THE COUNCIL OF THE CITY OF NEW ORLEANS, LA

REQUEST FOR QUALIFICATIONS STATEMENTS

FOR

DEMAND SIDE MANAGEMENT CONSULTANT

ISSUED SEPTEMBER 15, 2017

APPENDICES IV-V

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DEMAND SIDE MANAGEMENT CONSULTANT

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APPENDIX IV

DRAFT NEW ORLEANS TECHNICAL REFERENCE MANUAL

New Orleans Energy Smart Technical Reference Manual: Version 1.0

July 18, 2017

Draft 1

Prepared by:

ADM Associates, Inc.

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A.Introduction

This Technical Reference Manual (TRM) provides Unit Energy Savings (UES) estimates of kWh (energy savings) and kW (demand reductions) for the Entergy New Orleans Energy Smart Programs. The selection of measures for inclusion in this TRM was based on:

1. Historical implementation rates of measures;
2. Identification of measures in other programs that may warrant inclusion in Energy Smart; and
3. An assessment of whether a measure is an appropriate candidate for deemed savings or if it warrants custom analysis. Some viable measures (such as HVAC variable frequency drives, or VFDs) have been excluded from this TRM as they are more appropriate for custom analysis.

A.1. High Impact Measures

In this TRM, we refer to "High Impact Measures" (HIMs). Measures are classified as HIMs if they exceed a minimum of 1% of the sector-level savings for the residential or non-residential components of Energy Smart. Most HIMs have deemed savings parameters based off primary research conducted by ADM Associates (ADM) as part of the Program Year 5 (PY5) and Program Year 6 (PY6) evaluation, measurement, and verification (EM&V) efforts. Measures that are not HIMs have savings values that are typically either direct reference to existing sources (such as ENERGY STAR®, Food Service Technology Center, the Department of Energy, or the California Database for Energy Efficient Resources (DEER)). These measures have been updated to reflect New Orleans weather where appropriate.

HIMs are summarized in the subsections to follow.

A.1.1. Residential High Impact Measures

The following list includes all measures that produced a minimum of 1% of residential Energy Smart energy savings (kWh) in PY6).

- Duct Sealing: 61.7%
- Lighting: 15.7%
- Air Sealing: 13.4%
- Ceiling Insulation: 8.8%
- Central AC Tune-Up: 3.4%
- Low Flow Shower Heads: 3.2%
- Central AC Replacement: 1.1%

To-date, the EM&V activities have included primary research to refine savings estimates for all residential HIMs other than ceiling insulation and air sealing. The primary research informed 76.1% of Energy Smart PY6 residential savings. Ceiling insulation and air sealing are targeted for primary research in PY7. Their savings in this TRM are based on simulation results only. We note here that the percentages detailed above are percent of verified gross energy savings (kWh). Increased emphasis was placed on HVAC measures as their initial claimed savings were significantly higher; EM&V findings reduced gross savings for these measures by a minimum of 70% in each of PY5 and PY6 evaluations.

A.1.2. Commercial & Industrial (C&I) High Impact Measures

This following list includes all measures that produced a minimum of 1% of residential Energy Smart savings in Program Year 6 (PY6).

- Lighting: 89.7%
- Custom: 9.0%

Custom measures are not included in the TRM, and receive analysis unique to the facility based on the International Measurement & Verification Protocols (IPMVP). Though metering studies have not been completed for all facility types, the adjustments to New Orleans-specific projects has been significant. The primary research informed 98.7% of Energy Smart PY6 C&I savings.

A.2. New Orleans EM&V Studies

The following EM&V studies have been completed, allowing for incorporation of primary data into the TRM:

- Metering of residential air conditioning runtime, applied to AC replacement and duct sealing;
- Field assessment of average SEER for air conditioning units in duct sealing projects;
- Billing analysis to support reductions achieved from residential air conditioning tune-ups;
- Measurement of residential domestic hot water (DHW) temperature setpoints, incorporated into DHW replacements and low flow devices;
- Metering of residential lighting run-time;
- Metering of commercial lighting run-time for the following facility types:
    - K-12 Education;
    - Exterior Lighting (all commercial);
    - Food Preparation;
    - Food Sales: Non-24 Hour Supermarket;
    - Food Service: Fast Food;
    - Food Service: Sit-down Restaurant;
    - Health Care: In-Patient;

- Lodging: Common Areas;
- Lodging: Guest Rooms;
- Multifamily: Common Area;
- Religious Assembly/Worship;
- Retail: Freestanding; and
- Warehouse: Non-Refrigerated.

A.3. Incremental Costs

The TRM also provides incremental cost values for most measures. Incremental cost is defined under two possible scenarios:

- Normal replacement / New construction / Replace-on-burnout: these costs reflect the cost premium of efficient equipment compared to minimum code-compliant equipment.
- Early replacement: these costs reflect the full installed cost of the new equipment. For some measures, such as lighting controls, this is meant to capture that the measure is an add-on to existing equipment. For measures that have parameters defined for the early replacement of functioning equipment, this approach also includes the subtraction of the net present value (NPV) of the second equipment purchase.

A.4. Simulation Modeling

The savings for some weather sensitive measures were developed via simulation modeling. The model software platforms included are as follows:

- eQuest©;
- BEopt™; and
- EnergyGauge USA®.

A.5. Weather

Various measures in the TRM refer to Typical Meteorological Year version 3 (TMY3) weather data. This data is publicly available from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB).

This data reflects the typical year of New Orleans weather based off historical data, and is the common practice for projecting average annual savings of weather sensitive measures. Inputs from the TMY3 dataset for New Orleans included the following:

- Temperature;
- Humidity;
- Wind speed and direction;
- Cloud cover; and
- Solar radiation.

A.6. Application of Values in this TRM

It is the intent to have the values in this TRM provide parameters to stipulate ex-post gross energy savings (kWh) and demand reduction (kW) estimate. The values in this TRM do not account for free-ridership, as that is a parameter that may vary based on a program delivery mechanism (for example, the free-ridership rates for residential lighting differ significantly between retail markdown in the Consumer Products versus direct install in Green Light New Orleans).

The values in this TRM will be used to verify ex post gross energy savings (kWh) and demand reductions (kW), except when specified otherwise in an EM&V plan.

A.7. Future Studies

Each measure section includes a discussion of future studies suggested by the authors of this TRM. For many measures, no studies are recommended, and suggested updates include only updating when codes and standards affecting the specific measure change. The suggestion of future studies is focused on areas of high impact in the Energy Smart portfolio (such as duct sealing) and also for the identification of potential future high impact measures (such as ductless mini-split HVAC systems).

The studies detailed are suggestions on the part of the authors of the TRM and guidance and feedback on these issues is welcomed as part of the stakeholder advisory process.

B.Residential Measures

B.1. Appliances

B.1.1. Energy Star Clothes Washers

B.1.1.1. Measure Description

This measure involves the installation of a residential ENERGY STAR® clothes washer > 2.5 ft^3 in a new construction or replacement-on-burnout application. This measure applies to all residential applications.

B.1.1.2. Baseline and Efficiency Standards[1]

The baseline standard for deriving savings from this measure is the current federal minimum efficiency levels.

The efficiency standard is the ENERGY STAR® requirements for clothes washers.

Efficiency performance for clothes washers are characterized by Integrated Modified Energy Factor (IMEF) and Integrated Water Factor (IWF). The units for IMEF are ft^3/kWh/cycle. Units with higher IMEF values are more efficient. The units for IWF are gallons/cycle/ft^3. Units with lower IWF values will use less water and are therefore more efficient.

Table 1: ENERGY STAR® Clothes Washer – Baseline and Efficiency Levels

Clothes Washer Configuration	***ENERGY STAR® Efficiency Level Effective 3/7/2015***
Top Loading	MEF ≥ 2.06 WF ≤ 4.3
Front Loading	MEF ≥ 2.38 WF ≤ 3.7

1 Current federal standards for clothes washers can be found on the DOE website at: http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/39.

Current ENERGY STAR® criteria for clothes washers can be found on the ENERGY STAR® website at: http://www.energystar.gov/index.cfm?c=clotheswash.pr_crit_clothes_washers.

ENERGY STAR® Most Efficient criteria for clothes washers can be found at: http://www.energystar.gov/ia/partners/downloads/most_efficient/2015/Final_ENERGY_STAR_Most_Efficient_2015_Recognition_Criteria_Clothes_Washers.pdf.

B.1.1.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 14 years, according to the US DOE.[2]

B.1.1.4. Deemed Savings Values

For retrofit situations, baseline and efficiency case energy consumption is based on the configuration of the replaced unit and new unit (top loading or front loading). For new construction applications, a top loading clothes washer is assumed as the baseline and the efficient equipment is either top loading or front loading.

Table 2: ENERGY STAR® Clothes Washer – Deemed Savings

Baseline Configuration	Efficient Configuration	Water Heater Fuel Type	Dryer Fuel Type	kW Savings	kWh Savings	Therms Savings
Top Loading	Top Loading	Gas	Gas	0.005	23	9.9
		Gas	Electric	0.045	192	4.1
		Electric	Gas	0.027	114	5.8
		Electric	Electric	0.067	282	0.0
Top Loading	Front Loading	Gas	Gas	0.009	38	12.4
		Gas	Electric	0.047	198	7.0
		Electric	Gas	0.045	191	5.4
		Electric	Electric	0.083	351	0.0
Front Loading	Front Loading	Gas	Gas	0.002	6	4.1
		Gas	Electric	0.022	93	1.2
		Electric	Gas	0.008	32	3.0
		Electric	Electric	0.028	119	0.0

B.1.1.5. Calculation of Deemed Savings

Energy savings for this measure were derived using the ENERGY STAR® Clothes Washer Savings Calculator.[3] Unless otherwise specified, all savings assumptions are extracted from the ENERGY STAR® calculator. The baseline and ENERGY STAR® efficiency levels are set to those matching Table 1. The ENERGY STAR® calculator

[2] U.S. DOE "Technical Support Document: Energy Efficiency Program for Consumer Products and Commercial and Industrial Equipment: Residential Clothes Washers" Section 8.2.3 Product Lifetimes. April 2012. http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/39.

[3] The ENERGY STAR® Clothes Washer Savings Calculator can be found on the ENERGY STAR® website on the right hand side of the page at:www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=CW.

determines savings based on whether or not an electric or gas water heater is used. Calculations are also conducted based on whether or not the dryer is electric or gas.

For applications using an electric water heater and an electric dryer, the savings are calculated as follows:

$$kWh_{savings} = \left(E_{conv,machine} + E_{conv,WH} + E_{conv,dryer}\right) - \left(E_{ES,machine} + E_{ES,WH} + E_{ES,dryer}\right)$$

Where:

$E_{conv,machine}$= Conventional machine energy (kWh)

$E_{conv,WH}$= Conventional water heating energy (kWh)

$E_{conv,dryer}$= Conventional dryer energy (kWh)

$E_{ES,machine}$= ENERGY STAR® machine energy (kWh)

$E_{ES,WH}$= ENERGY STAR® water heating energy (kWh)

$E_{ES,dryer}$=ENERGY STAR® dryer energy (kWh)

B.1.1.5.1. Energy Savings

Energy consumption for the above factors can be determined using the following algorithms.

$$E_{conv,machine} = \frac{MCF \times RUEC_{conv} \times LPY}{RLPY}$$

$$E_{conv,WH} = \frac{WHCF \times RUEC_{conv} \times LPY}{RLPY}$$

$$E_{conv,dryer} = \left(\frac{CAP \times LPY}{IMEF_{FS}} - \frac{RUEC_{conv} \times LPY}{RLPY}\right) \times DUF$$

$$E_{ES,machine} = \frac{MCF \times RUEC_{ES} \times LPY}{RLPY}$$

$$E_{ES,WH} = \frac{WHCF \times RUEC_{ES} \times LPY}{RLPY}$$

$$E_{ES,dryer} = \left(\frac{CAP \times LPY}{IMEF_{ES}} - \frac{RUEC_{ES} \times LPY}{RLPY}\right) \times DUF$$

Where:

MCF= Machine electricity consumption factor = 20%

$WHCF$= Water heating electricity consumption factor = 80%

$RUEC_{conv}$= Rated unit electricity consumption (kWh/year) = 381 (Top Loading); 169 (Front Loading)

$RUEC_{ES}$ = Rated unit electricity consumption (kWh/year) = 230 (Top Loading); 127 (Front Loading)

CAP= Clothes washer capacity = 3.5 (ft^3)

$IMEF_{FS}$= Federal Standard Integrated Modified Energy Factor (ft^3/kWh/cycle)

$IMEF_{ES}$= ENERGY STAR® Integrated Modified Energy Factor (ft^3/kWh/cycle)

LPY = Loads per year = 295

$RLPY$= Reference loads per year = 392

DUF= Dryer use factor = 91%

B.1.1.5.2. Demand Savings

Demand savings are calculated using the following equation:

$$kW_{savings} = \frac{kWh_{savings}}{AOH} \times CF$$

AOH = Annual operating hours = LPY × d = 295 hours

CF = Coincidence factor = 0.07[4]

B.1.1.6. Incremental Cost

The incremental cost is $190[5].

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[4] Value from Clothes Washer Measure, Mid Atlantic TRM 2014. Metered data from Navigant Consulting "EmPOWER Maryland Draft Final Evaluation Report Evaluation Year 4 (June 1, 2012 – May 31, 2013) Appliance Rebate Program." March 21, 2014, p. 36.

[5] ENERGY STAR Appliance Calculator: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0ahUKEwihkoHI8f3OAhVW5mMKHe72Du4QFggeMAA&url=https%3A%2F%2Fwww.energystar.gov%2Fsites%2Fdefault%2Ffiles%2Fasset%2Fdocument%2Fappliance_calculator.xlsx&usg=AFQjCNFAy5-mu5GR3BjLp4MR1LqrOHegCA&sig2=8l5MGUh1_bJy3lSl9wAWIA

B.1.1.7. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans residents.

Deemed parameters should be updated whenever DOE standards or other applicable codes warrant it.

B.1.2. ENERGY STAR® Dryers

B.1.2.1. Measure Description

This measure involves the installation of a residential ENERGY STAR® dryers in a new construction or replacement-on-burnout application. This measure applies to all residential applications.

B.1.2.2. Baseline and Efficiency Standards[6]

The baseline standard for deriving savings from this measure is the current federal minimum efficiency levels. The efficiency standard is the ENERGY STAR® requirements for dryers.

ENERGY STAR® Clothes Dryers are more efficient than standard ones and save energy. They have a higher CEF (Combined Energy Factor) and may incorporate a moisture sensor to reduce excessive drying of clothes and prolonged drying cycles. ENERGY STAR® Heat pump dryers or ventless dryers have higher CEF than conventional ENERGY STAR® dryers.

Table 3: ENERGY STAR® Dryer – Baseline and Efficiency Levels[7]

	Vented Gas Dryer	***Ventless or Vented Electric, Standard ≥ 4.4 ft³***	***Ventless or Vented Electric, Compact (120V) < 4.4 ft³***	***Vented Electric, Compact (240V) < 4.4 ft³***	***Ventless Electric, Compact (240V) < 4.4 ft³***	***Heat Pump Clothes Dryer***
ENERGY STAR® Required CEF	3.48	3.93	3.80	3.45	2.68	7.60
Federal standard CEF	2.84	3.11	3.01	2.73	2.13	3.11
Average load (in lbs.)	8.45	8.45	3.0	3.0	3.0	8.45
Default loads per year	283	283	283	283	283	283
Default capacity (in ft³)	5.0	5.0	3.0	3.0	3.0	5.0

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[6] Current federal standards for clothes dryers can be found on the DOE website at: https://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/36.

Current ENERGY STAR® criteria for clothes dryers can be found on the ENERGY STAR® website at: https://www.energystar.gov/products/appliances/clothes_dryers.

ENERGY STAR® Most Efficient criteria for clothes washers can be found at: http://www.energystar.gov/ia/partners/downloads/most_efficient/2015/Final_ENERGY_STAR_Most_Efficient_2015_Recognition_Criteria_Clothes_Washers.pdf.

[7] The ENERGY STAR® Clothes Dryer Savings Calculator can be found on the ENERGY STAR® website on the right hand side of the page at: www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=CW

B.1.2.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 12 years, according to the US DOE.[8]

B.1.2.4. Deemed Savings Values

For retrofit situations, baseline and efficiency case energy consumption is based on the size of the replaced unit and new unit. For new construction applications.

Table 4: ENERGY STAR® Clothes Dryer – Deemed Savings

Product Type	Energy Savings (kWh/yr)	Demand Reduction (kW)
Vented Electric, Standard (4.4 ft³ or greater capacity)	152.42	.0226
Vented Electric, Compact (120V) (less than 4.4 ft³ capacity)	55.71	.0083
Vented Electric, Compact (240V) < 4.4 ft³	61.66	.0092
Ventless Electric, Compact (240V) < 4.4 ft³	77.71	.0115
Heat Pump Clothes Dryer	431.56	.0641

B.1.2.5. Calculation of Deemed Savings

B.1.2.5.1. Energy and Demand Savings

Energy savings for this measure were derived using the ENERGY STAR® Dryer Savings Calculator.[9] Unless otherwise specified, all savings assumptions are extracted from the ENERGY STAR® calculator.

The energy and demand savings are obtained through the following formulas:

$$\Delta kWh/yr = Cycles_{wash} \times \%_{dry/wash} \times Load_{avg} \times \left(\frac{1}{CEF_{base}} - \frac{1}{CEF_{ee}}\right)$$

$$\Delta kW_{peak} = \frac{\left(\frac{1}{CEF_{base}} - \frac{1}{CEF_{ee}}\right) \times Load_{avg}}{time_{cycle}} \times CF$$

Where:

$Cycles_{wash}$ = Number of washing machine cycles per year = 283 cycles/year

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[8] U.S. DOE "Technical Support Document: Energy Efficiency Program for Consumer Products and Commercial and Industrial Equipment: Residential Clothes Dryer" Section 8.2.3 Product Lifetimes. April 2011. https://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/36.

[9] The ENERGY STAR®Clothes Washer Savings Calculator can be found on the ENERGY STAR® website on the right hand side of the page at:www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=CW.

$Load_{avg}$ = Weight of average dryer load, in pounds per load = Standard Dryer: 8.45 lbs/load and Compact Dryer: 3.0 lbs/load[10] [11]

$\%_{\text{dry/wash}}$ = Percentage of homes with a dryer that use the dryer every time clothes are washed = 95%

CEF_{base} = Combined Energy Factor of baseline dryer (lbs/kWh) = See Table 14[12]

CEF_{ee} = Combined Energy Factor of ENERGY STAR® dryer (lbs/kWh) = See table 14[13]

$time_{cycle}$ = Duration of average drying cycle in hours = 1 hour

CF - Coincidence Factor = 0.042[14]

B.1.2.6. Incremental Cost

The incremental cost of high efficiency clothes dryers is detailed in Table 5.

[10] Test Loads for Compact and Standard Dryer in Appendix D2 to Subpart B of Part 430—Uniform Test Method for Measuring the Energy Consumption of Clothes Dryers. http://www.ecfr.gov/cgi-bin/text-idx?SID=9d051184ada3b0d0b5b553f624e0ab05&node=10:3.0.1.4.18.2.9.6.14&rgn=div9

[11] 2011-04 Technical Support Document: Energy Efficiency Program for Consumer Products and Commercial and Industrial Equipment. Residential Clothes Dryers and Room Air Conditioners, Chapter 7. Clothes Dryer Frequency from Table 7.3.3 for Electric Standard. http://www.regulations.gov/contentStreamer?objectId=0900006480c8ee11&disposition=attachment&contentType=pdf

[12] Federal Standard for Clothes Dryers, Effective January 1, 2015. http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/36

[13] ENERGY STAR® Specification for Clothes Dryers Version 1.0, Effective January 1, 2015. http://www.energystar.gov/products/specs/sites/products/files/ENERGY%20STAR%20Final%20Draft%20Version%201.0%20Clothes%20Dryers%20Specification_0.pdf

[14] 6) Central Maine Power Company. "Residential End-Use Metering Project". 1988. Using 8760 data for electric clothes dryers, calculating the CF according to the PJM peak definition.

Table 5: ENERGY STAR® Clothes Dryer Incremental Costs

Product Type	Incremental Cost
Vented Electric, Standard: (4.4 ft³ or greater capacity)	$40[15]
Vented Electric, Compact (120V): (less than 4.4 ft³ capacity)	$40
Vented Electric, Compact: (240V) < 4.4 ft³	$40
Ventless Electric, Compact: (240V) < 4.4 ft³	$40

B.1.2.7. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans residents.

Deemed parameters should be updated whenever DOE standards or other applicable codes warrant it.

[15] ENERGY STAR Appliance Calculator: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0ahUKEwihkoHI8f3OAhVW5mMKHe72Du4QFggeMAA&url=https%3A%2F%2Fwww.energystar.gov%2Fsites%2Fdefault%2Ffiles%2Fasset%2Fdocument%2Fappliance_calculator.xlsx&usg=AFQjCNFAy5-mu5GR3BjLp4MR1LqrOHegCA&sig2=8l5MGUh1_bJy3lSl9wAWIA

B.1.3. ENERGY STAR® Dishwashers

B.1.3.1. Measure Description

This measure involves the installation of an ENERGY STAR® dishwasher in a new construction or replacement-on-burnout situation. This measure applies to all residential applications.

B.1.3.2. Baseline and Efficiency Standards

The baseline for this measure is the current federal standard as displayed in the table below.

Table 6: ENERGY STAR® Criteria for Dishwashers[16]

	ENERGY STAR® Criteria		
	Capacity	***Annual Energy Consumption (AEC) kWh/Year***	***Gallons/Cycle***
Standard Model Size (Effective Until 1/26/2016)	> 8 place settings + 6 serving pieces	< 295	< 4.25
Standard Model Size (Effective On 1/26/2016)[17]	> 8 place settings + 6 serving pieces	AECbase + AECadderconnected AECbase: 270 AECadderconnected: 0.05 × AECbase	< 3.5
Compact Model Size (Effective On 1/26/2016)	< 8 place settings + 6 serving pieces	< 203	< 3.1

B.1.3.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 15 years, according to the US DOE.[18]

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[16] ENERGY STAR® criteria for dishwashers can be found on the ENERGY STAR® website at: www.energystar.gov/index.cfm?c=dishwash.pr_crit_dishwashers.

[17] ENERGY STAR® efficiency requirements as of January 26, 2016 are defined on their website at www.energystar.gov/sites/default/files/ENERGY%20STAR%20Residential%20Dishwasher%20Version%206.0%20Final%20Program%20Requirements_0.pdf.

[18] U.S. DOE, Technical Support Document: "Energy Efficiency Program for Consumer Products and Commercial Industrial Equipment: Residential Dishwashers, Section 8.2.3 Product Lifetimes." May 2012. http://www.regulations.gov/#!documentDetail;D=EERE-2011-BT-STD-0060-0007.

Download TSD at: http://www.regulations.gov/#!documentDetail;D=EERE-2011-BT-STD-0060-0007.

B.1.3.4. Deemed Savings Values

Deemed savings are per installed unit based on the water heating fuel type.

Table 7: ENERGY STAR® Dishwashers – Deemed Savings Values

	Water Heater Fuel Type	***kW Savings***	***kWh Savings***	***Therms Savings***
Standard Model Size	Gas	0.0005	5	0.3
Standard Model Size	Electric	0.0011	12	0.0

B.1.3.5. Calculation of Deemed Savings

B.1.3.5.1. Energy Savings

Energy savings for this measure were derived using the ENERGY STAR® Dishwasher Savings Calculator.[19] The baseline and ENERGY STAR® efficiency levels are set to those matching Table 7 and Table 8.

$$kWh_{Savings} = \left(E_{conv,machine} + E_{conv,WH}\right) - \left(E_{ES,machine} + E_{ES,WH}\right)$$

Where:

$E_{conv,machine}$= Conventional machine energy (kWh)

$E_{conv,WH}$= Conventional water heating energy (kWh)

$E_{ES,machine}$= ENERGY STAR® machine energy (kWh)

$E_{ES,WH}$= ENERGY STAR® water heating energy (kWh)

Algorithms to calculate the above parameters are defined as:

$$E_{conv,machine} = MCF \times RUEC_{conv}$$

$$E_{conv,WH} = WHCF \times RUEC_{conv}$$

$$E_{ES,machine} = MCF \times RUEC_{ES}$$

$$E_{ES,WH} = WHCF \times RUEC_{ES}$$

B.1.3.5.2. Demand Savings

Demand savings can be derived using the following:

[19] The ENERGY STAR® Dishwasher Savings Calculator, updated January 20, 2012, can be found on the ENERGY STAR® website.

$$kW_{Savings} = \frac{kWh_{Savings}}{AOH} \times CF$$

Where:

MCF= Machine electricity consumption factor = 44%

$WHCF$= Water heating electricity consumption factor = 56%

$RUEC_{conv}$= Rated unit electricity consumption = 307 (kWh/year)

$RUEC_{ES}$ = Rated unit electricity consumption = 295 (kWh/year)

CPY = Cycles per year = 215

d = Average wash cycle duration = 2.1 hours[20]

AOH = Annual operating hours = CPY × d = 451.5 hours

CF = Coincidence factor = 0.036[21]

$\eta_{gas\ WH}$= Gas water heater efficiency = 75%

B.1.3.6. Incremental cost

The incremental cost of ENERGY STAR© Dishwashers is $10[22].

B.1.3.7. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans residents.

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[20] Average of Consumer Reports Cycle Times for Dishwashers. http://www.consumerreports.org/cro/dishwashers.htm. Information available for subscribers only.

[21] Hendron, R. & Engebrecht, C. 2010, , National Renewable Energy Laboratory (NREL). “Building America Research Benchmark Definition: Updated December” US U.S. DOE. January 2010. p. 14 (peak hour of 4 PM was applied). http://www.nrel.gov/docs/fy10osti/47246.pdf

[22] ENERGY STAR Appliance Calculator: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0ahUKEwihkoHI8f3OAhVW5mMKHe72Du4QFggeMAA&url=https%3A%2F%2Fwww.energystar.gov%2Fsites%2Fdefault%2Ffiles%2Fasset%2Fdocument%2Fappliance_calculator.xlsx&usg=AFQjCNFAy5-mu5GR3BjLp4MR1LqrOHegCA&sig2=8l5MGUh1_bJy3lSl9wAWIA

Deemed parameters should be updated whenever DOE standards or other applicable codes warrant it.

B.1.4. ENERGY STAR® Refrigerators

B.1.4.1. Measure Description

This measure involves replace-on-burnout or early retirement of an existing refrigerator and installation of a new, full-size (7.75 ft^3 or greater) ENERGY STAR® refrigerator. This measure applies to all residential or small commercial applications.

To qualify for early retirement, the ENERGY STAR® unit must replace an existing, full-size, working unit that is at least six years old. For early retirement, the maximum lifetime age of an eligible piece of equipment is capped at the point at which it is expected that 75 percent of the equipment has failed. Where the age of the unit exceeds the 75 percent failure age, ROB savings should be applied. This cap prevents early retirement savings from being applied to projects where the age of the equipment greatly exceeds the estimated useful life of the measure.

B.1.4.2. Baseline and Efficiency Standards[23]

For ROB, the baseline for refrigerators is the DOE minimum efficiency standards for refrigerators, effective September 15, 2014.

