BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO DEPLOY ADVANCED METERING INFRASTRUCTURE, REQUEST FOR COST RECOVERY AND RELATED RELIEF	)))))	**DOCKET NO. UD-16-____**

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO DEPLOY ADVANCED METERING INFRASTRUCTURE, <u>REQUEST FOR COST RECOVERY AND RELATED RELIEF</u>

Entergy New Orleans, Inc. ("ENO" or the "Company") respectfully submits this Application to Deploy Advanced Metering Infrastructure, Request for Cost Recovery and Related Relief ("Application") to the Council of the City of New Orleans ("Council"). In support of its requests, the Company represents the following:

<u>INTRODUCTION</u>

I.

ENO is an electric and gas utility organized and operating under the laws of the State of Louisiana, with its general office and principal place of business at 1600 Perdido Street, Building 505, New Orleans, Louisiana 70112. The Company is engaged in the manufacture, production, transmission, distribution, and sale of electricity to residential, commercial, industrial, and governmental consumers throughout Orleans Parish. As of December 31, 2015, ENO furnished electric service to approximately 197,000 retail electric customers in Orleans Parish. ENO is also engaged in the provision of natural gas service throughout New Orleans and serves approximately 107,000 retail gas customers.

II.

Through this Application and supporting testimony, the Company proposes to enhance its electric system by deploying Advanced Metering Infrastructure ("AMI"), which is a system, including the associated hardware, software, and communications systems, that collects time-differentiated energy usage from advanced meters. AMI collects, processes, and records the information, then makes the information available to customers and utilities.

III.

AMI commonly includes three primary components: (1) advanced meters that enable two-way data communication; (2) a secure and reliable communications network that supports two-way data communication; and (3) related and supporting systems, including a Meter Data Management System ("MDMS"). Those components will be integrated into the Company's information technology ("IT") system. The Company also plans to update its legacy Outage Management System ("OMS") and implement a new Distribution Management System ("DMS"). Altogether, these components are referred to as the Company's "AMI deployment."

IV.

AMI is the foundation of the modernized power grid and will deliver reliability, customer service and empowerment improvements to ENO's customers, and will provide significant benefits to all of ENO's stakeholders. As customer expectations evolve regarding the provision of electric service and as technological innovation changes the way energy is supplied, ENO is focused on investing in new technology and infrastructure upgrades to move beyond the traditional, one-way centralized distribution grid and move towards a more advanced electric grid. As an initial and foundational step in that movement, ENO seeks to participate in a multi-company initiative, along with other Entergy Operating Companies, to implement AMI for its customers.

V.

Now is the right time for ENO to deploy AMI. The U.S. electric utility industry is undergoing significant change driven by new technology, the pace of technology innovation, increased customer expectations around availability of information/usage, increased customer interest around self-supply and control, an emphasis on efficiency, increasing regulation, aging infrastructure, and uncertainty surrounding evolving standards and environmental regulations. Moreover, technology and innovation are changing customer expectations as a result of how products and services are delivered both inside and outside of the utility industry. Added to this is the wealth of knowledge and services that are available to consumers via the Internet. Over the past several years, there has been a significant increase in customers' expectations that they be able to access information and manage services via mobile devices like smart phones, tablets, and other devices.

VI.

Customers can interact and conduct business electronically with many retailers, banks, and other service providers. To keep up with changing customer expectations, ENO has taken various steps to invest in communication technology that improves customers' access to usage and other important information via electronic devices. For example, ENO has implemented a mobile device application as well as added new features to its website, such as the ability to view outage information. But as technology evolves, so must the Company's capabilities.

VII.

ENO seeks a Council finding that its AMI deployment, including the removal and retirement of existing meters, is in the public interest. The Company also requests that the Council approve its AMI Rate Plan, accounting treatment requests. With this Application, the Company is submitting the Direct Testimonies of Charles L. Rice, Jr., Dennis P. Dawsey, Rodney W. Griffith, Michelle P. Bourg, Jay A. Lewis, Dr. Ahmad Faruqui, and Orlando Todd. The purpose of each testimony is as follows:

- **Charles L. Rice, Jr. –** Mr. Rice, President and Chief Executive Officer of ENO, provides an overview of the Project and the Application. He also introduces the testimony of the other witnesses supporting the Application.
- **Dennis P. Dawsey** – Mr. Dawsey is the Vice President of Customer Service for Louisiana. He presents testimony on how the AMI deployment will affect customer interactions, field operations, and ENO personnel and contractors. In particular, he reviews the Company's current meter reading and meter services operations' processes and describes which functions will no longer be necessary after AMI deployment. Mr. Dawsey describes the estimated personnel changes necessary to transition from the Company's current field practices to future operations under AMI. He also provides an overview of how customers may benefit from and use the information gathered through advanced meters and related systems. Mr. Dawsey also sponsors ENO's Customer Education Plan.
- **Rodney W. Griffith** – Mr. Griffith is the Director of AMI Implementation for ESI. He provides a technical discussion of the capabilities of AMI, as well as various functionalities that will be available when advanced meters are installed. Mr. Griffith

also describes the data that the advanced meters will collect, as well as how the data will be collected, stored, and transmitted. Lastly, Mr. Griffith discusses how the Company's AMI vendors were selected, the equipment and/or services that they will perform, the proposed AMI implementation approach and deployment schedule, and estimated costs of the AMI design and deployment.

- **Michelle P. Bourg** – Ms. Bourg is the Director of the Entergy Gas Distribution Business in Louisiana, and she describes the costs and benefits of the AMI deployment for ENO's natural gas customers.
- **Jay A. Lewis** – Mr. Lewis is the Vice President of Regulatory Policy for ESI, and he describes and quantifies specific benefits related to AMI and explains how the shared costs of AMI were allocated to each of the Entergy Operating Companies. Mr. Lewis addresses the operational savings associated with the meter reading and meter services changes described by Mr. Dawsey, as well as expected reductions in write-offs that will result from the functionalities provided by the AMI. He also quantifies other benefits from estimated reduction in customer usage, peak load, and associated capacity requirements, unaccounted-for energy ("UFE"), and the elimination of the need to maintain and replace existing meter reading equipment. He makes specific accounting proposals related to using a 15-year life for the AMI assets, and he also addresses the unrecovered costs of the existing meters that will be removed from service. Lastly, he provides an analysis of how the benefits of ENO's proposed AMI implementation outweigh its costs, which supports a Council finding that ENO's decision to implement AMI serves the public interest.

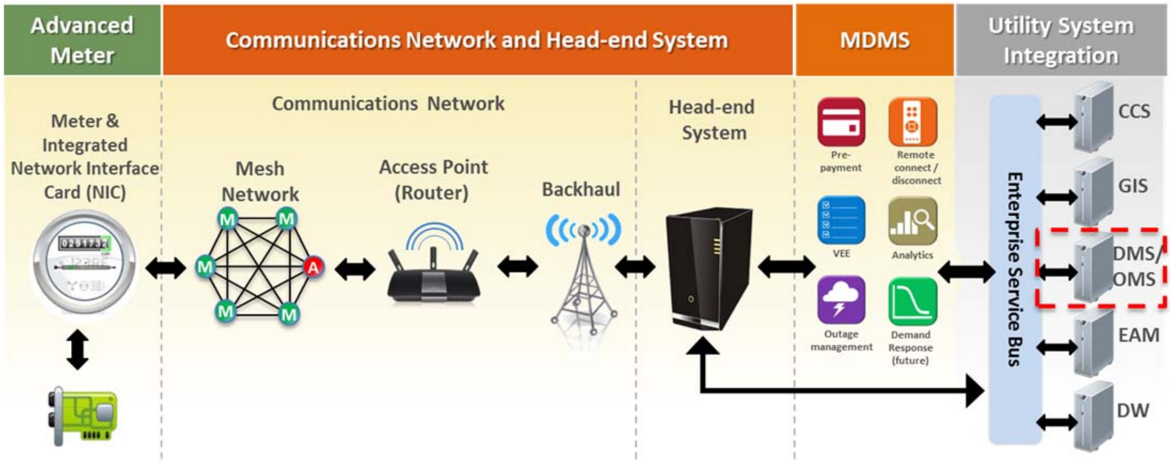
- **Dr. Ahmad Faruqui** – Dr. Faruqui is a Principal with The Brattle Group who offers an external viewpoint on the state of AMI deployment in the utility industry, as well as his opinions on ENO's assumptions in quantifying benefits associated with the Company's AMI deployment. His analysis of the estimated consumption and peak capacity benefit assumptions in particular are based on his broad experience with customer behavior research and experiences of other utilities that have deployed AMI. He concludes that the assumptions used in ENO's cost-benefit analysis are reasonable and consistent with current industry practices, and that the AMI deployment will provide significant benefit to customers.
- **Orlando Todd** – Mr. Todd is the Director of Finance for ENO; and he presents the Company's proposal for the recovery of the costs associated with the AMI deployment.

OVERVIEW OF AMI

VIII.

AMI is a broad term that encompasses a range of related technologies and processes. Essentially, as Company witness Mr. Griffith more fully describes, AMI is a system, including the associated hardware, software, and communications systems, that collects time-differentiated energy usage from advanced meters. As stated above, AMI commonly includes three primary components: (1) advanced meters that enable two-way data communication, (2) a secure and reliable communications network that supports two-way data communication, and (3) related and supporting systems, including a MDMS. Mr. Griffith provides a detailed discussion of these components and the technical capabilities of ENO's proposed AMI deployment. As Company witness Ms. Bourg describes, ENO also proposes AMI implementation for gas customers. The components are illustrated in Figure 1 below:

Figure 1



IX.

AMI will be designed and built to deliver a number of functionalities and operational applications immediately upon deployment, as well as to support additional applications that may be implemented over time. The applications that will be available immediately upon deployment and meter activation include: 1) automated remote meter reading, including recording and processing interval consumption data at 15-minute intervals for residential customers and 5-minute intervals for commercial and industrial customers, with the verified data being made available to customers daily, 2) two-way communications, 3) remote enabled service connection, disconnection and reconnection, 4) remote configuration and firmware upgrades; 5) automated meter health and status communication, 6) web-based customer data accessibility, which will facilitate customers' web portal access of their usage information, 7) customer usage goal-setting thresholds and alerts, 8) outage management support, including restoration verification, 9) theft and tamper notifications to the Company, 10) event and load profiling for analytics, 11) power quality reporting, 12) asset mapping and predictive asset management, 13) more accessible information for load forecasting and load research efforts, 14) support for implementation of optional pre-pay programs, and 15) ability to incorporate distributed energy resources ("DER"), which have grown more prevalent in recent years (*e.g.*, rooftop solar systems).

X.

AMI will also support additional applications that may be implemented over time. Those applications include features such as: 1) advanced usage analytics and energy savings tips that are customized to each unique customer, 2) dynamic pricing programs such as time-of-use and real-time pricing, 3) more expansive demand programs, 4) potential control and dispatch of DERs, 5) streetlight monitoring and control applications, 6) voltage optimization and control (*e.g.*, conservation voltage reduction or "CVR" programs), 7) enablement of distribution automation, and 8) enablement of distributed intelligence. These additional functions and applications are not included in ENO's AMI deployment, and each application will require some level of additional investment in order to achieve the described functionality.

XI.

Full AMI deployment is expected to take approximately five years. The first phase, design, which has already begun, encompasses the bidding process for the best solution and a detailed design and plan for implementation, including a customer education plan. The second phase, the system build phase, includes validating the system functionality, and beginning customer education. The third and final phase, meter and network deployment, is the point when the communication network and meters are deployed. Assuming Council approval is received in 2017, and after the necessary IT infrastructure and communications network are in place, the deployment and installation of the advanced meters and components at customers' premises would begin in early 2019 and would proceed as follows:

Preliminary Meter Deployment Schedule			
	2019	2020	2021
Electric Meters	24,000	102,000	73,000
Gas Modules	39,000	62,000	11,000

CUSTOMER BENEFITS

XII.

AMI offers a number of immediate and longer-term benefits to customers. As Company witness Mr. Lewis explains in his Direct Testimony, the Company has conducted a cost/benefit analysis that quantifies several of the expected benefits from AMI deployment. Those quantified benefits are broken down into two categories: (1) Operational Benefits; and (2) Other Benefits.

The Operational Benefits include: (i) routine meter reading; (ii) meter services; and (iii) reduced customer receivable write-offs. The Other Benefits include: (i) consumption reduction; (ii) peak capacity reduction; (iii) UFE reduction; and (iv) elimination of the need to maintain and replace existing meter reading equipment.

Company witnesses Mr. Griffith and Ms. Bourg explain the underlying categories of costs that will be incurred to obtain the benefits of AMI, which Mr. Todd explains fall within three different groupings for ratemaking purposes: AMI Implementation Costs, Customer Education Expenses, and Ongoing O&M Expenses.

As ENO witness Mr. Lewis explains, the cost/benefit analysis conducted by the Company shows that benefits are expected to exceed the overall costs of the deployment. Specifically, Mr. Lewis explains that AMI implementation will produce a collective benefit to ENO’s electric and gas customers of $27 million on a present value (“PV”) basis, assuming a 15-year useful life of the AMI assets, which is a reasonable useful life to assume. Table 1 in Mr. Lewis’ testimony provides a summary of the cost/benefit analysis on both a nominal and PV basis:

Table 1

		Nominal ($M)	PV ($M, 2016)
	Quantified Operational Benefits		
1	Routine Meter Reading	$45	$19
2	Meter Services	$47	$20
3	Reduced Customer Receivables Write-offs	$3	$1
4	**Total Quantified Operational Benefits**	$95	$40
	Quantified Other Benefits		
5	Consumption Reduction	$104	$42
6	Peak Capacity Reduction	$35	$14
7	Unaccounted For Energy Reduction	$38	$15
8	Meter Reading Equipment	$2	$1
9	**Total Quantified Other Benefits**	$178	$72
10	**Total AMI Quantified Benefits**	$273	$112

	AMI lifetime costs to customers[1]	**Nominal ($M)**	**PV ($M, 2016)**
11	Depreciation & Amortization	$74	$34
12	Return on Rate Base	$49	$28
13	AMI O&M Costs	$32	$14
14	Property Tax	$18	$9
15	**Total AMI Costs**[2]	$173	$85

16	**Net AMI Benefit**	**$101**	**$27**

XIII.

Once advanced meters and related infrastructure and systems are activated, ENO's customers will have access to more detailed energy usage data, which will help customers to better understand and manage their usage and reduce their energy bills. ENO will also educate customers regarding how to take advantage of that new information. For utilities that have

[1] Including the amortization of the Regulatory Asset for 2017 and 2018 customer education and O&M expenses.

[2] The Total AMI Costs are based on an assumption that all of the Entergy Operating Companies deploy AMI at the same time, which, as Mr. Griffith explains, provides opportunities for economies of scale and lower overall costs for customers. Should an Operating Company not deploy AMI, and there is a resulting material effect on the AMI costs that would be borne by ENO, the Company will advise the Council and its Advisors to ensure that moving forward with AMI at a higher cost continues to be in the public interest.

already implemented AMI, making detailed usage information available to customers via the Internet and mobile devices, along with education about how customers can better manage and reduce their energy consumption, has resulted in significant bill savings opportunities for customers. As discussed by Mr. Lewis, ENO expects similar consumption reduction benefits for its customers. ENO witness Dr. Ahmad Faruqui discusses in his Direct Testimony the benefits that will result from customers having access to this type of detailed usage information.

ENO customer service representatives will also have more timely and detailed customer energy usage data to help expedite and more effectively address customer billing questions and issues. AMI will also serve as the technical foundation and platform for the modernization of ENO's electric grid that will enable future products and services to customers.

With the new information and connectivity available through AMI, integrating an OMS and DMS will enhance the Company's ability to identify the location and scope of outages more quickly, and will provide enhanced information for devices throughout the distribution network. This capability will allow ENO to pinpoint and respond faster to service outages, which will directly benefit its customers. Accurate outage data means that customers will have more accurate outage and restoration information and notifications. Mr. Griffith provides an extensive discussion of these related systems and their benefits in his Direct Testimony.

XIV.

Ms. Bourg discusses the key benefits associated with ENO's implementation of gas AMI. As she explains, AMI will enhance the overall safety of the gas system. Today, the Company relies on a combination of routine field inspections and customer notifications to alert personnel of a potential gas leak. With AMI data, a large increase in consumption would trigger an alert, which would allow the Company to identify a potentially hazardous situation, like a leak within the service location.

In addition to public safety enhancements, there are several additional benefits that the Company expects to see as a result of its advanced gas meter implementation. These benefits include increased personnel and contractor safety, improved billing accuracy, reduced customer call volume, optimization of distribution system capital investment, refined process for gas forecasting and procurement, improved pipeline safety compliance, reduced metering tampering losses, and reduced losses due to inactive meters.

COST RECOVERY AND ACCOUNTING TREATMENT REQUESTS

XV.

The Company requests a Council decision, supported by the evidence and sound regulatory principles, that the deployment of AMI in its service territory is in the public interest and therefore prudent. As part of this decision, the Company requests that the Council approve its proposed AMI Rate Plan, which is discussed by Mr. Todd.

As Mr. Lewis explains in his Direct Testimony, the deployment of electric and gas AMI is expected to produce customer benefits. Those benefits, however, do not come without a cost. As Mr. Todd discusses, the Company's combined $75 million AMI capital investment represents a substantial commitment for ENO, as the investment from 2019-2021 represents an average increase of approximately 25% over ENO's annual baseline distribution capital investment budget for electric operations for the period 2016-2018.

In the past, the Council has allowed timely recovery of the costs associated with new resources obtained for the benefit of ENO's customers, such as Union Power Block 1 and the Power Purchase Agreement with respect to Ninemile 6. Such rate treatment provides an incentive for ENO to continue to undertake large investments or obligations in order to secure benefits for its customers. Unlike many previous large projects, however, the AMI project involves investments that will be closed to plant in service on a rolling basis, with the resulting benefits of those investments progressively accruing during the course of deployment through 2021.

Because of the significant overall investment required to deploy AMI – and the resulting benefit to customers as the deployment occurs – the Company is requesting the implementation of a charge calculated on a per-customer basis that would recover the costs of AMI, net of certain benefits, through a customer charge phased in over the period 2019 through 2022. This charge is referred to as the "AMI Customer Charge," and would be charged to all metered electric and gas ENO customers.

XVI.

As Mr. Todd explains, it is anticipated that rates resulting from the 2018 Combined Rate Case will be implemented for the first billing cycle following a determination by the Council resulting from the Combined rate case (August 2019), and implementation of the initial AMI Customer Charge would be part of the rate design of those rates. The initial AMI Customer Charge would reflect a *pro forma* adjustment to the Period II (2018) Combined Rate Case test year for known and measurable changes related to AMI. The AMI Customer Charge would be adjusted in January 2020 and January 2021 to reflect the incremental changes in AMI's costs and benefits for the 2020 and 2021 calendar years, respectively.

The Company will make filings in October 1, 2019 and October 1, 2020 that contain the estimated costs and estimated benefits to be included in the AMI Customer Charge. The October

1st filing date would allow the Council and its utility Advisors time to review the components of the annual AMI Customer Charge that would be implemented in January of 2020 and 2021.

The final Customer Charge would be implemented in May 2022, following a similar filing. All costs included in the AMI Customer Charge would be subject to the Council's review to ensure they were prudently-incurred, and any changes ordered by the Council would be reflected in a true-up included in the final AMI Customer Charge. As Mr. Todd notes, there are certain AMI benefits that will not be included in the AMI Customer Charge, but rather through ENO's other rate mechanism, *i.e.*, Fuel Adjustment Clause and Purchased Gas Adjustment.

XVII.

As part of its AMI deployment plan, it is necessary for the Company to incur certain O&M expenses and customer education expenses in 2017 and 2018. Because these expenses are prudent and necessary to ensure the deployment of AMI, and would not otherwise be recovered, the Company is requesting a Council order authorizing a deferral of the Customer Education and Ongoing AMI O&M Expenses incurred in 2017 and 2018, with carrying charges, for recovery commencing with the January 2020 AMI Customer Charge ("AMI Deferral"). Such an order would allow those expenses to be recorded on the Company's balance sheet as a regulatory asset. The Company would then amortize the AMI Deferral regulatory asset over two years.

XVIII.

As Mr. Dawsey and Mr. Lewis discuss in their Direct Testimony, the Company proposes to provide residential customers with the choice to opt out of having an advanced meter installed at their premises. It is important to note that, as part of offering this option, the Company will incur up-front and ongoing costs associated with a customer's choice to opt out of having an advanced meter. As a result, the Company proposes that the up-front costs, including the customer billing set-up, meter locks, trip charge, and processing of opt-out paperwork, be charged directly to an opt-out customer through a one-time fee. In addition, the Company proposes to charge an opt-out customer a monthly fee associated with the ongoing added costs of manual meter reading and billing. The Company would use a formal process to document the customer's decision to opt out, including having the customer fill out, sign, and submit a form indicating their voluntary decision to opt out of receiving an advanced meter. This process also requires the customer to acknowledge the added cost to him/her that is triggered by his/her decision to opt out, including the up-front fee and the monthly recurring fee. In his Direct Testimony, Company witness Mr. Lewis provides an illustration of the methodology that the Company requests would be used to establish the opt-out fees. Mr. Lewis also explains that the Company expects to make a compliance filing closer to deployment of advanced meters, which would include the opt-out form the customer would execute, the form of the tariff, as well as the proposed charges and associated costs used to derive the opt-out charges following the methodology approved by the Council, as part of this proceeding.

XIX.

As Mr. Lewis discusses in his Direct Testimony, the Company also requests continued recovery of the remaining book value of existing meters at the current rate and existing mechanisms until the undepreciated value is fully recovered. The recovery of and on existing meters, however, would occur through the Company's FRP or replacement base ratemaking mechanism, as it does today. As such, there will be no change in rates or revenue requirement associated with those assets.

XX.

As Mr. Dawsey explains, the Company has identified a few areas where revisions to service regulations, rate schedules or policies may be needed. The Company anticipates that additional details will be developed as it completes the AMI design phase and progresses toward deployment. ENO commits to work with the Council, the Advisors, and other parties to identify and revise, as appropriate, any service regulations, policies, or rate schedules that may be affected by the AMI deployment.

PUBLIC INTEREST

XXI.

Through this Application, ENO has submitted testimony and exhibits including the estimates and supporting documentation for the costs of deploying AMI, the separate identification of the estimated costs associated with the integration of AMI with current IT systems, and the other indirect costs associated with implementation. The quantifiable and non-quantifiable benefits associated with AMI support ENO's decision to deploy AMI within its service territory. Company witness Mr. Lewis provides testimony supporting the finding that ENO's implementation of its proposed AMI is in the public interest. For all of the reasons described herein, and in the Direct Testimony filed in support of this Application, the Council should find that ENO's implementation of its proposed AMI is in the public interest.

XXII.

ENO also notes that as a part of the EPC Agreement, ENO will require its contractors to provide opportunities to small and disadvantaged businesses for participation in the Company's AMI deployment. For the AMI project, the requests for proposal process described by Mr. Griffith was structured to explicitly solicit information from suppliers regarding their plan to utilize diverse and local suppliers.

SERVICE OF NOTICES AND PLEADINGS

XXIII.

The Company request that notices, correspondence, and other communications concerning this Application be directed to the following persons:

Gary E. Huntley Vice President, Regulatory and Governmental Affairs Entergy New Orleans, Inc. 1600 Perdido Street New Orleans, Louisiana 70112	Timothy S. Cragin Brian L. Guillot Alyssa Maurice-Anderson Harry M. Barton Entergy Services, Inc. 639 Loyola Avenue Mail Code: L-ENT-26E New Orleans, Louisiana 70113

REQUEST FOR CONFIDENTIAL TREATMENT

XXIV.

Certain exhibits supporting the Direct Testimony of Orlando Todd, Jay A. Lewis, and Rodney W. Griffith contain information considered by ENO to be proprietary and confidential. Public disclosure of certain of this information may expose ENO and its customers to an unreasonable risk of harm. Therefore, in light of the commercially sensitive nature of such information, these exhibits bear the designation "Highly Sensitive Protected Materials" or words of similar import. The confidential information and documents included with the Application may be reviewed by appropriate representatives of the Council and its Advisors pursuant to the provisions of the Official Protective Order adopted in Council Resolution R-07-432 relative to the disclosure of Highly Sensitive Protected Materials. As such, these confidential materials shall be exempt from public disclosure, subject to the provisions of Council Resolution R-07-432.

PRAYER FOR RELIEF

XXV.

WHEREFORE, Entergy New Orleans, Inc. respectfully requests that the Council, subject to the fullest extent of its jurisdiction, grant relief and give its approval as follows:

1. Find that the Company's deployment of AMI, including the removal and retirement of existing meters, installation of new advanced meters and supporting systems and equipment, and customer education plan, serves the public convenience and necessity and is in the public interest, and is therefore prudent;

2. Confirm that the Company's investments made pursuant to a public interest determination by the Council are presumed prudent and eligible for recovery from customers, and that the Company will have a full and fair opportunity to recover all prudently-incurred costs of the AMI deployment;

3. Find that the Company's AMI Rate Plan as presented in the Direct Testimony of ENO witness Orlando Todd, which includes the implementation of an AMI Customer Charge, which would recover the costs of AMI, net of certain benefits, through a customer charge phased in over the period 2019 through 2022 and quantified Other Benefits through corresponding Fuel Adjustment Clause, Purchased Gas Adjustment, or FRP as appropriate, is just and reasonable, and in the public interest;

4. Approve ENO's proposed AMI Customer Charge to be included in rates resulting from the 2018 Combined Rate Case and to be implemented in the first billing cycle following a determination of rates by the Council resulting from the contemplated 2018 Combined Rate Case; and approve the AMI Customer Charge to be adjusted in January 2020 and January 2021 to reflect the incremental changes in AMI costs and benefits for the 2020 and 2021 calendar years, respectively;

5. Authorize ENO to: a) defer all incremental 2017 and 2018 Customer Education Expenses and Ongoing AMI O&M Expenses incurred by the Company in 2017 and 2018 in connection with its AMI deployment, with carrying charges at the pre-tax Weighted Average Cost of Capital ("AMI Deferral"); b) establish a regulatory asset that includes the unamortized balance of the AMI Deferral; and c) commence recovery thereof with the January 2020 AMI Customer Charge, amortized over a two-year period;

6. Find that, with respect to existing electric and gas meters, the Company shall continue to recover the remaining book value of those assets at the current rate through the existing mechanisms, until the undepreciated value is fully recovered;

7. Approve the Company's proposed methodology that will be used to establish the opt-out fees and confirm to correct application of the approved methodology following a the Company's submission of compliance filing for this purpose;

8. Grant a waiver of any applicable requirement to the extent that such a waiver may be required to facilitate approval of the transaction described in this Application; and

9. Order such other general and equitable relief as to which the Company may show itself entitled.

Respectfully submitted,

Timothy S. Cragin, Bar No. 22313
Brian L. Guillot, Bar No. 31759
Alyssa Maurice-Anderson, Bar No. 28388
Harry M. Barton, Bar No. 29751
639 Loyola Avenue, Mail Unit L-ENT-26E
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ATTORNEYS FOR ENTERGY NEW ORLEANS, INC.

BEFORE THE

COUNCIL FOR THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO DEPLOY ADVANCED METERING INFRASTRUCTURE, AND REQUEST FOR COST RECOVERY AND RELATED RELIEF	**))))))**	**DOCKET NO. UD-16__**

DIRECT TESTIMONY

OF

CHARLES L. RICE, JR.

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

OCTOBER 2016

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EXHIBIT LIST

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Charles L. Rice, Jr. I am President and Chief Executive Officer of Entergy New Orleans, Inc. ("ENO" or the "Company"). My business address is 1600 Perdido Street, Building 505, New Orleans, Louisiana 70112.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying before the Council of the City of New Orleans ("CNO" or the "Council") on behalf of ENO.

Q3. WHAT ARE YOUR CURRENT DUTIES?

A. As President and Chief Executive Officer of ENO, a position I have held since June 2010, I have executive responsibility for the Company, which includes responsibility for the production, transmission, and distribution assets that are used to serve ENO's customers. In addition, my responsibilities include oversight of the field management of the electric distribution system, customer service, economic development, regulatory affairs, and governmental affairs groups of ENO, as well as oversight of the Company's gas operations.

Q4. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I earned a Bachelor of Science degree in Business Administration from Howard University in 1986. Following graduation, I was commissioned as a second lieutenant in the United States Army and served as a military intelligence officer with the 101st Airborne Division (Air Assault). In 1995, I earned a Juris Doctorate from Loyola University New Orleans School of Law. Upon admission to the Louisiana Bar, I began practicing law with the firm of Jones, Walker, Waechter, Poitevent, Carrère & Denègre, LLP. In 2000, I joined the Legal Department of Entergy Services, Inc. ("ESI").[1] In ESI's Legal Department, I held the position of Senior Counsel and was a member of the Casualty Litigation group. Shortly thereafter, I transferred to the Human Resources Department, where I served as Manager of Labor Relations Litigation Support.

In 2002, I left ESI to serve in local government as the City Attorney for the City of New Orleans. I later served as Chief Administrative Officer for the City of New Orleans, in which role I managed 6,000 employees and the City's $600 million budget. In 2004, I returned to private law practice as a partner with the law firm of Barrasso, Usdin, Kupperman, Freeman & Sarver, LLC. In 2009, I returned to Entergy to serve as Director of Utility Strategy for ESI. In that role, I was responsible for coordinating regulatory, legislative and communications efforts for Entergy's regulated utility companies. In early 2010, I transferred to ENO to lead the Regulatory Affairs Department, and, in June 2010, I was promoted to my current position. I also earned an Executive Master of Business Administration degree from Tulane University in 2012.

[1] ESI is a subsidiary of Entergy Corporation that provides technical and administrative services to all the Entergy Operating Companies. The Entergy Operating Companies include ENO, Entergy Arkansas, Inc., Entergy Louisiana, LLC, Entergy Mississippi, Inc., and Entergy Texas, Inc.

Q5. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. A listing of the cases in which I have previously testified is attached hereto as Exhibit CLR-1.

II. OVERVIEW

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Company's Application seeking CNO approval to implement Advanced Metering Infrastructure ("AMI") in New Orleans. AMI is the foundation of the modernized power grid and will deliver reliability, as well as customer service and empowerment improvements to our customers, while providing significant benefits to all of our stakeholders. As customer expectations evolve regarding the provision of electric and gas service and as technological innovation changes the way energy and related information is supplied, ENO is focused on investing in new technology and infrastructure upgrades to move beyond the traditional, one-way, centralized distribution grid and move towards a more advanced electric grid. As an initial and foundational step in that movement, ENO has decided to participate in a multi-company initiative, along with other Entergy Operating Companies, to implement AMI for ENO's customers. In its Application, ENO is requesting a finding from the Council that its proposed deployment of AMI, including the removal and retirement of existing meters and installation of new advanced meters and supporting systems and equipment, is in the public interest.

Specifically, my testimony will:

1. introduce the witnesses who are submitting testimony on behalf of the Company and provide a summary of the topics discussed by each witness;
2. provide an overview of the expected AMI deployment, including customer benefits, and explain why the Company has chosen to make this investment now; and
3. explain the Company's proposed cost recovery method for the AMI project.

III. OVERVIEW OF DIRECT TESTIMONY

Q7. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY WITNESSES' DIRECT TESTIMONY FILED IN SUPPORT OF THIS APPLICATION.

A. The Company offers six additional AMI witnesses:

- **Dennis P. Dawsey** – Mr. Dawsey is the Vice President of Customer Service for Louisiana. He presents testimony on how the AMI deployment will affect customer interactions, field operations, and ENO personnel and contractors. In particular, he reviews the Company's current meter reading and meter services operations' processes and describes which functions will no longer be necessary after AMI deployment. Mr. Dawsey describes the estimated personnel changes necessary to transition from the Company's current field practices to future operations under AMI. He also provides an overview of how customers may benefit from and use the information gathered through advanced meters and related systems. Mr. Dawsey also sponsors ENO's Customer Education Plan.

- **Rodney W. Griffith** – Mr. Griffith is the Director of AMI Implementation for ESI. He provides a technical discussion of the capabilities of AMI, as well as various functionalities that will be available when advanced meters are installed. Mr. Griffith also describes the data that the advanced meters will collect, as well as how the data will be collected, stored, and transmitted. Lastly, Mr. Griffith discusses how the Company's AMI vendors were selected, the equipment and/or services that they will perform, the proposed AMI implementation approach and deployment schedule, and the estimated costs of the AMI design and deployment.
- **Michelle P. Bourg** – Ms. Bourg is the Director of the Entergy Gas Distribution Business in Louisiana, and she describes the costs and benefits of the AMI deployment for ENO's natural gas customers.
- **Jay A. Lewis** – Mr. Lewis is the Vice President of Regulatory Policy for ESI, and he describes and quantifies specific benefits related to AMI and explains how the shared costs of AMI were allocated to each of the Entergy Operating Companies. Mr. Lewis addresses the operational savings associated with the meter reading and meter services changes described by Mr. Dawsey, as well as expected reductions in write-offs that will result from the functionalities provided by the AMI. He also quantifies other benefits from estimated reduction in customer usage, peak load, and associated capacity requirements, unaccounted for energy ("UFE"), and the elimination of existing meter reading equipment. He makes specific accounting proposals related to using a 15-year life for the AMI assets, and he also addresses the unrecovered costs of the existing meters that will be removed from service. Lastly, he provides an analysis of how the benefits of ENO's proposed AMI implementation outweigh its costs,

which supports a Council finding that ENO's decision to implement AMI serves the public interest.

- **Dr. Ahmad Faruqui** – Dr. Faruqui is a Principal with The Brattle Group who offers an external viewpoint on the state of AMI deployment in the utility industry, as well as his opinions on ENO's assumptions in quantifying benefits associated with the Company's AMI deployment. His analysis of the estimated consumption and peak capacity benefit assumptions in particular are based on his broad experience with customer behavior research and experiences of other utilities that have deployed AMI. He concludes that the assumptions used in ENO's cost/benefit analysis are reasonable and consistent with current industry practices, and that the AMI deployment will provide significant benefit to customers.
- **Orlando Todd** – Mr. Todd is the Director of Finance for ENO, and he presents the Company's proposal for the recovery of the costs associated with the AMI deployment.

IV. OVERVIEW OF AMI

Q8. WHAT IS AMI?

A. AMI is a broad term that encompasses a range of related technologies and processes. Essentially, as Mr. Griffith more fully describes, AMI is a system, including the associated hardware, software, and communications systems, that collects time-differentiated energy usage from advanced meters. AMI collects, processes, and records the information, and makes the information available to customers and utilities.

AMI commonly includes three primary components: (1) advanced meters that enable two-way data communication; (2) a secure and reliable communications network that supports two-way data communication; and (3) related and supporting systems, including a Meter Data Management System. Those components will be integrated into the Company's information technology system. The Company also plans to update its current Outage Management System ("OMS") and implement a new Distribution Management System ("DMS"). I refer to all of these components collectively as ENO's AMI deployment. Company witness Mr. Griffith provides a detailed discussion of these components and the technical capabilities of ENO's proposed AMI deployment.

Q9. DOES THE COMPANY'S AMI PROPOSAL INCLUDE UPGRADING THE COMPANY'S GAS METERS?

A. Yes. Company witness Ms. Bourg describes the specifics of the AMI implementation for gas customers and the many benefits that gas customers will receive.

Q10. WHAT IS THE EXPECTED SCHEDULE FOR THE COMPANY'S AMI DEPLOYMENT?

A. Assuming CNO approval is received in 2017, and after the necessary IT infrastructure and communications network are in place, the deployment and installation of the advanced meters and components at customers' premises would begin in early 2019 and take approximately three years to complete.

Preliminary Meter Deployment Schedule			
	2019	2020	2021
Electric Meters	24,000	102,000	73,000
Gas Modules	39,000	62,000	11,000

Q11. WHAT ARE THE BENEFITS OF AMI TO ENO'S CUSTOMERS?

A. A key benefit of AMI is that it will enable ENO to more accurately identify outage locations, which will allow quicker and more accurate detection of service problems, improved outage and restoration communications with customers, and overall faster outage restoration. AMI will also assist customer service representatives to more effectively address customer billing issues. Further, AMI will be able to provide customers timely access to their detailed energy usage data through a web portal that will include tools and notifications to allow customers to manage their energy bills more effectively. AMI will create value through enhanced reliability, operational efficiencies and new products and services, all while allowing ENO to provide reliable, safe and low-cost energy.

ENO witness Mr. Lewis provides testimony explaining that customers will substantially benefit from the AMI deployment and that the benefits are expected to exceed the overall costs of the deployment. Specifically, Mr. Lewis explains that the cost/benefit analysis associated with electric and gas AMI demonstrates a net benefit to ENO customers of $27 million on a present value ("PV") basis, assuming a 15-year useful life of the AMI assets. Table 1 in Mr. Lewis' testimony provides a summary of the cost/benefit analysis on both a nominal and PV basis:

		Nominal ($M)	PV ($M, 2016)
1	**Total Quantified Operational Benefits**	$95	$40
2	**Total Quantified Other Benefits**	$178	$72
3	**Total AMI Quantified Benefits**	**$273**	**$112**
4	**AMI Lifetime Costs to Customers**	**$173**	**$85**
5	**Net AMI Benefit:**	**$101**	**$27**

Q12. ENO IS NOT THE FIRST UTILITY TO DEPLOY AMI. PLEASE ELABORATE ON AMI DEPLOYMENT IN THE UNITED STATES, INCLUDING LOUISIANA.

A. Advanced meters are common not only throughout the United States, but also in Louisiana. Specifically, more than 45% of all meters in the United States are advanced meters.[2] In Louisiana, the Louisiana Public Service Commission ("LPSC") has already approved the implementation of AMI by Cleco Power, LLC, Dixie Electric Membership Corporation, Beauregard Electric Cooperative, Inc., and Northeast Louisiana Power Cooperative, Inc.[3] It is also ENO's understanding that Atmos Energy Corporation began the process of installing advanced gas meters in Louisiana several years ago. These facts support the conclusion that the hardware, technologies, and partners needed for AMI deployment have evolved to the point where reliability and integration are no longer cutting edge, but proven. ENO witness Dr. Faruqui notes that if advanced meter deployments continue on pace with

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[2] U.S. Department of Energy, Energy Information Administration ("EIA"), Form EIA-826, "Advanced Metering" as of June 2016, *available at*: https://www.eia.gov/electricity/data/eia826/.

[3] *See* LPSC Order Nos. U-31393, S-31210, S-33411, and S-33490 (corrected), respectively.

historical rates, the vast majority of all electric customers in the U.S. would have advanced meters by the time ENO finishes its AMI deployment.

Q13. WHY IS ENO PROPOSING TO DEPLOY AMI AT THIS TIME?

A. The U.S. electric utility industry is undergoing a time of significant change driven by new technology, the pace of technology innovation, increased customer interest around self-supply and control, an emphasis on efficiency, increasing regulation, aging infrastructure, and uncertainty surrounding evolving standards and environmental regulations. Moreover, technology and innovation are changing customer expectations as a result of how products and services are delivered both inside and outside of the utility industry. Added to this is the wealth of knowledge and services that are available to consumers via the Internet. Over the past several years, there has been a significant increase in customers' expectations that they be able to access information and manage services via mobile devices like smart phones, tablets, and other devices. For example, at any hour, customers can interact and conduct business electronically with many retailers, banks, and other service providers. To keep up with changing customer expectations, ENO has taken various steps to invest in communication technology that improves customers' access to usage and other important information via electronic devices. For example, ENO has implemented a mobile device application as well as added new features to its website, such as the ability to view outage information. But as technology evolves, so must the Company's capabilities.

As ENO fulfills its mission to power life, it is continually preparing to meet customers' rising expectations and transform its business as technology and the industry evolve. The Company has modernized its power plants over the last decade, adding both cleaner and more efficient energy sources in order to provide our customers with reliable, safe, and low-cost energy. It has also invested in transmission. In order to keep customers informed, we are planning updates to our digital communication technologies, including better support for smart phones and tablets, as well as making important information securely accessible via the Internet. Beyond AMI, there are opportunities for additional customer benefits across the distribution grid. Technological innovation continues to make possible additional ways to maximize the capabilities of the distribution grid, such as the creation of an integrated energy network with features such as distribution automation, self-healing networks, and further integration of distributed energy resources ("DER"). Even without AMI, ENO believes that additional customer benefits could be delivered through modernization of the distribution grid, such as with replacement of poles, conductor and other equipment and devices. Just as ENO's customers have benefitted from improvements in generation and transmission, ENO expects to continue to evaluate and pursue improvements to its distribution system that will benefit customers.

Q14. HOW DOES AMI FIT WITHIN THE CHANGING LANDSCAPE THAT YOU HAVE DESCRIBED?

A. AMI is a fundamental step in enabling ENO to deliver what customers increasingly want - ways to better understand and manage their utility bills and energy usage. Advanced meters and the accompanying communication network infrastructure will allow ENO to offer more granular energy usage information and energy management tools to customers. For example, with AMI, the Company's web portal will allow customers to track daily electricity and gas usage, analyze their historic and current usage patterns, and view an estimate of their monthly bills. Company witness Dr. Faruqui explains how such detailed information about energy usage enables customers to make more informed decisions about their usage that ultimately will result in lower bills for many customers.

AMI is also critical to our ability to meet customer expectations with regard to service restoration. ENO has seen first-hand how customer expectations have changed related to service restoration. With improved access to mobile devices and the Internet, customers are expecting faster, more up-to-date information regarding service restoration progress.

Q15. YOU STATED PREVIOUSLY THAT THE COMPANY'S AMI PROPOSAL INCLUDED A DMS AND OMS. PLEASE EXPLAIN THE PURPOSES OF THE DMS AND OMS.

A. With the new information and connectivity available through AMI, integrating a OMS and DMS will enhance the Company's ability to identify the location and scope of outages more quickly, and will provide enhanced information for devices throughout the distribution network. This capability will allow ENO to pinpoint and respond faster to service outages, which will directly benefit its customers. Accurate outage data means that customers will have more accurate outage and restoration information and notifications. Mr. Griffith provides an extensive discussion of these related systems and their benefits in his Direct Testimony.

Q16. WHY IS IT APPROPRIATE TO INVEST IN THOSE SYSTEMS NOW?

A. ENO has operated an OMS for many years, but it has become technologically dated and increasingly expensive to maintain. In fact, without significant upgrades, the current OMS could not integrate with and make use of the data provided by AMI. ENO does not have a modern, stand-alone DMS product but instead operates a few dated software systems that provide only some of the functionality of a modern DMS. While updating the OMS and deploying a DMS would certainly constitute improvements over the current systems, the functionality is further enhanced by the two-way communication capability and data that is captured and processed by AMI. Thus, the concurrent deployment of a modern OMS and DMS will complement AMI and expand the benefits delivered to our customers, particularly as it relates to service restoration after outages. Mr. Griffith explains these issues in more detail in his Direct Testimony.

Q17. AFTER THE COMPANY IMPLEMENTS AMI, WOULD IT BE POSITIONED TO TAKE ADDITIONAL STEPS TO MODERNIZE ITS ELECTRIC GRID?

A. Yes. With AMI in place, ENO would be positioned to invest in new technology and infrastructure upgrades to move beyond a largely centralized, one-way distribution grid and move towards a more advanced power grid. AMI is a foundational technology of an integrated energy network that would support additional features such as distribution automation and the further integration of DER. In other words, AMI is the first step towards integrating advanced technology into ENO's operations. Company witness Mr. Dawsey discusses in more detail some of the potential future capabilities that can be built upon AMI. Those future capabilities include the potential to prevent certain outages from occurring. Moreover, in instances when an outage does occur, Mr. Dawsey explains that, based on data from AMI, investments could be made so that power could be automatically rerouted after the outage, which would allow for fewer overall outages or shorter interruptions. These potential future capabilities would not be possible without the communications and information technology improvements that will be part of ENO's AMI deployment.

Q18. DOES THE AMI DEPLOYMENT INCLUDE OPPORTUNITIES FOR PARTICIPATION BY LOCAL AND DIVERSE SUPPLIERS?

A. Yes. The Company operates a Supplier Diversity & Development Program in which we seek to work with a diverse mix of suppliers who provide innovative ideas and a service-oriented approach. For the AMI project, the requests for proposal process described by Mr. Griffith was structured to explicitly solicit information from suppliers regarding their plan to utilize diverse and local suppliers.

V. REQUEST FOR COST RECOVERY

Q19. THROUGH ITS APPLICATION, IS THE COMPANY SEEKING THE COUNCIL'S APPROVAL TO REFLECT THE COSTS AND BENEFITS OF AMI IN ELECTRIC AND GAS CUSTOMER RATES?

A. Yes. Company witness Mr. Todd discusses the AMI Rate Plan that the Company seeks to implement in conjunction with its AMI deployment. As he explains, the Company is seeking approval to include AMI costs within a customer charge for both its electric and gas customers to permit the timely recovery of the investment required to implement AMI, as well as to ensure that customers receive contemporaneously the Operational Benefits discussed by Mr. Lewis that are netted against the AMI implementation costs. It is therefore appropriate that the Company be allowed to reflect the costs of AMI in rates as those costs are incurred, while also reflecting the Operational Benefits in rates as those benefits materialize.

Q20. PLEASE PROVIDE AN OVERVIEW OF THE PROPOSED AMI RATE PLAN.

A. Mr. Todd explains the details of the proposed AMI Rate Plan. The customer charge described above would become effective the first billing cycle of the month[4] following a Council determination regarding the Combined Rate Case currently

4 ENO currently anticipates that implementation of rates would become effective as of August 2019.

expected to be filed in 2018 and would be adjusted annually during the course of AMI deployment (in January 2020 and January 2021) to reflect the increased capital (and associated revenue requirements) placed in service as meters are deployed. In this way, the Company is allowed the opportunity to timely recover the AMI investment roughly contemporaneously with when the assets are closed to plant and providing benefits to customers.

The final adjustment to the customer charge would reflect the total implementation and ongoing costs of the AMI deployment, during its first year of full operation, which is estimated to occur in 2022 after meter deployment is completed in December 2021. This final adjustment to the customer charge would be net of the Operational Benefits described by Mr. Lewis. Assuming the December 2021 completion of meter deployment, the Company would expect to implement this final adjustment to the customer charge in May 2022.

As Mr. Todd describes, ENO has calculated an illustrative estimate of the monthly AMI customer charge for electric and gas customers that would be implemented the first billing cycle following the Council's determination in the 2018 Combined Rate Case (August 2019). The initial monthly customer charge is estimated to be $2.31 for electric customers and $0.48, and then it would be adjusted over the course of deployment. The final adjustment to the customer charge for electric customers is estimated to be approximately $3.23 and for gas customers $0.95.[5]

[5] The AMI Customer Charge would not reflect the quantified Other Benefits of AMI. The Other Benefits, as described by Mr. Lewis, result from a reduction to costs currently reflected in the Company's

Q21. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

standard rate mechanisms, the FAC for electric operations, the PGA for gas operations, and a FRP that has been assumed for both electric and gas operations. Those reductions would therefore be reflected in these same mechanisms (or other rate mechanisms in place at the time) along with the actual benefits realized from several other non-quantified benefits described by Mr. Dawsey and Ms. Bourg.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **CHARLES L. RICE, JR.**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Charles L. Rice, Jr.

