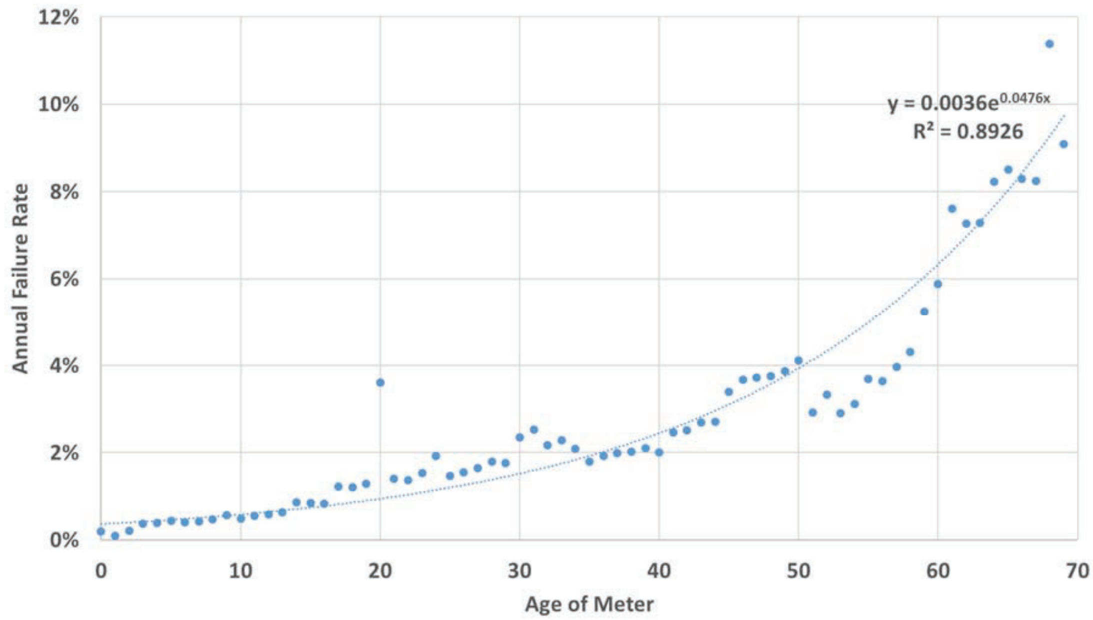


Figure 4: Electronic Failure Rate by Age

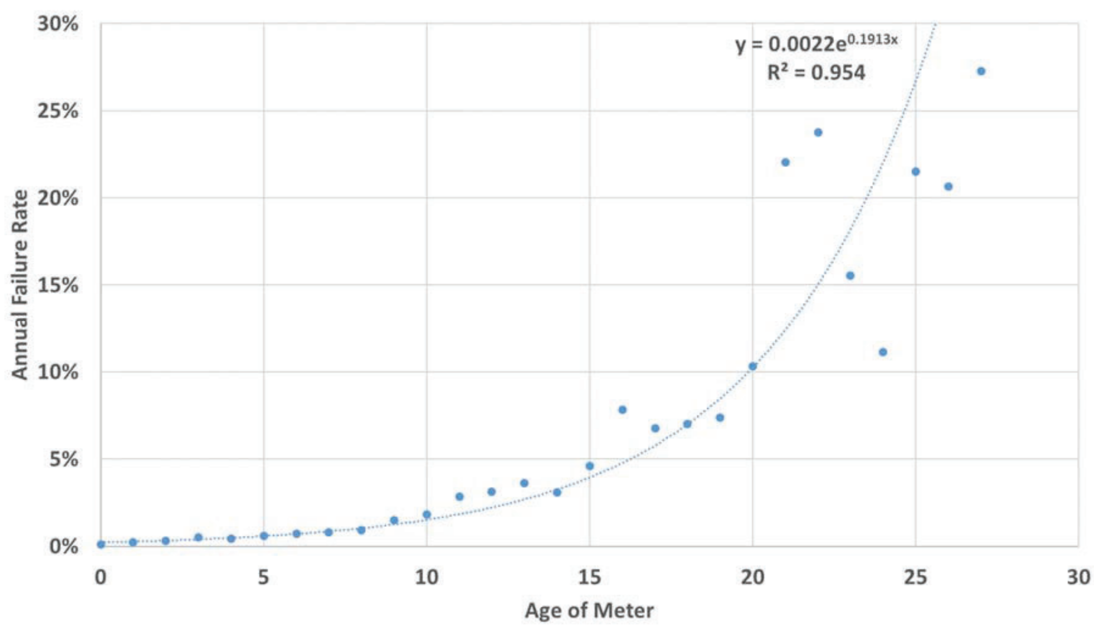
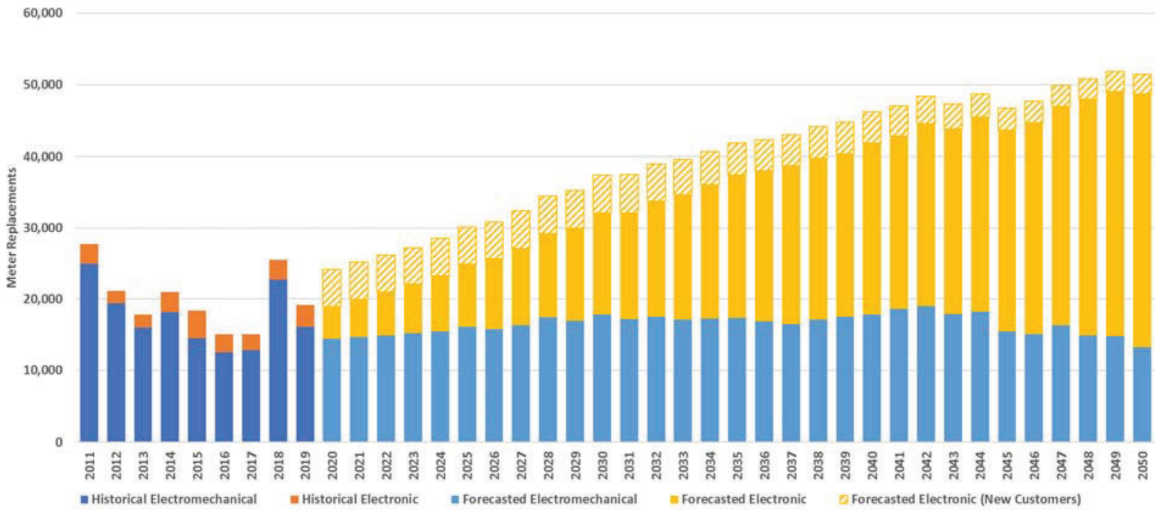


Figure 5 shows the forecasted need for new meters over the next 30 years. The forecasts of electromechanical and electronic meter replacements were developed by applying the meter failure curves from the 2019 Meter Life Study to the existing meter populations. The meter forecast for new customers is based on the Companies' customer forecasts. The total number of meters per year is expected to increase over time as longer-lived electromechanical meters are replaced with shorter-lived electronic meters.

Figure 5: Status Quo Meter Replacement Forecast (2019 Meter Life Study Failure Curves)



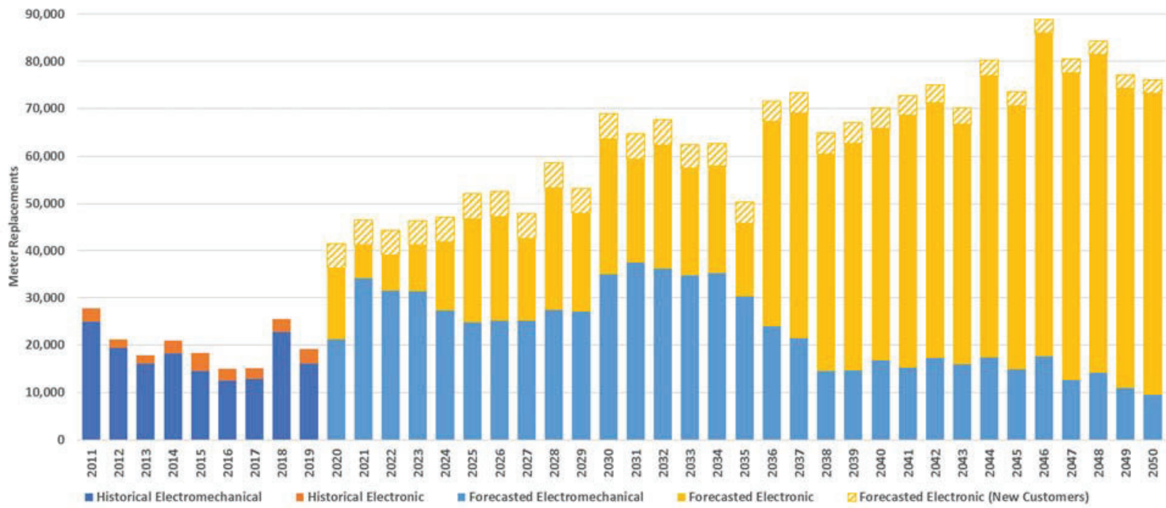
While the Companies' 2019 Meter Life Study and meter manufacturers support a 20-year operating life for electronic and AMI meters, the Companies' existing AMI meters have a 15-year depreciation life. At least in part, the shorter depreciation life reflects some likelihood that the meters will be proactively replaced before the end of their operating life. A similar assumption is made for the depreciation life of electromechanical and electronic meters, which are depreciated in one asset group. Based on the Companies' analysis, the weighted average operating life for these meters is 39.5 years but the depreciation life is 32 years on average.[8]

In addition to the operating life scenario based on failure curves from the 2019 Meter Life Study, the Companies modeled a shorter operating life scenario ("proactive replacement") where meters that haven't failed by a certain age are assumed to be replaced proactively (i.e., after 16 years for electronic meters and after 45 years for electromechanical meters). This assumption causes the average operating life to equal the depreciation life. The proactive replacement assumption causes total meter

[8] Approximately 75% and 25% of existing meters, respectively, are electromechanical and electronic meters. The weighted average operating life for all meters (39.5 years) = 75% * 46 years + 25% * 20 years. The average depreciation life for all meters (32 years) is the average of meter depreciation lives for KU (28 years) and LG&E (36 years).

replacements over the 30-year analysis period to be higher for all metering alternatives. Figure 6 shows the forecasted need for new meters in the Status Quo when meters are assumed to be replaced proactively. In the Status Quo, the impact of this assumption is greatest during the first 15 years of the analysis period as aging electromechanical meters are assumed to be replaced faster than they otherwise would be replaced.[9]

Figure 6: Status Quo Meter Replacement Forecast (Proactive Replacement Operating Life)

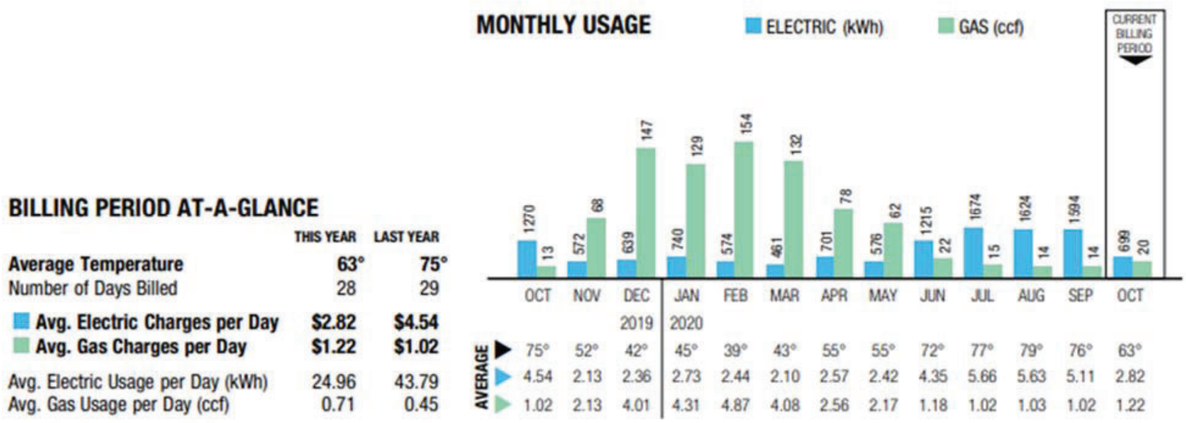


The Companies manually read the majority of in-scope meters each month. On average, approximately 60,000 meters are manually read each weekday. All customers are assigned to one of 20 billing cycles; the read date for each billing cycle generally occurs at the same time each month. Most meters are accessible by simply walking up to the meter. However, approximately 27,000 meters are located inside a customer's premise and must be accessed with a key or by coordinating with the customer. For each billing cycle, meter data is uploaded to the Companies' billing system where billing determinants are computed and checked for accuracy before customers are billed. In addition to total consumption, customer bills contain year-over-year comparisons of billing period usage, temperature, and other metrics to help customers manage their usage (see Figure 7).

---

[9] Section 5.1 evaluates all alternatives under both meter operating life scenarios. Because this assumption increases revenue requirements in all alternatives, the impact of this assumption on the PVRR differences between the various metering alternatives is small.

Figure 7: Example Customer Bill



All meter-related services are also provided manually. For example, off-cycle meter reads, move-out and move-in orders, and disconnect and reconnect orders are completed with an in-person visit to the customer's premise. Move orders are typically completed the day the customer requests a move but do require advance notice from the customer. Reconnect orders are typically completed the same day as long as the customer makes payments and requests reconnection by 5 PM; otherwise, they could be without service until the next day.

The Companies have an excellent track record for safety. Nonetheless, visiting more than 1 million customer premises each month to read meters and provide field services exposes hundreds of the Companies' employees and contractors to multiple hazards including customer threats, dog bites, and other injuries. In 2019, meter reading and field service staff sustained 17 recordable injuries and were the target of more than 100 customer threats. In addition, these groups drove approximately 5.5 million miles in 2019.

The Companies' meter operations impact some aspects of their distribution system operations. For example, to reliably accommodate growth in customer-owned generation and electric vehicles, additional voltage sensing and regulating equipment will be needed along selected distribution circuits to more precisely control voltage along these circuits and prevent voltage excursions. Additionally, with the current non-communicating meters, the Companies must contact customers after restoration occurs to confirm that service has been restored. This can negatively impact the efficiency of restoration crews.

4. Metering Alternatives

The Companies' contract for meter reading and field services expired in 2018. After a competitive bidding process, total annual contract costs for meter reading and field services increased in 2019 by $5.8 million (45%). Prior contracts executed in 2014 did not allow for annual increases so spending on these services was well under market at the end of the contract terms. Given this increase and the forecasted increase in the number of annual meter replacements, the Companies completed an analysis of metering alternatives to determine the best alternative for reliably serving customers at the lowest reasonable cost. In addition to the Status Quo alternative where existing meters continue to be replaced with non-communicating electronic meters as they fail, the Companies evaluated two alternatives with expanded AMI and one alternative with expanded AMR. AMI meters have two-way communications and a remote service switch that would enable the Companies to read meters and provide some field services remotely. AMR meters have short-range one-way communications. Instead of walking by each meter and reading the meter manually, AMR meters would enable the Companies to read meters by vehicle using mobile collectors.

The Companies evaluated the following metering alternatives in addition to the Status Quo:

- Full AMI Deployment ("Full AMI"): Install AMI in the electric and gas service territories; remotely read AMI meters and remotely provide some field services for electric customers.
- AMI + AMR in Gas-Only Territory ("AMI+AMR_GO"): Install AMR in the gas-only service territory; install AMI in electric service territory and remainder of gas service territory; remotely read AMI meters and remotely provide some field services for electric customers.
- Full AMR Deployment ("Full AMR"): Install AMR in the electric and gas service territories; drive by meters to read them; continue to manually provide field services.

Table 3 summarizes the differences between these alternatives. The following sections provide a more detailed overview of each alternative.

Table 3: Comparison of Metering Alternatives

	Item	Full AMI	AMI+AMR_GO	Full AMR
Increased Costs vs. Status Quo	IT Systems	Install systems to remotely read AMI meters and remotely provide some field services to electric customers		Enhancements to existing systems to support additional volume of AMR data
	Expanded AMI Network	Expand AMI network to electric and gas-only service territories	Expand AMI network to electric service territories	N/A
	Electric Meters	Replace in-scope electric meters with AMI meters		Replace in-scope electric meters with AMR meters
	Gas Meters	Add AMI module to all in-scope gas meters	Add AMI module to in-scope gas meters in electric service territory; add ERT to in-scope gas meters in gas-only service territory	Add ERT to all in-scope gas meters
Decreased Costs vs. Status Quo	Meter Reading	Remotely read all meters	Remotely read AMI meters; read AMR meters by vehicle	Read AMR meters by vehicle
	Field Services	Remotely provide some field services to electric customers		N/A
	Electric Distribution	Outage-related labor savings; avoided costs for voltage sensing equipment		N/A
	Fuel Savings	CVR; incremental energy efficiency		N/A
Non-Quantified Benefits	Improved Safety	Reduced threats and injuries to meter reading and field services staff		Reduced threats and injuries to meter reading staff
	Improved Reliability	Reduced customer inconvenience due to outages		N/A
	Improved Customer Experience	Ability to offer programs like prepay		N/A
	Reduced Non-Technical Losses	Limited impact to revenue requirements but reduced theft can place downward pressure on rates		N/A

4.1. Full AMI Deployment ("Full AMI")

In the Full AMI alternative, the existing RF mesh network is expanded throughout the electric and gas service territories and IT systems needed to support AMI are installed. All in-scope electric meters (approximately 1,000,000 meters) are replaced with AMI meters and an AMI communications module is added to all in-scope gas meters (approximately 340,000 meters).[10] The project to implement AMI will last five years and is assumed to begin in October 2021. Most AMI meters and modules are deployed during a coordinated 42-month meter deployment period beginning in September 2022. After Commission approval is received, any in-scope electric meters that fail prior to or outside the meter deployment project in a different part of the service territory will be replaced with AMI meters as they fail.

As AMI meters and modules are deployed, they will immediately begin communicating via the mesh network with a Meter Operations Center that monitors meter and network operations. Expanding the mesh network into the gas-only service territory will require pole attachment agreements with 13 neighboring electric providers for network equipment. Network installation as well as regular maintenance, inspections, and restoration for the network equipment will require coordination with these providers.

Customers will continue to be billed monthly, but because 15-minute consumption data is collected every 4 hours throughout the month, customers will be able to access this data anytime as an additional tool for managing their bill. AMI eliminates the need to manually read meters and manually upload meter data to the Companies' billing system. Instead, on the appropriate day each month, billing determinants will be automatically calculated and transferred to the Companies' existing billing system for review and for billing customers.

AMI will also eliminate the need to manually provide some field services. For example, most AMI meters will have a remote service switch that will enable the Companies to remotely connect and disconnect service based on current policies. This will enable the Companies to be more flexible and responsive to customer needs establishing service more quickly when moving in or settling overdue balances. Additionally, by eliminating the need to manually read meters and manually provide some field services, the Companies will eliminate majority of safety concerns from dog bites, unhappy customers, and other hazards.

AMI will also improve several aspects of the Companies' distribution operations. For example, AMI data will enable the Companies to anticipate transformer failures and reduce the duration of some transformer outages by replacing transformers shortly before they fail. In addition, AMI will provide automatic notification both when a customer's service is interrupted and when it is restored. The Companies will use this information to improve the efficiency of restoration crews and customer service during outage events. Furthermore, as discussed previously, additional voltage sensing and regulating equipment will be needed to reliably accommodate growth in customer-owned generation and electric vehicles. With

---

[10] The AMI meters included in both AMI alternatives are compatible with the AMI Mesh meters currently deployed for AMS Opt-in customers.

voltage data for every customer, AMI will not only eliminate the need for the additional voltage sensors, but it will also provide the granularity of voltage data needed to incrementally lower distribution voltages and reduce system energy requirements, thereby reducing fuel expense. The process of lowering distribution voltage to reduce system energy requirements is called Conservation Voltage Reduction ("CVR").

Finally, many AMS Opt-in customers have used their interval data to gain a better understanding of their usage and have taken actions as a result to reduce their electricity consumption. Expansion of interval data access to all other customers is likely another source of fuel savings attributed to AMI. In addition, AMI provides the foundation for offering prepay.

A number of AMI benefits either have no impact on revenue requirements or are very hard to quantify. These benefits are excluded from the financial analysis in an effort to focus on costs and benefits that are more certain. For example, with AMI, the Companies would expect to reduce theft and other non-technical losses. However, if customers who are caught stealing continue using electricity, reducing theft will place downward pressure on rates for paying customers but it will have no impact on total revenue requirements because the Companies' fixed costs and fuel expense will be unchanged. On the other hand, fuel expense would be reduced if customers who are caught stealing reduce their consumption but this reduction in fuel expense is very difficult to quantify. Therefore, in an effort to focus on costs and benefits that are more certain, the financial analysis ignores significant AMI benefits like these as well as improved customer experience, improved safety, improved reliability, and the ability to offer additional customer programs or services like prepay.

4.2. AMI + AMR in Gas-Only Territory ("AMI+AMR_GO")

The only differences between the Full AMI and AMI+AMR_GO alternatives pertain to the gas-only service territory. Of the roughly 19,000 gas meters in the gas-only service territory, about 7,500 already have an Encoder Receiver Transmitter ("ERT") for AMR. In the AMI+AMR_GO alternative, instead of adding an AMI communications module to all meters in the gas-only service territory, an ERT is added to meters that don't already have one so that all meters in the gas-only service territory can be read by vehicle using mobile collectors. The additional ERTs will be sourced from gas meters in the electric service territory that no longer need them due to AMI.[11] This alternative takes advantage of the opportunity to extend the use of existing ERTs and avoids the need to create and manage numerous 3rd party pole agreements with neighboring electric providers to support the installation and maintenance of the RF mesh network in service territories where the Companies do not typically serve.

Compared to the Status Quo, expanding AMR in the gas-only service territory actually reduces the Companies' exposure to the risk of obsolescence for AMR meters by reducing the total number of meters read by AMR. In addition, this alternative does not preclude the Companies from implementing AMI in the gas-only service territory at some point in the future.

[11] Approximately 27,000 gas meters in the electric service territory have ERTs that will be replaced by an AMI module, allowing the ERTs to be redeployed in the gas-only service territory.

4.3. Full AMR Deployment ("Full AMR")

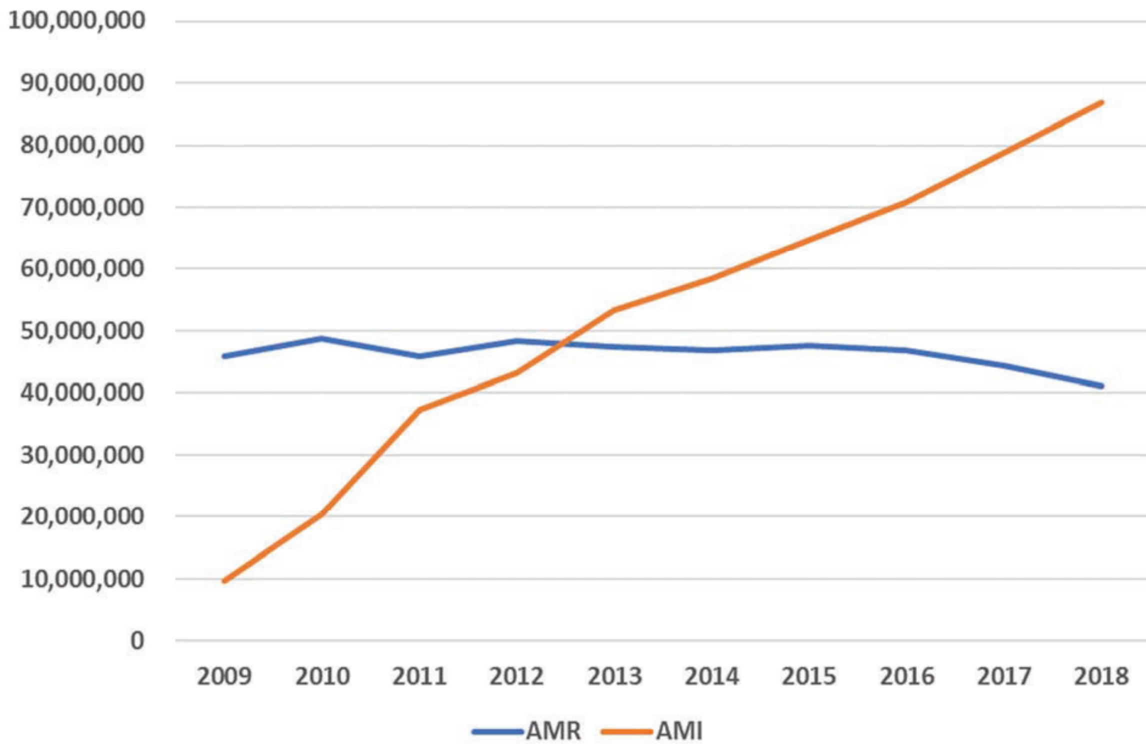
In the Full AMR alternative, most in-scope non-AMR electric meters (approximately 970,000 meters) are replaced with AMR meters and an ERT is added to all in-scope gas meters that do not already have an ERT (approximately 300,000 meters). Some portion of existing AMR electric meters and gas ERTs with limited remaining battery lives will also have to be replaced. The timeline for implementing the Full AMR alternative is the same as the AMI alternatives.