For an individual refrigerator early retirement program, the baseline for refrigerators is assumed to be the annual unit energy consumption of the refrigerator being replaced, as reported by the Association of Home Appliance Manufacturers (AHAM) refrigerator database24, adjusted for age according to the formula in the Measure Savings Calculations section. AHAM energy use data includes the average manufacturer-reported annual kilowatt hour usage, by year of production. This data dates back to the 1970s.

Alternatively, the baseline annual kilowatt hour usage of the refrigerator being replaced may be estimated by metering for a period of at least three hours using the measurement protocol specified in the US DOE report, "*Incorporating Refrigerator Replacement into the Weatherization Assistance Program*."[25]

To determine annual kWh of the refrigerator being replaced, use the formula:

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[23] Current federal standards for refrigerators can be found on the DOE website at: http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/43. Current ENERGY STAR® criteria for refrigerators can be found on the ENERGY STAR® website at: www.energystar.gov/index.cfm?c=refrig.pr_crit_refrigerators

[24] AHAM Refrigerator Database. http://rfdirectory.aham.org/AdvancedSearch.aspx

[25] Moore, A. 2001, D&R International, Ltd. *"Incorporating Refrigerator Replacement into the Weatherization Assistance Program: Information Tool Kit."* U.S. DOE. November 19. http://www.waptac.org/data/files/website_docs/training/standardized_curricula/curricula_resources/refrigerator_info_toolkit.pdf

$$kWh/yr = \frac{WH \times 8{,}760}{h \times 1{,}000}$$

Where:

WH = the watt-hours metered during a time period

h = measurement time period (hours)

$8{,}760$ = hours in a year

$1{,}000$ watt-hours = 1 kWh

For the early retirement application, all new refrigerators must replace refrigerators currently in use, and all replaced refrigerators must be dismantled in an environmentally-safe manner in accordance with applicable federal, state, and local regulations. The installer will provide documentation of proper disposal of refrigerators.

Newly-installed refrigerators must meet current ENERGY STAR® efficiency levels. All newly-installed refrigerators must be connected to an adequately-sized electrical receptacle and be grounded in accordance to the National Electric Code (NEC).

Minimum efficiency requirements for ENERGY STAR® refrigerators are set at 10% more efficient than required by the minimum federal government standard. The standard varies depending on the size and configuration of the refrigerator. See Table 9.

Configuration Codes (Table 9):

BF: Bottom Freezer

SD: Refrigerator Only – Single Door

SR: Refrigerator/Freezer – Single Door

SS: Side-by-Side

TF: Top Freezer

TTD: Through the Door (Ice Maker)

A: Automatic Defrost

M: Manual Defrost

P: Partial Automatic Defrost

AV[26] = Adjusted Volume

Table 8: Formulas to Calculate the ENERGY STAR® Criteria for each Refrigerator Product Category by Adjusted Volume (Effective September 15, 2014)[27]

Product Category	Federal Standard as of Sept 15, 2014 Standard (kWh/year)	Maximum ENERGY STAR® Energy Usage (kWh/year)[28]	Configuration(s)	Ice (Y/N)	Defrost
Refrigerator-only—manual defrost	6.79 × AV + 193.6	6.111 × AV + 174.24	SD	Y, N	M
Refrigerator-freezers—manual or partial automatic defrost	7.99 × AV + 225.0	7.191 × AV + 202.5	SS, TF, BF, SR	Y, N	M, P
Refrigerator-only—automatic defrost	7.07 × AV + 201.6	6.363 × AV + 181.44	SD	Y, N	A
Built-in refrigerator-only—automatic defrost	8.02 × AV + 228.5	7.218 × AV + 205.65	SD	Y, N	A
Refrigerator-freezers—automatic defrost with bottom-mounted freezer without an automatic icemaker	8.85 × AV + 317.0	7.965 × AV + 285.3	BF	N	A
Built-in refrigerator-freezers—automatic defrost with bottom-mounted freezer without an automatic icemaker	9.40 × AV + 336.9	8.46 × AV + 378.81	BF	N	A
Refrigerator-freezers—automatic defrost with bottom-mounted freezer with an automatic icemaker without TTD ice service	8.85 × AV + 401.0	7.965 × AV + 360.9	BF	N	A
Built-in refrigerator-freezers—automatic defrost with bottom-mounted freezer with an automatic icemaker without TTD ice service	9.40 × AV + 420.9	8.46 × AV + 378.81	BF	N	A
Refrigerator-freezers—automatic defrost with bottom-mounted	9.25 × AV + 475.4	8.325× AV + 427.86	BF	Y	A

[26] Adjusted Volume (AV) can be found for ENERGY STAR® certified refrigerators on their website under the "advanced view" option. https://data.energystar.gov/Active-Specifications/ENERGY-STAR-Certified-Residential-Refrigerators/p5st-her9. Scroll to the right until you reach the column named "Adjusted Volume".

[27] Available for download at http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/43.

[28] Ten percent more efficient than baseline, as specified in the ENERGY STAR® appliance calculator.

Product Category	Federal Standard as of Sept 15, 2014 Standard (kWh/year)	Maximum ENERGY STAR® Energy Usage (kWh/year)[28]	Configuration(s)	Ice (Y/N)	Defrost
freezer with an automatic icemaker with TTD ice service					
Built-in refrigerator-freezers—automatic defrost with bottom-mounted freezer with an automatic icemaker with TTD ice service	9.83 × AV + 499.9	8.847 × AV + 449.91	BF	Y	A
Refrigerator-freezers—automatic defrost with side-mounted freezer without an automatic icemaker	8.51 × AV + 297.8	7.659 × AV + 268.02	SS	N	A
Built-in refrigerator-freezers—automatic defrost with side-mounted freezer without an automatic icemaker	10.22 × AV + 357.4	9.198 × AV + 321.66	SS	N	A
Refrigerator-freezers—automatic defrost with side-mounted freezer with an automatic icemaker without TTD ice service	8.51 × AV + 381.8	7.659 × AV + 343.62	SS	N	A
Built-in refrigerator-freezers—automatic defrost with side-mounted freezer with an automatic icemaker without TTD ice service	10.22 × AV + 441.4	9.198 × AV + 397.26	SS	N	A
Refrigerator-freezers—automatic defrost with side-mounted freezer with an automatic icemaker with TTD ice service	8.54 × AV + 432.8	7.686 × AV + 389.52	SS	Y	A
Built-in refrigerator-freezers—automatic defrost with side-mounted freezer with an automatic icemaker with TTD ice service	10.25 × AV + 502.6	9.225 × AV + 452.34	SS	Y	A
Refrigerator freezers—automatic defrost with top-mounted freezer without an automatic icemaker	8.07 × AV + 233.7	7.263 × AV + 210.33	TF	N	A
Built-in refrigerator-freezers—automatic defrost with top-mounted freezer without an automatic icemaker	9.15 × AV + 264.9	8.235 × AV + 238.41	TF	N	A

Product Category	Federal Standard as of Sept 15, 2014 Standard (kWh/year)	Maximum ENERGY STAR® Energy Usage (kWh/year)[28]	Configuration(s)	Ice (Y/N)	Defrost
Refrigerator-freezers—automatic defrost with top-mounted freezer with an automatic ice maker without TTD ice service	8.07 × AV + 317.7	7.263 × AV + 285.93	TF	N	A
Built-in refrigerator-freezers—automatic defrost with top-mounted freezer without an automatic ice maker with TTD ice service	9.15 × AV + 348.9	8.235 × AV + 238.41	TF	N	A
Refrigerator-freezers—automatic defrost with top-mounted freezer with TTD ice service	8.40 × AV + 385.4	7.56 × AV + 346.86	TF	Y	A

B.1.4.3. Estimated Useful Life (EUL)

According to the Department of Energy Technical Support Document,[29] the Estimated Useful Life of High Efficiency Refrigerators is 17 years.

B.1.4.4. Measure Savings Calculations

Deemed peak demand and annual energy savings should be calculated as shown below. Note that these savings calculations are different depending on whether the measure is replace-on-burnout or early retirement.

B.1.4.4.1. Energy Savings

B.1.4.4.1.1. Replace-on-Burnout

$$kWh_{savings} = kWh_{baseline} - kWh_{ES}$$

Where:

$kWh_{baseline}$ = Federal standard baseline average energy usage (Table 9)

kWh_{ES}= ENERGY STAR® average energy usage (Table 9)

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[29] U.S. DOE 2011, Technical Support Document: "Residential Refrigerators, Refrigerator-Freezers, and Freezers, 8.2.3 Product Lifetimes." September 15. http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/43.

Download TSD at: http://www.regulations.gov/#!documentDetail;D=EERE-2008-BT-STD-0012-0128.

B.1.4.4.1.2. Early Retirement

Annual kWh and kW savings must be calculated separately for two time periods:

The estimated remaining life of the equipment that is being removed, designated the remaining useful life (RUL), and

The remaining time in the EUL period (17 – RUL)

For the RUL (Table 10):

$$kWh_{savings} = kWh_{pre} - kWh_{ES}$$

kWh_{pre} refers to manufacturer data or a measured consumption that is adjusted using applicable degradation factors.

$$kWh_{pre} = kWh_{manf} \times (1 + \mathrm{PDF})^{n}\ x\ SLF$$

For the remaining time in the EUL period:

Calculate annual savings as you would for a replace-on-burnout project using Equation (18). Lifetime kWh savings for Early Retirement Projects is calculated as follows:

$$Lifetime\ kWh_{savings} = \left(kwh_{savings,ER} \times RUL\right) + \left[kWh_{savings,ROB} \times (EUL - RUL)\right]$$

Where:

kWh_{NAECA}= NAECA baseline average energy usage (Table 9)

kWhpre = Adjusted manufacturer energy usage Equation (20)

kWh_{ES} = ENERGY STAR® average energy usage (Table 9)

kWh_{manf} = annual unit energy consumption from the Association of Home Appliance Manufacturers (AHAM) refrigerator database[30] (or from metering, using (17)

PDF = Performance Degradation Factor 0.0125/year. Refrigerator energy use is expected to increase at a rate of 1.25% per year as performance degrades over time[31]

n = age of replaced refrigerator (years)

SLF = Site/Lab Factor = 0.81 to account for the difference between DOE laboratory testing and actual conditions[32]

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[30] AHAM Refrigerator Database. http://rfdirectory.aham.org/AdvancedSearch.aspx.

[31] 2009 Second Refrigerator Recycling Program NV Energy – Northern Nevada Program Year 2009; M&V, ADM, Feb 2010, referencing Cadmus data on a California program, February 2010.

[32] Peterson, J, et. al., 2007, "Gross Savings Estimation for Appliance Recycling Programs: The Lab Versus In Situ Measurement Imbroglio and Related Issues" International Energy Program Evaluation Conference (IEPEC). Cadmus, et. al. "Residential Retrofit High Impact Measure Evaluation Report." February 8, 2010.

RUL = Remaining Useful Life (Table 10)

EUL = Estimated Useful Life = 17 years

B.1.4.4.2. Demand Savings

Since refrigerators operate 24/7, average kW reduction is equal to annual kWh divided by 8,760 hours per year. As shown below, this average kW reduction is multiplied by temperature and load shape adjustment factors to derive peak period kW reduction.

$$kW_{savings} = \frac{kWh_{savings}}{8{,}760\ hrs} \times \text{TAF} \times \text{LSAF}$$

Where:

TAF = Temperature Adjustment Factor[33] = 1.188

LSAF = Load Shape Adjustment Factor[34] = 1.074

[33] Proctor Engineering Group, Michael Blasnik & Associates, and Conservation Services Group, 2004, *"Measurement & Verification of Residential Refrigerator Energy Use: Final Report – 2003-2004 Metering Study"*. July 29. Factor to adjust for varying temperature based on site conditions, p. 47.

[34] Proctor Engineering Group, Michael Blasnik & Associates, and Conservation Services Group, 2004, "Measurement & Verification of Residential Refrigerator Energy Use: Final Report – 2003-2004 Metering Study". July 29. Used load shape adjustment for "hot days" during the 4PM hour, pp. 45-48.

B.1.4.4.3. *Derivation of RULs*

ENERGY STAR® Refrigerators have an estimated useful life of 17 years. This estimate is consistent with the age at which 50 percent of the refrigerators installed in a given year will no longer be in service, as described by the survival function in Figure 1.

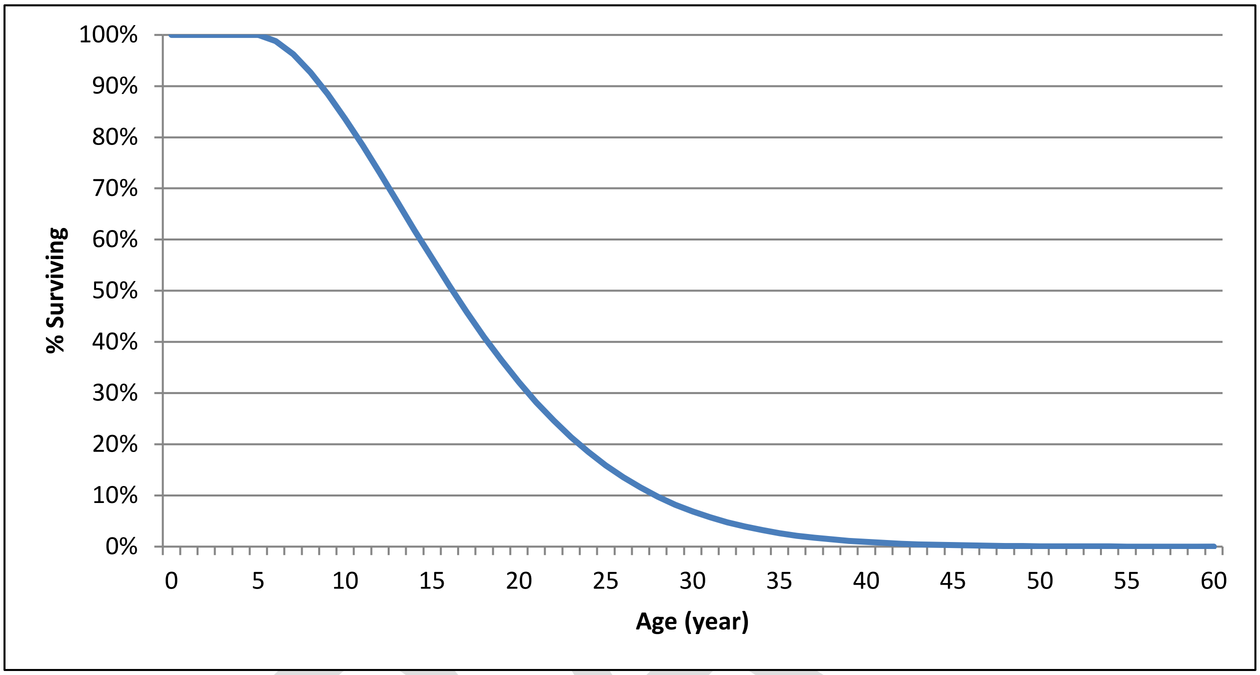

Figure 1: Survival Function for ENERGY STAR® Refrigerators[35]

The method for estimating the RUL of a replaced system uses the age of the existing system to re-estimate the projected unit lifetime based on the survival function shown in Figure 1. The age of the refrigerator being replaced is found on the horizontal axis, and the corresponding percentage of surviving refrigerators is determined from the chart. The surviving percentage value is then divided in half, creating a new estimated useful lifetime applicable to the current unit age. The age (year) that corresponds to this new percentage is read from the chart. RUL is estimated as the difference between that age and the current age of the system being replaced.

Table 9: Remaining Useful Life (RUL) of Replaced Refrigerator[36]

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[35] U.S. DOE, Technical Support Document, 2011, "Residential Refrigerators, Refrigerator-Freezers, and Freezers, 8.2.3 Product Lifetimes." September 15. http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/43.

Download TSD at: http://www.regulations.gov/#!documentDetail;D=EERE-2008-BT-STD-0012-0128.

Age of Replaced Refrigerator (years)	*RUL (years)*	*Age of Replaced Refrigerator (years)*	*RUL (years)*
6	10.3	15	6.0
7	9.6	16	5.8
8	8.9	17	5.5
9	8.3	18	5.3
10	7.8	19	5.1
11	7.4	20	4.9
12	7.0	21	4.8
13	6.6	22	4.6
14	6.3	23 +	0.0

B.1.4.5. Incremental Cost

The incremental cost for efficient refrigerators is $40[37] for ENERGY STAR units and $140[38] for CEE Tier II units.

For early retirement, incremental cost is calculated using:

1) Full installed cost of the refrigerator: program-actual purchase price should be used. If not available, use $451 for ENERGY STAR and $551 for CEE Tier 2 units[39].
2) Present value of replacement cost of a baseline refrigerator after the RUL of the initial replaced unit is exhausted. This unit costs $411[40] at the time of purchase, and should be discounted by the number of years of RUL. If RUL is unknown,

[36] Use of the early retirement baseline is capped at 22 years, representing the age at which 75 percent of existing equipment is expected to have failed. Equipment older than 22 years should use the ROB baseline.

[37] From ENERGY STAR appliance calculator

[38] Based on weighted average of units participating in Efficiency Vermont program and retail cost data provided in Department of Energy, "TECHNICAL REPORT: Analysis of Amended Energy Conservation Standards for Residential Refrigerator-Freezers", October 2005; http://www1.eere.energy.gov/buildings/appliance_standards/pdfs/refrigerator_report_1.pdf

[39] Based on weighted average of units participating in Efficiency Vermont program and retail cost data provided in Department of Energy, "TECHNICAL REPORT: Analysis of Amended Energy Conservation Standards for Residential Refrigerator-Freezers", October 2005; http://www1.eere.energy.gov/buildings/appliance_standards/pdfs/refrigerator_report_1.pdf

[40] Calculated by subtracting $40 incremental cost for ENERGY STAR refrigerators off of full purchase price of $451.

use 4 years. Default discount rate is 10%[41]. This results in a deferred replacement cost of $281.

3) Overall incremental cost of early retirement is then calculated as:
    a. ENERGY STAR: $451 - $281 = $70
    b. CEE Tier II: $170

A.1.1.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans residents.

Deemed parameters should be updated whenever DOE standards or other applicable codes warrant it.

[41] "Participant Discount Rate" recommended in CA Standard Practice Manual.

B.1.5. Advanced Power Strips

B.1.5.1. Measure Description

This measure involves the installation of a multi-plug Advanced Power Strip (APS, also known as “Smart Strips”) that has the ability to automatically disconnect specific loads depending on the power draw of a specified or “master” load.

There are two categories of smart strips:

1) **Tier 1:** Tier 1 advanced power strips have a master controls socket arrangement and will shut off items plugged into the controlled power-saver sockets when the sense that the appliance plugged into the master socket has been turned off. The power-saving functions of the control sockets is not used when the master appliance is turned on.
2) **Tier 2:** Tier 2 advanced power strips manage both active and standby consumption. Tier 2 smart strips manage standby power consumption by turning off devices from a control event; this could be a TV or other item powering off, which then powers off the controlled outlets to save energy. Active power consumption is managed by monitoring a user’s engagement or presence in a room either by infrared remote signals or motion sensing. After a period of inactivity, the Tier 2 unit will shut off controlled outlets.

B.1.5.2. Expected Useful Life

For Tier 1 advanced power strips, the EUL is 10 years[42].

For Tier 2 advanced power strips, there has not been a study performed to validate EUL. Until better data is available, they should default to using the current EUL of Tier 1 devices.

B.1.5.3. Baseline & Efficiency Standard

The baseline case is the absence of an APS, where peripherals are plugged in to a traditional surge protector or wall outlet.

The efficiency standard case is the presence of an APS, with all peripherals plugged into the APS.

B.1.5.4. Estimated Useful Life (EUL)

The measure life is 10 years according to the NYSERDA Advanced Power Strip Research Report from August 2011.[43]

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[42] New York State Energy Research and Development Authority (NYSERDA) 2011, *Advanced Power Strip Research Report*, p. 30. August.

B.1.5.5. Calculation of Deemed Savings

Energy and demand savings for a 5-plug APS in use in a home office or for a home entertainment system are calculated using the following algorithm, where kWh saved are calculated and summed for all peripheral devices:

Tier 1:

$$\Delta kWh/yr_{\text{unspecified use}} = \frac{(kW_{comp\ idle} \times HOU_{comp\ idle}) + (kW_{TVidle} \times HOU_{TV\ idle})}{2} \times 365\frac{\mathbf{days}}{\mathbf{yr}} \times ISR = 48.9\ kWh$$

(5-plug); 57.7 kWh (7-plug)

$$\Delta kWh/yr_{\text{entertainment center}} = kW_{TV\ idle} \times HOU_{TV\ idle} \times 365\frac{days}{yr} \times ISR = 62.1\ kWh$$ (5-plug); 74.5 kWh (7-plug)

$$\Delta kWh/yr_{\text{computer}} = kW_{Comp\ idle} \times HOU_{Comp\ idle} \times 365\frac{days}{yr} \times ISR = 35.8\ kWh$$ (5-plug); 42.9 (7-plug)

$$\Delta kW_{peak\ \text{unspecified use}} = \frac{CF \times (kW_{comp\ idle} + kW_{TV\ idle})}{2} \times ISR = 0.0056\ kW$$ (5-plug); 0.0067 kW (7-plug)

$$\Delta kW_{peak\ \text{entertainment center}} = CF \times kW_{TV\ idle} \times ISR = 0.0077\ kW$$ (5-plug); 0.0092 kW (7-plug)

$$\Delta kW_{peak\ \text{Computer}} = CF \times kW_{Comp\ idle} \times ISR = 0.0037\ kW$$ (5-plug); 0.0045 kW (7-plug)

Tier 2 Smart Strip:

$$\Delta kWh\ \text{unspecified use} = \frac{(kWh_{comp} + kWh_{TV})}{2} \times ESF \times ISR = 204.2\ kWh$$

$$\Delta kWh\ \text{entertainment center} = kWh_{TV} \times ESF \times ISR = 307.4\ kWh$$

$$\Delta kWh\ \text{Computer} = kWh_{Comp} \times ESF \times ISR = 100.9\ kWh$$

$$\Delta kW_{peak}\ \text{unspecified use} = \frac{CF \times (\Delta kWh_{comp} + \Delta kWh_{entertainment})}{2 \times 8760\frac{hours}{yr}} \times ISR = 0.0194\ kW$$

$$\Delta kW_{peak}\ \text{entertainment center} = \frac{CF \times \Delta kWh_{entertainment}}{8760\frac{hours}{yr}} \times ISR = 0.0316\ kW$$

$$\Delta kW_{peak}\ \text{Computer} = \frac{CF \times \Delta kWh_{computer}}{8760\frac{hours}{yr}} \times ISR = 0.0172\ kW$$

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[43] New York State Energy Research and Development Authority (NYSERDA) 2011, *Advanced Power Strip Research Report*, p. 30. August.

Table 10: APS Assumptions

Parameter	***Unit***	***Value***	***Source***
kWcomp idle, Idle kW of computer system	kW	.0049 (5-plug) .00588 (7-plug)	44, 45, 46
HOUcomp idle, Daily hours of computer idle time	Hours/day	20	44
kWTV idle, Idle kW of TV system	kW	. 0085 (5-plug) .00102 (7-plug)	44, 46
HOUTV idle, Daily hours of TV idle time	Hours/day	20	44
kWhTV, Annual kWh of TV system	kWh	602.8	46
kWhcomp, Annual kWh of computer system	kWh	197.9	46
ISR, In-Service-Rate	%	1.0	
CF, Coincidence Factor	%	Entertainment Center = .90 Computer System= .763 Unspecified = .832	47
ESF, Energy Savings Factor. Percent of baseline energy consumption saved by installing the measure	%	Entertainment Center = .51	48

B.1.5.6. Deemed Savings Values

Table 11: Deemed Savings for Residential APS

Tier	***Size***	***Usage***	***kW Savings***	***kWh Savings***

[44] "Electricity Savings Opportunities for Home Electronics and Other Plug-In Devices in Minnesota Homes", Energy Center of Wisconsin, May 2010.

[45] "Smart Plug Strips", ECOS, July 2009.

[46] "Advanced Power Strip Research Report", NYSERDA, August 2011"

[47] C F Values of Standby Losses for Entertainment Center and Home Office in Efficiency Vermont TRM, 2013, pg 16. Developed through negotiations between Efficiency Vermont and the Vermont Department of Public Service

[48] "Tier 2 Advanced Power Strip Evaluation for Energy Saving Incentive," California Plug Load Research Center, 2014. http://www.efi.org/docs/studies/calplug_tier2.pdf

Tier	Size	Usage	kW Savings	kWh Savings
1	5-plug	Unspecified	.0056	48.9
		Entertainment	.0077	62.1
		Computer	.0037	35.8
	7-plug	Unspecified	.0067	57.7
		Entertainment	.0092	74.5
		Computer	.0045	42.9
2	5-plug	Unspecified	.0194	204.2
		Entertainment	.0316	307.4
		Computer	.0172	100.9

B.1.5.7. Incremental Cost

The incremental cost for APS systems is as follows:

Tier (1) – 5-plug: $16[49]

Tier (1) – 7-plug: $26[50]

Tier (2): $65[51]

B.1.5.8. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure had exceedingly low participation in Energy Smart programs (a total of 336 kWh in PY6). As a result, savings are calculated using values cited from evaluation reports completed on behalf of the New York State Energy Research & Development Authority (NYSERDA) and Wisconsin Focus On Energy. If participation reached 1% of residential Energy Smart program savings, the evaluation should include fieldwork to support in-service rates and to document an inventory of the equipment actually installed in to the APS by New Orleans residents.

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[49] Price survey performed in NYSERDA Measure Characterization for Advanced Power Strips, p4

[50] Ibid

[51] California Technology Forum, June 2015: https://static1.squarespace.com/static/53c96e16e4b003bdba4f4fee/t/556e25a3e4b06957271187a1/1433281955286/2015-01-15+Tier+2+Advance+Power+Strip+Cal+TF+Workpaper+Presentation_January.pdf

B.1.6. ENERGY STAR® Ceiling Fans

B.1.6.1. Measure Description

ENERGY STAR® ceiling fans require a more efficient CFM/Watt rating at the low, medium, and high settings than standard ceiling fans as well ENERGY STAR® qualified lighting for those with light kits included. Both of these features save energy compared to standard ceiling fans.

B.1.6.2. Estimated Useful Life (EUL)

The measure life for ceiling fans is 20 years.[52]

B.1.6.3. Deemed Savings

Deemed savings are calculated for fan-only ceiling fans.

Table 12 ENERGY STAR® Ceiling Fan – Deemed Savings

Fan Type	Energy Savings (kWh)	Demand Reduction (kW)
ENERGY STAR Lighting	68.9	.0087
Fan Only	16.0	0.00132

B.1.6.4. Calculation of Deemed Savings

B.1.6.4.1. Energy Savings - Fan

The energy savings are obtained through the following formula:

$$\Delta kWh = \left[\left(\%_{low} \times (Low_{base} - Low_{ee})\right) + \left(\%_{med} \times (Med_{base} - Med_{ee})\right) + \left(\%_{high} \times (High_{base} - High_{ee})\right)\right] \times \frac{1\ kW}{1000\ W} \times HOU_{fan} \times 365 \frac{days}{yr}$$

Where:

$\%_{low}$ = percentage of low setting use = 40%[53]

$\%_{med}$ = percentage of medium setting use = 40%[53]

$\%_{high}$ = percentage of high setting use = 20%[53]

Low_{base} = Wattage of low setting, baseline (W) = 15W[53]

Med_{base} = Wattage of medium setting, baseline (W) = 34W[53]

$High_{base}$ = Wattage of high setting, baseline (W) = 67W[53]

Low_{ee} = Wattage of low setting, ENERGY STAR® (W) = 4.8W[54,55]

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[52] Residential and C&I Lighting and HVAC Report Prepared for SPWG, 2007. Pg C-2.