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 10th DAY OF OCTOBER, 2016

NOTARY PUBLIC

My commission expires: at death

Previous Testimony of Charles L. Rice				
TYPE OF TESTIMONY	**JURISDICTION**	**CLIENT**	**DOCKET**	**Filing Date**
Direct Testimony	CNO	ENO	UD-07-03	11/1/2010
Supplemental Direct Testimony	CNO	ENO	UD-07-03	1/4/2011
Supplemental Direct Testimony	CNO	ENO	UD-07-03	2/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-07-03	3/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-07-03	4/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-07-03	5/2/2011
Supplemental Direct Testimony	CNO	ENO	UD-07-03	5/12/2011
Supplemental Direct Testimony	CNO	ENO	UD-07-03	6/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	2/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	3/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	4/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	5/12/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	6/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	7/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	8/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	9/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	10/3/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	11/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	11/14/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	12/1/2011
Supplemental Direct Testimony	CNO	ENO	UD-11-01	1/3/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	2/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	3/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	5/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	4/2/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	6/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	7/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	8/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	9/4/2012
Direct Testimony	CNO	ENO	UD-12-01	9/12/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	10/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	11/1/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	12/3/2012
Supplemental Direct Testimony	CNO	ENO	UD-11-01	1/2/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	2/4/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	3/1/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	4/1/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	5/1/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	6/3/2013
Rebuttal Testimony	CNO	ENO	UD-12-01	6/12/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	7/1/2013

Previous Testimony of Charles L. Rice				
TYPE OF TESTIMONY	**JURISDICTION**	**CLIENT**	**DOCKET**	**Filing Date**
Supplemental Direct Testimony	CNO	ENO	UD-11-01	8/1/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	9/3/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	10/1/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	11/1/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	12/2/2013
Supplemental Direct Testimony	CNO	ENO	UD-11-01	1/2/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	2/3/2014
Direct Testimony	CNO	ENO	UD-14-01	2/28/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	3/3/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	4/1/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	5/1/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	6/2/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	7/1/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	8/1/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	9/2/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	10/1/2014
Direct Testimony	CNO	ENO	UD-14-02	10/30/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	11/1/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	12/1/2014
Supplemental Direct Testimony	CNO	ENO	UD-11-01	1/2/2015
Supplemental Direct Testimony	CNO	ENO	UD-11-01	2/3/2015
Direct Testimony	CNO	ENO	UD-15-01	2/8/2015
Supplemental Direct Testimony	CNO	ENO	UD-11-01	3/2/2015
Supplemental Direct Testimony	CNO	ENO	UD-15-01	8/21/2015
Direct Testimony	CNO	ENO	UD-16-02	6/20/2016
Direct Testimony	CNO	ENO	UD-16-03	7/22/2016

BEFORE THE

COUNCIL FOR THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO DEPLOY ADVANCED METERING INFRASTRUCTURE, AND REQUEST FOR COST RECOVERY AND RELATED RELIEF	**))))))**	**DOCKET NO. UD-16-__**

DIRECT TESTIMONY

OF

DENNIS P. DAWSEY

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

OCTOBER 2016

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Dennis P. Dawsey. I am employed by Entergy Services, Inc. ("ESI"),[1] and I currently serve as the Vice President of Customer Service for Louisiana. My business address is 446 North Boulevard, Baton Rouge, Louisiana 70802.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying before the Council for the City of New Orleans ("CNO" or the "Council") on behalf of ENO.

Q3. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL, PROFESSIONAL, AND BUSINESS EXPERIENCE.

A. I hold a Bachelor of Science degree in Electrical Engineering from Louisiana State University and a Master's Degree in Business Administration from Louisiana State University. My career within Entergy Corporation subsidiaries spans 36 years – 22 in Louisiana, 11 in Texas, and three in Mississippi. I am a registered professional engineer in Louisiana and Texas and a certified project management professional, and I have worked as a field-design engineer, industrial account representative, substation/relay/supervisory control and data acquisition design engineer, distribution-planning engineer, transmission-planning engineer, area design manager,

[1] ESI is a subsidiary of Entergy Corporation that provides technical and administrative services to all of the Operating Companies. The Entergy Operating Companies include Entergy Arkansas, Inc. ("EAI"); Entergy Louisiana, LLC ("ELL"); Entergy Mississippi, Inc. ("EMI"); Entergy New Orleans, Inc. ("ENO" or the "Company"); and Entergy Texas, Inc.

and network manager. I also have worked in a system-support role as manager of Systems Development and Management.

In 2001, I became Engineering Manager for Louisiana, overseeing distribution design activities for the state. Then, in 2004, I was named Southern Region Manager for ELL, and, in that capacity, I oversaw restoration work in Jefferson Parish following Hurricane Katrina. In 2006, I was promoted to Distribution Operations Director for EMI, and in 2008, I was promoted to Vice President of Transmission and Distribution Operations – Louisiana. While in this role I also served as the Louisiana State Incident Commander and oversaw statewide restoration work following Hurricanes Gustav, Ike, and Isaac. In January 2014, my position became Vice President of Customer Service.

In my current role, I am responsible for overseeing all aspects of providing electric service to approximately 197,000 electric customers in Orleans Parish that are served by ENO, as well as the reliability of the Company's electric distribution systems. My specific responsibilities include, but are not limited to, safety, operations, customer service, construction, reliability improvement, engineering, asset planning, distribution dispatching, meter services, contract management, and emergency restoration for the Company's respective transmission and distribution systems. A list of my prior testimony is attached as Exhibit DPD-1.

Q4. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to describe the customer service and operational benefits and changes resulting from ENO's proposed deployment of Advanced

Metering Infrastructure ("AMI"). As explained in greater detail by Company witness Mr. Rodney W. Griffith, AMI commonly includes three primary components: advanced meters, a two-way communications network, and a Meter Data Management System ("MDMS"). These components will be integrated into the Company's information technology system. The Company also plans to update its current Outage Management System ("OMS") and implement a new Distribution Management System ("DMS"). I refer to all of these components collectively as ENO's AMI deployment.

II. IMPROVED RELIABILITY AND CUSTOMER SERVICE

Q5. PLEASE PROVIDE AN OVERVIEW OF THE CUSTOMER BENEFITS OF AMI.

A. AMI offers a number of immediate and longer-term benefits to customers in addition to the quantified Operational and Other Benefits that Company witness Mr. Jay A. Lewis discusses in his Direct Testimony. First, AMI will better enable ENO to pinpoint and communicate outage locations, which will allow quicker and more accurate detection of service problems and will result in overall faster outage restoration. The information and capabilities provided by AMI will improve the accuracy and timeliness of outage and restoration communications with customers. The advanced meters and communication system also will allow for remote connection and disconnection of customers' electric service that will occur more quickly than the Company's manual process for existing electric meters, which requires a field visit.

Another benefit of AMI is that, once advanced meters and related infrastructure and systems are activated, ENO's customers will have access to more detailed energy usage data, which will help customers better understand and manage their usage and reduce their energy bills.[2] Another benefit of the availability of this data is that ENO customer service representatives will have more timely and detailed customer energy usage data to help expedite and more effectively address customer billing questions and issues.

Overall, ENO is committed to leveraging the functionalities that AMI enables to improve customer satisfaction and our customers' experience when they interact with the Company. To achieve this goal, an important customer-focused feature will be making customers' daily usage data available to them on the Company's web portal and educating customers how to take advantage of that new information. For utilities that have already implemented AMI, making detailed usage information available to customers via the Internet and mobile devices, along with education about how customers can better manage and reduce their energy consumption, has resulted in significant bill savings opportunities for customers. As discussed by Mr. Lewis, ENO expects similar consumption reduction benefits for its customers. ENO witness Dr. Ahmad Faruqui discusses in his Direct Testimony the benefits that will result from customers having access to this type of detailed usage information.

[2] Customer usage data will be collected in fifteen-minute intervals for residential customers and five-minute intervals for commercial and industrial customers, and usage data will be made available for customer access the following day (such as through the web portal I describe later in my testimony).

Lastly, as Company witness Mr. Charles L. Rice, Jr. discusses in his Direct Testimony, ENO is seeking to modernize its electric grid to meet customer expectations regarding how they interact with their service providers and the tools available for them to manage those services. To that end, AMI is the technical foundation and platform for the modernization of ENO's electric grid that will enable future products and services to customers. I describe some examples of those potential, future products and services below.

Q6. CAN YOU ELABORATE ON THE TYPE OF INFORMATION THAT WILL BE AVAILABLE TO CUSTOMERS THROUGH THE WEB PORTAL?

A. Yes. As described by Company witness Mr. Griffith, the advanced meters will record energy usage data in fifteen-minute intervals for residential customers and five-minute intervals for commercial and industrial customers. The next day, usage information will be available on the web portal through a computer and/or mobile device, which will allow customers to access detailed energy usage information for their homes and businesses.[3] Due to the timely accessibility of that information, customers can better and more easily track their electricity and gas usage,[4] analyze their historic and current usage patterns, and view an estimate of their monthly bills.

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[3] Residential, commercial, and industrial customers will have access to the web portal.

[4] As described by Company witness Michelle P. Bourg, there are approximately 107,000 customers who receive gas service from ENO. The Company's web portal will include for those customers their gas usage information, which will show gas usage data in one-hour intervals and be made available for customer access the following day.

By analyzing that information, customers will be able to identify times of high usage, which can result in changes that reduce consumption within the remainder of a billing cycle (*i.e.*, in-cycle). While such in-cycle changes can occur without AMI, the availability of in-cycle, detailed usage information and enhanced tools, such as text message alerts based on customer-specified criteria, provide additional opportunities for customers to consider changing their usage, as discussed by Company witness Dr. Faruqui. Customers also will have in-cycle information about how usage changes can affect their bill, much the same way that cellular phone customers can track and receive notifications about their data plan usage thresholds throughout a billing cycle.

Q7. HOW WOULD CUSTOMERS ACCESS THEIR USAGE INFORMATION?

A. Customers will have access to the web portal by computer and by mobile device. In addition to offering energy management information, the web portal will allow customers to set personalized notification preferences regarding how they would like to receive information about their energy use. For example, customers could set up text or email alerts to notify the account holder in the event of high usage or when a bill reaches a certain dollar amount based on a customer's pre-defined threshold.

Q8. HOW CAN AMI HELP CUSTOMERS LOWER THEIR ENERGY BILLS?

A. As further explained by Company witness Dr. Faruqui, customers can be expected to take more actions to adjust their consumption patterns and reduce their energy bills when provided access to the more detailed and timely usage information made possible by AMI technology. Ongoing customer feedback, as well as input from the

Council, the Advisors, and other stakeholders, indicates that customers desire more detailed and frequent usage information in order to better manage their energy usage and lower their electric bills. This information is similar in nature to cellular providers offering proactive notifications when a customer's usage has reached predetermined thresholds such as 75% or 90% of the data limit within their plan. Cellular customers can use that information to help adjust subsequent usage to stay within their desired budget. Dr. Faruqui explains how electric customers have reacted similarly when presented with more detailed usage information and notifications.

Q9. HOW ELSE COULD AMI ASSIST CUSTOMERS IN MANAGING THEIR ELECTRIC BILLS?

A. AMI will also have the capability to support pre-pay programs. A pre-pay program generally allows customers to pay in advance for consumption and track their energy use against their payments, to better manage their utility bill as a part of their overall household budget, and potentially avoid service interruption because of non-payment. Pre-pay programs improve flexibility for making payments because customers can pay throughout the month when funds are available rather than having to make one, typically larger, payment. Additionally, pre-pay programs have been shown to encourage energy conservation as compared to traditional, post-metering billing methods. While any pre-pay program offered by ENO would be voluntary for customers, such a program would provide an additional tool for customers to better manage their monthly electric bill. Through pre-pay programs, enrolled customers, particularly low-income customers, can benefit from the ability to pay for service in smaller amounts and multiple times per month.

Q10. HOW DOES A TYPICAL AMI PRE-PAY PROGRAM WORK?

A. Under a pre-pay program, an enrolled customer pays in advance of receiving service from the utility. The utility then deducts from the prepaid balance as electricity is used and measured by the meter. The customer is able to access his/her remaining account balance via notifications (*e.g.*, email or text message) and online, with additional alerts for low or zero balances. Customers typically have multiple avenues to make payments (*e.g.*, by phone, online, and, in some cases, through payment kiosks). Utilities offering optional pre-pay programs typically remotely disconnect service to the meter upon depletion of a customer's account balance, although disconnection may be temporarily delayed in the case of extreme weather, weekend, holidays or other conditions directed by regulators. Service is typically reconnected shortly after a positive balance is restored to the account.

Q11. IS THE COMPANY PLANNING TO IMPLEMENT A PRE-PAY PROGRAM?

A. Yes. However, the Company's voluntary pre-pay program is still under development. As AMI is designed and deployed, ENO will continue to update the Council on its pre-pay program and will separately seek approval of any necessary tariff to implement the program.

Q12. HOW DOES THE COMPANY PLAN TO MAKE CUSTOMERS AWARE OF THEIR ABILITY TO ACCESS AND UTILIZE THE INFORMATION AND PROGRAMS YOU DESCRIBED?

A. A comprehensive educational plan will coincide with the AMI ramp-up, infrastructure implementation, and meter deployment. This multi-phase plan is being designed to educate customers about the capabilities of advanced meters, ENO's plans to deploy them, and how customers can access and take advantage of the benefits enabled by AMI. First, the educational plan will introduce customers to AMI and educate them about the various features and benefits that are enabled by advanced meters. During this phase, ENO will gather information from customers about their awareness and perceptions of AMI. This information will enable ENO to design more effective educational materials to use during the remainder of the AMI deployment. Second, ENO will work to educate customers about the advanced meter installation process. Third, ENO will educate customers about the availability of energy usage information and tools for customers, once their advanced meter has been installed and activated. Finally, once all advanced meters have been deployed, ENO will continue providing education to all customers about how they can access and use the new information incorporated into the web portal, including associated tools to help facilitate changes to their energy usage. Additional details of each of these phases are provided in ENO's AMI Customer Education Plan, which is attached to my direct testimony as Exhibit DPD-2. The development of this plan began in 2016 in conjunction with the preliminary AMI design work described by Mr. Griffith.

Q13. WILL ENO OFFER AN OPTION IF A CUSTOMER DOES NOT WANT TO HAVE AN ADVANCED METER INSTALLED AT THEIR PREMISES?

A. Yes. As discussed by Company witness Mr. Lewis, the Company will provide residential customers with the choice to opt out of having an advanced meter installed at their premises. It is important to note that, as part of offering this option, the Company will incur up-front and ongoing costs associated with a customer's choice to opt out of having an advanced meter. As a result, the Company proposes that the up-front costs associated with the customer billing set-up, meter locks, trip charge, and processing of opt-out paperwork be charged directly to an opt-out customer through a one-time fee. In addition, the Company proposes to charge an opt-out customer a monthly fee associated with the ongoing added costs of manual meter reading and billing. The Company will use a formal process to document the customer's decision to opt out, including having the customer fill out, sign, and submit a form indicating their voluntary decision to opt out of receiving an advanced meter. This process also requires the customer to acknowledge the added cost to him/her that is triggered by his/her decision to opt out, including the up-front fee and the monthly recurring fee. In his Direct Testimony, Company witness Mr. Lewis provides an illustration of the proposed methodology that will be used to establish the opt-out fees and discusses generally when ENO would seek the Council's approval of those fees.

Q14. WILL CUSTOMERS WHO CHOOSE TO "OPT OUT" CONTINUE TO HAVE ACCESS TO THE INFORMATION THEY HAVE TODAY?

A. Generally speaking, yes. Residential customers that choose to opt out would be able to access copies of old bills through the web portal similar to what occurs today through myAccount Online. Opt-out customers would also have access to outage information that is currently available to them today through ENO's Outage Communications program, ENO's contact centers, and/or View Outage on http://www.entergy-neworleans.com.

III. OPERATIONAL IMPROVEMENTS

A. Meter-Related Operations

Q15. PLEASE PROVIDE AN OVERVIEW OF ENO'S METER-RELATED OPERATIONS ACTIVITIES.

A. ENO utilizes contract meter readers employed by firms that specialize in providing meter reading services to provide on-site meter readings. Additionally, a significant amount of miscellaneous meter services activity, including account activation for new service and de-activation for cancelled service, as well as disconnect activity related to past-due billings, involve on-site work performed at the meter. Because of the two-way data communication supported by AMI, all of the meter reading and nearly all meter services activity will be able to be performed remotely.

Q16. CAN YOU MORE FULLY DESCRIBE THE METER READING PROCESS?

A. Yes. On a daily basis, meter readers are assigned a route (or routes) that include the meters to be read during the current billing cycle. Depending on the geography of the route, the meter reader navigates the route by foot and truck. The meter reader must be able to see the meter to obtain the value indicated by the dials for older, analog meters or the digital display in newer meters. The reading is input into an electronic handheld device. Depending on the customer's rate schedule, this input may also include the demand information displayed on the meter or require the use of a probe device that downloads periodic demand information required for customer billing.

To obtain these readings, the meter reader must sometimes navigate numerous obstacles, including animals, locked fences, vegetation, and variable weather and traffic conditions. Meter readers also resort to using binoculars or monoscopes to read meters where they cannot get access or where it is more efficient to read from a distance.

Meter readers also reread a customer's meter in certain circumstances. For example, the Company's internal meter reading edit processes may indicate usage for a particular customer account is unusually high or low and a reread is needed. As rereads are not typically in the meter readers' current routes, they must work the reread into the day's work schedule, creating inefficiencies in the meter reading route. Once deployed, AMI is designed to eliminate the need for these processes.[5]

[5] Mr. Griffith discusses how AMI data will be collected and validated.

Q17. WHY DOES ENO USE CONTRACT METER READERS RATHER THAN COMPANY EMPLOYEES TO READ CUSTOMER METERS?

A. To reduce meter reading costs that are reflected in customer rates, the Company made a business decision approximately 20 years ago to switch from internal labor to third-party suppliers to perform all manual meter reading. To achieve an appropriate balance between cost and performance with the third-party suppliers, the Company uses competitive bidding techniques and requires a contractual high "service-level" agreement, which contains certain performance measures. The use of third-party suppliers for manual meter reading has resulted in lower costs over the years, which means the related savings from ENO's AMI deployment are expected to be lower than those of other utilities that transitioned their meter reading services from employees to remote meter reading through AMI.

Q18. HOW ARE METER READING SERVICES MANAGED?

A. ENO's meter reading service contracts are managed by employees familiar with the requirements of the contracts and holding the skills and knowledge necessary to evaluate contractor performance. In addition, a centralized group of employees supports the technology necessary for current meter reading operations.

Meter reading contracts have been periodically put out to bid. This periodic bidding process ensures that meter reading contract pricing is reflective of current market conditions, including any efficiencies developed by vendors, new entrants into the meter reading market, and other cost changes that may affect bids (fuel costs, local labor conditions, *etc.*). The Company also actively monitors contractor performance on a variety of performance measures to ensure the Company, and ultimately its customers, receive accurate and cost-effective meter reading services.

Q19. ARE METER READING COSTS INCLUDED IN CUSTOMER RATES?

A. Yes, and as Mr. Lewis describes, one component of the Operational Benefits of AMI is elimination of these costs and removal from customer rates. I provided the annual expense amount for meter reading contracts and support personnel to manage those contracts to Mr. Lewis for inclusion in his analysis.

Q20. WILL AMI ELMINATE ALL OF ENO'S CONTRACT METER READING COSTS?

A. Yes. When fully deployed, AMI will allow the Company to read all advanced meters remotely. It is not anticipated that readings because of exceptions, such as a failure in the communication module in an individual meter or as part of an investigation generated by unusual meter reading results, will necessitate the need for additional meter reading services contracts because these issues will be handled by ENO personnel.

Q21. PLEASE DESCRIBE THE METER SERVICES ACTIVITIES YOU NOTED ABOVE.

A. As I mentioned, there are meter services activities that take place at customers' meters. These services are performed by meter services personnel and not by meter readers. These services include the installation, maintenance, and testing of the existing meters. Today, meter services personnel perform the initial meter installation and any future meter changes or removals. Meter services personnel also perform the initial connection of service for a new customer and perform the disconnection when a customer asks to terminate service. Meter services personnel also perform service disconnections as a result of non-payment of bills as well as any subsequent reconnection of services after payment is received. Finally, meter services personnel perform meter rereads in certain circumstances (*e.g.*, there are meter access issues or a reread is requested by a customer).

All of this meter services activity is scheduled and coordinated by the Mobile Dispatch function. These dispatchers perform the scheduling and dispatching of certain meter services work orders, such as lighting repairs, equipment changes, meter reading verification, and location verification. Mobile Dispatch also assists in the dispatching of outage and emergency work orders to servicemen based on notifications made by the customer, and it also provides assistance when a problem exists with job readiness, the job location, or if a safety situation is present at the job site.

Q22. HOW WILL THOSE FUNCTIONS CHANGE AFTER AMI IS DEPLOYED?

A. Personnel will be needed to support the AMI deployment and ongoing operations, including installations, removals, and exchanges of metering equipment, once AMI is in place. There will also be new positions added in the Utility Operations Support organization of ESI to manage the communication and data aspects of ENO's AMI deployment. However, because of the capabilities of AMI, nearly all residential electric connections and disconnections, including temporary disconnections for non-payment of bills and subsequent reconnections following payment, will be performed remotely without requiring travel to the service location. Further, the need for physical rereads will be virtually eliminated because (1) customer service can perform remote read confirmation; (2) the opportunity for error in monthly manual reads is eliminated; and (3) the analytics software that will be utilized can detect errors and confirm accuracy.

Q23. ARE METER SERVICES COSTS INCLUDED IN CUSTOMER RATES?

A. Yes, and as Mr. Lewis describes, one component of the Operational Benefits is elimination of these costs and removal from customer rates. I provided the annual expense amount for meter services to Mr. Lewis for inclusion in his analysis.

B. Workforce Changes

Q24. HOW IS THE DEPLOYMENT OF AMI ESTIMATED TO AFFECT PERSONNEL WHO CURRENTLY PERFORM THE METER READING AND METER SERVICES FUNCTIONS YOU DESCRIBE ABOVE?

A. As I have explained, once AMI is fully deployed, ENO will be able to remotely read all of its meters, with a few limited exceptions, and thus expects to no longer need contracted meter reading services. It is anticipated that any meter reading activities that require an on-site reading will be performed by ENO employees. While the exact number of positions eliminated will be determined after the design phase of the AMI project, for purposes of estimating benefits, Mr. Lewis provides a calculation of the estimated effect of those changes, which will occur gradually over several years. Accordingly, in addition to the discontinuation of contracted meter reading services, Mr. Lewis' analysis reflects the elimination of the budget associated with 20 meter service positions in calculating the benefits of AMI. Meter reading and mobile dispatch support positions at ESI are also assumed to be eliminated for purposes of the analysis described by Mr. Lewis. Some of these positions are already vacant and simply would not be filled. Of those positions that are currently filled, it is possible that some of the employees may transfer to other roles within the Company, including new positions needed for AMI support, as I explain below. It is expected that as employees leave positions that will no longer exist, contractors may be used to fill any temporary needs during the transition to full AMI implementation. The determination of whether or not to fill temporary needs with contractors will be based on position, level of responsibility, required skill set, and duration of the role. As described below, the Company's initial focus will be to retain employees through training and skill enhancement.

The limited amount of meter services activities that are expected to continue to require on-site work, such as meter installations/removals and tampering investigations, are expected to be performed by ENO service personnel. For purposes of estimating ongoing costs in determining the net benefits of AMI, Mr. Lewis' analysis assumed that 3 ENO positions would be retained to handle those activities, though the number of positions could vary slightly during the transition to full AMI implementation.

Q25. HOW WILL THE COMPANY ADDRESS THE CURRENT METER READING CONTRACTS?

A. The Company is managing the current meter reading contracts and any necessary extensions to align with the AMI deployment schedule to allow for the meter reading contract services to reduce as AMI is implemented. This is also true for the modest amount of meter services work that is currently being done by contractors for ENO.

Q26. ARE ANY NEW POSITIONS ASSUMED TO BE CREATED AS A RESULT OF AMI?

A. Yes, in addition to retaining some meter services positions for post-AMI operations, described above, the Company has assumed that there will be new positions created to support the AMI deployment and ongoing AMI operations. The Company is still evaluating whether these positions would be filled by contractors, employees, or a mix of the two depending on position, level of responsibility, required skill set, and duration of the role. Mr. Lewis' analysis also assumes that there would be 43 new positions added in the Utility Operations Support organization of ESI to manage the communication and data aspects of AMI post-deployment.

Q27. DOES THE COMPANY ANTICIPATE THAT IT WOULD PROVIDE ASSISTANCE TO PERSONNEL WHOSE POSITIONS ARE BEING ELIMINATED AS A RESULT OF AMI?

A. Yes. The Company's initial focus would be to retain employees through training and skill enhancement that aligns to the opportunities in the newly designed organization or with the broader Entergy organization. The Company would also follow any applicable collective bargaining obligations or commitments under existing union contracts.

IV. ADDITIONAL EXPECTED BENEFITS

A. Unaccounted for Energy ("UFE")

Q28. ONE OF THE QUANTIFIED OTHER BENEFITS DISCUSSED BY MR. LEWIS IS LOWER BILLS RESULTING FROM THE IDENTIFICATION AND REDUCTION OF UFE. PLEASE EXPLAIN UFE ON THE ELECTRIC SYSTEM.

A. UFE includes both technical and non-technical losses. Technical losses occur due to power dissipation in electricity system components such as transmission and distribution lines, transformers, and measurement systems. These types of losses are difficult to avoid and relate to the basic physics of power delivery. Non-technical energy losses, on the other hand, occur for many reasons, including meter tampering, theft, improper installation, programming errors, meter damage/failure, and accuracy. Mr. Lewis explains how UFE ultimately increases costs to customers.

Q29. HOW WILL AMI FACILITATE THE IDENTIFICATION AND REDUCTION OF UFE?

A. In the course of replacing meters during AMI deployment, there will be an inspection of each meter for evidence of tampering and potential diversion. If such evidence is observed, it will be corrected during the advanced meter installation, thereby reducing

UFE in the future.[6] In addition, the advanced meters will detect and remotely report possible meter tampering to the utility. Over time, ENO will develop enhanced analytics capabilities in order to evaluate advanced meter data for patterns suggesting potential sources of non-technical losses, including some kinds of energy diversion. As these analytic systems improve over time, ENO will be better able to identify, investigate and mitigate non-technical losses, as well as pursue recovery through standardized processes.

B. Increased Customer Information

Q30. MR. LEWIS ALSO QUANTIFIES BENEFITS ASSOCIATED WITH CONSUMPTION AND PEAK CAPACITY REDUCTION RESULTING FROM INCREASED CUSTOMER INFORMATION. PLEASE EXPLAIN HOW THOSE BENEFITS ARE ACHIEVED THROUGH AMI.

A. Through customer education, ENO will seek to inform customers how their usage data, which will be available in greater detail and on a more frequent basis as a result of AMI, can be used in conjunction with other energy savings tips to reduce their consumption. As a result of the incorporation of AMI data into the web portal, and through related educational efforts I discussed earlier in this testimony, ENO will provide customers with tools to access, track, and decide whether and/or how to adjust their energy usage; these tools are separate from any existing energy efficiency

[6] ENO intends to pursue, consistent with the Council's rules, appropriate remedies, including back billing, in those instances where it detects evidence of fraud or tampering. Revenue from back billing is not included in the estimated UFE benefit provided by Mr. Lewis.

programs that may have similar consumption reduction goals. For example, ENO plans to provide interested customers with notifications of preset usage thresholds that would give them more frequent information about their usage and estimated bills. Customers will also be able to review usage patterns each day to see where opportunities to reduce or eliminate consumption may occur within each billing cycle, rather than after the billing cycle has ended. Dr. Faruqui explains how access to such enhanced data and notifications has led customers of other utilities to proactively reduce their consumption and why it is reasonable for ENO to expect customers to react similarly. Indeed, the success of ENO's existing energy efficiency programs also supports why it is reasonable for ENO to expect its customers to react favorably to being provided enhanced tools to help manage their energy usage.

Q31. DOES ENO ANTICIPATE OFFERING DEMAND RESPONSE PROGRAMS AND OTHER SIMILAR PROGRAMS TO ACHIEVE USAGE AND PEAK CAPACITY REDUCTIONS?

A. At this time, ENO does not plan for its AMI deployment to include dynamic pricing and/or specific new Demand Response programs that would provide a direct economic incentive to customers to reduce their usage and load during peak hours. Instead, ENO may seek to implement such programs as part of subsequent phases of its overall effort to modernize its grid, or through AMI-enabled energy efficiency programs. For example, future programs could include dynamic pricing programs, such as time-of-use pricing tariffs, in order to incentivize a change in customer usage in response to different prices of electricity for different time periods; likewise, such

AMI enabled offerings may prompt changes in the Company's energy efficiency programs included as part of its later energy efficiency filings.

However, ENO plans on providing customers with peak event notifications as part of its AMI deployment. This program will provide text message and/or email notifications to customers (subject to an opt-out procedure and applicable legal requirements related to such communication channels) suggesting that they take steps to reduce their usage during certain times of peak load on the overall system. Such notifications would be expected to occur on only a handful of days each year when the system load is anticipated to be at peak. While this program will not include any direct monetary incentives, Company witness Dr. Faruqui explains, based on his familiarity with the results of other utilities' efforts, why it is reasonable to believe that these informational notifications will result in a modest reduction to peak load.

Q32. HOW DO THESE EFFORTS FACILITATE PEAK LOAD SHFITING?

A. With a peak event notification, customers would be educated in advance about the importance of reducing load on select days of the year in response to notifications provided by the Company. Notifications would be provided by one or more communication channels at the customer's preference (*e.g.*, text and/or email and subject to applicable law related to such channels). The notifications would inform customers in advance of an upcoming "event" day, which would be a day that the utility projects as one of the highest load days of the year. The notification would ask customers to reduce (or in some instances shift) load during the "event" period, which typically coincides with the highest load hours (e.g., ~2:00 pm – 6:00 pm on a hot summer day). The notifications could also suggest various specific actions that customers could take to reduce or shift their load during the event periods. Because of AMI, customers will be informed with more detailed usage information upon which to base their decision. The total number of "event" days would be minimized to avoid burdening customers (*e.g.*, 5-10 "events" per summer). Most importantly, as a result of AMI, customers will receive an after-the-fact notification providing the results of their load shifting or reduction that would use data available through AMI. As Dr. Faruqui explains, other such utility programs provide quantifiable reductions in peak load during event periods, even without a direct financial incentive. Customers may, at any time, opt out of receiving such notifications.

C. Replacement of Existing Meter Reading Equipment

Q33. ANOTHER BENEFIT QUANTIFIED BY MR. LEWIS IS THE ELIMINATION OF THE NEED TO REPLACE EXISTING METER READING EQUIPMENT. WHY WILL THE EXISTING METER READING EQUIPMENT NO LONGER BE REQUIRED?

A. The existing meter reading equipment will no longer be required because meter readings will be performed remotely after the implementation of AMI. Though ENO uses contract meter reading services, it owns a number of handheld devices used by the contract meter readers to record the meter readings, and those devices will no longer be necessary. Eliminating the need for this equipment will avoid both the future capital of replacing these devices and the future O&M costs for software and repairs/warranties.[7]

V. NON-QUANTIFIED AMI BENEFITS

Q34. ARE THERE ADDITIONAL BENEFITS OF AMI THAT WERE NOT QUANTIFIED BY MR. LEWIS?

A. Yes. There are several additional benefits that ENO expects to see as a result of its AMI deployment. AMI is expected to provide improved outage management benefits. The ability to quickly identify the location of outages through AMI leads to more efficient restoration planning, and ultimately faster restoration of outages, as well as improved and more accurate customer outage communications, including more accurate outage maps available to customers through the Company's website. It provides for quicker outages notification, especially when customers are not even aware an outage has occurred (such as when they are sleeping or away from their home or business). AMI also limits the circumstances in which customers will be required to call the Company to report outages. As a result of the AMI data, less scouting would be required to identify outage areas, which has cost and safety benefits. AMI would also help to identify nested outages (customers still without power even after a main distribution feeder is restored) and aid in diagnosing false outages.

[7] Some meter reading equipment may be retained to support readings needed for exception situations, although the Company does not plan to incur O&M expense for maintaining that equipment, and it does not plan to replace it after it stops functioning.

AMI also helps to improve billing accuracy. Inaccurate billing data starts a cascade of work involving customer complaints, investigations, and reprocessing of customer bills that is difficult to quantify, but consumes employees' and customers' time. AMI improves billing accuracy due to several factors. For example, meter reading estimates are reduced or eliminated because there are no meter access issues. Errors caused by misread or mistyped meter readings would also be eliminated.

With the improvements in billing accuracy and meter data availability, calls to the Company's call centers may decrease. Customers will be able to verify their past and ongoing energy usage through the web portal using other tools like billing threshold notifications. Therefore, customers may not need to contact the Company to ask billing and usage-related questions because they will have the tools to answer them on their own. Additional customer information features such as usage notifications could also lead to fewer calls related to billing and payment issues.

In addition to the safety benefits associated with more accurate outage detection, AMI facilitates overall safer field operations by substantially reducing the number of personnel and vehicles that are in the field and by reducing certain tasks, such as scouting. As I discussed earlier, by virtually eliminating the need for physical meter reading, rereads, and, for electric customers, service connections and disconnections, there will be substantially fewer personnel and vehicles in the field exposed to accidents or other potentially dangerous or threatening situations.

There is a cost savings for customers who install self-generation equipment and are required to have bi-directional meters installed. Put another way, the new advanced meters will have the capability to provide data needed to bill customers with distributed generation (*e.g.*, rooftop solar systems). As a result, there will no longer be a need to install a new bi-directional meter for customers with self-generation equipment.

The data available from AMI may also allow for additional distribution system optimization and monitoring, which provides improved overall system reliability. Through improved engineering analysis of the detailed data made available through AMI, the Company may be able to identify where distribution system investments will be most effective. The Company will also be able to monitor distribution system load at a more discrete level, which should lead to fewer distribution transformer overloads and failures, as well as facilitate better integration of distributed generation equipment in the future.

In any event, even without quantifying these benefits, the Company's cost/benefit analysis shows that the benefits of ENO's AMI deployment outweigh its costs.

VI. FUTURE BENEFITS

Q35. DOES THE PROPOSED AMI DEPLOYMENT SUPPORT ADDITIONAL FUNCTIONALITIES THAT COULD BE IMPLEMENTED IN THE FUTURE?

A. Yes. There are several other functionalities and programs enabled by AMI, as proposed by the Company, and that could be implemented in the future. For example, greater grid resiliency could be accomplished in the distribution network. By deploying additional automated devices on the distribution grid connected to the AMI communication system, and combined with the data from the advanced meters, automatic rerouting of power due to an outage would allow for fewer overall outages and interruptions. Mr. Griffith provides additional discussion on this functionality in his Direct Testimony. In addition, the AMI interval data, in combination with other operational asset data and advanced analytics software, could identify assets (*e.g.*, transformers) that are approaching failure, and those assets could then be replaced prior to failure, which would prevent an outage from occurring. The availability of more detailed customer usage data generated by AMI will also provide essential information to grid planners for future grid modifications and improvements.

In addition, the availability of customer usage data at a more detailed level could allow for specifically-designed offerings for, and better assistance to, customers. For example, when a Company customer service representative is speaking with a customer about bill questions, the representative will be able to access the detailed usage data underlying the customer's bill, which will enable more efficient discussions with the customer. There could be more flexible billing and payment options developed based on the knowledge of the customer's usage patterns. Real-time, demand-side products and/or energy efficiency programs could be developed, enhanced, and/or acquired that would allow customers more energy management options beyond any that are available to them today. Lastly, future offerings could include dynamic pricing programs, such as time-of-use pricing tariffs, in order to incentivize a change in customer usage in response to different prices of electricity for different time periods.

Most of these functionalities and programs would require additional investments in infrastructure and technology at a later date in order to deploy and achieve the desired functionality. These features could provide a wide range of benefits such as customer savings, greater grid resiliency, and specifically-designed customer options, but should be accompanied by appropriate regulatory policies that are fair to both customers and the Company.

VII. DATA PROTECTION AND CONFIDENTIALITY

Q36. DOES THE COMPANY HAVE POLICIES IN PLACE TODAY TO PROTECT THE CONFIDENTIALITY AND PRIVACY OF CUSTOMER INFORMATION?

A. Yes. ENO, ESI, and the other Operating Companies have for many years maintained policies and procedures that address the protection of customer information. These policies include the *Protection of Information Policy*, which states the requirements and expectations to safeguard customer information that include a requirement that such data be protected against "loss, damage, theft, unauthorized access, unauthorized reproduction, unauthorized duplication, unauthorized use, unauthorized distribution, unauthorized disclosure, misappropriation, inappropriate disposal and mishandling." The *Communication Systems* and *Electronic Information Systems* policies similarly require the Company's employees and service providers to protect customer information. Moreover, as described further by Mr. Griffith, the Company has security standards and controls in place with respect to its current customer data storage systems, and controls related to AMI data storage and transmission are being developed as part of the AMI design phase.

Q37. DOES IMPLEMENTATION OF AMI NECESSITATE REVISIONS TO THESE POLICES AND PROCEDURES?

A. Not at this time. AMI increases both the amount and granularity of individual customer electricity consumption data received by the Company, but it does not otherwise fundamentally alter the Company's ongoing obligation to protect customer information. Nonetheless, those policies and procedures are periodically reviewed, and new policies and procedures are introduced as needed to reflect nuances presented by developments in the law, technology, and other factors.

VIII. SERVICE REGULATIONS, RATE SCHEDULES, AND POLICIES

Q38. HAS THE COMPANY IDENTIFIED ANY EXISTING SERVICE REGULATIONS, RATE SCHEDULES, OR OTHER POLICIES THAT MAY NEED TO BE REVISED IN LIGHT OF THE AMI DEPLOYMENT?

A. Yes. Based on the information currently available regarding the anticipated deployment process, the Company has identified a few areas where revisions may be needed. The Company anticipates that additional details will be developed as it completes the AMI design phase and progresses toward deployment. ENO commits to work with the Council, the Advisors, and other parties to identify and revise, as appropriate, any service regulations, policies, or rate schedules that may be affected by the AMI deployment.

Q39. IS ENO REQUESTING ANY RATE SCHEDULE CHANGES PERTAINING TO CUSTOMERS OPTING OUT OF RECEIVING AN ADVANCED METER?

A. Not at this time. As Mr. Lewis explains, the specific details of the tariff, including the costs and procedures that would be used by the Company to facilitate a customer's choice to opt out, would be presented to the Council in a separate filing after approval of the Company's Application in this docket, but in sufficient time to receive approval of the tariff prior to meter deployment.

IX. CONCLUSION

Q40. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **DENNIS P. DAWSEY**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Dennis P. Dawsey

Dennis P. Dawsey

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 11 DAY OF OCTOBER, 2016

NOTARY PUBLIC

My commission expires: at death

Lawrence J. Hand Jr.
Bar 23770 / Notary 52176
Notary Public in and for the
State of Louisiana.
My Commission is for Life.

List of Prior Testimony

TYPE OF TESTIMONY	JURISDICTION	CLIENT	DOCKET	Filing Date
Direct Testimony	LPSC	EGSL/ ELL	U-30981	5/11/2009
Direct Testimony	LPSC	EGSL/ ELL	U-32538	9/5/2012
Direct Testimony	CNO	ENO	UD-12-01	9/12/2012
Direct Testimony	LPSC	EGSL/ ELL	U-32764	4/9/2013
Direct Testimony	CNO	ENO	UD-14-01	12/26/2013

Advanced Metering Infrastructure (AMI) Customer Education Plan for Entergy New Orleans, Inc.

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INTRODUCTION

Overview

Entergy New Orleans, Inc. ("ENO") serves approximately 197,000 electric customers and approximately 107,000 natural gas customers in Orleans Parish.

As part of its ongoing commitment to providing reliable, safe and affordable electric service, ENO is planning to deploy a full-scale Advanced Metering Infrastructure (AMI) across the area it serves. As part of this effort, ENO is planning to replace all existing electric meters with new advanced meters as well as install new communication modules on existing gas meters in conjunction with an upgrade to its communications system to allow for two-way communications between the utility and the meter.[1] AMI will also allow ENO to introduce new online energy information and management features for customers.

The new technology will offer a number of important benefits to customers including but not limited to:

- Improved reliability as a result of remote meter reading and more accurate outage information, allowing for faster restoration after outages.
- New interval usage data from advanced meters that will enable online energy information resources to help customers better understand and manage energy use as well as potentially lower their bills.
- New interval usage data from advanced meters that will enable notification alerts that will let customers know they are approaching their monthly budget goals.
- Improved customer service due to more timely and detailed energy usage data that helps to address customer billing issues more effectively and expeditiously.

ENO has developed this education plan to ensure that its customers are educated about the benefits of AMI and understand how to take advantage of those benefits, particularly those that require specific customer action. This plan is separate and distinct from energy efficiency customer education plans.

Lastly, the education plan's multi-phase design will ensure that customers receive information that corresponds with the appropriate phase of the broader meter deployment, as follows:

Phase I – Pre-Deployment
Phase II – Meter Deployment and Individual Activation of Online Energy Management Information and Tools
Phase III – Energy Management Information and Tools Available to All Customers
Phase IV – Ongoing Education and Engagement

[1] For gas meters that cannot accept a new module, the entire meter will be replaced to accommodate the new advanced network.

Purpose and Content

As part of the installation of advanced meters, ENO will implement an education plan that focuses on the following:

- **Pre-Deployment Education**
  Once ENO receives approval from the New Orleans City Council, but prior to meter deployment, ENO's pre-deployment education will inform customers that they will be receiving an advanced meter. This communication also will take place during the meter installation process. It will include messages not only about the meter installation process for both residential and commercial customers, but also about the benefits customers can expect from the advanced meters. ENO will also inform residential customers about the steps for opting out of an advanced meter, along with associated costs, should such an option be approved.
- **Post-Deployment Ongoing Energy Management Education**
  Once the new meters are activated and online energy management tools become available to customers, ENO will roll out comprehensive details designed to educate customers on where and how to use customer communication channels to access the new energy information.

Plan Components

This plan includes and is based on:

<u>1) Background Research</u>

This education plan reflects a significant amount of research conducted by ENO. In preparation for developing this plan, ENO and its agents did extensive interviews with utilities that have deployed AMI as well as factored in its own ongoing quantitative and qualitative research in New Orleans.

<u>2) Development of Phased Approach</u>

This education plan identifies important milestones in AMI deployment, and it breaks down the communications channels, messages, and strategies by phase.

<u>3) Identification and Description of Recommended Tactics</u>

This plan identifies and defines key tactics for communications and education throughout all phases of implementation.

<u>4) Identification of Audiences</u>

This plan identifies different types of ENO customers, including residential and commercial, and hard to reach audiences.

ENO recognizes that education efforts must include aspects that reach all segments of the customer base. ENO recognizes that some customers will need additional education tools to help them take advantage of the benefits offered by advanced meters. With that in mind, ENO plans to focus efforts specifically on assisting such groups, including but not limited to the following subsets:

- Low income customers
- Non-computer users
- Senior citizens
- Non-English speaking customers
- Hearing/vision impaired

Education tools discussed in this plan will be aimed at reaching these special interest groups. Our market research efforts will include consideration of these groups and help contribute to the strategy and messaging targeting these audiences.

Some key tactics to communicate effectively with these audiences include:

- Spanish speakers in the contact centers
- Materials available in multiple languages as deemed appropriate
- Printed materials such as bill inserts and direct mail to support non-computer users
- A mobile-enabled web portal for low income users who primarily access the internet through their mobile devices

In addition, when appropriate, ENO will include special language aimed at these audiences in educational pieces, letting these audiences know that further information is available upon request.

<u>5) Market Research Plan and Related Metrics</u>

Market research plays a critical role in the execution of the AMI customer education plan as well as the measurement of its effectiveness. This plan outlines the research methods ENO will use, both qualitative and quantitative, on an ongoing basis throughout the different phases of the plan.

<u>6) Escalation Plan</u>

Communicating effectively with customers is a multi-faceted and challenging task. Ensuring customer satisfaction means meeting customer expectations and providing the appropriate level of information to answer their questions and concerns satisfactorily. Accordingly, implementation of an escalation plan will ensure seamless and timely transitioning of customer questions, complaints, and concerns to the appropriate subject matter experts within the customer service organization. Details of the escalation plan are included within this education plan.

7) Education Timeline

A timeline for outreach approaches is included in this plan to present a holistic view of multiple communications activities that will take place during each phase of the plan. The detailed education timeline is included within this plan.

8) Budget

An estimated customer education budget is included in this plan and correlates to the incremental costs associated with the first three phases of the customer education plan. Costs associated with Phase IV will be reflected as part of ENO's normal customer outreach and communications.

STRATEGY AND APPROACH

Best Practices

In preparation for this plan, ENO conducted research with other U.S. utility companies that have deployed advanced meters to gain insight into how their customer education plans were implemented. This plan reflects best practices obtained from those companies, which are summarized as follows:

- Customer satisfaction is critical to the overall success of AMI. Ensuring a customer education plan engages and informs customers throughout all phases of the project will expand customer engagement and reinforce the benefits offered by AMI, as well as help mitigate negative responses to deployment.
- Employees have an important role in educating customers on what AMI is and how it adds value to customers' lives.
- Education initiatives should be conducted in phases that are aligned with the deployment schedule, rather than attempting a one-time education effort.
- A successful education plan requires a comprehensive approach using multiple communication tools to reach all segments of the customer base.
- The education plan should use customer research conducted throughout the entire project in order to gauge and track the effectiveness of educational materials. Materials should be revised as needed based on customer feedback throughout the various phases of the project.

Leveraging Best Practices

While implementing this education plan, ENO will incorporate these best practices and actively engage with customers to guide and support appropriate revisions of educational materials and messaging.

One critical best practice is to ensure the customer education plan remains flexible in order to address customer feedback and adapt to changes in the AMI deployment. Should the deployment encounter unexpected challenges, ENO will be prepared to make adjustments to the customer communications as needed during the project. For that reason, this plan has been prepared as a flexible guideline for customer communications.

A Phased Approach to Customer Education

Because the implementation of AMI for a utility the size of ENO requires a multi-year deployment, ENO's plan will ensure customer education, communication, and engagement through each of the meter deployment phases.

The table below lists the milestones, key objectives, and available education tools for each phase of the education plan.

Phase	Milestone	Key Objectives	Available Education Tools[2]
Pre-Deployment (Phase I)	ENO is in the process of testing communications with customer segments and information technology ("IT") systems and preparing for the meter deployment phase.	Communicate with customers and stakeholders on the plan for meter installation and subsequent expected timing of installation of advanced meters, as well as immediate and long-term benefits of advanced meters.	• Website • Emails • Residential and commercial toolkits (FAQs, brochures, etc.) • Residential and commercial brochures • Stakeholder outreach • Letters/emails to customers (close to deployment) • Employee communications • Videos • Research • Community outreach • Display units for events • Search engine optimization

[2] See Appendix A for descriptions of selected education tools. Appendix B provides examples for illustrative purposes.