While the Full AMR alternative requires enhancements to existing IT systems, no additional IT systems are required. With the ability to read meters by vehicle, AMR will reduce the Companies' meter reading costs versus the Status Quo and reduce injuries incurred while manually reading meters. Compared to the AMI alternatives, the cost of meters in the Full AMR alternative is lower but the benefits are also lower. AMR reduces meter reading costs versus the Status Quo but not to the extent meter reading costs are reduced in the AMI alternatives. Also, AMR has no impact on the Companies' field services, energy requirements (i.e., no fuel savings from CVR or customer energy reductions), or electric distribution operations.

4.3.1. AMR Obsolescence Risk

The Full AMR alternative has significant risk relative to the other alternatives. Figure 8 shows the number of AMI and AMR meters in the United States. Since 2009, the total number of AMI meters has increased steadily while the number of AMR meters has declined since 2015. The Companies issued an RFI in March 2020 to gather information from meter vendors regarding the future availability and pricing for various meter types. The responses, which are summarized in Appendix B – Metering RFI Summary, indicate dwindling support for AMR metering, with only one vendor committing to future AMR research and investment. The market expectation for AMR meters is for higher cost increases over time relative to other meter types due to reduced economies of scale from less market share. The Companies' current experience with Power Line Carrier meters at Wilmore, Kentucky demonstrates that a non-competitive product can leave the Companies at the mercy of pricing from a sole-source vendor or be subject to the vendor dropping support altogether and rendering the product obsolete.

Figure 8: Comparison of AMR and AMI Meter Counts in United States[12]



The Companies believe that large-scale investment in AMR would be imprudent given the potential obsolescence risk. In addition, investment in AMR would hinder the Companies' ability to offer additional services to customers, such as prepay, mid-cycle usage notifications, alternative rate structures, or interval data access. AMR also does not provide the Companies with the data necessary to evaluate the impact of customer-owned generation on system reliability. Furthermore, the Companies observe other utilities' experience, such as Kentucky Power, who cite obsolescence as a key driver for moving away from AMR toward AMI.[13] To evaluate this risk, the Companies evaluated the alternatives under two AMR obsolescence scenarios: one where AMR is replaced with AMI midway through the analysis period and one where AMR remains viable throughout the entire 30-year analysis period.

AMR obsolescence would impact all alternatives except the Full AMI alternative. In the Status Quo, approximately 70,000 AMR electric meters would be replaced with mesh or cellular AMI meters, depending on the location of the meter and the economics of expanding the existing mesh network. Similarly, approximately 35,000 gas ERTs would be replaced with mesh or cellular gas AMI modules.

[12] Data source: https://www.eia.gov/electricity/annual/html/epa_10_10.html

[13] In the Matter of: Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) Approval Of A Certificate Of Public Convenience And Necessity; And (5) All Other Required Approvals And Relief, Case No. 2020-00174, Application and Testimony (Ky. PSC June 29, 2020)

Because the Companies' existing AMR meters were installed to solve problems related to accessing customers' meters, replacing AMR meters and gas ERTs with non-communicating devices is not a viable way to address AMR obsolescence.

Based on this analysis and the forecasted increases in meter reading and field services costs, the least-cost option for addressing AMR obsolescence for the AMI+AMR_GO and Full AMR alternatives would be to transition fully to AMI. For the AMI+AMR_GO alternative, this transition would entail simply expanding the LG&E mesh network throughout the gas-only territory and replacing the approximately 19,000 ERTs in the gas-only service territory with gas AMI modules. For the Full AMR alternative, this transition would require a wholesale replacement of all electric meters and gas ERTs with AMI. Customers would ultimately see the cost savings and other benefits associated with AMI, but the early replacement of meters would add significant cost to the Full AMR alternative.

5. Analysis of Metering Alternatives

The analysis of metering alternatives was completed in two phases. As discussed previously, the analysis is focused entirely on revenue requirements and sets aside non-quantified benefits. In the first phase, the Companies evaluated the PVRR for each alternative under two AMR obsolescence scenarios: one where AMR becomes obsolete midway through the analysis period and one where AMR remains viable for the full 30-year analysis period. In addition, all alternatives were evaluated with the assumption that the 5-year implementation project for the AMI and AMR alternatives would begin in October 2021. The results of this phase of the analysis demonstrate that the AMI+AMR_GO analysis is the least-cost alternative and has very little downside risk.

In the second phase of the analysis, the Companies evaluated the AMI+AMR_GO alternative over different implementation timelines. Delaying the beginning of the 5-year implementation project or deferring systems implementation so that more in-scope meters can be replaced as they fail increases the PVRR by postponing the project's benefits. The following sections summarize each phase of the analysis in more detail. A detailed discussion of model inputs is included in Appendix A – Model Inputs.

5.1. Phase 1 Analysis

Table 4 shows nominal cash flows in the Status Quo alternative under the two AMR obsolescence scenarios. Total cash flows are the same in both scenarios through 2030. Meter reading costs account for majority of total costs throughout the analysis period. As discussed previously, annual contract costs for meter reading and field services increased by 45% in 2019 and the number of meter replacements per year is expected to increase over time as electromechanical meters are replaced with non-communicating electronic meters. Both types of meters are assumed to be proactively replaced (i.e., after 16 years for electronic meters and after 45 years for electromechanical meters) so that their average operating lives equals their depreciation lives. The cash flows in Table 4 reflect base values for inputs in Appendix A – Model Inputs that are specified as a range of values. In total, annual Status Quo costs are forecasted to increase from $37.8 million in 2021 to more than $85 million in 2050.

Table 4: Status Quo Costs ($M, Capital and O&M, Proactive Replacement Operating Life)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Both AMR Obsolescence Scenarios										
Meter Costs	4.8	3.5	4.0	3.9	4.6	5.4	4.4	5.2	5.1	6.3
Non-Meter Costs	0.0	0.0	2.5	0.0	0.0	0.0	0.0	0.0	3.0	0.0
Meter Reading	18.6	19.0	19.5	20.1	20.7	21.3	21.9	22.6	23.2	23.9
Field Services	14.3	14.7	15.1	15.6	16.1	16.5	17.0	17.5	18.0	18.5
EDO Costs	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8
Total	37.8	38.7	42.6	41.1	42.9	44.9	45.0	47.0	51.1	50.6
	2031	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
AMR Becomes Obsolete Midway through Analysis Period										
Meter Costs	7.3	8.4	8.1	9.4	11.3	8.1	7.7	6.8	7.4	7.7
Non-Meter Costs	0.0	0.6	0.7	0.8	3.9	0.2	0.2	0.2	0.2	0.2
Meter Reading	24.6	25.3	25.9	26.6	27.3	28.0	28.8	29.6	30.5	31.4
Field Services	19.1	19.6	20.2	20.8	21.4	22.0	22.6	23.2	23.9	24.6
EDO Costs	1.9	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	52.8	54.1	55.1	57.7	64.1	58.4	59.5	60.1	62.2	64.1
AMR Remains Viable for 30-Year Analysis Period										
Meter Costs	7.3	6.5	6.1	6.3	8.5	8.3	7.9	7.0	7.6	7.9
Non-Meter Costs	0.0	0.0	0.0	0.0	3.6	0.0	0.0	0.0	0.0	0.0
Meter Reading	24.6	25.3	26.1	26.8	27.6	28.4	29.2	30.1	31.0	31.8
Field Services	19.1	19.6	20.2	20.8	21.4	22.0	22.6	23.2	23.9	24.6
EDO Costs	1.9	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	52.8	51.6	52.6	54.1	61.2	58.9	59.9	60.5	62.7	64.5
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
AMR Becomes Obsolete Midway through Analysis Period										
Total	71.6	68.3	69.9	72.8	74.3	79.0	84.4	84.0	85.3	87.2
AMR Remains Viable for 30-Year Analysis Period										
Total	72.1	68.7	70.3	73.2	74.7	79.3	84.8	82.1	83.4	85.6

To model the impact of AMR obsolescence, the Companies assumed AMR becomes obsolete by the end of 2035. In this scenario, approximately 70,000 AMR electric meters and 35,000 gas ERTs are replaced from 2032 to 2035 with AMI electric meters and gas modules. Because the Companies' existing AMR meters were installed to solve problems related to accessing customers' meters, replacing AMR meters and gas ERTs with non-communicating devices is not a viable way to address AMR obsolescence. Depending on their location and the economics of expanding the existing RF mesh network, the AMR meters and ERTs will be replaced with either mesh or cellular AMI meters and modules. For this analysis, the Companies assumed limited expansion of the mesh network throughout the gas-only service territory. After the AMR metering equipment is replaced, savings in meter reading costs more than offset the incremental cost of maintaining an expanded mesh network until the majority of the replacement AMI meters installed from 2032 to 2035 begin to be replaced in 2048.

Figure 9 compares nominal cash flows in the AMI and AMR alternatives to the Status Quo in the scenario where AMR is assumed to become obsolete midway through the analysis period. Figure 10 contains the same comparison for the scenario where AMR is assumed to remain viable for the entire 30-year analysis period. In both scenarios, nominal cash flows for the AMI and AMR alternatives are initially higher than the Status Quo due to the investment in meters and IT systems but are lower after the 5-year project implementation period. AMR obsolescence has no impact on the Full AMI alternative. Based on this analysis and the forecasted increases in meter reading and field services costs, the least-cost option for addressing AMR obsolescence for the AMI+AMR_GO and Full AMR alternatives would be to transition fully to AMI. Like in the Status Quo, this transition is assumed to occur from 2032 to 2035 for both alternatives. For the AMI+AMR_GO alternative, this transition would entail simply expanding the LG&E mesh network throughout the gas-only territory and replacing the approximately 19,000 ERTs in the gas-only service territory with gas AMI modules. For the Full AMR alternative, this transition would require a wholesale replacement of all electric meters and gas ERTs with AMI. Customers would ultimately see the cost savings and other benefits associated with AMI, but the early replacement of meters causes total meter costs in this scenario to be much higher. In Figure 9, the increased costs at the end of the analysis period for the Full AMR alternative reflect the beginning of a third wave of meter replacements.

Figure 9: AMI and AMR Nominal Cost Differences ($M, Capital and O&M, AMR Becomes Obsolete Midway through Analysis Period, Proactive Replacement Operating Life)

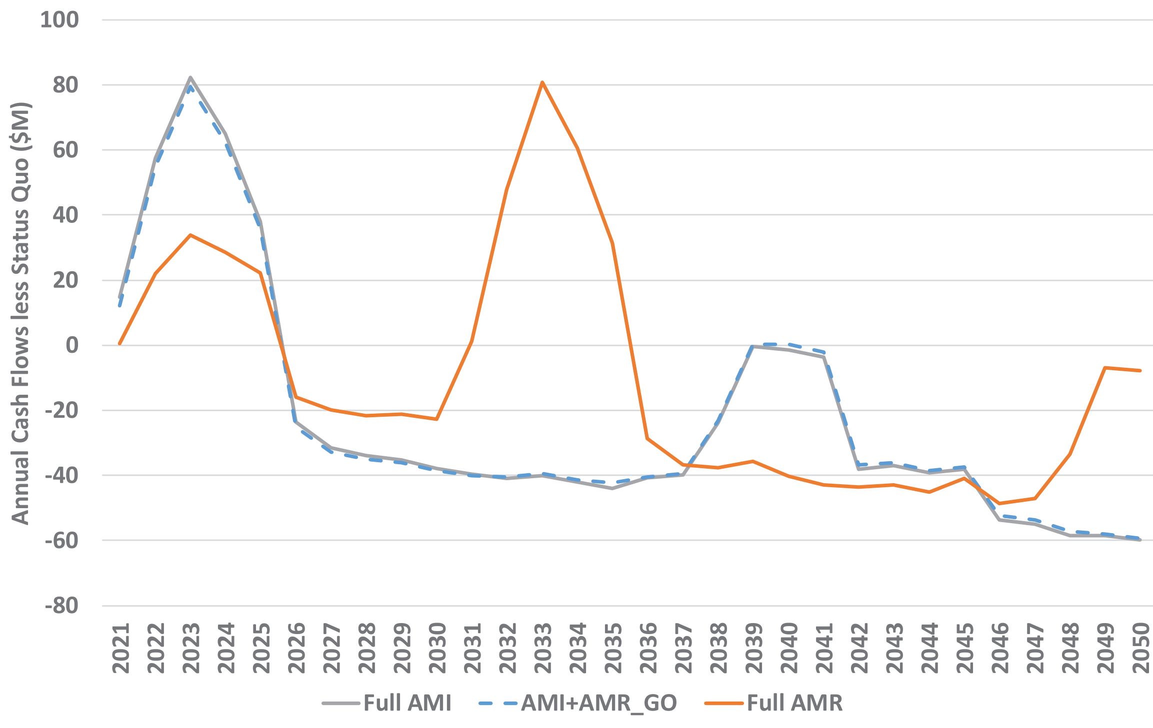
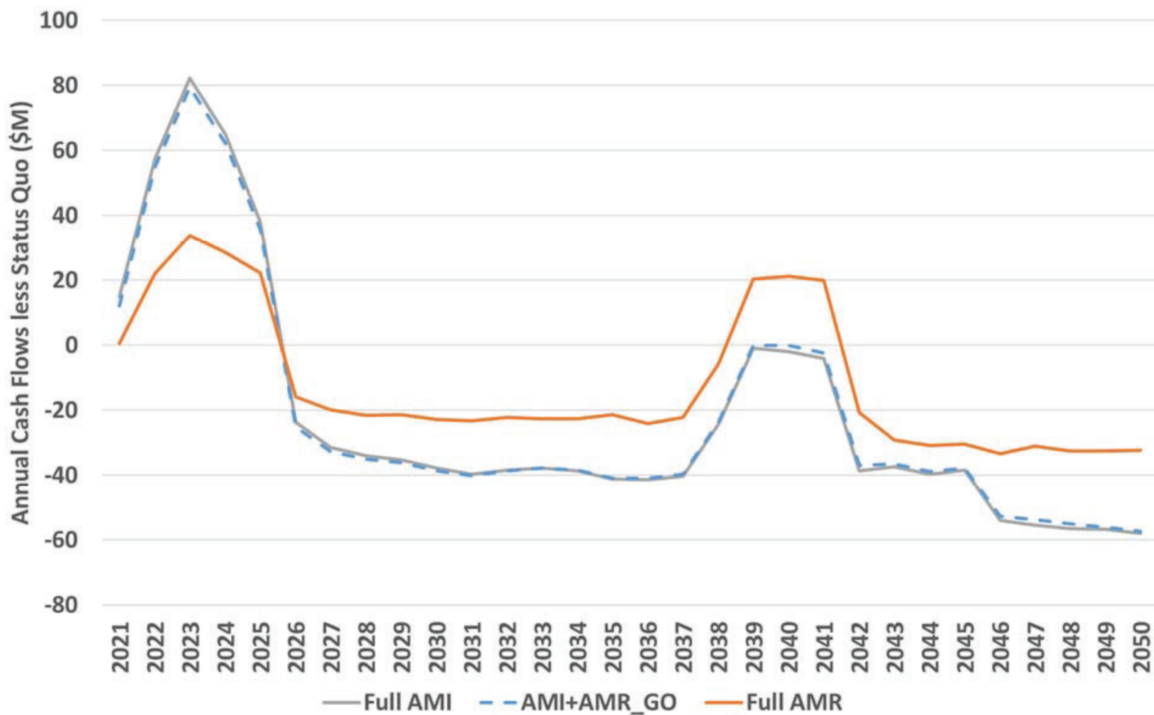


Figure 10: AMI and AMR Nominal Cost Differences ($M, Capital and O&M, AMR Remains Viable for 30-Year Analysis Period, Proactive Replacement Operating Life)



Based on the meter failure curves discussed in Section 3, the likelihood of a meter failing is initially very low and increases with age. The second wave of meter replacements is slightly less pronounced than in the initial 42-month meter deployment period due to the volume of meters that fails prior to the sixteenth year of operation when AMI and AMR meters that haven't failed are assumed to be proactively replaced. In both AMR obsolescence scenarios, total spending over the 30-year analysis period is lower for the AMI and AMR alternatives. This analysis determines whether the investment in AMI or AMR is justified by the savings.

Table 5 contains nominal cash flows for the AMI and AMR alternatives under each AMR obsolescence scenario. Total cash flows for each alternative are the same in both scenarios through 2030. For all alternatives, the cost of meters makes up the majority of total costs during the 2021 to 2026 project deployment period. The cost of meters in the Full AMR alternative is lower than in the AMI alternatives but the benefits are also lower. Additional information regarding each category of costs is included in Appendix A – Model Inputs.

Table 5: AMI and AMR Costs ($M, Capital and O&M, Proactive Replacement Operating Life)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Full AMI										
Meter Costs	3.7	21.0	50.0	49.9	51.0	7.6	1.4	1.7	2.0	2.4
Non-Meter Costs	15.9	42.2	43.8	34.9	14.5	4.6	4.7	4.5	7.7	4.8
Meter Reading	18.6	18.3	16.3	11.3	6.6	1.2	0.4	0.4	0.5	0.5
Field Services	14.3	14.7	15.1	10.8	10.1	10.0	10.2	10.5	10.8	11.1
EDO Costs	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.2	-0.2	-0.2	-0.3
Fuel Savings	0.0	-0.1	-0.3	-0.7	-1.0	-2.1	-3.1	-4.0	-4.9	-5.8
Total	52.5	96.1	124.9	106.2	80.9	21.2	13.5	13.0	15.8	12.7
AMI+AMR_GO										
Meter Costs	3.7	20.9	49.6	49.4	50.6	7.6	1.5	1.7	2.0	2.4
Non-Meter Costs	15.9	41.7	43.2	34.3	14.2	4.5	4.6	4.4	7.5	4.7
Meter Reading	18.6	18.3	16.4	11.3	6.7	1.3	0.5	0.5	0.5	0.6
Field Services	14.3	14.7	15.1	10.8	10.1	10.0	10.2	10.5	10.8	11.1
EDO Costs	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.2	-0.2	-0.2	-0.3
Fuel Savings	0.0	-0.1	-0.3	-0.7	-1.0	-2.1	-3.1	-4.0	-4.9	-5.8
Total	52.5	95.6	123.9	105.2	80.3	21.1	13.5	12.9	15.8	12.7
Full AMR										
Meter Costs	3.5	14.9	34.0	33.5	34.4	5.7	2.3	1.8	2.3	2.4
Non-Meter Costs	4.6	13.2	11.1	8.5	6.8	1.0	0.0	0.0	3.0	0.0
Meter Reading	18.6	18.4	16.6	12.2	8.0	5.5	5.3	5.4	5.6	5.7
Field Services	14.3	14.7	15.1	15.6	16.1	16.5	17.0	17.5	18.0	18.5
EDO Costs	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8
Fuel Savings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	41.0	62.7	78.4	71.3	66.7	30.3	26.3	26.4	30.6	28.4
	2031	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
AMR Becomes Obsolete Midway through Analysis Period										
Full AMI	13.1	13.1	14.9	15.6	20.1	17.6	19.6	36.2	61.7	62.6
AMI+AMR_GO	13.1	13.8	15.7	16.3	21.6	17.6	19.6	36.2	61.7	62.6
Full AMR	52.6	102.1	136.0	118.2	91.9	25.9	18.0	17.6	21.3	17.5
AMR Remains Viable for 30-Year Analysis Period										
Full AMI	13.1	13.1	14.9	15.6	20.1	17.6	19.6	36.2	61.7	62.6
AMI+AMR_GO	13.1	13.2	15.0	15.6	20.2	17.7	19.7	36.2	61.8	62.6
Full AMR	30.0	29.6	30.1	31.4	39.6	34.5	37.3	54.2	82.2	84.0
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
AMR Becomes Obsolete Midway through Analysis Period										
Full AMI	68.0	30.2	33.0	33.5	36.2	25.4	29.4	25.5	26.7	27.7
AMI+AMR_GO	67.9	29.9	32.2	32.7	35.4	25.2	29.3	25.5	26.7	27.6
Full AMR	22.4	18.2	20.5	21.0	26.6	23.4	30.3	43.3	71.9	72.9
AMR Remains Viable for 30-Year Analysis Period										
Full AMI	68.0	30.2	33.0	33.5	36.2	25.4	29.4	25.5	26.7	27.7
AMI+AMR_GO	68.0	30.1	32.3	32.8	35.5	25.3	29.5	25.6	26.8	27.7
Full AMR	90.3	46.4	39.5	40.8	42.7	44.5	52.3	48.2	50.4	52.9

Table 6 lists the PVRR for each metering alternative under each AMR obsolescence scenario. Like the other tables and figures in this section, the PVRR values in Table 6 reflect base values for inputs in Appendix A – Model Inputs that are specified as a range of values. The PVRR values include all revenue requirements for Meters, Non-Meter Deployment and On-Going Costs, Meter Reading, and Field Services. The PVRR for EDO Costs includes the cost of voltage sensing equipment and O&M savings, which are computed as a difference from the Status Quo for the Full AMI and AMI+AMR_GO alternatives. The PVRR for Fuel Savings is also computed as a difference from the Status Quo for the AMI alternatives. Revenue requirements for new meters and other deployment costs in the AMI and AMR alternatives were computed with the assumption that the Companies will record capital investments as Construction Work in Process during the 5-year implementation period and accrue an allowance for funds used during construction. After the 5-year implementation period, capital investments are assumed to be placed in service in the year the investments are made. In addition to the cost of meters during the 5-year implementation period and the cost of replacement meters over the remainder of the 30-year analysis period, the PVRR for meters includes revenue requirements associated with the Companies' existing meter assets as well as the portion of warehouse and Administrative & General ("A&G") costs that will be allocated to the AMI+AMR_GO alternative during the project implementation period. The investment in existing meter assets is a sunk cost, and the AMI and AMR alternatives will have no impact on total warehouse or A&G costs. Therefore, the PVRR for existing meter assets, warehouses, and A&G costs is the same in all alternatives.

Table 6: PVRR of Alternatives ($M, 2020 Dollars, 2021-2050)

AMR Becomes Obsolete Midway through Analysis Period				
Cost Item	**Status Quo**	**Full AMI**	**AMI+AMR_GO**	**Full AMR**
Meters	144.2	322.5	321.3	333.4
Non-Meter Deployment & On-Going Costs	9.8	180.4	179.0	124.8
Meter Reading	318.4	65.5	66.0	93.1
Field Services	248.0	165.9	165.9	206.5
EDO Costs	13.8	-2.7	-2.7	11.5
Fuel Savings	0.0	-48.6	-48.6	-20.1
Total (A)	734.2	683.0	680.9	749.3
Difference from Status Quo	0	-51.3	-53.3	15.0
AMR Remains Viable for 30-Year Analysis Period				
Cost Item	**Status Quo**	**Full AMI**	**AMI+AMR_GO**	**Full AMR**
Meters	139.7	322.5	321.3	264.7
Non-Meter Deployment & On-Going Costs	8.1	180.4	177.3	41.6
Meter Reading	320.4	65.5	66.4	119.7
Field Services	248.0	165.9	165.9	248.0
EDO Costs	13.8	-2.7	-2.7	13.8
Fuel Savings	0.0	-48.6	-48.6	0.0
Total (B)	729.9	683.0	679.6	687.8
Difference from Status Quo	0	-47.0	-50.4	-42.1
AMR Obsolescence Risk (A less B)	4.3	0	1.3	61.4

* Analysis ignores non-quantified benefits.

In both AMR obsolescence scenarios, the AMI+AMR_GO alternative is the least-cost alternative. The Status Quo alternative has the highest cost if AMR remains viable for the 30-year analysis period and the second highest cost if AMR becomes obsolete midway through the analysis period. For each alternative, AMR obsolescence risk is computed as the difference in PVRR between the two obsolescence scenarios. Unsurprisingly, the unfavorable impact of AMR obsolescence is greatest for the Full AMR alternative. AMR obsolescence increases the PVRR of the Full AMR alternative by $61.4 million and the PVRR of the AMI+AMR_GO alternative by only $1.3 million.

The favorability of the Full AMI and AMI+AMR_GO alternatives is explained primarily by meter reading and field services savings, but fuel savings are also significant. The PVRR for the Full AMI and AMI+AMR_GO alternatives is not materially different. However, because the AMI+AMR_GO alternative enables the Companies to utilize existing gas meter assets in the gas-only service territory and avoid the complexity associated with managing multiple 3rd party pole agreements, the AMI+AMR_GO alternative is clearly preferred over the Full AMI alternative. Based on the favorability of the AMI+AMR_GO alternative and the risk of obsolescence for AMR meters, further analysis is focused only on the AMI+AMR_GO alternative.