[53] ENERGY STAR® Lighting Fixture and Ceiling Fan Calculator. Updated September, 2013

Med_{ee} = Wattage of medium setting, ENERGY STAR® (W) = 18.2W[54,55]

$High_{ee}$ = Wattage of high setting, ENERGY STAR® (W) = 45.9W[54,55]

HOU_{fan} = fan daily hours of use (hours/day) = 3 hours/day[53]

B.1.6.4.2. Energy Savings – Lighting

The energy savings from lighting apply the deemed savings assumptions specified in the Residential Lighting chapter of this TRM. The assumed configuration is (3) 14W CFLs, applying a 43W baseline. Other inputs may be applied by program implementers if model-specific information is available.

B.1.6.4.3. Demand Savings – Lighting

Demand savings are calculated in accordance with protocols specified in the Residential Lighting chapter.

B.1.6.4.4. Demand Savings - Fans

Demand savings result from the lower connected load of the ENERGY STAR® fan and ENERGY STAR® lighting. Peak demand savings are estimated using a Coincidence Factor (CF).

$$\Delta kW = \left[\left(\%_{low} \times (Low_{base} - Low_{ee})\right) + \left(\%_{med} \times (Med_{base} - Med_{ee})\right) + \left(\%_{high} \times (High_{base} - High_{ee})\right)\right] \times \frac{1\ kW}{1000\ W} \times CF$$

Where:

CF = Demand Factor= 0.091[56]

B.1.6.5. Incremental Cost

The incremental cost of a three-lamp ENERGY STAR Ceiling Fan is $46[57].

B.1.6.6. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the

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[54] ENERGY STAR® Ceiling Requirements Version 3.0

[55] ENERGY STAR® Certified Ceiling Fan List, Accessed April 3, 2014.

[56] EmPOWER Maryland 2012 Final Evaluation Report: Residential Lighting Program, Prepared by Navigant Consulting and the Cadmus Group, Inc., March 2013, Table 50.

[57] ENERGY STAR® Lighting Fixture and Ceiling Fan Calculator. Updated September, 2013

evaluation should include a review of the models actually incented through the program. The key parameters to be examined include:

- Content of the lighting included with the fan;
- Rated wattage of the fans at low, medium, and high speeds.

Deemed parameters should be updated whenever DOE standards or other applicable codes warrant it.

B.1.7. ENERGY STAR® Dehumidifiers

B.1.7.1. Measure Description

ENERGY STAR® must meet the minimum qualifying efficiency standard established by the current ENERGY STAR Version 3.0.

B.1.7.2. Baseline & Efficiency Standard

Table 13 shows the federal standard minimum efficiency and ENERGY STAR® standards, effective October 1, 2012. Federal standards do not limit residential dehumidifier capacity, but since ENERGY STAR® standards do limit the capacity to 185 pints per day, Table 13 only presents standards for the range of dehumidifier capacities that savings can be claimed.

Table 13: Dehumidifier Minimum Federal Efficiency and ENERGY STAR® Standards

Capacity (pints/day)	***Federal Standard (L/kWh_{base})***	***ENERGY STAR® (L/kWh_{ee})***
≤ 35	1.35	≥ 1.85
> 35 ≤ 45	1.50	
>45 ≤ 54	1.60	
>54 < 75	1.70	
75 ≤ 185	2.5	≥ 2.80

B.1.7.3. Estimated Useful Life (EUL)

The measure life for dehumidifiers is 12 years[58]

B.1.7.4. Deemed Savings

Deemed savings are calculated for ENERGY STAR units over the federal minimum standards for each capacity range.

Table 14: Dehumidifier Default Energy Savings[59]

[58] EnergyStar Calculator Accessed July 2013 using ENERGY STAR® Appliances. February 2008. U.S. Environmental Protection Agency and U.S. Department of Energy. ENERGY STAR® . http://www.energystar.gov/.

Capacity Range (pints/day)	Default Capacity (pints/day)	Federal Standard (kWh/yr)	ENERGY STAR (kWh/yr)	ΔkWh/yr	ΔkW_{peak}
≤ 35	35	834	609	225	0.05584
> 35 ≤ 45	45	965	782	183	0.04541
>45 ≤ 54	54	1086	939	147	0.03648
>54 < 75	74	1,400	1,287	113	0.02804
75 ≤ 185	130	1,673	1,493	180	0.04467

B.1.7.5. Calculation of Deemed Savings

The general form of the equation for the ENERGY STAR® Dehumidifier measure savings algorithm is:

$$\Delta kWh/yr_{total} = Number\ of\ Dehumidifiers \times Savings\ per\ Dehumidifier$$

To determine resource savings, the per-unit estimates in the algorithms will be multiplied by the number of dehumidifiers. The number of dehumidifiers will be determined using market assessments and market tracking.

B.1.7.5.1. Energy Savings

Per unit energy and demand savings algorithms:

$$\Delta\, kWh/yr = \left(\frac{CAPY \times 0.437\frac{liters}{pint}}{24\frac{hours}{day}}\right) \times HOU \times \left(\frac{1}{L/kWh_{base}} - \frac{1}{L/kWh_{ee}}\right)$$

Where:

$CAPY =$ Average capacity of the unit (pints/day)

HOU = Annual hours of operation (hours/yr), 1,632[60]

$L/kWh_{base} =$ Baseline unit liters of water per kWh consumed (liters/kWh). See Table 13.

$L/kWh_{ee} =$ ENERGY STAR® qualified unit liters of water per kWh consumed (liters/kWh). See Table 13.

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[59] Derived from equations in section 2.4.8, matching values generated by Energy Star Appliance Savings Calculator: http://www.energystar.gov/ia/business/bulk_purchasing/bpsavings_calc/appliance_calculator.xlsx

[60] ENERGY STAR® Appliance Savings Calculator. Updated August, 2013. This may not accurately reflect New Orleans humidity and can be revised if this measure is a sizable contributor to Energy Smart energy savings.

B.1.7.5.2. *Demand Savings*

$$\Delta kW_{peak} = \frac{\Delta\, kWh/yr}{HOU} \times CF$$

Where:

$CF =$ Demand Factor 0.405[61]

B.1.7.6. Incremental Cost

The incremental cost for an ENERGY STAR Dehumidifier is $60[62].

B.1.7.7. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of the units actually installed, adjusting savings based on capacity and efficiency levels.

If the measure exceeds 1% of residential kWh savings, a metering study should be completed to validate usage assumptions.

Deemed parameters should be updated whenever DOE standards or other applicable codes warrant it.

[61] Dehumidifier Metering in PA and Ohio by ADM from 7/17/2013 to 9/22/2013. 31 Units metered. Assumes all non-coincident peaks occur within window and that the average load during this window is representative of the June PJM days as well.

[62] ENERGY STAR® Appliance Savings Calculator

B.1.8. ENERGY STAR® Pool Pumps

B.1.8.1. Measure Description

This measure involves the replacement of a single-speed pool pump with an ENERGY STAR® certified variable speed or multi-speed pool pump. This measure applies to all residential applications; however, pools that serve multiple tenants in a common area are not eligible for this measure.

Multi-speed pool pumps are an alternative to variable speed pumps. The multi-speed pump uses an induction motor that is basically two motors in one, with full-speed and half-speed options. Multi-speed pumps may enable significant energy savings. However, if the half-speed motor is unable to complete the required water circulation task, the larger motor will operate exclusively. Having only two speed-choices limits the ability of the pump motor to fine-tune the flow rates required for maximum energy savings.[63] Therefore, multi-speed pumps must have a minimum size of 1 horsepower (HP) to be eligible for this measure.

B.1.8.2. Baseline and Efficiency Standards

The baseline condition is a 0.5-3 horsepower (HP) standard efficiency single-speed pool pump.

The high efficiency condition is a 0.5-3 HP ENERGY STAR® certified variable speed or multi-speed pool pump.

B.1.8.3. Estimated Useful Life (EUL)

According to DEER 2014, the estimated useful life for this measure is 10 years.[64]

B.1.8.4. Deemed Savings Values

Deemed savings are per installed unit based on the pump horsepower.

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[63] Hunt, A. & Easley, S., 2012, "*Measure Guideline: Replacing Single-Speed Pool Pumps with Variable Speed Pumps for Energy Savings."* Building America Retrofit Alliance (BARA), U.S. U.S. DOE. May/. http://www.nrel.gov/docs/fy12osti/54242.pdf.

[64] Database for Energy Efficient Resources (2014). http://www.deeresources.com/.

Table 15: ENERGY STAR® Variable Speed Pool Pumps – Deemed Savings Values

Pump HP	kW Savings	kWh Savings
0.5	0.24	1,713
0.75	0.28	1,860
1	0.36	2,063
1.5	0.47	2,465
2	0.52	2,718
2.5	0.57	2,838
3	0.72	3,364

Table16: ENERGY STAR® Multi-Speed Pool Pumps – Deemed Savings Values

Pump HP	kW Savings	kWh Savings
1	0.30	1,629
1.5	0.40	1,945
2	0.41	1,994
2.5	0.46	2,086
3	0.54	2,292

B.1.8.5. Calculation of Deemed Savings

B.1.8.5.1. Energy Savings

Energy savings for this measure were derived using the ENERGY STAR® Pool Pump Savings Calculator.[65]

$$kWh_{Savings} = kWh_{conv} - kWh_{ES}$$

Where:

kWh_{conv}= Conventional single-speed pool pump energy (kWh)

kWh_{ES}= ENERGY STAR® variable speed pool pump energy (kWh)

Algorithms to calculate the above parameters are defined as:

$$kWh_{conv} = \frac{PFR_{conv} \times 60 \times hours_{conv} \times days}{EF_{conv} \times 1000}$$

[65] The ENERGY STAR® Pool Pump Savings Calculator, updated February 2013, can be found on the ENERGY STAR® website at: https://www.energystar.gov/products/certified-products/detail/pool-pumps.

$$hours_{conv} = \frac{V_{pool} \times PT}{PFR_{conv} \times 60}$$

$$kWh_{ES} = kWh_{HS} + kWh_{LS}$$

$$kWh_{HS} = \frac{PFR_{HS} \times 60 \times hours_{HS} \times days}{EF_{HS} \times 1000}$$

$$kWh_{LS} = \frac{PFR_{LS} \times 60 \times hours_{LS} \times days}{EF_{LS} \times 1000}$$

$$PFR_{LS} = \frac{V_{pool}}{t_{turnover} \times 60}$$

Where:

kWh_{HS} = ENERGY STAR® variable speed pool pump energy at high speed (kWh)

kWh_{LS} = ENERGY STAR® variable speed pool pump energy at low speed (kWh)

$hours_{conv}$ = Conventional single-speed pump daily operating hours (Table 17)

$hours_{HS,VS}$ = ENERGY STAR® variable speed pump high speed daily operating hours = 2 hours

$hours_{LS,VS}$ = ENERGY STAR® variable speed pump low speed daily operating hours = 10 hours

$hours_{HS,MS}$ = ENERGY STAR® multi-speed pump high speed daily operating hours = 2 hours

$hours_{LS,VS}$ = ENERGY STAR® multi-speed pump low speed daily operating hours (Table 18)

$days$ = Operating days per year = 7 months x 30.4 days/month = 212.8 days (default)

PFR_{conv} = Conventional single-speed pump flow rate (gal/min) (Table 17)

$PFR_{HS,VS}$ = ENERGY STAR® variable speed pump high speed flow rate = 50 gal/min (default)

$PFR_{LS,VS}$ = ENERGY STAR® variable speed pump low speed flow rate (gal/min) = 30.6 (default)

$PFR_{HS,MS}$ = ENERGY STAR® multi-speed pump high speed flow rate (gal/min) (Table 16)

$PFR_{LS,MS}$ = ENERGY STAR® multi-speed pump low speed flow rate (gal/min) (Table 18)

EF_{conv} = Conventional single-speed pump energy factor (gal/W·hr) (Table 17)

$EF_{HS,VS}$ = ENERGY STAR® variable speed pump high speed energy factor = 3.75 gal/W·hr (default)

$EF_{LS,VS}$ = ENERGY STAR® variable speed pump low speed energy factor = 7.26 gal/W·hr (default)

$EF_{HS,MS}$ = ENERGY STAR® multi-speed pump high speed energy factor (gal/W·hr) (Table 18)

$EF_{LS,MS}$ = ENERGY STAR® multi-speed pump low speed energy factor (gal/W·hr) (Table 18)

V_{pool} = Pool volume = 22,000 gal (default)

PT = Pool turnovers per day = 1.5 (default)

$t_{turnover,VS}$ = Variable speed pump time to complete 1 turnover = 12 hours (default)

$t_{turnover,MS}$ = Multi-speed pump time to complete 1 turnover (Table 18)

60 = Constant to convert between minutes and hours

1000 = Constant to convert W to kW

Table 17: Conventional Pool Pumps Assumptions

Pump HP	$hours_{conv}$	PFR_{conv} (gal/min)	EF_{conv} (gal/W·h)
0.5	11.0	50.0	2.71
0.75	10.4	53.0	2.57
1	9.2	60.1	2.40
1.5	8.6	64.4	2.09
2	8.5	65.4	1.95
2.5	8.1	68.4	1.88
3	7.5	73.1	1.65

Table 18: ENERGY STAR® Multi-Speed Pool Pumps Assumptions

Pump HP	$t_{turnover,MS}$	$hours_{MS,LS}$	$PFR_{HS,MS}$ (gal/min)	$EF_{HS,MS}$ (gal/W·h)	$PFR_{LS,MS}$ (gal/min)	$EF_{LS,MS}$ (gal/W·h)
1	11.8	9.8	56.0	2.40	31.0	5.41
1.5	11.5	9.5	61.0	2.27	31.9	5.43
2	11.0	9.0	66.4	1.95	33.3	5.22
2.5	10.8	8.8	66.0	2.02	34.0	4.80
3	9.9	7.9	74.0	1.62	37.0	4.76

B.1.8.5.2. Demand Savings

Demand savings can be derived using the following:

$$kW_{Savings} = \left[\frac{kWh_{conv}}{hours_{conv}} - \left(\frac{kWh_{HS} + kWh_{LS}}{hours_{HS} + hours_{LS}}\right)\right] \times \frac{CF}{days}$$

Where:

CF = Coincidence factor[66] = 0.31

B.1.8.6. Incremental Cost

The incremental cost for ENERGY STAR Pool Pumps is[67]:

- $549 for Variable Speed
- $235 for Multi-Speed

B.1.8.7. Future Studies

This measure has low-to-moderate participation in Energy Smart programs. In PY6, pool pump savings totaled 19,157 kWh. If measure savings reach a minimum of 500,000 kWh in a program year, ADM recommends a metering study to validate usage assumptions.

Deemed parameters should be updated whenever DOE standard s or other applicable codes warrant it.

[66] Southern California Edison (SCE) Design & Engineering Services, 2008., *"Pool Pump Demand Response Potential, DR 07.01 Report."* June 2008. Derived from Table 16 assuming a peak period of 2-6 PM.

[67] ENERGY STAR Pool Pump Calculator

B.2. Domestic Hot Water

B.2.1. Water Heater Replacement

B.2.1.1. Measure Description

This measure involves:

- The replacement of electric water heaters by heat pump water heaters (HPWH)
- The replacement of either electric or gas water heaters by ENERGY STAR® certified solar water heaters

Electric resistant storage tank water heaters do not qualify as the code update effective April 16, 2015 requires a minimum of 95% efficiency for this equipment category.

Heat Pump Water Heaters and Solar Water Heaters are eligible for systems that are no larger than 55 gallons.

Water heating deemed savings values are measured on an annual per-unit basis. Deemed savings variables include tank volume, estimated water usage, weather zone, and rated energy factor. Fuel substitution is not eligible for deemed savings. This measure applies to all residential applications.

B.2.1.2. Baseline and Efficiency Standards

The current baseline for electric and gas water heaters is the US DOE energy efficiency standard (10 CFR Part 430), which is consistent with the International Energy Conservation Code (IECC) 2009. April 16, 2015 must comply with the amended standards found in the Code of Federal Regulations, 10 CFR 430.32(d), as found in Table 19.

Table 19: Title 10: 430.32 (d) Water Heater Standards and their Compliance Dates

Product class	***Energy factor as of April 16, 2015***
Gas-fired Water Heater (≥ 20 gal and ≤ 100 gal)	For Vs ≤ 55 gallons: EF = 0.675−(0.0015 × Vs) For Vs > 55 gallons: EF = 0.8012−(0.00078 × Vs).
Electric Water Heater (≥ 20 gal and ≤120 gal)	For Vs ≤ 55 gallons: EF = 0.960−(0.0003 × Vs). For Vs > 55 gallons: EF = 2.057−(0.00113 × Vs).
Where Vs is the Rated Storage Volume which equals the water storage capacity of a water heater, in gallons, as certified by the manufacturer.	

Current baseline Energy Factors (efficiencies) for standard size electric and gas water heaters are calculated and shown in Table 20. Future baseline Energy Factors (efficiencies) to be used after 2015 for standard size electric and gas water heaters are calculated and shown in Table 21.

Table 20: Water Heater Replacement Baseline Energy Factors (Calculated)

Minimum Required Energy Factors by NAECA for Electric Resistance Heating Before 4/16/2015			
Tank Size (Gallons) of Replaced Water			
40	50	65	80
0.92	0.90	0.88	0.86

The Energy Factor of a replacement water heater must be at least 5 percent higher than the baseline for the corresponding fuel type and tank size shown in Table 20 and Table 21.

Table 21: Water Heater Replacement Baseline Energy Factors (Calculated)

Minimum Required Energy Factors by NAECA for Electric Resistance Heating After 4/16/2015[68]				
Fuel Type	Tank Size (Gallons) of Replaced Water Heating			
	40	50	65	80
Natural Gas or Propane	0.62	0.60	0.75	0.74
Electric	0.95	0.95	1.98	1.97

B.2.1.3. Estimated Useful Life (EUL)

The average lifetime of this measure is dependent on the type of water heating. According to DEER 2014, the following measure lifetimes should be applied:

- 10 years for Heat Pump Water Heaters
- 15 years for solar water heaters

B.2.1.4. Calculation of Deemed Savings – Heat Pump Water Heater (HPWH)

B.2.1.4.1. Energy Savings – Heat Pump Water Heater

The residential heat pump water heater (HPWH) measure involves the installation of an integrated ENERGY STAR® HPWH. The HPWHs available through the ENERGY STAR® product finder[69] have an average EF of 2.75.

[68] 10 CFR Part 430.32 Energy Conservation Program for Consumer Products: Energy Conservation Standards for Water Heaters; Final Rule. www.gpo.gov/fdsys/pkg/CFR-2012-title10-vol3/pdf/CFR-2012-title10-vol3-sec430-32.pdf

The variables affecting deemed savings are: storage tank volume, HPWH Energy Factor (EF), HPWH installation location (in conditioned or unconditioned space), and weather zone. This measure takes into account an air-conditioning energy savings ("Cooling Bonus") and an additional space heating energy requirement ("Heating Penalty") associated with the HPWH when it is installed inside conditioned space.

$$kWh_{Savings} = \frac{\rho \times C_p \times V \times \left(T_{SetPoint} - T_{Supply}\right) \times \left(\frac{1}{EF_{pre}} - \left(\frac{1}{(EF_{post} \times (1 + PA\%)} \times Adj\right)\right)}{3{,}412\ Btu/kWh}$$

Where:

ρ = Water density = 8.33 lb/gal

C_p = Specific heat of water = 1 BTU/lb·°F

V = Estimated annual hot water use (gal) from Table 22

$T_{SetPoint}$ = Water heater set point (value = 122.24°F, based on on-site testing of New Orleans homes)

T_{Supply} = Average New Orleans area supply water temperature, 74.8°F

EF_{pre} = Baseline Energy Factor from Table 20 or Table 21

EF_{post} = Energy Factor of new HPWH

$PA\%$ = Performance Adjustment to adjust the HPWH EF relative to ambient air temperature per DOE guidance[70] $= 0.00008 \times T_{amb}^3 + 0.0011 \times T_{amb}^2 - 0.4833 \times T_{amb} + 0.0857$

T_{amb}= Ambient temperature dependent on location of HPWH (Conditioned or Unconditioned Space) and Weather Zone from Table 23

Adj =HPWH-specific adjustment factor to account for Cooling Bonus and Heating Penalty on an annual basis, as well as backup electrical resistance heating which is estimated at 0.92 EF. Adjustment factors are listed in Table 24.

$Conversion\ Factor$ = 3,412 Btu/kWh

Table 22: Estimated Annual Hot Water Use (gal)

Tank Size (gal) of Replaced Water Heater	***40***	***50***	***65***	***80***

[69] www.energystar.gov/productfinder/product/certified-water-heaters/ accessed on 6/27/2015.

[70] Kelso, J. 2003. Incorporating Water Heater Replacement into The Weatherization Assistance Program, May. D&R International, Ltd. Information Tool Kit.

Estimated annual hot water usage	16,696	18,973	22,767	27,320

The average air ambient temperatures listed in Table 23 are applicable to the installation locations for the HPWH. Unconditioned space is considered to be an unheated garage-like environment. This data is based on local ambient temperatures for each weather zone calculated from TMY3 weather data. The conditioned space temperatures assume thermostat settings of 78F (cooling season) and 70F (heating season), and a “balance point temperature”71 of 65F. Unconditioned space ambient temperatures are adjusted from the local temperatures by seasonal factors72 to account for a garage-like setting.

Table 23: Average Ambient Temperatures by Installation Location

Conditioned Space	**Unconditioned Space**
74.02	74.43

Table 24: HPWH Adjustment[73]

Water Heater Location	**Furnace Type**	**Adjustment Factor**
Conditioned Space	Gas	0.917
	Heat Pump	1.201
	Elec. Resistance	1.395
Unconditioned Space	N/A	1.07

As an example, the following deemed electricity savings are applicable for the replacement of a 50-gallon electric storage tank water heater with a 50-gallon heat pump water heater using a model with an EF of 2.75 in conditioned space for a household using a gas furnace in New Orleans:

[71] “Average daily outside temperature at which a building maintains a comfortable indoor temperature without heating or cooling”; www.weatherdatadepot.com/faq#.USPZwKWvN8E

[72] ASHRAE: Standard 152-2004 Table 6.1b and 6.2b

[73] In order to facilitate an algorithmic approach: a spreadsheet model was created which modeled savings accounting for Cooling Bonus and Heating Penalty on an annual basis, as well as backup electrical resistance heating; HPWH Adjustment factors were derived to equate the results of this more extensive model to a simpler algorithm.

$$kWh_{Savings} = \frac{8.33 \times 1 \times 18{,}973 \times (122.24 - 74.8) \times \left(\frac{1}{0.90} - \left(\frac{1}{2.75 \times (1 + 0.027842)} \times .917\right)\right)}{3{,}412}$$

$$= 1{,}728.7\ kWh$$

B.2.1.4.2. Demand Savings – HPWH

$$kW_{savings} = kWh_{savings} \times Ratio_{Annual\ kWh}^{Peak\ kW}$$

Where:

$Ratio_{Annual\ kWh}^{Peak\ kW}$ = 0.0000877

Demand savings were calculated using the US DOE's "*Building America Performance Analysis Procedures for Existing Homes*" combined domestic hot water use profile.[74] Based on this profile, the ratio of Peak kW to Annual kWh for domestic hot water usage was estimated to be 0.0000877 kW per annual kWh savings

For the HPWH example shown in Equation above, peak demand savings is 1,728.7 kWh × 0.0000877 = 0.1516 kW.

B.2.1.5. Calculation of Deemed Savings – Solar Water Heating with Gas or Electric Backup

B.2.1.5.1. Energy Savings – Solar Water Heating Systems with Electric Backup

The residential solar water heater measure involves the installation of an ENERGY STAR® certified solar water heater rated by the Solar Rating and Certification Corporation (SRCC). Solar water heaters available through the ENERGY STAR® product finder[75] have an average Solar Energy Factor (SEF) of 8.7 for electric backup and 1.9 for gas backup.

The variables affecting deemed savings are: SEF and weather zone.

The SRCC determines SEF based on standardized 1,500 Btu/ft2-day solar radiation profile across the U.S. As solar insolation varies widely depending on geographic location, in order to derive more accurate estimates for a given locale, Localization Factors (LF) are used to adjust the SEF. The LF for the New Orleans weather zone have been calculated. The LF is based on the daily total insolation (1,598 in New

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[74] U.S. DOE "Building America Performance Analysis Procedures for Existing Homes" combined domestic hot water use profile.

[75] www.energystar.gov/productfinder/product/certified-water-heaters/results

Orleans), averaged annually, per a Satellite Solar Radiation model developed by the State University of New York (SUNY).

$$kWh_{Savings} = \frac{\rho \times C_p \times V \times (T_{SetPoint} - T_{Supply}) \times \left(\frac{1}{EF_{pre}} - \frac{1}{SEF\ x\ LF}\right)}{3412\ Btu/kWh}$$

(1)

Where:

ρ = Water density = 8.33 lb/gal

C_p = Specific heat of water = 1 BTU/lb·°F

V = Estimated annual hot water use (gal) from Table 22

$T_{SetPoint}$ = Water heater set point (default value = 122.24°F)

T_{Supply} = Average New Orleans area supply water temperature, 74.8°F

EF_{pre} = Baseline Energy Factor from Table 20 or Table 21

SEF = Solar Energy Factor of new water heater

LF = Localization Factor for SEF of new water heater in New Orleans, 1.068

As an example, the following deemed electricity savings are applicable for replacement of a 50-gallon electric storage tank water heater with a 50-gallon solar water heater with electric backup using a model with an EF of 8.7 for a household in New Orleans:

$$kWh_{Savings} = \frac{8.33 \times 1 \times 18{,}973 \times (122.24 - 74.8) \times \left(\frac{1}{0.90} - \frac{1}{(8.7\ \times\ 1.068)}\right)}{3{,}412\ Btu/kWh}$$

$$= 2{,}205.1\ kWh/yr$$

B.2.1.5.2. Demand Savings – Solar Water Heating Systems with Electric Backup

$$kW_{savings} = kWh_{savings} \times Ratio \frac{Peak\ kW}{Annual\ kWh}$$

Where:

$Ratio \frac{Peak\ kW}{Annual\ kWh}$ = 0.0000877

For the above example, peak demand savings is 2,205.1 kWh x 0.0000877 = 0.1934kW.

B.2.1.6. Incremental Cost

The incremental cost of a HPWH is $1,027[76].

The incremental cost of a Solar Water Heater is $8,401[77].

B.2.1.7. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans residents.

If participation reached 1% of residential Energy Smart program savings, ADM recommends a metering study to support usage assumptions.

If the measure is under consideration for inclusion or increased emphasis in Energy Smart, ADM recommends a market assessment to provide guidance as to the needs of New Orleans residents and plumbing contractors and to address savings potential.

Deemed parameters should be updated whenever DOE standards or other applicable codes warrant.

[76] Northeast Energy Efficiency Partnership: Incremental cost Study Phase 3 Final Report. http://www.neep.org/file/1003/download?token=Z0RB3yrZ

[77] California Solar Thermal Program: 2012 reported project costs.