Phase	Milestone	Key Objectives	Available Education Tools[2]
			• Social media
Meter Deployment and Individual Activation of Online Energy Management Information and Tools (Phase II)	Large volumes of advanced meters are being installed in the community. New energy management features are communicated in direct communications with affected customers as they become available. Education includes how to use these tools to access more detailed energy usage and billing data, including both historical and recent information from their current or most recent billing cycle.	While advanced meters are being installed, continue to educate residential and commercial customers about the features and benefits and what they have to do, if anything, when their meter is replaced and how, if at all, they will be affected. Promote adoption of energy management tools as advanced meters and web portal are activated.	• Website • Emails • Door hangers • Installer cards/rack cards • Press release • Telephone calls • Direct mail • Bill inserts • Social media • Media relations • Research • Community outreach • Display unit for events • Search engine optimization
Energy Management Information and Tools Available to All Customers (Phase III)	Most meters have been installed and are activated. New energy management tools are featured broadly in communications and education to all customers.	Active use of online energy management tools via web portal. Encourage all customers to use the web portal and explain how and where they can access information.	• Website • Emails • Press release • Mass advertising • Digital marketing and advertising • Direct mail • Bill inserts • Social media • Media relations • Customer surveys • Community outreach • Display unit for events • Search engine optimization
Ongoing Education and Engagement (Phase IV)	Full meter deployment is essentially complete; most meters have been	Ongoing education on the energy management tools	• Website • Emails • Mass advertising

Phase	Milestone	Key Objectives	Available Education Tools[2]
	installed and benefits are well underway. Post-deployment communication concentrates education around how customers can use the tools to manage energy use and how they can play a proactive role in their own energy management to reduce their bills as part of ongoing customer service and customer satisfaction communication.	and how to use them is critical. ENO plans to have in-person communications and tutorials around how to use the available tools.	• Direct mail • Bill inserts • In-person courses • Community outreach • Customer surveys • Display unit for events (Same as Phase III) • Digital marketing • Search engine optimization • Social media

Audiences

The installation process for residential, small and large commercial, and industrial customers will differ, which is due not only to the differences in the meter types for these customers but also due to potential for impacts from momentary service interruptions to commercial customers. In addition, because the process of installing commercial meters is likely to be different and require a level of scheduling that is not necessary for residential customers, communications during the deployment period will need to be customized to include those considerations. Implementation of this plan will include segmented messages and materials for each class of customer, whether they are residential, commercial or industrial.

It is worth noting, however, that large commercial or industrial customers will be handled closely through ENO's accounts team and the education will fall primarily in their hands. For that reason, this plan will not go into detail around customer education for large commercial and industrial customers, but rather will focus on customers who will not have this manner of communication.

IMPLEMENTATION PLAN

Use of Tactics by Phase

This section of the plan will provide a narrative around how each of the phases will be rolled out. It will include preliminary messaging. Final messaging will be refined following feedback from focus groups and other qualitative and quantitative research with customers.

Phase I

Phase I is designed to educate customers on ENO's plans to install advanced meters as well as help customers understand the features and benefits that AMI will bring. The messaging will refer to the installation process as an upgrade of ENO's meters with more advanced technologies that offer more capabilities.

Below are the primary messages that ENO expects to provide customers during Phase I:

- ENO is working with customers and other stakeholders to modernize our grid.
- Advanced meters will offer a number of benefits to customers for their homes and businesses, including improved reliability and customer service.
- The new and improved technology will offer both immediate and long-term benefits.
- Benefits available following installation of advanced meters include more detailed information about energy use, including tools to help manage and reduce energy usage.
- Additional benefits will be available in the future in conjunction with further investments in technology and grid modernization efforts.
- Advanced meter installation will start in the coming months.

Determining a Baseline and Rolling Out Market Research

Prior to the installation of advanced meters, ENO will conduct research to gauge customer perceptions, awareness and attitudes about AMI, including a baseline survey with customers to monitor progress made in future phases on familiarity with the technology and its benefits. During this research, ENO will also focus on learning more from customers about their communications preferences to ensure actions in this plan are effective and aligned with customer expectations.

Website

Prior to the installation of advanced meters, a dedicated web page will be developed to provide information regarding ENO's AMI plan. This central repository for all customer educational material will be linked to ENO's website.

Another important role of the web page is to allow ENO to evaluate the volume of customer visits and "click-throughs." Through this, ENO will be able to evaluate how effective the site is in meeting customer needs as well as what material they find the most interesting or most needed on the site. Metrics around viewership of the web page will be collected during the course of the deployment and studied to determine if any adjustments need to be made and/or what material needs to be enhanced or removed.

Through the use of dedicated web-based content, ENO will have the ability to modify and update its content in parallel with each AMI deployment phase, as well as use search engine optimization (SEO) technology to ensure the web page is prominently displayed when customers use search engines to learn more about AMI, and ENO's AMI plan in particular.

The web page will also contain videos and other digital media to help customers learn about the benefits of AMI.

Community Outreach

ENO often participates in community outreach events as a way of meeting face-to-face with customers and civic and business leaders. As part of the education process of Phase I, ENO will develop an AMI display unit, including educational materials to demonstrate how AMI works and provide information to customers they can refer to later.

Stakeholder Engagement

ENO has a separate stakeholder engagement effort to ensure external stakeholders will be made aware of the AMI deployment and benefits of advanced meters. A secondary rationale of ENO's effort to educate and engage stakeholders during Phase I is to foster them as advocates of the project and enable them to assist their constituents with questions they have.

ENO plans to continue to educate and engage stakeholders throughout all phases of the project with materials and communications specifically designed for them.

Direct Mail

Prior to receiving an advanced meter, a letter will be mailed directly to customer homes and businesses informing them that ENO is installing advanced meters and how to prepare.

Public Relations

ENO will actively communicate with the media about the deployment and provide informational materials to journalists as needed.

<u>Phase II</u>

Phase II of the customer education plan is focused on helping individual customers know what to expect when their new advanced meter is installed and understand the new energy management information tools that will be accessible after the installation.

Below are the primary messages that are planned to be explained to customers in Phase II of the plan:

- Advanced meters are the first step in ENO's grid modernization efforts.
- Installation of advanced meters has started in their area.

- If the installer is unable to reach the existing meter or complete the installation of an advanced meter, a door hanger will provide information on how to reschedule the installation.
- After customers get new meters and web portal access is activated for groups of customers, they will have access to more information and tools about their energy use and to set budget goals.
- Advanced meters also allow for enhancements to business processes such as remote disconnect and reconnect activities; explain these process changes.
- These tools and tips for energy reduction can help customers identify ways to lower bills and save money.
- Access to these new energy management tools is easy; explain how customers can access them.

Tracking Satisfaction and Awareness

During this period of meter installation, ENO will begin surveying customers to track and monitor their attitudes and awareness towards AMI. These surveys will help ENO determine if the education plan is effectively reaching customers and make any appropriate modifications.

Meter Installer "Rack Cards" and Door Hangers

During this period, meter installers will be supplied with materials to help answer installation and other AMI-related questions. Door hangers will let customers know if a meter has been installed or whether there is a need to reschedule an installation.

Community Outreach

During this period, ENO will continue to attend events in the community for the opportunity to communicate face-to-face with customers about the deployment and benefits of advanced meters as well as the new energy management information and tools available through AMI.

Direct Mail

During meter installation, ENO will use direct mail as a way of communicating with customers about the benefits of the meters.

Website

In addition to communications directed to customers as they receive advanced meters, web content containing general information will support awareness of AMI basics.

Public Relations

ENO will proactively communicate with the media about the deployment progress and provide informational materials to journalists as needed.

Phase III

Phase III of the customer education plan is focused on increasing use of online energy information tools.

Below are the primary messages that will be explained to customers in Phase III of the plan:

- Customers have access to more detailed information about their energy use.
- A variety of tools are available to help manage energy use and set budget goals.
- These tools and tips for energy reduction can help customers identify ways to lower bills and save money.
- Access to these new energy management tools is easy; explain how customers can access them.
- Customers should actively refer to their personal energy information found on the web portal.

Website
During this period, the website will be updated with information, videos and other digital materials that focus on customer tools now available. The content will be designed to help educate customers about new services, tools, and applications available to them and provide easy access to signing up.

ENO's website will also promote the web portal and encourage its use.

Bill Inserts

Bill inserts will promote the web portal and tools, as well as encourage customers to use them.

Promotion (Traditional and Digital)

Promotions via both traditional and digital channels will feature the web portal and encourage customers not already enrolled in MyAccountOnline to sign up. Direct channels (e.g., mail/email) will provide personalized, targeted messages to present the benefits of AMI that are most relevant to the specific customer. It will also encourage customers to make use of digital communication channels and/or the web portal. Indirect channels (e.g., paid media, search engine marketing, social media marketing) will provide targeted messaging presenting the benefits of AMI and new information tools available to customers.

Advertising and Paid Media

ENO will advertise in local media throughout New Orleans about the customer web portal and benefits of the online energy management tools. Advertisements will encourage engagement and use of tools.

Public Relations

A news release will be issued featuring the customer web portal, and ENO will actively promote benefits of the energy management tools. Social media will also be used to engage customers.

Phase IV

Phase IV includes continued efforts encouraging customers and informing them how to make use of their personal energy information via the various communication channels and notifications.

Below are the primary messages that will be explained to customers in Phase IV of the plan:

- Customers now have access to more detailed information about energy use.
- Here's how to use tools that are available to you to help manage energy use and set spending goals.
- These tools and tips for energy reduction can help customers identify ways to lower future bills and save money.
- Signing up is easy to get access to these new energy management tools, and explain how they can sign up today.

ESCALATION PLAN

Industry research has indicated that a small percentage of customers will need additional information to become comfortable with the benefits that AMI will provide. An even smaller percentage of customers may ultimately prefer not to receive an advanced meter. ENO anticipates that the Council, like many other utility regulators, will allow this small number of customers to opt out of receiving an advanced meter. When customers need additional information or want to discuss opt-out issues, ENO will have AMI Education Specialists available to discuss those issues.

The Company has developed an escalation plan so that the customer service team can handle all customer questions, concerns, and opt-out requests appropriately. The chart below outlines how different scenarios may warrant an escalation request:

Scenario	Response	Materials needed
Customer calls contact centers and does not want an advanced meter	Escalated to the appropriate ENO contact who is prepared to discuss in further detail	
Media calls ENO with question or concern	Directed to communications manager who will answer questions and provide materials if necessary	
Stakeholder calls ENO with constituent request or concern	Call will be directed to a trained ENO contact responsible for that stakeholder group	• FAQs • Informational toolkits when necessary • Rack cards

RESEARCH AND METRICS

Customer Research Applications

ENO believes that research and metrics are an integral part of designing and monitoring the success of the customer education plan, as well as enabling ongoing plan improvement and alignment with customer expectations. As such, customer education research will be used in two critical ways:

1. To gain valuable input on the content of educational materials; and
2. To monitor the effectiveness of education efforts and incorporate feedback during each phase of education.

Understanding Customers: The Role of Qualitative Market Research

In order to ensure significant input from customers on educational content and feedback from important customer segments, it is a recommended practice that critical pieces of the education plan, like letters, FAQs, brochures, and other communications, be tested via both in-person and panel focus groups.

Benefits of qualitative market research include:

- Utilizing focus groups at every stage of the AMI deployment to ensure education efforts and materials are aligned with the objective of familiarizing customers with the AMI deployment and its benefits.
- Ensuring educational materials and messaging to customers is more effective.

Measuring Success: Introduction to Tracking Surveys

Customer feedback is important to ensuring that materials support successful implementation of this plan.

Benefits of quantitative market research include:

- The ability to understand general customer communications preferences for purposes of future education efforts.
- The ability to track the level of customer understanding and value of AMI benefits throughout deployment process across the customer base.

ENO plans to conduct tracking surveys starting in Phase II of the deployment, compared against a Phase I baseline.

ENO has identified a number of key areas of customer responses that it will track throughout the course of the AMI deployment. These topics will be examined to ensure that ENO is effectively educating customers and responding to needs during the deployment.

Tracking of topics may include:

- Customer awareness of and sentiment toward energy management tools offered by advanced meters
- Customer awareness of and sentiment toward advanced meters and their benefits
- Ongoing awareness of communications tools offered by ENO about AMI

Segmentation

In its baseline research, ENO will poll a statistically valid sample of ENO's customers, including a diverse group representing all its different customer segments, regarding what they know about grid modernization and advanced meters. In addition to an appropriate customer sample representation, ENO will ensure that its customer sample embraces a demographically diverse pool of customers to participate in the study.

Within the sample size, ENO includes a representative sample of customers from the following customer segments:

1. Low income customers
2. Senior citizens
3. Non-computer users
4. Non-English speaking customers

This segmentation information will be important in developing unique communications to customers throughout the deployment.

Proposed Research Plan

The timeline for customer research will map to awareness and implementation for particular customers as follows:

Introduce	Pre-meter installation.	ENO Filing Date: October 18, 2016 Baseline survey followed by periodic surveys to monitor sentiment and customer attitudes.
Educate	Meter installation begins and access to online energy management information is made available.	Surveys directed to customers who have received an advanced meter. Surveys will start with deployment and carry on throughout the immediate post-activation period.

Engage	Approximately six months after meters are activated and at least six months of education has been conducted about how to use tools.	Surveys continue.

TIMING AND BUDGET

2016	2017-18	2019-2021	Late 2021	2022 and beyond
Early Phase I	Phase I	Phase II	Phase III	Phase IV
Education Planning	Pre-Deployment	Meter Deployment and Individual Activation of Online Energy Management Information and Tools	Energy Management Information and Tools Available to All Customers	Ongoing Engagement

2016	2017	2018	2019	2020	2021	TOTAL
$99,146	$99,146	$198,292	$227,850	$819,460	$539,025	$1,982,920

APPENDIX A

This section provides detailed descriptions of certain education tools to be used in various phases.

Education Tool	Description
Website	Educational website content will be developed to educate customers and stakeholders about ENO's AMI deployment. This content will be phased to introduce new information as it becomes relevant and available to customers. It will also serve as an important tool throughout all phases of the education plan. The website tools will also enable ENO to use digital channels to direct customers to AMI information and limit effort to acquire information on the AMI deployment.
Email	We will leverage our customer email list to deliver timely, measurable messages to our customers throughout the deployment.
Informational toolkits – residential and small- and medium-sized business	Materials will be created with information about the deployment including an overview document, brochure, frequently asked questions (FAQ), etc. These toolkits will be used as appropriate to communicate messages to stakeholders and may be tailored as appropriate for specific audiences. For example, materials for small- and medium-sized businesses will be prepared to target information applicable to those customers.
Informational toolkit – large commercial and industrial	For large commercial and industrial customers, toolkits will be prepared for account executives to help inform businesses of the meter replacement schedule, the benefits of AMI, and what to expect along the way.
Presentations	Presentations will be prepared for public relations and customer service employees to communicate with stakeholder groups about

	information on the deployment and benefits of AMI.
Letters to customers	Customers will receive a letter informing them about planned installation of their new advanced meter and any preparations close to their scheduled installation date.
Employee communications	ENO will create employee communications materials to explain the details and benefits of the deployment to employees. These communications will also educate employees on how to serve as ambassadors for the project with customers.
Videos	Videos will be created to explain the capabilities and benefits of the AMI technology.
Research	Baseline surveys and focus groups will be conducted to assess current and ongoing knowledge and attitudes towards AMI.
Community outreach	ENO will participate in community outreach events throughout New Orleans. To ensure customers will be able to have their AMI-related questions answered, a community outreach representative will be trained in AMI customer education strategies and will have details to answer questions about deployment.
Media relations	ENO will develop key talking points and FAQs to help with media response to inquiries about the AMI deployment, the capabilities of AMI technology and the benefits the AMI deployment is expected to provide ENO and its customers.
Display unit for events	Displays will be prepared to use at community outreach events to explain the benefits of AMI and information about the new advanced meters.
Digital marketing	ENO will utilize its digital marketing capabilities to support the customer education process.
Social media	Social media will be used to update customers about the AMI deployment and explain the benefits of advanced meters, as well as identify additional customer sentiment.
Search engine optimization (SEO)	In conjunction with web content created for the AMI deployment, SEO will be used to

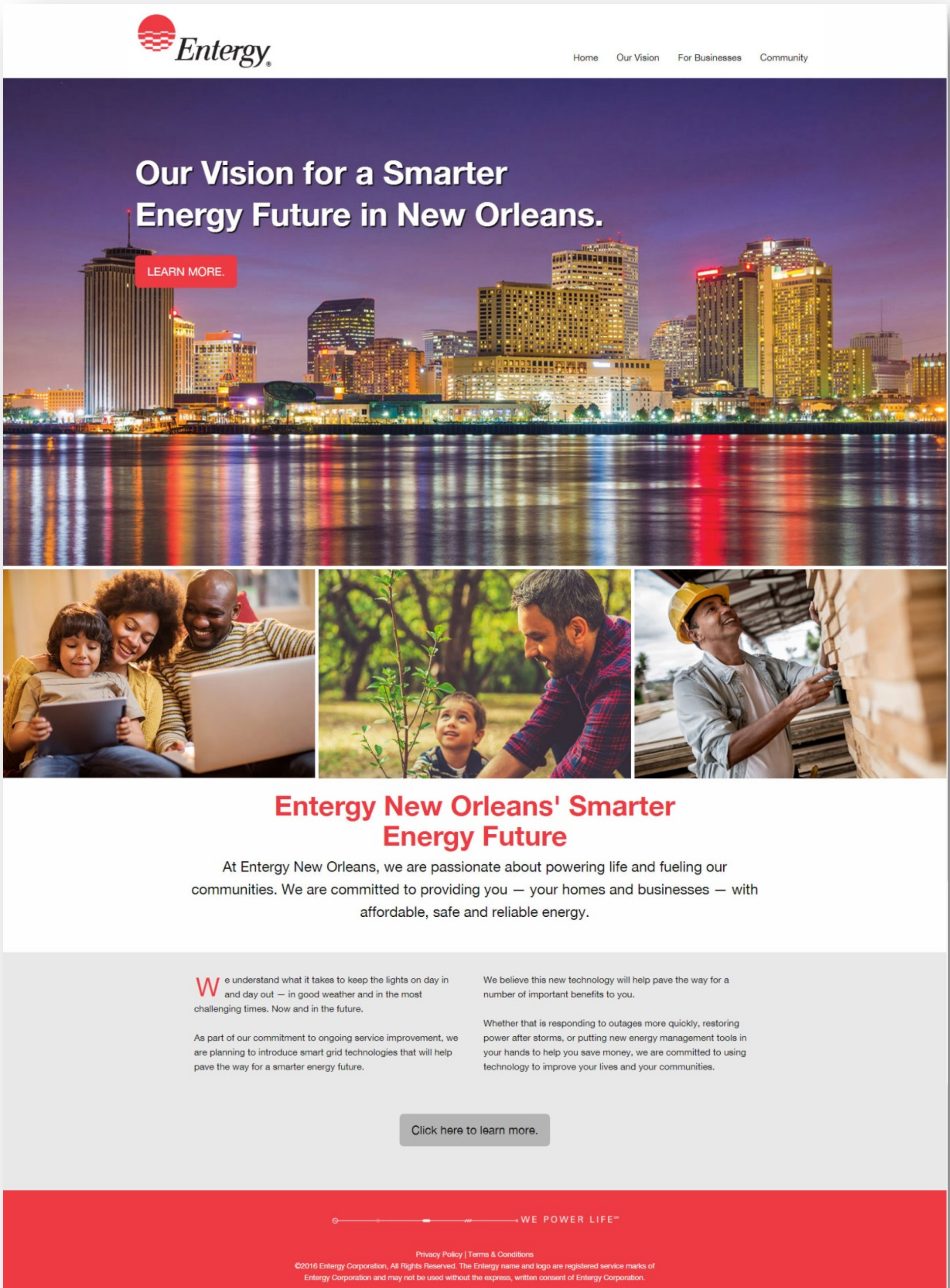
	enable customers to find information about AMI generally, and ENO's AMI deployment in particular, when using web search engines.
Door hangers	Door hangers will be developed to use during meter installation. The door hangers will notify customers if their advanced meter was successfully installed or whether they need to call to schedule an installation. The back of the door hanger will also contain overview information about ENO's AMI deployment.
Installer cards/rack cards	Installer cards will be developed and provided to the meter installers to use if customers have questions in the field. Installer cards will contain overview information about ENO's AMI deployment and a few FAQs.
News releases	ENO will develop news releases as needed throughout all phases of the deployment.
Telephone contact	Telephone contact may be made with customers throughout the deployment on a rolling basis and approximately 1-2 weeks before the customer's advanced meter installation.
Mass outreach	Once critical mass is achieved in the deployment of meters, ENO will launch multi-channel educational messages to target all demographics and customers who have received an advanced meter in order to reinforce availability of the new online information and benefits of the web portal.
Direct mail	Direct mail pieces will be developed to continue educating customers about the meter deployment and benefits of advanced meters. In addition, they will explain the new energy management information and benefits of the web portal. These direct mail pieces will target non-computer using customers, and provide instructions on what customers should do if they cannot access the new energy management information.
Bill inserts	Bill inserts will be developed to educate customers throughout the deployment, particularly those customers who do not access digital channels as frequently.
In-person courses	ENO will partner with community

	organizations to educate customers about how to use the online energy management tools. It will provide suggestions to customers on how they may be able to lower their monthly bill.

APPENDIX B

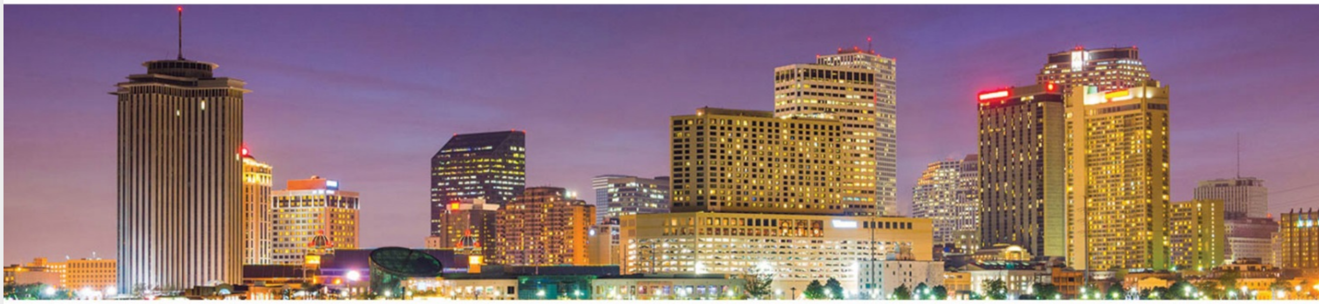
This section provides samples of educational materials for **illustrative purposes**. Actual information will be adjusted prior to dissemination based on design phase decisions and feedback from customers.

Web Page Mockups (Customers, Owners, Employees and Community Leaders)



Entergy.

Home Our Vision For Businesses Community



Our Vision

What is a Smarter Energy Future?

Our homes and our lives are benefiting daily from new technologies. Whether it is the convenience of using a mobile phone, paying your bills online, or using the Wi-Fi network in your local coffee shop, we all benefit from the advancements of technology.

As the local energy provider, we are in a position to use technology to make energy delivery more reliable and affordable. That is why we are pursuing a smarter grid in New Orleans that will offer you:

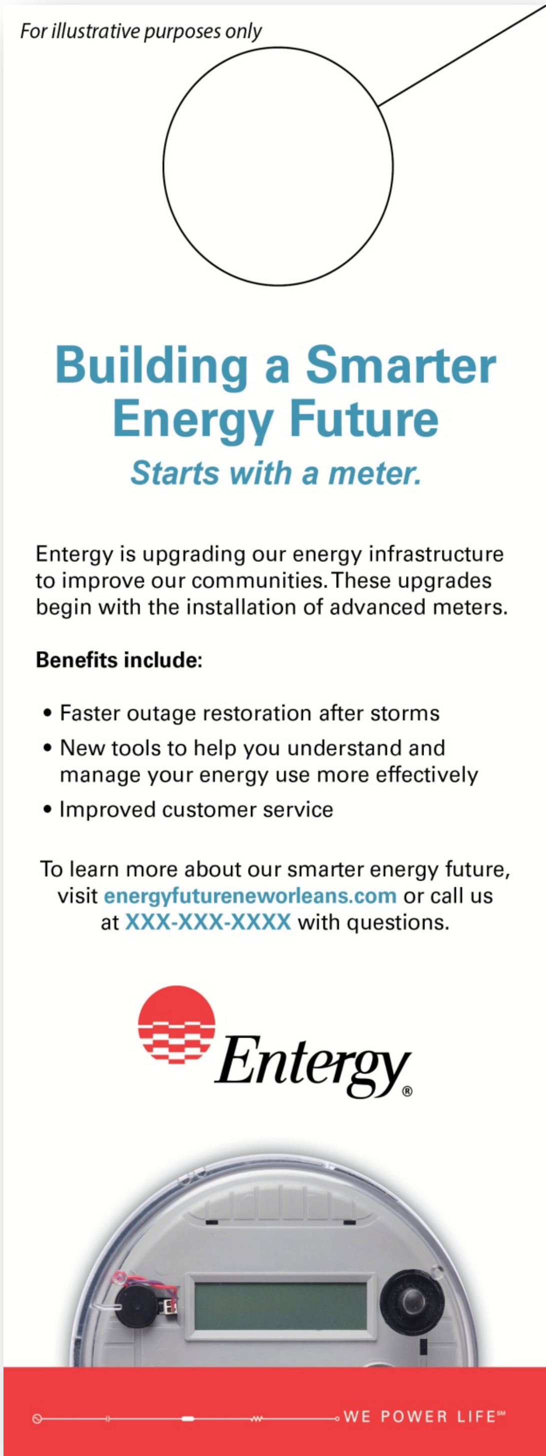
- Stronger and "smarter" localized electrical infrastructure to help improve community resiliency by helping us restore electricity in homes and businesses quicker after outages and potentially spot problems before they occur.
- More tools and better information to help customers understand and manage their energy use more effectively, which can lead to lower bills.
- Improved customer service, including better information that will allow us to answer customers' billing and service questions more quickly and effectively.
- Potential new programs to help further encourage and improve energy reduction and contribute to environmentally sustainable communities.

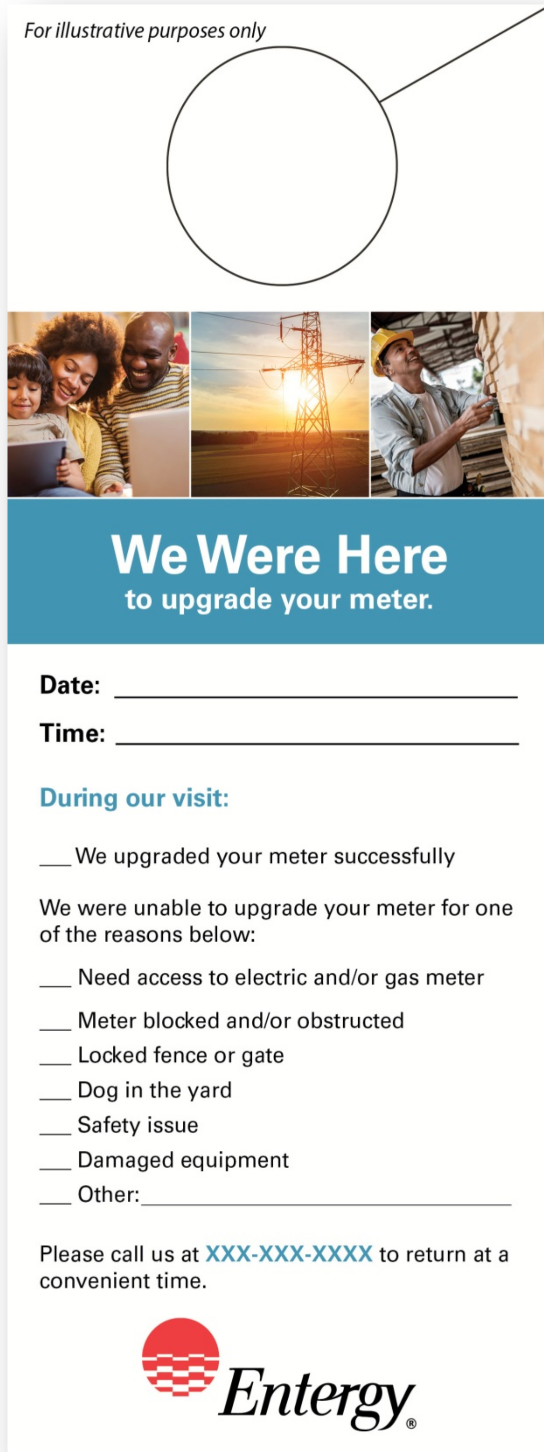
For more information about Entergy New Orleans' vision for a smarter energy future, call us at XXX-XXX-XXXX.

WE POWER LIFE℠

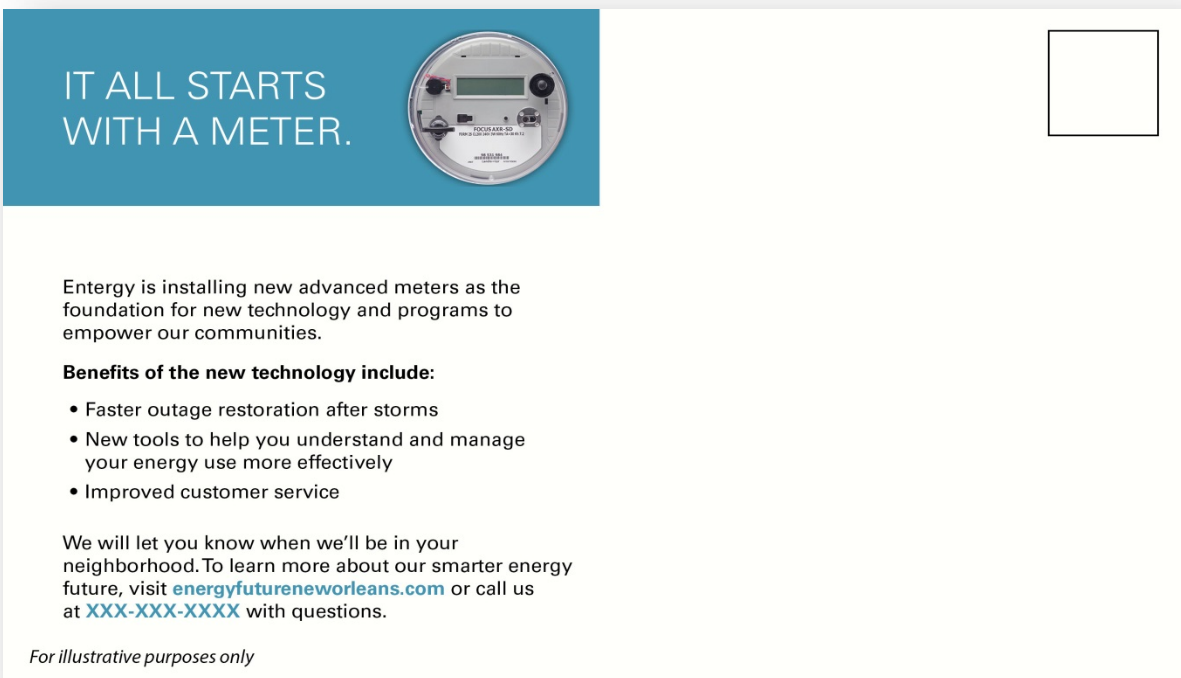
Privacy Policy | Terms & Conditions

Installation Door Hanger (Residential Customers)





Installation Direct Mail (Residential Customers)



BEFORE THE

COUNCIL FOR THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO DEPLOY ADVANCED METERING INFRASTRUCTURE, AND REQUEST FOR COST RECOVERY AND RELATED RELIEF	))))))	**DOCKET NO. UD-16-___**

DIRECT TESTIMONY

OF

RODNEY W. GRIFFITH

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

OCTOBER 2016

TABLE OF CONTENTS

EXHIBIT LIST

I. QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Rodney W. Griffith. I am employed by Entergy Services, Inc. ("ESI")[1] as Director, Advanced Metering Infrastructure ("AMI") Implementation. My business address is 9425 Pinecroft Dr., The Woodlands, Texas 77380.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying before the Council for the City of New Orleans ("CNO" or the "Council") on behalf of ENO.

Q3. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL, PROFESSIONAL, AND BUSINESS EXPERIENCE.

A. I have a Bachelor's of Science degree in Electrical Engineering from Lamar University. I have certificates for Managing for Execution, High Performance Leadership, and Leading Change from Cornell University.

I am a registered professional engineer in the State of Texas. I am a member of the Institute of Electrical and Electronics Engineers.

I began my career in 1974 as a Co-op Engineer at Gulf States Utilities Company ("GSU"), working there until graduation. In 1978, I joined Texas Eastman Chemical Company as an Instrument Engineer. In 1979, I returned to GSU. Since

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[1] ESI is a subsidiary of Entergy Corporation that provides technical and administrative services to all of the Operating Companies. The Entergy Operating Companies include Entergy New Orleans, Inc. ("ENO" or the "Company"); Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; and Entergy Texas, Inc. ("ETI").

that time, I have held numerous roles and assignments with GSU, which was subsequently acquired by Entergy Corporation in the early 1990s, within the Transmission, Distribution, Engineering and Operations organizations.

Most of my roles and assignments have involved the support and/or deployment of distribution and transmission technology. For example, in 2004, I began leading the Supervisory Control and Data Acquisition ("SCADA") Group's 11 Distribution and Transmission Controls Centers as the Manager, SCADA Systems Support. In 2007 my title changed to Manager, EMS Support Management, and my leadership role expanded to include SCADA support at the System Operation Center in addition to the 11 other Control Centers. In 2008, I became the Manager, Transmission Operations Process Control, and my responsibilities expanded to include oversight of all Operations Information Technology ("IT") support for all 12 Control Centers.

In 2012, I assumed the role of Manager, Engineering where I led the Distribution Engineering work group for ETI. In 2014, I became Manager, Compliance Systems Support, which included responsibility for business process assessment and support and the preparation of a Technology Roadmap for the distribution function. In this role, I also began leading the preliminary efforts related to AMI. In 2015, I was named Director, AMI Implementation, where I lead the implementation of AMI and supporting systems. A list of my prior testimony is attached as Exhibit RWG-1.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q4. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony describes the technical aspects of ENO's current plan to replace all of its existing electromechanical (*i.e.,* analog) and digital retail electric meters with advanced meters that enable two-way data communication,[2] to design and build a secure and reliable communications network that supports two-way data communication, and to implement supporting systems, including a Meter Data Management System ("MDMS"). Those three primary components (advanced meters, the communications network, and MDMS) are commonly referred to as AMI.[3] The Company also plans to update its legacy Outage Management System ("OMS") and implement a new Distribution Management System ("DMS") to enhance overall system performance, which will be capable of utilizing the additional data provided by AMI. I also discuss how ENO plans to integrate the MDMS, OMS, and DMS with an Enterprise Service Bus ("ESB") and legacy IT systems. Although some may refer to these components together as an advanced metering system, for practical purposes, the other ENO witnesses and I will refer to ENO's deployment of all those components in total as the AMI deployment.

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[2] Company witness Michelle P. Bourg addresses the Company's proposed implementation of advanced meters for its gas customers. Throughout my testimony, my discussion of advanced meters is in the context of electric meters.

[3] For example, the U.S. Department of Energy defines advanced metering infrastructure as "an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers." *See* https://www.smartgrid.gov/recovery_act/deployment_status/sdgp_ami_systems.html.

In my testimony I describe the individual components of the AMI deployment and the approach taken by ESI on behalf of ENO to identify, evaluate, and select vendors for the: (1) advanced meters, (2) communication system, (3) MDMS, and (4) system integration. I also describe ENO's approach to implement the various AMI components and the planned deployment schedule. I describe how the data that is collected, stored, and transmitted by the advanced meters will be protected with administrative, physical, and technological safeguards at various stages of the deployment. Finally, I discuss the capital and operations and maintenance ("O&M") costs associated with the Company's AMI deployment.

Q5. PLEASE SUMMARIZE ENO'S AMI DEPLOYMENT PLAN.

A. ENO is developing a design and implementation plan to implement AMI, which will be comprised of industry-accepted technology and equipment. The Company followed a rigorous approach to identify, evaluate and select experienced vendors and also negotiate fair contracts with commercial terms protecting the interests of the Company and its customers. The selected technology and vendors have a proven track record of success for large AMI implementations at other utilities throughout the United States and globally. Additionally, as part of its AMI implementation, ENO is updating the existing OMS and implementing a new DMS to enhance utility operations and provide an overall more reliable distribution system where service can be restored faster and more efficiently after customer outages.

The Company has planned a deployment schedule reflecting the complex interrelationships between various IT systems and managing the normal risks associated with a large-scale meter deployment.

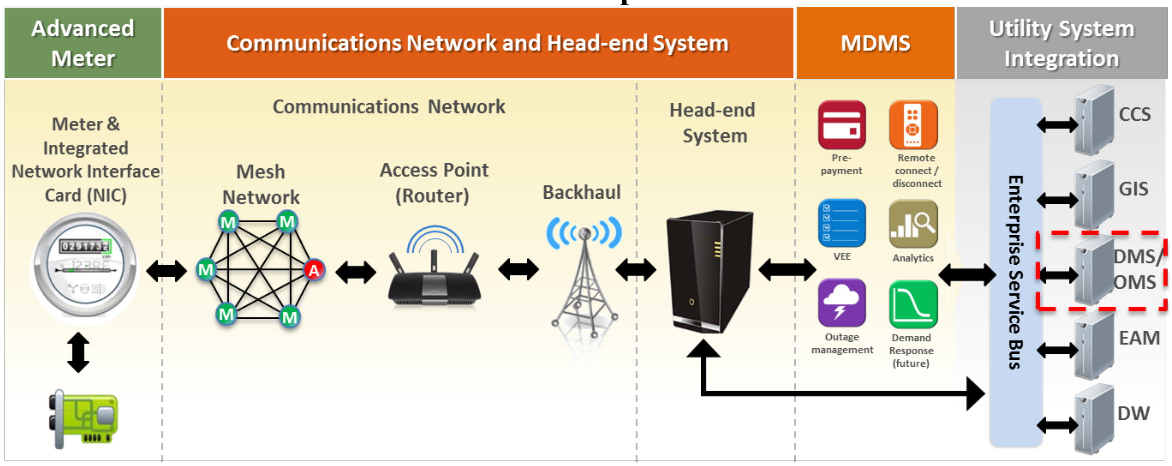
Finally, ENO established a comprehensive cost estimate for the design and deployment of AMI, incorporating vendor cost information from a competitive bidding process, internal Company costs associated with executing the AMI project control environment, and an appropriate and reasonable contingency. The contingency addresses the possibility of risks that naturally may arise from a large and complex project such as AMI deployment. The Company's approach to estimating AMI costs is reasonable and consistent with the approach used for other large capital programs.

III. ADVANCED METERING INFRASTRUCTURE

Q6. PLEASE PROVIDE AN OVERVIEW OF THE COMPONENTS OF THE COMPANY'S AMI DEPLOYMENT.

A. The components of AMI deployment consist of: (1) advanced electric meters; (2) a communication system, comprised of a network interface card ("NIC") that will be installed in the advanced meter, a communications network, and a head-end system; (3) an MDMS; (4) an update of the legacy OMS; and (5) the implementation of a new DMS. Finally, all of these components will be integrated into existing and planned IT applications and other systems via an ESB. The components are illustrated in Figure 1 below.

Figure 1
AMI Components



Q7. WHAT CAPABILITIES WILL BE INCLUDED WITH THE COMPANY'S PROPOSED AMI DEPLOYMENT?

A. AMI will be designed and built to deliver a number of functionalities and operational applications (commonly referred to as "use cases" or "applications") immediately upon deployment, as well as to support additional applications that may be implemented over time. The applications that will be available immediately upon deployment and meter activation include: 1) automated remote meter reading, including recording and processing interval consumption data at 15-minute intervals for residential customers and 5-minute intervals for commercial and industrial customers, with the verified data being made available to customers daily; 2) two-way communications; 3) remote enabled service connection, disconnection and reconnection; 4) remote configuration and firmware upgrades; 5) automated meter health and status communication; 6) web-based customer data accessibility, which will facilitate customers' web portal access of their usage information; 7) customer usage goal-setting thresholds and alerts; 8) outage management support, including restoration verification; 9) theft and tamper notifications to the Company; 10) event and load profiling for analytics; 11) power quality reporting; 12) asset mapping and predictive asset management; 13) more accessible information for load forecasting and load research efforts; 14) support for implementation of optional pre-pay programs; and 15) ability to incorporate distributed energy resources ("DER"), which have grown more prevalent in recent years (*e.g.,* rooftop solar systems).

Q8. WILL THE COMPANY'S AMI INCLUDE FUNCTIONALITIES THAT CAN SUPPORT ADDITIONAL APPLICATIONS AND PROVIDE FUTURE CUSTOMER BENEFITS?

A. Yes. AMI will support additional applications that may be implemented over time. Those applications include features such as: 1) advanced usage analytics and energy savings tips that are customized to each unique customer; 2) dynamic pricing programs such as time-of-use ("TOU") and real-time pricing; 3) more expansive demand response ("DR") programs; 4) potential control and dispatch of DERs; 5) streetlight monitoring and control applications; 6) voltage optimization and control (*e.g.,* conservation voltage reduction or "CVR" programs); 7) enablement of distribution automation; and 8) enablement of distributed intelligence.[4] These additional functions and applications are not included in ENO's AMI deployment,

[4] In the AMI project context, distributed intelligence is the ability to perform analytics at the edge of the grid to support true real-time control of grid devices without having to send information back through the head-end into utility systems for processing and decision making. In the future, the addition of DERs, electric vehicles ("EVs"), and microgrids would be expected to increase the amount of data that AMI will be required to transfer and process to ensure reliability and efficient grid operations.

and each application will require some level of additional investment in order to achieve the described functionality.

IV. OVERVIEW OF ENO'S APPROACH TO IMPLEMENT AMI

Q9. WHAT STEPS WILL THE COMPANY IMPLEMENT TO MANAGE THE AMI DEPLOYMENT?

A. AMI deployment is a large capital program that will be managed in compliance with ENO's management structure and control environment. At the outset of the program, ESI, in conjunction with ENO, established a Project Management Office ("PMO") structure for AMI to manage the program design, vendor selection, and AMI deployment. The PMO is a matrix organization that consists of multiple work teams, each of which is focused on specific functional areas and project execution activities. Work teams are coordinated by and report through the PMO.

The PMO is governed by an Executive Steering Committee that consists of representatives from each of the participating Operating Companies, including ENO (the "AMI Steering Committee"). The AMI Steering Committee is responsible for oversight and approval of PMO activities. ENO's participation on the AMI Steering Committee includes the Company's Vice President, Customer Service for operations in the State of Louisiana, Company witness Mr. Dennis P. Dawsey or ENO representatives acting at his direction. These ENO representatives not only participate in the decision-making for the project but also provide direct guidance and input to the PMO on issues specific to or otherwise affecting ENO's AMI deployment. For example, although Mr. Dawsey can directly address this, I am generally aware that the selected vendors I discuss later reflect ENO's preferred selections. In addition, I have worked with ENO representatives to review the various CNO requirements that in turn will help drive the design phase of ENO's AMI deployment.

A similar PMO approach has been used to manage and report on project performance parameters (*e.g.*, cost, schedule, scope, supply chain, risks, safety, and quality) for other large-scale utility projects. The Company's PMO approach and associated control environment are reasonable and appropriate for a project such as AMI.

Q10. WHAT IS YOUR ROLE IN THE PMO?

A. I am the PMO lead for AMI implementation. My responsibilities include overseeing the PMO activities and communications, managing the overall PMO logistics, resolving cross-functional issues across program work teams, and functioning as the point of accountability for the overall program implementation success.

Q11. WHAT IS THE EXPECTED SCHEDULE FOR AMI DESIGN AND DEPLOYMENT?

A. Preliminary design work began earlier this year (2016) and should be complete by the end of the year. The preliminary design work includes the results of a review of relevant Council rules in order to incorporate any specific requirements. The initial design work will be followed by the development of detailed IT functional requirements, system build, testing, and the eventual deployment of advanced meters.

Assuming Council approval is received in 2017, the communications network deployment is expected to begin by late 2018, after the necessary IT infrastructure is in place. Under the current expected schedule, the deployment and installation of the advanced meters on customers' premises would begin in early 2019 and take approximately three years to complete. Table 1 below shows ENO's preliminary meter deployment schedule using approximate meter numbers.

Table 1

Preliminary Deployment Schedule			
	2019	2020	2021
Electric Meters	24,000	102,000	73,000
Gas Communication Modules	39,000	62,000	11,000

Q12. CAN YOU ELABORATE ON WHY IT IS EXPECTED TO TAKE SEVERAL YEARS FOR ENO TO FULLY DEPLOY AMI?

A. As illustrated above, deployment of AMI includes significantly more than just replacing existing meters with advanced meters, which in itself is a time-consuming undertaking. It is necessary to first build the IT systems, which involves the development of detailed AMI business requirements, the deployment of software and hardware, and the integration of new and upgraded AMI systems with existing Company applications estimated to involve approximately 150 interfaces between 15-20 different IT systems. Once the basic IT infrastructure is installed, the systems must be integrated and tested, and employees must be trained to confirm AMI operates as expected and achieves its functional objectives. The next step is building the communications system that allows the IT systems to communicate with the advanced meters. That step involves installation of an estimated 70 access points and 370 repeaters, followed by testing communications from those points to the head-end system. The final step is replacing customers' existing meters with new advanced meters. For ENO, it is estimated that approximately 24,000 meters will be replaced in 2019, 102,000 meters in 2020, and then finally 73,000 meters in 2021. For gas communication modules, it is estimated that 39,000 will be installed in 2019, 62,000 will be installed in 2020, and 11,000 will be installed in 2021.

The Company believes that a three-year period for installing the advanced meters is appropriate. This time frame provides a reasonable balance between timely meter installation and efficient, cost-effective supply chain and installation crew management. The sequence of the deployment will also allow ENO and its customers to realize the benefits of advanced meters as they are deployed rather than wait until a later date. In other words, the communications network will be functional prior to the installation of meters, thereby enabling the remote communication functionality of the advanced meters and its associated benefits at the point of meter installation. Additionally, attempts to expedite deployment schedules can reasonably be expected to significantly increase installation costs due to the increased coordination and oversight that is needed, increased labor and overhead costs, and heightened pressures on the meter manufacturing and delivery processes. Accordingly, ENO is targeting a three-year deployment, beginning in 2019.

Q13. ARE OTHER ENTERGY OPERATING COMPANIES PLANNING TO DEPLOY AMI AT THE SAME TIME AS ENO?

A. Yes. There are common components of AMI that can be shared and will allow for contemporaneous deployment of AMI across various Entergy Operating Company service areas, including much of the IT systems and portions of the communications network. This timing of the various deployments and use of common components provides opportunities for economies of scale and lower overall costs for customers. For example:

- There will be one head-end system integrated into the existing and planned IT systems. This approach saves both time and expense compared to the alternative of ENO potentially purchasing a separate head-end system and integrating it with the IT systems at separate times. For example, the head-end system is estimated to cost $26 million, and of that amount, ENO's share is expected to be $2.2 million.
- There are volume discounts for field communications devices and advanced meter purchases. As a result, collectively contracting to purchase and install AMI technology results in lower costs than would be achieved if ENO separately purchased and installed AMI independently of the other Operating Companies at different times.
- A coordinated deployment leads to increased economies of scale for installation of field communication devices and advanced meters, as well as for associated vendor training, management, and oversight costs.

- Additional efficiencies can be realized from integrating billing systems with AMI at the same time.

V. THE AMI PROCUREMENT PROCESS AND COMPONENTS

Q14. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I will discuss in greater detail the major components of the Company's proposed AMI deployment, beginning with a discussion of the competitive solicitation through Requests for Proposals ("RFP") and contracting process utilized by the Company for the procurement of four key AMI components.

A. RFP and Contracting Process

Q15. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S VENDOR SELECTION AND CONTRACTING PROCESS.

A. Vendor selection for four of the AMI components was conducted by a team comprised of representatives from ENO, ESI, and the other Operating Companies. The selection team performed a rigorous, comprehensive and competitive vendor selection process to identify, attract, and contract with experienced and competent AMI equipment and service providers. The selection team followed the Company's standard vendor selection process for large capital programs, which included initial market research; a competitive RFP process; detailed bid evaluation; oral presentations from selected vendors; and a detailed contract negotiation process to establish clear and fair commercial terms and vendor performance expectations. Throughout the vendor selection process, the selection team relied on the

PowerAdvocate Sourcing Intelligence website ("PowerAdvocate") to control and manage all communication between the selection team and potential vendors.