5.1.1. Sensitivity Analysis

Table 7 shows the impact of changing various input assumptions on the PVRR difference between the AMI+AMR_GO and Status Quo alternatives, and indicates to which inputs this difference is most sensitive. Because the impact of AMR obsolescence is small for both alternatives, this portion of the analysis is focused on one AMR obsolescence scenario (i.e., where AMR is assumed to remain viable for the 30-year analysis period). The basis for each range of input values is discussed in more detail in Appendix A – Model Inputs. With base inputs, the AMI+AMR_GO alternative is $50.4 million favorable to the Status Quo. Because the downside risk associated with any single input in Table 7 is less than $50.4 million, the results in Table 7 demonstrate that the favorability of the AMI+AMR_GO alternative does not depend on any single input. For example, if customers do not reduce their energy usage based on their access to interval data and incremental ePortal savings turn out to be zero, the favorability of the AMI+AMR_GO alternative is reduced from $50.4 million by $13.8 million to $36.6 million, but the AMI+AMR_GO alternative is still favorable to the Status Quo.[14]

Table 7: Sensitivity Analysis Results ($M, 2020 Dollars, 2021-2050)

Input	Input Range			Impact of Changing Input on PVRR Difference (AMI+AMR_GO less Status Quo)	
	Base	Low	High	Low Case	High Case
Outside Services Labor Escalation Rate	2.5%	2.0%	3.0%	+$20.6 M	-$23.4 M
Meter Capital Escalation Rate	0.25%	0.0%	1.0%	-$1.3 M	+$4.3 M
Average Meter Operating Life (Electromechanical/ Electronic)[15]	37 Years/ 15 Years	N/A	46 Years/ 20 Years	N/A	-$0.4
Testing Removed Meters Waiver	Not Granted	Granted	N/A	-$2.5 M	N/A
PSC Inspection Waiver	Not Granted	Granted	N/A	-$4.2 M	N/A
CVR Fuel Savings	205 GWh	140 GWh	270 GWh	+$10.2 M	-$11.0 M
ePortal Fuel Savings	0.35%	0.0%	0.7%	+$13.8 M	-$13.8 M
Generation Fuel Prices	2021 BP Base	2021 BP Low	2021 BP High	+$10.6 M	-$10.4 M

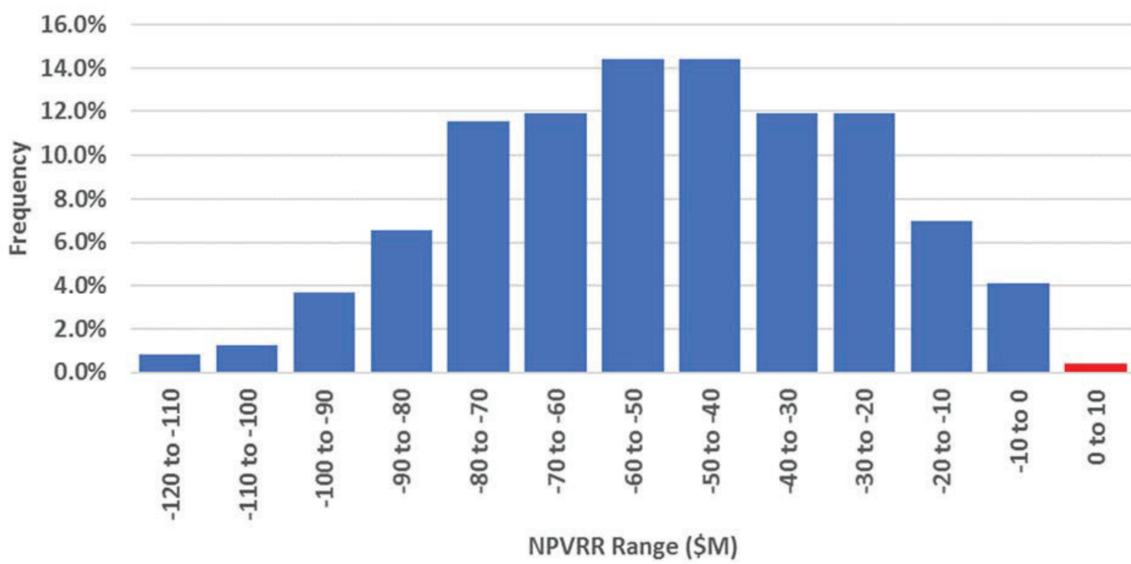
The Companies evaluated two meter operating life scenarios. In the proactive replacement operating life scenario, meters that haven't failed by a certain age are assumed to be replaced proactively (i.e., after 16 years for AMI, AMR, and electronic meters and after 45 years for electromechanical meters) so that the average meter operating life equals its depreciation life. In addition to the proactive replacement

[14] For an explanation of ePortal savings, see Section 6.6, Fuel Savings.
[15] Electronic meters include non-communicating electronic meters, AMI, and AMR meters.

operating life scenario, the Companies modeled a longer operating life scenario without proactive replacement. The proactive replacement assumption causes total meter replacements over the 30-year analysis period to be higher in both the Status Quo and AMI+AMR_GO alternatives. In the Status Quo alternative, the impact of this assumption is greatest during the first 15 years of the analysis period as aging electromechanical meters are replaced faster than they otherwise would be replaced. In the AMI+AMR_GO alternative, this assumption causes an uptick in meter replacements from 2038 to 2041 for the replacement of meters installed in the initial meter deployment period that haven't failed after 16 years. Because this assumption increases revenue requirements in both the Status Quo and the AMI+AMR_GO alternatives, the impact of this assumption on the PVRR difference is only $0.4 million. Assumptions regarding meter operating lives do not have a significant impact on deciding whether AMI is least-cost for customers.

The PVRR difference is most sensitive to outside services labor escalation, meter cost escalation, ePortal fuel savings, CVR fuel savings, and the generation fuel prices assumed for ePortal and CVR fuel savings. The Companies created 243 cases by varying these inputs (3 outside services labor escalation rate scenarios times 3 meter cost escalation rate scenarios times 3 ePortal fuel savings scenarios times 3 CVR fuel savings scenarios times 3 generation fuel price scenarios). Figure 11 plots the distribution of PVRR difference between the AMI+AMR_GO and Status Quo alternatives over these cases. The PVRR of the AMI+AMR_GO alternative is favorable to the Status Quo in 99.6% of the cases evaluated and ranges from only $4.2 million unfavorable to $115.4 million favorable. These results demonstrate that the AMI+AMR_GO alternative has very little downside risk.

Figure 11: Distribution of PVRR Difference (AMI+AMR_GO less Status Quo, $M, 2020 Dollars, 2021-2050)

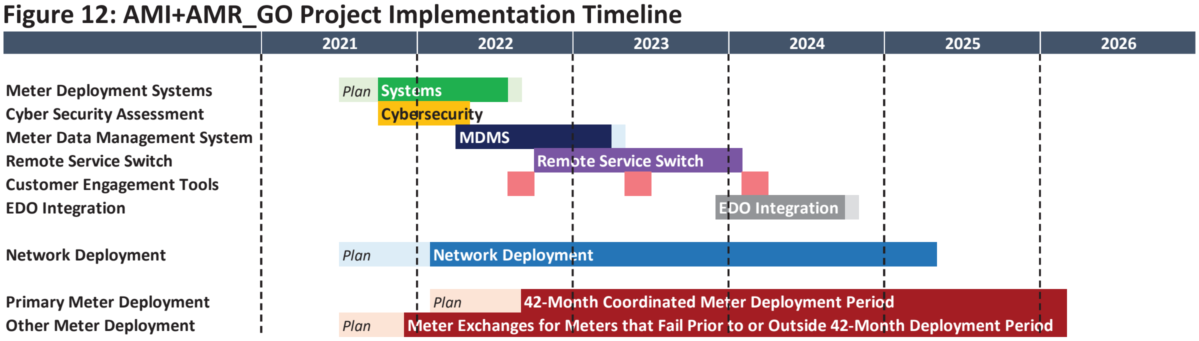


5.2. Phase 2 Analysis

In the Phase 2 analysis, the Companies evaluated the AMI+AMR_GO alternative over different implementation timelines to determine whether the 5-year implementation timeline beginning October

2021 ("base implementation timeline") is optimal. Figure 12 provides an overview of the base implementation timeline for the AMI+AMR_GO alternative. Systems development and network deployment begin in October 2021 and the coordinated 42-month meter deployment period begins in September 2022. The vast majority of meters will be replaced one neighborhood at a time through this 42-month period. Other meter replacement refers to meters that need to be replaced prior to or outside the coordinated meter deployment project in portions of the service territory where the mesh network has been installed. The timing of meter reading and field services cost savings is tied to availability of systems functionality in the Meter Data Management System ("MDMS") and the Remote Service Switch, respectively, as well as the number of meters deployed. The timing of EDO savings and CVR fuel savings is tied to the integration of AMI and EDO IT systems.

Figure 12: AMI+AMR_GO Project Implementation Timeline



A decision to delay the project would reduce the PVRR associated with deployment costs simply by deferring the capital investments. However, this delay would also defer meter reading, field services, and fuel savings benefits. In addition, a delay would cause the Companies to incur some portion of the cost of voltage sensing equipment that would otherwise be avoided. Table 8 summarizes the impact on PVRR difference between the AMI+AMR_GO and Status Quo alternatives from delaying the project. In addition to the case with base inputs, the Companies evaluated the impact of delay on the 25th and 75th percentile cases from the distribution of PVRR differences presented in Figure 11 in Section 5.1. For each case, delaying the project decreases the NPVRR by delaying the project's benefits. The base implementation timeline was developed to deliver savings as soon as possible and provide a good customer experience. Once AMI systems are in place, deploying AMI meters as soon as possible is least cost.

Table 8: NPVRR (AMI+AMR_GO less Status Quo, $M, 2020 Dollars, 2021-2050)

Implementation Start Year	Project Completion Year	25th Percentile Inputs	Base Inputs	75th Percentile Inputs
2021	2026	-67.9	-50.4	-31.9
2026	2031	-48.5	-30.5	-19.0
2031	2036	-25.2	-9.5	-2.8

For the implementation timelines evaluated thus far, network deployment and the installation of AMI systems occurs at the beginning of the implementation period. The Companies evaluated a final implementation timeline ("replace-as-meters-fail") where most systems implementation is deferred so that more in-scope meters can be replaced as they fail. This timeline requires a more robust network since AMI meters will not be able to rely on other AMI meters to communicate with systems in the Meter Operations Center (see Section 6.2).

For the replace-as-meters-fail timeline, the analysis assumes inside meters are proactively replaced to provide some immediate operational benefits and reduce presence inside customer premises. Beginning October 2021, the Companies will be able to bill residential and general service customers with an AMI meter from meter data collected remotely. Because approximately 90% of all customers are residential or general service customers, the analysis assumes the Companies will be able to remotely read 90% of the meters replaced on this timeline. However, replacing meters as they fail limits meter reading savings due to the non-contiguous nature of the meter replacements.[16] In addition, the Companies would not realize the economies of scale associated with a coordinated meter deployment project (i.e., no bulk meter cost discounts or labor savings). The Companies would avoid the cost of voltage sensing equipment but would not achieve CVR savings until AMI systems are in place and integrated to EDO systems.

Table 9 summarizes the results of this analysis. In the base timeline, AMI systems and meters are assumed to be fully deployed by 2026. In the replace-as-meters-fail timeline, AMI systems and the balance of meters are assumed to be fully deployed by 2031 or 2036. The replace-as-meters-fail timeline is favorable to the Status Quo but not as favorable as the base timeline. In addition, the sooner AMI systems and the balance of meters are fully deployed, the more favorable the PVRR.

Table 9: PVRR of Alternatives ($M, 2020 Dollars, 2021-2050, Base and Replace-as-Meters-Fail Timelines)

	Implementation Start Year	Project Completion Year	PVRR	PVRR Difference from Status Quo
Status Quo	N/A	N/A	729.9	0
AMI+AMR_GO: Base Timeline	2021	2026	679.6	-50.4
AMI+AMR_GO: Replace-As-Meters-Fail	2021	2031	688.3	-41.7
AMI+AMR_GO: Replace-As-Meters-Fail	2021	2036	706.8	-23.1

5.3. Conclusion

The results of this analysis show that the AMI+AMR_GO alternative is the least-cost metering alternative for customers and that the 5-year implementation timeline beginning October 2021 is optimal. In an effort to focus on costs and benefits that are more certain, the financial analysis sets aside hard-to-quantify benefits for the AMI alternatives such as improved customer experience, improved safety, improved reliability, the reduction of non-technical losses, and the ability to offer additional customer

[16] If non-AMI meters were replaced with AMI meters as they fail, the associated labor savings would not be as large as it would be via a coordinated replacement strategy because there would not be significant reductions in the quantities of meter reading routes nor the number of needed readers. While there would be fewer meters to read, the meter reading contract has provisions for pricing negotiations as the number of meters change. The longer the deployment lasts, the more often those provisions will come into play, limiting the overall labor savings.

programs or services like prepay. Even when these benefits are ignored, the AMI+AMR_GO alternative has very little downside risk.

6. Appendix A – Model Inputs

6.1. Meter Costs

Table 10 contains a detailed summary of meter costs for each alternative through 2030. Status Quo meter costs include the cost of replacing existing meters as they fail with non-communicating electronic meters as well as the cost of manual meter reading equipment and the cost of mobile collectors for reading AMR meters by vehicle. In the Full AMI alternative, these costs are eliminated. In the AMI+AMR_GO alternative, the cost of manual meter reading equipment is eliminated and only one mobile collector is needed to read AMR meters in the gas-only service territory by vehicle. In the AMR alternative, the cost of manual meter reading equipment is reduced, but additional mobile collectors are needed to read all meters by vehicle.

Table 10: Meter Costs ($M, Capital and O&M, Proactive Replacement Operating Life)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Status Quo										
New Meter Costs	4.8	3.5	4.0	3.9	4.6	5.4	4.4	5.2	5.1	6.3
Total Meters	4.8	3.5	4.0	3.9	4.6	5.4	4.4	5.2	5.1	6.3
Full AMI										
New Meter Costs	0.8	18.8	46.3	46.6	47.6	7.1	1.4	1.7	2.0	2.4
Legacy Meter Costs	2.9	1.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Meter Base Repairs	0.0	0.9	2.3	2.3	2.4	0.4	0.0	0.0	0.0	0.0
Test Removed Meters	0.0	0.3	0.9	0.9	1.0	0.1	0.0	0.0	0.0	0.0
Total Meters	3.7	21.0	50.0	49.9	51.0	7.6	1.4	1.7	2.0	2.4
AMI+AMR_GO										
New Meter Costs	0.8	18.7	45.9	46.2	47.2	7.1	1.5	1.7	2.0	2.4
Legacy Meter Costs	2.9	1.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Meter Base Repairs	0.0	0.9	2.3	2.3	2.4	0.4	0.0	0.0	0.0	0.0
Test Removed Meters	0.0	0.3	0.9	0.9	1.0	0.1	0.0	0.0	0.0	0.0
Total Meters	3.7	20.9	49.6	49.4	50.6	7.6	1.5	1.7	2.0	2.4
Full AMR										
New Meter Costs	0.6	12.7	30.4	30.3	31.0	5.2	2.3	1.8	2.3	2.4
Legacy Meter Costs	2.9	1.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Meter Base Repairs	0.0	0.9	2.2	2.3	2.4	0.3	0.0	0.0	0.0	0.0
Test Removed Meters	0.0	0.3	0.9	0.9	1.0	0.1	0.0	0.0	0.0	0.0
Total Meters	3.5	14.9	34.0	33.5	34.4	5.7	2.3	1.8	2.3	2.4

New meter costs for the AMI and AMR alternatives includes the cost of new meters, new meter inventory, and the cost of additional resources needed to test new meters during meter deployment. Legacy meter costs includes the cost of non-communicating electronic meters and related equipment necessary to maintain current operations until the AMI and AMR alternatives are adequately deployed. Total meter costs also include the cost of any meter base repairs during deployment and the cost of testing removed meters. Even though current regulations require customers to bear the cost of meter base repairs, the Companies are proposing that this cost be treated as a utility revenue requirement during meter deployment period to streamline the meter deployment project and improve the customer experience. The Companies are not proposing that this cost be capitalized. When a meter is replaced, the Companies are required by statute to test both the removed meter and the new meter. Both costs are included in the financial analysis but the Companies are requesting a waiver for the requirement to test removed meters.

In the Full AMI, AMI+AMR_GO, Full AMR alternatives, new meters are deployed over a 42-month meter deployment period beginning September 2022. The meter deployment period was designed to balance delivering benefits to customers as quickly as possible with levelizing back office support activities to ensure to ensure a good customer experience. Lengthier deployment timeframes would further levelize back office activities but would unnecessarily delay benefits for customers. A shorter deployment timeframe may deliver benefits faster but would include considerable risk of increased exception management costs. After the initial meter deployment period, annual meter costs in AMI alternatives are lower, despite a higher cost per meter, because the failure rate for the new population of meters is low.

Table 11 summarizes total meter costs for each alternative from 2031 to 2050 under the two AMR obsolescence scenarios. In the scenario where AMR remains viable throughout the 30-year analysis period, total meter costs for each alternative simply include the cost of replacing meters as they fail and the cost of meters for new customers. To model the impact of AMR obsolescence, the Companies assumed AMR becomes obsolete by 2035. In this scenario, approximately 70,000 AMR electric meters and 35,000 gas ERTs are replaced in the Status Quo over the four-year period from 2032 to 2035 with AMI electric meters and gas modules.[17] The nature of the replacement meters and modules (i.e., either mesh or cellular) would depend on the location of the meter and the economics of expanding the existing mesh network. For this analysis, the Companies assumed limited expansion of the mesh network throughout the gas-only service territory.[18] For the AMI+AMR_GO and Full AMR alternatives, the least-cost option for addressing AMR obsolescence would be to transition fully to AMI. In the AMI+AMR_GO alternative, the mesh network is expanded to include the gas-only service territory and the approximately 19,000 gas ERTs in the gas-only service territory are replaced with gas AMI modules in 2035. In the Full AMR alternative, all electric meters and gas ERTs are replaced with AMI meters and gas modules over the four-year period from 2032 to 2035.

[17] The Companies' existing AMR meters were installed to solve problems related to accessing customers' meters. Therefore, replacing AMR meters and gas ERTs with non-communicating devices is not a viable solution.
[18] The impact to network costs is discussed in Section 6.2.

Table 11: Meter Costs ($M, Capital and O&M, Proactive Replacement Operating Life)

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	AMR Becomes Obsolete Midway through Analysis Period									
Status Quo	7.3	8.4	8.1	9.4	11.3	8.1	7.7	6.8	7.4	7.7
Full AMI	2.7	3.0	3.4	3.9	4.5	5.2	6.5	23.2	47.0	47.9
AMI+AMR_GO	2.7	3.2	3.5	4.0	5.7	5.2	6.5	23.2	47.0	47.9
Full AMR	7.3	23.2	55.4	55.3	56.5	8.4	1.5	1.8	2.2	2.6
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	7.3	6.5	6.1	6.3	8.5	8.3	7.9	7.0	7.6	7.9
Full AMI	2.7	3.0	3.4	3.9	4.5	5.2	6.5	23.2	47.0	47.9
AMI+AMR_GO	2.7	3.2	3.5	4.0	4.6	5.3	6.7	23.3	47.1	48.1
Full AMR	3.2	3.7	3.5	4.0	7.9	5.6	7.5	23.6	50.7	51.6
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
	AMR Becomes Obsolete Midway through Analysis Period									
Status Quo	9.4	8.6	8.5	9.7	9.4	12.3	10.8	13.6	12.9	13.0
Full AMI	48.5	14.5	17.0	17.7	18.5	7.9	6.2	7.0	7.8	8.8
AMI+AMR_GO	48.5	14.3	16.2	16.9	17.7	7.7	6.2	6.9	7.7	8.7
Full AMR	3.0	3.3	3.8	4.3	4.9	5.7	7.2	25.7	52.1	53.1
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	9.5	8.8	8.7	9.8	9.5	12.3	10.8	11.3	10.7	10.8
Full AMI	48.5	14.5	17.0	17.7	18.5	7.9	6.2	7.0	7.8	8.8
AMI+AMR_GO	48.6	14.4	16.4	17.1	17.9	7.9	6.4	7.1	7.9	8.9
Full AMR	52.8	12.2	4.4	4.7	5.5	6.3	7.9	7.8	8.9	10.2

6.1.1. Forecast of New Meters

In Table 10 and Table 11, the cost of new meter capital for each alternative is a function of the Companies' forecast of new meters and the meter replacement cost. Table 12 shows the forecast of total in-scope meters over next 30 years. The forecast was developed based on the Companies' customer forecasts. Total meters are expected to grow by 0.3% to 0.5% per year during the 30-year analysis period. The forecast of total customers and meters is the same for each alternative, but the timing and need for new meters varies with each alternative.

Table 12: In-Scope Meter Forecast

Year	Electric	Gas	Total
2021	996,000	339,000	1,335,000
2022	1,001,000	340,000	1,341,000
2023	1,004,000	341,000	1,345,000
2024	1,009,000	342,000	1,351,000
2025	1,013,000	344,000	1,357,000
2026	1,018,000	345,000	1,363,000
2027	1,022,000	347,000	1,369,000
2028	1,027,000	348,000	1,375,000
2029	1,031,000	349,000	1,380,000
2030	1,036,000	350,000	1,386,000
2031	1,040,000	351,000	1,391,000
2032	1,045,000	352,000	1,397,000
2033	1,050,000	354,000	1,404,000
2034	1,055,000	355,000	1,410,000
2035	1,059,000	356,000	1,415,000
2036	1,063,000	357,000	1,420,000
2037	1,068,000	358,000	1,426,000
2038	1,072,000	360,000	1,432,000
2039	1,076,000	361,000	1,437,000
2040	1,080,000	362,000	1,442,000
2041	1,085,000	363,000	1,448,000
2042	1,088,000	364,000	1,452,000
2043	1,092,000	366,000	1,458,000
2044	1,095,000	367,000	1,462,000
2045	1,098,000	368,000	1,466,000
2046	1,101,000	369,000	1,470,000
2047	1,104,000	370,000	1,474,000
2048	1,106,000	372,000	1,478,000
2049	1,109,000	373,000	1,482,000
2050	1,112,000	374,000	1,486,000

As discussed in Section 3, while the Companies' 2019 Meter Life Study and outside report support a 20-year operating life for electronic, AMI, and AMR meters, the Companies' existing AMI meters have a 15-year depreciation life. At least in part, the depreciation life is shorter to reflect some likelihood that the meters will be proactively replaced before the end of their operating life. A similar assumption is made for the depreciation life of electromechanical and electronic meters, which are depreciated in one asset group. Based on the Companies' analysis, the weighted average operating life of these meters is 39.5 years but the depreciation life is 32 years.[19] For these reasons, the Companies evaluated two meter

[19] Approximately 75% and 25% of existing meters, respectively, are electromechanical and electronic meters. The weighted average operating life for all meters (39.5 years) = 75% * 46 years + 25% * 20 years.

operating life scenarios: one based on the 2019 Meter Life Study and a shorter meter operating life scenario ("proactive replacement") where meters that haven't failed by a certain age are assumed to be replaced proactively (i.e., after 16 years for AMI and electronic meters and after 45 years for electromechanical meters). This assumption causes the average operating life to equal the depreciation life. With an average operating life of 15 to 20 years for electronic, AMI, and AMR meters, the analysis evaluates more than one meter replacement cycle over the 30-year analysis period.

Table 13 contains the forecasted need for new meters in the proactive replacement meter operating life scenario. The forecast for new meters in the Status Quo was developed by applying the meter failure curves from the meter failure analysis to the existing electromechanical and electronic meter populations. Electronic meters that haven't failed after 16 years of life are assumed to be proactively replaced; electromechanical meters are assumed to be proactively replaced after 45 years if they haven't failed already. In the AMI and AMR alternatives, all in-scope meters are replaced by the end of the 42-month meter deployment period. After the meter deployment period, the need for new meters is driven by customer growth and meter failures. Meter failures were developed by applying the meter failure curve for electronic meters to the newly installed AMI and AMR meters. The significant uptick from 2038 to 2041 results from proactively replacing meters installed in the initial meter deployment period that have not failed after 16 years. In all alternatives, when a meter in the starting meter population is replaced, the failure of the replacement meter is modeled by applying the electronic meter failure curve to that meter.