B.2.2. Water Heater Jackets

B.2.2.1. Measure Description

This measure involves water heater jackets (WHJ) installed on water heaters located in an unconditioned space. These estimates apply to all weather regions. This measure applies to all residential applications.

B.2.2.2. Baseline and Efficiency Standards

Baseline is assumed to be the post-1991, storage-type water heater.

WHJ must be installed on storage water heaters having a capacity of 30 gallons or greater. The manufacturer's instructions on the WHJ and the water heater itself should be followed. If electric, thermostat and heating element access panels must be left uncovered. If gas, follow WHJ installation instructions regarding combustion air and flue access.

Table 25: Water Heater Jackets – Baseline and Efficiency Standards

Baseline	Efficiency Standard
Un-insulated water heater	Minimum insulation of R-6.7

B.2.2.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 13 years, according to NEAT v.8.6.

B.2.2.4. Deemed Savings Values

Deemed savings are per installed jacket based on the jacket thickness, the type of water heating and the tank size.

Table 26: Water Heater Jackets – Electric Heating Deemed Savings Values

	Electric Water Heating					
Approximate Tank Size (gal)	kWh Savings			kW Savings		
	40	52	80	40	52	80
2" WHJ savings kWh	68	76	101	0.005	0.006	0.008
3" WHJ savings kWh	94	104	139	0.007	0.008	0.011

B.2.2.5. Calculation of Deemed Savings

Energy consumption for baseline units, with and without insulation jackets, was calculated using industry-standard energy-use calculation methodologies for residential domestic water heating. Variables in the calculations include the following:

- Water heater fuel type (electric or gas/propane)
- Baseline EF

- Estimated U-value of baseline unit
- Ambient temperature
- Tank volume
- Tank surface area
- Tank temperature
- Estimated hot water consumption

To estimate peak energy consumption, a load profile for residential water heating was developed from individual load profiles for the following end-uses:

- Clothes washer
- Dishwasher
- Faucet
- Shower
- Sink-filling
- Bath
- Miscellaneous

This end-use load shape data was calibrated using metered end-used data obtained from several utility end-use metering studies.

B.2.2.6. Incremental Cost

The incremental cost of a Water Heater Jacket is equal to the full installed cost. If the cost is unknown, use $35[78].

B.2.2.7. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values based on NEAT v.8.6 estimates.

In the PY7 or PY8 evaluation of the Home Performance with Energy Star program, it is recommended that the percent of unjacketed water heaters is documented in order to inform whether water heater jackets warrant inclusion as a direct install measure.

[78] Based on review of available products for 40 and 50-gallon water heaters..

B.2.3. Water Heater Pipe Insulation

B.2.3.1. Measure Description

This measure requires water heater pipe insulation. Water heaters plumbed with heat traps are not eligible to receive incentives for this measure. New construction and water heater retrofits are not eligible for this measure, because they must meet current code requirements. This measure applies to all residential applications.

B.2.3.2. Baseline and Efficiency Standards

Baseline is assumed to be the typical gas or electric water heater with no heat.

All hot and cold vertical lengths of pipe should be insulated, plus the initial length of horizontal hot and cold water pipe, up to three feet from the transition, or until wall penetration, whichever is less.

Table 27: Water Heater Pipe Insulation – Baseline and Efficiency Standards

Baseline	Efficiency Standard
Un-insulated hot water pipes	Minimum insulation thickness of ½"

B.2.3.3. Estimated Useful Life (EUL)

The average lifetime of this measure is dependent on the type of water heater it is applied to. According to DEER 2008, the following measure lifetimes should be applied:

- 13 years for electric storage water heating
- 11 years for gas storage water heating
- 10 years for heat pump water heaters

B.2.3.4. Calculation of Deemed Savings

B.2.3.4.1. Energy Savings – Water Heater Pipe Insulation for Electric, Gas, or Heat Pump Water Heater (HPWH)

$$Annual\ Energy\ Savings = (U_{pre} - U_{post}) \times A \times (T_{Pipe} - T_{ambient}) \times \left(\frac{1}{RE}\right) \times \frac{Hours_{Total}}{Conversion\ Factor}$$

Where:

U_{pre}= 1/(2.03[79]) = 0.49 BTU/h sq. ft. degree F

U_{post}= 1/(2.03+$R_{Insulation}$)

$R_{Insulation}$= R-value of installed insulation

A = Surface area in square feet (πDL) with L (length) and D pipe diameter in feet

$T_{Pipe}(°\mathrm{F})$ = Average temperature of the pipe. Default value = 90 °F (average temperature of pipe between water heater and the wall)

$T_{ambient}(°\mathrm{F})$ = 68.78°F (New Orleans)

RE = Recovery Efficiency (or in the case of HPWH, EF); if unknown, use 0.98 as a default for electric resistance water heaters, 0.79 for natural gas water heaters, or 2.2 for heat pump water heaters[80]

$Hours_{Total}$ = 8,760 hr per year[81,82]

$Conversion\ Factor$ = 3,412 Btu/kWh for electric water heating or 100,000 Btu/Therm for gas water heating. For example, deemed savings for water heater pipe insulation with an R-value of 3 installed on an electric water heater in New Orleans would be:

$$kWh_{savings} = (0.49 - 0.20) \times 2.1 \times (90 - 68.78) \times \left(\frac{1}{0.98}\right) \times \frac{8{,}760}{3{,}412} = 33.9\ kWh/yr$$

B.2.3.4.2. Demand Savings

Peak demand savings for hot water heaters installed in conditioned space can be calculated using the following formula for electric:

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79 2.03 is the R-value representing the film coefficients between water and the inside of the pipe and between the surface and air. Mark's Standard Handbook for Mechanical Engineers, 8th edition.

80 Default values based on median recovery efficiency of residential water heaters by fuel type in the AHRI database, at https://www.ahridirectory.org/ahridirectory/pages/rwh/defaultSearch.aspx

81 Ontario Energy's Measures and Assumptions for Demand Side Management (DSM) Planning www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0346/Navigant_Appendix_C_substantiation_sheet_20090429.pdf

82 New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs Residential, Multi-Family, and Commercial/Industrial Measures http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/06f2fee55575bd8a852576e4006f9af7/$FILE/TechManualNYRevised10-15-10.pdf

$$kW_{savings} = \left(U_{pre} - U_{post}\right) \times A \times \left(T_{Pipe} - T_{ambientMAX}\right) \times \left(\frac{1}{RE}\right) \times \frac{1}{3{,}412\ Btu/kWh}$$

(2)

Where:

U_{pre} = 1/(2.03) =0.49 BTU/h sq ft degree F

U_{post} = 1/(2.03+$R_{Insulation}$)

$R_{Insulation}$ = R-value of installed insulation

$A =$ Surface area in square feet (πDL) with L (length) and D pipe diameter in feet

T_{Pipe}(°F) = Average temperature of the pipe. Default value = 90 °F (average temperature of pipe between water heater and the wall)

$T_{ambientMAX}$(°F) =For water heaters installed in unconditioned basements, use an average ambient temperature of 75°F; for water heaters inside the thermal envelope, use an average ambient temperature of 78 °F

RE = Recovery efficiency (or in the case of HPWH, EF); if unknown, use 0.98 as a default for electric resistance or 2.2 for heat pump water heaters.

B.2.3.5. Incremental Cost

The incremental cost of a Water Heater Pipe Insulation is equal to the full installed cost. If the cost is unknown, use $3 per linear foot of insulation[83].

B.2.3.6. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values based on NEAT v.8.6 estimates.

In the PY7 or PY8 evaluation of the Home Performance with Energy Star program, it is recommended that the percent of uninsulated hot water lines is documented in order to inform whether pipe insulation warrant inclusion as a direct install measure

[83] California DEER 2008

B.2.4. Faucet Aerators

B.2.4.1. Measure Description

This measure involves retrofitting aerators on kitchen and bathroom water faucets. The savings values are per faucet aerator installed. It is not a requirement that all faucets in a home be treated for the deemed savings to be applicable. This measure applies to all residential applications.

B.2.4.2. Baseline and Efficiency Standards

The 2.2 GPM baseline faucet flow rate[84] is based upon the Energy Policy Act of 1992 (EPAct 92) and subsequent EPAct actions which limited faucet flows to 2.2 GPM. The US EPA WaterSense® specification for faucet aerators is 1.5 gallons per minute (GPM).[85]

Table 28: Faucet Aerators – Baseline and Efficiency Standards

Baseline	Efficiency Standard
2.2 GPM	1.5 GPM maximum

The deemed savings values are for residential, retrofit-only installation of kitchen and bathroom faucet aerators.

B.2.4.3. Additional Requirement for Contractor-Installed Aerators

Aerators that have been defaced so as to make the flow rating illegible are not eligible for replacement. For direct install programs, all aerators removed shall be collected by the contractor and held for possible inspection by the utility until all inspections for invoiced installations have been completed.

B.2.4.4. Estimated Useful Life (EUL)

The average lifetime of this measure is 10 years, according to DEER 2014.

B.2.4.5. Effect of Weather Zones on Water Usage and Water Main Temperature

Average water main temperatures for the New Orleans is 74.8°F. The water main temperature data was approximated using the following formula.[86]

$$T\ of\ water\ main = T_{avg\ ambient} + R \times \Delta T_{amb}$$

[84] Maximum flow rate federal standard for lavatories and aerators set in Federal Energy Policy Act of 1992 and codified at 2.2 GPM at 60 psi in 10CFR430.32

[85] "High-Efficiency Lavatory Faucet Specification." WaterSense. EPA. October 1, 2007. http://www.epa.gov/watersense/partners/faucets_final.html

[86] Burch, J & Christensen, C. 2007. "Towards Development of an Algorithm for Mains Water Temperature." Proceedings of the 2007 ASES Annual Conference, Cleveland, OH.

Where:

$T_{avg\ ambient}$ = the average annual ambient dry bulb temperature, 68.8°F in New Orleans

R = 0.05

ΔT_{amb} = the average of maximum and minimum ambient air dry bulb temperature for the month (Tmax + Tmin)/2 where Tmax = maximum ambient dry bulb temperature for the month, and Tmin = minimum ambient dry bulb temperature for the month

Baseline and efficiency-standard water usages per capita were derived from an analysis of metered studies of residential water efficiency retrofit projects conducted for Seattle, WA.; the East Bay Municipal Utility District (CA); and Tampa, FL.[87, 88, 89]

B.2.4.6. Estimated Hot Water Usage Reduction

$$Water\ consumption = \frac{\frac{Faucet\ Use\ per\ Person}{Day} \times Occupants\ per\ Home \times \frac{365\ Days}{Year}}{Faucets\ per\ Home}$$

Applying the formula to the values from Table 29 returns the following baseline and post water consumption.

Baseline (2.2 GPM): 9.7 x 2.37 x 365 / 3.86 =2,174

Post (1.5 GPM): 8.2 x 2.37 x 365 / 3.86 = 1,838

Post (1.0 GPM): 7.2 x 2.37 x 365 / 3.86 = 1,614

Gallons of water saved per year can be found by subtracting the post consumption in gallons per year per aerator from the baseline consumption.

- Gallons of water saved per year (1.5 GPM): 2,174 – 1,838= 336

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[87] Seattle Home Water Conservation Study, 2000. "The Impacts of High Efficiency Plumbing Fixture Retrofits in Single-Family Homes." December. http://www.allianceforwaterefficiency.org/mainsearch.aspx?searchtext=Seattle%20Home%20Water%20Conservation%20Study

[88] Residential Indoor Water Conservation Study, 2003 "Evaluation of High Efficiency Indoor Plumbing Fixture Retrofits in Single-Family Homes in the East Bay Municipal Utility District Service Area." July. www.allianceforwaterefficiency.org/WorkArea/DownloadAsset.aspx?id=868

89 Tampa Water Department Residential Water Conservation Study, 2004, "The Impacts of High Efficiency Plumbing Fixture Retrofits in Single-Family Homes." January 8. https://www.cuwcc.org/Portals/0/Document%20Library/Resources/Water%20Efficient%20Product%20Information/End%20Use%20Studies%20-%20Multiple%20Technologies/Tampa-Residential-Water-Conservation-Final-Report.pdf

- Gallons of water saved per year (1.0 GPM): 2,174 – 1,614 = 560

Table 29: Estimated Aerator Hot Water Usage Reduction

Assumption Type	Seattle Study[90]	Tampa Study[91]	East Bay Study	Average	Value used for New Orleans
Faucet use gallons/person/day (baseline)	9.2	9.4	10.5	9.7	9.7
Faucet use gallons/person/day (1.5 GPM)	8.0	6.2	10.5	8.2	8.2
Faucet use gallons/person/day (1.0 GPM)[92]	--	--	--	--	7.2
Occupants per home	2.54	2.92	2.56	2.67	2.37[93]
Faucets per home[94]	--	--	--	--	3.86
Gal./yr./faucet (baseline)	--	--	--	--	2,467
Gal./yr./faucet (1.5 GPM)	--	--	--	--	2,086
Gal./yr./faucet (1.0 GPM)	--	--	--	--	1,831
Percent hot water	76.10%4	Not listed	57.60%5	66.90%	66.9%
Water gallons saved/yr./faucet (1.5 GPM)	--	--	--	--	336
Water gallons saved/yr./faucet (1.0 GPM)	--	--	--	--	560

Based on the average percentage hot water shown in Table 29, the average mixed water temperature across all weather zones was determined. The hot water temperature was found to be 122.24°F in a sample of 37 homes in New Orleans tested by ADM. The mixed water temperature used in the energy savings calculation can be seen in Table 30.

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[90] Average of pre-retrofit percent faucet hot water 72.7% on page 35, and post-retrofit percent faucet hot water 79.5% on page 53.

[91] Average of pre-retrofit percent faucet hot water 65.2% on page 31 and post-retrofit faucet hot water percentage 50.0% on page 54.

[92] This value is a linear extrapolation of gallons per person per day from the baseline (2.2 GPM) and the 1.5 GPM case.

[93] 2010-2014, US Census Bureau. http://www.census.gov/quickfacts/table/PST045215/2255000

[94] Faucets per home assumed to be equal to one plus the number half bathrooms and full bathrooms per home, taken from 2009 RECS, Table HC2.10.

Table 30: Mixed Water Temperature Calculation

Weather Zone	Average Water Main Temperature (°F)	Percent Hot Water	Mixed Water Temperature (°F)
New Orleans	74.8	66.9%	106.5

B.2.4.7. Calculation of Deemed Savings

B.2.4.7.1. Energy Savings

$$Annual\ Energy\ Savings\ = \frac{\rho \times C_P \times V \times \left(T_{Mixed} - T_{Supply}\right) \times \left(\frac{1}{RE}\right)}{Conversion\ Factor}$$

Where:

ρ = Water density = 8.33 lb/gal

C_P = Specific heat of water = 1 BTU/lb·°F

V = Gallons of water saved per year per faucet from Table 29

T_{Mixed} = Mixed water temperature, 106.5°F, from Table 30

T_{Supply} = Average New Orleans area supply water temperature, 74.8°F

RE = Recovery Efficiency (or in the case of HPWH, EF); if unknown, use 0.98 as a default for electric resistance water heaters, 2.2 for heat pump water heaters, or 0.79 for natural gas water heaters[95].

$Conversion\ Factor$ = 3,412 Btu/kWh for electric water heating or 100,000 Btu/Therm for gas water heating

B.2.4.7.2. Demand Savings

Demand savings for homes with electric water heating were calculated using the following formula:

$$kW_{savings} = kWh_{savings} \times Ratio_{Annual\ kWh}^{Peak\ kW}$$

(3)

Where:

$Ratio_{Annual\ kWh}^{Peak\ kW}$ = 0.000104

This value is taken from the DOE domestic hot water use study.[96] The DOE domestic hot water use study provided values for the share of daily water use per hour in a profile

[95] Default values based on median recovery efficiency of residential water heaters by fuel type in the AHRI database, at https://www.ahridirectory.org/ahridirectory/pages/rwh/defaultSearch.aspx

for shower bath, and sink hot water use. An average was calculated using peak hours of 3 PM to 6 PM to generate an average hourly share of daily water use during peak hours. That value was divided by 365 to generate a ratio of peak share to annual use.

B.2.4.7.3. Example Calculation of Deemed Savings Values

Deemed savings values are per faucet aerator installed.

Table 31: Example, Replacing 2.2 GPM with 1.5 GPM Faucet Aerator - Deemed Energy and Demand Savings

Faucet Aerator, New Orleans Weather Zone		
Water Usage Reduction (gal)	336	
T_{Supply}	74.8F	
T_{Mixed}	106.5°F	
Water heater RE (excluding standby losses)	0.98 (Electric) / 2.2 (Heat Pump)	
Energy Savings	Electric: 26.5 kWh	Heat Pump: 11.82 kWh
Demand Savings	Electric: 0.0028 kW	Heat Pump: 0.0012 kW

B.2.4.8. Future Studies

To-date, Energy Smart evaluations have provided two primary research points for this measure:

- New Orleans water main temperature;
- Water heater setpoint.

The water main temperature is a fixed value based on TMY3 weather data. The water heater setpoint should be supplemented with additional data collection in PY7.

Metering studies for water use are exceedingly expensive. In past metering efforts, ADM has found costs to exceed $750 per site. As such, we do not advise a metering study for this measure unless savings exceed 5% of residential program savings.

[96] U.S. DOE's 2006. "*Building America Performance Analysis Procedures for Existing Homes". National Renewable Energy Laboratory.* May. http://www.nrel.gov/docs/fy06osti/38238.pdf (See Figure 3, page 17.) This TRM looked at hourly share of daily water use at 3pm 4pm, 5pm, and 6pm in Figure 3. The fractions of hourly use derived were 0.022 for 3pm, 0.03 for 4pm, 0.04 for 5pm, and 0.06 for 6pm. The average of these fractions is 0.038, which is the average share of daily water use that falls on a peak hour per day. Dividing that value by 365 days calculates a ratio of 0.000104 as the ratio of peak share to annual use.

B.2.5. Low-Flow Showerheads

B.2.5.1. Measure Description

This measure consists of removing existing showerheads and installing low-flow showerheads in residences. This measure applies to all residential applications.

B.2.5.2. Baseline and Efficiency Standards

The baseline average flow rate of the existing stock of showerheads is based on the current US DOE standard.

The incentive is for replacement of an existing showerhead with a new showerhead rated at 2.0, 1.75 or 1.5 gallons per minute (GPM). The only showerheads eligible for installation are those that are not easily modified to increase the flow rate.

B.2.5.3. Additional Requirement for Contractor-Installed Showerheads

Existing showerheads that have been defaced so as to make the flow rating illegible are not eligible for replacement. All showerheads removed shall be collected by the contractor and held for possible inspection by the utility until all inspections for invoiced installations have been completed.

Table 32: Low-Flow Showerhead – Baseline and Efficiency Standards

Measure	*New Showerhead Flow Rate[97] (GPM)*	*Existing Showerhead Baseline Flow Rate (GPM)*
2.0 GPM showerhead	2.0	2.5
1.75 GPM showerhead	1.75	2.5
1.5 GPM showerhead	1.5	2.5

The U.S. Environmental Protection Agency (EPA) WaterSense Program has implemented efficiency standards for showerheads requiring a maximum flow rate of 2.0 GPM. http://www1.eere.energy.gov/femp/program/waterefficiency_bmp7.html.

B.2.5.4. Estimated Useful Life (EUL)

The average lifetime of this measure is 10 years, according to DEER 2014.

[97] All flow rate requirements listed here are the rated flow of the showerhead measured at 80 pounds per square inch of pressure (psi).

B.2.5.5. Effect of Weather Zones on Water Usage and Water Main Temperature

Average water main temperatures is 74.8. The water main temperature data was approximated using the following formula.[98]

$$T\ of\ water\ main = T_{avg\ ambient} + R \times \Delta T_{amb}$$

Where:

R = 0.05

$T_{avg\ ambient}$ = the average annual ambient dry bulb temperature

ΔT_{amb} = 74.8 (New Orleans), the average of maximum and minimum ambient air dry bulb temperature for the month (Tmax + Tmin)/2 where Tmax = maximum ambient dry bulb temperature for the month and Tmin = minimum ambient dry bulb temperature for the month

B.2.5.6. Estimated Hot Water Usage Reduction

Baseline and efficiency standard water usages per capita were derived from an analysis of metered studies of residential water efficiency retrofit projects conducted for Seattle, WA.; the East Bay Municipal Utility District (CA); and Tampa, FL.[99,100,101] See Table 29 for derivation of water usage values.

To determine water consumption, the following formula was used:

$$\frac{Gallons}{Shower} \times \frac{Showers\ per\ Person}{Day} \times \frac{365\ Days}{Year} \times \frac{Occupants\ per\ Home}{Showerheads\ per\ Home}$$

Applying the formula to the values from Table 11 returns the following baseline and post water consumption.

- Baseline (2.5 GPM): 20.7 x 0.69 x 365 x 2.37 / 1.62 = 7,627

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[98] Burch, J. & Christensen, C. 2007. *"Towards Development of an Algorithm for Mains Water Temperature"* Proceedings of the 2007 ASES Annual Conference, Cleveland, OH.

[99] Seattle Home Water Conservation Study, 2000. "The Impacts of High Efficiency Plumbing Fixture Retrofits in Single-Family Homes." December.

http://www.allianceforwaterefficiency.org/mainsearch.aspx?searchtext=Seattle Home Water Conservation Study

[100] Residential Indoor Water Conservation Study, 2003. "Evaluation of High Efficiency Indoor Plumbing Fixture Retrofits in Single-Family Homes in the East Bay Municipal Utility District Service Area." July. http://www.allianceforwaterefficiency.org/WorkArea/DownloadAsset.aspx?id=868

[101] Tampa Water Department Residential Water Conservation Study, 2004, *"The Impacts of High Efficiency Plumbing Fixture Retrofits in Single-Family Homes,"* January 8. https://www.cuwcc.org/Portals/0/Document%20Library/Resources/Water%20Efficient%20Product%20Information/End%20Use%20Studies%20-%20Multiple%20Technologies/Tampa-Residential-Water-Conservation-Final-Report.pdf

- Post (2.0 GPM): 16.5 x 0.72 x 365 x 2.37 / 1.62 = 6,344
- Post (1.5 GPM): 12.4 x 0.72 x 365 x 2.37 / 1.62 = 4,767

Although the referenced studies do not provide data on 1.75 GPM showerheads, the consumption values for 2.5, 2.0, and 1.5 GPM roughly follow a linear pattern. Taking a simple average of the consumption for 2.0 and 1.5 GPM showerheads returns a value for a 1.75 GPM showerhead:

- Post (1.75 GPM): (6,344 + 4,767) / 2 = 5,556

Gallons of water saved per year can be found by subtracting the post consumption in gallons per year per showerhead from the baseline consumption. These values are also in Table 15.

- Gallons of water saved per year (2.0 GPM): (7,627 – 6,344) = 1,283
- Gallons of water saved per year (1.75 GPM): (7,627 – 5,556) = 2,071
- Gallons of water saved per year (1.5 GPM): (7,627 – 4,767) = 2,860

Table 33: Estimated Showerhead Hot Water Usage Reduction

Assumption Type	Seattle Study[102]	Tampa Study	East Bay Study[103]	Average	Value used for New Orleans
Gallons/shower @ 2.5 GPM (baseline)	19.8	20.0	22.3	20.7	20.7
Gallons/shower @ 2.0 GPM	15.8	16.0	17.8	16.5	16.5
Gallons/shower @ 1.5 GPM	11.9	12.0	13.4	12.4	12.4
Showers/person/day (baseline)	0.51	0.92	0.65	0.69	0.69
Showers/person/day (post)	0.59	0.82	0.74	0.72	0.72
Occupants per home	2.54	2.92	2.56	2.67	2.37[104]
Showerheads per home[105]	not listed	not listed	not listed	not listed	1.62
Water gal./yr./showerhead @ 2.0 GPM saved	not listed	not listed	not listed	not listed	1,823
Water gal./yr./showerhead @ 1.75 GPM saved	not listed	not listed	not listed	not listed	2,071
Water gal./yr./showerhead @ 1.5 GPM saved	not listed	not listed	not listed	not listed	2,860
Percent hot water	74.3%	not listed	66%	70.1%	70.1%

Based on the average percentage hot water shown in Table 33, the average mixed water temperature across all weather zones was determined. The hot water temperature was found to be 122.24°F in a sample of 37 homes in New Orleans tested by ADM. The mixed water temperature used in the energy savings calculation can be seen Table 34.

Table 34: Mixed Water Temperature Calculation

[102] Seattle Study: Average of pre-retrofit percent shower hot water 73.1% on page 35, and post-retrofit percent shower hot water 75.5% on p. 53.

[103] East Bay Study: Average of pre-retrofit percent shower hot water 71.9% on page 31 and post-retrofit shower hot water percentage 60.0% on p. 54.

[104] 2010-2014, US Census Bureau. http://www.census.gov/quickfacts/table/PST045215/2255000

[105] Showerheads per home assumed to be equal to the number of full bathrooms per home, taken from 2009 RECS, Table HC2.10.

Weather Zone	Average Water Main Temperature (°F)	Percent Hot Water	Mixed Water Temperature (°F)
New Orleans	74.8	66.9%	106.5

B.2.5.7. Calculation of Deemed Savings

B.2.5.7.1. Energy Savings

$$Annual\ Energy\ Savings\ = \frac{\rho \times C_P \times V \times (T_{Mixed} - T_{Supply}) \times \left(\frac{1}{RE}\right)}{Conversion\ Factor}$$

Where:

ρ = Water density = 8.33 lb/gallon

C_P = Specific heat of water = 1 BTU/lb·°F

V = 2.0, 1.75, or 1.5 GPM showerhead water gallons saved per year (from Table 33)

T_{Mixed} = Mixed water temperature, 106.5°F, from Table 34

T_{Supply}= Average New Orleans area supply water temperature, 74.8°F

RE= Recovery Efficiency (or in the case of HPWH, EF); if unknown, use 0.98 as a default for electric resistance water heaters, 2.2 for heat pump water heaters,

$Conversion\ Factor$ = 3,412 Btu/kWh for electric water heating or 100,000 Btu/Therm for gas water heating

B.2.5.7.2. Demand Savings

Demand savings were calculated using the US Department of Energy's "Building America Performance Analysis Procedures for Existing Homes"[106] combined domestic hot water use profile which resulted in a ratio of 0.000104 Peak kW to Annual kWh. The DOE domestic hot water use study provided values for the share of daily water use per hour in a profile for shower, bath, and sink hot water use. An average was calculated using peak hours of 3pm to 6pm to generate an average hourly share of daily water use during peak hours. That value was divided by 365 to generate a ratio of peak share to annual use.[107]

$$kW_{savings} = kWh_{\ savings} \times Ratio^{Peak\ kW}_{Annual\ kWh}$$

[106] U.S. DOE's 2006, *"Building America Performance Analysis Procedures for Existing Homes"*. National Renewable Energy Laboratory. May. www.nrel.gov/docs/fy06osti/38238.pdf

[107] At 3pm, the hourly share of daily water use is 0.022, at 4pm is 0.03, at 5pm is 0.04, and at 6pm is 0.06. The average of these values is 0.038. Divided by 365 days, the result is a 0.000104 ratio of peak share to annual use.