Q16. WHEN DID THE COMPANY BEGIN THE RFP PROCESS?

A. On June 26, 2015, the Company, through ESI, issued four separate RFPs for (1) the advanced meters and installation; (2) the communications network; (3) the MDMS; and (4) system integration. Each of the RFPs identified the applications needed to achieve the benefits for ENO customers. The RFPs also specified the functional and technical requirements necessary to execute these applications. These requirements were based on what the Company believes to be generally-accepted industry standards and commercially proven technologies, which was evidenced by the many responses to the RFP and willingness of vendors to meet these requirements. On August 21, 2015, approximately 30 responses from 20 individual vendors were received. Some vendors submitted bids for more than one RFP.

Q17. HOW WERE THE RESPONSES EVALUATED?

A. Consistent with Company practices for procurements in large capital programs, technical and commercial evaluations of each RFP bid were run in parallel by two evaluation teams. The commercial evaluations were performed by the Supply Chain Group, and the technical evaluations were performed by various subject matter experts, including members of the AMI project team and ENO's manager of meter services. Each evaluation team was comprised of subject-matter experts across a variety of areas, including IT and engineering. Recommendations were approved by the AMI Steering Committee.

The technical and commercial evaluations were kept separate, which eliminated the risk that the technical evaluators would be influenced by cost considerations. The evaluation teams scored the bids on dozens of technical criteria, including ranking the functional capabilities of the products and/or services as well as the vendors' previous experience deploying them. The composite scores were used to identify which bids best met the requirements as defined in the RFPs. Those initial bids were narrowed by the technical evaluation team to a shortlist of vendors who were recommended to the AMI Steering Committee for approval.

Following approval of the shortlist, the selected vendors were invited to participate in the next round of the RFP process. During this round, the technical teams conducted a series of all-day meetings with individual vendors. The selected vendors were encouraged to present their best products and/or services and given opportunities through explanation and questioning to clarify their bids during these meetings. Following that process, the technical evaluation teams re-evaluated vendor scores based upon clarifications provided during the vendor meetings and identified the top two vendors from each RFP. These top vendors were then presented to the AMI Steering Committee for approval to begin contract negotiations. Next, the Supply Chain Group, supported by the PMO, engaged in contract negotiations with these top bidder(s) in each of the four RFPs. During those negotiations, the Supply Chain reported to the AMI Steering Committee, which provided feedback and approval during the negotiations process.

Q18. UPON WHAT CRITERIA WERE THE BIDS EVALUATED?

A. The evaluation teams scored each bid on dozens of technical criteria. The criteria measured the quality of the bids in the following broad areas: (1) capability of the technical product and/or service; (2) ability of the product and/or service to support the desired functional and technical requirements; (3) scope of services offered; (4) experience of the bidder and their proposed team members on AMI projects at peer utilities; and (5) other general considerations, such as the bidder's current financial standing and general understanding of the products or services solicited in the RFP.

Q19. HAS THE COMPANY EXECUTED CONTRACTS WITH THE SELECTED BIDDERS?

A. Yes. I identify the selected vendors and the rationale for their selection in the following section of my testimony.

Q20. PLEASE DESCRIBE THE KEY FEATURES OF THE CONTRACTS.

A. The contracts are designed with an end-to-end solution to achieve cost certainty. In other words, the contracts specify pricing for the products and services for every phase of the project, from design through deployment. Equipment and software prices are not expected to change. Implementation costs, on the other hand, are fixed based on the anticipated scope and timing of the deployment, which is currently in the design phase. Accordingly, adjustments to scope may be required following completion of the design phase. However, any proposed changes that would increase project costs by more than 10 percent of the contract price would require certain internal approvals.

The contracts also entitle the Company to purchase the meter, communications and supporting software technology that are available at the time of deployment. In other words, the advanced meters and communications network that are installed will be the current technology in 2019 (as opposed to 2016 technology), but the maximum price (subject to adjustment for changes in the Purchase Price Index in certain circumstances) for those products has been fixed in the contract.

Additional features of the contracts intended to enhance cost certainty, mitigate risk, and increase flexibility include the points outlined below. The specific features of each contract will vary depending on the type of products, software and services involved:

- Wherever practicable, vendor payments are tied to the delivery of products and/or the completion of project milestones. Importantly, meters and network equipment, and associated installation charges, will not be billed to the Company until they are installed and functioning. Vendors therefore have an incentive to complete their work on time.
- A portion of vendor service charges are subject to holdbacks and potential credits if key performance indicators ("KPIs") are not satisfied. Depending on the type of work involved, the KPIs may include metrics relating to timeliness, work quality, safety, and diversity.

- Additionally, liquidated damages may be imposed if a vendor is late in delivering products.

Q21. HOW WILL THE CONTRACTS BE COORDINATED AND MANAGED?

A. A cross-project governance framework will be used to coordinate and manage all vendor interactions and dependencies. In addition, the PMO and ESI's Supply Chain group will manage contract implementation and performance of the vendors for all related contracts. A dedicated ESI contract manager will have oversight of these activities, with the PMO and/or ESI's Supply Chain group seeking AMI Steering Committee approval for any material changes in scope.

Q22. HAS THE COMPANY EXECUTED A CONTRACT FOR THE DMS AND OMS COMPONENTS OF AMI?

A. Not yet. The Company is currently engaged in the design phase of the DMS and OMS, which will be followed by the execution of a contract to deploy the two systems.

Q23. HAS THE COMPANY SELECTED A VENDOR FOR THE OMS AND DMS?

A. Yes. The Company is working with its current vendor of related systems, *i.e.*, SCADA, to implement the DMS and OMS. As discussed later, the current vendor is familiar with the legacy IT systems, which will provide for an efficient system integration, and the Company already owns the license for DMS software, which avoids costs compared to acquiring a different product from a new vendor.

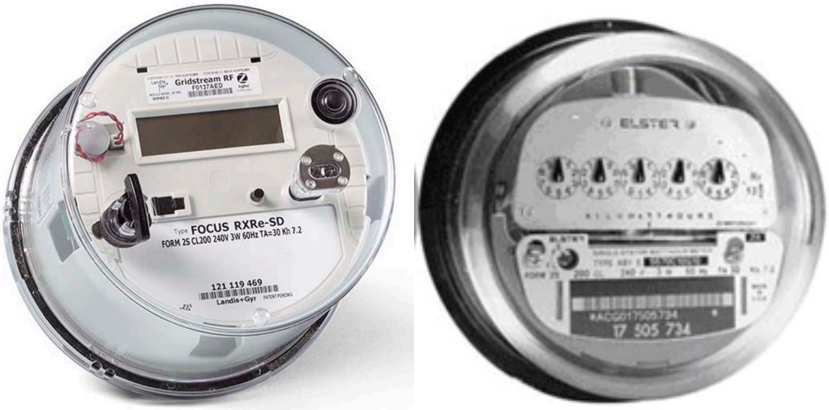
B. AMI Components

1. Advanced Electric Meters

Q24. WHAT IS AN ADVANCED ELECTRIC METER?

A. An advanced electric meter is similar in appearance and purpose to the traditional analog and digital meters used today for recording energy usage at customers' premises. However, the advanced meter measures, records, and transmits both the register reading and time-differentiated energy usage information, as well as other information like power outage, power restoration, voltage, and meter alarms to the Company through a NIC. The Company can also send signals and commands to the advanced meter for reasons such as checking its status, upgrading firmware, or remotely connecting or disconnecting service. Traditional analog and digital electric meters, on the other hand, lack communications capabilities. These traditional meters must be read manually by a meter reader, cannot remotely provide time-differentiated energy usage information, provide no remote indication of power status or voltage information, cannot receive commands or report alarms, and cannot be used to remotely connect or disconnect service.

Figure 2
**A modern, advanced electric meter (left)
and an older, analog meter (right)**



Q25. WHAT VENDORS DID THE COMPANY SELECT FOR ADVANCED METERS?

A. In order to mitigate single-sourcing meter vendor risks, and consistent with the experience of peer utilities that have previously deployed advanced meters, the AMI Steering Committee approved a dual-source meter vendor strategy. As a result of the RFP process described above, Elster Solutions, LLC, a Honeywell Company ("Elster") was selected to be the primary vendor for the advanced electric meters,[5] with Landis+Gyr Technology, Inc. ("Landis+Gyr") as the secondary vendor. Additionally, Elster was selected as the vendor responsible for meter installation.

[5] Elster was also selected to be the vendor of the approximately 8,000 gas meters discussed by Company witness Ms. Bourg that will need to be replaced with new meters capable of accepting a gas communication module.

Q26. WHAT IS THE DISTINCTION BETWEEN BEING A PRIMARY VERSUS SECONDARY VENDOR?

A. The distinction between primary and secondary vendors is the anticipated volume of advanced meters supplied. It is anticipated that the Company will purchase a substantial majority of the advanced meters from the primary vendor. By supplying a substantial majority of the volume, the volume pricing discounts discussed earlier are maximized with respect to the primary supplier pricing.

Q27. WHAT ARE THE RISKS ASSOCIATED WITH A SINGLE-SOURCE METER VENDOR STRATEGY?

A. In discussions with vendors and other utilities, several instances were noted where a utility chose a single-source meter vendor, and during deployment the meter vendor had manufacturing or production issues. In those circumstances, the options included: (1) delaying deployment while the single-source meter vendor caught up with production; or (2) contracting with another meter vendor, which requires significant time to negotiate the contract, design the product, and ramp up production. In that situation, contracting with another meter vendor during the deployment phase creates pricing risk. By contracting with a secondary vendor at the same time the primary meter vendor contracts are executed, such risks have been mitigated. In other words, having only a single meter vendor at the outset of the project could significantly delay deployment and increase costs. Those risks have been mitigated by contracting with a secondary meter vendor that will be involved in the AMI project from start to finish. The secondary vendor will also produce a portion of the advanced meters for ENO's AMI deployment. Should the Company's primary meter vendor become unable to meet the deployment schedule, the Company can more quickly increase reliance on its secondary meter vendor in order to avoid lengthy or costly delays and additional cost uncertainty during deployment.

Q28. WHY WERE ELSTER AND LANDIS+GYR METERS SELECTED FOR AMI DEPLOYMENT?

A. The Elster and Landis+Gyr meters have the functional and technical capabilities to achieve the required applications, exceeded some of the technical requirements of the RFP, and are among the lowest cost meters bid into the RFP. These meters also support the functional and technical capabilities to achieve potential future applications discussed earlier, are designed to meet or exceed applicable American National Standards Institute ("ANSI") standards, and are based on safe and reliable designs from the manufacturers. Additionally, based on representations supplied by the vendors, over 100,000,000 advanced meters have been or are being deployed by these meter vendors worldwide, 43,000,000 of which are in the U.S.

Some of the technical aspects of these advanced meters include that they are equipped with an on-board computational engine that provides faster metrology; they are capable of receiving firmware and/or programming upgrades remotely and therefore can, to a certain extent, be upgraded to keep pace with technological advances; and they have the potential to support future applications to be computed and stored at the meter.

2. Communications Infrastructure

Q29. WHY IS A COMMUNICATIONS SYSTEM A NECESSARY COMPONENT OF AMI?

A. Without the communications system there would be no capability to communicate remotely with, or receive data from, advanced meters, which is essential to achieving the customer and operational benefits of AMI described by ENO witnesses Mr. Dawsey, Ms. Bourg, Jay A. Lewis, and Dr. Ahmad Faruqui. The communications network is also a critical piece of the infrastructure backbone and serves as the foundation upon which potential future integrated grid functionalities can be implemented. These future capabilities are discussed in more detail by ENO witnesses Mr. Charles L. Rice, Jr., Mr. Dawsey, and Ms. Bourg.

Q30. PLEASE DESCRIBE THE COMMUNICATIONS INFRASTRUCTURE AND THE FUNCTIONS IT WILL PROVIDE.

A. The communications infrastructure is a system of communications components that provide for two-way data transfer – both from the meter and other AMI components to the Company and from the Company to those AMI components. For purposes of ENO's AMI deployment, the communications system includes the NIC, a "mesh" communications network, a backhaul communications network, and the head-end system at the Company's data center.

The NIC is a modular circuit board located inside each advanced meter. It is the component that connects the advanced meter to various networks and enables remote two-way communication between the meter and the Company in a reliable and secure manner. The NIC will be procured from the communications system vendor by the meter vendor. The meter vendor will install the NIC into the meter prior to delivery and installation.

The mesh communications network is a wireless network made up of radio "nodes" that have the ability to communicate with each other. Each NIC and network component (*e.g.*, access points and relays) is a separate node in the mesh network. Meter data and messages "hop" from node-to-node until reaching a destination node, which can be a NIC, relay, or access point, depending on the direction the data is traveling. Data is communicated between the access points and the head-end system at the data center via the backhaul network, which will be a combination of cellular service and Company-owned fiber.[6] I discuss below why the Company chose a mesh network.

The head-end system refers to the hardware and software components in the data center that reliably and securely: 1) receive information from field components, including meters; 2) transmit data to those components; and 3) route meter information to appropriate internal IT systems, including the MDMS. In addition, the head-end system will contain basic data validation and error checking functionality in its role of collecting and passing data, information, and commands between various utility systems (*e.g.,* the MDMS) and field components.

[6] There may be some limited instances where, due to the remote location of a meter or meters, the NIC inside the meter will include a cellular radio that will be used to directly access the backhaul cellular network.

Q31. WHY DID THE COMPANY CHOOSE A MESH NETWORK FOR THE AMI DEPLOYMENT?

A. A mesh network provides a number of advantages over competing technologies like direct point-to-point cellular and point-to-point wireless, including:

- The network can adapt when the physical world changes (*e.g.*, new buildings emerge) by establishing new communications paths automatically, as needed, to neighboring meters.
- Adding devices to mesh networks creates new paths through the network, improving routing options and, thus, improving network reliability.
- Mesh technology is very well-suited for supporting low-cost, low-power battery-operated devices because of its redundant communications pathways.
- Mesh nodes communicate with each other within clusters at no additional cost (much like nodes in an enterprise WiFi network do not require a "data plan" within the enterprise location), and therefore provide a lower-cost solution.
- Using the mesh technology enables increased network bandwidth and the higher demands of AMI applications.
- Mesh technology architecture incorporates well-established, historically-proven, cybersecurity standards.

Q32. WHAT VENDOR WAS SELECTED FOR THE COMMUNICATIONS NETWORK?

A. After evaluating the RFP responses and engaging in the negotiation process discussed earlier, Silver Springs Networks, Inc. ("SSN") was selected to be the vendor of the communication network, including the gas communications modules described by Ms. Bourg.

Q33. WHY WAS SSN SELECTED FOR AMI DEPLOYMENT?

A. SSN is an industry leader in wireless communication networks for advanced meters. The evaluation teams scored SSN's proposal highly for having (1) best-in-class technology that provides the fastest available mesh network speeds and extremely low failure rates for its manufactured NICs; (2) experience supporting the applications the Company is deploying for this project; (3) experience supporting the applications the Company may deploy in the future, *e.g.*, distribution automation; (4) experience deploying AMI at several other U.S. utilities with similar geography and customer classes as the Company (*e.g*., Oklahoma Gas & Electric and City Public Service ("CPS") in San Antonio, Texas); (5) experience integrating its NICs with the selected meter manufacturers (including both Elster and Landis+Gyr); (6) experience integrating its head-end system with the leading MDMS platforms (including Accenture, the selected MDMS vendor identified below); and (7) a broad services offering, including a high-quality approach for designing the network. SSN was also willing to contractually commit to high-quality SLAs in supporting the overall AMI project, including reliable and timely meter reading, high head-end system availability, and timely outage and restoration notifications. SSN was also willing to commit to service level credits for failure to meet the performance criteria established in the SLAs.

3. MDMS

Q34. WHAT IS A MDMS?

A. A MDMS is a sophisticated software system that collects, stores, manages, and validates meter data.[7] It also functions as the interface between other IT systems, including billing, workforce management, asset management, and outage management. In addition, it provides various reporting capabilities to support load forecasting, load research, management reporting, and customer service metrics.

Q35. HOW DOES A MDMS ENHANCE THE FUNCTIONALITY OF AMI?

A. While AMI is not required for a MDMS to provide incremental value and functionality as compared to the status quo, the MDMS is a necessary and critical component of AMI. The MDMS will electronically collect, process, analyze and validate granular, time-differentiated data received from the advanced meters via the head-end system; perform two-way distribution of information and commands between the head-end and other IT systems; store meter data for access and retrieval; and provide customized reports based on meter data and analytics performed. As further explained by Mr. Dawsey, the MDMS, in conjunction with AMI, can further serve as a platform for additional applications, *e.g.,* analytical programs designed to identify sources of unaccounted for energy and implementation of new products and services for customers.

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[7] The MDMS performs what is known as "VEE" – validation, estimating, and editing. The VEE process serves as a check on the data. For example, if there is a communications issue, the meter will store interval data until communications are reestablished. During this "dark" period, the MDMS would use estimated data until the actual data is received later.

Q36. WHAT VENDOR DID THE COMPANY SELECT?

A. After evaluating the RFP responses and engaging in the negotiation process discussed earlier, Accenture, LLP ("Accenture") was selected to be the vendor of the MDMS.

Q37. WHY WAS ACCENTURE SELECTED AS THE MDMS PROVIDER FOR THIS DEPLOYMENT?

A. Accenture has extensive experience with large-scale deployments at peer utilities, such as CenterPoint Energy, CPS Energy, and Alliant Energy. This experience includes integration with the Company's chosen bidder for the communication system (SSN) and the Company's existing customer billing system. The Accenture team members proposed for the project have multiple years of experience on AMI projects similar to the Company's. From an architecture perspective, Accenture's product provides pre-built adapters for integration with the Company's existing customer billing system and chosen head-end system. Accenture's product is also capable of calculating complex billing determinants required to support the Company's large commercial and industrial customers. Accenture is a leader in MDMS technology and brings a well-defined product roadmap and focused research and development investment. This focus is important as the Company considers implementing future applications beyond the initial AMI deployment, *e.g.,* dynamic pricing programs. The service delivery approach proposed by Accenture is also advantageous because it currently provides the Company with support for existing applications, including the customer billing system.

4. System Integration

Q38. PLEASE EXPLAIN THE PURPOSE OF SYSTEM INTEGRATION.

A. System integration involves integrating the various AMI components into the existing and planned IT infrastructure, resulting in a single, unified system. System integration will be performed by a third-party vendor (the System Integrator), who will be responsible for designing the AMI solution architecture. This includes definition of integration points between all relevant systems and the ESB, data conversions, data integrations, and data governance. System integration is necessary to help ensure that all components sought through the AMI RFPs can be combined together into a functioning single, unified AMI solution.

Outside of the system integration role, the System Integrator will be responsible for mapping, proposing, and obtaining approval from the PMO (which receives direction from ENO) with respect to the business processes affected or created as a result of AMI and implementation of the applications. Further, the System Integrator will provide services related to change management and business process design (*e.g.*, business readiness) to ENO so it can effectively use AMI to deliver the intended operational and other customer benefits, both initially and into the future.

Q39. WHICH VENDOR WAS SELECTED AS THE SYSTEM INTEGRATOR?

A. The Company selected International Business Machines Corporation ("IBM") as the System Integrator for the advanced meters, communications infrastructure, and MDMS.

Q40. WHY WAS IBM SELECTED?

A. IBM is a recognized global leader in providing system integration services, including extensive experience in developing AMI and advanced grid deployment strategies. Importantly, IBM has proven experience in AMI planning and implementation, especially in the U.S. market, where IBM has provided system integration services for over half of the AMI deployments in the country. The evaluation teams gave IBM high scores for: (1) demonstrating technical systems expertise with clear strengths in implementation philosophy, methodology, cyber-security, and complex billing conditions; (2) demonstrating superior understanding of the complexities of large scale, multi-jurisdictional AMI implementations; (3) providing personnel who have significant technical experience with implementing AMI; (4) including program accelerators that can be leveraged as starting points for key activities, which can potentially result in a more efficient deployment; (5) IBM's broad multi-jurisdictional U.S. experience, including specialization on advanced grid technologies that can complement the Company's long-term advanced grid goals discussed by Mr. Rice; (6) providing an approach that is more structured and drives towards a standardized solution versus a highly customized one, as compared to other bids; (7) considerable recent experience with end-to-end AMI deployments; and (8) having a substantial

U.S.-based presence, which reduces risk and drives efficiencies required for cost and schedule certainty.

Q41. WHAT STEPS WILL ENO TAKE TO MANAGE THE SYSTEM INTEGRATION?

A. The activities of the System Integrator will be performed in coordination with and under the oversight of the PMO.

C. DMS and OMS

Q42. WHAT ARE THE PURPOSES OF A DMS?

A. A DMS is a software platform that supports the full suite of distribution management activities and optimization of distribution operations. It provides ENO the ability to monitor and control the distribution grid through a rich, map-based user interface that includes functions to optimize and automate the execution of switching activities that facilitate outage restoration of the distribution grid.[8]

Q43. HOW ARE SWITCHING ACTIVITIES MANAGED TODAY?

A. In today's operational environment, switching orders are produced to document the steps required to safely perform equipment switching. Present day processes require a series of mostly manual steps for preparation and execution of switching orders.

[8] Switching involves the opening and closing of electrical devices on distribution lines to isolate the problem causing an outage, and in some circumstances, this can allow for power to be rerouted and restored to customers while the cause of the outage is being repaired.

These steps take place in several different systems and paper processes, and complex switching orders may require engineering studies to ensure safe load transfers.

Q44. HOW DOES DMS IMPROVE THE SWITCHING PROCESS, AND WHAT ARE THE BENEFITS?

A. DMS streamlines the switching order process by bringing all information about the distribution system, including grid connectivity and real-time power flow, into a single platform. For a given outage, DMS will rapidly produce the most effective switching order needed to achieve restoration of service, identifying the switching steps that will restore the most customers in the shortest timeframe. This capability reduces the time that operators must spend preparing the documentation needed to manually perform safe switching of distribution equipment during outage restoration activities. The full-function simulator in DMS can be used to observe the projected effect of any switching activities on the distribution grid, reducing the need for engineering studies on more complex switching scenarios. Importantly, these combined capabilities support faster restoration of service for ENO customers following outages. In addition, the DMS simulator can be used for training operators in outage response activities, which can also lead to faster outage restoration.

Q45. WHY IS IT IS REASONABLE TO IMPLEMENT A NEW DMS AT THIS TIME?

A. The nature and extent of the energy usage data made available to the Company through AMI creates a new opportunity to enhance the Company's energy distribution management activities and modernize the electric grid. While the

Company currently has a few separate systems that allow it to perform some distribution management functions, it does not have a modern, unified DMS. Building on AMI technology and associated energy usage data availability, the new DMS will provide distribution operators with a modern tool designed to merge and display real-time information from substations, distribution lines, and customer meters, which provides a complete picture of what is happening on the distribution grid. Once integrated with AMI, DMS will provide timely information to perform asset life analytics and improve network design and operations, which can reduce costs. It will also provide the ability to better monitor assets, which aids in preventive maintenance that can extend asset life and prevent outages from occurring.

A modern DMS, in conjunction with AMI, also lays the foundation for valuable future applications and functions like distribution automation. The automation of devices like reclosers and feeder switches, along with communicative sensors, would allow distribution operators to remotely reroute power around an outage, which can minimize the number of customers affected by an outage. Further, the ability to remotely operate distribution devices can decrease the duration of outages. Additional beneficial future applications include: fault location, isolation and restoration ("FLISR"); volt/volt-ampere reactive optimization; conservation through voltage reduction (a/k/a CVR); peak demand management; and additional support for new DERs (*e.g.,* rooftop solar systems, micro-grids, and electric vehicles).

Q46. WHAT ARE THE PURPOSES OF AN OMS?

A. An OMS is a utility distribution network management software application that models network topology for efficient field operations related to outage restoration. It assists in the detection, analysis, and restoration of service following outages. An OMS tightly integrates with call centers and advanced meters to provide timely, accurate, customer-specific outage information, as well as SCADA systems for real-time-confirmed switching and breaker operations. These systems track, group and display outages for safe and efficient management of service restoration activities.

Q47. WHY IS THE COMPANY PROPOSING TO UPDATE THE OMS AT THIS TIME?

A. The Company's current OMS has limited capability for tracking the effects of automated outage reporting, requiring manual data correction during post-outage analysis. Further, the current OMS is a custom-built, legacy system that would require substantial customization and upgrades to integrate with AMI. Through the meter reporting and two-way communications features of AMI, a modern OMS will allow operators to accurately determine the number of customers affected by unscheduled and planned system outages within a central operating environment that includes data from SCADA, the advanced meters, and real-time system analysis, among other functionality. The results will be more efficient, and therefore faster, restoration of outages, particularly after storm-related outage events, and will limit the circumstances in which customers need to call the Company and report outages. More accurate outage data means that customers will have more accurate outage and restoration notifications, as well as improved accuracy of outage maps available to customers on the Company's website. Additional benefits of implementing a modern OMS along with AMI include: a single, consolidated interface for outage management, SCADA, and other system activity; utilization of all available data (advanced meter data, trouble calls, SCADA) for enhanced outage analysis; the ability to manage large weather events more efficiently (*e.g.*, hurricanes and ice storms); management of outages directly from the real-time network view; and utilization of a dynamic network operations connectivity model. All of these features should enhance ENO's already outstanding storm restoration capabilities so that the Company can restore service to customers even more quickly and efficiently after outages.

Q48. PLEASE DESCRIBE THE VENDOR OF THE DMS AND OMS THAT WILL BE IMPLEMENTED, AND EXPLAIN WHY THAT VENDOR WAS SELECTED.

A. GE Grid Solutions, f/k/a Alstom Grid LLC ("Alstom"), an industry leader in DMS and OMS, is the vendor for the DMS and OMS. Alstom is a current supplier (including the SCADA system) and long-term partner of ENO, ESI, and other Entergy Operating Companies, which provides integration benefits through Alstom's knowledge of the legacy IT systems. In addition, ENO, with ESI support and along with other Operating Companies, has already participated in a co-development agreement with Alstom for a DMS, and as a result already co-owns the necessary software license for the DMS.

Q49. WHAT ARE THE ESTIMATED COSTS OF THE DMS AND OMS?

A. The total estimated cost of the DMS/OMS system and the work to integrate those systems is $77 million, with ENO's share estimated to be $5.5 million.

VI. CYBER SECURITY AND DATA PROTECTION

Q50. HOW WILL DATA BEING COLLECTED, STORED, AND TRANSMITTED BY THE ADVANCED METERS BE PROTECTED?

A. The data that is collected, stored, and transmitted by the advanced meters will be protected with administrative, physical, and technological safeguards at various stages of the deployment. As Mr. Dawsey describes, ENO, ESI, and the other Operating Companies have privacy and protection policies already in place and will continue to be applicable to any new data collected through AMI. Additionally, data protection and encryption designed to protect AMI data will be built into the advanced meters, communication systems, and data-processing systems. Cyber security industry standards were included as part of the procurement process, and cyber security controls for advanced meters and related systems that store and transmit data collected by advanced meters are being implemented. Standards and research such as those from the following entities are being used by our vendors to guide the development and implementation of AMI cyber security controls to protect AMI components and customer data:

- NIST (National Institute of Standards and Technology)
- IEC (International Electrotechnical Commission)
- IEEE (Institute for Electrical and Electronics Engineers)

- NERC (North American Electric Reliability Corporation) Critical Infrastructure Protection (CIP) v5
- EPRI (Electric Power Research Institute)
- IETF (Internet Engineering Task Force)
- Other standards such as ANSI, ISO/IEC would also be applied to functional requirements

Q51. WHEN WILL THOSE CONTROLS BE IMPLEMENTED?

A. While the Company already has cyber security controls in place with respect to its current customer data storage systems, controls related to the new advanced meters and related infrastructure are being developed as part of the AMI design phase. These new controls will be implemented during the build, test and deployment phases of the project to ensure continued protection of Company and customer data after AMI is deployed.

VII. SUMMARY OF AMI COST ESTIMATES

A. Implementation Costs

Q52. WHAT ARE THE ESTIMATED IMPLEMENTATION COSTS OF THE AMI DEPLOYMENT?

A. The costs of deploying AMI are broken down into the main components described above plus "other" costs, described below. Table 2 below provides the breakdown of these costs, and additional detail is provided in Highly Sensitive Exhibit RWG-2.

Table 2[9]
AMI Deployment Costs for ENO

Line item	($M)
Meters and installation	29.8
Communication network and head-end	18.8
MDMS	2.1
System integration	5.2
DMS/OMS	3.6
Other	17.1
Total implementation cost	**76.6**

Q53. WHAT ARE THE COMPONENTS OF THE "OTHER" CATEGORY?

A. The "other" category contains the following components:

- vendor costs for legacy systems – costs for existing vendors to modify and configure legacy IT systems so that the System Integrator can effectively integrate those systems with the ESB and new AMI components;
- dedicated internal resources – internal resources supporting the PMO for AMI, managing vendors and supporting deployment and business process changes;
- capitalized property tax – capitalized costs for property taxes incurred on year-end construction work-in-progress (CWIP) balances; and
- customer education – O&M expenses incurred to provide customer education on the benefits, functionality, and tools provided by AMI technology.

[9] These costs include the incremental costs of the gas components of AMI deployment, which are described and supported in Company witness Ms. Bourg's Direct Testimony.

Q54. DO THE ESTIMATED IMPLEMENTATION COSTS INCLUDE A CONTINGENCY AMOUNT?

A. Yes. Contingencies are a normal and essential component of an estimate for any large capital project. They provide an allowance for project uncertainty and risks at the time the estimate and associated budgets are prepared. As with any large scale, multi-year project, there is the potential for risks that could affect the timing and/or cost of AMI deployment. For instance, various conditions within the Company's service area may affect the timing and cost of full deployment of the advanced meters. For example, I am aware that other utilities have experienced delays and increased costs where installers have been unable to connect meters at certain locations due to accessibility issues or unforeseeable, unique meter attachment configurations. Additionally, severe weather could delay the Company's meter deployment if resources are required to be diverted to storm restoration. Each of these situations is an example of risks that have emerged for other utilities on similar deployments, but whether or not the risk will materialize cannot be reasonably predicted at this stage of the project, and accordingly a contingency allowance is reasonable from a cost estimation perspective.

The Company included an estimated contingency to reflect the potential that it could incur additional costs related to specific risks, both known and unknown. However, the PMO will continue to exercise risk avoidance and mitigation measures and will update the contingency over the life of the project.

Q55. WHEN WILL THE COSTS OF THE COMPONENTS YOU IDENTIFIED ABOVE BE INCURRED?

A. A small portion of the costs began to be incurred in support of the AMI project in 2015 with the development of the vendor RFPs, high level project design, and cost estimation. Costs to design and implement the shared infrastructure for IT and communications systems will largely be incurred from 2016 through 2018. Following the installation of the common IT and communications infrastructure by the end of 2018, the communications network and advanced meter deployment is expected to begin. This is expected to be complete by 2021. The estimated costs by year are provided in Highly Sensitive Exhibit RWG-2 attached to my Direct Testimony.

Q56. HAS THE COMPANY IMPLEMENTED A PROCESS TO TRACK SPENDING AND ENSURE COMPLIANCE WITH THE CONTRACTS AND BUDGETS?

A. Yes. Consistent with its standard accounting practices, the Company will budget and track the costs of each of the major activities through the use of project codes. The PMO will also oversee spending and compliance with budgets and contract terms. In addition, a cost and scheduling project manager will provide oversight and coordinate control with the PMO over project spending.

B. Ongoing Costs

Q57. WILL THERE BE ONGOING COSTS INCURRED BY THE COMPANY TO SUPPORT AMI OVER THE EXPECTED 15-YEAR LIFE OF THE ADVANCED METERS?

A. Yes. Ongoing O&M costs will be incurred for the vendor-supported systems as well as internal support for continued data analytics in the network operations center, unaccounted for energy detection, maintenance of the communications network, and various other meter services related to supporting AMI.

Q58. HAS THE COMPANY ESTIMATED THE AMOUNT OF THOSE ONGOING COSTS?

A. Yes. The Company's estimated first full year of ongoing annual AMI-related electric and gas O&M starting in 2022 is currently estimated to be $1.7 million. Additional detail is provided in Highly Sensitive Exhibit RWG-3 attached to my Direct Testimony.

Q59. WHAT TYPES OF COSTS ARE INCLUDED IN THE O&M ESTIMATE PROVIDED ABOVE?

A. The costs included in the above estimate include:

- Meter Support – the ongoing costs to support meter additions and removals, meter replacements, and meter testing. Meter Support also includes the ongoing support for connections and disconnections of gas service.

- Communications Network – the ongoing costs for communication device additions, removals, and replacements; the backhaul network, firmware updates, analysis, troubleshooting, and issue resolution of event notifications; network performance analysis and optimization; vendor costs for the head-end system administration; and monitoring and hardware maintenance and backups.
- Software Systems Support – the ongoing costs to support the MDMS, ESB, and the DMS and OMS. This includes cost for the system administration and monitoring, hardware maintenance and backups. The ongoing costs for the MDMS include ongoing data analytics and business operations center.
- Internal Support – internal labor costs to support the new software systems and ongoing non-meter related mobile dispatch support.

Q60. ARE ALL OF THE COSTS YOU DESCRIBE REFLECTED IN THE COST/BENEFIT ANALYSIS THAT IS SUPPORTED BY MR. LEWIS?

A. Yes, and it is my understanding that those costs are netted against the Operational Benefits described by ENO witnesses Dawsey, Bourg, and Lewis.

VIII. CONCLUSION

Q61. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF LOUSIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **RODNEY W. GRIFFITH**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Rodney W. Griffith

Rodney W. Griffith

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 12 DAY OF OCTOBER, 2016

NOTARY PUBLIC

My commission expires: death

Lawrence J. Hand Jr.
Bar 23770 / Notary 52176
Notary Public in and for the
State of Louisiana.
My Commission is for Life.

Listing of Previous Testimony Filed by Rodney W. Griffith

DATE	TYPE	JURISDICTION	DOCKET NO.
November 1999	Direct	PUCT	20125
November 1999	Supplemental	PUCT	20125
September 2016	Direct	APSC	16-060-U

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW	)	
ORLEANS, INC. FOR APPROVAL TO	)	
DEPLOY ADVANCED METERING	)	
INFRASTRUCTURE, AND REQUEST	)	**DOCKET NO. UD-16-___**
FOR COST RECOVERY AND	)	
RELATED RELIEF		

EXHIBIT RWG-2

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

OCTOBER 2016

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO DEPLOY ADVANCED METERING INFRASTRUCTURE, AND REQUEST FOR COST RECOVERY AND RELATED RELIEF	)))))	**DOCKET NO. UD-16-___**

EXHIBIT RWG-3

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DIRECT TESTIMONY

OF

MICHELLE P. BOURG

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

OCTOBER 2016

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I. QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Michelle P. Bourg. I am employed by Entergy Services, Inc. ("ESI")[1] as the Director of Gas Distribution. My business address is 3700 Tulane Avenue, New Orleans, Louisiana 70119.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying before the Council for the City of New Orleans ("CNO" or the "Council") on behalf of ENO.

Q3. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL, PROFESSIONAL, AND BUSINESS EXPERIENCE.

A. I graduated from Louisiana State University with a Bachelor of Science in Electrical Engineering and subsequently earned a Master of Business Administration from Tulane University. I am a registered professional engineer in the state of Louisiana.

In 2002, I began working for ESI's Transmission organization as a planning engineer in the Transmission Operational Planning department and, in April 2006, became the department's Manager, Transmission Planning. In September 2009, I accepted the position of Manager, Performance Management in ESI's Utility Operations department and, in December 2010, assumed the position of Director,

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[1] ESI is a subsidiary of Entergy Corporation that provides technical and administrative services to all the Entergy Operating Companies. The Entergy Operating Companies include: Entergy Arkansas, Inc.; Entergy Louisiana, LLC ("ELL"); Entergy Mississippi, Inc.; Entergy New Orleans, Inc. ("ENO" or the "Company"); and Entergy Texas, Inc.

Performance Management where I was responsible for developing, refining, and overseeing the performance reporting processes and benchmarking activities for the Utility and Energy Delivery businesses. In 2014, I transitioned into my current position as Director of the Entergy Gas Distribution Business in Louisiana. In this capacity, I oversee all aspects of the safe, reliable delivery of natural gas to all Entergy natural gas customers, including those customers served by ENO and ELL. My specific responsibilities include, but are not limited to, safety, compliance with applicable pipeline safety regulations, operations, customer service, construction, maintenance, engineering, planning, and gas real-time system monitoring and dispatch for the Company's gas distribution system.

Q4. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony describes ENO's plan to modernize its gas metering system through the implementation of advanced gas meters that are capable of integrating into the proposed Advanced Metering Infrastructure ("AMI") that Company witness Rodney W. Griffith describes in his Direct Testimony. Additionally, I describe the costs, customer benefits, and enhanced customer experiences associated with the advanced gas meter implementation.

II. ENO'S GAS DISTRIBUTION BUSINESS

Q5. PLEASE DESCRIBE ENO'S GAS DISTRIBUTION BUSINESS.

A. ENO provides natural gas service to approximately 107,000 residential, commercial, industrial, and governmental customers located in Orleans Parish. My group is responsible for the operations, planning, engineering, construction, maintenance, and emergency response for ENO's gas system in compliance with all applicable federal Pipeline and Hazardous Materials Safety Administration ("PHMSA") and associated Louisiana Department of Natural Resources, Office of Conservation, Pipeline Division safety regulations.

Q6. DOES THE GAS DISTRIBUTION BUSINESS HAVE A DIFFERENT METER READING PROCESS THAN THE ELECTRIC METER READING PROCESS?

A. No. ENO's gas meters are read by the same contract meter readers used by ENO to read electric meters. As described by Company witness Dennis P. Dawsey, these contractors specialize in providing meter reading services and are managed by a shared services organization. Gas meters are read in conjunction with electric meters to improve efficiency and to manage meter reading costs with regionally-based employees.

Q7. DOES ENO'S GAS DISTRIBUTION BUSINESS HAVE A METER SERVICES FUNCTION SIMILAR TO THE ELECTRIC BUSINESS?

A. Yes. ENO's meter services function includes the gas distribution business, which installs and maintains the Company's gas meters. Meter services performs the initial connection of service for a new customer, and it performs the disconnect when a customer asks to terminate service. Meter services personnel also perform service disconnections as a result of non-payment of bills, subsequent reconnection of services after payment is received, and miscellaneous billing investigations.

III. ADVANCED GAS METERING

Q8. WHAT IS AN ADVANCED GAS METER?

A. An advanced gas meter is a gas meter that is equipped with a two-way communication module that: (1) captures and stores interval data; (2) transmits consumption information and other status information to the Company; and (3) allows the Company to send signals to the advanced meter to, for example, upgrade firmware as well as check its health, tampering status, and battery life. The gas meters currently installed by the Company, on the other hand, must be read manually, cannot send or receive commands remotely, and do not have the other functionality I describe that will allow ENO to provide better and safer gas service to its customers.

Q9. WHAT ACTIONS ARE REQUIRED TO CONVERT THE EXISTING GAS METERS TO ADVANCED GAS METERS?

A. Approximately 93% of ENO's installed gas meters are currently able to accept a communication module that would convert them into an advanced gas meter. So, unlike the electric meter conversion described by Mr. Griffith, which requires the complete replacement of the meter, the majority of the Company's existing gas meters can be converted to advanced gas meters by simply installing a communication module on the existing meter. The remaining gas meters (approximately 8,000), however, will need to be replaced with new meters that will accept the communication module.

Q10. FOR THE GAS METERS THAT CAN ACCEPT A COMMUNICATION MODULE, WHAT STEPS ARE NEEDED TO INSTALL THAT MODULE?

A. The steps are relatively straightforward and do not require the meter to be disconnected. A gas meter can be retrofitted by removing the standard index and replacing it with the communication module. Once the module is installed, it is programmed to interface with the meter and the AMI communications and IT systems. ENO's gas service will remain uninterrupted during the installation of the communication module because no piping modifications are required. From start to finish, the process of installing a new communications module on an existing meter takes approximately fifteen minutes.

Q11. HOW WILL THE PROCESS BE DIFFERENT FOR THOSE 8,000 METERS THAT NEED TO BE REPLACED?

A. The installation of an advanced gas meter for those 8,000 customers will require service interruption so that a new meter capable of accepting the communication module can be installed prior to the installation of the communications module. As I discuss later, the replacement of the existing 8,000 meters would begin after the Council approves the AMI project, and it is expected to be completed by the time communication modules will begin to be installed. The Company will coordinate with customers to schedule an appointment at a mutually-agreed-upon time to perform a meter change, and it will notify customers in advance of meter replacements in a given area. The Company will make every attempt to minimize the service interruption to customers resulting from the meter change out, with a typical service interruption lasting thirty minutes. If a customer is not available for an appointment, the Company will replace the meter and re-initiate service at the customer's convenience.

Q12. WILL THE ADVANCED GAS METERS USE THE SAME COMMUNICATIONS AND IT INFRASTRUCTURE AS THE ADVANCED ELECTRIC METERS?

A. Yes. Once equipped with communication modules, the advanced gas meters will utilize the same communications and IT infrastructure that form a mesh network, like that of the advanced electric meters, through which it will send usage data back to the same Meter Data Management System ("MDMS") that Mr. Griffith describes in his Direct Testimony. In addition, the System Integrator that is discussed in Mr. Griffith's testimony will also manage the integration of the advanced gas meters into the Company's current systems, including its customer information system.

Q13. GIVEN THE TWO-WAY COMMUNICATIONS ENABLED BY THE ADVANCED GAS METERS, WILL ENO CONTINUE TO NEED CONTRACT SERVICES TO READ GAS METERS AFTER ENO IMPLEMENTS ITS GAS AMI?

A. No. The AMI will allow the Company to read the advanced gas meters remotely, which will eliminate the need to physically read gas meters. But, for those customers that "opt out" of using advanced meters, the Company will still need to employ manual reading techniques. Messrs. Dawsey and Lewis describe that process, along with the associated proposed customer opt-out fee methodology.

Q14. HOW WILL THE GAS METER SERVICES FUNCTION CHANGE AFTER AMI IS IMPLEMENTED?

A. As Mr. Dawsey explains, some meter services functions will be needed post-AMI, and this is particularly true for the gas business. Unlike with electric service, ENO cannot remotely connect or reconnect gas service. For safety reasons, the Company's personnel verify that there are no leaks on the customers' piping, all gas valves are either off or capped, and all appliances are working properly before connecting or reconnecting gas service.[2] At this time, the Company also does not plan to enable remote disconnects of ENO gas service post-AMI deployment because the gas disconnect technology is new and currently cost prohibitive. For this reason, the meter services function will continue to perform gas service connections and disconnections, as well as interruptions for non-payment of bills and subsequent reconnections following payment.

Q15. HOW WILL AMI IMPLEMENTATION AFFECT PERSONNEL WHO CURRENTLY PERFORM THE FUNCTIONS YOU DESCRIBE ABOVE?

A. As Mr. Dawsey explains, ENO's implementation of AMI will eliminate the need for the services provided by meter reading contractors and some meter services positions.

[2] Entergy personnel perform safety checks as required by the National Fire Protection Association ("NFPA") National Fuel Gas Code Handbook (2015) Section 8.2.2 '*Turning Gas On*.'

As it relates specifically to gas, a limited number of meter services positions that perform certain routine gas meter reads and billing investigations will be eliminated following the deployment of gas AMI, although the exact number of positions eliminated will be determined in the design phase of the project. Mr. Dawsey further explains that there will be efforts to retain employees through placement in other positions through training and skill enhancement.

IV. CUSTOMER BENEFITS

Q16. HOW WILL ADVANCED GAS METERS ENHANCE CUSTOMERS' EXPERIENCE WITH THE GAS SERVICE ENO PROVIDES?

A. Advanced gas meters will be capable of two-way data communications, which will enable the transmission of interval readings over a wireless communications network on a scheduled basis. These interval readings will provide ENO's customers with usage data on a far more granular level than what is currently available. Providing individual customers with their own detailed usage information, and having that detailed information available to customer service representatives, is expected to improve the quality of interactions between customers and the Company. For example, access to detailed usage information is likely to lead to quicker resolution of customer inquiries, including questions about high bills, and is expected ultimately to increase customer satisfaction in their experience interacting with ENO. Similarly, when customers have access to their detailed usage data and can gain an understanding of how their personal decisions affect their usage, this new-found sense of empowerment also should improve their satisfaction in the gas service being provided.

Q17. HOW WILL CUSTOMERS ACCESS THEIR GAS USAGE DATA?

A. ENO's gas customers will have secure access to their usage and other meter data through the same web portal that Mr. Dawsey describes for electric customers. The web portal will provide customers access to their own detailed gas usage data,[3] which will provide information that will help customers better understand and manage their gas usage to reduce their bills. Enhanced tools that utilize the AMI data will be incorporated into the web portal, which will, for example, allow gas customers to set notifications to promote customer cost savings opportunities (*e.g.,* preset threshold alerts). These features are integral to enhancing customers' experience with the overall quality of the gas service that ENO provides and are an important customer benefit that ENO seeks to provide through the modernization of its gas metering.

Q18. WHAT ARE SOME OF THE OTHER CUSTOMER BENEFITS THAT WILL RESULT FROM ENO'S DEPLOYMENT OF ADVANCED GAS METERS?

A. Many of the broader AMI benefits that Mr. Dawsey describes are applicable to the advanced gas meter deployment as well. By deploying advanced gas meters, ENO's electric and gas customers will benefit from being able to access their usage data from a single technology since energy usage for both electric and gas services will be

[3] ENO expects that gas customer usage data will be collected in one-hour intervals, which will be made available to customers the following day.

available through a single web portal. This will allow customers to be able to manage their total energy use in their household or business via a single platform. In addition, meter reading personnel will no longer be required to access meters located on customer property, minimizing customer inconvenience and potential safety concerns from both the Company and customer perspective, which Mr. Dawsey describes in his Direct Testimony.

Q19. ARE THERE OTHER POTENTIAL FUTURE CUSTOMER BENEFITS OF ADVANCED GAS METERS?

A. Yes. The gas industry is currently exploring additional capabilities of AMI that has the potential to further improve operational efficiency and public safety and lead to reduced cost of service. While some of these applications are commercially available today, they are not widely deployed and are costly. Just as ENO has monitored advanced meter deployments by other utilities, ENO plans to monitor similar enhancements in gas AMI functionalities. As more gas utilities implement these applications, the price of these applications would be expected to decrease, and technology improvements could be made. As discussed later in my testimony, integrating advanced gas meters will allow ENO's gas distribution business to continue to explore new applications and ideas in order to take future advantage of cost reductions and technology improvements.

V. GAS AMI COSTS

Q20. WHAT ARE THE ESTIMATED INCREMENTAL COSTS OF THE GAS AMI DEPLOYMENT?

A. The total estimated cost for the installation of gas AMI is $12.9 million. This includes $11.3 million for the communications modules, communication module installation, and incremental communications software cost specific to the gas business. The estimated cost also includes $1.6 million to replace the limited number of existing meters (and associated hardware) that cannot accept a communications module, as previously discussed.

Q21. WHEN WILL THE COSTS OF THE GAS COMPONENTS YOU IDENTIFIED ABOVE BE INCURRED?