Table 13: Forecast of New Meters (Proactive Replacement Operating Life Scenario; AMR Remains Viable for 30-Year Analysis Period)

	SQ	Full AMI			AMI+AMR_GO				Full AMR		
Year	Electronic Meters	Electronic Meters	AMI Meters	Gas Modules	Electronic Meters	AMI Meters	Gas Modules	Gas ERTs[20]	Electronic Meters	AMR Meters	Gas ERTs
2021	47,000	22,000	4,000	0	22,000	4,000	0	0	22,000	4,000	0
2022	44,000	12,000	113,000	33,000	12,000	113,000	31,000	1,100	12,000	109,000	32,000
2023	46,000	6,000	273,000	98,000	6,000	273,000	93,000	3,300	6,000	263,000	93,000
2024	47,000	0	284,000	98,000	0	284,000	93,000	3,300	0	274,000	93,000
2025	52,000	0	293,000	98,000	0	293,000	93,000	3,300	0	284,000	93,000
2026	53,000	0	48,000	18,000	0	48,000	17,000	1,600	0	46,000	17,000
2027	48,000	0	15,000	5,000	0	15,000	4,000	1,000	0	15,000	4,000
2028	59,000	0	16,000	4,000	0	16,000	4,000	1,000	0	16,000	4,000
2029	53,000	0	17,000	4,000	0	17,000	4,000	1,000	0	17,000	5,000
2030	69,000	0	18,000	4,000	0	18,000	4,000	1,000	0	18,000	5,000
2031	65,000	0	20,000	4,000	0	20,000	4,000	1,000	0	20,000	6,000
2032	68,000	0	21,000	4,000	0	21,000	4,000	1,000	0	21,000	6,000
2033	62,000	0	23,000	4,000	0	23,000	4,000	1,000	0	23,000	7,000
2034	63,000	0	25,000	4,000	0	25,000	4,000	1,000	0	25,000	8,000
2035	50,000	0	28,000	4,000	0	28,000	4,000	1,000	0	28,000	9,000
2036	72,000	0	31,000	4,000	0	31,000	4,000	1,000	0	31,000	10,000
2037	73,000	0	38,000	4,000	0	38,000	4,000	1,000	0	38,000	11,000
2038	65,000	0	126,000	4,000	0	126,000	4,000	1,000	0	126,000	39,000
2039	67,000	0	251,000	4,000	0	251,000	4,000	1,000	0	251,000	89,000
2040	70,000	0	253,000	5,000	0	253,000	4,000	1,000	0	253,000	87,000
2041	73,000	0	253,000	5,000	0	253,000	4,000	1,000	0	253,000	84,000
2042	75,000	0	54,000	35,000	0	54,000	33,000	1,000	0	54,000	20,000
2043	70,000	0	21,000	93,000	0	21,000	88,000	1,000	0	21,000	7,000
2044	80,000	0	22,000	94,000	0	22,000	89,000	1,000	0	22,000	7,000
2045	74,000	0	24,000	94,000	0	24,000	89,000	1,000	0	24,000	8,000
2046	89,000	0	26,000	22,000	0	26,000	21,000	1,000	0	26,000	9,000
2047	80,000	0	28,000	7,000	0	28,000	7,000	1,000	0	28,000	10,000
2048	84,000	0	31,000	7,000	0	31,000	7,000	1,000	0	31,000	11,000
2049	77,000	0	35,000	7,000	0	35,000	7,000	1,000	0	35,000	12,000
2050	76,000	0	39,000	7,000	0	39,000	7,000	1,000	0	39,000	14,000

The financial analysis includes the cost of meter inventories but the meter counts in Table 13 do not include meters purchased for inventory. The Companies plan to carry approximately 1% of total electric meters and 2% of total gas meters in inventory. New meters in the Status Quo and AMR alternatives carry a three-year warranty. Therefore, when a new meter fails in the first three years of its life, the cost of the replacement meter is paid by the Companies' meter vendor and the Companies incur only the cost of labor to replace the meter. The negotiated warranty in the Full AMI and AMI+AMR_GO alternatives is

[20] The Companies plan to redeploy existing gas ERTs from the electric service territory to the gas-only service territory in the AMI+AMR_GO alternative, so no additional ERT capital is needed during deployment.

5 years. The negotiated warranty of the gas modules in the AMI alternatives is 20 years with declining warranty coverage as the module ages. Gas ERTs are assumed to fail ratably throughout the analysis period after the initial meter deployment period. The analysis assumes 50% of existing ERTs will be replaced during the meter deployment period due to battery life.

The need for electronic meters in the AMI and AMR alternatives declines sharply as new meters are deployed and occurs in portions of the service territory slated to receive new meters in the latter part of meter deployment period where the mesh network has not yet been installed. Compared to the Status Quo alternative, total electric meter replacements in the AMI and AMR alternatives are lower in the years following the meter deployment period because the average failure rate for the new population of meters is low.

Table 14 compares total meter replacements in the proactive replacement operating life scenario to total meter replacements with no proactive replacement. If meters are not proactively replaced, the average meter operating life for electronic, AMI, and AMR meters increase from 15 to 20 years, and the average meter operating life for electromechanical meters increases from 37 to 46 years. Unsurprisingly, total meter replacements over the 30-year analysis period are lower for all alternatives if meters are not proactively replaced. In the Status Quo, the impact of proactively replacing meters is greatest during the first 15 years of the analysis period as aging electromechanical meters are replaced faster than they otherwise would be replaced.

Table 14: Meter Replacement Comparison (AMR Remains Viable for 30-year Analysis Period)

Year	SQ		Full AMI / AMI+AMR_GO		Full AMR	
	Proactive Replacement	No Proactive Replacement	Proactive Replacement	No Proactive Replacement	Proactive Replacement	No Proactive Replacement
2021	47,000	25,000	26,000	13,000	26,000	13,000
2022	44,000	26,000	125,000	109,000	121,000	106,000
2023	46,000	27,000	279,000	271,000	269,000	260,000
2024	47,000	29,000	284,000	288,000	274,000	278,000
2025	52,000	30,000	293,000	305,000	284,000	295,000
2026	53,000	31,000	48,000	50,000	46,000	48,000
2027	48,000	32,000	15,000	15,000	15,000	15,000
2028	59,000	34,000	16,000	16,000	16,000	16,000
2029	53,000	35,000	17,000	17,000	17,000	17,000
2030	69,000	37,000	18,000	18,000	18,000	18,000
2031	65,000	37,000	20,000	20,000	20,000	20,000
2032	68,000	39,000	21,000	21,000	21,000	21,000
2033	62,000	40,000	23,000	23,000	23,000	23,000
2034	63,000	41,000	25,000	25,000	25,000	25,000
2035	50,000	42,000	28,000	27,000	28,000	27,000
2036	72,000	42,000	31,000	31,000	31,000	31,000
2037	73,000	43,000	38,000	35,000	38,000	35,000
2038	65,000	44,000	126,000	39,000	126,000	39,000
2039	67,000	45,000	251,000	45,000	251,000	45,000
2040	70,000	46,000	253,000	51,000	253,000	51,000
2041	73,000	47,000	253,000	57,000	253,000	57,000
2042	75,000	48,000	54,000	63,000	54,000	63,000
2043	70,000	47,000	21,000	69,000	21,000	69,000
2044	80,000	49,000	22,000	76,000	22,000	76,000
2045	74,000	47,000	24,000	82,000	24,000	82,000
2046	89,000	48,000	26,000	86,000	26,000	86,000
2047	80,000	50,000	28,000	89,000	28,000	89,000
2048	84,000	51,000	31,000	90,000	31,000	90,000
2049	77,000	52,000	35,000	87,000	35,000	87,000
2050	76,000	51,000	39,000	85,000	39,000	85,000

6.1.2. Meter Replacement Cost

Table 15 contains the weighted average meter replacement cost for each metering alternative. The cost of replacing a meter includes the cost of the meter and the cost of labor required to install the meter. Meter costs are based on the results of a recent RFP. The cost of labor is based on the Companies' current meter replacement costs and is assumed to grow at 3% per year in all alternatives. Table 15 contains the weighted average meter cost for each metering alternative because the cost per meter varies depending on the type of service for which consumption is measured. For example, the cost of an AMI meter is less

CONFIDENTIAL INFORMATION REDACTED

for a residential customer than for a Power Service Primary customer because the residential meter requires fewer components to register the consumption of electricity.

Table 15: Replacement Meter Costs (2021 Dollars)[21]

	Status Quo	Full AMI / AMI+AMR_GO	Full AMR
Weighted Average Electric Meter Cost	[redacted]		
Installation Labor Cost	42.88	42.88	42.88
Total Meter Replacement Cost	[redacted]		
Weighted Average Gas AMI Module Cost	N/A	[redacted]	N/A
Installation Labor Cost	N/A		N/A
Total Module Replacement Cost	N/A		N/A
Gas ERT	[redacted]		
Installation Labor Cost			
Total Replacement Cost			

The costs in Table 15 do not reflect any discounts that will be realized during the meter deployment period for the AMI and AMR alternatives. In the AMI alternatives, the weighted average meter cost will be approximately [redacted]% lower for all meters replaced during the meter deployment period due to negotiated discounts for the volume of meters purchased as part of the coordinated project. The same [redacted]% discount is assumed for the Full AMR alternative. The cost of labor for installing an electric meter during the coordinated meter replacement project is [redacted]% lower ($[redacted]/meter). This decrease reflects the increased economies of scale associated with this project but is not applicable to all meters replaced during the 42-month period. For example, if a new home is constructed in a neighborhood after existing meters are replaced, the meter is assumed to be replaced at the normal labor cost.

Table 16 summarizes the Companies' weighted average meter cost from their last three RFPs. The cost declined by 1.2% per year from 2012 to 2015 but increased by 2.6% per year from 2015 to 2020. From 2012 to 2020, meter costs escalated at 1.1% per year.

Table 16: Historical Meter Costs

Year RFP Issued	Weighted Average Electric Meter Cost
2012	[redacted]
2015	
2020	

As discussed in Section 4.3 and summarized in Appendix B – Metering RFI Summary, the Companies issued an RFI to gather information regarding the future availability and pricing for various meter types. Table

[21] Multiple models of meters exist within each form, depending upon whether the meter simply registers energy or requires additional functionality such as registering demand or time-of-use energy. Meter costs reflect a weighted average of costs based on the Companies' meter population.

CONFIDENTIAL INFORMATION REDACTED

17 summarizes the responses that were received regarding future meter pricing. For non-communicating electronic and AMI meters, two of three respondents said future prices would be flat or stable. No respondents said future AMI meter costs would increase. For AMR meters, two of three respondents said future prices would increase as industry support for the technology wanes.

Table 17: Meter Cost Escalation Assumptions from RFI

Respondent	Non-Communicating Electronic	AMR	AMI
[redacted]			

Based on the similar responses for non-communicating electronic and AMI meters, the Companies assumed non-communicating electronic and AMI meters would escalate at the same rate. Both meter types have the same meter platform. The only difference is that AMI meters have 2-way communications and the ability to remotely connect and disconnect service. The Companies evaluated a range of meter cost escalation from 0% to 1% with base value of 0.25%. The low end of the range is based on the RFI results. The high end of the range is the observed escalation rate over the last 3 RFP results. The base value is weighted toward RFI results and is arguably high for AMI meters and low for electronic meters. The same assumptions were used for gas AMI modules.

AMR meters have the same meter platform as AMI meters but industry support for 1-way communications is waning. As a result, Companies assumed the cost of AMR meters would escalate at the general rate of inflation, which is assumed to be 2% per year. The same escalation rate was used in all alternatives for AMR ERTs.

6.2. Non-Meter Deployment & On-Going Costs

Figure 13 provides an overview of AMI systems and the RF mesh network. The mesh network consists of multiple routers and collectors. For a given area, the need for routers and collectors depends on the topography and density of customers in that area. When an electric meter or gas module is installed, it immediately begins securely communicating via other electric meters and the mesh network with corporate IT systems.[23] Employees in the Meter Operations Center monitor the operation of the network and meters to ensure communication channels stay open, ensure meter data is delivered to the appropriate corporate IT systems, and develop processes for handling meter alarms (e.g., high

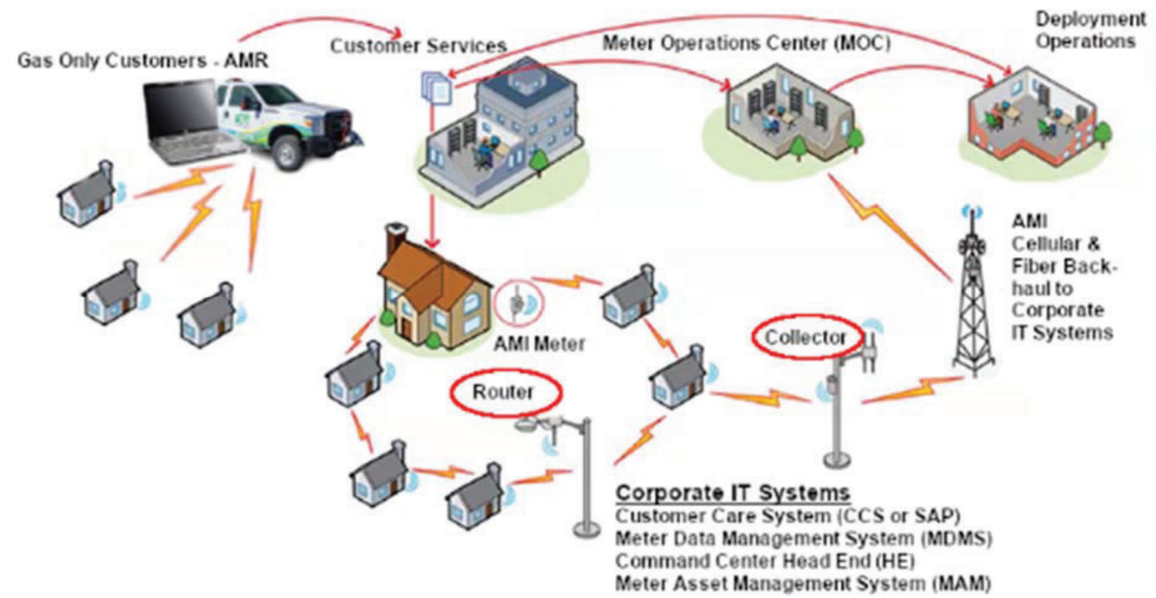
---

[22] [redacted] stated for all meter types that "We strive to meet a 2.5% per year cost reduction to counter CPI increase as a goal in an effort to minimize the increase in cost of our product." The Companies are defining this to mean prices will be stable.

[23] Routers transmit data from multiple electric meters and gas modules to a collector and collectors transmit data from multiple routers and electric meters to corporate IT systems.

temperature or meter tampering alarms). Network deployment must lead AMI meter deployment so that the meters can communicate properly when they are first installed.

Figure 13: AMI Systems and Network Overview



Metered interval data is stored in the MDMS and must be integrated with corporate IT systems to bill customers and remotely provide some field services. AMI systems must also be integrated with existing EDO systems to implement CVR and improve outage restoration. In the AMI alternatives, the three functionality releases that enable customer benefits are the enhanced MDMS, Remote Service Switch, and EDO integration implementations. The timing of meter reading and field services cost savings is tied to availability of systems functionality in the Meter Data Management System ("MDMS") and the Remote Service Switch, respectively. The timing of EDO savings and CVR fuel savings is tied to the integration of AMI and EDO IT systems.

Table 18 contains non-meter deployment and on-going costs for each alternative. In the Status Quo and AMR alternatives, this includes a routine upgrade to the Meter Asset Management ("MAM") system every 6 years, with a cost of $2.5 million in 2023. In the AMI alternatives, the 2023 upgrade is embedded in the overall project scope, but all future upgrades are considered as part of the on-going costs. For the AMI alternatives, the cost of systems is the same and differences in network costs pertain to the gas-only service territory. For the Full AMR alternative, in addition to the MAM upgrades, the cost of systems includes enhancements that are needed for existing systems to support additional AMR data. Program management and change management costs consist of activity and resource coordination as well as training development and delivery. Communications costs include the costs of mail campaigns and other items to inform customers about the timing of upcoming meter replacements and educate them on accessing data if applicable. The project includes 17.5% contingency on systems capital, and 5% contingency on network and meter capital. The total contingency for the Full AMI and AMI+AMR_GO alternatives is $22.5 million and $22.3 million, respectively, which equates to 7% contingency on the sum of meter and non-meter deployment costs. The total contingency for Full AMR is $8.1 million, which equates to 5% contingency on the total project.

Table 18: Non-Meter Deployment & On-Going Costs ($M, Capital and O&M, Proactive Replacement Operating Life)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Status Quo										
Systems	0.0	0.0	2.5	0.0	0.0	0.0	0.0	0.0	3.0	0.0
Full AMI										
Systems	9.8	18.8	20.2	14.2	4.3	3.0	4.1	3.7	6.8	3.9
Network	0.0	4.2	5.4	5.8	2.5	0.6	0.6	0.8	0.9	0.9
Program Management	3.2	9.5	6.1	5.5	2.5	0.4	0.0	0.0	0.0	0.0
Change Management	0.8	4.1	4.5	2.7	0.4	0.1	0.0	0.0	0.0	0.0
Communications	0.0	0.6	1.3	1.3	1.8	0.2	0.0	0.0	0.0	0.0
Contingency	2.1	5.1	6.4	5.4	3.1	0.4	0.0	0.0	0.0	0.0
Total	15.9	42.2	43.8	34.9	14.5	4.6	4.7	4.5	7.7	4.8
AMI+AMR_GO										
Systems	9.8	18.8	20.2	14.2	4.3	3.0	4.1	3.7	6.8	3.9
Network	0.0	3.7	4.9	5.2	2.2	0.4	0.5	0.7	0.8	0.8
Program Management	3.2	9.5	6.1	5.5	2.5	0.4	0.0	0.0	0.0	0.0
Change Management	0.8	4.1	4.5	2.7	0.4	0.1	0.0	0.0	0.0	0.0
Communications	0.0	0.6	1.3	1.3	1.8	0.2	0.0	0.0	0.0	0.0
Contingency	2.1	5.1	6.3	5.4	3.0	0.4	0.0	0.0	0.0	0.0
Total	15.9	41.7	43.2	34.3	14.2	4.5	4.6	4.4	7.5	4.7
Full AMR										
Systems	1.1	1.5	2.5	0.0	0.0	0.0	0.0	0.0	3.0	0.0
Network	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Management	2.4	7.6	3.6	3.5	2.5	0.4	0.0	0.0	0.0	0.0
Change Management	0.5	1.9	1.9	1.9	0.6	0.1	0.0	0.0	0.0	0.0
Communications	0.0	0.5	1.1	1.2	1.8	0.2	0.0	0.0	0.0	0.0
Contingency	0.5	1.6	1.9	1.9	1.8	0.3	0.0	0.0	0.0	0.0
Total	4.6	13.2	11.1	8.5	6.8	1.0	0.0	0.0	3.0	0.0

After AMI is fully deployed in 2026, the Companies will upgrade the MDMS and replace storage hardware associated with the MDMS and other systems every six years. Ongoing network costs include labor and equipment replacement costs, the cost to upgrade backhaul hardware every six years, and annual maintenance on network equipment. For the Full AMI alternative, on-going network costs also include the cost of cellular service for network assets in the gas-only service territory.

Table 19 summarizes non-meter deployment and on-going costs under the two AMR obsolescence scenarios for 2031 to 2050. In the scenario where AMR remains viable for the entire analysis period, the costs in Table 19 simply include on-going systems and network costs. To model the impact of AMR obsolescence, the Companies assumed AMR becomes obsolete by the end of 2035. The costs for this scenario in the Status Quo reflect the cost of expanding the mesh network throughout the gas-only service territory. For the AMI+AMR_GO and Full AMI alternatives, the costs for this scenario reflect the non-meter costs associated with transitioning fully to AMI. This transition is straight-forward for the AMI+AMR_GO alternative but very costly for Full AMR alternative.

Table 19: Non-Meter Deployment Costs & On-Going Systems and Network Costs ($M, Capital and O&M, Proactive Replacement Operating Life)

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	0.0	0.6	0.7	0.8	3.9	0.2	0.2	0.2	0.2	0.2
Full AMI	4.7	4.2	5.4	5.1	8.8	5.4	5.3	4.8	6.2	5.8
AMI+AMR_GO	4.6	4.6	5.9	5.7	9.0	5.4	5.3	4.8	6.2	5.8
Full AMR	20.4	53.4	55.1	43.7	21.7	5.9	5.9	5.7	9.7	6.0
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	0.0	0.0	0.0	0.0	3.6	0.0	0.0	0.0	0.0	0.0
Full AMI	4.7	4.2	5.4	5.1	8.8	5.4	5.3	4.8	6.2	5.8
AMI+AMR_GO	4.6	4.0	5.3	5.0	8.7	5.2	5.2	4.6	6.0	5.6
Full AMR	0.0	0.0	0.0	0.0	3.6	0.0	0.0	0.0	0.0	0.0
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	4.5	0.2	0.2	0.2	0.2	0.2	5.3	0.2	0.2	0.2
Full AMI	10.2	6.1	6.1	5.5	7.1	6.6	11.9	6.9	6.9	6.4
AMI+AMR_GO	10.2	6.1	6.1	5.5	7.1	6.6	11.9	6.9	6.9	6.4
Full AMR	10.2	5.3	6.8	6.4	11.1	6.8	11.8	6.0	7.8	7.3
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	4.3	0.0	0.0	0.0	0.0	0.0	5.1	0.0	0.0	0.0
Full AMI	10.2	6.1	6.1	5.5	7.1	6.6	11.9	6.9	6.9	6.4
AMI+AMR_GO	10.0	5.9	5.9	5.3	6.9	6.4	11.7	6.7	6.7	6.2
Full AMR	4.3	0.0	0.0	0.0	0.0	0.0	5.1	0.0	0.0	0.0

6.3. Meter Reading Costs

The primary function of meter reading is to perform manual meter reads and meter safety inspections. Most meter reads are entered manually into handheld devices, but a portion are obtained by vehicle using mobile collectors for AMR-enabled meters. The Meter Reading group is also responsible for the management of keys or coordination with customers to obtain access to approximately 27,000 meters located inside customers' premises. Table 20 summarizes meter reading costs for each of the four alternatives over the next 10 years.

Table 20: Meter Reading and Inspections Costs ($M, O&M, No Opt Out, Proactive Replacement Operating Life)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Status Quo	18.6	19.0	19.5	20.1	20.7	21.3	21.9	22.6	23.2	23.9
Full AMI	18.6	18.3	16.3	11.3	6.6	1.2	0.4	0.4	0.5	0.5
AMI+AMR_GO	18.6	18.3	16.4	11.3	6.7	1.3	0.5	0.5	0.5	0.6
Full AMR	18.6	18.4	16.6	12.2	8.0	5.5	5.3	5.4	5.6	5.7

In the AMI and AMR alternatives, the costs of manual monthly reads are phased out as AMI meters are deployed, and meter safety inspections are eventually replaced at a much smaller cost of approximately $300k/year as part of line inspections already performed by Electric Distribution Operations.[24] In the AMI alternatives, meter reading is a fully automated process with no incremental operating costs, while in the AMR alternative, monthly meter reads are transitioned from a pedestrian-based process to a vehicle-based process. While customers will be given the option to opt out of AMI, the costs in Table 20 were developed with the assumption that no customers opt-out. If any customers choose to opt-out, incremental meter reading costs associated with this group will be recovered through an opt-out fee.

Meter reading costs are primarily based on third party contracts executed with meter reading vendors in 2019. At that time, the cost per read increased by 56%, with future annual cost escalations capped at 2.5% until the end of the contract in 2024. Over the full analysis period, the cost per read is assumed to escalate between 2% per year (the general rate of inflation) and 3% per year (the Companies' assumed escalation rate for labor costs), with a base escalation of 2.5%. These costs are also growing as a function of the growth in total meters. As shown in Table 12, total meters are expected to grow by 0.3% to 0.5% per year during the 30-year analysis period.

Table 21 summarizes meter reading and inspections costs under the two AMR obsolescence scenarios for 2031 to 2050. To model the impact of AMR obsolescence, the Companies assumed AMR becomes obsolete by the end of 2035. In this scenario, after AMR meters and gas ERTs are replaced with AMI meters and gas modules, Status Quo meter reading costs are incrementally lower due to the ability to read the meters remotely. In the AMI+AMR_GO and Full AMR alternatives, meter reading and inspection costs are aligned with the Full AMI alternative by 2036 after the transition to AMI is complete.

[24] The Companies are requesting a waiver of these meter inspections due to AMI's enhanced meter monitoring capabilities, but the analysis includes this annual cost.

Table 21: Meter Reading and Inspections Costs ($M, O&M, No Opt Out, Proactive Replacement Operating Life)

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	24.6	25.3	25.9	26.6	27.3	28.0	28.8	29.6	30.5	31.4
Full AMI	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6
AMI+AMR_GO	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.6
Full AMR	5.9	5.9	5.7	5.4	4.9	1.2	0.6	0.6	0.6	0.6
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	24.6	25.3	26.1	26.8	27.6	28.4	29.2	30.1	31.0	31.8
Full AMI	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6
AMI+AMR_GO	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
Full AMR	5.9	6.0	6.2	6.4	6.6	6.7	6.9	7.1	7.3	7.5
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	32.3	33.2	34.2	35.1	36.1	37.2	38.2	39.3	40.4	41.5
Full AMI	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8	0.8
AMI+AMR_GO	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8	0.8
Full AMR	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8	0.8
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	32.8	33.7	34.7	35.6	36.7	37.7	38.7	39.8	40.9	42.1
Full AMI	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8	0.8
AMI+AMR_GO	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9
Full AMR	7.7	8.0	8.2	8.4	8.6	8.9	9.1	9.4	9.7	9.9

6.4. Field Services Costs

The primary function of field services is to complete customer requested orders, such as move-outs and move-ins, off-cycle meter reads and service disconnects/reconnects related to non-payment. Table 22 summarizes field service costs associated with this project for each of the four alternatives.