B.2.5.7.3. Example Calculation of Deemed Savings Values

Table 35: Example, 2.0, 1.75, and 1.5 GPM Showerhead Retrofit Deemed Energy Savings

2.0 GPM Showerhead		
Water gal. saved /year/showerhead @ 2.0 GPM	1,283	
T_{Supply}	74.8°F	
T_{Mixed}	106.5°F	
Water heater RE	0.98 (Electric Resistance) / 2.2 (Heat Pump)	
Energy Savings	Electric: 101 kWh	Heat Pump: 45 kWh
Demand Savings	Electric: 0.0105kW	Heat Pump: 0.0047 kW
1.75 GPM Showerhead		
Water gal. saved /year/showerhead @ 1.5 GPM	2,071	
T_{Supply}	74.8°F	
T_{Mixed}	105.0°F	
Water heater EF (excluding standby losses)	0.98 (Electric Resistance) / 2.2 (Heat Pump)	
Energy Savings	Electric: 164 kWh	Heat Pump: 73 kWh
Demand Savings	Electric: 0.0170 kW	Heat Pump: 0.0076 kW
1. 5 GPM Showerhead		
Water gal. saved /year/showerhead @ 1.5 GPM	2,860	
T_{Supply}	74.8°F	
T_{Mixed}	105.0°F	
Water heater EF (excluding standby losses)	0.98 (Electric Resistance) / 2.2 (Heat Pump)	
Energy Savings	Electric: 226 kWh	Heat Pump: 101 kWh
Demand Savings	Electric: 0.0235 kW	Heat Pump: 0.0105 kW

B.2.5.1. Future Studies

To-date, Energy Smart evaluations have provided two primary research points for this measure:

- New Orleans water main temperature;
- Water heater setpoint.

The water main temperature is a fixed value based on TMY3 weather data. The water heater setpoint should be supplemented with additional data collection in PY7.

Metering studies for water use are exceedingly expensive. In past metering efforts, ADM has found costs to exceed $750 per site. As such, we do not advise a metering study for this measure unless savings exceed 5% of residential program savings.

B.3. HVAC

B.3.1. Central Air Conditioner Replacement

B.3.1.1. Measure Description

This measure involves a residential retrofit with a new central air conditioning system or the installation of a new central air conditioning system in a residential new construction (packaged unit, or split system consisting of an indoor unit with a matching remote condensing unit). Maximum cooling capacity per unit is 65,000 BTU/hour. This measure applies to all residential applications.

B.3.1.2. Baseline and Efficiency Standards[108]

For new construction (NC) and ROB projects, the cooling baseline is 14 SEER, consistent with the current federal minimum standard[109].

For Early Replacement projects, the baseline is consistent with the previous federal standard. The cooling baseline is 13 SEER (code which took effect January 23, 2006).

For Early Replacement, the maximum lifetime age of an eligible piece of equipment is capped at the point at which it is expected that 75 percent of the equipment has failed. Where the age of the unit exceeds the 75 percent failure age, ROB savings should be applied. This cap prevents early retirement savings from being applied to projects where the age of the equipment greatly exceeds the estimated useful life of the measure.

Air conditioning equipment shall be properly sized to the dwelling, based on ASHRAE or ACCA Manual J standards. Manufacturer data sheets on installed air conditioning equipment or the AHRI reference number must be provided to the utility. The installed central air conditioning equipment must be AHRI certified.

Table 36: Central Air Conditioner – Baseline and Efficiency Levels

	SEER	EER
New Construction and Normal Replacement	14	11.8
Early Replacement	13	11.2
Required Efficiency	15	12.5 (split) 12.0 (packaged)

[109] DOE minimum efficiency standard for residential air conditioners/heat pumps. www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/75.

B.3.1.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 19 years, according to the US DOE.[110]

B.3.1.4. Deemed Savings Values

B.3.1.4.1. Replace-on-Burnout

$$kW_{Savings} = CAP_c \times 1{,}000\, {}^{W}\!/_{kW} \times \left(\frac{1}{EER_{base}} - \frac{1}{EER_{Eff}}\right) \times \%CF$$

$$kWh_{Savings} = CAP_c \times 1{,}000\, {}^{W}\!/_{kW} \times \left(\frac{1}{SEER_{base}} - \frac{1}{SEER_{Eff}}\right) \times EFLH_C$$

Where,

CAP_c = Cooling capacity (in BTU)

EER_{base} = Full-load efficiency of baseline equipment (see *Table* 36)

EER_{eff} = Full-load efficiency of baseline equipment (see *Table* 36)

$SEER_{base}$ = Seasonal efficiency of baseline equipment (see *Table* 36)

$SEER_{eff}$ = Seasonal efficiency of efficient equipment (see *Table* 36)

EFLHc = Equivalent Full-Load Cooling Hours

%CF = Peak Coincidence Factor

B.3.1.4.2. Equivalent Full-Load Hours

Equivalent Full-Load Cooling Hours (EFLHc) measures the total annual runtime of HVAC equipment. To support development of this value, the usage of 68 HVAC systems in New Orleans was metered. This runtime was then normalized to correspond to Typical Meteorological Year ("TMY") weather data for New Orleans.

The resulting EFLHc is 1,637.

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[110] U.S. DOE, 2011 *Technical Support Document: "Residential Central Air Conditioners, Heat Pumps, and Furnaces, 8.2.3.5 Lifetime."* June www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/75.

B.3.1.4.3. *Peak Coincidence Factor*

The Peak Coincidence Factor is defined as the percent time during the ENO peak period where the residential central air conditioner is operational. Peak hours were defined as:

- Weekdays
- Non-holidays
- 4:00-5:00 PM
- Average ambient temperature exceeding 90 degrees Fahrenheit.

The average central AC runtime during qualified hours was 77%. This peak coincidence factor is applied to calculate peak kW demand reductions from this measure.

B.3.1.4.4. *Uncertainty Analysis*

The uncertainties associated with the two key parameters collected in EM&V are as follows:

- EFLHc: ±7.81%
- % Coincidence: ±2.11%

B.3.1.5. Incremental Cost

The incremental cost of high central air conditioners is detailed in *Table* 37[111].

Table 37: High Efficiency Central AC Replacement Incremental Costs

Product Type	*Incremental Cost Per Ton*
15 SEER	$119
16 SEER	$238
17 SEER	$357
18 SEER	$477
19 SEER	$596
20 SEER	$715
21 SEER	$789

B.3.1.6. Future Studies

This measure should be considered for supplementary data collection pertaining to runtime and peak coincidence in three years (PY9, program year 2019-2020).

[111] CA DEER 2008

B.3.2. Heat Pump Replacement

B.3.2.1. Measure Description

This measure involves a residential retrofit with a new neat pump system or the installation of a new heat pump system in a residential new construction (packaged unit, or split system consisting of an indoor unit with a matching remote condensing unit). Maximum cooling capacity per unit is 65,000 BTU/hour. This measure applies to all residential applications.

B.3.2.2. Baseline and Efficiency Standards[112]

For new construction (NC) and ROB projects, the cooling baseline is 14 SEER and 8.0 HSPF, consistent with the current federal minimum standard[113].

For Early Replacement projects, the baseline is consistent with the previous federal standard. The cooling baseline is 13 SEER (code which took effect January 23, 2006).

For Early Replacement, the maximum lifetime age of an eligible piece of equipment is capped at the point at which it is expected that 75 percent of the equipment has failed. Where the age of the unit exceeds the 75 percent failure age, ROB savings should be applied. This cap prevents early retirement savings from being applied to projects where the age of the equipment greatly exceeds the estimated useful life of the measure.

Heat Pump equipment shall be properly sized to the dwelling, based on ASHRAE or ACCA Manual J standards. Manufacturer data sheets on installed air conditioning equipment or the AHRI reference number must be provided to the utility. The installed central air conditioning equipment must be AHRI certified.

Table 38: Heat Pump – Baseline and Efficiency Levels

	SEER	***EER***	***HSPF***
New Construction and Normal Replacement	14	11.8	8.2 (split) 8.0 (packaged)
Early Replacement – Heat Pump	13	11.2	7.7 (split & packaged)
Early Replacement – Electric Resistance	13	11.2	3.41
Required Efficiency	15	12.5 (split) 12.0 (packaged)	9.0

[113] DOE minimum efficiency standard for residential air conditioners/heat pumps. www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/75.

B.3.2.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 16 years, according to the US DOE.[114]

B.3.2.4. Deemed Savings Values

B.3.2.4.1. Replace-on-Burnout

B.3.2.4.1.1. Cooling Savings

$$kW_{Savings} = CAP_c \times 1{,}000\,{}^{W}/_{kW} \times \left(\frac{1}{EER_{base}} - \frac{1}{EER_{Eff}}\right) \times \%CF$$

$$kWh_{Savings} = CAP_c \times 1{,}000\,{}^{W}/_{kW} \times \left(\frac{1}{SEER_{base}} - \frac{1}{SEER_{Eff}}\right) \times EFLH_C$$

Where,

CAP_c = Cooling capacity (in BTU)

EER_{base} = Full-load efficiency of baseline equipment (see Table 38)

EER_{eff} = Full-load efficiency of baseline equipment (see Table 38)

$SEER_{base}$ = Seasonal efficiency of baseline equipment (see Table 38)

$SEER_{eff}$ = Seasonal efficiency of efficient equipment (see Table 38)

EFLHc = Equivalent Full-Load Cooling Hours

%CF = Peak Coincidence Factor

Equivalent Full-Load Cooling Hours

Equivalent Full-Load Cooling Hours (EFLHc) measures the total annual runtime of HVAC equipment. To support development of this value, the usage of 68 HVAC systems in New Orleans was metered. This runtime was then normalized to correspond to Typical Meteorological Year ("TMY") weather data for New Orleans.

The resulting EFLHc is 1,637.

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[114] US U.S. DOE, 2011. *Technical Support Document: "Residential Central Air Conditioners, Heat Pumps, and Furnaces, 8.2.3.5 Lifetime*". June. www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/75.

Peak Coincidence Factor

The Peak Coincidence Factor is defined as the percent time during the ENO peak period where the residential central air conditioner is operational. Peak hours were defined as:

- Weekdays
- Non-holidays
- 4:00-5:00 PM
- Average ambient temperature exceeding 90 degrees Fahrenheit.

The average central AC runtime during qualified hours was 77%. This peak coincidence factor is applied to calculate peak kW demand reductions from this measure.

Heating Energy Savings

Heating savings are calculated with the following formula:

$$kWh_{Savings} = CAP_c \times 1{,}000\, {}^{W}\!/_{kW} \times \left(\frac{1}{HSPF_{base}} - \frac{1}{HSPF_{Eff}}\right) \times EFLH_h$$

Where,

CAP_c = Cooling capacity (in BTU)

EER_{base} = Full-load efficiency of baseline equipment (see Table 38)

EER_{eff} = Full-load efficiency of baseline equipment (see Table 38)

$HSPF_{base}$ = Heating Season Performance Factor of baseline equipment (see Table 38)

$HSPF_{eff}$ = Heating Season Performance Factor of efficient equipment (see Table 38)

EFLHh = Equivalent Full-Load Heating Hours

%CF = Peak Coincidence Factor

Equivalent Full Load Heating Hours

A stipulated EFLH of 1,118 is applied when calculating heating savings from heat pumps. This value cites the ENERGY STAR Heat Pump calculator. There has not been a metering study performed to revise this value due to the low participation rate for heat pumps.

B.3.2.4.2. Uncertainty Analysis

The uncertainties associated with the two key parameters collected in EM&V are as follows:

- EFLHc: ±7.81%
- % Coincidence: ±2.11%

B.3.2.5. Incremental Cost

The incremental cost of high central air conditioners is detailed in Table 37[115].

Table 39: High Efficiency Central AC Replacement Incremental Costs

Product Type	***Incremental Cost Per Ton***
15 SEER	$303
16 SEER	$438
17 SEER	$724
18 SEER	$724

B.3.2.6. Future Studies

As with Central Air Conditioning, the cooling side of this measure should be considered for supplementary data collection pertaining to runtime and peak coincidence in three years (PY9, program year 2019-2020).

If heat pump replacement and tune-up ever exceed 1% of program kWh savings, it is recommended to conduct a metering study to validate $EFLH_h$ estimates for heating season savings.

[115] CA DEER 2008

B.3.3. Ground Source Heat Pump Replacement

B.3.3.1. Measure Description

This measure involves the installation of water-to-air ground source heat pump as a replacement for an existing air-source heat pump. Maximum cooling capacity per unit is 65,000 BTU/hour. This measure applies to all residential applications.

B.3.3.2. Baseline and Efficiency Standards[116]

For new construction (NC) and ROB projects, the cooling baseline is 14 SEER and 8.0 HSPF, consistent with the current federal minimum standard[117]. Due to the high cost of this equipment, all projects are assumed to be replacement on burnout or new construction.

Heat Pump equipment shall be properly sized to the dwelling, based on ASHRAE or ACCA Manual J standards. Manufacturer data sheets on installed air conditioning equipment or the AHRI reference number must be provided to the utility. The installed central air conditioning equipment must be AHRI certified.

Table 40: Heat Pump – Baseline and Efficiency Levels

	SEER	***EER***	***HSPF***
New Construction and Normal Replacement	14	11.8	8.2 (split) 8.0 (packaged)
Early Replacement – Heat Pump	13	11.2	7.7 (split & packaged)
Early Replacement – Electric Resistance	13	11.2	3.41
Energy Star Criteria – Water-to-Air		Closed Loop: 17.1 Open Loop: 21.1	Closed Loop: 12.3 Open Loop: 14.0
Energy Star Criteria – Water-to-Water		Closed Loop: 16.1 Open Loop: 20.1 DGX: 16	Closed Loop: 10.6 Open Loop: 11.9 DGX: 12.3

B.3.3.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 25 years, according to the US DOE.[118]

[117] DOE minimum efficiency standard for residential air conditioners/heat pumps. www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/75.

[118] Source DOE Energy Savers website: www.energysavers.gov/your_home/space_heating_cooling/index.cfm/mytopic=12640 .

B.3.3.4. Deemed Savings Values

Savings are calculated in the same manner as for Heat Pump Replacement. See Section A.3.2.4.

B.3.3.5. Incremental Cost

The incremental cost should use the full installed cost, minus an assumed installation cost of baseline equipment. The baseline cost is $1,381 per ton for a minimum-efficient air source heat pump[119].

B.3.3.6. Future Data Collection Needs

As with Central Air Conditioning, the cooling side of this measure should be considered for supplementary data collection pertaining to runtime and peak coincidence in three years (PY9, program year 2019-2020).

If heat pump replacement and tune-up ever exceed 1% of program kWh savings, it is recommended to conduct a metering study to validate $EFLH_h$ estimates for heating season savings.

[119] Based on data provided on Home Advisor website, providing national average ASHP cost based on 2465 cost submittals. http://www.homeadvisor.com/cost/heating-and-cooling/install-a-heat-pump/

B.3.4. Ductless Heat Pump

B.3.4.1. Measure Description

This measure involves the installation of ductless mini-split heat pumps (DMSHP). These systems have increased savings over efficient air source heat pumps as they use less fan energy to move heat and cooled air and don't incur distribution losses.

B.3.4.2. Baseline and Efficiency Standards[120]

For new construction (NC) and ROB projects, the cooling baseline is 14 SEER and 8.0 HSPF, consistent with the current federal minimum standard[121]. Due to the high cost of this equipment, all projects are assumed to be replacement on burnout or new construction.

A DMSHP must be a high-efficiency, variable-capacity system that exceeds program minimum efficiency requirements. Qualified systems will typically have an inverter-driven DC motor.

Heat Pump equipment shall be properly sized to the dwelling, based on ASHRAE or ACCA Manual J standards. Manufacturer data sheets on installed air conditioning equipment or the AHRI reference number must be provided to the utility. The installed central air conditioning equipment must be AHRI certified.

Table 41: Heat Pump – Baseline and Efficiency Levels

	SEER	***EER***	***HSPF***
New Construction and Normal Replacement	14	11.8	8.2 (split) 8.0 (packaged)
Early Replacement – Heat Pump	13	11.2	7.7 (split & packaged)

B.3.4.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 18 years.[122]

B.3.4.4. Deemed Savings Values

Savings are calculated in the same manner as for Heat Pump Replacement. See Section A.3.2.4.

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[121] DOE minimum efficiency standard for residential air conditioners/heat pumps. www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/75.

[122] Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures, GDS Associates, Inc., June 2007

B.3.4.5. Incremental Cost

The incremental cost should use the full installed cost, minus an assumed installation cost of baseline equipment. The baseline cost is $1,381 per ton for a minimum-efficient air source heat pump[123].

B.3.4.6. Future Data Collection Needs

As with Central Air Conditioning, the cooling side of this measure should be considered for supplementary data collection pertaining to runtime and peak coincidence in three years (PY9, program year 2019-2020).

If heat pump replacement and tune-up ever exceed 1% of program kWh savings, it is recommended to conduct a metering study to validate $EFLH_h$ estimates for heating season savings.

Further, this measure represents significant savings potential for the residential HVAC market. ADM advises that a market assessment be completed to provide strategic data to ENO, their implementers, and other stakeholders to support future marketing of this measure.

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[123] Based on data provided on Home Advisor website, providing national average ASHP cost based on 2465 cost submittals. http://www.homeadvisor.com/cost/heating-and-cooling/install-a-heat-pump/

B.3.5. Central Air Conditioner Tune-Up

B.3.5.1. Measure Description

This measure applies to central air conditioners and heat pumps. An AC tune-up, in general terms, involves checking, adjusting and resetting the equipment to factory conditions, such that it operates closer to the performance level of a new unit. This measure applies to all residential applications.

For this measure, the service technician must complete the following tasks according to industry best practices:

- Air Conditioner Inspection and Tune-Up Checklist[124]
- Inspect and clean condenser, evaporator coils, and blower.
- Inspect refrigerant level and adjust to manufacturer specifications.
- Measure the static pressure across the cooling coil to verify adequate system airflow and adjust to manufacturer specifications.
- Inspect, clean, or change air filters.
- Calibrate thermostat on/off set points based on building occupancy.
- Tighten all electrical connections, and measure voltage and current on motors.
- Lubricate all moving parts, including motor and fan bearings.
- Inspect and clean the condensate drain.
- Inspect controls of the system to ensure proper and safe operation. Check the starting cycle of the equipment to assure the system starts, operates, and shuts off properly.
- Provide documentation showing completion of the above checklist to the utility or the utility's representative.

B.3.5.2. Baseline and Efficiency Standards

The baseline is a system with demonstrated imbalances of refrigerant charge.

After the tune-up, the equipment must meet airflow and refrigerant charge requirements. To ensure the greatest savings when conducting tune-up services, the eligibility minimum requirement for airflow is the manufacturer specified design flow rate, or 350 CFM/ton, if unknown. Also, the refrigerant charge must be within +/- 3 degrees of target

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[124] Based on ENERGY STAR® HVAC Maintenance Checklist. www.energystar.gov/index.cfm?c=heat_cool.pr_maintenance

sub-cooling for units with thermal expansion valves (TXV) and +/- 5 degrees of target super heat for units with fixed orifices or a capillary.

The efficiency standard, or efficiency after the tune-up, is assumed to be the manufacturer specified energy efficiency ratio (EER) of the existing central air conditioner or heat pump. The efficiency improvement resulting from the refrigerant charge adjustment depends on the pre-adjustment refrigerant charge.

B.3.5.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 10 years, according to CA DEER 2014.

B.3.5.4. Deemed Savings Values

There are two ways in which deemed savings can be calculated for this measure:

1) Test-in and test-out efficiency; or
2) Application of a stipulated reduction in annual use.

B.3.5.4.1. Test-in and Test-out Efficiency

$$kW_{Savings} = CAP_c \times 1{,}000\,{}^{W}/_{kW} \times \left(\frac{1}{EER_{pre}} - \frac{1}{EER_{post}}\right) \times \%CF$$

$$kWh_{Savings\_Cooling} = CAP_c \times 1{,}000\,{}^{W}/_{kW} \times \left(\frac{1}{EER_{pre}} - \frac{1}{EER_{post}}\right) \times EFLH_C$$

Where,

CAP_c = Cooling capacity (in BTU)

EER_{pre} = Efficiency of the equipment prior to tune-up

EER_{post}= Nameplate efficiency of the existing equipment

EFLHc = Equivalent Full-Load Cooling Hours

EFLHh = Equivalent Full-Load Heating Hours

%CF = Peak Coincidence Factor

B.3.5.4.2. Baseline Efficiency

Baseline efficiency is calculated as:

$$EER_{pre} = (1 - EL) \times EER_{post}$$

EL is the Efficiency Loss based on the current refrigerant charge level. The EL values are summarized in Table 42 and Table 43.

Table 42: Efficiency Loss by Refrigerant Charge Level (Fixed Orifice)

% Charged	**EL**
≤70	.37
75	.29
80	.20
85	.15
90	.10
95	.05
100	0
≥120	.03

Table 43: Efficiency Loss by Refrigerant Charge Level (TXV)

% Charged	**EL**
≤70	.12
75	.09
80	.07
85	.06
90	.05
95	.03
100	.00
≥120	.04

B.3.5.4.3. Equivalent Full-Load Hours

Equivalent Full-Load Cooling Hours (EFLHc) measures the total annual runtime of HVAC equipment. To support development of this value, the usage of 68 HVAC systems in New Orleans was metered. This runtime was then normalized to correspond to Typical Meteorological Year ("TMY") weather data for New Orleans.

The resulting EFLHc is 1,637.

B.3.5.4.4. Peak Coincidence Factor

The Peak Coincidence Factor is defined as the percent time during the ENO peak period where the residential central air conditioner is operational. Peak hours were defined as:

- Weekdays
- Non-holidays
- 4:00-5:00 PM

- Average ambient temperature exceeding 90 degrees Fahrenheit.

The average central AC runtime during qualified hours was 77%. This peak coincidence factor is applied to calculate peak kW demand reductions from this measure.

B.3.5.4.5. % Off of Annual Use

Alternatively, program administrators may elect to claim savings based off of a percent reduction in annual use.

$$kW_{Savings} = CAP_c \times 1{,}000 \, {}^{W}\!/_{kW} \times \left(\frac{1}{EER_{pre}}\right) \times \%CF\%Reduction$$

$$kWh_{Savings} = CAP_c \times 1{,}000 \, {}^{W}\!/_{kW} \times \left(\frac{1}{EER_{pre}}\right) \times EFLH_C \times \%Reduction$$

In this, EERpre is assumed to be 9.52[125]. %Reduction is 10.1%. This value is derived from PY5 EM&V of the Residential Heating & Cooling Program.

B.3.5.4.6. Uncertainty Analysis

The uncertainties associated with the two key parameters collected in EM&V are as follows:

- EFLHc: ±7.81%
- % Coincidence: ±2.11%

B.3.5.5. Incremental cost

The incremental cost of an AC Tune-Up is $175[126].

B.3.5.6. Future Studies

Due to low realization of this measure in PY5 M&V, it is suggested that this measure be evaluated each year until such time that program plan numbers align with M&V results.

The incremental cost value is very sensitive to labor costs, and as such a New Orleans-specific cost study should be conducted to revise this value.

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[125] 11.8 EER nameplate with 85% charge

[126] Illinois TRM

B.3.6. Duct Sealing

B.3.6.1. Measure Description

This measure is comprised of performing duct sealing using mastic sealant or metal tape to the distribution system of homes with a central air conditioning system. Materials should be long-lasting materials such as UL 181A or UL 181 B-approved foil tape. Fabric-based duct tape is not allowed.

In calculating savings for this measure, program administrators are to use the leakage-to-unconditioned space metric, entailing a blower-door subtraction test method. this technique is described in detail on p.44 of the Energy Conservatory Blower Door Manual; which can be found on the Energy Conservatory website[127].

B.3.6.2. Baseline and Efficiency Standards

The baseline for this measure is unsealed ductwork, with a maximum pre-installation leakage rate of 40% of total fan flow[128]. This cap is imposed because interior temperature in homes that exceed 40 percent total leakage would be above the thermally acceptable comfort levels published by ASHRAE in its 2009 Fundamentals publication. Historically, homeowners would remedy a situation in such a state of disrepair, and out of concern for the validity of baseline test measurements performed by duct sealing contractors and to ensure that the savings are program attributable, program administrators must cap baseline leakage at 40% of fan flow, and report the extent to which contractors' baseline leakage measurements exceed this fan flow.

B.3.6.3. Estimated Useful Life (EUL)

According to DEER 2014, the Estimated Useful Life for air infiltration is 18 years.

B.3.6.4. Deemed Savings Values

The following formulas shall be used to calculate deemed savings for duct sealing.

B.3.6.4.1. Cooling Savings

$$kWh_{cooling} = \frac{\left(DL_{pre} - DL_{post}\right) \times EFLH_c \times (h_{out}\rho_{out-}h_{in}\rho_{in}) \times 60}{1000 \times SEER}$$

Where,

DL_{pre} = Pre-measurement of leakage to unconditioned space

DL_{post} = Post-measurement of leakage to unconditioned space

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[127] As of Oct 2014: http://www.energyconservatory.com/sites/default/files/documents/mod_3-4_dg700_-_new_flow_rings_-_cr_-_tpt_-_no_fr_switch_manual_ce_0.pdf

[128] Total Fan Flow = Cooling Capacity (tons) × 400

$EFLH_c$ = Equivalent Full Load Cooling Hours, 1,637, based on ADM metering of New Orleans homes

H_{out} = Outdoor design enthalpy, 40 BTU/lb.

H_{in} = Indoor design enthalpy, 30 BTU/lb.

P_{out} = Density of outdoor air at 95 deg. F, .0740 lb./ft.^{3}

P_{in} = Density of outdoor air at 95 deg. F, .0756 lb./ft.^{3}

SEER = Seasonal Efficiency Rating of existing systems (BTU/W*hr). Default of 13

1,000 = W/kW conversion factor

60 = Minutes/hour conversion factor

The default of 13 SEER is based on the inspection of 182 program participants in Home Performance with ENERGY STAR and Assisted Home Performance with ENRGY STAR. These 182 participants had 135 unique model numbers, with an average SEER of 12.98. The minimum code prior to 2015 was 13 SEER, and given how close the mean value is to that code value, we recommend a default SEER of 13.

B.3.6.4.2. Heating Savings (Heat Pump)

Heating savings are calculated as:

$$kWh_{Heating,Heat\ Pump} = \frac{\left(DL_{pre} - DL_{post}\right) \times HDD \times (h_{out}\rho_{out-}h_{in}\rho_{in}) \times 24 \times .018}{1000 \times HSPF}$$

Where,

DL_{pre} = Pre-measurement of leakage to unconditioned space

DL_{post} = Post-measurement of leakage to unconditioned space

HDD = Heating degree days for New Orleans, based on TMY3 data: 1,349

H_{out} = Outdoor design enthalpy, 40 BTU/lb.

H_{in} = Indoor design enthalpy, 30 BTU/lb.

P_{out} = Density of outdoor air at 95 deg. F, .0740 lb./ft.^{3}

P_{in} = Density of outdoor air at 95 deg. F, .0756 lb./ft.^{3}

HSPF = Heating Season Performance Factor of existing systems (BTU/W*hr). Default of 7.7

1,000 = W/kW conversion factor

24 = Hours/Day conversion factor

.018 = Volumetric heat capacity of air (BTU./Ft.^{3} *deg. F)

The default HSPF of 7.7 is based on our findings with inspections of residential air conditioners. The amount of heat pumps was too limited to develop a statistically valid average HSPF. However, of the 182 participants visited in EM&V of Home Performance with ENERGYS STAR and Assisted Home Performance with ENERGYS STAR found an average SEER of 12.98. Given this, ADM concluded that the average unit to receive duct sealing was installed in the 2006-2015 code period, which had a minimum requirement of 7.7 HSPF.