A. The IT infrastructure, including the incremental infrastructure needed for gas customers, is expected to be in place by the end of 2018. Then, deployment of the broader communication network is expected to begin in late 2018 and will continue as the advanced electric meters are installed beginning in 2019. The replacement of those gas meters that cannot accept a communications module will commence following regulatory approval. The installation of gas communication modules is expected to commence beginning in 2019, and deployment is targeted to be completed in 2021. The overall AMI deployment schedule is detailed in Mr. Griffith's Direct Testimony.

Q22. WILL THERE BE ONGOING COSTS INCURRED BY THE COMPANY TO SUPPORT GAS AMI OVER THE EXPECTED LIFE OF THE GAS MODULES?

A. Yes. Mr. Griffith provides an estimate of the annual overall ongoing costs of supporting operations in the year following the AMI deployment. Of that total estimate, approximately $400,000 is related to gas operations.

Q23. HAS THE COMPANY IMPLEMENTED A PROCESS TO TRACK SPENDING AND ENSURE COMPLIANCE WITH THE CONTRACTS AND BUDGETS?

A. Yes. The Company will budget and track the costs of each of the major activities through the use of project codes. The AMI Project Management Office will also oversee spending and compliance with budgets and contract terms, and a cost and scheduling project manager is dedicated to providing oversight and control over project spending. Mr. Griffith provides more detail about this process in his Direct Testimony.

Q24. ARE ALL THE GAS COSTS YOU DESCRIBE REFLECTED IN THE COST/BENEFIT ANALYSIS THAT IS SUPPORTED BY MR. LEWIS?

A. Yes, they are.

Q25. WHAT USEFUL LIFE HAS ENO ASSUMED FOR THE GAS AMI COMPONENTS?

A. As detailed in Mr. Lewis' Direct Testimony, ENO has assumed a 15-year useful life for the gas communications module and other AMI components. The useful life for the gas meters themselves, along with their associated hardware, will not change as a result of the gas AMI deployment.

VI. GAS AMI BENEFITS

Q26. HAS THE COMPANY QUANTIFIED ANY OF THE BENEFITS TO GAS CUSTOMERS OF AMI?

A. Yes. The Operational Benefits and Other Benefits described by Mr. Lewis are inclusive of the benefits to gas customers. Specifically, there are quantified Operational Benefits for gas customers included in (i) the routine meter reading benefits; and (ii) the meter services benefits discussed by Mr. Lewis. In addition there are quantified Other Benefits for gas customer included in (i) the consumption reduction benefit; and (ii) the benefit from eliminating the need to replace existing meter reading equipment discussed by Mr. Lewis.

Q27. ARE THERE ANY DIFFERENCES IN THE ASSUMPTIONS USED BY MR. LEWIS IN CALCULATING THE OPERATIONAL AND OTHER BENEFITS AS THEY RELATE TO THE GAS BUSINESS?

A. Only with respect to the consumption reduction benefit. As Mr. Lewis explains, the methodology for the gas consumption reduction assumes that gas customers will experience a 0.75% reduction in consumption during the five highest consumption months over the winter peak. Mr. Lewis' HSPM Exhibit JAL-2 shows the gas commodity costs and gas fuel revenue forecast used in the calculation.

Q28. WHY DO YOU EXPECT GAS CUSTOMERS WILL REDUCE THEIR USAGE AS A RESULT OF DEPLOYING A GAS AMI?

A. Through education programs offered with ENO's AMI implementation, ENO will seek to educate customers about how their usage data, which will be available in greater detail as a result of the AMI implementation, can be used in conjunction with other energy savings tips and tools to reduce consumption. In addition, ENO will provide customers several tools to access, track, and decide whether to adjust their energy usage. For example, ENO will provide customers with detailed usage data via a web portal, as I have previously discussed, through which customers will be able to review daily usage patterns and better identify opportunities to reduce their consumption within each billing cycle. Company witness Dr. Faruqui explains how such data and notifications have led customers of other utilities to take proactive steps to reduce their consumption, and he explains the level of consumption reduction experienced by those utilities, which supports the 0.75% estimate used by the Company.

Q29. HAS THE COMPANY CONDUCTED A COST/BENEFIT ANALYSIS OF A STAND-ALONE GAS AMI DEPLOYMENT?

A. Yes. Company witness Mr. Lewis describes AMI benefits on a combined electric and gas basis throughout his testimony, which demonstrate substantial net benefits for ENO customers. Mr. Lewis also provides in his supporting workpaper calculations for the AMI cost/benefit analysis a separate calculation for ENO's gas customers, which as he notes in his Direct Testimony, does not produce net benefits. I believe that the analysis of the net benefits of a stand-alone gas AMI deployment undervalues the benefits that ENO's gas customers would likely achieve because the operating costs of the gas business would likely be greater if the electric business implemented AMI while the gas business did not. That is because there are economies of scale that are accomplished by employing the same contract meter readers to read both the electric and gas meters. When the need to manually read electric meters is eliminated through AMI, I expect there would be an increase in costs to manually read only the remaining gas meters, regardless of whether that work continues to be performed by contractors or company personnel (in which case additional personnel would be required). Accordingly, ENO's estimates for contract meter reading costs on a stand-alone gas basis are conservative because they do not take into account this annual increase and any further escalation of that increase over time. Moreover, there are several benefits that gas customers would experience from AMI, explained below, and that, while difficult to quantify, are likely to produce real value for ENO's gas customers. Finally, ENO's customers, the vast majority of whom take both gas and electric service, would experience the substantial quantified net benefits that Mr. Lewis provides in his combined cost/benefit analysis.

Q30. WHAT ARE THE ADDITIONAL NON-QUANTIFIED BENEFITS OF ADVANCED GAS METERS?

A. One key benefit is an enhancement of the overall safety of the gas system. By electronically analyzing daily gas consumption, the Company can compare current usage to historical usage at each individual service location. Today, the Company relies on a combination of routine field inspections and customer notifications to alert personnel of a potential gas leak. With AMI data, a large increase in consumption would trigger an alert, which would allow the Company to identify a potentially hazardous situation, like a leak within the service location, in a more timely manner.

In addition to public safety enhancements, there are several additional benefits that the Company expects to see as a result of its advanced gas meter implementation. These benefits include:

- Increased personnel and contractor safety. Deploying gas AMI significantly reduces vehicle drive time for our employee and contract personnel and reduces the likelihood of our personnel to encounter hazardous conditions.
- Improved billing accuracy. Automating the existing manual meter reading process greatly enhances the customer billing process. This will result in reduced data entry errors and an overall lower cost of processing customer bills.
- Reduced customer call volume. By providing customers with more frequent access to consumption data, and a better understanding of how they can control their usage, call volume to the Company's contact centers may decrease as a result of fewer billing inquiries and high bill complaints.
- Better optimization of distribution system capital investment. More accurate customer consumption data will enable the gas system planning function to more accurately model the gas distribution system, and as result, design and construct more cost-effective projects.

- Refined process for gas forecasting and procurement. More granular customer demand information (hourly and daily versus monthly) will allow for the quantification of peak day demand based on actual consumption versus estimated information. This will result in a more accurate gas supply plan, which may result in lower overall cost of service.
- Improved pipeline safety compliance. PHMSA Distribution Integrity Management Program regulations require pipeline operators such as ENO to identify threats and mitigate risks for improved public safety. Enhanced customer load information made available through the deployment of gas AMI will improve the Company's ability to demonstrate compliance with this regulation.
- Reduced metering tampering losses. Gas AMI will include the capability to alert ENO of potential theft of gas service through notifications to the Company, greatly reducing the likelihood (and potential duration) of gas losses.
- Reduced losses due to inactive meters. Gas AMI will enable more timely identification of locations where there is no active account with a meter that is still registering gas consumption.

Q31. DOES THE PROPOSED AMI SUPPORT ADDITIONAL FUNCTIONALITIES THAT COULD BE IMPLEMENTED IN THE FUTURE?

A. Yes. There are several other functionalities and programs enabled by AMI, as proposed by the Company, that ENO could implement in the future. In other words, gas AMI is a technical foundation upon which future products and services can be built to provide additional operational, reliability, and safety benefits for customers. Most of these functionalities will require additional investments in infrastructure and technology, and ENO will continue to monitor industry trends as these technologies continue to mature and evolve. Examples of these additional functionalities and programs include:

- Increased situational awareness and public safety:
    - In addition to existing proactive leak survey activities, deployment of advanced leak detection methane sensors would allow for the continuous monitoring of potentially hazardous conditions.
    - Remote pressure monitoring equipment would improve real-time knowledge of system operations and would allow the Company to monitor and identify areas of high or low pressure or areas with service interruption.
- Reduced operational costs:
    - Deployment of remote cathodic protection sensors would eliminate manual voltage readings on the gas cathodic protection system, provide for real-time centralized data collection, improve maintenance efficiency, and reduce the likelihood for system corrosion.
    - While commercially available today, remote meter shutoff technology continues to evolve and become more cost effective. This technology could be used in the future to interrupt gas service in routine circumstances (*e.g.*, move-out) or in emergencies (*e.g.*, during a fire).

- Remote meter shutoff would also reduce the amount of revenue that becomes uncollectible by eliminating the lag between when a disconnect order is issued and a technician is dispatched to disconnect service. As discussed by Mr. Lewis, the operational benefit that would be expected to result from the remote disconnect functionality of the advanced electric meters is significant.

VII. CONCLUSION

Q32. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **MICHELLE P. BOURG**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Michelle P. Bourg

Michelle P. Bourg

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 17th DAY OF OCTOBER, 2016

NOTARY PUBLIC

My commission expires: at death

JONATHAN R. BOURG
NOTARY PUBLIC, Notary ID # 87598
BAR NO. 31058
STATE OF LOUISIANA

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO DEPLOY ADVANCED METERING INFRASTRUCTURE, AND REQUEST FOR COST RECOVERY AND RELATED RELIEF	)))))	**DOCKET NO. UD-16-__**

DIRECT TESTIMONY

OF

JAY A. LEWIS

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

OCTOBER 2016

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EXHIBIT LIST

I. QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Jay A. Lewis. I am employed by Entergy Services, Inc. ("ESI")[1] as Vice President, Regulatory Policy. My business address is 639 Loyola Avenue, New Orleans, Louisiana 70113.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying before the Council for the City of New Orleans ("CNO" or the "Council") on behalf of ENO.

Q3. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL, PROFESSIONAL, AND BUSINESS EXPERIENCE.

A. I have a Masters of Business Administration from Tulane University and a Bachelor of Business Administration degree in Accounting from the University of Louisiana at Monroe. I am a Certified Public Accountant and licensed to practice in Louisiana and Mississippi. I am a member of the American Institute of Certified Public Accountants and the Society of Louisiana Certified Public Accountants. I am also a member and past Chairman of the Accounting Standards Committee of the Edison Electric Institute.

[1] ESI is a subsidiary of Entergy Corporation that provides technical and administrative services to all the Entergy Operating Companies. The Entergy Operating Companies include; Entergy Arkansas, Inc. ("EAI"); Entergy Louisiana, LLC ("ELL"); Entergy Mississippi, Inc.; Entergy New Orleans, Inc. ("ENO" or the "Company"); and Entergy Texas, Inc.

I began my career with ESI in 1999 as Director of Accounting Policy and Research. Beginning in 2004, I served as the Vice President and Chief Financial Officer of the Utility Operations Group. In 2008, I was named Vice President and Chief Accounting Officer-Designate for Enexus, a company proposed to be created by Entergy Corporation through a spinoff transaction. I assumed the position of Vice President, Finance for ESI in May 2010 and transferred to the position of Vice President, Regulatory Strategy in July 2011. I assumed the position of Vice President, Regulatory Policy in January 2014, and I recently transitioned into a part-time role in conjunction with my phased retirement from ESI. Prior to my career with ESI, I was employed in public accounting roles with Legier & Materne and Deloitte & Touche. In August 2016, I became an Instructor of Accounting at the University of Louisiana at Monroe.

Q4. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY COMMISSION?

A. Yes, I testified before the Council on a variety of accounting and financial matters. I have also testified before the Louisiana Public Service Commission, the Public Utility Commission of Texas, the Arkansas Public Service Commission, and the Federal Energy Regulatory Commission ("FERC") on accounting and financial matters. A list of my prior testimony is attached as Exhibit JAL-1.

II. PURPOSE OF TESTIMONY

Q5. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I present and support the analysis that demonstrates that ENO's Advanced Metering Infrastructure ("AMI")[2] deployment will produce net benefits for ENO's customers, and I explain why the Company's proposed AMI deployment is in the public interest. I explain the options available to a customer who may desire to opt out of having an advanced meter installed on his or her residence. I also make specific accounting proposals related to the useful life for the proposed advanced meters and related AMI infrastructure as well as address the unrecovered costs of the existing meters that will be retired from service and replaced by advanced meters.

III. QUANTIFIED AMI BENEFITS

A. Overview

Q6. HAS THE COMPANY PREPARED AN ANALYSIS THAT QUANTIFIES BENEFITS THAT ARE EXPECTED TO RESULT FROM ENO'S ELECTRIC AND GAS AMI DEPLOYMENT?

A. Yes. The Company has conducted a cost/benefit analysis that quantifies several of the expected benefits from AMI deployment. Those quantified benefits are broken

[2] For purposes of my testimony, the Company's AMI deployment includes advanced meters that enable two-way data communication, a secure and reliable communications network that supports two-way data communication, along with related and supporting systems, including a Meter Data Management System ("MDMS"), an Outage Management System ("OMS"), and a Distribution Management System ("DMS"), which ENO plans to integrate with its legacy information technology ("IT") systems via an Enterprise Service Bus ("ESB"). The advanced meters, two-way communications system, and MDMS are commonly referred to as advanced metering infrastructure, or "AMI." The functionalities of each of these are discussed in the Direct Testimony of Mr. Rodney W. Griffith.

down into two categories: (1) Operational Benefits; and (2) Other Benefits. The Operational Benefits include: (i) routine meter reading; (ii) meter services; and (iii) reduced customer receivable write-offs. The Other Benefits include: (i) consumption reduction; (ii) peak capacity reduction; (iii) unaccounted for energy ("UFE") reduction; and (iv) elimination of the need to maintain and replace existing meter reading equipment. ENO witness Orlando Todd describes in his Direct Testimony that the estimated AMI revenue requirement includes the quantified Operational Benefits. I will describe later in this testimony how each of these benefits is calculated. ENO witness Mr. Griffith describes how the total costs of the AMI deployment and ongoing annual operations and maintenance ("O&M") costs were derived. In my testimony I describe the derivation of ENO's portion of the total costs, which I am including in the cost/benefit analysis for ENO. I also explain why the Company has assumed a 15-year useful life for the AMI assets in calculating these benefits.

Q7. HAS THE COMPANY ATTEMPTED TO QUANTIFY ALL OF THE BENEFITS THAT WILL RESULT FROM AMI?

A. No. The Company has quantified many of the benefits of AMI, which are described later in my testimony; however, there are a number of other benefits that have been identified by other utilities in conjunction with their respective AMI deployments, such as increased billing accuracy and reduced customer service call volume. These other potential benefits were not included with ENO's cost/benefit analysis. ENO witnesses Mr. Dennis P. Dawsey and Ms. Michelle P. Bourg describe these other potential benefits in more detail.

Q8. HOW WERE AMI COSTS FOR EACH OPERATING COMPANY DERIVED?

A. The costs for the meter hardware, meter installation, network interface cards ("NIC"), communications network devices and components, including the gas communication modules, and the related internal resources and contractors will be directly incurred by ENO and were computed based on ENO's current number of customer meters. Final costs will be tied to the actual number of meters and meter types deployed. Certain components of the AMI deployment, such as the IT systems and project support, will be shared by the Operating Companies. This approach results in lower overall costs to customers as compared to each Operating Company maintaining separate systems, as discussed by Mr. Griffith. Specifically, the cost of the communications network design and the head-end component of the communications network, the MDMS, the DMS, the OMS, certain software licensing costs, the costs related to the meter testing facility, as well as the overall system integration and project support are assigned based on the total number of customers located in each Operating Company's jurisdiction. Certain costs incurred solely in support of the gas business, such as incremental communications network software and design, as well as certain software licensing fees, are directly assigned to ENO and ELL based on the total number of gas customers located in each Entergy Operating Company's service area.

Q9. WHY HAS THE COMPANY ASSUMED A 15-YEAR USEFUL LIFE IN DETERMINING THE BENEFIT TO CUSTOMERS ASSOCIATED WITH THE AMI DEPLOYMENT?

A. The Company anticipates a 15-year useful life for a number of reasons. First, it is a reasonable assumption because the 15-year useful life falls within the range presented by other utilities in recent deployments. For example, the Louisiana Public Service Commission approved the 15-year useful life proposed by Cleco Power, LLC.[3] In addition, the Arkansas Public Service Commission approved a 15-year useful life in Oklahoma Gas & Electric's AMI proceeding.[4] Second, the 15-year useful life that the Company is proposing takes into consideration the effects of technological obsolescence. Specifically, as explained by Company witness Griffith, the advanced meters include a NIC for communicating with the centralized systems such as the MDMS. Given that this technology continues to evolve, it is reasonable to assume that the Company's business needs and customer expectations 15 years from now may demand a different communications network and/or more processing capability on the meter.

[3] LPSC Order No. U-31393 (Mar. 25, 2011).

[4] Docket No. 10-109-U, Order No. 8 (August 3, 2011).

Q10. WHAT IS THE RESULT OF THE COST/BENEFIT ANALYSIS?

A. Using the cost information provided by Mr. Griffith, the analysis shows that it is reasonable to expect that on a combined basis, gas and electric customers will substantially benefit from the AMI deployment, and that the benefits exceed the overall costs of the deployment over the 15-year expected life.[5] Specifically, the AMI cost/benefit analysis demonstrates a net benefit to ENO customers of $27 million on a net present value ("NPV") basis, assuming a 15-year useful life of the assets. Table 1 below provides a summary of the cost/benefit analysis on both a nominal and present value ("PV") basis.

Table 1[6]
Summary of Cost/Benefit Analysis

		Nominal ($M)	PV ($M, 2016)
	Quantified Operational Benefits		
1	Routine Meter Reading	$45	$19
2	Meter Services	$47	$20
3	Reduced Customer Receivables Write-offs	$3	$1
4	**Total Quantified Operational Benefits**	$95	$40
	Quantified Other Benefits		
5	Consumption Reduction	$104	$42
6	Peak Capacity Reduction	$35	$14
7	Unaccounted For Energy Reduction	$38	$15
8	Meter Reading Equipment	$2	$1
9	**Total Quantified Other Benefits**	$178	$72
10	**Total AMI Quantified Benefits**	$273	$112

[5] I have also prepared a separate, stand-alone gas AMI cost/benefit analysis, which I will discuss later in my testimony.

[6] Totals in Table 1 may not foot or tie due to rounding.

	AMI lifetime costs to customers[7]	**Nominal ($M)**	**PV ($M, 2016)**
11	Depreciation & Amortization	$74	$34
12	Return on Rate Base	$49	$28
13	AMI O&M Costs	$32	$14
14	Property Tax	$18	$9
15	**Total AMI Costs**	$173	$85
16	**Net AMI Benefit**	**$101**	**$27**

B. Operational Benefits

1. Routine Meter Reading Benefit

Q11. PLEASE DESCRIBE THE ROUTINE METER READING BENEFIT THAT IS REFLECTED IN TABLE 1.

A. As described in more detail by Company witnesses Mr. Dawsey and Ms. Bourg, the Company incurs expenses for contract personnel (and their vehicles) to physically travel to and read customer meters each month. The two-way communications functionality of the advanced meters along with the communications and IT infrastructure being deployed with the AMI allows meters to be read remotely, and therefore eliminates the need for routine meter reading trips. As reflected in Table 1, over the estimated useful life of the AMI, the analysis shows benefits of $45 million on a nominal basis compared to a scenario in which AMI is not deployed (*i.e.*, maintaining the status quo). On a PV basis, the benefits are $19 million. *See* HSPM Exhibit JAL-2 for the supporting calculations.

[7] Includes the amortization of the Regulatory Asset for 2017 and 2018 customer education and O&M expenses.

Q12. HOW DID THE COMPANY ESTIMATE THE LEVEL OF ROUTINE METER READING COSTS THAT COULD BE AVOIDED?

A. Mr. Dawsey provides the estimated amount of annual O&M expense for routine meter reading and internal support and management of electric and gas meter reading contracts. The amount provided for 2016 is expected to grow slightly by the first year of meter deployment in 2019. In calculating the total benefits expected over the useful life of the AMI, the Company made the following assumptions:

- The meter reading contracts are sourced on a three-year cycle with the contract renegotiations for post-AMI ENO occurring in 2020. ENO expects an increase of a certain percentage over the 2019 levels upon renewal of the contracts and every three years thereafter for subsequent renewals. These anticipated increases are consistent with the expected inflation rate. *See* HSPM Exhibit JAL-2.
- A 2% annual inflation rate was used for non-contract meter reading costs such as internal support and management of the meter reading contracts.
- The benefits were scaled to match the expected meter deployment schedule. For example, as reflected in the meter deployment schedule described by ENO witness Mr. Griffith, it is expected that 12% of ENO's electric customers and 35% of gas customers would receive advanced meters by the end of 2019, so the routine meter reading benefits for 2019 are scaled proportionally to match the average percentage installation rate for that timeframe. As existing meters

continue to be replaced over the three-year deployment period (2019-2021), the benefits are increased proportionally.

2. Meter Services Benefit

Q13. PLEASE DESCRIBE THE METER SERVICES BENEFIT THAT IS REFLECTED IN TABLE 1.

A. As described in more detail by Company witnesses Mr. Dawsey and Ms. Bourg, the Company incurs expenses for personnel (and their vehicles) to travel to customer premises for a variety of meter-related services, which include service starts and stops, certain meter rereads, and service disconnections related to non-payment as well as any subsequent reconnections. The advanced meters and related communications infrastructure will eliminate the need for the vast majority of these physical trips.[8] As reflected in Table 1, over the useful life of the AMI, the analysis indicates benefits of $47 million on a nominal basis compared to a scenario in which AMI is not deployed, *i.e.*, maintaining the status quo. On a present value basis, the benefits are $20 million. *See* HSPM Exhibit JAL-2 for the supporting calculations.

Q14. HOW DID THE COMPANY ESTIMATE THE METER SERVICES BENEFITS?

A. The Company estimates are based on historical experience that 90% of electric meter services payroll and vehicle costs are O&M expenses (the remaining 10% are

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[8] Ms. Bourg explains, however, that meter services personnel will still be needed for connections and disconnections of gas service.

associated with capital additions), and that 100% of the supporting mobile dispatch payroll and contracted meter services costs are O&M. Based upon the application of those percentages to the meter services costs for payroll, vehicle, mobile dispatch, and contracted meter services costs that, as Mr. Dawsey explains, the Company expects to incur in 2016, the Company estimated the annual meter services O&M expenses that will be eliminated as a result of AMI. In calculating the total benefits over the expected life of AMI, the Company assumed a modest annual inflation rate that was applied to the 2016 budgeted meter services costs and scaled the benefits to match the expected meter deployment schedule, as discussed previously.

3. Reduced Customer Receivables Write-Offs

Q15. PLEASE DESCRIBE THE REDUCED CUSTOMER RECEIVABLES WRITE-OFFS BENEFIT THAT IS REFLECTED IN TABLE 1.

A. After a disconnect ticket to suspend service for non-payment is issued to field personnel, it takes additional time to physically go to the customer premises and disconnect the service at the meter. Eliminating the lag between scheduling and dispatching a technician to disconnect electric service through use of the remote disconnect feature of advanced electric meters reduces the amount of revenue that becomes uncollectible and is ultimately reflected in rates through bad debt expense. As reflected in Table 1, over the estimated useful life of the AMI, the analysis shows benefits of $3 million on a nominal basis compared to a scenario in which AMI is not deployed. On a PV basis, the benefits are $1 million.

Q16. HOW DID THE COMPANY ESTIMATE THE REDUCED WRITE-OFF BENEFITS?

A. The Company estimated the total electric write-off amount each year through 2020 and adjusted it proportionally based upon the expected reduction in disconnection time described above. In 2019, the estimated total write-off amount is $2.1 million. The Company calculated as a percentage the number of days that are eliminated from the time it normally takes to disconnect an electric customer for non-payment as a result of the remote disconnect feature of AMI. This percentage was applied to the 2019 estimated annual write-off amount of $2.1 million to derive an estimated dollar benefit of $169,000 annually. Similar to the routine meter reading and meter services benefit calculations, the estimated benefits were escalated annually at a 2% inflation rate and also scaled to match the expected meter deployment schedule. *See* HSPM Exhibit JAL-2 for the supporting calculations.

C. Other Benefits

1. Consumption Reduction Benefit

Q17. PLEASE DESCRIBE THE CONSUMPTION REDUCTION BENEFIT THAT IS REFLECTED IN TABLE 1.

A. As described by Company witnesses Mr. Dawsey and Ms. Bourg, AMI technology will be coupled with new tools and resources, as accessed through a web portal with a computer and/or mobile device, which provide detailed usage data in order to help customers better understand and manage their energy usage. In addition, Company witness Dr. Ahmad Faruqui explains why it is well-recognized that this access to information allows customers to better manage their energy usage in ways that reduce consumption. Reduced consumption, in turn, results in ongoing fuel cost savings for customers due to less energy being produced. Over the near-term, reduced consumption by customers also results in non-fuel cost savings for electric customers until rates are reset to reflect the reduction in sales over which the Company's fixed costs are spread.[9] Table 1 reflects, over the useful life of the AMI, benefits of $104 million on a nominal basis and $42 million on a present value basis compared to a scenario in which AMI is not deployed, *i.e.*, maintaining the status quo.

Q18. WHY ARE THE NON-FUEL BENEFITS FOR ELECTRIC CUSTOMERS ONLY PRODUCED FOR A LIMITED TIME?

A. ENO's residential and small commercial customer bills are primarily based on usage (kWh) and charges expressed in terms of $/kWh. Non-residential customer bills also typically include demand (kW) charges. Rates charged to customers are fixed periodically based on the revenue requirement divided by the total kWh (and/or kW as applicable) billing determinants for each rate class for a given period. After the AMI deployment, a reduction in customer usage will result in lower billings of non-fuel revenue collected by ENO until base rates are next reset. Put another way, ENO's current rates would be multiplied by fewer kWh (and/or kW) used by the

[9] *E.g.*, rate reset may be either through a formula rate plan ("FRP") or a base rate case.

individual customer producing less overall revenue, which results in otherwise lower bills to those customers. However, when rates are next reset, the lower kWh (and/or kW) reflecting the consumption reduction benefits that result from ENO's AMI deployment would be used in calculating rates, and those new rates would be applied to calculate future bills. In other words, unlike the fuel savings which result in on-going benefits to all customers through avoided fuel costs, the reduced consumption would eventually be reflected in the calculation of new rates, which all things being equal will result in slightly higher rates because there are fewer kWh and/or kW to spread the fixed costs over. These new rates would be applied to the lower kWh usage for customers to meet the utility's approved revenue requirement.[10]

Q19. WHAT LEVELS OF CONSUMPTION REDUCTION DID THE COMPANY ESTIMATE WILL OCCUR AS A RESULT OF THE AMI DEPLOYMENT?

A. The analysis estimates an overall annual electric usage reduction of 1.75% and gas usage reduction of 0.75% for residential and commercial customers. It is important to note that this analysis does not expect every single residential and commercial customer to reduce their usage by 1.75% or 0.75%, respectively, as a result of having both an advanced meter and access to the more detailed usage data via a web portal coupled with new tools and alerts. Rather, the overall reduction represents the Company's estimate of the total residential and commercial sales reduction based on

[10] Based on the different rate structure applicable to gas customers, which is much more significantly driven by fuel costs, the Company did not calculate non-fuel cost savings for gas customers in connection with the expected reduction of gas usage discussed by Ms. Bourg.

the total spectrum of changes in customer behavior in response to AMI deployment, with some customers responding by aggressively reducing their usage with access to the new information and tools and other customers having little, if any, change in their energy usage as a result of AMI. Further, it should be emphasized that this estimated reduction in energy consumption was limited to residential and commercial customers, which means the calculation of this benefit does not include any reduction in industrial or governmental usage.

Q20. WHAT IS THE COMPANY'S BASIS FOR THE 1.75% ESTIMATED ELECTRIC CONSUMPTION REDUCTION BENEFIT?

A. The Company reviewed consumption reduction benefits estimated by other utilities that have deployed AMI. Exhibit JAL-3 includes the utilities that the Company reviewed and their reported consumption reduction. Some utilities have offered specific pricing techniques, such as time-of-use or time-varying pricing, to provide customers with additional incentives for consumption reduction in conjunction with AMI deployment. The Company does not plan to provide dynamic pricing options, such as time-varying pricing, when it initially deploys AMI. Instead, the Company focused on consumption reduction benefits that are expected to be achieved solely through customer access to detailed usage data to help customers better understand and manage their energy usage via methods like the web portal and text and/or email communications, including tips on how to save energy and bill alerts.

The information provided in Exhibit JAL-3 demonstrates that the amount of consumption reduction that reasonably can be expected based on customer access to detailed usage data ranges between 1.5% and 2.0%. Based on that range, ENO selected 1.75% for purposes of calculating the expected benefits of the AMI deployment. Dr. Faruqui discusses the reasonableness of this estimate in more detail in his Direct Testimony.

Q21. WHAT IS THE COMPANY'S BASIS FOR THE 0.75% ESTIMATED GAS CONSUMPTION REDUCTION SAVINGS?

A. The Company reviewed consumption reduction savings estimated by BG&E and Southern California Gas Company in their gas AMI deployments. Both utilities offered their gas customers access to their daily gas usage data through a customer web portal, just as ENO intends to do in its AMI deployment. BG&E and Southern California Gas have realized consumption reduction savings through gas AMI deployments of 0.81% and over 1% respectively.[11] The Company's estimate of 0.75% consumption reduction is conservative compared to that range. Company witness Dr. Faruqui discusses the findings of BG&E and Southern California Gas as well as the reasonableness of ENO's estimate in more detail in his Direct Testimony.

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[11] *Smart Energy Manager Program 2015 Evaluation Report,* prepared for Baltimore Gas & Electric by Navigant Consulting, March 11, 2016, p. ii.; and Direct Testimony of Sarah J. Darby before the Public Utilities Commission of the State of California, in support of the Application of Southern California Gas Company for Approval of Advanced Metering Infrastructure, A. 08-09-023/U 904-G, September 29, 2008. *See* also Darby, 2006 as in footnote 7.

Q22. WHAT ARE THE BENEFITS ASSOCIATED WITH A REDUCTION IN RESIDENTIAL AND COMMERCIAL USAGE?

A. Based on projected residential and commercial gas and electric usage in 2019, the Company calculated annual benefits of $8.7 million, which were then scaled to match the average expected meters deployed, as discussed previously. To calculate the total benefits over the expected advanced meter useful life, the Company assumed the following:

- Annual sales are estimated to grow according to Company sales projections.
- The estimated benefits are scaled to match the annual average expected meter deployment schedule (*i.e.*, beginning in 2019).
- The electric non-fuel rates associated with residential and commercial customer classes are held constant at the FERC Form 1 2015 values for simplicity, which also adds a level of conservatism to these assumptions as it ignores the effects of any non-fuel rate increases.
- The electric customer fuel savings are based on projected annual marginal energy costs as reflected by Midcontinent Independent System Operator, Inc. ("MISO") locational marginal prices ("LMPs") applicable to ENO's load zone within MISO.
- The gas customer fuel savings are based on the Company's forecast of the total cost of delivered natural gas for the gas customers.

- Fuel benefits calculated for electric customers accrue throughout the expected AMI useful life, but the non-fuel benefits only accrue until the next instance where rates may change either via, *e.g.*, a FRP or base rate case
- The gas customer fuel savings were applied as a reduction to fuel revenue during the peak winter months. As noted earlier, non-fuel benefits were not calculated for gas customers.

See HSPM Exhibit JAL-2 for the supporting calculations.

2. Peak Capacity Reduction Benefit

Q23. PLEASE DESCRIBE THE PEAK CAPACITY REDUCTION BENEFIT THAT IS REFLECTED IN TABLE 1.

A. Table 1 reflects that the Company has estimated a benefit of $35 million on a nominal basis over a 15-year period for peak capacity reductions. That equates to $14 million on a PV basis. As explained by Mr. Dawsey, the information and tools made available to customers as a result of AMI will encourage customers to take various actions to reduce energy usage at peak times. Because the Company's peak load is a key component in determining its need for capacity planning reserves, reducing peak load would result in a decrease in capacity needs. The reduction in peak load occurs in two ways: (1) in conjunction with the overall 1.75% reduction in energy consumption described previously, and (2) from specific notifications that encourage customers to voluntarily reduce or shift energy use from peak times to other times of the day on the highest use days.

Q24. HOW DID THE COMPANY DEVELOP THE ESTIMATE OF PEAK CAPACITY REDUCTION?

A. Based on a review of other utility AMI deployments, the Company believes it is reasonable to expect that 5% of residential and commercial customers would voluntarily take action, *i.e.*, be "action takers," in response to text alerts or email messages. The Company's 5% estimate is near the lower end of estimates seen at other utilities. Exhibit JAL-4 includes estimated peak usage or load reductions of other utilities that provide similar notifications.

In order to estimate how much peak load shifting will occur as a result of the behavior of the 5% of customers that are expected to be action takers, the Company again considered the results of other utilities. Using that information, the Company estimated that the action takers will voluntarily shift or reduce 7.5% of their peak usage on the handful of days each year when they are sent alerts. The 7.5% estimate is at the lower end of results seen by other utility AMI deployments, as shown on Exhibit JAL-4.

Based on those two figures, the Company estimated that the peak capacity reduction attributable to those action takers would be 0.375% (5% times 7.5%). Combined with the 1.75% overall estimated usage reduction discussed above, which is assumed to occur throughout the day, including at peak times, the Company estimated a peak capacity reduction of 2.125% attributable to the AMI deployment, which was applied to peak load from the residential and commercial customer classes to arrive at the estimate of customer benefits. Dr. Faruqui further supports the reasonableness of the total peak capacity reduction assumption.

Q25. HOW DID THE COMPANY CALCULATE THE PEAK CAPACITY REDUCTION BENEFITS THAT ARE ESTIMATED AS A RESULT OF THE AMI DEPLOYMENT?

A. The Company applied the capacity benefits percentage calculated above (2.125%) to the Company's forecasted capacity requirement associated with forecasted load for ENO's residential and commercial customers. In 2019, this would be expected to result in an estimated reduction to the annual capacity of 20 MW. As discussed previously, the analysis was limited to the residential and commercial customer classes and does not assume any change in industrial customer behavior that would be directly attributable to AMI. The reduced capacity need is assumed to result in a decrease in capacity purchases or increase in capacity sales in MISO's capacity market, which benefits all customers. To calculate total benefits over the useful life of the AMI, the Company factored in projections of ENO's future capacity requirements and MISO capacity cost projections. In addition, as was done with other benefit calculations, the benefits were scaled to match the expected meter deployment schedule. *See* HSPM Exhibit JAL-2 for the supporting calculations.

3. UFE Reduction Benefit

Q26. PLEASE EXPLAIN THE UFE REDUCTION BENEFIT.

A. As explained by Company witness Mr. Dawsey, there is always more energy injected into an electric grid than recorded by the end-point meters as having been consumed. There are a number of reasons for this, including energy losses due to the physical makeup of the electric grid, which are categorized as "technical losses." Other reasons include such things as meter failures, inaccurate meters, tampering, and theft of services, which are categorized as "non-technical losses." An expected reduction in overall UFE associated with the AMI deployment is based upon an expected reduction in non-technical losses.

Q27. HOW DOES UFE AFFECT CUSTOMERS?

A. First, the overall efficiency of electricity delivery decreases as UFE increases, resulting in increased fuel and other variable operating costs associated with the additional amount of electric generation needed to support load from customers. Stated differently, for each megawatt-hour of UFE, the utility must generate or purchase an extra megawatt-hour to serve load. Second, as UFE increases, the quantity of billed utility sales falls, which lowers billing determinants for rate making purposes and ultimately raises the per unit rate (*e.g.*, $/kWh rate) required to produce revenues sufficient to recover the utility's costs.

Q28. HOW DID THE COMPANY DEVELOP THE ESTIMATE OF THE UFE REDUCTION BENEFIT?

A. The first step is to estimate the percentage of non-technical UFE losses relative to annual sales. According to a 2001 Electric Power Research Institute ("EPRI") study,[12] incidences of non-technical losses range from approximately 1% to 3% of residential and commercial sales and associated revenues. For purposes of estimating the benefits associated with reducing UFE, the Company estimated non-technical UFE losses at 1% of annual sales from ENO's residential and commercial customer classes, which is on the low end of the EPRI range. Dr. Faruqui discusses the reasonableness of this assumption in more detail in his Direct Testimony.

The next step is estimating the percentage of non-technical UFE that will be identified and addressed through the AMI deployment (*e.g.*, discovering an existing meter that has been tampered with or that has stopped functioning correctly and replacing it with an advanced meter). Company witness Mr. Dawsey explains why the AMI deployment will enable the Company to better identify and address sources of non-technical UFE. Other utilities estimate the identification rate to be anywhere from half to three fourths of the total non-technical losses.[13] Therefore, consistent with the expectations of other utilities, the Company estimated that half of the 1%, or 0.5%, of the total residential and commercial UFE that is estimated to exist would be identified and addressed as a result of AMI deployment.

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[12] EPRI, "Revenue Metering Loss Assessment: Final Technical Report," November 2001 (prepared for EPRI by Plexus Research, Inc.).

[13] *See* Exhibit JAL-5.

Finally, of the 0.5% of non-technical UFE that is identified and addressed, the Company estimated that half of that UFE, or 0.25%, would be eliminated (and the corresponding energy would not need to be generated), and the other 0.25% would be converted to billable sales. In other words, if the Company discovers that a customer has been stealing electricity, it is reasonably likely that not all of that customer's prior level of usage will be converted to billable sales. One would expect some portion to be converted to billable sales, but some level of usage may simply stop after the theft is identified and addressed. This 0.25% conversion assumption is also consistent with the other utilities' estimates shown in Exhibit JAL-5. Dr. Faruqui also discusses the reasonableness of these assumptions in more detail in his Direct Testimony.

After it estimated the amount of non-technical UFE affected by AMI, the Company included two different components of customer benefits related to the estimated reduction in UFE: fuel and non-fuel benefits. Fuel benefits result because, once the source of non-technical losses is identified and addressed, one of two things happens: (1) either the previously unaccounted for usage stops, which results in less energy being produced, less fuel burned, and lower fuel costs for customers; or (2) the UFE is converted to sales, which are billed and collected. The billing and collection for what was previously lost as UFE results in those customers paying their fair share of fuel costs and correspondingly less fuel costs being recovered from all other customers.

The non-fuel benefits result from the 0.25% of UFE that is identified and converted to billable sales, which results in elimination of the situation in which some customers are not paying for their full usage.

The Company's approach to calculate benefits from reduced UFE is consistent with the approach taken by other utilities which also estimate the benefit to be in the range of 0.25% of sales.[14]

Q29. WHAT IS THE UFE REDUCTION BENEFIT THAT IS ESTIMATED TO OCCUR AS A RESULT OF THE AMI DEPLOYMENT?

A. The result of the estimates I described previously regarding the assumed amount of non-technical UFE (*i.e.*, 1% of residential and commercial sales) that would be identified and addressed as a result of AMI, would result in $977,000 in fuel benefits in 2019. An additional $724,000 in non-fuel benefits results from converting half of the identified UFE to billable sales in 2019 (the other half of the identified UFE is assumed to be eliminated as a result of AMI). Both of these estimates reflect the potential savings before being scaled to adjust for the number of advanced meters deployed throughout 2019. In calculating total benefits over the useful life of the meters, residential and commercial sales were increased according to Company forecasts, and the UFE benefits were scaled to match the expected meter deployment schedule. Residential and commercial non-fuel rates were held constant at 2015 values derived from the FERC Form 1. As with the consumption reduction benefit,

[14] *See* Exhibit JAL-5.

the fuel savings are based on the projected annual average marginal energy costs as reflected by MISO LMPs applicable to ENO's load zone. This produces 15-year nominal benefits of $38 million. The PV benefit is $15 million. *See* HSPM Exhibit JAL-2 for the supporting calculations.

4. Benefit from Eliminating Existing Meter Reading Equipment

Q30. WHAT IS THE BENEFIT ASSOCIATED WITH ELIMINATING EXISTING METER READING EQUIPMENT?

A. There are a number of handheld electronic devices used by the Company's contract meter readers to perform manual meter reads today. There are capital costs incurred by the Company associated with the purchase and replacement of these handheld devices, as well as O&M costs associated with annual software and warranty costs. In the future, meter reading will be performed remotely, and these devices will no longer be required.

Q31. WHAT DID THE COMPANY CALCULATE AS THE PROJECTED BENEFIT ASSOCIATED WITH ELIMINATING THE METER READING EQUIPMENT?

A. The Company estimated future avoided O&M costs would amount to a benefit of $28,000 in 2019, plus another $248,000 in future avoided capital replacement costs. In calculating total benefits over the expected useful life of the AMI, the following assumptions were made:

- Costs of warranty, software and replacement costs increase at an assumed annual vendor inflation rate.
- The warranty and software benefits were scaled to match the expected meter deployment schedule.
- The handheld readers have a certain life and are first scheduled to be replaced in 2020.

The result is 15-year nominal benefits of $2 million, which is $1 million on a PV basis. *See* HSPM Exhibit JAL-2 for supporting calculations.

D. Net Benefits

Q32. DOES THE COMPANY EXPECT THAT THE CUSTOMER BENEFITS OF THE AMI DEPLOYMENT WILL BE GREATER THAN ITS ESTIMATED COSTS?

A. Yes. As reflected in Table 1, there is expected to be a net customer benefit of $27 million on a net present value basis. As I previously discussed, the net benefits reflected in the analysis include only those benefits that have been quantified and described in this testimony and do not reflect additional customer benefits that are likely to result from the AMI deployment.[15]

[15] *See* ENO witness Dawsey's and Bourg's testimony for examples of additional customer benefits that may result from the AMI deployment, but which were not quantified in ENO's cost/benefit analysis.

Q33. DOES THE COMPANY EXPECT THAT ITS GAS CUSTOMERS WILL BENEFIT FROM THE AMI DEPLOYMENT?

A. Yes. I have conducted a cost-benefit analysis that shows that the combined costs and benefits of ENO's AMI deployment result in a net benefit for its electric and gas customers. Included in the supporting calculations for HSPM Exhibit JAL-2 is an analysis which reflects that, when considering the incremental costs and benefits of a stand-alone gas AMI deployment,[16] the analysis does not produce a net benefit. However, as discussed by Ms. Bourg, the analysis of the standalone gas AMI deployment undervalues the benefits that ENO's gas customers would likely achieve because the operating costs of the gas business would likely be greater if the electric business implemented AMI while the gas business did not. She also notes that there are several other benefits that gas customers would experience from AMI that are not captured within the cost/benefit analysis. These other benefits, while difficult to quantify, are likely to produce real value for ENO's gas customers. Additionally, notwithstanding the results produced by the gas-only cost/benefit analysis, all of ENO's gas customers are electric customers, so they will experience the substantial quantified net benefits that are depicted in the combined cost/benefit analysis that I previously explained.

[16] By stand-alone gas AMI deployment, I mean an assumption that electric AMI is deployed even if the gas AMI deployment does not proceed.

IV. EXISTING METERS

Q34. HOW DOES THE COMPANY PROPOSE TO RECOVER THE REMAINING UNDEPRECIATED BOOK VALUE OF THE EXISTING METERS THAT WILL BE RETIRED WITH THE DEPLOYMENT OF ADVANCED METERS?

A. The Company is seeking confirmation from this Council that it will be allowed to continue to include the remaining book value of the existing meters in rate base, consistent with the normal treatment of asset retirements, and to depreciate those assets using current depreciation rates.

Q35. WHAT IS THE REMAINING BOOK VALUE OF THE EXISTING METERS, AND WHAT DEPRECIATION RATE IS CURRENTLY USED TO RECOVER THESE COSTS?

A. The book value and annual depreciation rate of the existing meters as of December 31, 2015 are reflected below. It should be noted that this is the amount included in the FERC account for meters, which includes ancillary equipment that will remain in service as well as meters for all customer classes. The gas balances included in the table represent the total balance related to gas meters, gas regulators and gas meter index devices and not necessarily the full amount that will be retired. The Company expects only to retire gas meters older than 25 years, some amount of the gas regulators, and all of the gas meter index devices.

Existing Meter Net Book Value

	Plant in Service	Accumulated Reserve	Net Book Value	Depreciation Rate	Annual Depreciation Expense	Remaining Life
Electric Meters	$ 24,849,892	$ 3,658,754	$ 21,191,138	3.09%	$ 767,862	28
Gas Meters	$ 20,498,587	$ 839,592	$ 19,658,996	2.44%	$ 500,166	39
Gas Meters Inst	$ 4,794,051	$ 3,393,520	$ 1,400,531	1.78%	$ 85,334	16
Gas Regulators	$ 1,462,622	$ 834,058	$ 628,564	2.02%	$ 29,545	21
Gas Regulators Inst	$ 401,132	$ 317,093	$ 84,039	1.92%	$ 7,702	11

Q36. WHAT IS THE COMPANY'S RATIONALE FOR CONTINUED COST RECOVERY OF EXISTING METERS THAT WILL BE RETIRED?

A. The fundamental rationale for the continued recovery of the Company's remaining investment in existing meters is that these amounts represent prudent investments that have not yet been fully recovered from customers. It is common utility ratemaking practice to include in rate base the unrecovered cost of assets that are retired early, and there is no reason to depart from that practice in this instance. The retirement of the existing meters will be contingent upon the Council agreeing with the Company that AMI deployment is in the best interests of its customers. Accordingly, there is no basis to disallow or otherwise alter the method or timing of recovery of these unrecovered costs, because the Company has not acted improperly in either investing in or retiring these existing meters. The Company proposes to continue to utilize existing depreciation rates to recover the costs of the existing meters.

V. OPT-OUT POLICY

Q37. IS THE COMPANY PROVIDING RESIDENTIAL CUSTOMERS WITH AN OPTION TO OPT OUT OF RECEIVING AN ADVANCED METER?

A. Yes. Although it believes the concerns to be unfounded, the Company is sensitive to various concerns that have been raised within other AMI proceedings around the country. Accordingly, ENO proposes that an opt-out option be available, but that it be limited to residential customers. This approach will minimize the types of non-advanced meters that would have to be maintained, thereby minimizing costs to the small number of opt-out customers expected by ENO. The Company also proposes that any combination gas and electric customers that choose to opt out of receiving an advanced meter for one service be automatically opted out of the other service. This will avoid incremental costs to process multiple customer opt-out requests for a single customer and will streamline the opt-out process.

Q38. GIVEN ALL OF THE BENEFITS THAT WILL RESULT FROM ENO'S AMI DEPLOYMENT, WHY DO YOU BELIEVE RESIDENTIAL CUSTOMERS SHOULD HAVE AN OPTION TO OPT OUT OF RECEIVING AN ADVANCED METER?

A. As described by Company witness Dr. Faruqui, based on the experience of other utilities that have deployed advanced meters, it is likely that a very small number of customers will prefer not to have an advanced meter installed on their home. The Company plans to conduct a broad educational outreach to its customers in order to explain the benefits, functionality, and advantages provided by the AMI technology. However, based on the experience of other utilities, a very small number of customers are likely to oppose having an advanced meter installed under any circumstance, even with this outreach effort. The Company believes that the various concerns and objections that have been raised about advanced meters by customers in other jurisdictions lack merit and are unsubstantiated. Nonetheless, the Company recommends providing an option for any customers who have those concerns to avoid having an advanced meter installed on their home.