Table 22: Field Services Costs ($M, O&M, No Opt Out, Proactive Replacement Operating Life)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Status Quo	14.3	14.7	15.1	15.6	16.1	16.5	17.0	17.5	18.0	18.5
Full AMI	14.3	14.7	15.1	10.8	10.1	10.0	10.2	10.5	10.8	11.1
AMI+AMR_GO	14.3	14.7	15.1	10.8	10.1	10.0	10.2	10.5	10.8	11.1
Full AMR	14.3	14.7	15.1	15.6	16.1	16.5	17.0	17.5	18.0	18.5

Costs related to off-cycle reads and service disconnects/reconnects are unchanged in the SQ and AMR alternatives. In the AMI alternatives, these costs are reduced as remote off-cycle reads and remote disconnect/reconnect capabilities are enabled. While these costs are greatly reduced in the AMI alternatives, some level of field services must be retained to complete work that cannot be performed remotely. Like meter reading costs, field services costs were developed with the assumption that no customers choose to opt out of AMI. The timing of field services cost savings is tied to the availability of the Remote Service Switch systems functionality.

A significant portion of field services costs are based on contracts executed with field services vendors in 2019. At that time, the costs increased by 22%, with future annual cost escalations capped at 2.5% until the end of the contract in 2024. Contractor field services are assumed to escalate between 2% per year (the general rate of inflation) and 3% per year (the Companies' assumed escalation rate for labor costs) during the full analysis period, with a base escalation of 2.5%. These costs are also growing as a function of the growth in total meters. As shown in Table 12, total meters are expected to grow by 0.3% to 0.5% per year during the 30-year analysis period.

Table 23 summarizes field services costs under the two AMR obsolescence scenarios for 2031 to 2050. To model the impact of AMR obsolescence, the Companies assumed AMR becomes obsolete by the end of 2035. AMR obsolescence has no impact on field services costs in the Status Quo. In the AMI+AMR_GO and Full AMR alternatives, field services costs are aligned with the Full AMI alternative by 2036 after the transition to AMI is complete.

Table 23: Field Services Costs ($M, No Opt Out, O&M, Proactive Replacement Operating Life)

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	19.1	19.6	20.2	20.8	21.4	22.0	22.6	23.2	23.9	24.6
Full AMI	11.5	11.8	12.1	12.5	12.8	13.2	13.6	13.9	14.3	14.7
AMI+AMR_GO	11.5	11.8	12.1	12.5	12.8	13.2	13.6	13.9	14.3	14.7
Full AMR	19.1	19.6	20.2	14.5	13.7	13.2	13.6	13.9	14.3	14.7
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	19.1	19.6	20.2	20.8	21.4	22.0	22.6	23.2	23.9	24.6
Full AMI	11.5	11.8	12.1	12.5	12.8	13.2	13.6	13.9	14.3	14.7
AMI+AMR_GO	11.5	11.8	12.1	12.5	12.8	13.2	13.6	13.9	14.3	14.7
Full AMR	19.1	19.6	20.2	20.8	21.4	22.0	22.6	23.2	23.9	24.6
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	25.3	26.0	26.7	27.5	28.3	29.1	29.9	30.7	31.6	32.4
Full AMI	15.2	15.6	16.0	16.5	17.0	17.4	17.9	18.4	19.0	19.5
AMI+AMR_GO	15.2	15.6	16.0	16.5	17.0	17.4	17.9	18.4	19.0	19.5
Full AMR	15.2	15.6	16.0	16.5	17.0	17.4	17.9	18.4	19.0	19.5
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	25.3	26.0	26.7	27.5	28.3	29.1	29.9	30.7	31.6	32.4
Full AMI	15.2	15.6	16.0	16.5	17.0	17.4	17.9	18.4	19.0	19.5
AMI+AMR_GO	15.2	15.6	16.0	16.5	17.0	17.4	17.9	18.4	19.0	19.5
Full AMR	25.3	26.0	26.7	27.5	28.3	29.1	29.9	30.7	31.6	32.4

6.5. Electric Distribution Operations

The Electric Distribution Operations ("EDO") group is responsible for providing safe, reliable, and low-cost operations of the electric distribution system. Some aspects of EDO operations will be impacted by AMI. For example, to reliably accommodate growth in customer-owned generation and electric vehicles, additional voltage sensing and regulating equipment will be needed along selected distribution circuits to more precisely control voltage along these circuits and prevent voltage excursions. AMI will enable the Companies to avoid the cost of these voltage sensors. In addition, AMI will enable the Companies to improve the efficiency of some of its EDO operations. Table 24 summarizes EDO costs for each metering alternative. These costs do not include the full scope of EDO's budget; EDO capital savings are computed as differences from the status quo and are related to the avoided need for voltage sensors. EDO O&M savings are computed as differences from the Status Quo and pertain to improved management of in-service assets like overloaded transformers, improved sustained outage characterization and location on circuits not outfitted from the Distribution Automation efforts, and avoided costs associated with investigation of outage reports where the service is found to be ok on arrival. The timing of EDO O&M savings is tied to the integration of AMI and EDO systems.

Table 24: EDO Costs Affected by AMI Deployment ($M, Capital and O&M, Proactive Replacement Operating Life)

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Status Quo / Full AMR										
Voltage Sensors	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8
Total	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8
Full AMI / AMI+AMR_GO										
Voltage Sensors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EDO O&M Savings	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.2	-0.2	-0.2	-0.3
Total	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.2	-0.2	-0.2	-0.3

Table 25 summarizes EDO costs under the two AMR obsolescence scenarios for 2031 to 2050. To model the impact of AMR obsolescence, the Companies assumed AMR becomes obsolete by the end of 2035. AMR obsolescence has no impact on EDO costs in the Status Quo, Full AMI, or AMI+AMR_GO alternatives. In the Full AMR alternative, EDO costs are aligned with the Full AMI alternative by 2036 after the transition to AMI is complete.

Table 25: EDO Costs Affected by AMI Deployment ($M, Capital and O&M, Proactive Replacement Operating Life)

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	1.9	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Full AMI	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
AMI+AMR_GO	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
Full AMR	1.9	0.0	0.0	0.0	-0.2	-0.3	-0.3	-0.3	-0.3	-0.3
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	1.9	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Full AMI	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
AMI+AMR_GO	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
Full AMR	1.9	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Full AMI	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.5
AMI+AMR_GO	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.5
Full AMR	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.5
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Full AMI	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.5
AMI+AMR_GO	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.5
Full AMR	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2

6.6. Fuel Savings

As discussed previously, the Companies will need to be able to more precisely control voltage across a circuit to reliably accommodate continued growth in distributed generation and the number of electric vehicles. With voltage data for all customers, AMI will not only enable that control and avoid the need for additional voltage sensors but also incrementally enable the Companies to implement Conservation Voltage Reduction ("CVR"). CVR uses AMI data and more precise voltage controls to incrementally reduce grid voltage such that energy requirements are lowered. CVR cannot be reliably implemented without AMI data.

The Companies estimated the energy savings potential from CVR using voltage data from the AMS Opt-in program. The analysis focused on distribution circuits having the highest saturation of AMS Opt-in customers with meters recording voltage.[25] The analysis estimated the CVR energy savings potential over a range of voltage control thresholds (e.g., 116 to 118 volts). Based on this analysis, the Companies

[25] A summary of the CVR Potential Study is included as Appendix D – CVR Potential Study.

evaluated CVR-related energy savings ranging from 145 GWh to 270 GWh with a base value of 205 GWh. This range is 0.5% to 0.9% of total energy requirements and is consistent with other utilities' experience.

Many AMS Opt-in customers have used their interval data to gain a better understanding of their usage and have taken actions as a result to reduce their electricity consumption. Tetra Tech completed a study in 2020 to estimate incremental energy savings for AMS Opt-in customers resulting from their access to interval data through the ePortal. Tetra Tech determined that AMS Opt-In customers had 1.4% to 1.7% lower energy consumption than customers who requested an AMI meter but hadn't received one due to the limited number of meters available through the AMS Opt-in program.[26] Because the AMS Opt-in program is an opt-in program, it is difficult to extrapolate energy savings to the broader population of all customers. Therefore, the Companies have evaluated this benefit very conservatively using a range of energy savings from 0.0% to 0.70% (i.e., half of the lower level of energy savings reported by Tetra Tech for AMS Opt-in customers) with a base value of 0.35%.

These energy savings reduce the Companies' fuel expense. To compute this savings, the Companies multiplied the energy savings by its marginal cost of energy. Table 26 contains total fuel savings based on mid fuel prices from the Companies' 2021 Business Plan. As a sensitivity, the Companies also evaluated low and high fuel price scenarios for marginal fuel costs. Both categories of energy savings are phased in gradually. CVR savings don't begin until EDO integration and then are phased in gradually based on planned addition of more precise voltage controls. ePortal savings are modeled as a function of the number of AMI meters deployed.

Table 26: Fuel Savings ($M, O&M, Proactive Replacement Operating Life)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Full AMI / AMI+AMR_GO										
CVR Savings	0.0	0.0	0.0	0.0	0.0	-0.9	-1.7	-2.6	-3.6	-4.5
ePortal Savings	0.0	-0.1	-0.3	-0.7	-1.0	-1.3	-1.3	-1.3	-1.3	-1.3
Total	0.0	-0.1	-0.3	-0.7	-1.0	-2.1	-3.1	-4.0	-4.9	-5.8

Table 27 summarizes fuel savings under the two AMR obsolescence scenarios for 2031 to 2050. To model the impact of AMR obsolescence, the Companies assumed AMR becomes obsolete by the end of 2035. AMR obsolescence has no impact on fuel savings in the Full AMI or AMI+AMR_GO alternatives. In the Full AMR alternative, fuel savings are aligned with the Full AMI alternative by 2040 after the transition to AMI is complete and CVR is fully implemented.

[26] A summary of the Tetra Tech study is included as Appendix E – Tetra Tech AMS Opt-In Study.

Table 27: Fuel Savings ($M, O&M, Proactive Replacement Operating Life)

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	AMR becomes Obsolete Midway through Analysis Period									
Full AMI	-6.0	-6.1	-6.3	-6.1	-6.3	-6.4	-6.1	-6.0	-6.0	-6.2
AMI+AMR_GO	-6.0	-6.1	-6.3	-6.1	-6.3	-6.4	-6.1	-6.0	-6.0	-6.2
Full AMR	0.0	-0.1	-0.4	-0.7	-1.2	-2.5	-3.3	-4.2	-5.1	-6.2
	AMR Remains Viable for 30-Year Analysis Period									
Full AMI	-6.0	-6.1	-6.3	-6.1	-6.3	-6.4	-6.1	-6.0	-6.0	-6.2
AMI+AMR_GO	-6.0	-6.1	-6.3	-6.1	-6.3	-6.4	-6.1	-6.0	-6.0	-6.2
Full AMR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
	AMR becomes Obsolete Midway through Analysis Period									
Full AMI	-6.2	-6.3	-6.4	-6.5	-6.7	-6.8	-6.9	-7.1	-7.2	-7.3
AMI+AMR_GO	-6.2	-6.3	-6.4	-6.5	-6.7	-6.8	-6.9	-7.1	-7.2	-7.3
Full AMR	-6.2	-6.3	-6.4	-6.5	-6.7	-6.8	-6.9	-7.1	-7.2	-7.3
	AMR Remains Viable for 30-Year Analysis Period									
Full AMI	-6.2	-6.3	-6.4	-6.5	-6.7	-6.8	-6.9	-7.1	-7.2	-7.3
AMI+AMR_GO	-6.2	-6.3	-6.4	-6.5	-6.7	-6.8	-6.9	-7.1	-7.2	-7.3
Full AMR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

6.7. Financial Assumptions

Table 28 lists the inputs used to compute capital revenue requirements in this analysis. For the AMI and AMR alternatives, capital revenue requirements during the 5-year implementation period were computed with the assumption that the Companies will record capital investments as Construction Work In Process and accrue an allowance for funds used during construction ("AFUDC"). After the 5-year implementation period, capital investments are assumed to be placed in service in the year the investments are made. In Table 28, the property tax rate is applicable to meter and network investments but not to investments in IT systems.

Table 28: Financial Assumptions

	Combined Companies
% Debt	47%
% Equity	53%
Cost of Debt	4.02%
Cost of Equity	10.00%
Tax Rate	24.95%
Property Tax Rate	1.73%
WACC (After-Tax)	6.75%

7. Appendix B – Metering RFI Summary

[redacted]

REDACTED

CONFIDENTIAL INFORMATION REDACTED

[redacted]

REDACTED

CONFIDENTIAL INFORMATION REDACTED

[redacted]

REDACTED

CONFIDENTIAL INFORMATION REDACTED

[redacted]

REDACTED

CONFIDENTIAL INFORMATION REDACTED

[redacted]

CONFIDENTIAL INFORMATION REDACTED

[redacted]

REDACTED

CONFIDENTIAL INFORMATION REDACTED

[redacted]

Meter Life Study

PPL companies

September 2019

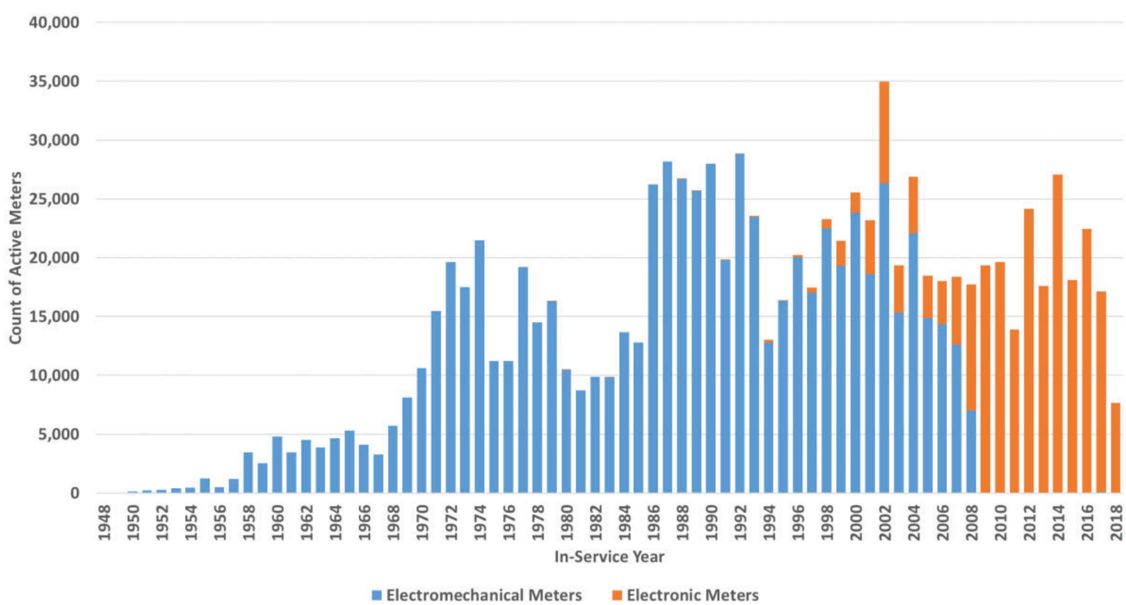
1. Background

LG&E and KU's ("The Companies'") electric meter population is aging, and meter failures are expected to increase as meters age. The use of data analytics to develop a forecast of meter failures allowed the Companies to determine how long the existing meter population will continue to be operational and also helped the Companies more effectively evaluate metering alternatives.

There are two different types of meters, each with different operating life characteristics. Electromechanical meters, or analog meters, are an older technology which measures energy by counting revolutions of a metal disc that rotates as energy flows. These meters typically had long operating lives but offered limited additional functionality and are no longer commercially available. Electronic meters, or digital meters, rely on sensors and transmit data to a digital display. These meters enable more functionality and are widely commercially available. AMI and AMR meters are subsets of electronic meters with communications, and their operating lives are expected to be functionally equivalent to that of a non-communicating electronic meter because they have the same meter platform.

Electromechanical meters were the standard technology for the Companies for most of the 20th century. The Companies began installing electronic meters in the 1990s, and electronic meters became the standard replacement meter after 2008. At the beginning of 2019, the Companies had approximately 1 million electric meters in service, with a split of 75% electromechanical and 25% electronic. Figure 1 shows a distribution of the Companies' meters by type and in-service year.[1]

Figure 1: Electric Meter Population by Type and In-Service Year



[1] This analysis excludes existing AMI meters, as well as roughly 2,000 meters that measure consumption primarily for time-of-day rates using specialized meters for many of the Companies' largest customers.

The Companies' electromechanical meter population ranges between 11 and 71 years old, with an average age of 31.4 years. The Companies' electronic meter population ranges between 0 and 28 years old, with an average age of 8.4 years.

The Companies began cataloging meter data in 2009. This includes meter failures, which for the purposes of this study includes meters that were taken out of service for any reason, including but not limited to mechanical failures. The objective of this study is to use historical failure data to create a forecast of future meter failures. To do this, the Companies evaluated historical failures over a 10-year period to develop actuarial meter failure curves for electromechanical and electronic meters, and then applied those curves to the existing meter population to develop a forecast.

2. Failure Curve Development

2.1 Electromechanical Failure Curves

The first step in developing a meter failure curve is to segment the number of meters and meter failures in each year of the historical period by age. Table 1 contains an example failure rate calculation for 40-year old meters using data from 2009 through 2018. In 2009, the meter population included 11,160 40-year old meters, and 83 of those meters were no longer active at the beginning of 2010, which implies a failure rate of 0.74%. Over the course of a 10-year period, the Companies had 169,257 meters that were 40 years old at the start of a year. During this time, annual failure rates ranged between 0.2% and 3.6%, with a weighted average failure rate of 2.1%. Based on this information, for a given population of 40-year old meters at the beginning of a year, on average 2.1% should fail, and 97.9% should remain in service and become 41-year old meters in the following year.

Table 1: Electromechanical Failures for 40-Year Old Meters

In-Service Year	Failure Year	Active Electromechanical Meters at Start of Year	Active Electromechanical Meters Retired During Year	Average Failure Rate
1969	2009	11,160	83	0.74%
1970	2010	13,787	26	0.19%
1971	2011	18,976	683	3.60%
1972	2012	22,927	532	2.32%
1973	2013	20,118	506	2.52%
1974	2014	23,604	622	2.64%
1975	2015	12,032	209	1.74%
1976	2016	11,927	228	1.91%
1977	2017	19,911	355	1.78%
1978	2018	14,815	304	2.05%
Total / Weighted Average		169,257	3,548	2.10%

Figure 2 shows the results of repeating this process for the entire range of ages across all electromechanical meters, with each dot reflecting the weighted average failure rate of a given age. Across the bulk of the age range, each dot reflects tens or hundreds of thousands of meters, though sample sizes are smaller beginning around age 60 where the electromechanical meter population is relatively sparse. The higher failure rate for 20-year old meters was the result of a high volume of a failed lot of meters in a single year from routine testing.[2] As expected, Figure 2 demonstrates that the failure rate increases as the meter ages.

[2] The Companies meter sampling process tests a wide variety of meters, and when a high failure rate is discovered among a specific model and manufacturing run, the other meters with those characteristics are declared a failed lot and will be retired. Failed lots can occur at any age, and the Companies elected not to omit or edit this data for purposes of this analysis.

Figure 2: Electromechanical Failure Rate by Age

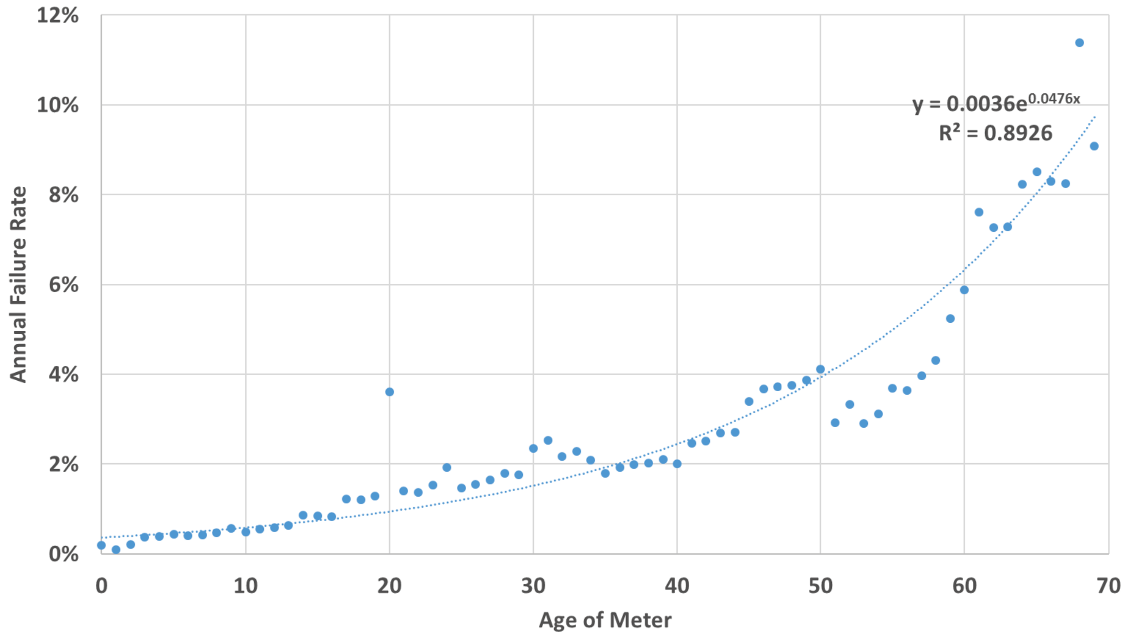


Figure 2 also shows the fitted curve and equation used to estimate meter failures.[3] An exponential curve provided the best fit and is well-suited for failure rates because it is always greater than zero, always increasing, and experiences a sharp increase in later years consistent with the Companies' data. The fitted curve yields an R^2 of 89%. Given the low number of meters greater than 70 years old in the Companies' meter population, this analysis assumes a meter failure rate of 100% after age 70.

This curve can be applied to a hypothetical meter population to determine an implied average meter life. As a demonstration, the Companies considered a population of 10,000 electromechanical meters installed in year 0 and removed from service based on the failure curves. In the first year, 35 meters are retired, and 9,965 remain in service at the end of year 0:

Meters at start of year 0:	10,000
Less failed meters in year 0 (@ 0.35%):	-35
Meters at end of year 0 / start of year 1:	9,965

During the second year, 36 of the original meters are retired, and 9,929 remain in service at the end of year 1. During the third year, 38 of the original meters are retired, and 9,891 remain in service at the end of year 2:

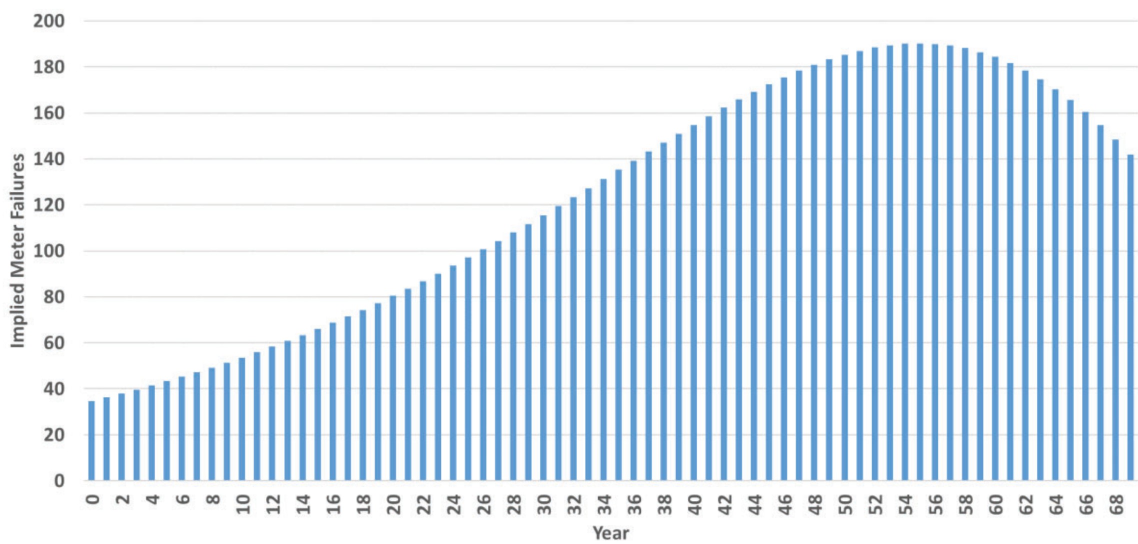
Meters at end of year 0 / start of year 1:	9,965
Less failed meters in year 1 (@ 0.36%):	-36
Meters at end of year 1 / start of year 2:	9,929

[3] See Appendix I for a complete table of failure rates by age.

Meters at end of year 1 / start of year 2:	9,929
Less failed meters in year 2 (@ 0.38%):	-38
Meters at end of year 2 / start of year 3:	9,891

Figure 3 shows the distribution of failed meter counts for this illustrative 10,000-meter population until all remaining meters are retired after age 70. Taking the weighted average of meter failures by age yields an average meter life of 46.4 years for electromechanical meters, which is to say the Companies expect an electromechanical meter to be in operation for an average of 46.4 years, but does not imply that an electromechanical meter cannot operate after 46.4 years.