B.3.6.4.3. Heating Savings (Electric Resistance)

Heating savings are calculated as:

$$kWh_{Heating,Heat\ Pump} = \frac{\left(DL_{pre} - DL_{post}\right) \times HDD \times (h_{out}\rho_{out-}h_{in}\rho_{in}) \times 24 \times .018}{3{,}412}$$

Where,

DL_{pre} = Pre-measurement of leakage to unconditioned space

DL_{post} = Post-measurement of leakage to unconditioned space

HDD = Heating degree days for New Orleans, based on TMY3 data: 1,349

H_{out} = Outdoor design enthalpy, 40 BTU/lb.

H_{in} = Indoor design enthalpy, 30 BTU/lb.

P_{out} = Density of outdoor air at 95 deg. F, .0740 lb./ft.^{3}

P_{in} = Density of outdoor air at 95 deg. F, .0756 lb./ft.^{3}

3,412 = Conversion of BTU/kWh

24 = Hours/Day conversation factor

.018 = Volumetric heat capacity of air (BTU./Ft.^{3} *deg. F)

B.3.6.4.4. Demand Savings (Cooling)

Demand savings are calculated by applying peak coincidence to the Cooling kWh savings. If the residence does not have central air conditioning (i.e., the ductwork is used only for heating distribution) then demand savings are 0.

$$kW = \frac{kWh_{cooling}}{EFLH_c} \times Coincidence\%$$

Where,

$kWh_{cooling}$ = Calculated kWh cooling savings

$EFLH_c$ = Equivalent Full Load Cooling Hours, 1,637, based on ADM metering of New Orleans homes

Coincidence% = 77%, calculated based on ADM metering of New Orleans homes.

B.3.6.4.5. Uncertainty Analysis

The uncertainties associated with the two key parameters collected in EM&V are as follows:

- EFLHc: ±7.81%
- % Coincidence: ±2.11%

B.3.6.5. Incremental cost

The incremental cost of this measure is the full installed cost.

B.3.6.6. Future Studies

This is a high impact measure, regularly constituting a large percent of Energy Smart program savings. This measure also has significant interaction with other measures (AC Tune-Up, building envelope improvements).

In PY7 or PY8, a measure interaction study between Duct Sealing, AC Tune-Up, and high impact Building Envelope improvements should be completed to provide adjustment factors for multiple-measure installation.

Further, ADM recommends that savings estimates for Duct Sealing be validated with a billing analysis of the past three years of program participants.

B.4.1. Attic Knee Wall Insulation

B.4.1.1. Measure Description

This measure involves adding attic knee wall insulation to un-insulated knee wall areas in residential dwellings of existing construction. A wall with an insulation value of R-0 has no insulation, but does have a nominal wall R-value made up of interior and exterior wall materials, air film and wood studs. This measure applies to all residential applications.

B.4.1.2. Baseline and Efficiency Standards

This measure applies to existing construction only.

Table 44: Attic Knee Wall Insulation – Baseline and Efficiency Standards

Baseline	***Efficiency Standard***
Uninsulated knee wall	Minimum R-19 or R-30

B.4.1.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 20 years, based on NEAT v. 8.6.

B.4.1.4. Deemed Savings Values

Please note that the savings per square foot is a factor to be multiplied by the square footage of the attic knee wall area that is being insulated. Gas Heat (no AC) kWh applies to forced air furnace systems only.

Table 45: Knee Wall Insulation – Deemed Savings Values

Ceiling Insulation Base R-Value	**AC/Gas Heat kWh**	**Gas Heat (no AC) kWh**	**AC/Electric Resistance kWh**	**Heat Pump kWh**	**AC Peak Savings (kW)**
	(/ sq. ft.)	**(/ sq. ft.)**	**(/ sq. ft.)**	**(/ sq. ft.)**	**(/ sq. ft.)**
R-19	3.600	0.980	6.698	2.324	0.000
R-30	4.477	0.608	7.540	2.610	0.000

B.4.1.5. Calculation of Deemed Savings

The deemed savings are dependent on the R-value of the attic knee wall, pre- and post-retrofit.

BEopt™ was used to estimate energy savings for a series of models using the DOE EnergyPlus simulation engine. Since attic knee wall insulation savings are sensitive to weather, available TMY3 weather data specific to each of the four Arkansas weather regions was used for the analysis. The prototype home characteristics used in the BEopt™ building model are outlined in Appendix A.

B.4.1.6. Incremental Cost

The incremental cost of this measure is equal to the full installed cost.

B.4.1.7. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values based on simulation results. If this measure is added to Energy Smart programs and exceeds 1% of residential savings, then the simulation model should be updated to align with the billed use of customers that install the measure.

B.4.2. Ceiling Insulation

B.4.2.1. Measure Description

This measure requires adding ceiling insulation above a conditioned area in a residential dwelling of existing construction to a minimum ceiling insulation value of R-38. Savings are also estimated for an optional final insulation level of R-49. This measure applies to all residential applications.

This measure pertains to ceiling insulation only (attic floor). There is a separate measure (Measure 2.2.5) for roof deck insulation.

B.4.2.2. Baseline and Efficiency Standards

In existing construction, ceiling insulation levels vary greatly, depending on the age of the home, type of insulation, and attic space utilization (such as using the attic for storage and HVAC equipment). The average pre-retrofit insulation level of the treated area will be determined and documented by the insulation contractor according to the ranges in Table 77. Degradation due to age and condition of the existing insulation will need to be considered by the insulation contractor. Care must be exercised in differentiating between an existing R-value in the 0-1 range versus in the 2-4 range as the resulting savings are very sensitive in the lower ranges.

The eligibility standard for this measure (minimum final R-value) is R-38, as specified in IECC 2009. Savings are also provided for R-49 as an optional final R-value, as specified for IECC climate zone 4 beginning in IECC 2012.

Table 46: Ceiling Insulation – Baseline and Efficiency Standards

Baseline	***Efficiency Standard***
R-0 to R-1	R-38 or R-49
R-2 to R-4	
R-5 to R-8	
R-9 to R-14	
R-15 to R-22	

B.4.2.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 20 years, according to DEER 2014.

B.4.2.4. Deemed Savings Values

Deemed savings values have been calculated for each of the four weather zones. The deemed savings are based on the R-value of the ceiling insulation pre-retrofit and a combined post-retrofit R-value (R-values of the existing insulation and the insulation being added) of at least R-38. Savings are also provided for R-49, and linear interpolation may be used to claim savings for final R-values between R-38 and R-49.

Note that the savings per square foot is a factor to be multiplied by the square footage of the ceiling area over a conditioned space that is being insulated. Gas Heat (no AC) kWh applies to forced air furnace systems only.

For deemed savings for installation between the range of R-38 to R-49, linear interpolation can be used to determine the value that can be claimed as savings.

Table 47: Deemed Savings for R-38

Ceiling Insulation Base R-Value	**AC/Gas Heat kWh**	**Gas Heat (no AC) kWh**	**AC/Electric Resistance kWh**	**Heat Pump kWh**	**AC Peak Savings (kW)**
	(/ sq. ft.)	**(/ sq. ft.)**	**(/ sq. ft.)**	**(/ sq. ft.)**	**(/ sq. ft.)**
0 to 1	2.0126	0.0646	0.0678	5.0885	3.1265
2 to 4	1.0152	0.0362	0.0389	2.7848	1.6709
5 to 8	0.6139	0.0227	0.0251	1.7468	1.0544
9 to 14	0.3835	0.0153	0.0169	1.1304	0.6785
15 to 22	2.0126	0.0646	0.0678	5.0885	3.1265

Table 48: Deemed Savings for R-38

Ceiling Insulation Base R-Value	**AC/Gas Heat kWh**	**Gas Heat (no AC) kWh**	**AC/Electric Resistance kWh**	**Heat Pump kWh**	**AC Peak Savings (kW)**
	(/ sq. ft.)	**(/ sq. ft.)**	**(/ sq. ft.)**	**(/ sq. ft.)**	**(/ sq. ft.)**
0 to 1	2.4277	0.0653	0.0654	6.1381	3.7714
2 to 4	1.2613	0.0377	0.0387	3.4600	2.0760
5 to 8	0.8000	0.0248	0.0262	2.2764	1.3741
9 to 14	0.5524	0.0184	0.0195	1.6282	0.9773
15 to 22	2.4277	0.0653	0.0654	6.1381	3.7714

B.4.2.5. Calculation of Deemed Savings

BEopt™ was used to estimate energy savings for a series of models using the DOE EnergyPlus simulation engine; available TMY3 weather data specific to each of the four Arkansas weather regions were used for the analysis. The prototype home characteristics used in the BEopt™ building model are outlined in Appendix A.

B.4.2.6. Incremental Cost

The incremental cost for this measure is the total cost. The cost is $0.035 per sq. ft. per "R" unit of insulation[129].

B.4.2.7. Future Studies

This measure is a High Impact Measure, having constituted 8.7% of PY6 program savings. To-date, the evaluations have not conducted significant primary research on this measure due to the focusing of EM&V budget on Residential Lighting and Residential HVAC studies.

This measure should have its simulation model recalibrated to the billed use of the past three years of program participants. Further, the next EM&V study should measure the level of interaction between this measure and other significant building envelope and HVAC improvements (duct sealing, air sealing, AC tune-up, etc.).

[129] Public Service Company of New Mexico Commercial & Industrial Incentive Program Work Papers, 2011.

B.4.3. Wall Insulation

B.4.3.1. Measure Description

This measure consists of adding wall insulation in the wall cavity in residential dwellings of existing construction. This measure applies to all residential applications.

B.4.3.2. Baseline and Efficiency Standards

In order to qualify for this measure, there must be no existing wall cavity insulation. Post-retrofit condition will be a wall cavity filled with either fiberglass or cellulose insulation (R-13 nominal value), open cell insulation (R-13 nominal value), or closed cell foam insulation (R-23 nominal value). Each type of insulation's nominal R-value depends on a full thickness application within the cavity of a wall with 2x4 inch studs.

Table 49: Wall Insulation – Baseline and Efficiency Standards

Baseline	**Efficiency Standard (Nominal R-Values)**	
Uninsulated wall cavity	Fiberglass/Cellulose	R-13
	Open Cell Foam	R-13
	Closed Cell Foam	R-23

B.4.3.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 20 years, according to DEER 2014.

B.4.3.4. Deemed Savings

The savings per square foot is a factor to be multiplied by the square footage of the net wall area insulated. Wall area must be part of the thermal envelope of the home, and shall not include window or door area. Electrical energy savings for Gas Heat (no AC) are the reduction in electricity used by the furnace's air handler during the heating season.

Deemed savings for R-13 can be achieved with either fiberglass, cellulose, or open cell foam insulation. Deemed savings for R-23 is only applicable to closed cell insulation. The R-value represents the nominal value of the cavity insulation and not the R-value of the wall assembly.

For deemed savings for installation between the range of R-13 to R-23, linear interpolation can be used to determine the value that can be claimed as savings.

Table 50: Wall Insulation – Deemed Savings Values - Zone 3: New Orleans

Ceiling Insulation Base R-Value	**kWh Savings / sq. ft.**		**kW Peak Savings / sq. ft.**	
	R-13	**R-23**	**R-13**	**R-23**
Electric Cooling with Gas Heat	0.78286	0.82574	0.00033	0.00060
Gas Heat (No AC)	0.48270	0.48270	n/a	n/a
Electric Cooling with Electric Resistance Heat	3.33772	3.74885	0.00033	0.00060
Electric Cooling with Electric Heat Pump	1.05252	1.13064	0.00033	0.00051

B.4.3.5. Calculation if Deemed Savings

Deemed savings values have been calculated for each of the four weather zones. The deemed savings are dependent on the R-value of the wall pre- and post-retrofit. BEopt™ was used to estimate energy savings for a series of models using the DOE EnergyPlus simulation engine. Since wall insulation savings are sensitive to weather, available TMY3 weather data specific to each of the four Arkansas weather regions were used for the analysis. The prototype home characteristics used in the BEopt™ building model are outlined in Appendix A.

B.4.3.6. Incremental Cost

The incremental cost of this measure is equal to the full installed cost.

B.4.3.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values based on simulation results. If this measure is added to Energy Smart programs and exceeds 1% of residential savings, then the simulation model should be updated to align with the billed use of customers that install the measure.

B.4.4. Floor Insulation

B.4.4.1. Measure Description

This measure presents two eligible scenarios for retrofitting a crawl space underneath an uninsulated floor[130]:

1. Insulating the underside of the floor (above the vented crawl space), where the floor previously had no insulation
2. "Encapsulating" the crawl space – sealing and insulating the vented perimeter skirt or stem wall between the ground (finished grade) and the first floor of the house, leaving the underside of the first floor structure uninsulated

This measure applies to all residential applications.

B.4.4.2. Baseline and Efficiency Standards

The baseline is considered to be a house with pier and beam construction, no insulation under the floor of the conditioned space, and a vented crawl space. In order to qualify for deemed savings, either the floor can be insulated to a minimum of R-19 or the crawl space can be encapsulated as described below. Deemed savings are provided for each option.

- Option 1 – Insulating the underside of the floor to a minimum of R-19.
- Option 2 – Encapsulating the crawl space: The crawl space perimeter skirt or stem walls are sealed in a sound and durable manner and the ground (floor of the crawl space) is sealed with a heavy plastic vapor barrier. The skirt or stem wall interior surfaces are insulated to R-13 (minimum) with closed cell foam[131]. The underside of the floor above the crawlspace is left uninsulated. A small flow of conditioned air to the crawl space is recommended to moderate humidity levels[132].

Occupational Safety and Health Administration (OSHA) standards and applicable versions of the IECC and IRC codes will be pertinent to the installation. Note that this will include ensuring that any oil or gas-fueled furnaces or water heaters located in the

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[130] U.S. DOE publication *"Building America Best Practices Series, Vol 17, "Insulation"* found at http://apps1.eere.energy.gov/buildings/publications/pdfs/building_america/insulation_guide.pdf (accessed 7-8-15) has extensive building science and code conformance information regarding insulating floors as well as sealing and insulating crawl spaces.

[131] IECC 2012, Table R402.1

[132] U.S. DOE publication *"Building America Best Practices Series, Vol 17, "Insulation"* found at http://apps1.eere.energy.gov/buildings/publications/pdfs/building_america/insulation_guide.pdf (accessed 7-8-15), p. 58, 1 cfm per every 50 sq. ft. of floor area.

crawlspace be provided with dedicated combustion air supply or be sealed-combustion units equipped with a powered combustion system.[133]

Table 51: Floor Insulation – Baseline and Efficiency Standards

Baseline	Efficiency Standard
No insulation under floor	(1) R-19 installed under floor, OR (2) Encapsulated crawl space with air-sealed perimeter having R-13 insulation on the interior side, no floor insulation under the floor above, and moisture-sealed grade under the crawl space

B.4.4.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 20 years, according to DEER 2014.

B.4.4.4. Deemed Savings Values

The deemed savings values listed below are per square foot of first level floor area above the crawl space.

For homes with gas heat and electric air conditioning, the deemed savings include the heating season therm savings plus the heating season (furnace fan) and cooling season kWh savings.

For homes with gas heat and no air conditioning, the deemed savings the furnace fan kWh savings.

Table 52: R-19 Floor Insulation – Deemed Savings Values - Zone 3: New Orleans

Equipment Type	kWh Savings / sq. ft.	kW Peak Savings / sq. ft.
Electric Cooling with Gas Heat	-0.2408	Negligible
Gas Heat (No AC)	0.0665	n/a
Electric Cooling with Electric Resistance Heat	0.4945	Negligible
Electric Cooling with Electric Heat Pump	0.0952	Negligible

B.4.4.5. Calculation of Deemed Savings

Deemed savings values have been calculated for each of the four weather zones. BEopt™ was used to estimate energy savings for both options using the same base case model (uninsulated floor) and the DOE EnergyPlus simulation engine. Savings are

[133] Ibid (p. 59).

sensitive to weather; therefore, available TMY3 weather data specific to New Orleans used for the analysis. The prototype home characteristics used in the BEopt™ building model are outlined in Appendix A.

B.4.4.6. Incremental Cost

The incremental cost of this measure is equal to the full installed cost.

B.4.4.7. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values based on simulation results. If this measure is added to Energy Smart programs and exceeds 1% of residential savings, then the simulation model should be updated to align with the billed use of customers that install the measure.

B.4.5. Window Film

B.4.5.1. Measure Description

This measure consists of adding solar film to east and west facing windows. This measure applies to all residential applications.

B.4.5.2. Baseline and Efficiency Standards

This measure is applicable to existing homes only. Low E windows and tinted windows are not applicable for this measure. In order to qualify for deemed savings, solar film should be applied to east and west facing glass.

Table 53: Window Film – Baseline and Efficiency Standards

Baseline	***Efficiency Standard***
Single- or double-pane window with no existing solar films, solar screens, or low-e coating	Solar Film with SHGC <0.50

B.4.5.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 10 years, according to DEER 2014.

B.4.5.4. Deemed Savings Values

Please note that the savings per square foot is a factor to be multiplied by the square footage of the window area to which the films are being added. Gas Heat (no AC) kWh applies to forced air furnace systems only.

Table 54: Window Film – Deemed Savings Values

Existing Window Pane Type	**AC/Gas Heat kWh**	**Gas Heat (no AC) kWh**	**AC/Electric Resistance kWh**	**Heat Pump kWh**	**AC Peak Savings (kW)**
	(/ sq. ft.)	**(/ sq. ft.)**	**(/ sq. ft.)**	**(/ sq. ft.)**	**(/ sq. ft.)**
Single Pane	1.610	-0.089	-0.661	4.216	0.001
Double Pane	0.826	-0.045	-0.226	2.465	0.001

B.4.5.5. Calculation of Deemed Savings

Deemed savings values have been calculated for each of the four weather zones. The deemed savings are dependent on the SHGC of pre- and post-retrofit glazing. BEopt™ was used to estimate energy savings for a series of models using the DOE EnergyPlus simulation engine. Since window film savings are sensitive to weather, available TMY3 weather data specific to New Orleans was ere used for the analysis. The prototype home characteristics used in the BEopt building model are outlined in Appendix A.

B.4.5.6. Incremental Cost

The incremental cost of this measure is equal to the full installed cost.

B.4.5.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values based on simulation results. If this measure is added to Energy Smart programs and exceeds 1% of residential savings, then the simulation model should be updated to align with the billed use of customers that install the measure.

B.4.6. Air Infiltration

B.4.6.1. Measure Description

This measure reduces air infiltration into the residence, using pre- and post-treatment blower door air pressure readings to quantify the air leakage reduction. There is no post-retrofit minimum infiltration requirement, however, installations must comply with the prevailing Arkansas mechanical code. This measure applies to all residential applications.

B.4.6.2. Baseline and Efficiency Standards

The baseline for this measure is the existing leakage rate of the residence to be treated. The existing leakage rate should be capped to account for the fact that the deemed savings values per CFM50 leakage reduction are only applicable up to a point where the existing HVAC equipment would run continuously. Beyond that point, energy use will no longer increase linearly with an increase in leakage.

Baseline assumptions used in the development of these deemed savings are based on the *2013 ASHRAE Handbook of Fundamentals, Chapter 16*, which provides typical infiltration rates for residential structures. In a study of low income homes reported in ASHRAE, approximately 95 percent of the home infiltration rates were below 3.0 ACH_{Nat}.[134] Therefore, to avoid incentivizing homes with envelope problems not easily remedied through typical weatherization procedures, or improperly conducted blower door tests, these savings should only be applied starting at a baseline ACH_{Nat} of 3.0 or lower.

To calculate the maximum allowable $CFM_{50,\ pre}$ value for a particular house, use the following equation:

$$CFM_{50,pre}/ft^2 = \frac{ACH_{Nat,pre} \times h \times N}{60}$$

Where:

$CFM_{50,pre}/_{ft^2}$ = Per square foot pre-installation infiltration rate (CFM50/ft2)

$ACH_{Nat,pre}$ = Maximum pre-installation air change rate (ACH_{Nat}) = 3.0

60 = Constant to convert from minutes to hours

h = Ceiling height (ft.) = 8.5 (default)135

N = N factor (Table 51:)

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[134] 2013 ASHRAE *Handbook of Fundamentals, Chapter 16,* pp. 16.18, Figure 12.

[135] Typical ceiling height of 8 feet adjusted to account for greater ceiling heights in some areas of a typical residence.

Table 55: Air Infiltration – N Factor [136]

	Number of Stories		
Wind Shielding	**Single Story**	**Two Story**	**Three + Story**
Well Shielded	25.8	20.6	18.1
Normal	21.5	17.2	15.1
Exposed	19.4	15.5	13.5

Well Shielded is defined as urban areas with high buildings or sheltered areas, and buildings surrounded by trees, bermed earth, or higher terrain.

Normal is defined as buildings in a residential neighborhood or subdivision setting, with yard space between buildings. Approximately 80-90 percent of houses fall in this category.

Exposed is defined as buildings in an open setting with few buildings or trees around and buildings on top of a hill or ocean front, exposed to winds.

Maximum CFM_{50} per square foot values are available in Table 56. Pre-retrofit leakage rates are limited to fa maximum per square foot value specified in the table, as this generally indicates severe structural damage not repairable by typical infiltration reduction techniques.

Table 56: Pre-Retrofit Infiltration Cap (CFM_{50}/ft^2)

	Number of Stories		
Wind Shielding	**Single Story**	**Two Story**	**Three + Story**
Well Shielded	11.0	8.8	7.7
Normal	9.1	7.3	6.4
Exposed	8.2	6.6	5.7

B.4.6.3. Estimated Useful Life (EUL)

According to DEER 2014, the Estimated Useful Life for air infiltration is 11 years.

[136] Krigger, J. & Dorsi, C. 2005, *Residential Energy: Cost Savings and Comfort for Existing Buildings, 4th Edition. Version RE. Appendix A-11: Zone 3 Building Tightness Limits*, p. 284., December 20. www.waptac.org/data/files/Website_docs/Technical_Tools/Building%20Tightness%20Limits.pdf.

B.4.6.4. Deemed Savings Values

The following formulas shall be used to calculate deemed savings for infiltration efficiency improvements. The formulas apply to all building heights and shielding factors.

$$kWh_{savings} = CFM_{50} \times ESF$$

$$kW_{savings} = CFM_{50} \times DSF$$

Where:

CFM_{50} = Air infiltration reduction in Cubic Feet per Minute at 50 pascals, as measured by the difference between pre- and post-installation blower door air leakage tests

ESF = corresponding energy savings factor (Table 57)

DSF = corresponding demand savings factor (Table 57)

Electrical energy savings for Gas Heat (no AC) are the reduction in electricity used by the furnace's air handler during the heating season.

Table 57: Air Infiltration Reduction – Deemed Savings Values

Equipment Type	kWh Savings / CFM_{50} (ESF)	kW Savings / CFM_{50} (DSF)
Electric AC with Gas Heat	0.4108	0.000331
Elec. AC with Resistance Heat	1.018	0.000332
Heat Pump	0.721	0.000332

B.4.6.5. Calculation of Deemed Savings

BEopt™ was used to estimate energy savings for a series of models using the US DOE EnergyPlus simulation engine. Since infiltration savings are sensitive to weather, available TMY3 weather data specific to New Orleans was used for the analysis. The prototype home characteristics used in the BEopt™ building model are outlined in Appendix A.

The deemed savings are dependent on the pre- and post-CFM_{50} leakage rates of the home and are presented as annual savings / CFM_{50} reduction. A series of model runs was completed in order to establish the relationship between various CFM_{50} leakage rates and heating and cooling energy consumption. The resulting analysis of model outputs was used to create the deemed savings tables of kWh and kW per CFM_{50} of air infiltration reduction.

B.4.6.6. Incremental Cost

The incremental cost of this measure is equal to the full installed cost.

B.4.6.7. Future Studies

This measure is a High Impact Measure, having constituted 13.3% of PY6 program savings. To-date, the evaluations have not conducted significant primary research on this measure due to the focusing of EM&V budget on Residential Lighting and Residential HVAC studies.

This measure should have its simulation model recalibrated to the billed use of the past three years of program participants. Further, the next EM&V study should measure the level of interaction between this measure and other significant building envelope and HVAC improvements (duct sealing, ceiling insulation, AC tune-up, etc.).

B.5. Residential Lighting

B.5.1. ENERGY STAR® Compact Fluorescent Lamps (CFLs)

B.5.1.1. Measure Description

This measure provides a method for calculating savings for replacing an incandescent lamp with a standard CFL in residential applications.

B.5.1.2. Baseline

The baseline equipment is assumed to be an incandescent or halogen lamp with adjusted baseline wattages compliant with EISA 2007 regulations dictate higher efficiency baseline lamps.

The first Tier of EISA 2007 regulations were phased in from January 2012 to January 2014. Beginning January 2012, a typical 100W lamp wattage was reduced to comply with a maximum 72W lamp wattage standard for a rated lumen output range of 1,490-2,600 lumens. Beginning January 2013, a typical 75W lamp wattage was reduced to comply with a maximum 53W lamp wattage standard for a rated lumen output range of 1,050-1,489 lumens. Beginning January 2014, typical 60W and 40W lamp wattages were reduced to comply with maximum 43W and 29W lamp wattage standards for rated lumen output ranges of 750-1,049 and 310-749 lumens.

The second Tier of EISA 2007 regulations go into effect beginning January 2020. At that time, general service lamps must comply with a 45 lumen per watt efficacy standard. Since the EUL of some lamps in this measure extend beyond that date, the baseline should be adjusted to the second Tier for any years after 2022.[137]

B.5.1.3. Efficiency Standard

CFLs must be a standard ENERGY STAR® qualified CFL.

Exceptions to the ENERGY STAR® label are allowed for unlisted lamps, fixtures or other lighting-related devices that have been submitted to ENERGY STAR® for approval. If the lamp or fixture does not achieve ENERGY STAR® approval within the AR DSM program year, however, then the lamp or fixture would have to be immediately withdrawn from the program.

[137] First tier EISA compliant halogens have a lifetime of 4 years (3,000 hours at 2.17 hours per day). The last year these lamps are available is 2019, and they will need replacement at the end of 2022. Thus, the new standard must be used after 2022.

B.5.1.4. Estimated Useful Life (EUL)

The average measure life is based upon rated lamp life of the CFL shown in the following table. The measure life assumes an average daily use of 2.25 blended[138] hours for indoor/outdoor applications and applies a 0.688[139] degradation factor to indoor residential CFLs. This table shows the useful life that should be used for the first tier EISA baseline, and the useful life remaining for the increased second tier EISA standard baseline.

Note that the values are in this table are incremented each program year so that the first tier values do not exceed 2023 minus the program year. For PY7 (calendar year 2017), the first tier measure life cannot exceed the result of 2023 - 2017, which is equal to 6 years. The remainder of the measure life is applied to the second tier.

Table 58: ENERGY STAR® CFLs – Measure Life[140]

Rated Measure Life (Hours)	***First Tier EISA Standard Baseline***		***Second Tier EISA Standard Baseline***	
	CFL Indoor Application – Measure Life (Years)	***CFL Outdoor Application – Measure Life (Years)***	***CFL Indoor Application – Measure Life (Years)***	***CFL Outdoor Application – Measure Life (Years)***
8,000	6	6	1	1
10,000	6	6	3	3
12,000	6	6	4	4
15,000	6	6	7	7

B.5.1.5. Lighting Hours of Use (HOU) Metering

Hours of use were estimated through direct monitoring of lighting in the on-site sample homes. Each logger was extrapolated to full annual usage by using a linear model with day length as the predictor, where day length varies inversely with the number of hours of use. Latitude and longitude coordinates for New Orleans, Louisiana were used in the computation of day length (29.9511, -90.0715). The regression used to extrapolate the meter data to a full year is shown in the equation below.

$$H_d = \alpha + \beta * \text{Day Length} + \varepsilon_d$$

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[138] ADM lighting metering, detailed in this chapter.