Q39. DOES A CUSTOMER'S VOLUNTARY CHOICE TO OPT OUT OF ENO'S INSTALLATION OF AN ADVANCED METER INCREASE THE COSTS TO SERVE THAT CUSTOMER?

A. Yes. As described below, some of the costs associated with a customer choosing to opt out depend upon the timing of the opt-out request. In addition, regardless of when the customer opts out of advanced metering, the Company will incur other up-front costs associated with the purchase of meter locks, processing of the opt-out paperwork, and billing set-up costs to make the necessary modifications to the Company's customer billing system. There will also be ongoing monthly costs associated with the need to continue to manually read the meter, manage billing and customer data such as tracking move outs, and manually perform meter services such as meter rereads.

Q40. HOW DOES ENO PROPOSE TO HANDLE OPT OUT REQUESTS?

A. If a customer chooses to opt out of an advanced meter prior to the installation of the advanced meter, the Company proposes to allow the customer to keep his/her existing meter following an inspection of that existing meter for safety-related issues or tampering issues and a test to ensure the meter meets the Company's and the Council's applicable standards for accuracy. By conducting a meter inspection and test, the Company will be able to identify potential safety issues, inaccurate or defective meters as well as evaluate whether tampering or theft may be occurring, and install a new meter seal with the correct color and barrel lock on the meter.

If the customer chooses to opt out after an advanced meter has already been installed on their home, then the Company will incur further costs to remove the advanced meter, install a non-advanced meter, and ensure the new meter meets safety and accuracy standards.

Q41. DOES ENO PROPOSE THAT CUSTOMERS BE REQUIRED TO PAY THE ADDITIONAL COSTS ASSOCIATED WITH THEIR DECISION TO CHOOSE A NON-ADVANCED METER?

A. Yes. The Company is proposing that the up-front costs associated with the customer billing set-up, meter locks, trip charge, and processing of opt-out paperwork be charged to the opt-out customer through a one-time fee when they opt out. In addition, the Company proposes to charge opt-out customers a monthly fee associated with the ongoing monthly costs of manual meter reading and resulting customer service activities necessary to schedule, bill and support these opt-out customers. The Company will use a formal process to document the customer's voluntary decision to opt out, including having the customer fill out, sign, and submit a form indicating their decision to opt out of advanced metering and their acknowledgement of the added cost to serve them, including their acceptance that they will incur an up-front fee as well as the monthly recurring fee on their bill.

Q42. HOW DOES THE COMPANY PROPOSE TO CALCULATE THE ONE-TIME AND MONTHLY FEES FOR OPT-OUT CUSTOMERS?

A. The Company proposes that the fees be cost-based. Based on actual opt-out rates of other utilities that have deployed AMI, the Company estimates that approximately 0.25% of ENO's customers may choose to opt out of having an advanced meter on their home. This equates to approximately 769 ENO customers. The 0.25% estimate is based on the average reported opt-out rate of other electric utilities, excluding several outliers that have either much higher or much lower than average opt-out rates. *See* Exhibit JAL-6 for the opt-out rates used to determine the 0.25% estimate. For illustrative purposes, the Company has estimated the up-front costs and ongoing costs in order to demonstrate the possible charges an opt-out customer would incur. The illustrative fees include use of Company servicemen to perform the meter reads, tests, and removal/installation. The illustration assumes that the travel time to read an opt-out customer's meter averages five minutes, site time averages five minutes for reads, and initial meter testing and removal/installation averages 30 minutes.[17] The table below illustrates the components of the up-front and monthly fees. Exhibit JAL-7 includes the calculation of the cost components included in these illustrative opt-out fee calculations.

Up-front Fee Components	**Estimated Cost**	**Estimated # Opt-Out Customers**	**Estimated Fee**
Billing programming changes to build the one-time and monthly fees in CCS	$ 27,500	769	$ 35.76
Barrel lock and seal for non-advanced meters	$20.73/ea		$ 20.73
Opt out paperwork mailing costs for one-time mailing to customers, to enroll and confirm opt-out election	$2/ea		$ 2.00
Trip charge: employee labor and vehicle costs to perform field test and inspect meter (Assuming opt-out occurs prior to installation of advanced meter)	$37.99/ea		$ 37.99
Total Up-Front Fee for Opt-Out pre Advanced Meter Install			**$ 96.48**
Meter fee for replacing AMI meter with tested salvaged digital meter (Assuming opt-out occurs after installation of advanced meter)	$6.41/ea		$ 6.41
Total Up-Front Fee for Opt-Out Post Advanced Meter Install			**$ 102.89**

Monthly Fee components	**Estimated Cost**	**Estimated # Opt Out Customers**	**Estimated Monthly Fee**
Trip charge: employee labor and vehicle costs for meter reads	$12.34/ea		$ 12.34
ENO Share of Salary for two ESI customer service specialists (Estimate = $186K annual labor / 7,750 system opt outs * ENO Opt-Outs)	$ 18,456	769	$ 2.00
Total Monthly Fee for Opt-Out Customers			**$ 14.34**

17 Should new handheld meter reading devices or other equipment be necessary in the future to perform meter reads for opt-out customers, the capital and O&M costs associated with that new equipment should be added to the fee components.

Q43. WILL CUSTOMERS WHO VOLUNTARILY CHOOSE NOT TO HAVE AN ADVANCED METER INSTALLED AT THEIR HOUSE ALSO BE REQUIRED TO PAY THE AMI DEPLOYMENT COSTS?

A. Yes, they will. As the Company's analysis shows, all customers benefit from AMI, even those that opt out, and it is therefore reasonable and appropriate for opt-out customers to pay the AMI deployment costs in addition to the up-front and ongoing fees associated with opting out. As described previously, advanced meters provide benefits that help customers reduce consumption, which will, in turn, result in reduced fuel costs for all customers. In addition, customers that use the advanced meters to reduce peak load will reduce the Company's future capacity requirements and therefore reduce overall costs for all customers. Opt-out customers will also benefit in other ways from the AMI deployment. For example, as described by Company witnesses Mr. Dawsey and Mr. Griffith, the AMI deployment includes an OMS that will help speed up and improve service restoration, especially after significant outage events. It would be unfair and inappropriate for opt-out customers to share in these benefits without having to pay for the associated costs of the AMI deployment.

Q44. HAS THE COMPANY INCLUDED A PROPOSED OPT-OUT TARIFF, INCLUDING THE ASSOCIATED CHARGES, IN THIS PROCEEDING?

A. No. The Company is not seeking approval of a specific opt-out tariff in this filing, but it is requesting approval of the methodology I described above to calculate the opt-out charges. The Company expects to make a compliance filing closer to deployment of advanced meters. That filing will include the opt-out form the customer would execute, the form of the tariff, as well as the proposed charges and associated costs used to derive the opt-out charges following the methodology approved by the Council, as part of this proceeding.

VI. PUBLIC INTEREST

Q45. PLEASE DESCRIBE WHAT IS MORE BROADLY CONSIDERED AS THE PUBLIC INTEREST.

A. The public interest is that which is thought to best serve everyone; it is the common good. If the net effect of a decision is believed to be positive or beneficial to society as a whole, it can be said that the decision serves the "public interest."

Public utilities in general, and electric utilities in particular, affect nearly all elements of society. Public utilities have the ability to influence the cost of production of the businesses that are served by them, to affect the standard of living of their customers, to affect employment levels in the areas they serve, and to affect the interests of their investors. In sum, public utilities affect the general economic activity in the state.

In determining whether a particular decision or policy is in the public interest, there is no immutable law or principle that can be applied. It is recognized that public interest cannot simply be defined as lower prices. For example, if lower prices are achieved through a reduction in the reliability or quality of service, it may very well be perceived that the lower prices have not advanced public interest. Similarly, higher prices might not produce negative net benefits or detriments. For example, if an existing price is low due to a cross-subsidy, removing that subsidy would raise that price, but doing so would not necessarily be detrimental. The Louisiana Supreme Court reached just such a conclusion in *City of Plaquemine v. Louisiana Public Service Commission,* 282 So. 2d 440 (1973), when it found that:

> The entire regulatory scheme, including increases as well as decreases in rates, is indeed in the public interest, designed to assure the furnishing of adequate service to all public utility patrons at the lowest reasonable rates consistent with the interest both of the public and of the utilities.
>
> Thus the public interest necessity in utility regulation is not offended, but rather served by reasonable and proper rate increases notwithstanding that an immediate and incidental effect of any increase is improvement in the economic condition of the regulated utility company.[18]

Objective measurement of how a decision affects the public interest is problematic at best. For the past fifty or more years, regulatory decision-making has been tested in the courts by a balancing-of-interests standard. In these cases, beginning with *Federal Power Commission v. Hope Natural Gas Company* 320 U.S. 591, 660 (1944), the courts have found that if the regulatory body's decision reflected a reasonable balancing of customer and investor interests, the decision was to be affirmed as just and reasonable.

In sum, determining whether a decision is in the "public interest" requires a balancing of the various effects of a particular course of action measured subjectively

[18] *Id*. at 442-43.

over the longer run. Whether a course of action is in the public interest will depend upon factors that are potentially quantifiable on an estimated basis, such as likely changes in costs, as well as upon other factors that are not quantifiable, such as the effect of that course of action on the reliability of electric service. Finally, while witnesses can provide facts and opinions that bear on this issue, the decision-maker, the Council, must ultimately determine whether the proposed course of action is consistent with the public interest.

Q46. WHAT EVIDENCE HAS THE COMPANY OFFERED TO SUPPORT A FINDING THAT ITS IMPLEMENTATION OF AMI IS IN THE PUBLIC INTEREST?

A. Through its Application, ENO has submitted testimony and exhibits including the estimates and supporting documentation for the costs of deploying ENO's AMI, the separate identification of the estimated costs associated with the integration of ENO's AMI with legacy software systems, and the other indirect costs associated with implementation. In addition, I provide the supporting documentation and assumptions to show the reasoning and methodology used in developing the estimated net benefits and operational savings that ENO anticipates will result from its implementation of AMI, which supports the conclusion that the estimated benefits of ENO's proposed AMI implementation are greater than its estimated costs. My analysis supports the finding that ENO's implementation of its proposed AMI is in the public interest. For all of these reasons, the Council should find that ENO's implementation of its proposed AMI is in the public interest.

VII. CONCLUSION

Q47. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF OUACHITA

NOW BEFORE ME, the undersigned authority, personally came and appeared, **JAY A. LEWIS**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

____
Jay A. Lewis

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 14th **DAY OF OCTOBER, 2016**

____
NOTARY PUBLIC

My commission expires: Death

ROBERT E HARRIS JR
NOTARY PUBLIC
COMMISSIONED FOR LIFE
NOTARY ID NO 86191
OUACHITA PARISH, LA

Listing of Previous Testimony Filed by Jay A. Lewis

DATE	TYPE	JURISDICTION	DOCKET NO.
August 2004	Direct	PUCT	30123
March 2007	Rebuttal	APSC	06-101-U
April 2007	Sur-Surrebuttal	APSC	06-101-U
September 2007	Direct	PUCT	34800
February 2008	Rebuttal	APSC	06-152-U
March 2008	Sur-Surrebuttal	APSC	06-152-U
May 2008	Rebuttal	PUCT	34800
October 2008	Direct	MPSC	2008-AD-381
November 2010	Supplemental	FERC	EL10-55-001
May 2011	Supplemental Direct	APSC	10-011-U
August 2011	Rebuttal	APSC	10-011-U
August 2011	Sur-Surrebuttal	APSC	10-011-U
September 2011	Direct	PUCT	39741
November 2011	Direct	CNO	UD-11-01
November 2011	Rebuttal	APSC	11-069-U
December 2011	Sur-Surrebuttal	APSC	11-069-U
December 2011	Supplemental Direct	PUCT	39896
April 2012	Rebuttal	PUCT	39896
June 2012	Cross Answering	CNO	UD-11-01
August 2012	Rebuttal	CNO	UD-11-01
September 2012	Direct	APSC	12-069-U
September 2012	Direct	CNO	UD-12-01
September 2012	Direct	FERC	ITC Application
September 2012	Direct	LPSC	U-32538
October 2012	Direct	MPSC	2012-UA-358
January 2013	Direct	LPSC	U-32148
January 2013	Direct	CNO	UD-08-03
February 2013	Direct	PUCT	41223
February 2013	Direct	PUCT	41235
February 2013	Direct	LPSC	U-32707
February 2013	Direct	LPSC	U-32708
March 2013	Direct	APSC	13-028-U

DATE	TYPE	JURISDICTION	DOCKET NO.
March 2013	Supplemental	ENO	UD-12-01
April 2013	Direct	PUCT	41235
April 2013	Supplemental	PUCT	41235
May 2013	Rebuttal	PUCT	41223
May 2013	Rebuttal	APSC	12-069-U
May 2013	Rebuttal	LPSC	U-32538
June 2013	Rebuttal	CNO	UD-08-03
June 2013	Rebuttal	CNO	UD-12-01
June 2013	Sur-Surrebuttal	APSC	12-069-U
July 2013	Supplemental	APSC	12-069-U
July 2013	Rebuttal	LPSC	U-32675
August 2013	Rejoinder Testimony	CNO	UD-12-01
August 2013	Rebuttal	APSC	13-028-U
August 2013	Supplemental Rebuttal	APSC	12-069-U
September 2013	Sur-Surrebuttal	APSC	13-028-U
September 2013	Direct	PUCT	41850
September 2013	Direct	PUCT	41791
November 2013	Rebuttal	PUCT	41850
December 2013	Settlement	LPSC	U-32708
February 2014	Rebuttal	CNO	UD-13-01
April 2014	Rejoinder Testimony	CNO	UD-13-01
June 2014	Direct	MPSC	EC-123-0082-00
June 2014	Direct	MPSC	EC-123-0082-00
September 2014	Direct	LPSC	U-33244
October 2014	Direct	CNO	UD-14-02
November 2014	Direct	CNO	UD-14-03
January 2015	Supplemental	CNO	UD-14-01
January 2015	Direct	LPSC	UD-33510
January 2015	Direct	APSC	14-118-U
February 2015	Direct	CNO	UD-15-01
April 2015	Direct	APSC	15-015-U
April 2015	Rebuttal	CNO	UD-14-01
May 2015	Rebuttal	LPSC	U-33244

DATE	TYPE	JURISDICTION	DOCKET NO.
June 2015	Rebuttal	LPSC	U-33510
June 2015	Direct	PUCT	44704
June 2015	Direct	LPSC	U-33033
June 2015	Direct	LPSC	U-33645
July 2015	Rebuttal	APSC	14-118-U

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW	)	
ORLEANS, INC. FOR APPROVAL TO	)	
DEPLOY ADVANCED METERING	)	
INFRASTRUCTURE, AND REQUEST	)	**DOCKET NO. UD-16-___**
FOR COST RECOVERY AND	)	
RELATED RELIEF		

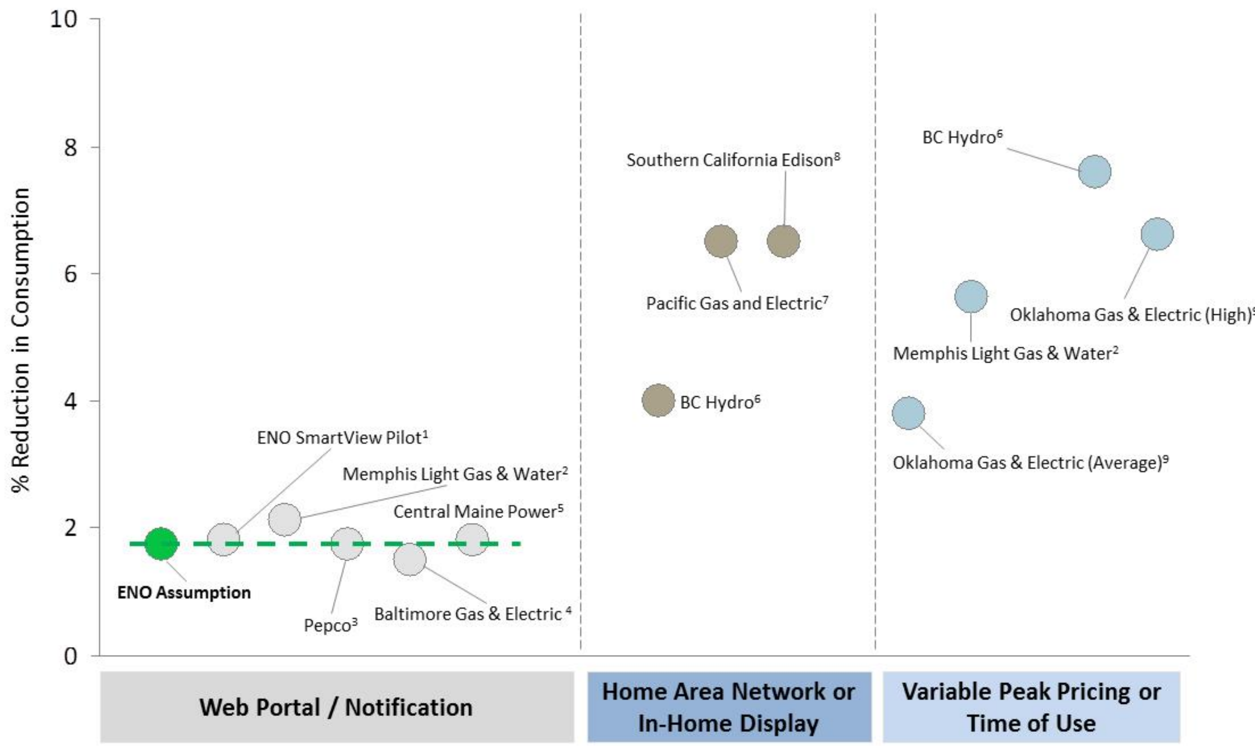
EXHIBIT JAL-2

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

OCTOBER 2016

Exhibit JAL-3
Consumption reduction of other utilities related to AMI



Sources:

1. Entergy New Orleans SmartView Pilot Final Evaluation Report, prepared by Navigant Consulting on behalf of Entergy New Orleans, Inc., August 30, 2013, page 20
2. Memphis Light Gas & Water Smart Meter 2020 Vision, President Briefing on April 11, 2013, slide 4
3. Direct Testimony of Ahmad Faruqui before the Maryland Public Service Commission, on behalf of Potomac Electric Power Company, in support of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*,* Case No. 9418, at. 10. April 19, 2016
4. Direct Testimony of William B. Pino before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, in the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to Its Electric and Gas Base Rates*,* Case No. 9406*,* at 38. November 6, 2015
5. U.S. Department of Energy Report on Central Maine Power's Smart Grid Investment Grant (SGIG) Pilot, dated January 2014, page 2
6. BC Hydro Smart Metering & Infrastructure Program Business Case, pages 23 & 28
7. California Public Utilities Commission Decision 09-03-026, March 12, 2009 relating to Pacific Gas & Electric's Application to Upgrade its Smart Meter Program, page 101
8. California Public Utilities Commission Application 07-12-009, Exhibit SCE-7, Rebuttal Testimony filed by Southern California Edison on February 19, 2008 supporting Edison SmartConnect Deployment Funding and Cost Recovery, page 13.
9. OG&E Smart Study TOGETHER Impact Results; Final Report, Summer 2011, Table 4-11 and Table 4-13; consumption reduction varies by the type of dynamic pricing rate offered to the program participant: Time-of-Use versus Variable Peak Pricing

Exhibit JAL-4
Peak Reduction for other Utilities

Entity	Pricing Technique	Action Takers (%)	Peak Reduction by Action Takers (%)
ComEd[1]	**Flat Rate:** No financial incentive to respond to "event" notification	5.7%	7.2%
	Inclining Block Rate: Higher rates for higher usage; no financial incentive to respond to "event" notification	6.8%	5.6%
	Time-of-Use: Lower rates for nights and weekends; no additional financial incentive to respond to "event" notification	9.4%	11.3%
	Day Ahead – Real Time Pricing: Hourly prices available a day ahead; Financial incentive to respond to "event" notification	9.5%	14.4%
	Peak Time Rebate: Rebate for reduced use during peak time; financial incentive to respond to "event notification	9.9%	14.7%
	Critical Peak Pricing: Significantly higher pricing during "events"; financial incentive to respond to "event" notification	11.6%	21.8%

Entity	Pricing Technique	Peak Load Reductions per Event
Opower[2]	**Behavioral Demand Response:** no financial incentive to respond to "event" notifications	3 – 5%
ENO SmartView Pilot[3]	**A/C Load Management:** A/C automatically cycled off for 10 minute increments twice per hour during "event"	16.3%
	Peak Time Rebate: Rebate for reduced use during peak time; financial incentive to respond to "event notification	10.6%
Oklahoma Gas & Electric[4]	**Time-of-Use with Critical Price:** Lower rates for night and weekend use; additional financial incentive to respond to "events" in the form of high critical price	7.5 – 19.1%
	Variable Peak Pricing with Critical Price: Variable pricing for higher load times of weekdays; additional financial inventive to respond to "events" in the form of high critical price	6.6 – 21.6%
BC Hydro[5]	**Time-of-Use:** Lower rates for nights and weekends	11.5%

Sources:

1. Electric Power Research Institute Report: The Effect on Electricity Consumption of the Commonwealth Edison Customer Applications Program, October 2011, pages 5-20 & 5-26
2. Opower White Paper: Transform Every Customer into a Demand Response Resource, 2015, page 3; based upon results of multiple utility programs in three states during the summer of 2014
3. Entergy New Orleans SmartView Pilot Final Evaluation Report, prepared by Navigant Consulting on behalf of Entergy New Orleans, Inc., August 30, 2013, page 20; based upon those enrolled across the pilot's treatment group for the specified pricing technique (A/C Load Management and Peak Time Rebate)
4. OG&E Smart Study TOGETHER Impact Results, Table 4-16 starting on page 4-47; range of values include the average on-peak demand reductions for residential customers measured across seven event days in 2011; values included in this exhibit are based only upon the pilot participants using a web portal technology (i.e., results from pilot participants with access to an in-home display, programmable controllable thermostat or all three technologies are not shown)
5. BC Hydro Smart Metering & Infrastructure Program Business Case, page 23; based upon the Conservation Research Institute program launched by BC Hydro

Exhibit JAL-5
UFE of Other Utilities

	Identification Rate (%)	Conversion to Billable Rate (%)
ComEd[1]	50%	20-50%
BC Hydro[2]	67-75%	N/A
McKinsey Model[3]	50%	50-75%

Utility AMI Business Case	UFE Benefit Estimate (calculated as a percentage of revenue)
Consolidated Edison[4]	0.25%
Ameren Illinois[5]	0.25%

Sources:

1. Black & Veatch Advanced Metering Infrastructure (AMI) Evaluation Final Report for Commonwealth Edison, July 2011, Appendix F.1, page 115-117.
2. BC Hydro Smart Metering & Infrastructure Program Business Case, page 27: "realization of theft benefits is estimated at an initial 75 percent, declining to about 67 percent…"
3. Public Utility Commission of Texas (PUCT) Case No. 33874, Advanced Metering Infrastructure Example Project Valuation Model Version 1.00 ("the McKinsey Model") filed June 1, 2007 by PUCT staff; the methodology to quantify UFE is provided under the benefit labelled "Revenue Enhancement"
4. ConEdison Advanced Metering Infrastructure Business Plan filed on October 15, 2015 in New York State Public Service Commission Case 13-E-0030, p. 47-48, 51 and 58.
5. Ameren Illinois Advanced Metering Infrastructure Cost / Benefit Analysis filed in June 2012 in Illinois Commerce Commission Docket No. 12-0244, p.24-25.

Exhibit JAL-6
Opt-out Rates of Other Utilities

Utility	Opt-out rate
PG&E	0.95%
Southern California Edison	0.45%
NV Energy	0.31%
DTE Electric Company	0.31%
San Diego Gas & Electric	0.19%
Florida Power & Light	0.13%
Georgia Power	0.02%
AEP Texas	0.01%
Oncor	0.01%
CenterPoint	0.00%
Average opt-out rate	**0.24%**

Sources:

1. The opt-out rates shown in the table are calculated as the number of reported opt-out customers divided by the number of total customers for each utility. Sources for the number of opt-out customers at each utility is provided from public sources listed below. Energy Information Agency (EIA) Form 826 data reported for December 2015 was used for the total customer count at each utility.
2. Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric opt-out customers: California Public Utility Commission, California Smart Grid: Annual Report to the Legislature (also known as “2015 Smart Grid Report”), January 1, 2016, page 17.
3. NV Energy, Electric Rate Case, Prepared Direct Testimony of Gary P. Smith, filed in Docket No. 14-050004 to the Public Utilities Commission of Nevada on May 2, 2014, page 17.
4. DTE Electric Company, Electric Rate Case, Direct Testimony of Robert E. Sitkauskas, filed in Case No. U-18014 to the Michigan Public Utility Commission on February 1, 2016, page RES-19.
5. Florida Power & Light Company, Smart Meter Progress Report, filed in Docket No. 16-0002-EG to Florida Public Service Commission on February 29, 2016, page 4.
6. Georgia Power: Savannah Morning News, “For a price, Georgia Power customers can opt out of smart meters,” January 22, 2014
7. AEP Texas Central Company and AEP Texas North Company, Compliance Report, filed in Docket No. 44129 to the Public Utility Commission of Texas on July 7, 2016
8. Oncor Electric Delivery Company, Compliance Report, filed in Docket No. 44129 to the Public Utility Commission of Texas on July 15, 2016
9. CenterPoint Energy Houston Electric, LLC, Compliance Report, filed in Docket No. 44129 to the Public Utility Commission of Texas on January 7, 2016

Entergy New Orleans, Inc.
Advanced Metering Infrastructure
Illustrative Calculation of Opt-Out Fee

Ln #	Up-front Fee Components	Estimated Cost	Estimated # Opt-Out Customers	Estimated Fee
1	Billing programming changes to build the one-time and monthly fees in CCS	$ 27,500	769	$ 35.76
2	Barrel lock and seal for non-advanced meters	$20.73/ea		$ 20.73
3	Opt out paperwork mailing costs for one-time mailing to customers, to enroll and confirm opt-out election	$2/ea		$ 2.00
4	Trip charge: employee labor and vehicle costs to perform field test and inspect meter (Assuming opt-out occurs prior to installation of advanced meter)	$37.99/ea		$ 37.99
5	**Total Up-Front Fee for Opt-Out pre Advanced Meter Install**			**$ 96.48**
7	Meter fee for replacing AMI meter with tested salvaged digital meter (Assuming opt-out occurs after installation of advanced meter)	$6.41/ea		$ 6.41
8	**Total Up-Front Fee for Opt-Out Post Advanced Meter Install**			**$ 102.89**
	Monthly Fee components	**Estimated Cost**	**Estimated # Opt Out Customers**	**Estimated Monthly Fee**
9	Trip charge: employee labor and vehicle costs for meter reads	$12.34/ea		$ 12.34
10	ENO Share of Salary for two ESI customer service specialists (Estimate = $186K annual labor / 7,750 system opt outs * ENO Opt-Outs)	$ 18,456	769	$ 2.00
11	**Total Monthly Fee for Opt-Out Customers**			**$ 14.34**

ENTERGY NEW ORLEANS, INC.
ILLUSTRATIVE CALCULATION OF METER READING FEE FOR OPT-OUT CUSTOMERS
(Based on) MISCELLANEOUS FEES WORK PAPER

A	B	C	D	E	F	G	H	I	J	K
ENOI	**Vehicle Rate ($/Mile)**	**Vehicle Speed (Miles/Hour)**	**Calculated Vehicle Rate ($/Minute)**	**Travel Time (Minutes)**	**Transportation Costs**	**Direct Site Time (Minutes)**	**Total Direct Time (Minutes)**	**Loaded Wage Rate ($/Hour)**	**Labor Costs**	**Sub-Total**
Formula for Calculations			**BxC/60**		**DxE**		**E+G**		**HxI/60**	**F+J**
Serviceman	0.83	30	0.42	5	2.08	5	10	36.33	6.06	8.13

Payroll Overhead	69.47%	4.21
Total Trip Costs		12.34

ENTERGY NEW ORLEANS, INC.
ILLUSTRATIVE CALCULATION OF METER READING FEE FOR OPT-OUT CUSTOMERS
(Based on) MISCELLANEOUS FEES WORK PAPER

A	B	C	D	E	F	G	H	I	J	K
ENOI	**Vehicle Rate ($/Mile)**	**Vehicle Speed (Miles/Hour)**	**Calculated Vehicle Rate ($/Minute)**	**Travel Time (Minutes)**	**Transportation Costs**	**Direct Site Time (Minutes)**	**Total Direct Time (Minutes)**	**Loaded Wage Rate ($/Hour)**	**Labor Costs**	**Sub-Total**
Formula for Calculations			**BxC/60**		**DxE**		**E+G**		**HxI/60**	**F+J**
Serviceman	0.83	30	0.42	5	2.08	30	35	36.33	21.19	23.27

Payroll Overhead	69.47%	14.72
Total Trip Costs		37.99

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO DEPLOY ADVANCED METERING INFRASTRUCTURE, AND REQUEST FOR COST RECOVERY AND RELATED RELIEF	)))))	**DOCKET NO. UD-16-__**

DIRECT TESTIMONY

OF

AHMAD FARUQUI, PH.D.

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

OCTOBER 2016

TABLE OF CONTENTS

EXHIBIT LIST

I. QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Ahmad Faruqui. I am a Principal with The Brattle Group. My business address is 201 Mission Street, Suite 2800, San Francisco, California 94105.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying before the Council for the City of New Orleans ("CNO" or the "Council") on behalf of Entergy New Orleans, Inc. ("ENO" or the "Company").

Q3. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL, PROFESSIONAL, AND BUSINESS EXPERIENCE.

A. I have 40 years of academic, consulting and research experience as an energy economist. During my career, I have advised 135 clients in the energy industry, including utilities, regulatory commissions, government agencies, transmission system operators, private energy companies, equipment manufacturers, and information technology ("IT") companies. Besides the U.S., my clients have been located in Australia, Canada, Chile, Egypt, Hong Kong, Jamaica, Philippines, Saudi Arabia, South Africa, and Vietnam. I have advised them on a wide range of issues including cost-benefit analysis of advanced metering technologies, demand response, energy efficiency, rate design, load forecasting, distributed energy resources, integration of retail and wholesale markets, and integrated resource planning. I have testified or appeared before several state, provincial and federal regulatory commissions and legislative bodies. I have been an invited speaker at major energy conferences in Africa, Asia, Australia, Europe, North America, and South America. Finally, I have authored, co-authored or co-edited more than 150 articles, books, editorials, papers and reports on various facets of energy economics. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as Exhibit AF-1.

Q4. WHAT ARE YOUR RESPONSIBILITIES AS A PRINCIPAL OF THE BRATTLE GROUP?

A. I lead the firm's practice in helping clients understand and manage the changing needs of energy consumers.

Q5. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS RELATED TO THE DEPLOYMENT OF ADVANCED METERING INFRASTRUCTURE ("AMI")?[1]

A. Yes. I testified in California on behalf of Pacific Gas & Electric Company and Southern California Edison, in Connecticut on behalf of Connecticut Light & Power, in Illinois on behalf of Ameren and Commonwealth Edison, in Maryland on behalf of Baltimore Gas & Electric and Pepco Holdings, Inc., and in Washington, D.C., also on behalf of Pepco Holdings, Inc.

[1] For purposes of my testimony, AMI refers to advanced meters that enable two-way data communication, a secure and reliable communications network that supports two-way data communication, along with related and supporting systems, including a Meter Data Management System ("MDMS"), an Outage Management System ("OMS"), and a Distribution Management System ("DMS") – which, in the case of ENO, are planned to be integrated with its current IT systems via an Enterprise Service Bus ("ESB"). Similar deployments in other jurisdictions are sometimes referred to as an "Advanced Metering System" or "AMS." For simplicity, I use the term "AMI" throughout my testimony.

II. SUMMARY

Q6. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to support the reasonableness of the methodology and assumptions used by ENO to quantify certain non-operational benefits associated with the Company's planned deployment of AMI, as described in the Direct Testimony of ENO witness Mr. Jay A. Lewis as "Other Benefits." The primary focus of my testimony is on the expected impacts of new, more detailed information and enhanced tools (*e.g.*, the ability to estimate a bill) that will be made available to customers as a result of the AMI deployment. The new information and enhanced tools provide customers with actionable information that would lead them to change their energy consumption in a manner that reduces electricity and natural gas system costs and can lower customer bills.

I also review and comment on some other elements of the proposed AMI deployment. These are ENO's advanced meter opt-out policy and the benefits arising from reductions in what is called "unaccounted for energy" ("UFE"). Throughout, I provide a general review of the overall methodological framework of these quantified benefits for consistency with established industry practices.

Q7. PLEASE SUMMARIZE YOUR TESTIMONY.

A. ENO's AMI deployment will provide significant benefits which could not be achieved without upgrading its existing metering infrastructure. Customers will have access to new information about their energy use that previously could not be provided due to technological constraints of the legacy metering system. In response to this information – delivered through a web portal, text alerts, and email notifications – customers are expected to change their energy consumption and manage their usage in a way that will save on fuel and capacity costs, and ultimately reduce bills for all customers.

ENO's AMI deployment will also allow ENO to reduce the current level of UFE. Within the electricity industry, the term UFE is used to refer to technical losses in the electricity system from sources like line and transformation losses, as well as non-technical losses resulting from electricity that is consumed by customers but not metered nor billed by the utility, typically due to metering malfunction or theft. The improved metering accuracy provided by AMI will help ENO mitigate non-technical UFE and reduce situations where customers are receiving electricity but not paying for their full energy use. Addressing non-technical UFE should also lead to less overall electricity consumption, which will result in a net reduction in total electricity costs for all customers.

ENO's methodology for estimating the expected impacts of these features of the AMI deployment is consistent with that of utilities in other jurisdictions. The assumptions used in the Company's analysis align well with the recent experience of these other utilities, much of which has been validated through empirical assessment of AMI pilot projects and full-scale AMI rollouts.

ENO's proposed opt-out policy will provide residential customers with the option to keep their existing meter (subject to certain safety and accuracy tests) or, if an advanced meter has already been installed, switch from an advanced meter to a non-advanced meter, as long as those customers are willing to cover their share of the associated cost of maintaining a legacy metering system, including manual meter reads each month. ENO's proposed policy is consistent with that of many other U.S. utilities. The policy provides a pragmatic degree of choice to its customers, even though only a small number are likely to decide to opt out from having an advanced meter installed at their home.

Overall, the aspects of the AMI deployment that I have reviewed are reasonable, consistent with current industry practices, and demonstrate that ENO's AMI deployment will provide significant benefits to its customers.

Q8. HOW IS YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized as follows. Section III provides an overview of AMI experience in the U.S. Section IV is an assessment of the expected benefits of the new information and enhanced tools that will be provided to customers as a result of ENO's AMI deployment. Section V discusses other assumptions in the AMI deployment. Section VI summarizes the conclusions of my review of certain aspects of the AMI deployment.

III. AMI EXPERIENCE IN THE UNITED STATES

Q9. HOW COMMON IS AMI IN THE U.S.?

A. According to the most recent publicly available information, nearly 50 million U.S. households have advanced meters, accounting for more than 45 percent of all meters.[2]

[2] EIA, Form EIA-826, "Advanced Metering" as of June 2016, *available at* https://www.eia.gov/electricity/data/eia826/#ammeter.

More than 300,000 advanced meters have been deployed in Louisiana. There are also many examples of large utility AMI deployments in ENO's neighboring states in the Southern U.S. For instance, AMI has been deployed to over 7 million customers across Texas. Southern Company has deployed advanced meters to more than 4 million customers in Georgia, Alabama, and Florida. Florida Power & Light has separately installed nearly 5 million advanced meters in Florida. Oklahoma Gas & Electric has deployed over 850 thousand advanced meters in Oklahoma and Arkansas.

There has been continued growth in adoption of advanced meters over the past decade. I expect this growth trend to continue as utilities replace legacy metering systems and modernize their power grids. If the meter adoption rate continues to follow the historical trend, the vast majority of all electricity customers in the U.S. would have advanced meters by the time ENO has finished its deployment.[3]

Q10. WHY HAVE ADVANCED METERS BECOME SO COMMON AMONG U.S. UTILITIES AND ALSO AMONG UTILITIES LOCATED OVERSEAS?

A. Utilities and regulators across the industry have recognized that new digital infrastructure is needed to modernize the grid so that utilities can keep up with advancements in energy technologies on both the supply- and demand-side. AMI unlocks many benefits, both operational and customer-facing, which can reduce costs

[3] According to a 2015 Federal Energy Regulatory Commission ("FERC") report, there were around 13 million advanced meters in the U.S. in late-2009 and 50 million advanced meters by mid-2014. This implies average annual installations of around 8 million advanced meters per year. *See* FERC, 2015 Assessment of Demand Response and Advanced Metering, Staff Report, December 2015, p. 3, *available at* http://www.ferc.gov/legal/staff-reports/2015/demand-response.pdf.

and improve reliability and quality of service for all customers. In its most recent annual report on advanced metering, the FERC Staff states that "…deployment of advanced meters continues to progress throughout the nation's electric system, providing support for two-way communications networks that utilities can use to improve electric system operations, enable new technological platforms and devices, and facilitate consumer engagement."[4]

Q11. HOW WILL THE DEPLOYMENT OF ADVANCED METERS IMPROVE THE CUSTOMER EXPERIENCE?

A. First, an upgraded metering system will enable the growing trend toward – and need for – greater customer engagement. For instance, rooftop solar PV installations are growing quickly in many regions of the U.S. Participation in demand response programs has also increased significantly in the past decade,[5] and many consumers are purchasing smart appliances, such as internet-connected digital thermostats.[6] In short, utility customers are becoming more engaged consumers of energy, and AMI has become necessary to support this level of engagement.

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[4] *See* FERC (2015), p. 5.

[5] *See* FERC (2015), p. 17.

[6] For instance, a survey of 1,600 customers in North America found that "50% of people [are] saying they plan to buy at least one smart home product in the next year (U.S. intent is slightly higher at 54%)". S*ee* Icontrol Networks, 2015 State of the Smart Home Report, June 2015, p. 3, *available at* https://www.icontrol.com/wp-content/uploads/2015/06/Smart_Home_Report_2015.pdf.

In addition, Berg Insight, a Swedish market research firm, reports that the number of smart thermostats in North America and Europe more than doubled in 2014. Their "Smart Homes and Home Automation" report also forecasts that this number will grow at a compound annual growth rate of 64.2 percent during the next five years. *See* David Murphy, "Smart Thermostat Sales Double in a Year," Mobile Marketing, January 12, 2015, available at http://mobilemarketingmagazine.com/smart-thermostat-sales-double-in-a-year/, accessed August 31, 2016.

Second, as I discuss throughout my testimony, the deployment of AMI will provide customers with access to new information that could not be provided through the existing metering system. Customers will be able to develop a better understanding of their energy consumption and when it occurs. In addition, they will receive various tips and alerts that will improve their overall experience as an energy consumer, and if followed, can result in lower individual customer bills.

Third, as quantified in Mr. Lewis's testimony, there are expected to be bill savings for all customers resulting from an overall reduction in consumption as a result of the new information about customers' energy usage available through AMI. Further, all customers will benefit from the operational cost savings provided by AMI.

IV. THE IMPACTS OF NEW INFORMATION AND ENHANCED TOOLS IN ENO'S AMI DEPLOYMENT

Q12. PLEASE DESCRIBE THE NEW INFORMATION AND ENHANCED TOOLS THAT WILL BE MADE AVAILABLE AS A RESULT OF ENO'S AMI DEPLOYMENT.

A. There are two aspects to what ENO is proposing to implement. The first is the incorporation of more detailed, time-differentiated usage data into the Company's customer web portal, which can be accessed through the internet by computer or mobile device.[7] In other words, through their computer or mobile device, customers

[7] Data collected by the U.S. Census Bureau shows that internet access has increased over time. In 1997, 18.0 percent of households reported home internet use. By 2013, these estimates had increased to 74.4 percent. For the state of Louisiana, 70.3 percent were reported to have access to high-speed internet. I would expect this

will have access to enhanced usage and billing information, targeted energy saving tips, and other features like the ability to set targeted bill and usage alerts, which collectively comprise a robust resource of energy management information for electricity and natural gas customers. ENO witness Dennis P. Dawsey explains these features in more detail in his direct testimony.

The second aspect is the implementation of a peak event notification program for electricity customers, also described by Mr. Dawsey. To reduce electricity demand during the small number of hours of the year that drive the system peak, notifications would be sent to customers encouraging a voluntary, temporary reduction in electricity use. My understanding is that these messages could be sent in anticipation of a peak event by text and/or email (subject to an opt-out procedure and applicable legal requirements related to such communication channels). The program is expected to include post-event feedback, educating customers about the extent to which they reduced their peak electricity consumption, and which is only possible with the time-differentiated usage data produced by AMI. Following the AMI deployment, customers would be enrolled in the notification program, although as I understand it, customers can choose to not receive such notifications if they wish.

Q13. HOW WILL THE NEW INFORMATION AND ENHANCED TOOLS BENEFIT CUSTOMERS?

trend to continue, meaning internet access may be higher by the time the Company's AMI deployment is expected to start in 2019. *See* Thom File and Camille Ryan, "Computer and Internet Use in the United States: 2013," United States Census Bureau, November 2014, pp. 4 and 10, *available at* http://www.census.gov/content/dam/Census/library/publications/2014/acs/acs-28.pdf.

A. The incorporation of the AMI data into the Company's web portal will give customers access to detailed and more up-to-date energy usage information to help them make better informed decisions about their usage. I expect some customers to reduce their overall electricity and natural gas consumption in response to this enhanced information. Similarly, I expect some customers to reduce their peak demand when notified of peak events. The impacts of the information made available by AMI through the web portal and peak event notification program will translate into cost savings for ENO and ultimately for its customers. In the short run, the reduction in total electricity consumption will result in a reduction in fuel and variable operations and maintenance costs. In the longer-term, lower system peak demand should reduce fuel and capacity costs. Likewise, the reduction in natural gas consumption will result in short-term and long-term cost decreases.

Q14. WHAT HAS ENO ESTIMATED WILL BE THE IMPACTS OF THE NEW INFORMATION AND ENHANCED TOOLS ON ELECTRICITY USAGE?

A. ENO has estimated that the new information and enhanced tools made available through the web portal will lead to an overall reduction in residential and commercial electricity consumption of between 1.5 percent and 2.0 percent. ENO used the mid-point of that range (1.75 percent) to calculate consumption reduction benefits, as discussed in the Direct Testimony of Mr. Lewis. ENO has assumed that these energy savings will occur uniformly during peak and off-peak periods, resulting also in a proportional peak demand reduction of 1.5 to 2.0 percent. ENO used 1.75 percent as the midpoint of this range to calculate peak demand-related benefits as well. The peak event notifications are expected to lead to an additional reduction in residential peak demand of approximately 0.4 percent, with no associated energy savings. These assumptions are summarized in Table 1 and are discussed in more detail in the Direct Testimony of Mr. Lewis. Mr. Lewis quantifies the value of these impacts in his direct testimony.

Table 1: Impact of New Information and Enhanced Tools on Residential and Commercial Electricity Use

	Energy Savings	Peak Demand Savings
Web portal	1.75%	1.75%
Peak notifications	0.00%	0.38%
Total	**1.75%**	**2.13%**

Q15. IN GENERAL, IS THERE EVIDENCE THAT CUSTOMERS RESPOND TO MORE DETAILED INFORMATION ABOUT THEIR ELECTRICITY USAGE?

A. Yes, there is empirical evidence in academic journal articles and industry reports indicating that customers respond to detailed information about their energy consumption. The studies have analyzed a variety of ways in which this energy information can be provided to customers. For instance, more than a dozen utility pilot projects implemented over the past decade found that customers reduce energy consumption when provided with new information that is displayed electronically and is easily accessible.[8] The means to display the information could be a screen

[8] Many of these studies are summarized in Ahmad Faruqui, Sanem Sergici, and Ahmed Sharif, "The Impact of Informational Feedback on Energy Consumption – A Survey of the Experimental Evidence," *Energy*, 2010, *available at* http://www.myaztech.ca/wp-content/uploads/faruqui_impactoffeedback_2010.pdf. *See also* Sarah Darby, "The Effectiveness of Feedback on Energy Consumption: A Review for Defra of the Literature on

reporting instantaneous energy use, an "orb" that glows different colors depending on energy consumption levels, or a web-based platform that the customer accesses from a computer or mobile device. Additionally, firms that offer a platform for certain types of energy efficiency programs, like OPower, have observed significant energy reductions when providing utility customers with bill inserts that compare their consumption to that of similarly-situated neighbors.[9] There have also been studies specifically on the impacts of providing AMI usage data through a web portal, similar to the capability that ENO proposes in its AMI deployment, which I will summarize later in my testimony.

Importantly, these studies have found that customers respond to new energy consumption information even in the absence of changes in price. Simply being better informed about their energy use in conjunction with new tools like targeted text alerts and conservation tips is enough to induce energy savings among some customers. Changes in the pricing structure, or the adoption of new home automation technologies, would further enhance response.

Q16. IS ENO'S ASSUMED ELECTRICITY IMPACT FROM THE AMI USAGE DATA MADE AVAILABLE THROUGH THE WEB PORTAL AND RELATED ENERGY MANAGEMENT INFORMATION REALISTIC?

Metering, Billing, and Direct Displays," Environmental Change Institute at the University of Oxford, April 2006, *available at* http://www.eci.ox.ac.uk/research/energy/downloads/smart-metering-report.pdf.

[9] Studies have indicated that OPower's programs reduce residential electricity use by two percent on average. A full library of OPower's measurement and verification reports can be found here: https://opower.com/resource_type/verification-reports/.

A. Yes. An estimate of 1.5 percent to 2.0 percent savings in energy consumption is reasonable and consistent with evidence from other jurisdictions. As I noted previously, Mr. Lewis has used an estimate of 1.75 percent, which is within this range. I am aware of similar estimates that have been developed by other utilities.

For instance, Potomac Electric Power Company ("Pepco") recently detected energy savings of 1.73 percent from a similar full-scale web-based offering.[10] The utility's offering is centered primarily around more detailed and time-specific information about each customer's electricity consumption, which is provided through both a web portal and the customer's bill. Pepco has offered this AMI information in Maryland since Spring 2013.[11] Pepco filed an empirical assessment of the impacts of its web-based AMI information as part of cost recovery proceedings before the Maryland Public Service Commission ("Maryland PSC"). I led the assessment of Pepco's AMI-enabled energy savings and have submitted testimony to the Maryland PSC in support of that analysis.[12]

Baltimore Gas & Electric ("BGE") has offered new AMI-enabled usage information to its customers since Fall 2012. BGE's offering includes interactive online tools, usage alerts, weekly usage emails, and home energy reports. BGE has

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10 *See Direct Testimony of Ahmad Faruqui on behalf of Potomac Electric Power Company, Maryland Public Service Commission* – Case No. 9418, April 19, 2016, p. 10.

11 Additionally, Pepco Holdings began offering a web portal in its Delmarva Maryland jurisdiction in Fall 2014.

12 *See* Faruqui (2016).

reported energy savings of between 1.38 and 1.5 percent resulting from the provision of this information.[13]

Many other utilities that have deployed AMI included assumptions about the impacts of web-based AMI information in their AMI business cases. In some cases, such as those of BC Hydro and Southern California Edison, the assumed impacts reached 2.0 percent.[14] In the case of the Company's web-based AMI pilot, impacts were estimated to be 1.8 percent.[15] But what makes the Pepco and BGE cases particularly relevant is that they reflect **actual** impacts that were measured on an *ex post* basis. They are statistically significant estimates observed from customers across the utilities' entire respective service territories.