Figure 3: Implied Electromechanical Meter Failures for 10,000 Meter Population



2.2 Electronic Failure Curves

Figure 4 shows the results of repeating the curve development process described in section 2.1 for electronic meters instead of electromechanical meters. Across the bulk of the age range, each dot reflects tens or hundreds of thousands of meters, though sample sizes are smaller beginning around age 20 where the electronic meter population is relatively sparse. As expected, Figure 4 demonstrates that the failure rate increases as the meter ages.

Figure 4: Electronic Meter Failure Rate by Age

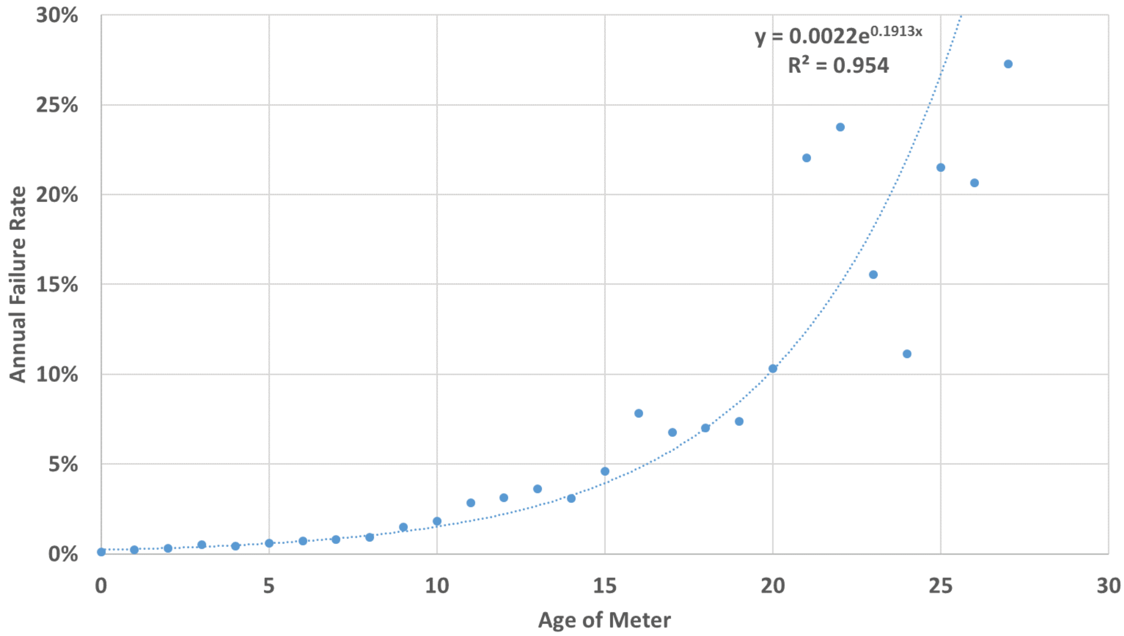


Figure 4 also shows the fitted curve and equation used to estimate meter failures.[4] Consistent with the electromechanical fitted curve, an exponential curve provided the best fit and is well-suited for failure rates because it is always greater than zero, always increasing, and experiences a sharp increase in later years consistent with the Companies' data. The fitted curve yields an R^2 of 95%. Given the low number of meters greater than 28 years old in the Companies' meter population, this analysis assumes a meter failure rate of 100% after age 28.

This curve can be applied to a hypothetical meter population to determine an implied average meter life. As a demonstration, the Companies considered a population of 10,000 electronic meters installed in year 0 and removed from service based on the failure curves. In the first year, 22 meters are retired, and 9,978 remain in service at the end of year 0:

Meters at start of year 0:	10,000
Less failed meters in year 0 (@ 0.22%):	-22
Meters at end of year 0 / start of year 1:	9,978

During the second year, 27 of the original meters are retired, and 9,951 remain in service at the end of year 1. During the third year, 33 of the original meters are retired, and 9,918 remain in service at the end of year 2:

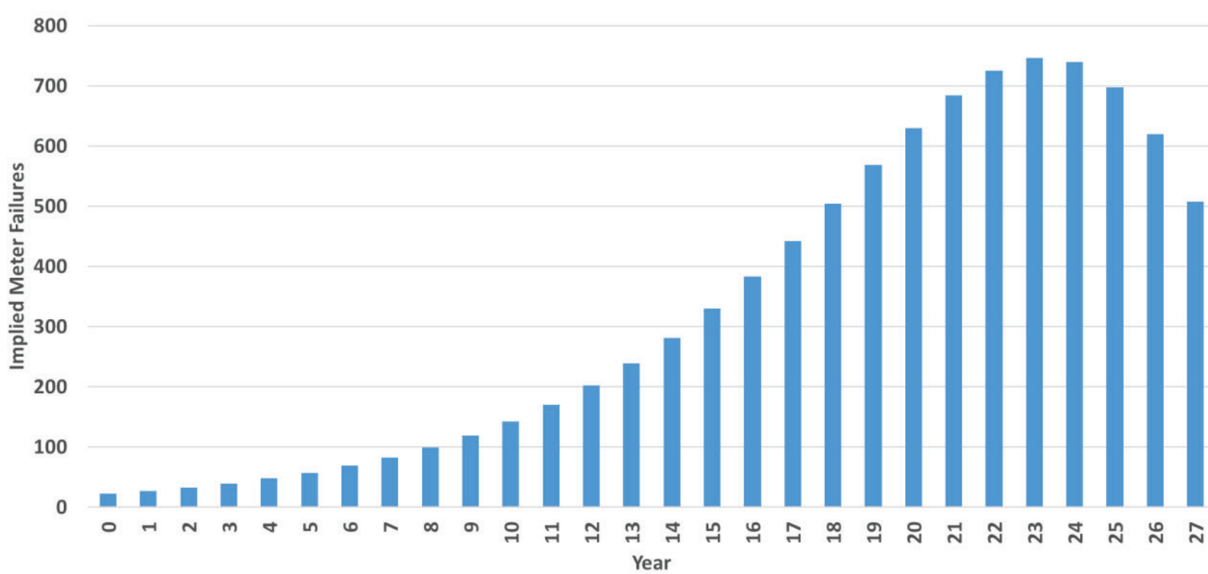
Meters at end of year 0 / start of year 1:	9,978
Less failed meters in year 1 (@ 0.27%):	-27
Meters at end of year 1 / start of year 2:	9,951

[4] See Appendix I for a complete table of failure rates by age.

Meters at end of year 1 / start of year 2:	9,951
Less failed meters in year 2 (@ 0.33%):	-33
Meters at end of year 2 / start of year 3:	9,918

Figure 5 shows the distribution of failed meter counts for this illustrative 10,000-meter population until all remaining meters are retired after age 28. Taking the weighted average of meter failures by age yields an average meter life of 20.2 years for electronic meters, which is to say the Companies expect an electronic meter to be in operation for an average of 20.2 years, but does not imply that an electronic meter cannot operate after 20.2 years.

Figure 5: Implied Electronic Meter Failures for 10,000 Meter Population



3. Forecast

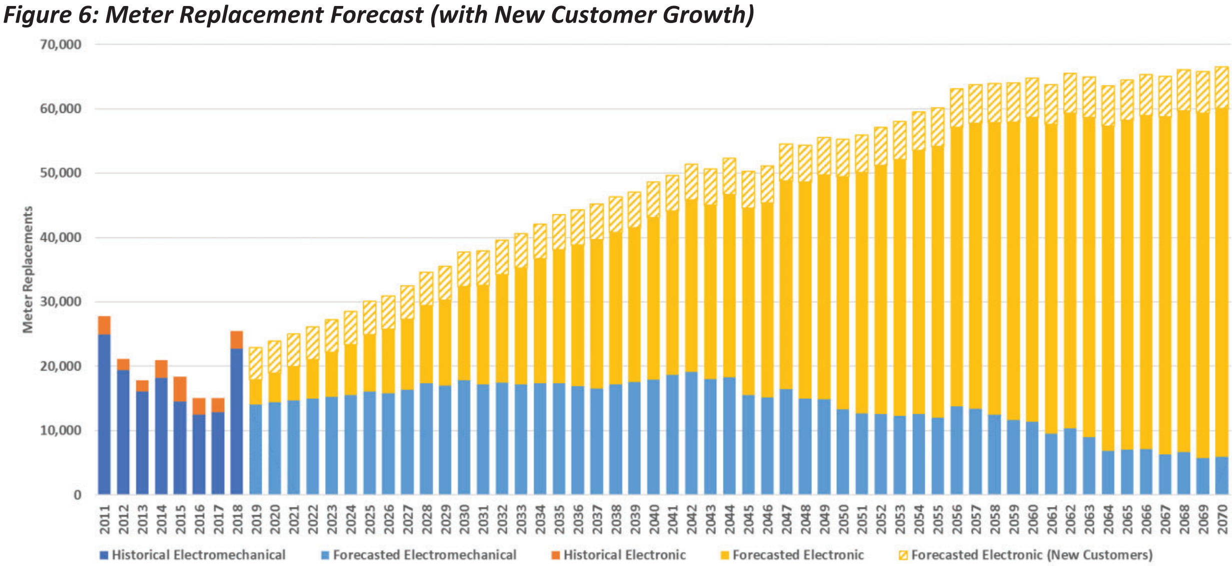
To develop the meter replacement forecast, the Companies applied the meter failure curves to the current electromechanical and electronic meter populations as of the beginning of 2019 to estimate the quantity of failed meters expected during the year. Existing electromechanical and electronic meters are assumed to be replaced with electronic meters when they fail. The calculations for forecasted meter replacements in 2019 are available in Appendix II. In each subsequent year, the remaining meters are assumed to fail at the average rate corresponding to their age, with newly-installed meters from the previous year representing the count of one-year old electronic meters in the current year.

This process was repeated through 2070 to develop a long-term forecast. Over time, electromechanical meters (with an average life of 46.4 years) would be replaced with electronic meters (with an average life of 20.2 years). Eventually, all meters would be replaced, including replacements of replacement meters, and replacements of those meters as well.

In addition to the replacement of existing meters, the Companies expect additional electronic meters and subsequent replacements will be needed for assumed growth due to the addition of new customers. The Companies' customer growth forecast is higher in earlier years – consistent with recent history – but levels off in the latter portion of the forecast period consistent with population forecasts from IHS Global Insight.

Figure 6 shows the meter replacement forecast including new customer growth. The dark blue bars reflect historical electromechanical meter failures, while the light blue bars reflect forecasted electromechanical meter failures. The orange bars reflect historical electronic meter failures, while the yellow bars reflect forecasted electronic meter failures. The hashed yellow bars reflect new customer growth.

Figure 6: Meter Replacement Forecast (with New Customer Growth)



Forecasted meter replacements in the short term are in line with recent history for both electromechanical and electronic meters. But as the proportion of longer-lived electromechanical meters decreases, the proportion of shorter-lived electronic meters increases, which results in an increasing volume of meter replacements over time.

Absent customer growth, the Companies would expect annual meter replacements to converge to a steady state given a long time horizon. For example, a meter population of 1 million electromechanical meters, which have an average life of 46.4 years, should on average experience 1 million / 46.4 annual meter replacements, or roughly 22,000 annual meter replacements. Similarly, a meter population of 1 million electronic meters, which have an average life of 20.2 years, should on average experience 1 million / 20.2 annual meter replacements, or roughly 50,000 annual meter replacements.

Since the Companies' current meter population is mostly electromechanical, but is expected to shift toward electronic over time, the Companies should expect a short-term forecast closer to 22,000 annual meter replacements, growing over time to a long-term forecast closer to 50,000 annual meter replacements. After considering additional meters for customer growth, the meter replacement forecast is consistent with these expectations.

4. Appendix I

Table 2: Expected Annual Meter Failures by Age

Age	Electromechanical Meter Failure Rate	Electronic Meter Failure Rate
0	0.35%	0.22%
1	0.36%	0.27%
2	0.38%	0.33%
3	0.40%	0.40%
4	0.42%	0.48%
5	0.44%	0.58%
6	0.46%	0.70%
7	0.49%	0.85%
8	0.51%	1.03%
9	0.53%	1.25%
10	0.56%	1.52%
11	0.59%	1.83%
12	0.62%	2.22%
13	0.65%	2.69%
14	0.68%	3.26%
15	0.71%	3.94%
16	0.74%	4.77%
17	0.78%	5.78%
18	0.82%	7.00%
19	0.86%	8.47%
20	0.90%	10.26%
21	0.94%	12.42%
22	0.99%	15.04%
23	1.04%	18.21%
24	1.09%	22.04%
25	1.14%	26.69%
26	1.20%	32.32%
27	1.26%	39.13%
28	1.32%	100.00%
29	1.38%	
30	1.45%	
31	1.52%	
32	1.59%	
33	1.67%	
34	1.75%	
35	1.84%	
36	1.93%	
37	2.02%	
38	2.12%	
39	2.22%	
40	2.33%	
41	2.45%	
42	2.57%	
43	2.69%	
44	2.82%	
45	2.96%	
46	3.10%	
47	3.26%	
48	3.41%	
49	3.58%	
50	3.75%	
51	3.94%	
52	4.13%	
53	4.33%	
54	4.54%	
55	4.76%	

Age	Electromechanical Meter Failure Rate	Electronic Meter Failure Rate
56	5.00%	
57	5.24%	
58	5.49%	
59	5.76%	
60	6.04%	
61	6.34%	
62	6.65%	
63	6.97%	
64	7.31%	
65	7.66%	
66	8.04%	
67	8.43%	
68	8.84%	
69	9.27%	
70	100.00%	

5. Appendix II

Table 3: Forecasted Electromechanical Meter Replacements in 2019

In-Service Year	Meter Age	Electromechanical Meter Failure Rate	Active Electromechanical Meters at Start of 2019	Electromechanical Meters Expected to Fail in 2019	Active Electromechanical Meters at End of 2019
1948	71	100.00%	10	10	0
1949	70	100.00%	35	35	0
1950	69	9.27%	149	14	135
1951	68	8.84%	247	22	225
1952	67	8.43%	262	22	240
1953	66	8.04%	386	31	355
1954	65	7.66%	466	36	430
1955	64	7.31%	1,231	90	1,141
1956	63	6.97%	480	33	447
1957	62	6.65%	1,178	78	1,100
1958	61	6.34%	3,440	218	3,222
1959	60	6.04%	2,531	153	2,378
1960	59	5.76%	4,820	278	4,542
1961	58	5.49%	3,448	189	3,259
1962	57	5.24%	4,502	236	4,266
1963	56	5.00%	3,887	194	3,693
1964	55	4.76%	4,669	222	4,447
1965	54	4.54%	5,316	241	5,075
1966	53	4.33%	4,090	177	3,913
1967	52	4.13%	3,252	134	3,118
1968	51	3.94%	5,744	226	5,518
1969	50	3.75%	8,146	306	7,840
1970	49	3.58%	10,640	381	10,259
1971	48	3.41%	15,495	529	14,966
1972	47	3.26%	19,617	639	18,978
1973	46	3.10%	17,508	543	16,965
1974	45	2.96%	21,498	636	20,862
1975	44	2.82%	11,202	316	10,886
1976	43	2.69%	11,212	302	10,910
1977	42	2.57%	19,212	493	18,719
1978	41	2.45%	14,511	355	14,156
1979	40	2.33%	16,301	380	15,921
1980	39	2.22%	10,499	234	10,265
1981	38	2.12%	8,723	185	8,538
1982	37	2.02%	9,904	200	9,704
1983	36	1.93%	9,849	190	9,659
1984	35	1.84%	13,659	251	13,408
1985	34	1.75%	12,777	224	12,553
1986	33	1.67%	26,233	439	25,794
1987	32	1.59%	28,181	449	27,732
1988	31	1.52%	26,706	406	26,300
1989	30	1.45%	25,667	372	25,295
1990	29	1.38%	27,977	387	27,590
1991	28	1.32%	19,811	261	19,550
1992	27	1.26%	28,813	362	28,451
1993	26	1.20%	23,483	282	23,201
1994	25	1.14%	12,809	146	12,663
1995	24	1.09%	16,370	178	16,192

In-Service Year	Meter Age	Electromechanical Meter Failure Rate	Active Electromechanical Meters at Start of 2019	Electromechanical Meters Expected to Fail in 2019	Active Electromechanical Meters at End of 2019
1996	23	1.04%	20,062	209	19,853
1997	22	0.99%	17,044	169	16,875
1998	21	0.94%	22,473	212	22,261
1999	20	0.90%	19,328	174	19,154
2000	19	0.86%	23,847	205	23,642
2001	18	0.82%	18,607	152	18,455
2002	17	0.78%	26,309	206	26,103
2003	16	0.74%	15,327	114	15,213
2004	15	0.71%	22,087	157	21,930
2005	14	0.68%	14,864	101	14,763
2006	13	0.65%	14,384	93	14,291
2007	12	0.62%	12,613	78	12,535
2008	11	0.59%	7,031	41	6,990
2009	10	0.56%	0	0	0
2010	9	0.53%	0	0	0
2011	8	0.51%	0	0	0
2012	7	0.49%	0	0	0
2013	6	0.46%	0	0	0
2014	5	0.44%	0	0	0
2015	4	0.42%	0	0	0
2016	3	0.40%	1	0	1
2017	2	0.38%	65[5]	0	65
2018	1	0.36%	0	0	0
Total	N/A	N/A	750,988	13,999	736,989

[5] Electromechanical meters are no longer manufactured; however, in 2016 and 2017, the Companies were able to procure a small volume of reconditioned electromechanical meters as a less expensive alternative to new electronic meters.

Table 4: Forecasted Electronic Meter Replacements in 2019

In-Service Year	Meter Age	Electronic Meter Failure Rate	Active Electronic Meters at Start of 2019	Electronic Meters Expected to Fail in 2019	Active Electronic Meters at End of 2019
1991	28	100.00%	24	24	0
1992	27	39.13%	6	2	4
1993	26	32.32%	70	23	47
1994	25	26.69%	197	53	144
1995	24	22.04%	20	4	16
1996	23	18.21%	183	33	150
1997	22	15.04%	415	62	353
1998	21	12.42%	810	101	709
1999	20	10.26%	2,090	214	1,876
2000	19	8.47%	1,686	143	1,543
2001	18	7.00%	4,589	321	4,268
2002	17	5.78%	8,658	500	8,158
2003	16	4.77%	4,032	192	3,840
2004	15	3.94%	4,785	189	4,596
2005	14	3.26%	3,620	118	3,502
2006	13	2.69%	3,647	98	3,549
2007	12	2.22%	5,779	128	5,651
2008	11	1.83%	10,714	197	10,517
2009	10	1.52%	19,336	293	19,043
2010	9	1.25%	19,638	246	19,392
2011	8	1.03%	13,892	144	13,748
2012	7	0.85%	24,146	206	23,940
2013	6	0.70%	17,592	124	17,468
2014	5	0.58%	28,626	167	28,459
2015	4	0.48%	20,571	99	20,472
2016	3	0.40%	26,148	104	26,044
2017	2	0.33%	17,314	57	17,257
2018	1	0.27%	9,950	27	9,923
Total	N/A	N/A	248,538	3,868	244,670

Table 5: Expected Meter Populations After First Year of Forecast

In-Service Year	Meter Age	Active Electromechanical Meters at Start of 2020	Active Electronic Meters at Start of 2020
1950	70	135	0
1951	69	225	0
1952	68	240	0
1953	67	355	0
1954	66	430	0
1955	65	1,141	0
1956	64	447	0
1957	63	1,100	0
1958	62	3,222	0
1959	61	2,378	0
1960	60	4,542	0
1961	59	3,259	0
1962	58	4,266	0
1963	57	3,693	0
1964	56	4,447	0
1965	55	5,075	0
1966	54	3,913	0
1967	53	3,118	0
1968	52	5,518	0
1969	51	7,840	0
1970	50	10,259	0
1971	49	14,966	0
1972	48	18,978	0
1973	47	16,965	0
1974	46	20,862	0
1975	45	10,886	0
1976	44	10,910	0
1977	43	18,719	0
1978	42	14,156	0
1979	41	15,921	0
1980	40	10,265	0
1981	39	8,538	0
1982	38	9,704	0
1983	37	9,659	0
1984	36	13,408	0
1985	35	12,553	0
1986	34	25,794	0
1987	33	27,732	0
1988	32	26,300	0
1989	31	25,295	0
1990	30	27,590	0
1991	29	19,550	0
1992	28	28,451	4
1993	27	23,201	47
1994	26	12,663	144
1995	25	16,192	16
1996	24	19,853	150
1997	23	16,875	353
1998	22	22,261	709
1999	21	19,154	1,876
2000	20	23,642	1,543
2001	19	18,455	4,268
2002	18	26,103	8,158
2003	17	15,213	3,840
2004	16	21,930	4,596
2005	15	14,763	3,502
2006	14	14,291	3,549
2007	13	12,535	5,651
2008	12	6,990	10,517

In-Service Year	Meter Age	Active Electromechanical Meters at Start of 2020	Active Electronic Meters at Start of 2020
2009	11	0	19,043
2010	10	0	19,392
2011	9	0	13,748
2012	8	0	23,940
2013	7	0	17,468
2014	6	0	28,459
2015	5	0	20,472
2016	4	1	26,044
2017	3	65	17,257
2018	2	0	9,923
2019	1	0	17,867[6]

[6] Sum of 13,999 electromechanical meters and 3,868 electronic meters expected to fail in the forecast, which would be replaced with new electronic meters.

LG&E and KU

CVR Potential Study

Generation Planning & Electric Distribution Planning

October 2020

Executive Summary

The continued growth of distributed energy resources and new loads such as electric vehicles are placing increasingly dynamic demands on the distribution grid. To reliably accommodate this growth, additional voltage sensing and regulating equipment will be needed along selected distribution circuits to more precisely control voltage along these circuits and prevent voltage excursions. If Advanced Metering Infrastructure ("AMI") is deployed throughout the Companies' service territories, the Companies will have voltage data for every customer. With this data, AMI will enable the Companies to implement Conservation Voltage Reduction ("CVR"), which uses AMI data and more precise voltage controls to incrementally reduce grid voltage such that energy requirements are lowered. Lower energy requirements result in avoided generation costs thus reducing revenue requirements for rate payers.

This analysis estimates the CVR energy savings potential for a subset of circuits in the LG&E and KU system using data gathered from the existing AMS Opt-In Program. 12 circuits with high saturations of AMS Opt-In voltage data were studied in detail, and the estimated CVR energy savings rates found in those 12 circuits were applied to a broader pool of 404 CVR candidate circuits. On an annual energy basis, the 404 candidate circuits represent roughly a third of LG&E and KU system. Table 1 summarizes the potential range of annualized CVR energy savings from the analysis.

Table 1: Range of Annual CVR Energy Savings

Scenario	GWh CVR Energy Savings	Percent of CVR Circuit Load	Percent of System Load
High	-270	-2.61%	-0.87%
Mid	-205	-1.99%	-0.66%
Low	-145	-1.40%	-0.47%

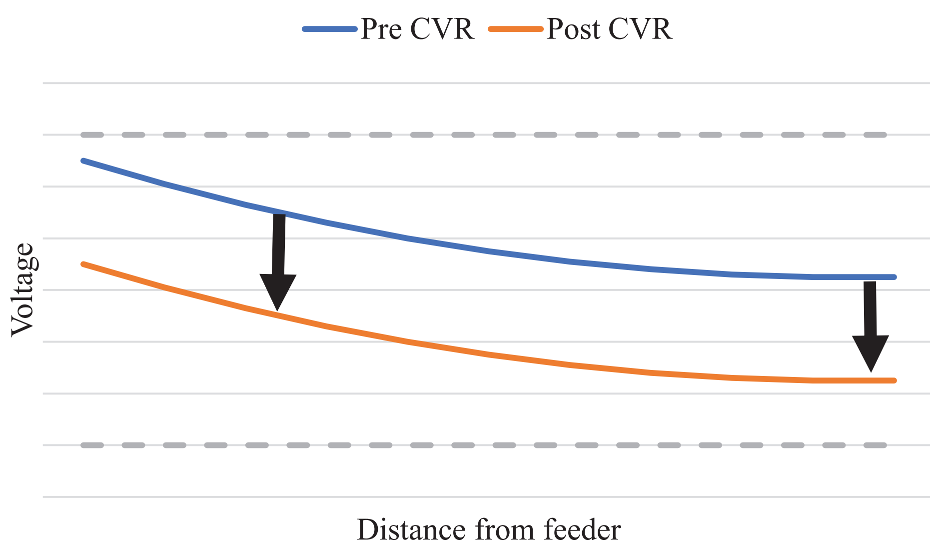
For a given circuit, CVR savings between 1 and 4 percent[1] are commonly reported in the industry. While this would be a new strategy for LG&E and KU, electric utility experience with CVR initiatives over recent years suggests any implementation risk may be substantially mitigated by industry experience and proven technology. The balance of the paper addresses the details of the methodology used to estimate the circuit-level CVR savings potential.

[1] EPA (2017)

Conservation Voltage Reduction

Conservation Voltage Reduction (CVR) is a technology that can reduce energy consumption with no change in customer behavior or the customer experience. CVR is implemented by controlling the voltage on a distribution circuit to lower portions of the tolerance band (114-126 volts as defined by ANSI C84.1) as shown in Figure 1. Conservation then occurs on the circuit when certain end-use loads draw less power.