[139] Average of 0.526 and 0.85. Original 0.526 is from Itron, Hirsch and Associates, and Research Into Action, "Welcome to the Dark Side: The Effect of Switching on CFL Measure Life"2008 ACEEE Summer Study on Energy Efficiency in Buildings, p. 2-146; and 0.85 is from ENERGY STAR® CFL THIRD PARTY TESTING AND VERIFICATION Off-the-Shelf CFL Performance: Batch 3. Figure 27, p. 47.

[140] EUL = Rated Measure Life in Hours * Degradation Factor / (365.25 * Average Hours of Daily Use). Degradation Factor = 0.526 for indoor applications and 1.000 for outdoor applications.

Where:

H_d = hours of use on day d

Day Length = Number of daylight hours on day d

α and β are coefficients determined by the regression

ε_d = residual error.

A similar model was run which added room type as an explanatory variable in order to estimate hours of use for each room type.

B.5.1.5.1. Hours of Use Results

Results of the regressed logger data provided ADM with overall efficient lighting hours of use, as well as breakdowns of hours of use by room type as shown in Table 59. In total 176 lighting loggers were used, and all results were found to meet precision requirements. Overall daily HOU are 2.25, which corresponds to 819 annual HOU. The coefficients from the overall model and the model which adds room type are also shown below.

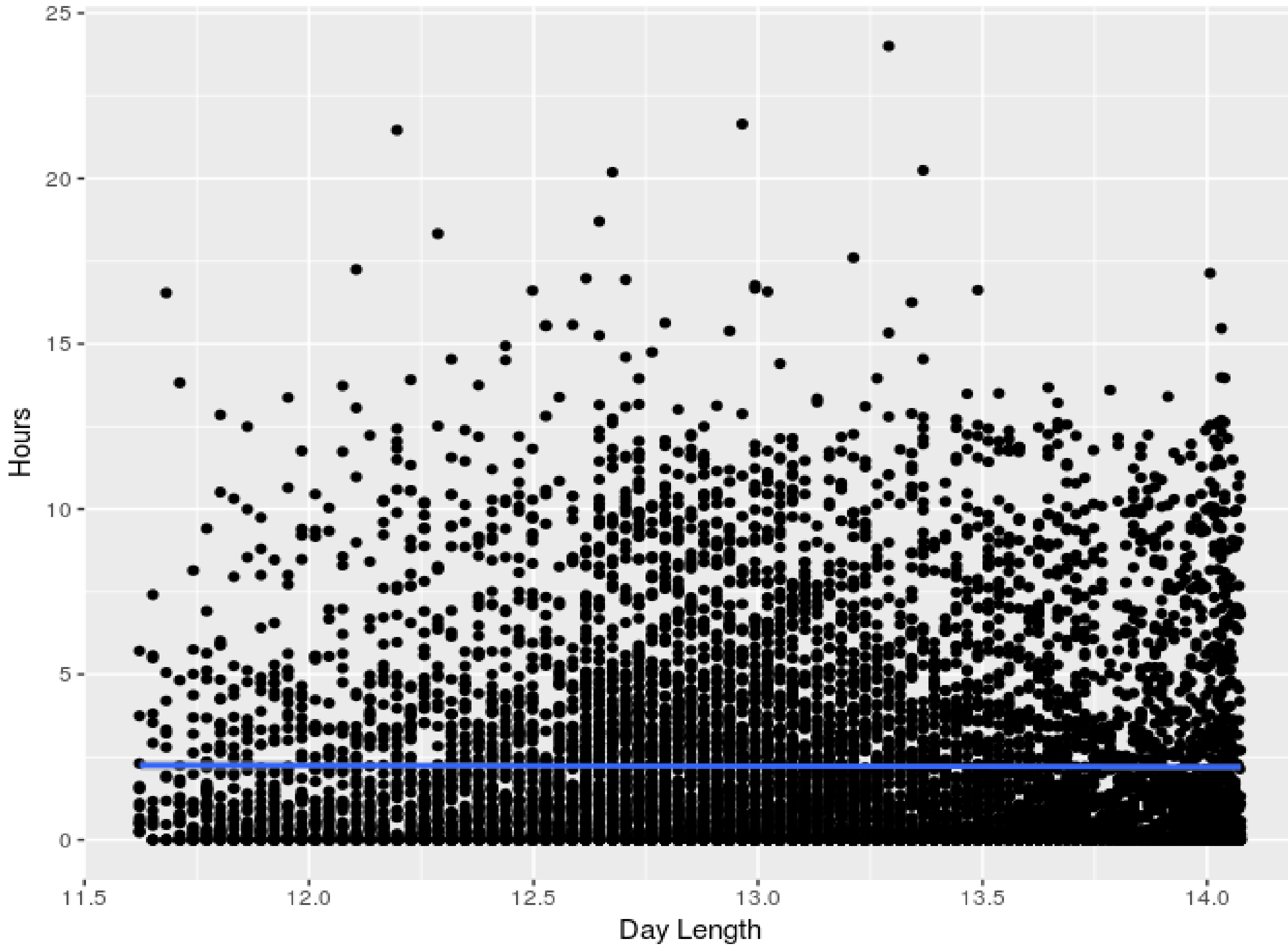
Table 59: Hours of Use by Area

Area/Room	***HOU Annual***	***HOU Daily***	***# Loggers***	***Precision***
Kitchen	761	2.08	39	0.06
Living Room	669	1.83	39	0.06
Bedroom	775	2.12	28	0.08
Bath	1,143	3.13	34	0.05
Dining Room	790	2.17	36	0.06
Overall	**819**	**2.25**	**176**	**0.03**

Table 60: Lighting Model Coefficients

Coefficient	***Estimate***	***SE***	***T-Stat***	***P-value***
Intercept	2.526	0.694	3.640	0.000
Day Length	-0.023	0.053	-0.437	0.662

The graph below is a scatterplot showing average hours of use for all of the loggers in the M&V sample and the corresponding day length (based on New Orleans, LA). The fitted line shows a slightly negative relationship between average daily hours and day length, which is the pattern one would expect ex-ante. The day length coefficients for



both models also confirm this relationship, as they are both negative, although neither is statistically significant.

Table 61: Lighting Room Model Coefficients

Coefficient	Estimate	SE	T-Stat	P-value
Intercept	2.607	0.690	3.777	0.000
Day Length	-0.043	0.052	-0.818	0.413
Bedroom	-0.250	0.097	-2.572	0.010
Dining Room	0.038	0.104	0.362	0.718
Kitchen	1.048	0.099	10.600	0.000

Living Room	0.081	0.097	0.828	0.408

B.5.1.5.2. Coincidence Factor

ADM calculated the coincident factor (CF) based on actual lighting logger data in June between the hours of 3 and 6 pm as 12.74%.

B.5.1.6. Calculation of Deemed Savings

For retail (time of sale) programs, increased savings may be claimed based on sales to nonresidential customers.[141] Based on a review of 23 utility programs across 10 states, 6.7% of installed lamps may be allocated to the commercial program. To implement, multiply the total number of fixtures by 6.7% and apply the savings methodologies described in the Commercial Lighting Efficiency measure. Since no building type will have been identified, apply the weighted average annual operating hours and coincidence factor based on a review of the building types that participating in commercial lighting programs during the current program year.

Calculate savings for the remaining 93.3 percent of fixtures using the residential savings calculations described below. If it is not possible to apply the commercial allocation strategy described above, a program may calculate savings for all fixtures using the residential savings calculations described below. This will result in a conservative estimate for upstream programs. Note: This strategy should only be applied to retail (time of sale) programs. For all other programs, use the residential savings calculations exclusively.

B.5.1.6.1. Energy Savings

$$kWh_{savings} = \left(\left(W_{base} - W_{post}\right)/1000\right) \times Hours \times ISR \times IEF_E$$

Where:

W_{base} = Based on wattage equivalent of the lumen output of the purchased CFL lamp and the program year purchased/installed

W_{post} = Actual wattage of CFL purchased/installed

$Hours$ = Average hours of use per year

IEF_E = Interactive Effects Factor to account for cooling energy savings and heating energy penalties; this factor also applies to outdoor and unconditioned spaces

[141] Dimetrosky, S., Parkinson, K. & Lieb, N. 2015, "Residential Lighting Evaluation Protocol – The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures." January.

ISR = In Service Rate, or percentage of rebate units that get installed, to account for units purchased but not immediately installed

When the EISA 2007 standard goes into effect for a CFL, the reduced wattage savings should be claimed for the rest of the measure life. For example, up until 2022, a 20W CFL with 1200 lumens may claim a 53W baseline. After 2022, the baseline becomes 27W for the remainder of the measure life.

Table 62: ENERGY STAR® CFLs – EISA Baselines[142]

Minimum Lumens	***Maximum Lumens***	***Incandescent Equivalent 1st Tier EISA 2007 (W_{base})***	***Incand. Equiv. 2nd Tier EISA 2007 (W_{base})***[143]	***Effective dates for 2nd Tier EISA 2007 Baselines***
310	749	29	12	1/1/2023
750	1,049	43	20	1/1/2023
1,050	1,489	53	28	1/1/2023
1,490	2,600	72	45	1/1/2023

Table 63: ENERGY STAR® CFLs – Average Hours of Use Per Year

Installation Location	***Hours***
Blended Indoor/Outdoor[144]	819.43

Table 64: ENERGY STAR® CFLs – In Service Rates

Program	***CFL ISR***
Retail (Time of Sale) and Direct Install[145]	0.98

[142] Note that ENERGY STAR® has assigned new incandescent equivalent wattage lumen bins for the upcoming ENERGY STAR® lighting standards, coming into effect September 2014. Due to the likelihood of sell-through of existing ENERGY STAR® lighting through fall 2014 and the on-going use of the EISA bin definitions, this TRM maintains the EISA lumen bins for assigning baseline wattage. Future TRM iterations of the AR TRM, however, may incorporate these new lumen bins for baseline wattage estimates.

[143] Wattages developed using the 45 lpw standard that goes into effect in 2020.

[144] Indoor Hours based off aggregated lighting study performed by ADM looking at lighting logger data from 80 homes.

[145] Dimetrosky, S. et al, 205, ,"Residential Lighting Evaluation Protocol – The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures." January. ISR for upstream programs, including storage lamps installed within four years of purchase.

Table 65: ENERGY STAR® CFLs – Interactive Effects Factor for Cooling Energy Savings and Heating Energy Penalties

Heating Type	Interactive Effects Factor (IEF_E)[146]
Gas Heat with AC	1.10
Gas Heat with no AC	1.00
Electric Resistance Heat with AC	0.83
Electric Resistance Heat with no AC	0.73
Heat Pump	0.96
Heating/Cooling Unknown[147]	0.91

B.5.1.6.2. Peak Demand Savings

$$kW_{savings} = \left(\left(W_{base} - W_{post}\right)/1000\right) \times CF \times ISR \times IEF_D$$

Where:

CF = Coincidence Factor, 12.74%

IEF_D = Interactive Effects Factor to account for cooling demand savings; this factor also applies to outdoor and unconditioned spaces

Table 66: Residential Lighting Efficiency – Summer Peak Coincidence Factor

Lamp Location	CF
Indoor[148]	10%
Outdoor	0%

[146] Refer to Appendix I, Arkansas TRM 6.0 Volume 3.

[147] Unknown factors are based on EnergyStar Interactive effects, weighted by primary data collected on New Orleans typical HVAC arrangements.

[148] Residential light logging study by Cadmus - Entergy Arkansas, Inc. 2013 EM&V Evaluation Report.

Table 67: ENERGY STAR® CFLs – Interactive Effects Factor for Cooling Demand Savings

Heating Type	Interactive Effects Factor (IEF_D)[149]
Gas Heat with AC	1.29
Gas Heat with no AC	1.00
Electric Resistance Heat with AC	1.29
Electric Resistance Heat with no AC	1.00
Heat Pump	1.29
Heating/Cooling Unknown[150]	1.21

B.5.1.6.3. Heating Penalty for Natural Gas Heated Homes

$$Therms_{penalty} = \left((W_{base} - W_{post})/1000\right) \times ISR \times IEF_G$$

Where:

IEF_G = Interactive Effects Factor to account for gas heating penalties (Δtherm/kWh); this factor also applies to outdoor and unconditioned spaces

Table 68: ENERGY STAR® CFLs – Interactive Effects Factor for Gas Heating Penalties

Heating Type	Interactive Effects Factor (IEF_G)[151]
Gas Heat with AC	-0.011
Gas Heat with no AC	-0.011
Electric Resistance Heat with AC	0
Electric Resistance Heat with no AC	0
Heat Pump	0
Heating/Cooling Unknown[152]	-0.0063

[149] Refer to Appendix I, Arkansas TRM 6.0 Volume 3.

[150] Unknown factors are based on EnergyStar Interactive effects, weighted by primary data collected on New Orleans typical HVAC arrangements.

[151] Refer to Appendix I, Arkansas TRM 4.0 Volume 3

[152] Weighted average based on Residential Energy Consumption Survey (RECS) 2009 data. http://www.eia.gov/consumption/residential/data/2009/.

B.5.1.7. Annual kW, Annual kWh, and Lifetime kWh Savings Calculation Example

A 5W CFL is installed in program year (PY) 2016. In July 2014 Tier 1 EISA 2007 standards went into effect, and the baseline shifted to 29 watts. In January 2023, due to Tier 2 EISA 2007 standards going into effect, the baseline will shift again to 12 watts. This CFL has a rated life of 15,000 hours. Necessary inputs for calculating the kWh savings include the EUL (13.0 years), IEF_D (1.25 for unknown heating/cooling type), IEF_E (0.97 for unknown cooling/heating type), ISR (0.98), summer coincidence factor (0.1), and Hours of Use per Year (819.43 hours). All kWh values are rounded to the second decimal place.

PY 2016 through PY 2022 Savings: From January 2016 to December 2022, the baseline is 29 watts. 2023 – 2016 is 7 years.

$$2017\ to\ 2023\ kW\ Savings\ (for\ each\ year) = \left(\frac{[29-5]}{1000}\right) \times 0.1 \times 1.25 \times 0.98$$

$$= 0.0029\ kW$$

$$Cumulative\ 2017\ to\ 2023\ kWh\ Savings = \left(\frac{[29-5]}{1000}\right) \times 819.43 \times 0.97 \times 0.98 \times 6$$

$$= 112.17\ kWh$$

PY 2023 through PY 2028 Savings: In January 2023, the baseline changes to the 2nd Tier EISA 2007 standard. The baseline wattage changes from 29 watts to 12 watts. The remaining measure life is 7 years.

$$2023\ to\ 2028\ kW\ Savings\ (for\ each\ year) = \left(\frac{[12-5]}{1000}\right) \times 0.1 \times 1.25 \times 0.98$$

$$= 0.0009\ kW$$

$$Cumulative\ 2023\ to\ 2028\ kWh\ Savings = \left(\frac{[12-5]}{1000}\right) \times 819.43 \times 0.97 \times 0.98 \times 7$$

$$= 38.17\ kWh$$

Lifetime kWh Savings:

$$112.17 + 38.17 = 15034\ kWh\ lifetime\ savings$$

B.5.1.8. Incremental Cost

Costs by delivery channel area as follows:

- Retail Markdown: $1.20[153]

[153] Cites Illinois TRM.

- Direct Install: program actual. If unavailable, use full measure cost of $2.45 per bulb plus $5 installation cost[154].
- Efficiency Kits: program actual.

B.5.1.1. Future Studies

This measure is a High Impact Measure, having constituted more than 1% of residential Energy Smart program savings. However, the major research need (hours of use and coincidence) has been completed. Further, given the pending code change to EISA Phase II starting in 2020, this measure should not be the focus of research studies for future program implementation. EM&V for this measure should focus on savings validation.

ADM recommends that this measure cease implementation when EISA Phase II takes effect in 2020, unless program administrators can show that the savings are still cost-effective under the more stringent baseline.

[154] Assumes 15 minutes at $20/hour. This includes proration of travel time to the site.

A.1.2. ENERGY STAR® Specialty Compact Fluorescent Lamps (CFLs)

B.5.1.2. Measure Description

This measure provides a method for calculating savings for replacing a specialty incandescent or halogen lamp with an ENERGY STAR® qualified specialty CFL. These lamps include R, PAR, ER, BR, BPAR, globes G40, decorative globes equal to or less that 60W with candelabra base, and decorative candles equal to or less than 60W with candelabra base.

B.5.1.3. Baseline Wattage

The baseline wattages for specialty lamps are presented in Table 69 and Table 70.

Table 69: ENERGY STAR® Specialty CFLs - Default Baseline Wattage for Reflector Lamps[155]

Lamp Type (a)	***Incandescent Equivalent (Pre-EISA) (b)***	***$Watts_{Base}$ (Post-EISA) (c)***
PAR20	50	35
PAR30	50	35
R20	50	45
PAR38	60	55
BR30	65	EXEMPT
BR40	65	EXEMPT
ER40	65	EXEMPT
BR40	75	65
BR30	75	65
PAR30	75	55
PAR38	75	55
R30	75	65
R40	75	65
PAR38	90	70
PAR38	120	70
R20	≤ 45	EXEMPT
BR30	≤ 50	EXEMPT
BR40	≤ 50	EXEMPT
ER30	≤ 50	EXEMPT
ER40	≤ 50	EXEMPT

For other specialty, EISA exempt lamps[156], use the baseline wattage in Table 70. Commonly used EISA exempt lamps include 3-way lamps, globes with ≥ 5” diameter or ≤ 749 lumens, and candelabra base lamps with ≤ 1049 lumens. See EISA legislation for

[155]Based on manufacturer available reflector lighting products as available in August 2013.

[156] A complete list of the 22 incandescent lamps exempt from EISA 2007 is listed in the United States U.S. DOE Impact of EISA 2007 on General Service Incandescent Lamps: FACT SHEET. www1.eere.energy.gov/buildings/appliance_standards/residential/pdfs/general_service_incandescent_factsheet.pdf.

full list of exemptions. If rated lumen values fall above or below these values, use manufacturer rated equivalent incandescent wattage.

Table 70: Default Baseline Wattage for Specialty, EISA Exempt Lamps[157]

Minimum Lumens	Maximum Lumens	Incandescent Equivalent (Wbase)
310	749	40
750	1,049	60
1,050	1,489	75
1,490	2,600	100

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B.5.1.4. Efficiency Standard

CFLs must be an ENERGY STAR® specialty CFL.

Exceptions to the ENERGY STAR® label are allowed for unlisted lamps, fixtures or other lighting-related devices that have been submitted to ENERGY STAR® for approval. If the lamp or fixture does not achieve ENERGY STAR® approval within the program year, however, then the lamp or fixture would have to be immediately withdrawn from the program.

B.5.1.5. Estimated Useful Life (EUL)

The average measure life is based upon rated lamp life of the CFL shown in the following table. The measure life assumes an average daily use of 2.24 blended hours for indoor/outdoor applications and applies a 0.688[158] degradation factor to indoor residential CFLs.

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[157]Note that ENERGY STAR® has assigned new incandescent equivalent wattage lumen bins for the upcoming ENERGY STAR® lighting standards, coming into effect September 2014. Due to the likelihood of sell-through of existing ENERGY STAR® lighting through fall 2014 and the on-going use of the EISA bin definitions, this TRM maintains the EISA lumen bins for assigning baseline wattage. Future TRM iterations of the AR TRM, however, may incorporate these new lumen bins for baseline wattage estimates.

[158] Average of 0.526 and 0.85. Original 0.526 is from Itron, Hirsch and Associates, and Research Into Action, "Welcome to the Dark Side: The Effect of Switching on CFL Measure Life". 2008 ACEEE Summer Study on Energy Efficiency in Buildings, p. 2-146; and 0.85 is from ENERGY STAR® CFL THIRD PARTY TESTING AND VERIFICATION Off-the-Shelf CFL Performance: Batch 3. Figure 27, p. 47.

Table 71: ENERGY STAR® Specialty CFLs – Measure Life[159]

Rated Measure Life (Hours)	Measure Life (Years)
8,000	7
10,000	9
12,000	10
15,000	13

B.5.1.6. Coincidence Factor

Coincidence factors align with those specified for standard configuration CFLs, 12.75%, based on ADM metering.

B.5.1.7. Calculation of Deemed Savings

Deemed savings are calculated in the same manner as for standard CFLs (see Section B.5.1.7).

A.1.2.1. Incremental Cost

Costs by delivery channel area as follows:

- Retail Markdown: $5.00[160]
- Direct Install: program actual. If unavailable, use full measure cost of $8.50 per bulb plus $5 installation cost[161]
- Efficiency Kits: program actual

B.5.1.1. Future Studies

This measure is a High Impact Measure, having constituted more than 1% of residential Energy Smart program savings. However, the major research need (hours of use and coincidence) has been completed. Further, given the pending code change to EISA Phase II starting in 2020, this measure should not be the focus of research studies for future program implementation. EM&V for this measure should focus on savings validation.

ADM recommends that this measure cease implementation when EISA Phase II takes effect in 2020, unless program administrators can show that the savings are still cost-effective under the more stringent baseline.

[159] EUL = Rated Measure Life in Hours * Degradation Factor / (365.25 * Average Hours of Daily Use). Degradation Factor = 0.526 for indoor applications and 1.000 for outdoor applications.

[160] NEEP Residential Lighting Survey, 2011 .

[161] Assumes 15 minutes at $20/hour. This includes proration of travel time to the site.

A.1.3. ENERGY STAR® Directional LEDs

B.5.1.2. Measure Description

This measure provides a method for calculating savings for replacing an incandescent or halogen reflector or decorative lamp with an ENERGY STAR® qualified LED lamp. These lamp shapes include PAR, R, BR, MR, and similar lamp shapes.

B.5.1.3. Baseline

Directional lamps are not covered under EISA legislation. Instead, directional lamps are governed by a 2009 DOE rulemaking for Incandescent Reflector Lamps (IRL)—this ruling went into effect in July 2012. The baselines for these products are from this IRL ruling in July 2012.

Table 72: ENERGY STAR® Directional LEDs – Default Baseline Wattage for Reflector Lamps[162]

Lamp Type (a)	Incandescent Equivalent (Pre-EISA) (b)	$Watts_{Base}$ (Post-EISA) (c)
PAR20	50	35
PAR30	50	35
R20	50	45
PAR38	60	55
BR30	65	EXEMPT
BR40	65	EXEMPT
ER40	65	EXEMPT
BR40	75	65
BR30	75	65
PAR30	75	55
PAR38	75	55
R30	75	65
R40	75	65
PAR38	90	70
PAR38	120	70
R20	≤ 45	EXEMPT

[162] Based on manufacturer available reflector lighting products as available in August 2013.

Lamp Type (a)	*Incandescent Equivalent (Pre-EISA) (b)*	*Watts$_{Base}$ (Post-EISA) (c)*
BR30	≤ 50	EXEMPT
BR40	≤ 50	EXEMPT
ER30	≤ 50	EXEMPT
ER40	≤ 50	EXEMPT

For other specialty, EISA exempt lamps[163], use the baseline wattage in Table 75. Commonly used EISA exempt lamps include 3-way lamps, globes with ≥ 5” diameter or ≤ 749 lumens, and candelabra base lamps with ≤ 1049 lumens. See EISA legislation for full list of exemptions. If rated lumen values fall above or below these values, use manufacturer rated equivalent incandescent wattage.

Table 73: ENERGY STAR® Directional LEDs – Default Baseline Wattage for Specialty, EISA Exempt Lamps[164]

Minimum Lumens	*Maximum Lumens*	*Incandescent Equivalent (W_{base})*
310	749	40
750	1,049	60
1,050	1,489	75
1,490	2,600	100

B.5.1.4. Efficiency Standard

LEDs must be ENERGY STAR® qualified for the relevant lamp shape being removed.

Exceptions to the ENERGY STAR® label are allowed for unlisted lamps, fixtures or other lighting-related devices that have been submitted to ENERGY STAR® for approval. If the lamp or fixture does not achieve ENERGY STAR® approval within the

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[163] A complete list of the 22 incandescent lamps exempt from EISA 2007 is listed in the United States U.S. DOE Impact of EISA 2007 on General Service Incandescent Lamps: FACT SHEET. www1.eere.energy.gov/buildings/appliance_standards/residential/pdfs/general_service_incandescent_factsheet.pdf.

[164] Note that ENERGY STAR® has assigned new incandescent equivalent wattage lumen bins for the upcoming ENERGY STAR® lighting standards, coming into effect September 2014. Due to the likelihood of sell-through of existing ENERGY STAR® lighting through fall 2014 and the on-going use of the EISA bin definitions, this TRM maintains the EISA lumen bins for assigning baseline wattage.

Arkansas DSM program year, however, then the lamp or fixture would have to be immediately withdrawn from the program.

B.5.1.5. Estimated Useful Life (EUL)

The measure life for indoor and outdoor LED reflector and decorative lamps is 20 years.[165]

B.5.1.6. Daily Hours of Use

These deemed savings assume an average daily use of 2.24 blended hours for indoor/outdoor applications.

A.1.3.1. Coincidence Factor

Coincidence factors align with those specified for standard configuration CFLs, 12.75%, based on ADM metering.

B.5.1.7. Incremental Cost

Prices for LEDs decrease each year. Given this, actual lighting costs should be compared to a stipulated baseline cost where feasible. If that information is not available, use costs detailed in the table below

Table 74: ENERGY STAR® Directional LEDs Incremental Costs[166]

Lamp Type	Year	Incandescent Cost	LED Cost	Incremental Cost
Recessed Downlight Luminaires	2017-2019	$4.00	$94.00	$90.00
Track Lights	2017-2019	$4.00	$60.00	$56.00
Directional	2017	$3.53	$6.24	$2.71
	2018-2019		$5.18	$1.65
Decorative & Globe	2017	$1.60	$3.50	$1.90
	2018-2019	$1.74	$3.40	$1.66

A.1.3.1. Calculation of Deemed Savings

Deemed savings are calculated in the same manner as for standard CFLs (see Section A.6.2.6).

[165] Emerging Technologies Research Report prepared for the Regional Evaluation, Measurement, and Verification Forum facilitated by the Northeast Energy Efficiency Partnerships (NEEP). February 13, 2013.

[166] Based on Illinois TRM.

Table 75: ENERGY STAR® Directional LEDs – Default Baseline Wattage for Reflector Lamps[167]

Lamp Type (a)	Incandescent Equivalent (Pre-EISA) (b)	$Watts_{Base}$ (Post-EISA) (c)
PAR20	50	35
PAR30	50	35
R20	50	45
PAR38	60	55
BR30	65	EXEMPT
BR40	65	EXEMPT
ER40	65	EXEMPT
BR40	75	65
BR30	75	65
PAR30	75	55
PAR38	75	55
R30	75	65
R40	75	65
PAR38	90	70
PAR38	120	70
R20	≤ 45	EXEMPT
BR30	≤ 50	EXEMPT
BR40	≤ 50	EXEMPT
ER30	≤ 50	EXEMPT
ER40	≤ 50	EXEMPT

For other specialty, EISA exempt lamps[168], use the baseline wattage in Table 76. Commonly used EISA exempt lamps include 3-way lamps, globes with ≥ 5" diameter or ≤ 749 lumens, and candelabra base lamps with ≤ 1049 lumens. See EISA legislation for

[167] Based on manufacturer available reflector lighting products as available in August 2013.