Q17. DID PEPCO AND BGE HAVE PRE-EXISTING ENERGY EFFICIENCY OR DEMAND-SIDE MANAGEMENT PROGRAMS ("EE/DSM") WHEN THEY DEPLOYED AMI?

[13] An evaluation by Navigant Consulting identified a 1.38 percent impact, and testimony by BGE witness William Pino refers to a 1.5 percent impact. *See* Navigant Consulting Inc., *Smart Energy Manager Program – 2015 Evaluation Report,* prepared for Baltimore Gas Electric, March 11, 2016, p. ii. *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, p. 38.

[14] *See* BC Hydro, *Smart Metering & Infrastructure Program Business Case*, p. 28, *available at* https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/projects/smart-metering/smi-program-business-case.pdf.

See Southern California Edison, *Rebuttal Testimony Supporting Edison SmartConnect Deployment Funding and Cost Recovery*, California Public Utilities Commission, Application No. A.07-07-026, February 19, 2008, p. 11.

[15] ENO conducted a pilot program in 2011 and 2012 evaluating customer behavior in response to advanced metering and other technologies for low-income customers. While the average impact of the pilot was estimated to be 1.8 percent, the result was not considered to be statistically significant. This could be due to the relatively small number of participants in the pilot. *See* Navigant Consulting Inc., *Entergy New Orleans SmartView Pilot, Final Evaluation Report*, August 30, 2013, Table ES-2, p. v. Additionally, Entergy Louisiana, LLC conducted a small pilot, but it did not include the types of information-only treatments that I am analyzing in my testimony.

A. Yes. Both utilities offered robust EE/DSM portfolios prior to AMI deployment, and continue to do so.[16] The utilities have been working for years to achieve what I would consider to be substantial energy savings targets in Maryland.[17]

Q18. ARE THE ENERGY SAVINGS ESTIMATES ASSOCIATED WITH BGE'S AND PEPCO'S WEB PORTALS INCREMENTAL TO THE IMPACTS OF THE UTILITIES' EE/DSM PROGRAMS?

A. Yes. The energy savings that are associated with BGE's and Pepco's web portals are entirely incremental to the energy savings that are attributable to the utilities' EE/DSM programs. In the Pepco study, which I led, I structured the analysis such that it isolated the impact of the web-based AMI information and excluded any effect from existing EE/DSM programs.

I did not conduct the cited analysis for BGE, but I have reviewed the final report describing the methodology in that analysis.[18] It is my understanding that the BGE study similarly excluded the impacts of existing EE/DSM programs when quantifying the energy savings associated with web-based AMI information.

Q19. WOULD YOU EXPECT CUSTOMERS TO REDUCE NATURAL GAS USAGE DUE TO THE ACCESSIBILITY OF AMI USAGE DATA VIA A WEB PORTAL

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16 For more information on the utility EE/DSM offerings in Maryland, see the Pepco MD website: http://www.pepco.com/my-home/save-money-and-conserve-energy/efficiency-rebates-and-incentives-and-programs/md-customers/. *Also see* the BGE website: http://www.bgesmartenergy.com/.

17 For more information, see the EmPOWER website: http://energy.maryland.gov/pages/facts/empower.aspx.

18 *See* Navigant Consulting Inc. (2016).

AND RELATED ENERGY MANAGEMENT INFORMATION?

A. Yes. Given the previously described changes in electricity consumption behavior, I would expect to observe related changes in natural gas consumption.

Q20. IS ENO'S ASSUMED IMPACT ON NATURAL GAS CONSUMPTION FROM AMI DATA ACCESSIBLE VIA A WEB PORTAL AND RELATED ENERGY MANAGEMENT INFORMATION REALISTIC?

A. Yes. An estimate of 0.5 percent to 1.0 percent savings in natural gas consumption is reasonable and consistent with available studies on the topic. Similar to electricity, there is empirical evidence indicating that customers respond to detailed information about their natural gas consumption. For instance, in testimony on behalf of Southern California Gas Company ("SoCalGas"), Dr. Sarah Darby of Oxford University, a noted authority on the subject of the impact of information on customer energy use, cites several pilot studies that have found that electronic display of energy information has an impact on natural gas usage.[19]

Furthermore, I am aware of two utilities – SoCalGas and BGE – that have detected natural gas savings in this range through the provision of new energy information. Since 2012, SoCalGas has offered AMI usage data via a web portal providing online next-day gas usage information combined with the distribution of home energy reports. BGE's Smart Energy Manager program offers similar

19 *See Prepared Direct Testimony of Sarah J. Darby in support of the Application of Southern California Gas Company for Approval of Advanced Metering Infrastructure*, California Public Utilities Commission, Application No. A. 08-09-023, September 29, 2008. *See also* Darby (2006), footnote 8.

information and tools. In both instances, the inclusion of home energy reports means that the suite of offerings by these two utilities differs slightly from ENO's proposed offering. However, these two studies are the best available information that I am aware of on information-induced changes in natural gas consumption behavior.

In its August 2014 and 2015 *Advanced Meter Semi-Annual Reports*, SoCalGas measured conservation for residential customers due to web-based access to usage information. The August 2014 report shows savings between 0.70 and 1.54 percent observed for various treatment groups in Winter 2013-2014.[20] The August 2015 report shows similar savings of between 0.74 and 1.45 percent between April 2014 and March 2015. The study also demonstrates that the consumption reduction persists in the second year of treatment, with measured savings of 1.12 to 1.33 percent for the groups of customers that started being observed in 2013-2014.[21] In the context of its cost recovery proceeding before the Maryland PSC, BGE measured 0.81 percent of natural gas savings due to their Smart Energy Manager program.[22]

Q21. IN ADDITION TO OVERALL ENERGY SAVINGS, ENO HAS ASSUMED THAT THE AMI INFORMATION ACCESSIBLE VIA THE COMPANY'S WEB

[20] *See* Nexant, "Evaluation of Southern California Gas Company's 2013-2014 Conservation Campaign," July 2014, Table 6-1, p. 33, as Exhibit E in *Southern California Gas Company Advanced Meter Semi-Annual Report*, August 29, 2014. Only statistically significant results for customers with a My Account are included in this range.

[21] *See* Nexant, "Evaluation of Southern California Gas Company's 2014-2015 Conservation Campaign," August 2015, Table 5-1, p. 36 and Table 5-3, p. 46, as Exhibit E in *Southern California Gas Company Advanced Meter Semi-Annual Report*, August 31, 2015. Only statistically significant results for customers with a My Account are included in this range.

[22] *See* Navigant Consulting (2016), p. ii.

PORTAL WILL LEAD TO PEAK ELECTRICITY DEMAND REDUCTIONS. IS THEIR ESTIMATE REALISTIC?

A. Yes, ENO's estimate of 1.5 to 2.0 percent peak demand savings for residential and commercial customers due to incorporation of AMI data into the web portal is reasonable. Specifically, ENO has assumed that peak demand savings attributable to the accessibility of AMI data via a web portal is proportional to energy savings on a percentage basis. This assumption is consistent with that of other utility business cases and reasonable relative to recent empirical evidence.[23]

Three independent studies of behavioral energy efficiency programs have looked specifically at the extent to which peak savings differ from energy savings. The studies were conducted by Lawrence Berkeley National Laboratory ("LBNL"),[24] DNV-GL (on behalf of the California Public Utilities Commission),[25] and The Cadmus Group (on behalf of PPL Electric).[26] The studies evaluated actual load data for customers who were provided information about how their energy use compares to similarly-situated neighbors. I would expect the programs evaluated in these three

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[23] Both the BGE and Pepco studies that I mentioned previously assumed proportional energy and peak savings.

[24] *See* Annika Todd et al, "Insights from Smart Meters: The Potential for Peak-Hour Savings from Behavior-Based Programs," Lawrence Berkeley National Laboratory Paper LBNL-6598E, March 2014, *available at* http://escholarship.org/uc/item/2nv5q42n#page-1.

[25] *See* DNV-GL, "Review and Validation of 2014 Pacific Gas and Electric Home Energy Reports Program Impacts (Final Draft)," prepared for the California Public Utilities Commission, March 1, 2016, p. 30, *available at* http://www.energydataweb.com/cpucFiles/pdaDocs/1441/Res3_1_PGE_HER2014_FINALdraft_forPublicComments.pdf.

[26] Based on evaluation of data supporting James Stewart and Pete Cleff, "Are You Leaving Peak Demand Savings on the Table? Estimates of Peak-Coincident Demand Savings from PPL Electric's Residential Behavior-Based Program," AESP working paper, 2014, *available at* http://aespnational2014.conferencespot.org/polopoly_fs/1.429338.1389116220!/fileserver/file/67651/filename/Session_3A_Peter_Cleff.pdf.

studies to elicit the same type of response when that information is accessed through a web portal; in both instances, customers are responding to general information about their energy use as opposed to information that would be specific to the time of day.

All three of the studies found that peak savings were proportionally **greater** than energy savings. One likely reason is that customers tend to have more discretionary load during peak hours (*e.g.*, air-conditioning or lighting in unoccupied rooms), and thus more opportunity for savings. The LBNL study elaborates on this point:

> These results show that this pilot program rollout resulted in savings that are higher during peak hours. It is particularly interesting because the savings disproportionately increase during the peak hours. Without hourly data, one assumption that was commonly used (based on anecdotal evidence) was that this was not the case; that either the savings are spread out evenly in proportion to the electricity usage, or that savings are actually harder to achieve during peak hours.[27]

Thus, all of the available empirical evidence that I am aware of supports the conclusion that ENO has been conservative in its assumption that peak impacts of incorporating the AMI data into its web portal will be proportional to (and not greater than) energy savings.

Q22. IN ADDITION TO PROVIDING NEW INFORMATION THROUGH A WEB PORTAL, ENO WILL SEND CUSTOMERS NOTIFICATIONS OF PEAK EVENTS. IS ENO'S ASSUMED IMPACT FROM THE PEAK NOTIFICATIONS REALISTIC?

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27 *See* Todd et al (2014), pp. 6-7.

A. Yes. In fact, the estimate of a 0.4 percent peak demand reduction among residential and commercial customers is conservative relative to studies elsewhere. The peak demand impacts of such notifications have recently been tested through pilot programs. Some utilities have begun to consider offering these notifications as an alternative to conventional demand response programs which require installing control equipment on individual sources of load like an air conditioner or pool pump.

In some cases, these notifications are being deployed on a full-scale basis. Most recently, the California Independent System Operator ("CAISO") issued "flex alerts" to customers in California in response to higher than expected demand driven by high temperatures, concerns about natural gas shortages at the Aliso Canyon storage facility, and challenging grid conditions caused by nearby wildfires.[28]

Several studies have estimated the impacts of these pilot programs in the past few years. I have identified seven such studies. Much like ENO's proposed method of deployment, most of these programs appear to have been rolled out on a default basis, meaning all participants were automatically enrolled in the program.[29] Aggregate peak demand reductions identified in the studies ranged from 1.7 percent to 5.8 percent.[30] The impacts estimated in each study are summarized in Figure 1,

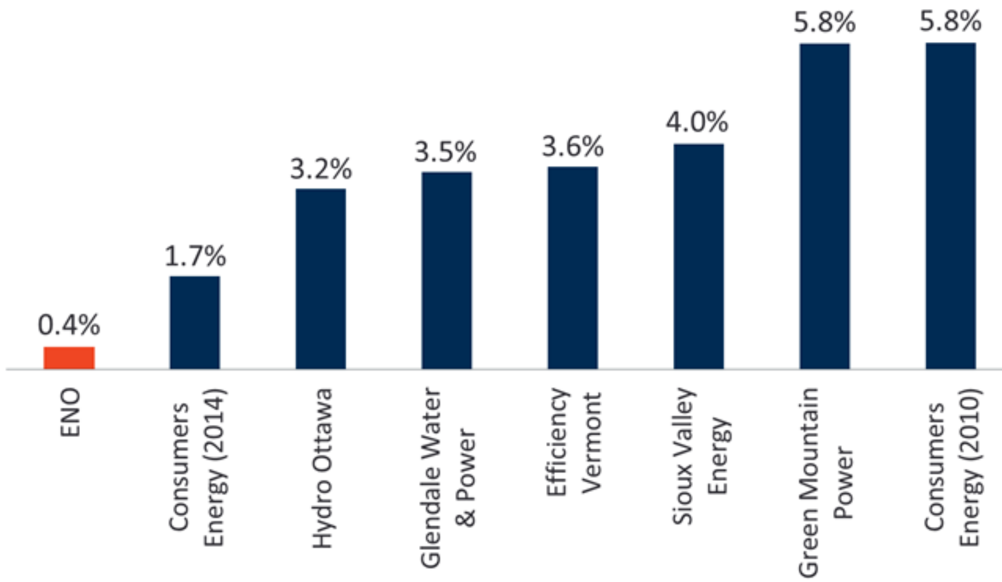
[28] *See* Kassia Micek, "CAISO Calls on Consumers to Conserve Electricity," *Platts*, June 20, 2016, *available at* http://www.platts.com/latest-news/electric-power/houston/caiso-calls-on-consumers-to-conserve-electricity-21758647, last accessed September 2, 2016.

[29] Based on my review of the seven pilot studies shown in Figure 1, I believe only the Consumers Energy (2010) pilot included opt-in deployment. I believe all the other six pilot programs, including the Consumers Energy (2014) pilot, automatically enrolled customers to receive peak event notifications.

[30] While some of these seven pilots included a subset of customers receiving a financial incentive to reduce peak usage, all of the values provided in Figure 1 are based off information-only peak event notification programs.

with ENO's assumption shown for comparison purposes. Full citations to all seven studies are provided in Exhibit AF-2.[31]

Figure 1: Residential and Commercial Peak Demand Reductions from Behavioral Demand Response Programs



Notes:
[1] Value for ENO is assumption from AMI cost benefit analysis.
[2] Results for Green Mountain Power were not determined to be statistically significant.
[3] For pilots that reported a range of impacts, the midpoint of the range is shown.
[4] Impacts are average across all pilot participants and can be reasonably scaled to the class as a whole.

ENO's assumed residential and commercial peak impact of 0.4 percent is conservative relative to the range of findings of the pilots summarized in Figure 1. While I believe a higher assumed impact could be justified, it makes sense to be somewhat conservative with this assumption given that the industry has not been

[31] Note that the source document for the Consumers Energy (2014) result identifies the utility as CMS Energy, which is a holding company. The only utility subsidiary of CMS Energy is Consumers Energy, so I refer to the utility as Consumers Energy in Figure 1.

studying the impacts of these programs for as long as some other types of programs such as web portals.

V. OTHER ASPECTS OF ENO'S AMI DEPLOYMENT

Q23. WHAT OTHER ASPECTS OF THE AMI DEPLOYMENT HAVE YOU REVIEWED?

A. I have reviewed ENO's assumed reductions in UFE and the Company's proposed advanced meter opt-out policy.

A. Benefits of UFE Reduction

Q24. WHAT IS "UFE"?

A. UFE reflects losses in the electricity system between the generator and customer meter. This includes line and transformation losses (or "technical losses") as well as electricity that is being consumed from the grid by customers but not metered nor billed by the utility (so-called "non-technical losses"). These non-technical losses could be due to meter malfunction, such as a meter that has slowed down over time or stopped working entirely. Or, non-technical losses could be caused by tampering and electricity theft. The cost of UFE, regardless of source, is borne by all customers as it effectively is treated as a system loss. This is further explained in ENO witness Lewis's Direct Testimony.

Q25. WHAT HAS ENO ASSUMED REGARDING THE BENEFITS OF REDUCTION IN UFE?

A. As discussed by Mr. Lewis, ENO has assumed that roughly one percent of residential and commercial energy sales are unaccounted for currently due to non-technical UFE losses. ENO assumes it will be able to detect and address half of this one percent as a result of the AMI deployment. ENO further assumes that, once detected, half of this 0.5 percent, or 0.25 percent of all residential and commercial sales, will actually cease as a result of the detection, while the other half is converted to billable sales. Put another way, deploying AMI will allow ENO to improve fairness in revenue collection and reduce residential and commercial electricity consumption by 0.25 percent.

Mr. Lewis distinguishes two different types of benefits that this reduction in UFE will provide to ENO's customers. First, the 0.25 percent reduction in electricity consumption amounts to an avoided cost. That is electricity that ENO no longer needs to generate (or procure), so it translates into a cost reduction associated with the need for less fuel, which ultimately lowers the fuel adjustment for all customers. Next, the 0.5 percent UFE detection represents an overall improvement in fairness in revenue collection. As described above, the cost of that electricity was being borne by customers other than those who were consuming it. While there is not a net reduction in total system-level costs associated with correcting that until rates are next reset, it represents an improvement in fairness and equity and a reduction in bills for those customers who were previously unintentionally covering the cost of the undetected electricity consumption.

Q26. ARE THESE UFE-RELATED BENEFITS CONSISTENT WITH ASSUMPTIONS

YOU HAVE OBSERVED IN OTHER APPROVED UTILITY AMI DEPLOYMENT APPLICATIONS?

A. Yes. Reduced UFE is a common benefit cited within approved AMI deployment applications. In fact, in an informal survey of approved utility AMI deployment applications and AMI cost recovery proceedings over the past few years, I identified eight that quantified the benefit related to reduced UFE. Those utilities are Ameren Illinois, Baltimore Gas & Electric, BC Hydro, Commonwealth Edison ("ComEd"), Consolidated Edison, Duke Energy Ohio, a joint filing by the Hawaiian utilities, and Public Service Company of Oklahoma. A complete list of citations to each utility AMI cost benefit-analysis is provided in Exhibit AF-2.

Regarding the magnitude of the UFE reduction, I have found that ENO's assumed reduction is consistent with that of other utility AMI cost-benefit analyses. For instance, ComEd estimated 0.91 percent of sales to be non-technical UFE. Like ENO, ComEd assumed that half of this UFE would be detected through the use of AMI. Of the detected UFE, ComEd assumed that 50 to 80 percent would cease, resulting in a net reduction in electricity use of 0.23 to 0.36 percent.[32] This is similar to ENO's assumption of 0.25 percent.

I believe it is reasonable to expect that some portion of UFE will simply go away once it is detected. Customers may become more energy efficient or curtail illicit use of electricity when faced with the full cost of the electricity that they were

[32] (0.91% non-technical UFE sales) X (50% detected via AMI) X (50% ceased consumption) = 0.23%, and 0.91% X 50% X 80% = 0.36%. *See* Black & Veatch, for Commonwealth Edison Company. *Advanced Metering Infrastructure (AMI) Evaluation-Final Report*, July 2011, p. 117.

previously consuming. There is a vast literature in energy economics which shows conclusively that customers consume less electricity when the price increases (or in this case their overall costs).[33]

Finally, I have noted that avoided peak demand associated with the reduced UFE could also be included as a benefit in ENO's cost-benefit analysis (similar to the avoided peak demand benefits from the web portal). ENO has not included this potential benefit of reduced UFE, focusing only on the avoided energy costs, and therefore the Company's estimate is conservative in this sense.

B. ENO's Opt-out Policy

Q27. ENO HAS PROPOSED TO ALLOW RESIDENTIAL CUSTOMERS TO VOLUNTARILY "OPT OUT" OF HAVING AN ADVANCED METER. WHAT DOES THIS MEAN?

A. As Mr. Lewis describes in his testimony, ENO's proposed opt-out policy means that residential customers can choose to avoid receiving an advanced meter before their existing meter is replaced (subject to certain safety and accuracy tests), or can have their advanced meter (if already installed) replaced with a non-advanced electric meter. Those customers who opt out of the advanced meter would pay, in addition to standard residential rates and applicable riders, a fee that consists of an initial payment and a recurring monthly payment. The monthly fee is designed to cover the

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[33] *See*, for instance, Mark Bernstein and James Griffin, "Regional Differences in the Price-Elasticity of Demand for Energy," RAND Corporation Technical Report, 2005, *available at* http://www.rand.org/content/dam/rand/pubs/technical_reports/2005/RAND_TR292.pdf.

costs of maintaining a redundant metering system as well as manually having their meter read each month. While not all utilities offer an opt-out option to their customers, allowing a customer to opt out is a common way to address the needs of the very small, but vocal minority of customers who have asserted privacy- or health-related concerns about advanced meters.

Q28. DO YOU FEEL IT IS APPROPRIATE FOR ENO TO OFFER RESIDENTIAL CUSTOMERS THE OPTION TO OPT OUT OF AN ADVANCED METER?

A. Yes. That said, the credible evidence that I have seen suggests that advanced meters do not pose a health risk to customers, do not improperly infringe on customer privacy, or otherwise represent a safety risk. For instance, The California Council on Science and Technology found that there are no adverse health effects associated with advanced meters.[34] Advanced meters do not come anywhere near the Federal Communication Commission's ("FCC") established limits for radiofrequency ("RF") exposure.[35] And to the extent that some customers have privacy, data security, or other concerns in spite of ENO's data protection policies (as described by Mr. Griffith and Mr. Dawsey in their testimony), those customers will have the option to opt out of an advanced meter.

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[34] *See* California Council on Science and Technology, "Health Impacts of Radio Frequency Exposure from Smart Meters," CCST whitepaper, April 2011, *available at* https://ccst.us/publications/2011/2011smart-final.pdf.

[35] *See* Electric Power Research Institute, "An Investigation of Radiofrequency Fields Associated with the Itron Smart Meter," Report 1021126. December 2010, *available at* http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001021126.

To address the views of customers who feel strongly about these issues, I do believe it is pragmatic for ENO to give them the option to avoid having an advanced meter record and transmit their energy usage as long as those customers agree to pay for the additional associated costs that ENO would incur.[36]

Q29. DO YOU AGREE WITH ENO'S PROPOSED METHODOLOGY FOR ESTABLISHING UPFRONT AND ON-GOING OPT-OUT FEES, AS DESCRIBED BY MR. LEWIS?

A. My understanding is that ENO is proposing to charge the full cost of opting out only to those customers who opt out of AMI, including administrative paperwork, the inspection of existing meters, the removal/installation of the relevant meter, customer service, manual meter reads, and billing each month. The cost will be spread equally across all customers who opt out, in the form of an up-front charge and a recurring monthly charge.

Conceptually, this approach makes sense. Otherwise, the customers who opt out are unfairly subsidized by customers who accept a new advanced meter. Since customers that opt out still receive benefits through reduced rates (due to reduced operational costs and fuel costs, for example), it is reasonable that opt-out customers should be required to pay other applicable residential rates and riders, including any CNO-approved recovery of the AMI deployment.

[36] My understanding is that customers would be required to provide adequate notice and acknowledge via signed form that they have opted out of the advanced meter and accept the associated upfront and on-going fees.

Q30. WHEN PRESENTED WITH THE OPTION, WHAT PERCENTAGE OF CUSTOMERS HAVE TYPICALLY OPTED OUT OF AN ADVANCED METER OFFERING IN OTHER JURISDICTIONS?

A. Even in PG&E's Northern California service territory, where the most vocal opposition to advanced meters surfaced a few years ago, the percentage of customers who opted-out is only around one percent.[37] That is one of the highest opt-out rates that I am aware of. In other utility cases, including other utilities in California, the opt-out rate is only a fraction of one percent. Only a very small portion of a utility's customers are expected to opt out of an advanced meter offering.

Figure 2 summarizes AMI opt-out rates from a number of North American utilities.[38] Because the opt-out rate is likely influenced in part by the magnitude of the opt-out fees,[39] I have included the on-going monthly fee on the horizontal axis.[40] Support for the information shown in this figure is provided in Exhibit AF-3.

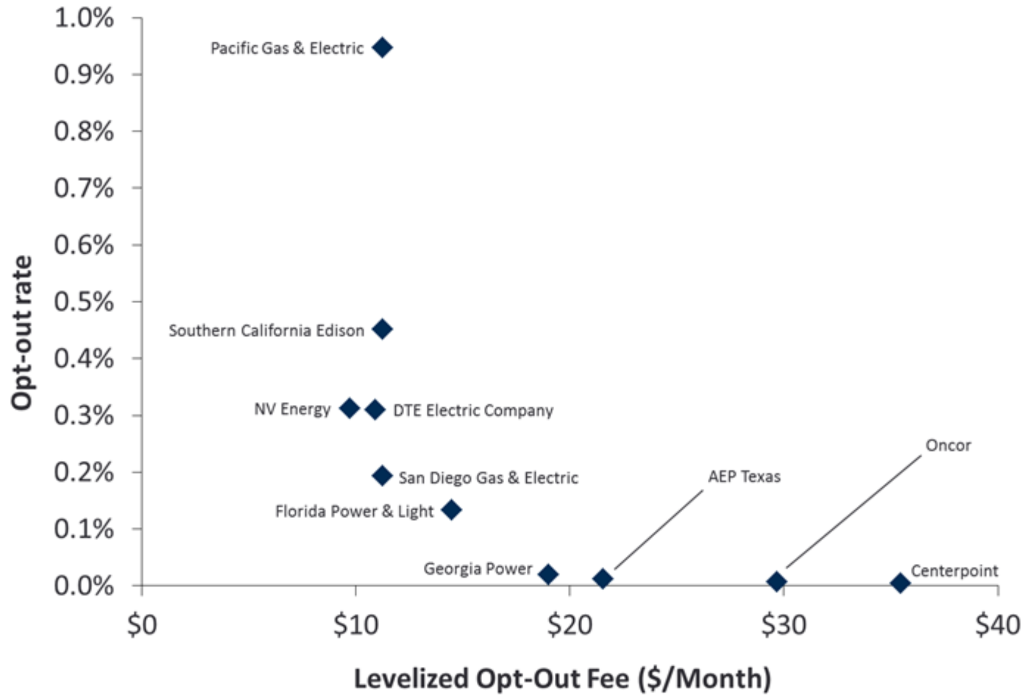
[37] That is 52,205 customers who were enrolled in PG&E's SmartMeter Opt-Out Program as of October 2015 out of a total of 5,518,718 customers. *See California Smart Grid – Annual Report to the Governor and the Legislature, in Compliance with Public Utilities Code 913.2, California Public Utilities Commission* (January 1, 2016), p. 17 and EIA Form EIA-826 (December 2015), "Sales and Revenue".

[38] I reviewed the analysis in Mr. Lewis's testimony and Exhibit JAL-6 and have reproduced those opt-out rates here.

[39] Other factors that could influence the opt-out rate are the amount of time that has passed since the meter opt-out policy was put in place, differences in perceived risk from advanced meters across utility service territories, and the extent to which advanced meters enable various customer-side benefits that customers would not want to forgo by opting out.

[40] The fee is commonly composed of an initial, one-time payment plus an ongoing monthly payment. In these instances, I have levelized the one-time-payment over an assumed period of 60-months and added it to the monthly fee in order to create an average all-in monthly fee that is comparable across the utilities.

Figure 2: Opt-out Fees and Rates from Selected Utilities with Publicly Available Opt-out Data



Notes:
[1] Opt-out rates are calculated as the number of customers who opt out divided by total customers as of December 2015. Number of customers who opt out are based on the latest publicly available data, which spans a period from 2012 to 2016 depending on the utility.
[2] The initial opt-out fee has been levelized over an assumed 5-year period.

I have reviewed the illustrative opt-out fee example in Mr. Lewis's testimony. Based on that review, I believe the assumed rate of 0.25 percent is reasonable relative to the utilities shown in Figure 2.

VI. CONCLUSIONS

Q31. WHAT DO YOU CONCLUDE ABOUT THE REASONABLENESS OF ENO'S AMI PROPOSAL?

A. Advanced metering is a necessary platform to keep up with customer expectations in the digital age and to facilitate the integration of new energy technologies on both sides of the customer's meter. ENO's methodological framework for assessing the costs and benefits of AMI is consistent with industry practices and includes reasonable assumptions that embody the latest available research on the topic. If anything, ENO has been conservative in its assessment of the many benefits of deploying AMI. In some cases, there are additional potential benefits of the AMI proposal which ENO has not quantified (*e.g.*, peak demand reductions due to reduced UFE). There are also additional new AMI-enabled programs which ENO could offer in the future (*e.g.*, dynamic pricing options). For these reasons, I believe the future realized benefits of ENO's proposed AMI deployment could be even higher than those quantified by Mr. Lewis.

Q32. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF CALIFORNIA

COUNTY OF San Francisco

NOW BEFORE ME, the undersigned authority, personally came and appeared, **AHMAD FARUQUI, PH.D.**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

____

Ahmad Faruqui, Ph.D.

SWORN TO AND SUBSCRIBED BEFORE ME
THIS ______ DAY OF OCTOBER, 2016

____

NOTARY PUBLIC

My commission expires: ____________________

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of California
County of San Francisco
Subscribed and sworn to (or affirmed) before me this 12 day of October, 2016, by AHMAD FARUQUI

____________________, proved to me on the basis of satisfactory evidence to be the person~~(s)~~ who appeared before me.

Signature ________________ (Seal)

C. ALVAREZ LANDAUER
Commission # 2124114
Notary Public - California
San Francisco County
My Comm. Expires Aug 20, 2019

Ahmad Faruqui
Principal

San Francisco, CA | +1.415.217.1000 | Ahmad.Faruqui@brattle.com

Dr. Ahmad Faruqui is an economist with 40 years of academic, consulting and research experience in the efficient use of energy. He has assisted clients in the conceptualization, design, analysis, and evaluation of a wide range of programs related to advanced metering infrastructure, conservation voltage reduction, combined heat and power, demand charges, distributed energy resources, dynamic pricing, demand response, energy efficiency and newly emerging technologies, such as plug-in electric vehicles, rooftop solar, and distributed generation. He has provided regulatory support and testimony in proceedings related to these issues in 34 states, the District of Columbia and Canada.

He has assisted numerous utilities in carrying out cost benefit analysis, smart grid investments, and in developing business cases for advanced metering infrastructure. These have been carried out in California, Connecticut, Delaware, District of Columbia, Illinois, Maryland, and Michigan.

During the past decade, Dr. Faruqui has been at the forefront of experiments with dynamic pricing and enabling technologies. He serves on the U.S. Department of Energy's Technical Advisory Group for Customer Behavior Studies. He also co-authored a guide on how to evaluate smart grid demonstration projects and led a team of consultants that developed demand response potential estimates on a state-by-state basis for the Federal Energy Regulatory Commission (FERC) in 2009. His report entitled, "Time-Varying and Dynamic Rate Design," was published by The Regulatory Assistance Project (RAP) in 2012.

Dr. Faruqui's survey of the early experiments with time-of-use pricing in the U.S. is referenced in Professor Bonbright's treatise on public utilities. He managed the integration of results across the top five of these experiments in what was the first meta-analysis involving innovative pricing. Two of his dynamic experiments have won professional awards, and he was named one of the world's Top 100 experts on the smart grid by Greentech Media.

He has consulted with more than 135 energy organizations around the globe and testified or appeared before 19 state and provincial commissions and legislative bodies in the United States and Canada. He has also advised the Alberta Utilities Commission, the Edison Electric Institute, the Electric Power Research Institute, FERC, the Institute for Electric Efficiency, the Ontario Energy Board, the Saudi Electricity and Co-Generation Regulatory Authority, and the World Bank. His research on the energy behavior of consumers has been cited in Business Week, The Economist, Forbes, National Geographic, The New York Times, Fortune, the San Francisco Chronicle, the San Jose Mercury News, the Wall Street Journal, The Times (London) and USA Today. He has appeared on Fox Business News, National Public Radio and Voice of America.

Dr. Faruqui is the author, co-author or co-editor of four books and more than 150 articles, papers, and reports on efficient energy use. He has published in peer-reviewed journals such as Energy Economics, Energy Journal, Energy Efficiency, and the Journal of Regulatory Economics and trade journals such as The Electricity Journal and the Public Utilities Fortnightly. He has taught economics at San Jose State University, the University of California at Davis and the University of Karachi. He holds a an M.A. in agricultural economics and a Ph. D. in economics from The University of California at Davis, where he was a Regents Fellow, and B.A. and M.A. degrees in economics from The University of Karachi, where he was awarded the Rashid Minhas Gold Medal in economics and the Government of Pakistan Overseas Scholarship.

AREAS OF EXPERTISE

- *Cost-benefit analysis of advanced metering infrastructure*. He has assessed the feasibility of introducing smart meters and other devices, such as programmable communicating thermostats that promote demand response, into the energy marketplace, in addition to new appliances, buildings, and industrial processes that improve energy efficiency.

- *Regulatory strategy.* He has helped design forward-looking programs and services that exploit recent advances in rate design and digital technologies in order to lower customer bills and improve utility earnings while lowering the carbon footprint and preserving system reliability.

- *Innovative pricing*. He has identified, designed and analyzed the efficiency and equity benefits of introducing innovative pricing designs such as dynamic pricing, time-of-use pricing and inclining block rates.

- *Demand forecasting and weather normalization*. He has pioneered the use of a wide variety of models for forecasting product demand in the near-, medium-, and long-term, using econometric, time series, and engineering methods. These models have been used to bid into energy procurement auctions, plan capacity additions, design customer-side programs, and weather normalize sales.

- *Customer choice*. He has developed methods for surveying customers in order to elicit their preferences for alternative energy products and alternative energy suppliers. These methods have been used to predict the market size of these products and to estimate the market share of specific suppliers.

- *Hedging, risk management, and market design*. He has helped design a wide range of financial products that help customers and utilities cope with the unique opportunities and challenges posed by a competitive market for electricity. He conducted a widely-cited market simulation to show that real-time pricing of electricity could have saved Californians millions of dollars during the Energy Crisis by lowering peak demands and prices in the wholesale market.

- *Competitive strategy*. He has helped clients develop and implement competitive marketing strategies by drawing on his knowledge of the energy needs of end-use customers, their values and decision-making practices, and their competitive options. He has helped companies reshape and transform their marketing organization and reposition themselves for a competitive marketplace. He has also helped government-owned entities in the developing world prepare for privatization by benchmarking their planning, retailing, and distribution processes against industry best practices, and suggesting improvements by specifying quantitative metrics and follow-up procedures.

- *Design and evaluation of marketing programs*. He has helped generate ideas for new products and services, identified successful design characteristics through customer surveys and focus groups, and test marketed new concepts through pilots and experiments.

- *Expert witness*. He has testified or appeared before state commissions in Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, Illinois, Indiana, Iowa, Kansas, Michigan, Maryland, Ontario (Canada) and Pennsylvania. He has assisted clients in submitting testimony in Georgia and Minnesota. He has made presentations to the California Energy Commission, the California Senate, the Congressional Office of Technology Assessment, the Kentucky Commission, the Minnesota Department of Commerce, the Minnesota Senate, the Missouri Public Service Commission, and the Electricity Pricing Collaborative in the state of Washington. In addition, he has led a variety of professional seminars and workshops on public utility economics around the world and taught economics at the university level.

EXPERIENCE

Smart Grid Strategy

- **Development of a smart grid investment roadmap for Vietnamese utilities.** For the five Vietnamese power corporations, developed a roadmap to guide future smart grid investment decisions. The report identified and described the various smart grid investment options, established objectives for smart grid deployment, presented a multi-phase approach to deploying the smart grid, and provided preliminary recommendations regarding the best investment opportunities. Also presented relevant case studies and an assessment of the current state of the Vietnamese power grid. The project involved in-country meetings as well as a stakeholder workshop that was conducted by Brattle staff.

- **Cost-Benefit Analysis of the Smart Grid: Rocky Mountain Utility.** Reviewed the leading studies on the economics of the smart grid and used the findings to assess the likely cost-effectiveness of deploying the smart grid in one geographical location.

- **Modeling benefits of smart grid deployment strategies.** Developed a model for assessing benefits of smart grid deployment strategies over a long-term (e.g., 20-year) forecast horizon. The model, called iGrid, is used to evaluate seven distinct smart grid programs and technologies (e.g., dynamic pricing, energy storage, PHEVs) against seven key metrics of value (e.g., avoided resource costs, improved reliability).

- **Smart grid strategy in Canada.** The Alberta Utilities Commission (AUC) was charged with responding to a Smart Grid Inquiry issued by the provincial government. Advised the AUC on the smart grid, and what impacts it might have in Alberta.
- **Smart grid deployment analysis for collaborative of utilities.** Adapted the iGrid modeling tool to meet the needs of a collaborative of utilities in the southern U.S. In addition to quantifying the benefits of smart grid programs and technologies (e.g., advanced metering infrastructure deployment and direct load control), the model was used to estimate the costs of installing and implementing each of the smart grid programs and technologies.
- **Development of a smart grid cost-benefit analysis framework.** For the Electric Power Research Institute (EPRI) and the U.S. DOE, contributed to the development of an approach for assessing the costs and benefits of the DOE's smart grid demonstration programs.
- **Analysis of the benefits of increased access to energy consumption information.** For a large technology firm, assessed market opportunities for providing customers with increased access to real time information regarding their energy consumption patterns. The analysis includes an assessment of deployments of information display technologies and analysis of the potential benefits that are created by deploying these technologies.
- **Developing a plan for integrated smart grid systems.** For a large California utility, helped to develop applications for funding for a project to demonstrate how an integrated smart grid system (including customer-facing technologies) would operate and provide benefits.

Innovative Pricing

- **Report examining the costs and benefits of dynamic pricing in the Australian energy market.** For the Australian Energy Market Commission (AEMC), developed a report that reviews the various forms of dynamic pricing, such as time-of-use pricing, critical peak pricing, peak time rebates, and real time pricing, for a variety of performance metrics including economic efficiency, equity, bill risk, revenue risk, and risk to vulnerable customers. It also discusses ways in which dynamic pricing can be rolled out in Australia to raise load factors and lower average energy costs for all consumers without harming vulnerable consumers, such as those with low incomes or medical conditions requiring the use of electricity.

- **Whitepaper on emerging issues in innovative pricing.** For the Regulatory Assistance Project (RAP), developed a whitepaper on emerging issues and best practices in innovative rate design and deployment. The paper includes an overview of AMI-enabled electricity pricing options, recommendations for designing the rates and conducting experimental pilots, an overview of recent pilots, full-deployment case studies, and a blueprint for rolling out innovative rate designs. The paper's audience is international regulators in regions that are exploring the potential benefits of smart metering and innovative pricing.
- **Assessing the full benefits of real-time pricing.** For two large Midwestern utilities, assessed and, where possible, quantified the potential benefits of the existing residential real-time pricing (RTP) rate offering. The analysis included not only "conventional" benefits such as avoided resource costs, but under the direction of the state regulator was expanded to include harder-to-quantify benefits such as improvements to national security and customer service.
- **Pricing and Technology Pilot Design and Impact Evaluation for Connecticut Light & Power (CL&P).** Designed the Plan-It Wise Energy pilot for all classes of customers and subsequently evaluated the Plan-It Wise Energy program (PWEP) in the summer of 2009. PWEP tested the impacts of CPP, PTR, and time of use (TOU) rates on the consumption behaviors of residential and small commercial and industrial customers.
- **Dynamic Pricing Pilot Design and Impact Evaluation: Baltimore Gas & Electric.** Designed and evaluated the Smart Energy Pricing (SEP) pilot, which ran for four years from 2008 to 2011. The pilot tested a variety of rate designs including critical peak pricing and peak time rebates on residential customer consumption patterns. In addition, the pilot tested the impacts of smart thermostats and the Energy Orb.
- **Impact Evaluation of a Residential Dynamic Pricing Experiment: Consumers Energy (Michigan).** Designed the pilot and carried out an impact evaluation with the purpose of measuring the impact of critical peak pricing (CPP) and peak time rebates (PTR) on residential customer consumption patterns. The pilot also tested the influence of switches that remotely adjust the duty cycle of central air conditioners.

- **Impact Simulation of Ameren Illinois Utilities' Power Smart Pricing Program.** Simulated the potential demand response of residential customers enrolled to real- time prices. Results of this simulation were presented to the Midwest ISO's Supply Adequacy Working Group (SAWG) to explore alternative ways of introducing price responsive demand in the region.
- **The Case for Dynamic Pricing: Demand Response Research Center.** Led a project involving the California Public Utilities Commission, the California Energy Commission, the state's three investor-owned utilities, and other stakeholders in the rate design process. Identified key issues and barriers associated with the development of time-based rates. Revisited the fundamental objectives of rate design, including efficiency and equity, with a special emphasis on meeting the state's strongly-articulated needs for demand response and energy efficiency. Developed a score-card for evaluating competing rate designs and applied it to a set of illustrative rates that were created for four customer classes using actual utility data. The work was reviewed by a national peer-review panel.
- **Developed a Customer Price Response Model: Consolidated Edison**. Specified, estimated, tested, and validated a large-scale model that analyzes the response of some 2,000 large commercial customers to rising steam prices. The model includes a module for analyzing conservation behavior, another module for forecasting fuel switching behavior, and a module for forecasting sales and peak demand
- **Design and Impact Evaluation of the Statewide Pricing Pilot: Three California Utilities.** Working with a consortium of California's three investor-owned utilities to design a statewide pricing pilot to test the efficacy of dynamic pricing options for mass-market customers. The pilot was designed using scientific principles of experimental design and measured changes in usage induced by dynamic pricing for over 2,500 residential and small commercial and industrial customers. The impact evaluation was carried out using state-of-the-art econometric models. Information from the pilot was used by all three utilities in their business cases for advanced metering infrastructure (AMI). The project was conducted through a public process involving the state's two regulatory commissions, the power agency, and several other parties.
- **Economics of Dynamic Pricing: Two California Utilities.** Reviewed a wide range of dynamic pricing options for mass-market customers. Conducted an initial cost-

effectiveness analysis and updated the analysis with new estimates of avoided costs and results from a survey of customers that yielded estimates of likely participation rates.

- **Economics of Time-of-Use Pricing: A Pacific Northwest Utility.** This utility ran the nation's largest time-of-use pricing pilot program. Assessed the cost-effectiveness of alternative pricing options from a variety of different perspectives. Options included a standard three-part time-of-use rate and a quasi-real time variant where the prices vary by day. Worked with the client in developing a regulatory strategy. Worked later with a collaborative to analyze the program's economics under a variety of scenarios of the market environment.

- **Economics of Dynamic Pricing Options for Mass Market Customers – Client: A Multi-State Utility.** Identified a variety of pricing options suited to meet the needs of mass-market customers, and assessed their cost-effectiveness. Options included standard three-part time-of-use rates, critical peak pricing, and extreme-day pricing. Developed plans for implementing a pilot program to obtain primary data on customer acceptance and load shifting potential. Worked with the client in developing a regulatory strategy.

- **Real-Time Pricing in California – Client: California Energy Commission.** Surveyed the national experience with real-time pricing of electricity, directed at large power customers. Identified lessons learned and reviewed the reasons why California was unable to implement real-time pricing. Catalogued the barriers to implementing real-time pricing in California, and developed a program of research for mitigating the impacts of these barriers.

- **Market-Based Pricing of Electricity – Client: A Large Southern Utility.** Reviewed pricing methodologies in a variety of competitive industries including airlines, beverages, and automobiles. Recommended a path that could be used to transition from a regulated utility environment to an open market environment featuring customer choice in both wholesale and retail markets. Held a series of seminars for senior management and their staffs on the new methodologies.

- **Tools for Electricity Pricing – Client: Consortium of Several U.S. and Foreign Utilities.** Developed Product Mix, a software package that uses modern finance theory and econometrics to establish a profit-maximizing menu of pricing products. The products range from the traditional fixed-price product to time-of-use prices to hourly real-time prices, and also include products that can hedge customers' risks based on financial derivatives. Outputs include market share, gross revenues, and profits by product and provider. The calculations are performed using probabilistic simulation, and results are provided as means and standard deviations. Additional results include delta and gamma parameters that can be used for corporate risk management. The software relies on a database of customer load response to various pricing options called StatsBank. This database was created by metering the hourly loads of about one thousand commercial and industrial customers in the United States and the United Kingdom.

- **Risk-Based Pricing – Client: Midwestern Utility.** Developed and tested new pricing products for this utility that allowed it to offer risk management services to its customers. One of the products dealt with weather risk; another one dealt with risk that real-time prices might peak on a day when the customer does not find it economically viable to cut back operations.

Demand Response

- **National Action Plan for Demand Response: Federal Energy Regulatory Commission.** Led a consulting team developing a national action plan for demand response (DR). The national action plan outlined the steps that need to be taken in order to maximize the amount of cost-effective DR that can be implemented. The final document was filed with U.S. Congress in June 2010.

- **National Assessment of Demand Response Potential: Federal Energy Regulatory Commission.** Led a team of consultants to assess the economic and achievable potential for demand response programs on a state-by-state basis. The assessment was filed with the U.S. Congress in 2009, as required by the Energy Independence and Security Act of 2007.

- **Evaluation of the Demand Response Benefits of Advanced Metering Infrastructure: Mid-Atlantic Utility.** Conducted a comprehensive assessment of the benefits of advanced metering infrastructure (AMI) by developing dynamic pricing rates that are enabled by AMI. The analysis focused on customers in the residential class and commercial and industrial customers under 600 kW load.

- **Estimation of Demand Response Impacts: Major California Utility.** Worked with the staff of this electric utility in designing dynamic pricing options for residential and small commercial and industrial customers. These options were designed to promote demand response during critical peak days. The analysis supported the utility's advanced metering infrastructure (AMI) filing with the California Public Utilities Commission. Subsequently, the commission unanimously approved a $1.7 billion plan for rolling out nine million electric and gas meters based in part on this project work.

Demand Forecasting

- **Comprehensive Review of Load Forecasting Methodology: PJM Interconnection.** Conducted a comprehensive review of models for forecasting peak demand and re-estimated new models to validate recommendations. Individual models were developed for 18 transmission zones as well as a model for the RTO system.
- **Analyzed Downward Trend: Western Utility.** We conducted a strategic review of why sales had been lower than forecast in a year when economic activity had been brisk. We developed a forecasting model for identifying what had caused the drop in sales and its results were used in an executive presentation to the utility's board of directors. We also developed a time series model for more accurately forecasting sales in the near term and this model is now being used for revenue forecasting and budgetary planning.
- **Analyzed Why Models are Under-Forecasting: Southwestern Utility.** Reviewed the entire suite of load forecasting models, including models for forecasting aggregate system peak demand, electricity consumption per customer by sector and the number of customers by sector. We ran a variety of forecasting experiments to assess both the ex-ante and ex-post accuracy of the models and made several recommendations to senior management.
- **U.S. Demand Forecast: Edison Electric Institute.** For the U.S. as a whole, we developed a base case forecast and several alternative case forecasts of electric energy consumption by end use and sector. We subsequently developed forecasts that were based on EPRI's system of end-use forecasting models. The project was done in close coordination with several utilities and some of the results were published in book form.
- **Developed Models for Forecasting Hourly Loads: Merchant Generation and Trading Company.** Using primary data on customer loads, weather conditions, and economic activity, developed models for forecasting hourly loads for residential, commercial, and industrial customers for three utilities in a Midwestern state. The information was used to develop bids into an auction for supplying basic generation services.
- **Gas Demand Forecasting System – Client: A Leading Gas Marketing and Trading Company, Texas.** Developed a system for gas nominations for a leading gas marketing company that operated in 23 local distribution company service areas. The system made

week-ahead and month-ahead forecasts using advanced forecasting methods. Its objective was to improve the marketing company's profitability by minimizing penalties associated with forecasting errors.