Figure 1: Stylized CVR Voltage Reduction



Power savings is calculated using a combination of Ohm's Law and a power calculation as shown below.

Ohm's Law: $Voltage = Current * Resistance$

Power: $Power = Voltage * Current$

Since the resistance of a load typically remains constant, lowering the voltage also lowers the current. Lowering both the voltage and current results in lower power consumption. However, not all electrical loads respond the same to voltage reductions. For resistive loads with near unity power factor (e.g., incandescent lamps, heating elements), a one percent drop in voltage will result in a near one percent drop in power consumption. For reactive loads with lower power factors, the change in power consumption will be less than one percent. The "CVR factor" is the degree to which power consumption on a given circuit is sensitive to changes in voltage. CVR factors typically exist in the range of 0.5 to 1 and can vary seasonally. For the LG&E and KU system as a whole, a range of CVR factors from 0.7 to 0.8 is assumed in this analysis.[2]

AMI is critical for providing the information that is needed to reliably implement CVR. Connected loads can be damaged if voltages fall outside the upper or lower limits of the ANSI-specified tolerance band.

[2] Simms (2016)

With voltage data for every customer, AMI provides the feedback needed to control voltage to lower portions of the tolerance band without jeopardizing reliability or power quality for customers.

LG&E and KU CVR Potential Evaluation

Electric Distribution Operations ("EDO") identified 404 circuits for this analysis that would be good candidates for implementing CVR. Candidate circuits were selected based on a number of criteria including: circuit length; number of customers served; uniformity of circuits on a given substation; existing voltage control assets such as capacitors, regulators, and LTCs; and availability of communications. From within this CVR candidate circuit pool, 12 circuits were selected for a detailed analysis of the circuits' CVR energy savings potential. The data for this analysis was gathered from AMS Opt-in meters that report voltage data; the circuits selected for the detailed analysis have good coverage of these meters along the entire circuit. A range of potential energy savings for all CVR candidate circuits was developed based on the results of the detailed analysis.

Detailed Analysis of 12 Selected Circuits

Table 2 below lists each of the 12 circuits and describes several attributes including the number of AMI service points per circuit as well as the amount of energy consumed on the circuit in 2019.

Table 2: Summary of Circuits Evaluated in Detailed Analysis

Circuit Name	AMI Service Points	Total Service Points	AMI Percent	2019 Annual Energy (GWh)	Power Factor	Total Conductor Length (ft)
CF1201	12	479	2.51%	13.2	94.3%	274,210
CF1202	19	933	2.04%	21.8	93.8%	302,810
CF1205	18	752	2.39%	15.7	95.0%	144,025
CW1222	39	1657	2.35%	32.6	94.6%	280,709
CW1224	25	1281	1.95%	41.2	91.9%	260,048
CW1226	18	494	3.64%	11.5	94.1%	124,806
CW1227	15	901	1.66%	18.6	93.9%	176,144
CW1228	25	1015	2.46%	28.4	93.5%	378,221
HL1155	14	369	3.79%	7.6	94.8%	74,755
HL1156	37	1226	3.02%	30.2	93.0%	269,830
HL1157	32	1132	2.83%	22.5	94.5%	147,557
HL1158	11	368	2.99%	11.0	93.7%	168,563

For each circuit, the 5-minute data analysis is conducted independently. Cases are developed by changing two key parameters of voltage control threshold and CVR Factor. In the context of this analysis, the voltage control threshold is the voltage level to which the minimum voltage meter on the circuit is dynamically adjusted in each five-minute interval; it is not the average voltage across the circuit. The analysis further assumes that the required adjustment to the minimum voltage meter is applied across the entire circuit profile (see Table 3 and discussion for further context). The analysis contemplates three voltage control thresholds of 116, 117 and 118.

The CVR Factor relates the percent change in voltage to the percent change in power. As described in the CVR Factor section, certain loads respond differently to changes in voltage, so the CVR Factor effectively derates the intuition from the classic power formula (Watts = Volts * Amps). The analysis contemplates two CVR Factors of 0.7 and 0.8, which are typical according to a number of other utilities.[3]

For each circuit, there are a total of six cases resulting from the combination of three voltage control thresholds and two CVR factors. The procedure outlined below was evaluated independently for each circuit and case to estimate the associated CVR energy saving. For clarity of explanation, the procedure is broken out into three separate steps with sub-steps and commentary.

[3] Simms (2016)

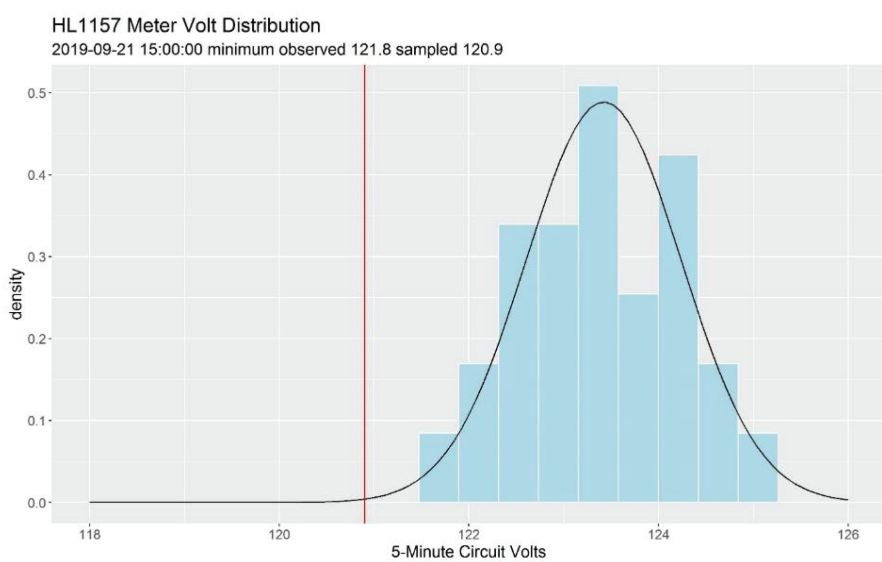
Step #1 - *Estimate* the minimum voltage on the circuit in each five-minute interval.

1. Using the 5-minute minimum line to neutral voltage data from each AMI meter on the circuit calculate the minimum, mean, and standard deviation in the five-minute interval. The minimum voltage for all meters on the circuit is the "actual minimum" voltage.
2. Use as inputs the mean and standard deviation to the normal cumulative distribution function and take the voltage level for which 99.9% of observations are expected to be greater. This is the "sampled minimum" voltage.
3. Take the minimum of the actual minimum voltage and the sampled minimum voltage as the expected minimum voltage in the given 5-minute interval. This is the step#1 result.

In "sampling" from the voltage observations to a voltage level that is oftentimes lower than the actual minimum voltage, the analysis reflects the likelihood that other meters on the circuit had lower voltage than the AMS Opt-In meters for which data is available. This would not be necessary if AMI were fully deployed.

Figure 2: represents the distribution of observed meter data with the blue histogram bars while the vertical red line at 120.9 represents the "sampled minimum" voltage from a normal distribution based on the observed voltage data. The sampled minimum voltage is 0.9 volts lower than the actual minimum voltage which is 121.8 volts

Figure 2: Voltage "Sampling" Example



Step#2 - Calculate the CVR Load Impact

Step #2 is also carried out in each 5-minute interval. Effectively, the percent difference between the voltage control threshold for the case (e.g. 118) and the expected minimum voltage on the circuit is applied to the load on the entire circuit. Table 3 illustrates the calculation given various parameter changes in columns A - D. Instances of CVR savings in Table 3 occur in the first and third row where Circuit Minimum Voltage (column C; i.e. the result of step #1 above) is greater than the Voltage Control Threshold (column B). Instances of upregulating voltage to the control threshold occur when the expected minimum voltage is less than the control threshold as in rows two and four; in these instances, Post CVR Circuit Load (column F) is greater than the original Circuit Load (column A). The CVR Factor scales the CVR Delta (column E) in that otherwise similar rows have greater effect with the 80% CVR Factor vs 70% (e.g. the -0.034 MW effect in row three is greater than -0.029 MW in row one).

Table 3: CVR Load Impact Calculation Example

A	B	C	D	E *(B/C-1)*D*A*	F *A + E*
Circuit Load (MW)	**Voltage Control Threshold**	**Expected Minimum Voltage**	**CVR Factor**	**CVR Delta (MW)**	**Post CVR Circuit Load (MW)**
5	118	119	70%	-0.029	4.971
5	118	117	70%	0.030	5.030
5	118	119	80%	-0.034	4.966
5	118	117	80%	0.034	5.034

Step #3 - Aggregate the 5-minute CVR load impacts and compute annual percentage load reduction

The net energy impact of each five-minute interval is aggregated across the study period to estimate the annual net energy impact. The final aggregated results are therefore *net* avoided energy inclusive of any increased load from 5-minute intervals requiring voltage upregulation relative to the control threshold (as shown in Table 3 above).

Table 4 summarizes the results of the analysis annually by circuit for various voltage control thresholds. The 70% and 80% CVR factor cases are averaged thus reflecting a 75% CVR factor.

Table 4 CVR Annual Avoided Energy Percent by Circuit and Control Threshold

	Circuit Voltage Control Threshold		
	116	**117**	**118**
CF1201	-0.84%	-0.19%	0.00%
CF1202	-1.97%	-1.34%	-0.71%
CF1205	-2.77%	-2.14%	-1.52%
CW1222	-2.68%	-2.06%	-1.43%
CW1224	-2.51%	-1.89%	-1.26%
CW1226	-3.51%	-2.91%	-2.29%
CW1227	-2.55%	-1.92%	-1.31%
CW1228	-1.62%	-0.98%	-0.36%
HL1155	-4.10%	-3.50%	-2.87%
HL1156	-2.68%	-2.06%	-1.44%
HL1157	-3.51%	-2.89%	-2.27%
HL1158	-2.62%	-2.02%	-1.38%
Avg.	**-2.61%**	**-1.99%**	**-1.40%**

Range of CVR Energy Savings Potential

The analysis of the 12 selected circuits provides a reasonable basis for predicting what CVR energy savings may be on the remaining CVR candidate circuits. However, in recognition of the limited data and general uncertainty associated with high-level estimates of potential CVR energy savings, a set of High, Mid and Low CVR energy savings scenarios were developed.

Table 5 shows the annual avoided energy by scenario rounded to the nearest 5 GWh. The savings for each scenario are the product of the CVR candidate circuit 2019 total energy (10,384 GWh) and the CVR percent savings associated with each voltage control threshold in Table 4. The High, Mid and Low scenarios are associated with the 116, 117 and 118 voltage control threshold, respectively.

Table 5 CVR Avoided Energy Scenarios

Scenario	CVR Candidate Circuit 2019 GWh	Percent CVR Savings	CVR Avoided Energy GWh
High	10,384	-2.61%	-270
Mid	10,384	-1.99%	-205
Low	10,384	-1.40%	-145

Literature Review

Reports that many utilities find 1% to 4% savings on initial deployment.

EPA. (2017). *Conservation Voltage Reduction/Volt VAR Optimization EM&V Practices.* Retrieved from https://www.energystar.gov/sites/default/files/asset/document/Volt%20Var%20and%20CVR%20EMV%20Best%20Practice%2006-01-17clean%20-%20508%20PASSED.PDF

Presentation slides from Duke Energy to an IEEE conference in which support for a 70% CVR Factor as typical though there is significant variation.

Simms, M. (2016). *IEEE SDWG 2016: Duke Energy Production Experience with CVR.* Retrieved from http://grouper.ieee.org/groups/td/dist/da/doc/Duke%20Energy%20Production%20Experience%20with%20CVR.pdf

Pilot at Dominion Virginia Power including two circuits with average of 2.8% in savings.

IEEE. (2014). *Technologies for Advanced Volt/Var Control Implementation: Integration of Advanced Metering Data* (PowerPoint page #13). Retrieved from https://www.ieee-pes.org/presentations/gm2014/PESGM2014P-002524.pdf

To:	Jonathan Whitehouse and John Hayden, LG&E and KU
Cc:	Stacy Harvey, LG&E and KU Andrew Meyerhofer and Carrie Koenig, Tetra Tech
From:	Jonathan Hoechst and Sue Hanson, Tetra Tech
Date:	October 28, 2020
Subject:	Advanced Metering Program Evaluation – 2020 Update Executive Summary

This memo summarizes savings estimates for Louisville Gas and Electric Company and Kentucky Utilities Company's (LG&E and KU's) Advanced Metering Program (AMP), using consumption and participation data spanning from January 2014 to July 2020. We first provide an overview of our findings, and then present a summary of results in the following main topic areas:

- Analysis 1: nonparticipants and earliest adopters[1]
- Analysis 2: treatment and contrast group
- Analysis 3: participants and waitlist customers.

EXECUTIVE SUMMARY

Since 2016, Tetra Tech's analyses of LG&E and KU's AMP has indicated that electric savings occurred amongst participants in excess of naturally occurring reductions in energy usage among LG&E and KU customers that do not have advanced metering equipment. A summary of Tetra Tech's analyses is provided in Table 1, below, including the estimated energy savings associated with installing an advanced meter and the number of accounts supporting each analysis.

Table 1. AMP Savings Estimates

Year of Analysis*	Estimated Electric Savings (%)	Number of Treatment Accounts**	Number of Contrast Accounts***
October 25, 2016****	6.0%	82	199
January 3, 2018	3.8%	1,353	357
January 28, 2019	1.3%	2,635	1,094
September 22, 2020			
Analysis 2	1.7%	3,448	6,273
Analysis 3	1.4%	8,946	1,998

* The date provided is the date a memo was delivered to LG&E and KU.

** Treatment accounts are AMP participants. We use these words interchangeably throughout this memo.

*** Contrast accounts are essentially AMP nonparticipants, but how the nonparticipants were defined varied somewhat by the analysis method and timeframe. The term "control group" is avoided because households were not randomly assigned.

**** The 2016 analysis is included as a preliminary estimate, as this particular analysis included a relatively small number of accounts in both the treatment and contrast groups, increasing the potential for extreme values to unduly influence overall results.

[1] Throughout this memo, the term "earliest adopters" specifically refers to AMP participants with a meter installation that occurred in 2016.

The analyses presented in this memo support the findings that since program inception (1) LG&E and KU customers with an advanced meter installed through AMP use less electricity, on average, after installation of their meter, and (2) AMP participants have reduced their electric use by an amount greater than naturally occurring energy savings. These results are consistent across all analyses conducted by Tetra Tech for AMP.

In addition, the results of the analyses in Table 1 are similar to energy savings estimates claimed by utilities when filing dockets after AMI deployment. In particular:

- Baltimore Gas and Electric reported energy savings between 1.38 and 1.5 percent after offering advanced meters to its customers.[2]
- An evaluation of energy consumption among residential customers of Potomac Electric Power Company estimated electric savings of 1.73 percent after activation of smart meters.[3]

Tetra Tech also notes a few utilities that have filed planned energy savings estimates in support of proposed AMI deployment, but do not have actual results at this time. In particular:

- Entergy New Orleans approved filing estimated savings of 1.75 of electricity and 0.75 percent of gas consumption, and included a web portal.[4]
- Entergy Arkansas' 2016 AMI approved plan included a web portal that customers can access to see energy use and estimated electric savings of 1.75 percent across residential and commercial customers.[5]
- In Canada, BC Hydro's smart meter plan included energy savings of 2 percent from customers using their website in conjunction with new advanced meters.[6]

The more recent analysis of AMP participants was completed because AMP was fully subscribed. Tetra Tech compared electric usage among the earliest AMP participants *prior to* installation of their advanced meter to a statistically valid sample of LG&E and KU nonparticipating customers to examine whether the two groups consumed electricity at similar rates. The results indicated that, on average, AMP participants used more electricity per day before receiving their advanced meter than nonparticipating customers. This supports the notion that the general population of LG&E and KU customers *consume* electricity at different rates than program participants. However, we note that the results cannot be used to determine whether potential electric *savings* achievable through installation of an advanced meter would be different or similar between participants and current nonparticipants, as savings are relative to individuals' baseline energy usage.

[2] Navigant Consulting Inc., Smart Energy Manager Program – 2015 Evaluation Report, prepared for Baltimore Gas Electric, March 11, 2016. See also Direct Testimony of William B. Pino on behalf of Baltimore Gas & Electric Company, before the Maryland Public Service Commission – Case No. 9406, November 6, 2015.

[3] Direct Testimony of Ahmad Faruqui on behalf of Potomac Electric Power Company, Maryland Public Service Commission – Case No. 9418, April 19, 2016.

[4] New Orleans City Council Docket UD-16-04, Application of Entergy New Orleans, Inc. for Approval to Deploy Advanced Metering Infrastructure. Available at https://www.all4energy.org/uploads/1/0/5/6/105637723/2016_10_13_ud-16-04_app_for_ami_testimony_exhibits_final_public.pdf.

[5] Arkansas Public Service Commission Docket No. 16-060-U, Document 23. Available at http://www.apscservices.info/pdf/16/16-060-U_23_1.pdf.

[6] "Smart Metering & Infrastructure Program Business Case," BC Hydro. Available at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/projects/smart-metering/smi-program-business-case.pdf.

As summarized in Table 1, AMP participants persist in decreasing their energy usage more than naturally occurring decreases in energy usage seen by the contrast accounts. Importantly, the reduction in energy use remains among AMP participants as the program continued to add participants. As participation numbers increased, the program necessarily starts to reflect the LG&E and KU population of customers more closely, a fact that supports the idea that energy savings will occur among LG&E and KU customers after installation of an advanced meter.

Using two separate methodologies to analyze electric usage, Tetra Tech's iterative modeling approach estimated savings for AMP participants to be between 1.4 and 1.7 percent greater than naturally occurring usage reductions. Put another way, Tetra Tech estimates that AMP participants reduced their electric usage by 1.4 to 1.7 percent more than nonparticipants.

SAVINGS ESTIMATION METHODOLOGY OVERVIEW

Tetra Tech conducted three distinct analyses in support of the evaluation of all AMP participants.

- First, Tetra Tech examined consumption records of program participants that installed their meter in 2016 (referred to as "earliest adopters") prior to their enrollment in the program, comparing their usage patterns to a random sample of LG&E and KU nonparticipating customers. The goal of this analysis was to examine whether participants and nonparticipants exhibited similar electric usage *before* (i.e. in 2015) any advanced meter installations for earliest adopters.
- Second, Tetra Tech updated prior analyses that estimated savings by comparing electric usage among program participants by separating participants into a treatment and a contrast group based on the date of their advanced meter installation. More recent participants were placed into the contrast group; their consumption *prior* to advanced meter installation served as a contrast period to compare to longer term program participants.
- Finally, Tetra Tech conducted an analysis of electric usage among all program participants and compared usage patterns to LG&E and KU customers currently on a waitlist to enroll in the AMP. This waitlist group of customers is available as a comparison (contrast) group because AMP is currently limited to 20,000 participants and is fully enrolled, creating the need for a waitlist for customers interested in participating in the program.

SUMMARY OF RESULTS

ANALYSIS 1. EARLIEST ADOPTERS AND NONPARTICIPANTS

The results indicate that average daily energy use was not equal between earliest adopters and nonparticipants in 2015. On average, the nonparticipants used 1.8 kWh less per day than earliest adopters, with a confidence interval of ± 0.07 kWh. Nonparticipants consumed 39.4 kWh per day, and earliest adopters used 41.1 kWh daily. The corresponding confidence interval around the estimate of ± 0.07 kWh is at 95 percent confidence. Simply put, if Tetra Tech drew 100 new random samples of nonparticipating residential contracts and conducted this exact analysis 100 times, Tetra Tech expects the resulting difference to be within 1.71 and 1.85 kWh in 95 of 100 analyses. Table 2 provides additional detail about the t-test results.

Table 2. Analysis 1: Summary Statistics for Average Daily Consumption by Group

Group	N	Mean	Std. Dev.	Lower CL[7]	Upper CL
Earliest Adopters	1,781	41.14	26.7	41.17	41.21
Nonparticipants	18,601	39.36	27.1	39.34	39.38
Difference	N/A	1.78	0.4	1.71	1.85

ANALYSIS 2: TREATMENT AND CONTRAST GROUP

The second analysis consisted of an approach to estimate savings using the consumption data of customers in the treatment and contrast groups. The contrast group for this analysis were customers who enrolled in AMP since the beginning of February 2019 and had at least 28 months of pre-period consumption data that overlapped with the treatment group pre and post-installation energy consumption data. The analysis indicated average household energy savings of approximately 2.2 percent compared with the pre-installation period among households in the treatment group. Consumption among households in the contrast group fell by approximately 0.5 percent compared to pre-installation levels during the same period. The results for each analysis group are shown in Table 3. The treatment group reduced its normalized annual consumption (NAC) between the pre- and post-periods by an average of 326 kWh, or about 2.2 percent. The contrast group, however, reduced its NAC during this time by 73 kWh, or about 0.5 percent of baseline consumption. Thus, the estimated average impact of AMP is 1.7% x 14,520 kWh = 253 kWh.

Table 3. Normalized Annual Consumption

Analysis Group	n	NAC (kWh)
Treatment – pre period	3,448	14,520
Treatment – post period	3,448	14,194
Contrast – pre period	6,273	14,626
Contrast – post period	6,273	14,554

The 90 percent confidence interval around treatment group savings is ± 19 percent of the estimated value. Thus, the lower limit to the NAC for the treatment group is 264 kWh, and the upper limit is 387 kWh. Relative uncertainty around the contrast group impact was higher, resulting in a 90 percent confidence interval around the contrast group having bounds 18 kWh and 128 kWh, with a mean of 72 kWh.

ANALYSIS 3: PARTICIPATING CUSTOMERS AND WAITLISTED CUSTOMERS

After weather normalizing the data, Tetra Tech found that AMP participants had decreased their usage more during the post period than the waitlist group. The NAC kWh savings for the participants was 1,135 kWh, while waitlisted customers reduced consumption by 1,027 kWh, leaving the participants with an additional 1.4 percent savings over the waitlist group. Full NAC for each group can be seen in Table 4. AMP participants reduced NAC between the pre and post periods by an average of 1,135 kWh, or about 7.7 percent. The waitlist group, however, reduced its NAC during this time by 1,027 kWh, or about 6.3 percent of baseline consumption. Thus, the estimated average impact of AMP is 1.4% x 14,669 kWh = 205 kWh.

[7] All confidence limits (CL) are at 95 percent.

Table 4. Normalized Annual Consumption by Analysis Group

Analysis Group	N	NAC (kWh)
Participants – pre-period	8,946	14,669
Participants – post-period	8,946	13,534
Waitlisted – pre-period	1,998	16,264
Waitlisted – post-period	1,998	15,237

CONFIDENTIAL INFORMATION REDACTED

Appendix F – [redacted] Meter Life Study

Division 7-50

Request:

Provide an example of a real-time power flow study completed by PPL as referenced in response to DIV 2-48.

Response:

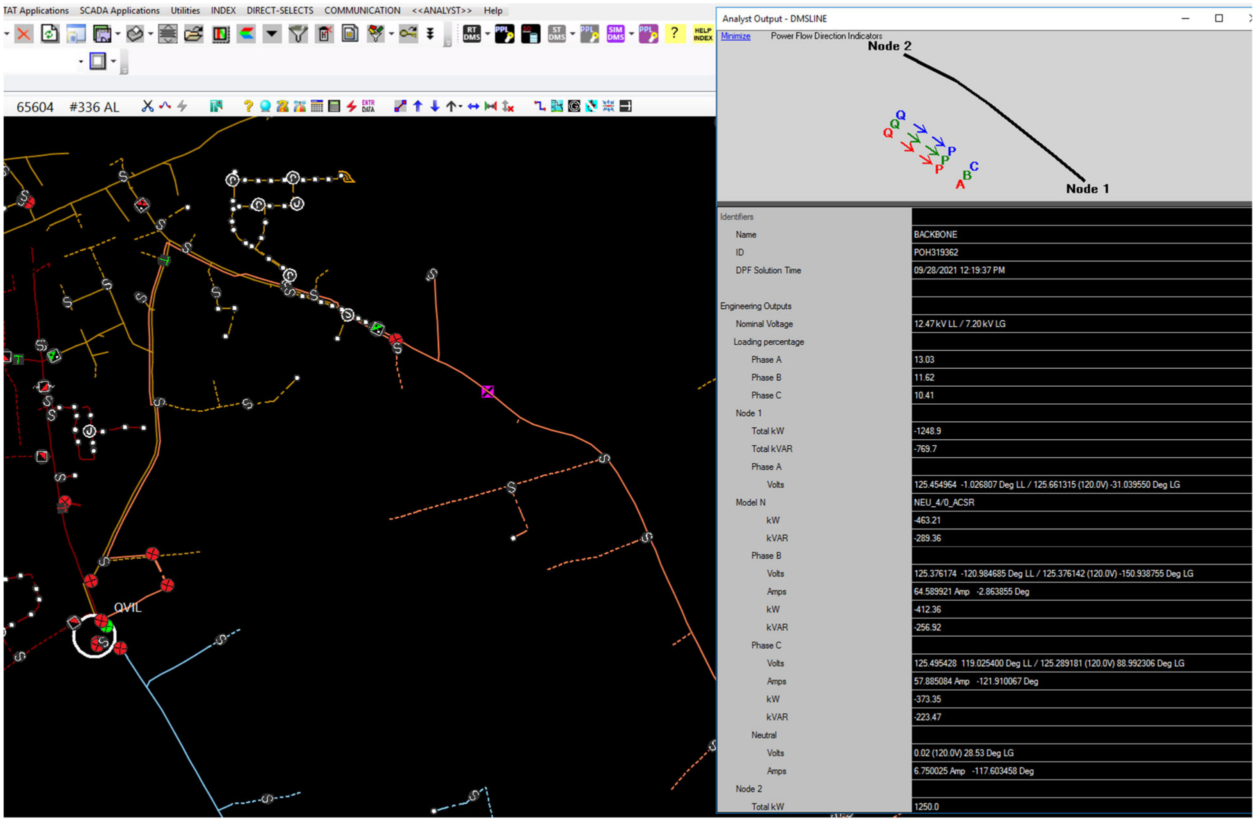
PPL's real-time power flow analysis runs on a continuous basis in PPL's Advanced Distribution Management System ("ADMS") and produces a solution based on the inputs outlined in PPL and PPL RI's responses to data request Division 2-48. In the control operations, real-time environment, power flow is able to identify reliability risks and automatically reconfigure the lines in the most advantageous way to eliminate exceeding equipment limitations while restoring the greatest amount of customers. At any point, real-time information can be imported into a study environment. This allows the control center operators to assess reliability risks associated with system reconfiguration based on the data produced by power flow. An example of the real-time power flow analysis is the detection and monitoring by a smart grid device that sends data into the real-time power flow analysis where the ADMS system analyzes the data to determine if changes in the system configuration are warranted in order to maintain reliability or restoration of customer outages.

Below are screen shots providing an example of this Real-Time Power Flow Analysis:

QVIL - DPF Feeder Results

Feeder	Operating Voltage (kV)	Highest Load or Bus Voltage (%)	Lowest Load or Bus Voltage (%)	Current Phase A (Amps)	Current Phase B (Amps)	Current Phase C (Amps)	Real Power Phase A (kW)	Real Power Phase B (kW)	Real Power Phase C (kW)	Total Real Power (kW)	Reactive Power Phase A (kVAR)	Reactive Power Phase B (kVAR)	Reactive Power Phase C (kVAR)	Total Reactive Power (kVAR)	Three Phase Power Factor	Feeder Head Branch
65601	12.47	105.76	103.41	45.50	42.00	52.80	326.70	277.96	387.04	991.70	-110.61	-154.52	-102.01	-367.13	0.9378 Leading	
65602	12.47	105.28	100.24	72.80	56.90	55.30	544.36	398.30	381.26	1323.91	88.53	165.36	173.18	427.07	0.9517 Lagging	
65603	12.47	105.15	99.01	70.90	79.20	53.10	537.47	592.00	396.35	1525.82	-9.09	99.23	70.25	160.39	0.9945 Lagging	
65604	12.47	105.14	99.16	72.30	65.00	57.30	469.15	422.77	376.27	1268.19	283.07	252.41	216.61	752.09	0.8601 Lagging	

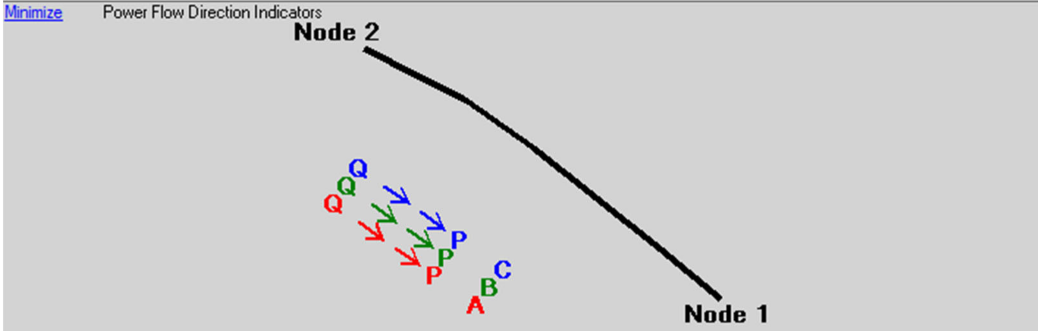
Prepared by or under the supervision of: Salim Salet



Prepared by or under the supervision of: Salim Salet

Analyst Output - DMSLINE

Minimize Power Flow Direction Indicators



Identifiers	
Name	BACKBONE
ID	POH319362
DPF Solution Time	09/28/2021 12:19:37 PM
Engineering Outputs	
Nominal Voltage	12.47 kV LL / 7.20 kV LG
Loading percentage	
Phase A	13.03
Phase B	11.62
Phase C	10.41
Node 1	
Total kW	-1248.9
Total kVAR	-769.7
Phase A	
Volts	125.454964 -1.026807 Deg LL / 125.661315 (120.0V) -31.039550 Deg LG
Model N	NEU_4/0_ACSR
kW	-463.21
kVAR	-289.36
Phase B	
Volts	125.376174 -120.984685 Deg LL / 125.376142 (120.0V) -150.938755 Deg LG
Amps	64.589921 Amp -2.863855 Deg
kW	-412.36
kVAR	-256.92
Phase C	
Volts	125.495428 119.025400 Deg LL / 125.289181 (120.0V) 88.992306 Deg LG
Amps	57.885084 Amp -121.910067 Deg
kW	-373.35
kVAR	-223.47
Neutral	
Volts	0.02 (120.0V) 28.53 Deg LG
Amps	6.750025 Amp -117.603458 Deg
Node 2	
Total kW	1250.0

Division 7-51

Request:

Please explain in detail if PPL's ADMS system and FLISR operations are monitored from a single PPL control center or if each state has its own control center. If each state has its own control center, please provide the location of each control center associated with the ADMS and FLISR operations. Additionally, please explain how PPL Rhode Island will be incorporated into this operation.

Response:

PPL's Advanced Distribution Management System ("ADMS") system and Fault Location, Isolation, and Service Restoration ("FLISR") operations in Pennsylvania presently are monitored and operated out of a single PPL control center in Allentown, PA. Additionally, there is a fully functional backup control center located in Harrisburg, PA, which is used in the event that the Allentown, PA location is unavailable. LGE-KU's ADMS and FLISR systems are monitored and operated out of a single LGE-KU control center located in Simpsonville, KY. Additionally, there is a fully functional backup control center located in Lexington, KY. PPL and PPL RI will monitor and operate the Narragansett distribution system from an existing National Grid facility located in Lincoln, RI. Over time, the Rhode Island distribution system will be incorporated into ADMS. During normal operations, the control center in each state will only operate for the geographic footprint of their respective state. In the event of an emergency, the control center in each state (PA or RI) will have the ability to monitor and control both states' distribution systems. The redundancy of two fully staffed, fully functional control centers, each with the ability to monitor and control ADMS and FLISR operations, will minimize disruption and help maintain continuity of the operation of the distribution system in the event of an emergency or loss of a control center.

Prepared by or under the supervision of: Salim Salet

Division 7-52

Request:

National Grid has made investments in Rhode Island towards deployment of ADMS, including IT, as part of its pre-approved Grid Modernization Plan. Identify those investments that align with PPL's ADMS system and that PPL intends to utilize in serving Rhode Island customers. For investments that will not be utilized, explain how any stranded assets will be treated. If the Transaction is approved, and if National Grid's investments in AMI and GMP are not fully utilized, explain how costs incurred and recovered, or planned for future recovery, will be reimbursed to Rhode Island ratepayers.

Response:

PPL and PPL Rhode Island intend to migrate away from the legacy Narragansett Distribution Management System that has been implemented in Rhode Island and will be upgrading to an Advanced Distribution Management System ("ADMS") platform currently in use by PPL Electric Utilities ("PPL Electric") in Pennsylvania. National Grid's investments in ADMS, Advanced Metering Functionality ("AMF"), and Grid Modernization Plans ("GMP") will be utilized by PPL Rhode Island where practical and feasible, and evaluations of which investments can be used by PPL Rhode Island are ongoing. PPL and PPL Rhode Island have not yet determined how any unused assets would be treated.

PPL Rhode Island anticipates that it will leverage the expertise and experience of PPL Electric in implementing ADMS, AMF, and smart grid facilities in Rhode Island. This will allow PPL Rhode Island to invest in ADMS, AMF, and smart grid facilities at a much lower cost than it would be able to if it were not able to rely on the prior experience of PPL Electric.

Narragansett's existing base rates as approved in its last rate case will remain in effect after the Transaction closes. PPL Rhode Island does not intend to seek cost recovery for expenses that may duplicate expenses for which National Grid or Narragansett has already sought recovery through base rates. That said, PPL Rhode Island may seek to recover portions of the costs of its investments that replace unused assets after close to the extent that PPL Rhode Island can demonstrate the incremental benefits of these transition costs.

Examples of potential merger-related incremental benefits of these transition costs include:

- Deploying Fault Location Isolation Service Restoration ("FLISR") capability in the ADMS;

Prepared by or under the supervision of: Matthew Green and Stephen K. Breininger

- Achieving real time visibility into the operation of the grid through the use of remote-controlled smart grid facilities; and
- Building Distributed Energy Resource Management ("DERMS") capabilities inside of the ADMS.

Division 7-53

Request:

Please provide details on National Grid's investment as of 8/1/2021 for the proposed AMI program. Specify the type of investment and associated costs necessary to prepare and submit the filings, including but not limited to internal resources, engineering, IT, consulting, legal and regulatory. Separately identify any capital and O&M costs incurred for investments related to AMI.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-53.

Division 7-54

Request:

Please provide details on National Grid's investment as of 8/1/2021 for the proposed GMP program. Specify the type of investment and associated costs necessary to prepare and submit the filings, including but not limited to internal resources, engineering, IT, consulting, legal and regulatory. Separately identify all capital and O&M costs incurred for investments related to GMP, specifying those that were pre-approved through regulatory proceedings.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 7-54.

Division 7-55

Request:

Please provide an estimate of how many existing National Grid jobs occupied by RI residents will be lost as a result of the Transaction because those positions and job functions will be performed by PPL employees located outside of RI. Provide an estimate of the total salaries paid to RI residents that will be filled by PPL employees not located in RI after the Transaction is completed.

Response:

PPL and PPL Rhode Island at this time cannot confirm the number of jobs of existing National Grid employees who are Rhode Island residents that will be lost as a result of the Transaction. As explained in National Grid and Narragansett's response to data request Division 7-28, the parties are continuing to determine the full scope of National Grid USA Service Company, Inc. ("Service Company") employees who will transfer to PPL and the Service Company employees who will remain with National Grid.

Division 7-56

Request:

Referencing PPL's statement in its response to DIV 2-1 that "PPL expects the implementation of its operational model will provide economies of scale by focusing the Rhode Island organization as described above and utilizing the Pennsylvania operations will bring enhanced reliability and customer satisfaction over the long term," compare and contrast PPL's proposed operational model to National Grid's current operational model and clearly indicate where the economies of scale will be achieved. How does PPL intend to enhance Narragansett's reliability? How will operations located in Pennsylvania be superior to operations currently located either directly in Rhode Island or in an adjacent region?

Response:

PPL's planned operational model for Rhode Island has been described in its response to data requests Division 2-1 and Division 7-42. As explained in PPL's response to data request Division 6-1(c), PPL's operating philosophy across all jurisdictions is based on prudent investments and operational efficiency that leads to strong reliability and premier customer satisfaction.

PPL and PPL Rhode Island will utilize support from a services company and affiliate utilities to achieve economies of scale in much the same manner as National Grid USA does currently with Narragansett. Areas where PPL anticipates economies of scale are in transmission, finance and accounting, remittance processing, business services, electric support, Information Technology, smart grid strategy, and customer experience strategy. These functions can be effectively performed outside of Rhode Island or adjacent areas without there being any degradation of service to Rhode Island customers. It should be noted that National Grid USA is performing some of these functions in areas that are not adjacent to Rhode Island currently, and that PPL Rhode Island will be bringing functions to Rhode Island that are not presently being performed in the state. Certain functions that are currently provided by National Grid USA that are planned to be created in Rhode Island are customer contact and back office functions, electric dispatch and control room operations, gas control and dispatch functions, gas and electric training operations and miscellaneous service company functions.

PPL has a proven track record of operational excellence, which it intends to bring to Rhode Island. There are several areas where PPL has identified that it can deploy its existing operational expertise with a goal to enhance reliability in Rhode Island. With respect to vegetation management practices, PPL will be using data analytics to address high risk areas that need to be addressed. This allows more surgical vegetation management investments with the goal of achieving excellent results. In addition, PPL's experience with the implementation of smart grid technology to provide

Fault Location Isolation Sectionalize and Restore ("FLISR") capability on the grid provides self-healing capabilities and, ultimately, enhanced reliability. Also, PPL's extensive use of data analytics for system maintenance programs, capital investments for lightning protection, avian protection, and asset replacement allows for very targeted investments, with the goal of strong reliability results and reduced operations and maintenance costs. PPL plans to leverage the strategy used in Pennsylvania that has resulted in award winning customer service and top decile reliability performance and bring that success to Rhode Island.

Indicative of PPL's strong performance are the numerous awards PPL Electric Utilities Corporation has won, which include:

- 28 JD Power awards for customer satisfaction. Top among large utilities in the East region for residential satisfaction 17 of the past 22 years. Nine straight J.D. Power Customer Satisfaction awards for large electric utilities in the eastern U.S.;
- 2021 Association of Edison Illuminating Companies ("AEIC") Achievement Award for vegetation management;
- 2021 Most Trusted Utility Brand in the Nation by Escalent;
- 2021 Energy Star Partner of the Year;
- 2021 S.E.E. Chairman's Award for Innovative Downed Wire Technology;
- 2021 E Source Website Usability Benchmark (Ranked 1st);
- 2020 Public Utilities Fortnightly Foremost Innovator Award (DERMS);
- 2020 Public Utilities Fortnightly Top Innovator Award (3D modeling for substations);
- 2019 Smart Electric Power Alliance Investor-Owned Utility of the Year;
- 2019 AEIC Achievement Award;
- 2019 Electric Power Research Institute Technology Transfer Award; and
- 2018 S.E.E. Industry Excellence Award for Safety.

Prepared by or under the supervision of: David J. Bonenberger

---

Division 7-57

Request:

Please supplement the response to DIV 2-10(a) to:

a. Provide a response for (a) which separately identifies the total capital investments for the years 2011 through 2020 broken out by distribution and transmission investments;

b. Provide the average annual distribution capital expenditure per customer and per 1,000 kWh; and

c. State whether PPL, LG&E, or KU has been denied cost recovery for any capital investments between 2011 and 2020. If yes, identify the amount, year, and description of the investment for which cost recovery was denied.

Response:

a. See Attachment PPL-DIV 7-57-1 and PPL-DIV 7-57-2.

b. See Attachment PPL-DIV 7-57-1 and PPL-DIV 7-57-2.

c. PPL Electric Utilities Corporation, LG&E and KU have not been denied cost recovery for any capital investments between 2011 and 2020.

Prepared by or under the supervision of: Lonnie E. Bellar, Stephen K. Breininger, and Salim Salet

Year	Company Name	Total Transmission Plant: Add ($000)	Total Distribution Plant: Add ($000)	Total Retail Electric Customers, Total (actual)	Distribution Capital/Customer	Total Retail Electric Volume, Total (MWh)	Sales for Resale Volume (MWh)	Total Sales of Electricity Volume (MWh)	Distribution Capital/MWH Sales
2011Y	Kentucky Utilities Company	32,097	72,040	540,839	$ 133.20	19,256,438	3,125,213	22,381,651	$ 3.22
2011Y	Louisville Gas and Electric Company	11,178	55,609	394,063	$ 141.12	11,641,054	5,185,682	16,826,736	$ 3.30
2012Y	Kentucky Utilities Company	37,752	82,571	538,461	$ 153.35	19,069,476	2,247,873	21,317,349	$ 3.87
2012Y	Louisville Gas and Electric Company	16,381	71,999	393,438	$ 183.00	11,837,729	3,632,775	15,470,504	$ 4.65
2013Y	Kentucky Utilities Company	42,404	66,870	540,882	$ 123.63	19,389,816	2,240,177	21,629,993	$ 3.09
2013Y	Louisville Gas and Electric Company	16,161	47,343	395,312	$ 119.76	11,698,975	2,779,341	14,478,316	$ 3.27
2014Y	Kentucky Utilities Company	44,056	87,349	542,227	$ 161.09	19,724,648	2,262,210	21,986,858	$ 3.97
2014Y	Louisville Gas and Electric Company	29,548	78,051	398,042	$ 196.09	11,817,164	3,556,567	15,373,731	$ 5.08
2015Y	Kentucky Utilities Company	49,166	77,963	544,307	$ 143.23	19,046,395	2,763,736	21,810,131	$ 3.57
2015Y	Louisville Gas and Electric Company	38,265	78,271	401,371	$ 195.01	11,767,029	1,735,184	13,502,213	$ 5.80
2016Y	Kentucky Utilities Company	74,824	105,455	547,069	$ 192.76	18,881,364	2,556,599	21,437,963	$ 4.92
2016Y	Louisville Gas and Electric Company	45,370	78,681	404,744	$ 194.40	11,947,052	1,209,441	13,156,493	$ 5.98
2017Y	Kentucky Utilities Company	61,742	83,549	550,636	$ 151.73	18,228,738	2,269,059	20,497,797	$ 4.08
2017Y	Louisville Gas and Electric Company	8,951	85,938	408,738	$ 210.25	11,526,591	1,606,543	13,133,134	$ 6.54
2018Y	Kentucky Utilities Company	123,782	113,265	552,923	$ 204.85	19,124,695	2,463,012	21,587,707	$ 5.25
2018Y	Louisville Gas and Electric Company	37,558	92,502	411,711	$ 224.68	12,063,888	1,792,146	13,856,034	$ 6.68
2019Y	Kentucky Utilities Company	106,441	165,366	556,129	$ 297.35	18,558,732	1,254,604	19,813,336	$ 8.35
2019Y	Louisville Gas and Electric Company	27,360	123,247	415,853	$ 296.37	11,655,309	1,515,848	13,171,157	$ 9.36
2020Y	Kentucky Utilities Company	157,548	113,402	560,922	$ 202.17	17,465,718	1,425,929	18,891,647	$ 6.00
2020Y	Louisville Gas and Electric Company	28,446	102,631	421,842	$ 243.29	11,008,049	1,090,488	12,098,537	$ 8.48

DIV 7-57. Please supplement the response to DIV 2-10(a) to:

a. Provide a response for (a) which separately identifies the total capital investments for the years 2011 through 2020 broken out by distribution and transmission investments

	Distribution	Transmission	General & Intangible	Future Use	CWIP	Total
2011	$ 219,791,835	$ 88,045,227	$ 33,475,805	$ 2,643,434	$ 67,431,553	$ 411,387,854
2012	$ 185,988,835	$ 190,631,421	$ 105,356,136	$ 1,442,494	$ 119,407,939	$ 602,826,825
2013	$ 260,765,906	$ 346,649,463	$ 21,936,377	$ 2,555,303	$ 231,043,258	$ 862,950,307
2014	$ 231,198,057	$ 473,774,760	$ 29,598,053	$ 5,054,110	$ 136,317,794	$ 875,942,774
2015	$ 222,093,561	$ 941,478,295	$ (716,124)	$ (2,321,324)	$ (212,291,107)	$ 948,243,301
2016	$ 273,720,229	$ 513,032,750	$ 160,586,125	$ (15,532,500)	$ 110,148,449	$ 1,041,955,053
2017	$ 284,834,724	$ 799,067,952	$ 65,067,634	$ (5,982,966)	$ (131,264,773)	$ 1,011,722,571
2018	$ 239,667,590	$ 598,277,094	$ 19,291,092	$ (315,229)	$ 72,258,752	$ 929,179,299
2019	$ 230,069,949	$ 673,572,885	$ 47,190,163	$ (346,606)	$ 24,221,910	$ 974,708,301
2020	$ 239,485,652	$ 662,719,621	$ 29,540,042	$ 75,163	$ 28,863,138	$ 960,683,616
Total	$ 2,387,616,338	$ 5,287,249,468	$ 511,325,303	$ (12,728,121)	$ 446,136,913	$ 8,619,599,901

b. Provide the average annual distribution capital expenditure per customer and per 1,000 kWh

	per Customer	per 1,000 kwh
2011	$ 156.55	$ 5.80
2012	$ 132.18	$ 5.03
2013	$ 184.86	$ 6.91
2014	$ 163.47	$ 6.08
2015	$ 156.56	$ 5.85
2016	$ 191.85	$ 7.28
2017	$ 199.31	$ 7.71
2018	$ 166.37	$ 6.23
2019	$ 158.66	$ 6.06
2020	$ 164.32	$ 6.48

* PPL Electric has not changed base distribution rates since January 1, 2016.

c. State whether PPL, LG&E, or KU has been denied cost recovery for any capital investments between 2011 and 2020. If yes, identify the amount, year, and description of the investment for which cost recovery was denied.

2012 Rate Case No capital investment denial
2015 Rate Case Settled

Division 7-58

Request:

Is PPL currently a member of ISO New England (ISO-NE)? If yes, does PPL currently operate as a transmission owner or load serving entity in this region?

Response:

PPL is not currently a member of ISO-NE. PPL is working with National Grid USA and ISO-NE personnel on the steps necessary to become a member.

Prepared by or under the supervision of: David J. Bonenberger

---

Division 7-59

Request:

Assuming that Narragansett's assets would be the first transmission assets in ISO-NE owned by PPL, please provide all studies or assessments prepared by or for PPL comparing the procedures, tools or approaches of PJM and ISO-NE.

Response:

PPL has not prepared any studies or assessments comparing the procedures, tools or approaches of PJM Interconnection, LLC ("PJM)" and ISO-NE, nor has it had any such studies or assessments prepared for it. PPL personnel have been reviewing and analyzing the ISO-NE rules, policies, and procedures and, although there are differences between PJM's operations and ISO-NE's operations, PPL's experience owning transmission assets in PJM will provide a strong baseline for PPL's ownership of transmission assets in ISO-NE. Additionally, PPL and/or its affiliates will be hiring National Grid USA Service Company, Inc. personnel with direct experience with the procedures, tools, and approaches of ISO-NE to complement PPL's experience in PJM and will work with National Grid USA through the Transition Services Agreement to further develop experience working with ISO-NE during the transition period.

Prepared by or under the supervision of: David J. Bonenberger

---

Division 7-60

Request:

Transmission and primary distribution revenue requirements for Narragansett Electric-owned facilities utilized for purposes of providing wholesale transmission service by New England Power Company d/b/a National Grid (NEP) to Narragansett are currently determined under Schedule III-B to NEP's FERC Tariff No. 1. Please provide estimates of these charges for the periods noted below by category of costs as identified in Schedule III-B. Additionally, please identify any incremental charges to those amounts as a result of the Transaction, including during the transition period or any period thereafter.

a. Actual year-to-date 2021

b. Forecast for the balance of 2021 before the assumed transaction close date

c. Forecast for the remainder of 2021 post the assumed transaction close date

d. Annual forecasts thereafter for the period 2022 through 2025

Response:

a. See National Grid USA's ("National Grid") response to Division 7-60.

b. See National Grid's response to Division 7-60.

c. See National Grid's response to Division 7-60. It is anticipated that the Transaction will close in 2022 and PPL has not prepared forecasts for the remainder of 2021.

d. During the transition, PPL will separate the Rhode Island transmission facilities from the New England Power Company d/b/a National Grid and withdraw from the Integrated Facilities Agreement. New England ISO, which Narragansett will join after the Transaction closes, is transitioning to a new formula based on FERC docket # ER20-2054. PPL is still analyzing the transmission revenue requirement and whether Narragansett will need any company-specific issues to be addressed in the formula rate. Therefore, a forecast of future revenue requirements is not available.

Prepared by or under the supervision of: Stephen K. Breininger

---

Division 7-61

Request:

Referencing New England Power Company's Electric Tariff No. 1, Schedule 1, Page 33, there is a discussion of the calculations necessary to credit RI distribution assets that are co-located with company transmission assets, including (among others) plant, substation and building assets. Please provide the following:

a. Please state whether any such assets will be jointly owned by PPL and National Grid after the close of the Transaction, or will otherwise require allocation of shared costs.

b. Are there other assets, such as poles and towers, whose costs and revenue requirements will likewise need to be allocated between the two companies post-Transaction?

c. Are there any shared services (maintenance or otherwise) related to co-located assets which will remain in place post-Transaction? If yes, please explain how the costs will be allocated.

Response:

a. PPL and PPL RI do not intend to jointly own any assets after the close of the Transaction or otherwise allocate shared costs with National Grid USA ("National Grid").

b. PPL and PPL RI do not intend to allocate costs and revenue requirements for other assets such as poles and towers post-Transaction with National Grid. PPL RI is acquiring all such assets owned by Narragansett.

c. PPL and PPL RI do not intend to retain any shared services related to co-located assets with National Grid.

Prepared by or under the supervision of: David J. Bonenberger