Demand Side Management

- **The Economics of Biofuels.** For a western utility that is facing stringent renewable portfolio standards and that is heavily dependent on imported fossil fuels, carried out a systematic assessment of the technical and economic ability of biofuels to replace fossil fuels.
- **Assessment of Demand-Side Management and Rate Design Options: Large Middle Eastern Electric Utility.** Prepared an assessment of demand-side management and rate design options for the four operating areas and six market segments. Quantified the potential gains in economic efficiency that would result from such options and identified high priority programs for pilot testing and implementation. Held workshops and seminars for senior management, managers, and staff to explain the methodology, data, results, and policy implications.
- **Likely Future Impact of Demand-Side Programs on Carbon Emissions – Client: The Keystone Center.** As part of the Keystone Dialogue on Climate Change, developed scenarios of future demand-side program impacts, and assessed the impact of these programs on carbon emissions. The analysis was carried out at the national level for the U.S. economy, and involved a bottom-up approach involving many different types of programs including dynamic pricing, energy efficiency, and traditional load management.
- **Sustaining Energy Efficiency Services in a Restructured Market – Client: Southern California Edison.** Helped in the development of a regulatory strategy for implementing energy efficiency strategies in a restructured marketplace. Identified the various players that are likely to operate in a competitive market, such as third-party energy service companies (ESCOS) and utility affiliates. Assessed their objectives, strengths, and weaknesses and recommended a strategy for the client's adoption. This strategy allowed the client to participate in the new market place, contribute to public policy objectives, and not lose market share to new entrants. This strategy has been embraced by a coalition of several organizations involved in the California PUC's working group on public purpose programs.

- **Organizational Assessments of Capability for Energy Efficiency – Client: U.S. Agency for International Development, Cairo, Egypt.** Conducted in-depth interviews with senior executives of several energy organizations, including utilities, government agencies, and ministries to determine their goals and capabilities for implementing programs to improve energy end-use efficiency in Egypt. The interviews probed the likely future role of these organizations in a privatized energy market, and were designed to help develop U.S. AID's future funding agenda.
- **Enhancing Profitability Through Energy Efficiency Services – Client: Jamaica Public Service Company.** Developed a plan for enhancing utility profitability by providing financial incentives to the client utility, and presented it for review and discussion to the utility's senior management and Jamaica's new Office of Utility Regulation. Developed regulatory procedures and legislative language to support the implementation of the plan. Conducted training sessions for the staff of the utility and the regulatory body.

Advanced Technology Assessment

- **Competitive Energy and Environmental Technologies – Clients: Consortium of clients, led by Southern California Edison, Included the Los Angeles Department of Water and Power and the California Energy Commission**. Developed a new approach to segmenting the market for electrotechnologies, relying on factors such as type of industry, type of process and end use application, and size of product. Developed a user-friendly system for assessing the competitiveness of a wide range of electric and gas-fired technologies in more than 100 four-digit SIC code manufacturing industries and 20 commercial businesses. The system includes a database on more than 200 end-use technologies, and a model of customer decision making.
- **Market Infrastructure of Energy Efficient Technologies – Client: EPRI.** Reviewed the market infrastructure of five key end-use technologies, and identified ways in which the infrastructure could be improved to increase the penetration of these technologies. Data was obtained through telephone interviews with equipment manufacturers, engineering firms, contractors, and end-use customers.

TESTIMONY

Arizona

Testimony before the Arizona Corporation Commission on behalf of Arizona Public Service Company, in the matter of the Application for UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of UNS Electric, Inc. Devoted to the its Operations Throughout the State of Arizona, and for Related Approvals, Docket No. E-04204A-15-0142, December 9, 2015.

California

Rebuttal Testimony before the Public Utilities Commission of the State of California, Pacific Gas and Electric Company Joint Utilities on Demand Elasticity and Conservation Impacts of Investor-Owned Utility Proposals, in the Matter of Rulemaking 12-06-013, October 17, 2014.

Testimony before the Public Utilities Commission of the State of California on behalf of Pacific Gas and Electric Company on rate relief, Docket No. A.10-03-014, summer 2010.

Testimony before the Public Utilities Commission of the State of California, on behalf of Southern California Edison, Edison SmartConnect™ Deployment Funding and Cost Recovery, exhibit SCE-4, July 31, 2007.

Testimony on behalf of the Pacific Gas & Electric Company, in its application for Automated Metering Infrastructure with the California Public Utilities Commission. Docket No. 05-06-028, 2006.

Colorado

Rebuttal Testimony before the Public Utilities Commission of the State of Colorado in the Matter of Advice Letter No. 1535 by Public Service Company of Colorado to Revise its Colorado PUC No.7 Electric Tariff to Reflect Revised Rates and Rate Schedules to be Effective on June 5, 2009. Docket No. 09al-299e, November 25, 2009.

Testimony before the Public Utilities Commission of the State of Colorado, on behalf of Public Service Company of Colorado, on the tariff sheets filed by Public Service Company of Colorado with advice letter No. 1535 – Electric. Docket No. 09S-__E, May 1, 2009.

Connecticut

Testimony before the Department of Public Utility Control, on behalf of the Connecticut Light and Power Company, in its application to implement Time-of-Use , Interruptible Load Response, and Seasonal Rates- Submittal of Metering and Rate Pilot Results- Compliance Order No. 4, Docket no. 05-10-03RE01, 2007.

District of Columbia

Testimony before the Public Service Commission of the District of Columbia on behalf of Potomac Electric Power Company in the matter of the Application of Potomac Electric Power Company for Authorization to Establish a Demand Side Management Surcharge and an Advance Metering Infrastructure Surcharge and to Establish a DSM Collaborative and an AMI Advisory Group, case no. 1056, May 2009.

Illinois

Testimony on rehearing before the Illinois Commerce Commission on behalf of Ameren Illinois Company, on the Smart Grid Advanced Metering Infrastructure Deployment Plan, Docket No. 12-0244, June 28, 2012.

Testimony before the State of Illinois – Illinois Commerce Commission on behalf of Commonwealth Edison Company regarding the evaluation of experimental residential real-time pricing program, 11-0546, April 2012.

Rebuttal Restimony before the Illinois Commerce Commission on behalf of Commonwealth Edison, on the Advanced Metering Infrastructure Pilot Program, ICC Docket No. 06-0617, October 30, 2006.

Indiana

Testimony before the State of Indiana, Indiana Utility Regulatory Commission, on behalf of Vectren South, on the smart grid. Cause no. 43810, 2009.

Kansas

Testimony before the State Corporation Commission of the State of Kansas, on behalf of Westar Energy, in the matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in Their Charges for Electric Service, Docket No. 15-WSEE-115-RTS, March 2, 2015.

Maryland

Testimony before the Maryland Public Service Commission, on behalf of Potomac Electric Power Company in the matter of the application of Potomac Electric Power Company for adjustments to its retail rates for the distribution of electric energy, April 19, 2016.

Rebuttal testimony, before the Maryland Public Service Commission, on behalf of Baltimore Gas and Electric Company in the matter of the application of Baltimore Gas and Electric Company for adjustments to its electric and gas base rates, Case No. 9406, March 4, 2016.

Testimony before the Public Service Commission of Maryland, on behalf of Potomac Electric Power Company and Delmarva Power and Light Company, on the deployment of Advanced Meter Infrastructure, Case no. 9207, September 2009.

Testimony before the Maryland Public Service Commission, on behalf of Baltimore Gas and Electric Company, on the findings of BGE's Smart Energy Pricing ("SEP") Pilot program. Case No. 9208, July 10, 2009.

Minnesota

Rebuttal Testimony before the Minnesota Public Utilities Commission State of Minnesota on behalf of Northern States Power Company, doing business as Xcel Energy, in the matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E002/GR-12-961, March 25, 2013.

Testimony before the Minnesota Public Utilities Commission State of Minnesota on behalf of Northern States Power Company, doing business as Xcel Energy, in the matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E002/GR-12-961, November 2, 2012.

Nevada

Rebuttal Testimony before the Public Utilities Commission of Nevada on behalf of Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy, in the matter of net metering and distributed generation cost of service and tariff design, Docket Nos. 15-07041 and 15-07042, November 3, 2015.

Testimony before the Public Utilities Commission of Nevada on behalf of Nevada Power Company d/b/a NV Energy, in the matter of the application for approval of a cost of service study and net metering tariffs, Docket No. 15-07, July 31, 2015.

New Mexico

Testimony before the New Mexico Regulation Commission on behalf of Public Service Company of New Mexico in the matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 507, Case No. 14-00332-UT, December 11, 2014.

Pennsylvania

Testimony before the Pennsylvania Public Utility Commission, on behalf of PECO on the Methodology Used to Derive Dynamic Pricing Rate Designs, Case No. M-2009-2123944, October 28, 2010.

Oklahoma

Rebuttal Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Oklahoma Gas and Electric Company for an order of the Commission authorizing applicant to modify its rates, charges and tariffs for retail electric service in Oklahoma, Cause No. PUD 201500273, April 11, 2016.

Direct Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Oklahoma Gas and Electric Company for an order of the Commission authorizing applicant to modify its rates, charges and tariffs for retail electric service in Oklahoma, Cause No. PUD 201500273, December 3, 2015.

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REGULATORY APPEARANCES

Arkansas

Presented before the Arkansas Public Service Commission, "The Emergence of Dynamic Pricing" at the workshop on the Smart Grid, Demand Response, and Automated Metering Infrastructure, Little Rock, Arkansas, September 30, 2009.

Delaware

Presented before the Delaware Public Service Commission, "The Demand Response Impacts of PHI's Dynamic Pricing Program" Delaware, September 5, 2007.

Kansas

Presented before the State Corporation Commission of the State of Kansas, "The Impact of Dynamic Pricing on Westar Energy" at the Smart Grid and Energy Storage Roundtable, Topeka, Kansas, September 18, 2009.

Ohio

Presented before the Ohio Public Utilities Commission, "Dynamic Pricing for Residential and Small C&I Customers" at the Technical Workshop, Columbus, Ohio, March 28, 2012.

Texas

Presented before the Public Utility Commission of Texas, "Direct Load Control of Residential Air Conditioners in Texas," at the PUCT Open Meeting, Austin, Texas, October 25, 2012.

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Presentations

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3. "A Conversation About Standby Rates," presented to Standby Rate Working Group, Michigan Public Service Commission, Lansing, Michigan, January 20, 2016.

4. "Imaging the Utility of the Future," presented to Commonwealth Edison Company, January 12, 2016.

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6. "Comments on the Straw Proposal on behalf of the California Water Association," presented at the CPUC Workshop on Balanced Rates Rulemaking (R.) 11-11-0008, San Francisco, October 13, 2015.

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11. "Currents of Change in the Design of Tariffs for Distribution Networks," presented at Energy Network Association: Energy Transformed, Sydney, Australia, May 7, 2015.

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13. "Time-Variant Pricing (TVP) in New York," presented at the Time-Variant Pricing Forum, NYU School of Law, New York, New York, March 31, 2015. http://www.sallan.org/Sallan_In-the-Media/2015/04/rev_agenda_time_variant_p.php

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16. "The Five Forces Shaping the Future of Demand Response (DR)," presented at the Demand Response Virtual Summit 2015, February 19, 2015.

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21. "Quantile Regression for Peak Demand Forecasting," with Charlie Gibbons, July 1, 2014.

22. "Strategies for Surviving Sub-One Percent Growth and the Emergence of the Energy Services Utility," presented at the 2014 UEC Summit, Coeur d'Alene, Idaho, June 24, 2014.

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24. "Surviving Sub-One Percent Sales Growth," presented at the ACC Workshop, Phoenix, Arizona, March 20, 2014.

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117. "The Residential Demand for Electricity by Time-of-Use: A survey of twelve experiments with peak load pricing," with J. Robert Malko, *Energy: The International Journal*, Volume 8, Issue 10, October 1983, pp. 781-795.

118. "Time-of-Use Rates and the Modification of Electric Utility Load Shapes," with J. Robert Malko, *Challenges for Public Utility Regulation in the 1980s*, edited by H.M. Trebing, Michigan State University Public Utilities Papers, 1981.

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120. "Incorporating the Social Imperatives in Economic Structure: Pakistan in the years ahead," *The Journal of Economic Studies*, Volume 1, No. 1, Autumn 1974.

Exhibit AF-2 – Citations to Relevant Studies

Full citations for the pilots referred to in "Figure 1: Residential Peak Demand Reductions from Behavioral Demand Response Programs" are listed below.

Utility	Citation
Consumers Energy (2014)	Brandon, Alec, John List, Robert Metcalfe, and Michael Price. *The Impact of the 2014 Opower Summer Behavioral Demand Response Campaigns on Peak-Time Energy Consumption.* University of Chicago/University of Georgia (June 28, 2014): 4.
Hydro Ottawa	DNV-GL. *Hydro Ottawa Behavioral Demand Response Program Impact Evaluation.* (December 23, 2015): 4.
Glendale Water & Power	Brandon, Alec, John List, Robert Metcalfe, and Michael Price. *The Impact of the 2014 Opower Summer Behavioral Demand Response Campaigns on Peak-Time Energy Consumption.* University of Chicago/University of Georgia (June 28, 2014): 4.
Efficiency Vermont	Brandon, Alec, John List, Robert Metcalfe, and Michael Price. *The Impact of the 2014 Opower Summer Behavioral Demand Response Campaigns on Peak-Time Energy Consumption.* University of Chicago/University of Georgia (June 28, 2014): 4.
Sioux Valley Energy	Sioux Valley Energy and Power System Engineering, Inc. *EmPOWER Critical Peak Pricing Pilot Assessment* (March 2, 2012): 18.
Green Mountain Power	Blumsack, Seth and Paul Hines. *Load Impact Analysis of Green Mountain Power Critical Peak Events, 2012 and 2013.* Pennsylvania State University and University of Vermont (March 5, 2015): 4.
Consumers Energy (2010)	Faruqui, Ahmad, Sanem Sergici, and Lamine Akaba. *Consumers Energy's Personal Power Plan Pilot.* The Brattle Group (December 2, 2010): 67.

Full citations for the AMI applications and reports that quantify UFE are listed below.

Utility	Citation
Ameren Illinois	Ameren Illinois. *Advanced Metering Infrastructure (AMI) – Cost/Benefit Analysis.* (June 2012): 24.
Baltimore Gas & Electric	*Direct Testimony of Michael B. Butts on behalf of Baltimore Gas & Electric.* Maryland Public Service Commission – Case No. 9406 (November 6, 2015): 43-44.
BC Hydro	BC Hydro. *Smart Metering & Infrastructure Program Business Case.* 27.
Commonwealth Edison	Black & Veatch, for Commonwealth Edison Company. *Advanced Metering Infrastructure (AMI) Evaluation – Final Report.* (July 2011): 115-117.
Consolidated Edison	Consolidated Edison Company of New York, Inc. *Advanced Metering Infrastructure Business Plan.* (November 16, 2015): 51 and 58.
Duke Energy Ohio	MetaVu. *Duke Energy Ohio Smart Grid Audit and Assessment.* Prepared for The Staff of the Public Utilities Commission of Ohio. (June 30, 2011): 71.
Hawaiian Utilities	Hawaiian Electric Company, Inc., Hawai'i Electric Light Company, Inc., and Maui Electric Company, Limited. Application in Public Utilities Commission of the State of Hawai'i – Docket No. 2016-0087 (March 31, 2016): Exhibit B, p. 69.
Public Service Company of Oklahoma	Supplemental Rebuttal Testimony of Derek S. Lewellen on behalf of Public Service Company of Oklahoma. Corporate Commission of Oklahoma – Case No. PUD 201300217 (July 15, 2014): Exhibit DSL-SR1, p. 1.

Exhibit AF-3 – Summary of AMI Opt-out Rates and Fees

Data for Figure 2: Opt-out Rates and Fees from Selected Utilities with Publically Available Opt-out Data

	Utility	Opt-out Rate	Up-front Fee	Monthly Fee	Levelized Monthly Fee
		[A]	[B]	[C]	[D]
[1]	Pacific Gas & Electric	0.95%	$75.00	$10.00	$11.25
[2]	Southern California Edison	0.45%	$75.00	$10.00	$11.25
[3]	NV Energy	0.31%	$52.86	$8.82	$9.70
[4]	DTE Electric Company	0.31%	$67.20	$9.80	$10.92
[5]	San Diego Gas & Electric	0.19%	$75.00	$10.00	$11.25
[6]	Florida Power & Light	0.13%	$89.00	$13.00	$14.48
[7]	Georgia Power	0.02%	$0.00	$19.00	$19.00
[8]	AEP Texas	0.01%	$153.75	$19.00	$21.56
[9]	Oncor	0.01%	$179.83	$26.69	$29.69
[10]	CenterPoint	0.00%	$159.25	$32.80	$35.45

Sources and Notes:

[A]: Calculated as the number of customers who chose to opt-out ÷ total customers. Source for number of customers who opt-out are listed below. Total customers data from EIA Form 826 (December 2015), "Sales & Revenue". For [8]-[10], total meter counts from the "Advanced Metering" section are used instead (customer count data is not available in the "Sales & Revenue" database for those Texas distribution utilities because they do not directly serve retail customers).

[D]: Levelized monthly fee includes monthly fee plus up-front fee levelized over 5 years (60 months).

[1A]: *California Smart Grid – Annual Report to the Governor and the Legislature, in Compliance with Public Utilities Code 913.2.* California Public Utilities Commission (January 1, 2016): 17.

[1B]–[1C]: Electric Schedule E-SOP – Residential Electric SmartMeter (TM) Opt-Out Program. Pacific Gas & Electric. Effective January 1, 2015. Cal. PUC Sheet No. 35105-E.

[2A]: *California Smart Grid – Annual Report to the Governor and the Legislature, in Compliance with Public Utilities Code 913.2.* California Public Utilities Commission (January 1, 2016): 17.

[2B]–[2C]: Schedule ESC-OO – Edison SmartConnect Opt-out. Southern California Edison Company. Effective February 6, 2015. Cal. PUC Sheet No. 56208-E.

[3A]: Prepared Direct Testimony of Gary P. Smith on behalf of Nevada Power Company. Nevada Public Utilities Commission – Docket No. 14-050004 (May 2, 2014): footnote 6, p. 17.

[3B]–[3C]: Schedule NSMO-1 – Non-Standard Metering Option Rider, Residential Service. Nevada Power Company. Effective March 14, 2014. PUCN Sheet No. 11B.

[4A]: *Direct Testimony of Robert Sitkauskas on behalf of DTE Electric Company.* Michigan Public Service Commission – Case No. U-18014 (February 1, 2016): RES-19.

[4B]–[4C]: Rate Book for Electric Service – Non-Transmitting Meter Provision (Residential Only). DTE Electric Company. Effective May 15, 2013. Sheet No. C-24.01.

[5A]: *California Smart Grid – Annual Report to the Governor and the Legislature, in Compliance with Public Utilities Code 913.2.* California Public Utilities Commission (January 1, 2016): 17.

[5B]–[5C]: Rate Schedule E-SMOP – Residential Electric Smart Meter Opt-Out Program. San Diego Gas & Electric Company. Effective March 6, 2015. Cal. PUC Sheet No. 26151-E.

[6A]: *Smart Meter Progress Report.* Florida Power & Light Company. Florida Public Service Commission – Docket 16-0002-EG. (February 29, 2016): 4.

[6B]–[6C]: Rate Schedule – Non-Standard Meter Rider. Florida Power & Light. Effective January 2, 2015. Sheet No. 8.120.

[7A]: Landers. 'For a price, Georgia Power customers can opt out of smart meters'. Savannah Morning News. January 22, 2014. Last accessed July 15, 2016.

[7B]–[7C]: Electric Service Tariff – AMI Meter Opt Out Schedule. Georgia Power. Effective March 2014. Page No. 10.80.

[8A]: *AEP Texas Central Company and AEP Texas North Company Compliance Report.* Public Utility Commission of Texas – Docket No. 44129. July 7, 2016.

[8B]–[8C]: Tariff for Electric Delivery Service, Schedule 6.1.2 Discretionary Charges – Non-Standard Meter Installation Charges. AEP Texas Central Company and AEP Texas North Company. Effective July 7, 2014.
The values shown are for AEP Texas Central Company. The values for AEP Texas North Company are of similar magnitude but slightly higher.

[9A]: *Compliance Report of Oncor Electric Delivery Company LLC.* Public Utility Commission of Texas – Docket No. 44129. July 15, 2016.

[9B]–[9C]: Tariff for Retail Delivery Service, Schedule 6.1.2 Discretionary Charges, July 17, 2014. Sheet 1.
Oncor appears to charge different opt-out fees to customers with a standard (non-AMS) meter who choose not to have an AMS meter installed, and those who have already received an AMS meter and want to revert to a standard meter. The fees shown are for customers without an AMS meter.

[10A]: *CenterPoint Energy Houston Electric, LLC Compliance Report.* Public Utility Commission of Texas – Docket No. 44129. January 7, 2016.

[10B]–[10C]: Rate Schedule 6.1.2 Discretionary Charges – Non-Standard Meter Installation Charges. CenterPoint Energy, Inc. Effective July 7, 2014. Sheet No. 6.15.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO DEPLOY ADVANCED METERING INFRASTRUCTURE, REQUEST FOR COST RECOVERY AND RELATED RELIEF	)))))))	**DOCKET NO. UD-16-__**

DIRECT TESTIMONY

OF

ORLANDO TODD

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

OCTOBER 2016

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, TITLE AND CURRENT BUSINESS ADDRESS.

A. My name is Orlando Todd. My business address is 1600 Perdido Street, New Orleans, Louisiana 70112.

Q2. WHAT ARE YOUR CURRENT DUTIES?

A. I am employed by Entergy Services, Inc. ("ESI"),[1] as Finance Director for Entergy New Orleans, Inc. ("ENO" or the "Company"). In that capacity, I am responsible for financial management, financial planning and monitoring, and assisting in the resolution of regulatory issues for ENO.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying in this proceeding before the Council of the City of New Orleans ("CNO" or the "Council") on behalf of ENO.

Q4. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a B.B.A. in Accounting from Southern Arkansas University and an M.B.A. from the University of Arkansas - Little Rock. I am a Certified Public Accountant. I began my career with Entergy Corporation and its subsidiaries in 1983. I started in Property

[1] ESI is a subsidiary of Entergy Corporation that provides technical and administrative services to all of the Operating Companies. The Entergy Operating Companies include Entergy Arkansas, Inc.; Entergy Louisiana, LLC ("ELL"); Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc.

Accounting and have worked in other departments, including General Accounting, Finance Operations Center, and Corporate Reporting. Prior to my career with the Entergy System, I worked for Price Waterhouse (now known as PricewaterhouseCoopers).

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The Company's Application seeks approval of its plan to deploy Advanced Metering Infrastructure ("AMI" or the "Project") within ENO's service area for both its electric and gas customers. I support the Company's proposal to reflect the costs and benefits of the Project in electric and gas customer rates, which proposal I refer to as the AMI Rate Plan. As part of the AMI Rate Plan, the Company requests deferral of AMI customer education and incremental AMI Ongoing O&M expenses incurred in 2017 and 2018, and recovery of AMI costs, net of certain quantified benefits, through a customer charge phased in over the period 2019 through 2022.

Q6. PLEASE GENERALLY DESCRIBE THE AMI RATE PLAN.

A. As Company witnesses Jay A. Lewis and Dennis P. Dawsey explain in their Direct Testimony, collectively, AMI will bring substantial benefits to ENO's electric and gas customers: approximately $27 million[2] over the 15-year useful life of the assets. Those benefits, however, cannot be achieved without a cost. As shown in the workpapers to HSPM Exhibit JAL-2 and Table 1 below, ENO is expected to invest roughly $62 million

[2] This amount represents the present value of those benefits ($2016).

in electric plant and approximately $13 million in gas plant over the course of four years to achieve those customer benefits.[3]

Table 1. Estimated Annual AMI Electric and Gas Plant Closings 2018-2021 ($000's)				
	2018	**2019**	**2020**	**2021**
Estimated Annual AMI Electric Plant in Service Closings	$23,213	$7,720	$18,324	$12,450
Estimated Cumulative Electric Plant in Service Closings	$23,213	$30,933	$49,257	$61,707
Estimated Annual AMI Gas Plant in Service Closings	$1,043	$4,534	$6,193	$1,126
Estimated Cumulative Gas Plant in Service Closings	$1,043	$5,577	$11,770	$12,896

This represents a substantial investment for ENO, as the AMI investment from 2019-2021 represents an average increase of approximately 25% over ENO's annual baseline distribution capital investment budget for electric operations for the period 2016-2018.[4] Further, these investments are in addition to the significant other investments the Company has recently made and is currently planning to make through 2018 for the benefit of its customers (*e.g.*, Union Power Block 1 ($237 million), Ninemile Unit 6 Power Purchase Agreement (approximately $18 million annual revenue requirement)).

[3] There is a small amount of capital spending assumed in the first quarter of 2022 for any remaining communications optimization once the full meter deployment is complete in 2021. This amount is included in the totals reflected in Company witnesses, Jay Lewis' and Rodney W. Griffith's testimony and exhibits.

[4] The referenced percentages are based on ENO's planned construction and other capital investments for the period 2016-2018. Form 10-K for the Fiscal Year Ended December 31, 2015 for Entergy Corporation and its six registrant subsidiaries, at 388.

All of these projects, like the combined electric and gas AMI deployment, provide net benefits to customers, but require an up-front investment by the Company.

Because of the significant overall investment required to implement AMI – and the resulting benefit to customers as the Project is deployed – the Company is requesting the implementation of a charge calculated on a per-customer basis that would recover the costs of the AMI deployment in rates roughly contemporaneously with the assets being placed in service and providing customer benefits. This charge, which I refer to as the "AMI Customer Charge," would be charged to all metered ENO customers.

Later in my testimony, I summarize the categories of costs that ENO anticipates will be incurred and the benefits ENO expects will be realized from the AMI deployment, and I explain how the vast majority of those categories of costs and benefits would factor into the incremental annual revenue requirement that should ultimately be reflected in rates following the Combined Rate Case[5], either through the proposed AMI customer charge or through ENO's monthly Fuel Adjustment Clause ("FAC") or monthly Purchased Gas Adjustment ("PGA").

5 The Agreement in Principle approved by the Council in Docket UD-14-02 requires that ENO submit a filing demonstrating its cost to provide electric and gas service to both Legacy ENO Customers and customers located in the Fifteenth Ward of the City of New Orleans no earlier than the first quarter than 2018, based on calendar year 2017, *i.e.,* the "Combined Rate Case."

Q7. PLEASE SUMMARIZE THE CATEGORIES OF BENEFITS THAT WILL BE REFLECTED AS PART OF THE COMPANY'S PROPOSED AMI RATE PLAN.

A. Mr. Lewis, Mr. Dawsey, and Ms. Bourg describe, in detail, the many benefits to customers associated with AMI. Mr. Lewis identifies those benefits that have been quantified for purposes of his cost/benefit analysis and describes them in two groups:

(1) Operational Benefits, which include (a) reduction in routine meter reading expense; (b) reduction in meter services expense; and (c) reduced customer receivable write-offs resulting in reduced bad debt expense; and

(2) Other Benefits, which include (a) consumption reduction; (b) peak capacity reduction; (c) unaccounted for energy ("UFE") reduction; and (d) avoiding future costs associated with the need to maintain and replace existing meter reading equipment.

Q8. PLEASE PROVIDE A SUMMARY OF THE CATEGORIES OF COSTS THE COMPANY EXPECTS TO INCUR IN DEPLOYING AMI.

A, Mr. Griffith and Ms. Bourg explain the underlying categories of costs that will be incurred to obtain the benefits of AMI, which I discuss within three different groupings for ratemaking purposes:

(1) AMI Implementation Costs, which for purposes of my testimony include: the costs to design, test, and deploy AMI, and which will be recovered through the depreciation expense associated with those investments (*i.e.*, the return of); the Company's authorized return on its AMI capital investments (*i.e.*, the return on); and the property tax expense incurred as a result of those investments.

(2) Customer Education Expense incurred to provide the Customer Education Plan described by Mr. Dawsey, which is designed to inform electric and gas customers of the capabilities of their advanced meters and how to use those capabilities to reduce their energy bills.

(3) Ongoing AMI O&M Expense, which is the expense associated with operating and maintaining AMI after it is implemented.

II. AMI CUSTOMER CHARGE IMPLEMENTATION

Q9. AT THE OUTSET OF YOUR TESTIMONY, YOU INDICATED THAT THE COMPANY IS PROPOSING TO RECOVER THE COSTS OF AMI THROUGH A CUSTOMER CHARGE PHASED IN OVER THE PERIOD 2019 THROUGH 2022. WHY IS A PHASED-IN AMI CUSTOMER CHARGE APPROPRIATE?

A. The Company is proposing this phased-in approach because, although the AMI Project is similar to other large capital projects in many ways, it is also different in terms of the accrual of operational savings and ratemaking. Unlike many large projects, such as the recent construction of Ninemile Unit 6 and acquisition of Power Block 1 of the Union Power Station, the AMI project involves assets that will be closed to plant in service on a rolling basis, with the resulting benefits from the investment in those assets progressively accruing during the course of deployment through 2021. As described by Mr. Lewis, the quantified collective AMI benefits for electric and gas operations, over time, outweigh its costs. Under the Company's phased-in approach, during a three-year meter deployment period, those benefits will be reflected in rates as the benefits occur, whether through the

Company's monthly FAC or monthly PGA and or through its base rate mechanism(s), such as a customer charge and Formula Rate Plan ("FRP") rider.[6]

As Mr. Griffith explains in his Direct Testimony, the Company expects to complete and place into service the IT infrastructure necessary to support the advanced meters by the end of 2018. Based on the preliminary deployment schedule, the remaining components of the communications network and the advanced meters themselves are expected to then be installed over a three-year period from 2019-2021. These components of the communications network and the advanced meters will be closed to plant and placed in service on a continuous basis during this three-year deployment period. And the customer benefits described by Mr. Lewis will be realized during this same three-year period, increasing as the number of deployed advanced meters increases. The Company's proposal to recover AMI through an AMI Customer Charge will provide for a better matching of costs with benefits that will be realized by customers and a reasonable opportunity for ENO to fully recover its costs and earn its authorized return contemporaneously with customers' realization of AMI benefits.

Also, the Council has previously recognized that investments of this magnitude warrant recovery outside of the traditional base rate mechanisms. For example, the Council recently approved recovery for the Company's investment to acquire Power Block 1 of the Union Power Station. Some of the principles underlying recovery in those instances (*e.g.*, significant investment outside of normal operations and better matching of

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[6] ENO anticipates requesting the implementation of a FRP and has assumed implementation of an FRP in the results of its AMI Rate Plan reflected in this testimony.

costs of a multi-year project with benefits realized over time) apply to the Company's combined $75 million AMI investment.

Finally, the AMI costs that would be recovered through the AMI Customer Charge represent a roughly fixed, non-variable cost to the Company. As such, a per-customer charge represents a just and reasonable way to recover those costs.[7]

Q10. WOULD THIS PHASED-IN APPROACH HAVE THE EFFECT OF CHARGING SOME CUSTOMERS FOR AMI BEFORE THEY RECEIVE AN ADVANCED METER AT THEIR LOCATION?

A. Yes, but all customers will be receiving the benefits of AMI during deployment, which benefits will grow as each advanced meter is placed in service. The AMI Rate Plan calls for implementation of the initial AMI Customer Charge in 2019, as a result of the 2018 Combined Rate Case. At that time, some, but not all, customers will have an advanced meter. But, as I describe in more detail later, all customer rates will reflect the Operational and Other Benefits that arise from the deployed AMI. The Company proposes that those rates also reflect the AMI Customer Charge during this time.

Q11. IS THERE AN ALTERNATIVE TO IMPLEMENTING A PER-CUSTOMER CHARGE PRIOR TO FULL AMI DEPLOYMENT?

A. Yes. One alternative to implementing the AMI Customer Charge as described herein is for the Company to defer recovery of the capital costs and expenses associated with the

[7] Class allocation of the per-meter charge could be finally determined in connection with the Combined Rate Case.

AMI deployment for the three-year meter deployment period, until full AMI deployment is completed. This would require a Council order authorizing a deferral so that the Company could record a regulatory asset for future recovery through a final customer charge. Deferring the recovery of all AMI costs until all costs are incurred would result in a one-time rate increase for customers at the end of full AMI deployment, a charge that, all else equal, would be higher than the cumulative effect of that proposed by the Company due to the accrual of carrying charges. Moreover, customers would be receiving the Operational and quantified Other Benefits without bearing the costs of deploying AMI.

The Company's proposal, on the other hand, would allow gradual reflection of the AMI costs in customer rates while the AMI benefits are likewise progressively reflected in those rates. This proposal would provide greater rate stability during the AMI deployment, better match the benefits and costs of AMI, and ultimately lead to a lower cost for customers than deferring the costs for the full three-year implementation cycle.

Q12. PLEASE EXPLAIN IN DETAIL HOW THE AMI COSTS AND BENEFITS WOULD BE REFLECTED IN RATES CHARGED TO CUSTOMERS?

A. It is anticipated that rates resulting from the 2018 Combined Rate Case will be implemented for the first billing cycle of August 2019, and implementation of the initial AMI Customer Charge would be part of the rate design of those rates. The initial AMI Customer Charge would reflect a *pro forma* adjustment to the Period II (2018) Combined Rate Case test year for known and measurable changes related to AMI. Those known and measurable changes would include 1) return on and of the capital in service as of

December 31, 2019 (consisting of those capital costs directly incurred by ENO, as well as those components of AMI such as the IT systems and project support that are shared by all of the Entergy Operating Companies and allocated based on each Operating Company's total number of customers) and related Property Tax Expense;[8] 2) the Customer Education Expense for 2019; 3) the Ongoing AMI O&M Expense for 2019; and 4) an offset for Operational Benefits expected to be realized in 2019. The AMI Customer Charge would be adjusted in January 2020 and January 2021 to reflect the estimated changes in these components for the 2020 and 2021 calendar years, respectively. The 2020 and 2021 AMI Customer Charge calculations would also include the full amortization of the deferred 2017 and 2018 Customer Education and Ongoing O&M over those two years.

The January implementation of the re-determined AMI Customer Charge will follow October 1, 2019 and October 1, 2020 filings that contain the estimated costs and estimated benefits to be included in the AMI Customer Charge. The October 1 filing date would allow the Council and its utility Advisors time to review the components of the annual AMI Customer Charge that would be implemented in January of 2020 and 2021.

The final Customer Charge would be implemented in May 2022 following a similar filing in April 2022. The final AMI Customer Charge will reflect the first full year of revenue requirement following the completion of the deployment of AMI meters in December 2021. All costs included in the AMI Customer Charge would be subject to the

[8] As Mr. Lewis describes in his Direct Testimony, these components include the cost of the communications network design and the head-end component of the communications network, the Meter Data Management System, the Distribution Management System and Outage Management System, certain software licensing costs, the costs related to the meter testing facility, as well as the overall system integration and project support, the cost of which are assigned based on the total number of customers located in each Operating Company's jurisdiction.

Council's review to ensure they were prudently-incurred, and any changes ordered by the Council would be reflected in a true-up included in the final AMI Customer Charge.

Table 2 below summarizes the components to be included in the annually re-determined AMI Customer Charge for the years 2019-2022:

Table 2. Costs Included in Monthly AMI Customer Charge, 2019-2022

	Initial 2019 AMI Customer Charge	2020 AMI Customer Charge	2021 AMI Customer Charge	Final (2022) AMI Customer Charge
Filing Date	2018 Combined Rate Case	October 1, 2019	October 1, 2020	April 1, 2022
Estimated Implementation Date	August 2019	January 2020	January 2021	May 2022
AMI Implementation Costs	Based on estimated capital closed to plant at end of 2019	Based on estimated capital closed to plant at end of 2020	Based on estimated capital closed to plant at end of 2021	Based on capital closed to plant at end of 2021
Ongoing AMI O&M Expense	Based on estimated 2019 expense offset by 2019 estimated Operational Benefits	Based on estimated 2020 expense offset by 2020 estimated Operational Benefits, including deferred 2017 & 2018 amortization	Based on estimated 2021 expense offset by 2021 estimated Operational Benefits, including deferred 2017 & 2018 amortization	Based on estimated 2022 expense offset by 2022 estimated Operational Benefits
Customer Education Expense	Based on estimated 2019 expenses	Based on estimated 2020 expenses, including deferred 2017 & 2018 amortization	Based on estimated 2021 expenses, including deferred 2017 & 2018 amortization	None

Q13. WHAT AMI COSTS AND BENEFITS WOULD NOT BE INCLUDED IN THE AMI CUSTOMER CHARGE?

A. The AMI Customer Charge would not reflect the quantified Other Benefits of AMI. The Other Benefits, as described by Mr. Lewis, result from a reduction to costs currently reflected in the Company's standard rate mechanisms, the FAC for electric operations, the

PGA for gas operations, and a FRP that has been assumed for both electric and gas operations. Those reductions would therefore be reflected in these same mechanisms (or other rate mechanisms in place at the time) along with the actual benefits realized from several other non-quantified benefits described by Mr. Dawsey and Ms. Bourg. The actual AMI Implementation Costs, Ongoing AMI O&M Expense, and Operational Benefits would be reflected in the assumed annual FRP Evaluation Report, with appropriate adjustments to reflect the estimated costs and savings levels included in the annual AMI Customer Charge. As explained later in my testimony, the FRP adjustment would serve as a prospective "true-up" to actual costs incurred and benefits realized.

The Operational Benefits of AMI are largely driven by the reduction in O&M expense associated with routine meter reading and meter services. As Mr. Lewis's cost/benefit analysis shows, however, there is an Ongoing AMI O&M Expense, which is estimated by Mr. Griffith. During the three-year advanced meter deployment, the net effect of these two items will vary. It is anticipated that during the first two years of the electric meter deployment (2019 and 2020), and the first year of the gas meter deployment, the Ongoing AMI O&M Expense will exceed the Operational Benefits, resulting in a net increase in O&M expense. The net effects of these items are not subject to precise quantification during the three-year transition period from initial AMI deployment to full AMI deployment. However, the implementation of the AMI Customer Charge working in tandem with the assumed FRP would result in customers being charged just and reasonable rates resulting from the AMI deployment. Later in my testimony, I explain that the AMI Customer Charge can be implemented in the absence of a FRP rider.

Q14. HAS THE COMPANY ESTIMATED THE NET EFFECT OF THE OPERATIONAL BENEFITS AND THE ONGOING AMI O&M EXPENSE?

A. Yes. In the first year after full AMI deployment (2022), it is expected that the Operational Benefits from the electric AMI deployment will exceed the Ongoing AMI O&M Expense by approximately $2.9 million; for gas customers the Operational Benefits will exceed Ongoing AMI O&M Expense by approximately $1 million. The Company has estimated the annual difference between Ongoing AMI O&M Expense and Operational Benefits as reflected in Tables 3 and 4 below:

Table 3. Estimated Electric Operational Benefits and Ongoing AMI O&M Expense for Years 2018-2022 ($000s)

	2018	**2019**	**2020**	**2021**	**2022**
Ongoing AMI O&M Expense	$ 136[9]	$ 595	$ 826	$ 1,163	$ 1,328
Operational Benefits	$0	$ 239	$ 1,545	$ 3,386	$ 4,195
Net O&M	$ 136	$ 356	($719)	($2,223)	($2,867)

9 ENO requests deferral of this amount along with the 2017 amount of $0.089 million.

Table 4. Estimated Gas Operational Benefits and Ongoing AMI O&M Expense for Years 2018-2022 ($000s)

	2018	2019	2020	2021	2022
Ongoing AMI O&M Expense	$ 1[10]	$ 68	$ 220	$ 340	$ 368
Operational Benefits		$ 233	$ 870	$ 1,331	$ 1,411
Net O&M	$ 1	($ 165)	($ 650)	($ 991)	($ 1,043)

Q15. HOW WOULD THE AMI CUSTOMER CHARGE – AND THE ITEMS IT INCLUDES – BE REFLECTED IN ENO'S FRPS?

A. The costs included in the AMI Customer Charge will be included in the revenue requirement calculated in the FRPs. Likewise, the revenue collected as part of the AMI Customer Charge will be included in the Present Rate Revenues calculated in the FRPs. As such, the annual FRP evaluation will ensure that prospective rates reflect the actual full test year costs incurred and benefits realized and related revenues.

Q16. HAVE YOU CALCULATED THE ESTIMATED MONTLY AMI CUSTOMER CHARGE FOR ELECTRIC AND GAS OPERATIONS?

A. Yes, ENO has performed an illustrative calculation. Actuals will vary based on changes in the components, *e.g.*, estimated costs, benefits, class allocation, final rate design, cost of capital, *etc*. Table 5 provides the results of those illustrative calculations:

[10] ENO deferral of this amount.

Table 5. Estimated Monthly Per-Customer AMI Customer Charge, 2019 – 2022

	August 2019	January 2020	January 2021	May 2022
Electric	$2.31	$3.33	$3.57	$3.23
Gas	$0.48	$0.99	$0.98	$0.95

Q17. WILL THERE BE ANY FURTHER INCREASES TO THE AMI CUSTOMER CHARGE AFTER MAY 2022?

A. No. The final AMI Customer Charge implemented in May 2022 will remain in effect until rates are reset.

Q18. PLEASE DESCRIBE IN GREATER DETAIL THE COMPONENTS OF THE AMI CUSTOMER CHARGE?

A. The first component, the AMI Implementation Costs, includes the return of and on plant in service along with the property tax expense incurred as a result of those investments. For each year that the AMI Customer Charge is calculated, the Company will include the known and measurable depreciation expense and property tax expense based on the assets expected to be placed in service as of the calendar year-end. For example, the initial AMI Customer Charge implemented in August 2019 will include the depreciation expense calculated for those assets placed in service through December 2019. The depreciation expense will be based on a depreciation rate of 6.67%, which represents the 15-year useful life described by Mr. Lewis as the reasonably-estimated useful life of the AMI assets, and is consistent with the depreciation rates used by other utilities deploying similar AMI technology. The property tax included in 2019 will be calculated on the 2018 ending net plant balance.

The return on the AMI rate base will be based on the rate base in service as of the calendar year-end. This amount will then be offset by the corresponding accumulated reserve for depreciation balance for the same period. Then, this amount will be further reduced by the cash-tax benefit resulting from accelerated depreciation on the AMI assets, which would be recognized as accumulated deferred income taxes ("ADIT"). The resulting rate base amount is then multiplied by the pretax rate of return authorized in the Combined Rate Case to determine the return on AMI rate base. An illustration of the calculation of the AMI Customer Charge is presented in Highly Sensitive Exhibits OT-1 (electric) and OT-2 (gas). The illustrative calculation is based on a pretax rate of return that reflects the capitalization ratios and cost rates of capital as of December 31, 2015. The actual annual AMI Customer Charge ultimately reflected in rates will use the pretax rate of return based on the capitalization ratios and cost rates of capital for the year last approved by the Council.

Q19. THE ILLUSTRATIVE CALCULATION OF THE AMI CUSTOMER CHARGE USES THE ESTIMATED AMI CAPITAL COSTS PRESENTED BY MR. GRIFFITH. WILL THIS BE THE AMOUNT ACTUALLY REFLECTED IN RATES WHEN THE CUSTOMER CHARGE IS IMPLEMENTED?

A. No, unless the estimated and actual capital costs match precisely. This is because for purposes of the calculation presented in Highly Sensitive Exhibits OT-1 and OT-2, I am using the estimate of capital costs presented by Mr. Griffith, which reflects the estimated

AMI deployment timing, including contingency to account for project risks. But when the AMI Customer Charge is calculated for implementation, the Company will use the actual, prudently-incurred costs of AMI placed in service as of the relevant date, as well as the then-projected estimate of the plant to be placed in service for that year. The 2022 final AMI Customer Charge calculation will use only the actual, prudently-incurred capital costs of AMI, which may be higher or lower than the amount estimated by Mr. Griffith.

Q20. PLEASE FURTHER DESCRIBE THE SECOND COMPONENT OF THE AMI CUSTOMER CHARGE.

A. The second component of the AMI Customer Charge is the Customer Education Expense, which is the expense that will be incurred to deploy the Customer Education Plan described by Mr. Dawsey. The estimated annual amount of this Customer Education Expense for the period 2017 through 2022, which would be included in the Annual AMI Customer Charge, is summarized in the table below:

Table 6. Estimated Annual Customer Education Expense for the Years 2017-2022 ($000s)

	2017	**2018**	**2019**	**2020**	**2021**
Customer Education Expense – Electric	$ 89	$ 179	$ 173	$ 733	$ 523
Customer Education Expense – Gas	$ 10	$ 20	$ 55	$ 86	$ 16

Q21. DOES THE INCLUSION OF THE 2017 AND 2018 CUSTOMER EDUCATION AND O&M EXPENSES IN THE JANUARY 2020 AMI CUSTOMER CHARGE REQUIRE A SPECIFIC ORDER BY THE COUNCIL?

A. It is my understanding that it does. As part of the AMI Rate Plan, the Company is requesting a Council order authorizing a deferral of the Customer Education and Ongoing AMI O&M Expenses incurred in 2017 and 2018, with carrying charges, for recovery commencing with the January 2020 AMI Customer Charge. Such an order would allow those expenses to be recorded on the Company's balance sheet as a regulatory asset. The Company would then amortize that regulatory asset over two years.

Q22. DOES THE AMI CUSTOMER CHARGE INCLUDE RECOVERY OF THE REMAINING UNDEPRECIATED COST OF EXISTING METERS?

A. No. Mr. Lewis supports the Company's request for continued recovery of the remaining book value of the existing meters at the current rate and existing mechanisms until the undepreciated value is fully recovered. The recovery of and on existing meters, however, would occur through the Company's FRP or replacement base ratemaking mechanism, as it does today. As such, there will be no change in rates or revenue requirement associated with those assets.

Q23. IS THE PROPOSED AMI RATE PLAN DEPENDENT ON THE EXISTENCE OF AN FRP RIDER?

A. No. The proposed AMI Rate Plan, including the AMI Customer Charge, can be implemented regardless of whether an FRP is in place at the time of implementation. The Company therefore requests that the Commission's approval of the Electric Rate Plan not be contingent upon the existence of the FRP. This would provide the Company with the necessary assurance that it will have a reasonable opportunity to fully recover its prudently-incurred AMI investment for the benefit of its customers.

Q24. HOW DOES ENO PROPOSE TO IMPLEMENT THE AMI CUSTOMER CHARGE IN THE ABSENCE OF A FRP?

A. I discussed earlier in my testimony that ENO is proposing that the Operational Benefits and incremental AMI O&M Expense and benefits reflected in Tables 3 and 4 would be reflected in the actuals of the FRP. However, in the event that an FRP is not in place for ENO at the time of the AMI implementation, in addition to the components I indicated would be reflected in the AMI Customer Charge, ENO would reflect an annual true-up of the estimated AMI Implementation Costs and AMI O&M Expense and the Operational Benefits included in the annual AMI Customer Charge estimates.

Q25. HOW WOULD THE AMI CUSTOMER CHARGE BE REFLECTED ON A CUSTOMER BILL?

A. At this time, ENO would propose to display the AMI Customer Charge as a line item on the electric and gas customer bills for all rate schedules. However, the manner in which the charge will be presented is a question that may better be addressed in connection with the 2018 Combined Rate Case, as it is not certain at this time whether the current rate design structure will be maintained.

Q26. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **ORLANDO TODD**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Orlando Todd

Orlando Todd

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 13th DAY OF OCTOBER, 2016

NOTARY PUBLIC

My commission expires: at death

Harry M. Barton
Notary Public
Notary ID# 90845
Parish of Orleans, State of Louisiana
My Commission is for Life

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO DEPLOY ADVANCED METERING INFRASTRUCTURE, AND REQUEST FOR COST RECOVERY AND RELATED RELIEF	)))))	**DOCKET NO. UD-16-___**

EXHIBIT OT-1

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

OCTOBER 2016

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO DEPLOY ADVANCED METERING INFRASTRUCTURE, AND REQUEST FOR COST RECOVERY AND RELATED RELIEF	)))))	**DOCKET NO. UD-16-___**

EXHIBIT OT-2

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

OCTOBER 2016