[168]A complete list of the 22 incandescent lamps exempt from EISA 2007 is listed in the United States U.S. DOE Impact of EISA 2007 on General Service Incandescent Lamps: FACT SHEET. www1.eere.energy.gov/buildings/appliance_standards/residential/pdfs/general_service_incandescent_factsheet.pdf.

full list of exemptions. If rated lumen values fall above or below these values, use manufacturer rated equivalent incandescent wattage.

Table 76: ENERGY STAR® Directional LEDs – Default Baseline Wattage for Specialty, EISA Exempt Lamps[169]

Minimum Lumens	Maximum Lumens	Incandescent Equivalent (W_{base})
310	749	40
750	1,049	60
1,050	1,489	75
1,490	2,600	100

B.5.1.1. Future Studies

This measure is a High Impact Measure, having constituted more than 1% of residential Energy Smart program savings. However, the major research need (hours of use and coincidence) has been completed. Further, given the pending code change to EISA Phase II starting in 2020, this measure should not be the focus of research studies for future program implementation. EM&V for this measure should focus on savings validation.

ADM recommends that this measure cease implementation when EISA Phase II takes effect in 2020, unless program administrators can show that the savings are still cost-effective under the more stringent baseline.

[169] Note that ENERGY STAR® has assigned new incandescent equivalent wattage lumen bins for the upcoming ENERGY STAR® lighting standards, coming into effect September 2014. Due to the likelihood of sell-through of existing ENERGY STAR® lighting through fall 2014 and the on-going use of the EISA bin definitions, this TRM maintains the EISA lumen bins for assigning baseline wattage.

A.1.4. ENERGY STAR® Omni-Directional LEDs

B.5.1.2. Measure Description

This measure provides a method for calculating savings for replacing an incandescent lamp with an omni-directional LED in residential applications. The applicable lamp types that are omni-directional LEDs are the following shapes, using ANSI C79.1-2002 nomenclature: A, BT, P, PS, S, and T.[170]

B.5.1.3. Baseline

The baseline equipment is assumed to be an incandescent or halogen lamp with adjusted baseline wattages compliant with EISA 2007 regulations dictate higher efficiency baseline lamps.

The first Tier of EISA 2007 regulations were in from January 2012 to January 2014. Beginning January 2012, a typical 100W lamp wattage was reduced to comply with a maximum 72W lamp wattage standard for a rated lumen output range of 1,490-2,600 lumens. Beginning January 2013, a typical 75W lamp wattage was reduced to comply with a maximum 53W lamp wattage standard for a rated lumen output range of 1,050-1,489 lumens. Beginning January 2014, typical 60W and 40W lamp wattages were reduced to comply with maximum 43W and 29W lamp wattage standards for rated lumen output ranges of 750-1,049 and 310-749 lumens.

The second Tier of EISA 2007 regulations go into effect beginning January 2020. At that time, general service lamps must comply with a 45 lumen per watt efficacy standard. Since the EUL of some lamps in this measure extend beyond that date, the baseline should be adjusted to the second Tier for any years after 2022. [171]

The baselines are summarized in Table 77.

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[170] According to ENERGY STAR®, omni-directional LED products "…shall have an even distribution of luminous intensity (candelas) within the 0° to 135° zone (vertically axially symmetrical). Luminous intensity at any angle within this zone shall not differ from the mean luminous intensity for the entire 0° to 135° zone by more than 20%. At least 5% of total flux (lumens) must be emitted in the 135°-180° zone. Distribution shall be vertically symmetrical as measured in three vertical planes at 0°, 45°, and 90°."
http://www.energystar.gov/ia/partners/product_specs/program_reqs/Integral_LED_Lamps_Program_Requirements.pdf.

[171] First tier EISA compliant halogens have a lifetime of 4 years (3,000 hours at 2.17 hours per day). The last year these lamps are available is 2019, and they will need replacement at the end of 2022. Thus, the new standard must be used after 2022.

Table 77: ENERGY STAR® Omni-Directional LEDs – EISA Baselines

Minimum Lumens	Maximum Lumens	Incandescent Equivalent 1st Tier EISA 2007 (W_{base})	Incandescent Equivalent 2nd Tier EISA 2007 (W_{base})[172]	Effective dates for 2nd Tier EISA 2007 Baselines
310	749	29	12	1/1/2023
750	1,049	43	20	1/1/2023
1,050	1,489	53	28	1/1/2023
1,490	2,600	72	45	1/1/2023

B.5.1.4. Efficiency Standard

Omni-directional LEDs must be a standard ENERGY STAR® qualified omni-directional LED.

Exceptions to the ENERGY STAR® label are allowed for unlisted lamps, fixtures or other lighting-related devices that have been submitted to ENERGY STAR® for approval. If the lamp or fixture does not achieve ENERGY STAR® approval within the Arkansas DSM program year, however, then the lamp or fixture would have to be immediately withdrawn from the program.

B.5.1.5. Estimated Useful Life (EUL)

The measure life for indoor and outdoor LED omni-directional lamps is 20 years.[173] Due to the EISA standards, the savings over the useful life will need to be adjusted to account for second tier EISA standards for all years after 2022.

Table 78: ENERGY STAR® Omni-Directional LEDs – Measure Life

Rated Measure Life (Hours)	First Tier EISA Standard Baseline	Second Tier EISA Standard Baseline
$\geq$ 25,000[174]	6	14

B.5.1.6. Daily Hours of Use

These deemed savings assume an average daily use of 2.24 blended hours for indoor/outdoor applications.

A.1.4.1. Coincidence Factor

[172] Wattages developed using the 45 lpw standard that goes into effect in 2020.

[173] Emerging Technologies Research Report prepared for the Regional Evaluation, Measurement, and Verification Forum facilitated by the Northeast Energy Efficiency Partnerships (NEEP). February 13, 2013.

[174] Minimum requirement from current ENERGY STAR® specification. https://www.energystar.gov/products/lighting_fans/light_bulbs/key_product_criteria.

Coincidence factors align with those specified for standard configuration CFLs, 12.75%, based on ADM metering.

A.1.4.1. Calculation of Savings

Deemed savings are calculated in the same manner as for standard CFLs (see Section B.5.1.7.

B.5.1.7. Incremental Cost

Prices for LEDs decrease each year. Given this, actual lighting costs should be compared to a stipulated baseline cost where feasible. If that information is not available, use costs detailed in the table below.

Table 79: ENERGY STAR® Directional LEDs Incremental Costs[175]

Year	EISA-Compliant Halogen	LED A-Lamp	Incremental Cost
2017	$1.25	$3.21	$1.96
2018	$1.25	$3.21	$1.96
2019	$1.25	$3.11	$1.86

B.5.1.1. Future Studies

This measure is a High Impact Measure, having constituted more than 1% of residential Energy Smart program savings. However, the major research need (hours of use and coincidence) has been completed. Further, given the pending code change to EISA Phase II starting in 2020, this measure should not be the focus of research studies for future program implementation. EM&V for this measure should focus on savings validation.

ADM recommends that this measure cease implementation when EISA Phase II takes effect in 2020, unless program administrators can show that the savings are still cost-effective under the more stringent baseline.

[175] Based on Illinois TRM.

C.Commercial Measures

C.1. Commercial Motors

C.1.1. Electronically Commutated Motors for Refrigeration and HVAC Applications

C.1.1.1. Measure Description

An electronically commutated motor (ECM) is a fractional horsepower direct current (DC) motor used most often in commercial refrigeration applications such as display cases, walk-in coolers/freezers, refrigerated vending machines, and bottle coolers. ECMs can also be used in HVAC applications, primarily as small fan motors for packaged terminal units or in terminal air boxes. ECMs generally replace shaded pole (SP) or permanent split-capacitor (PSC) motors and offer energy savings of at least 50 percent.

C.1.1.2. Baseline and Efficiency Standards

The standard motor type for this application is a shaded pole or permanent split-capacitor motor.

Any ECM up to 1 HP in size will meet the minimum requirements for both retrofit and new construction installations.

C.1.1.3. Estimated Useful Life (EUL)

In accordance with DEER 2008, the estimated useful life (EUL) is 15 years.

C.1.2. Calculation of Deemed Savings

C.1.2.1. Energy Savings

$$kWh_{savings} = (kW_{base} - kW_{ECM}) \times Hrs \times DC \times (1 + \frac{1}{COP})$$

Where:

kW_{base} = Power of the motor being replaced; use known wattage of motor, or if unknown, use 132W (SP motors)[176] or 72W (PSC motors)[177]

[176] http://www.fishnick.com/publications/appliancereports/refrigeration/GE_ECM_revised.pdf

[177] The Massachusetts TRM specifies a load factor of 54% for SP motors and a load factor of 29% for PSC motors, as specified by National Resource Management (NRM). Multiplying the 132 W default value for SP motors by the ratio of PSC load factor to SP load factor results in a default PSC motor wattage of 72 watts.

kW_{ECM} = Power of the replacement EC motor; use known wattage of motor, or if unknown, use 40W[178]

The motor's power for either Base or ECM can be calculated using the following equation if power is not known. The values for rated wattage and phase can be found on motor's nameplate:

$$kW_{motor} = \frac{Volts \times Amperage}{1000} \times \sqrt{Phase} \times Power\ Factor$$

Hrs = Hours of yearly operation, use 8,760 hours for refrigeration and 4,386 for HVAC

DC = Duty cycle, only use a value of 0.94 if the application of the motor being replaced is for a freezer refrigeration. This is because the freezer will complete four 20-min defrost cycles per day where the evaporator fan will not be used. Use a value of 1 if the application is for a cooler refrigeration or HVAC.

$PowerFactor$ = Power factor of the motor, if not known an average value of 0.55 can be used for ECM in refrigeration, 0.7 for ECM in HVAC, and 0.85 for base motor in both applications.[179]

COP = Coefficient of Performance for the motors operation based on application. COP value depends on the end temperature of the refrigeration process. The COP values to use for refrigeration analysis are 1.3 for freezers and 2.5 for coolers[180]. For HVAC, use the EER value from install spec sheet and the conversion COP = 3.412/EER.

C.1.2.2. Demand Savings

$$kW_{HVAC\ reduction} = (kW_{base} - kW_{ECM}) \times CF \times (1 + \frac{1}{COP})$$

$$kW_{Refrigeration\ reduction} = (kW_{base} - kW_{ECM}) \times DC \times CF \times (1 + \frac{1}{COP})$$

Where:

CF = Coincidence Factor, use values from Table 80 for HVAC applications; default value of 1.0 for refrigeration applications[181]

[178] http://www.fishnick.com/publications/appliancereports/refrigeration/GE_ECM_revised.pdf

[179] http://www.ecw.org/sites/default/files/230-1.pdf

[180] PSC of Wisconsin, Focus on Energy Evaluation, Business Programs: Deemed Savings Manual V1.0, pp. 4-103 -4-106.

[181] CF set to 1.0 for refrigeration applications based on annual run-time assumption of 8,760 hours

DC = Duty cycle, only use a value of 0.94 if the application of the motor being replaced is for a freezer refrigeration. This is because the freezer will complete four 20-min defrost cycles per day where the evaporator fan will not be used. Use a value of 1 if the application is for a cooler refrigeration of HVAC.

Table 80: Commercial Coincidence Factors by Building Type[182]

Building Type	Coincidence Factor
Assembly	0.82
College	0.84
Fast Food	0.78
Full Menu	0.85
Grocery	0.90
Health Clinic	0.85
Large Office	0.84
Lodging	0.77
Religious Worship	0.82
Retail	0.88
School	0.71
Small Office	0.84

C.1.2.3. Incremental Cost

Incremental cost by end-use type is $177.[183]

C.1.2.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans business and updates for applicable codes.

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[182] Values for Assembly and Religious Worship building types developed using an adjustment factor derived through a comparison of average CFs for College/University and Assembly/Religious Worship building types from the Texas state Technical Reference Manual. College/University was selected as a reference building type due to average alignment with Assembly/Religious worship building types in other TRMs, inclusion of a summer session, and increased evening usage.

[183] Difference in the fully installed cost ($468) for ECM motor and controller, listed in Work Paper PGE3PREF126, "ECM for Walk-In Evaporator with Fan Controller," June 20,2012, and the measure cost specified in 4.6.6 ($291)

C.1.3. Premium Efficiency Motors

C.1.3.1. Measure Description

Currently a wide variety of NEMA premium efficiency motors from 1 to 500 HP are available. Deemed saving values for demand and energy savings associated with this measure must be for motors with an equivalent operating period (hours x Load Factor) over 1,000 hours.

C.1.3.2. Baseline and Efficiency Standards

C.1.3.2.1. Replace on Burnout

The EISA 2007 Sec 313 adopted the new federal standard and required that electric motors that are manufactured and sold in the United States meet the new standard by December 19, 2010. The standards can also be found in sections 431.25(c)-(f) of the Code of Federal Regulations (10 CFR Part 431).

With these changes, any 1-500 HP motor bearing the "NEMA Premium" trademark will align with national energy efficiency standards and legislation. The Federal Energy Management Program (FEMP) has already adopted NEMA MG 1-2006 Revision 1 2007 in its Designated Product List for federal customers.

In addition to the new standards for 200-500 HP motors, additional motors in the 1-200 HP range are now included in the NEMA Premium standard. These new motors are referred to as "General Purpose Electric Motors (Subtype II)". These additional types of motors include:

- U-Frame Motors
- Design C Motors
- Close-coupled pump motors
- Footless motors
- Vertical solid shaft normal thrust (tested in a horizontal configuration)
- 8-pole motors
- All poly-phase motors with voltages up to 600 volts other than 230/460 volts (230/460 volt motors are covered by EPAct-92)

C.1.3.2.2. Early Retirement

The baseline for early retirement projects is the nameplate efficiency of the existing motor to be replaced, if known. If the nameplate is illegible and the in situ efficiency cannot be determined, then the baseline should be based on the minimum efficiency allowed under the Federal Energy Policy Act of 1992 (EPAct), as listed in Table 82.

NEMA Premium Efficiency motor levels continue to be industry standard for minimum-efficiency levels. The savings calculations assume that the minimum motor efficiency for both replace on burnout and early retirement projects exceeds that listed in Table 81.

For early retirement, the maximum age of an eligible piece of equipment is capped at the point at which it is expected that 75 percent of the equipment has failed. Where the age of the unit exceeds the 75 percent failure age, ROB savings should be applied. This cap prevents early retirement savings from being applied to projects where the age of the equipment greatly exceeds the estimated useful life of the measure.

Table 81. Premium Efficiency Motors – Replace on Burnout Baseline Efficiencies by Motor Size; Also for use with $kWh_{SavingsROB}$ when calculated for Early Retirement Projects[184]

hp	$\eta_{baseline, Open Motors}$			$\eta_{baseline, Closed Motors}$		
	6-Pole	4-Pole	2-Pole	6-Pole	4-Pole	2-Pole
1	82.5	85.5	77.0	82.5	85.5	77.0
1.5	86.5	86.5	84.0	87.5	86.5	84.0
2	87.5	86.5	85.5	87.5	86.5	85.5
3	88.5	89.5	85.5	89.5	89.5	86.5
5	89.5	89.5	86.5	89.5	89.5	88.5
7.5	90.2	91.0	88.5	91.0	91.7	89.5
10	91.7	91.7	89.5	91.0	91.7	90.2
15	91.7	93.0	90.2	91.7	92.4	91.0
20	92.4	93.0	91.0	91.7	93.0	91.0
25	93.0	93.6	91.7	93.0	93.6	91.7
30	93.6	94.1	91.7	93.0	93.6	91.7
40	94.1	94.1	92.4	94.1	94.1	92.4
50	94.1	94.5	93.0	94.1	94.5	93.0
60	94.5	95.0	93.6	94.5	95.0	93.6
75	94.5	95.0	93.6	94.5	95.4	94.1
100	95.0	95.4	93.6	95.0	95.4	94.1
125	95.0	95.4	94.1	95.0	95.4	95.0
150	95.4	95.8	94.1	95.8	95.8	95.0
200	95.4	95.8	95.0	95.8	96.2	95.4
250	94.5	95.4	94.5	95.0	95.0	95.4
300	94.5	95.4	95.0	95.0	95.4	95.4
350	94.5	95.4	95.0	95.0	95.4	95.4
400	n/a	95.4	95.4	n/a	95.4	95.4
450	n/a	95.8	95.8	n/a	95.4	95.4
500	n/a	95.8	95.8	n/a	95.8	95.4

Table 82: Premium Efficiency Motors – Early Retirement Baseline Efficiencies by Motor Size[185]

[184] Federal Standards for Electric Motors, Table 1: Full Load Efficiencies for Standard Electric Motors, http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/50. Accessed June 2013.

hp	$\eta_{baseline, Open Motors}$			$\eta_{baseline, Closed Motors}$		
	6-Pole	4-Pole	2-Pole	6-Pole	4-Pole	2-Pole
1	80.0	82.5	75.5	80.0	82.5	75.5
1.5	84.0	84.0	82.5	85.5	84.0	82.5
2	85.5	84.0	84.0	86.5	84.0	84.0
3	86.5	86.5	84.0	87.5	87.5	85.5
5	87.5	87.5	85.5	87.5	87.5	87.5
7.5	88.5	88.5	87.5	89.5	89.5	88.5
10	90.2	89.5	88.5	89.5	89.5	89.5
15	90.2	91.0	89.5	90.2	91.0	90.2
20	91.0	91.0	90.2	90.2	91.0	90.2
25	91.7	91.7	91.0	91.7	92.4	91.0
30	92.4	92.4	91.0	91.7	92.4	91.0
40	93.0	93.0	91.7	93.0	93.0	91.7
50	93.0	93.0	92.4	93.0	93.0	92.4
60	93.6	93.6	93.0	93.6	93.6	93.0
75	93.6	94.1	93.0	93.6	94.1	93.0
100	94.1	94.1	93.0	94.1	94.5	93.6
125	94.1	94.5	93.6	94.1	94.5	94.5
150	94.5	95.0	93.6	95.0	95.0	94.5
200	94.5	95.0	94.5	95.0	95.0	95.0
250	94.5	95.4	94.5	95.0	95.0	95.4
300	94.5	95.4	95.0	95.0	95.4	95.4
350	94.5	95.4	95.0	95.0	95.4	95.4
400	n/a	95.4	95.4	n/a	95.4	95.4
450	n/a	95.8	95.8	n/a	95.4	95.4
500	n/a	95.8	95.8	n/a	95.8	95.4

C.1.3.3. Estimated Useful Life (EUL)

According to DEER 2008, the estimated useful life (EUL) is 15 years.

C.1.3.4. Calculation of Deemed Savings

Actual motor operating hours are expected to be used to calculate savings. Every effort should be made to capture the estimated operating hours. Short and/or long term

[185] Federal Standards for Electric Motor Efficiency from the Federal Energy Policy Act of 1992 (EPACT). http://www1.eere.energy.gov/manufacturing/tech_assistance/pdfs/e-pact92.pdf . Accessed June 2013.

metering can be used to verify estimates. If metering is not possible, interviews with facility operators and review of operations logs should be conducted to obtain an estimate of actual operating hours. If there is not sufficient information to accurately estimate operating hours, then the annual operating hours in Table 83 or Table 87.

Table 83. Premium Efficiency Motors – Operating Hours, Load Factor (HVAC)

Building Type	***Load Factor*** [186]	***HVAC Fan Hours*** [187]
College/ University	0.75	4,581
Fast Food Restaurant		6,702
Full Menu Restaurant		5,246
Grocery Store		6,389
Health Clinic		7,243
Lodging		4,067
Large Office (>30k SqFt)		4,414
Small Office (≤30k SqFt)		3,998
Retail		5,538
School		4,165

Table 84: Premium Efficiency Motors – Operating Hours, Load Factor (Non-HVAC)

Industrial	***Load***	***Hours*** [189]

[186] Itron 2004-2005 DEER Update Study, Dec 2005; Table 3-25. Accessed May 2013.http://www.deeresources.com/deer2005/downloads/DEER2005UpdateFinalReport_ItronVersion.pdf .

[187] Fan schedule operating hours taken as the average of operating hours from the Connecticut, Maine, and Pennsylvania Technical Reference Manuals: CL&P and UI Program Savings Documentation for 2008 Program Year, Connecticut Lighting & Power Company; Efficiency Maine Technical Reference User Manual No. 2007-1; Pennsylvania Utility Commission Technical Reference Manual June 2012.

Processing	Factor[188]	Chem	Paper	Metals	Petroleum Refinery	Food Production	Other
1-5 hp	0.54	4,082	3,997	4,377	1,582	3,829	2,283
6-20 hp	0.51	4,910	4,634	4,140	1,944	3,949	3,043
21-50 hp	0.60	4,873	5,481	4,854	3,025	4,927	3,530
51-100 hp	0.54	5,853	6,741	6,698	3,763	5,524	4,732
101-200 hp	0.75	5,868	6,669	7,362	4,170	5,055	4,174
201-500 hp	0.58	5,474	6,975	7,114	5,311	3,711	5,396
501-1,000 hp		7,495	7,255	7,750	5,934	5,260	8,157
>1,000 hp		7,693	8,294	7,198	6,859	6,240	2,601

C.1.3.4.1. Measure/Technology Review

Premium efficiency motors are a mature technology and a wealth of information exists on the measure. A summary of the key resources is included in Table 85.

Table 85: Premium Efficiency Motors- Review of Motor Measure Information

Resource	Notes
PG&E 2006[190]	Savings for common motor retrofits

[189] United States Industrial Electric Motor Systems Market Opportunities Assessment, Dec 2002; Table 1-15. Accessed May 2013. www1.eere.energy.gov/manufacturing/tech_assistance/pdfs/mtrmkt.pdf

[188] United States Industrial Electric Motor Systems Market Opportunities Assessment, Dec 2002; Table 1-19. Accessed May 2013. www1.eere.energy.gov/manufacturing/tech_assistance/pdfs/mtrmkt.pdf

Xcel Energy 2006[191]	Program level savings estimates for high-efficiency motors
DEER 2008[192]	Savings and cost for common motor retrofit
KEMA 2010[193]	Motor savings included in comprehensive potential study
CEE[194]	Industrial motor efficiency initiative
RTF[195]	Savings for common motor retrofit
ITP[196]	Savings for common motor retrofit
NPCC 2010[197]	Market information and overview of savings potential
NEMA 2009[198]	Minimum efficiency level for premium efficiency motors
MotorMaster+[199]	Comprehensive resource of motor efficiencies and tools to calculate savings
PacifiCorp 2009[200]	Motor savings included in comprehensive potential study

Deemed electric motor demand and energy savings should be calculated by the following formulas:

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[190] Pacific Gas & Electric (PG&E). 2006. *2006 Motors Unit Savings Workpapers.V14.*

[191] Xcel Energy. 2006. 2007/2008/2009 *Triennial Plan Minnesota Natural Gas and Electric Conversation Improvement Program.*

[192] Consortium of Energy Efficiency. Commercial Lighting Program. http://library.cee1.org/content/commercial-lighting-qualifying-products-lists

[193] KEMA. 2010. *Measurement Manual*. Prepared for Tennessee Valley Authority.

[194] Consortium for Energy Efficiency. 2010. Industrial Motors & Motor Systems. http://library.cee1.org/content/cee-2012-summary-member-programs-motors-motor-systems

[195] Regional Technical Forum (RTF). http://rtf.nwcouncil.org/measures/

[196] Industrial Technologies Program http://www1.eere.energy.gov/industry/

[197] Northwest Power and Conservation Council (NPCC). 2010. *The Sixth Northwest Electric Power and Conservation Plan.*

[198] National Electrical Manufacturers Association (NEMA). 2009. *Motors and Generators. NEMA* MG 1-2009.

[199] MotorMaster+. 2010. https://www1.eere.energy.gov/manufacturing/tech_assistance/software_motormaster.html

[200] PacifCorp. 2009. *FinAnswer Express Market Characterization and Program Enhancements Utah Service Territory.*

C.1.3.4.2. Replace on Burnout (ROB)

$$kWh_{savings} = Rated\ Horsepower\ \times Conversion\ Factor\ \times LF\ \times \left(\frac{1}{\eta_{baseline}} - \frac{1}{\eta_{post}}\right) \times hours$$

$$kW_{reduction} = Rated\ Horsepower\ \times Conversion\ Factor\ \times LF\ \times \left(\frac{1}{\eta_{baseline}} - \frac{1}{\eta_{post}}\right) \times CF$$

Where:

$Rated\ HorsePower$ = Nameplate horsepower data of the motor

$Conversion\ Factor$ = 0.746 kW/hp

LF= Estimated load factor for the motor; if load factor is not available, deemed load factors in Table 83 or Table 8 can be used.

$\eta_{baseline}$= Efficiencies listed in Table 81 should be used (in the case of rewound motors, in situ efficiency may be reduced by a percentage as found in Table 82)

η_{post}= Efficiency of the newly installed motor

$Hours$= Estimated annual operating hours for the motor; if unavailable, annual operating hours in Table 83 or Table 8 be used.

CF = Coincidence Factor = 0.74[201]

C.1.3.4.3. Early Retirement (ER)

Annual kWh and kW savings must be calculated separately for two time periods:

1. The estimated remaining life (RUL, see Table 86) of the equipment that is being removed, designated the first N years, and
2. Years EUL - N through EUL, where EUL is 15 years.

Table 86: Premium Efficiency Motors – Remaining Useful Life (RUL) of Replaced Systems[202,203]

[201] Itron 2004-2005 DEER Update Study, Dec 2005; Table 3-25. http://www.deeresources.com/deer2005/downloads/DEER2005UpdateFinalReport_ItronVersion.pdf Accessed May 2013.

Age of Replaced System (Years)	RUL (Years)
5	10.0
6	9.1
7	8.2
8	7.3
9	6.5
10	5.7
11	5.0
12	4.4
13	3.8
14	3.3
15	2.8
16	2.5
17	2.2
18	1.9
19	0.0

For the first N years:

$$kWh_{savings} = Rated\ Horsepower\ \times Conversion\ Factor\ \times LF\ \times \left(\frac{1}{\eta_{baseline}} - \frac{1}{\eta_{post}}\right) \times hours$$

$$kW_{reduction} = Rated\ Horsepower\ \times Conversion\ Factor\ \times LF\ \times \left(\frac{1}{\eta_{baseline}} - \frac{1}{\eta_{post}}\right) \times CF$$

Where:

$Rated\ HorsePower$ = Nameplate horsepower data of the motor

$Conversion\ Factor$ = 0.746 kW/hp

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[202] Because the motor EUL is 15 years, it is consistent for use with the RUL determined using the Weibull distribution offered in the DOE’s Life Cycle Cost Analysis Spreadsheet, “lcc_cuac_hourly.xls”.

http://www1.eere.energy.gov/buildings/appliance_standards/standards_test_procedures.html.

[203] Use of the early retirement baseline is capped at 18 years, representing the age at which 75 percent of existing equipment is expected to have failed. Systems older than 18 years should use the ROB baseline.

$\boldsymbol{LF}$= Estimated load factor for the motor; if load factor is not available, deemed load factors in Table 83 can be used

$\boldsymbol{\eta_{baseline}}$= In situ efficiency of the baseline motor; if unavailable, efficiencies listed in Table 82 can be used (in the case of rewound motors, in situ efficiency may be reduced by a percentage as found in Table 87).

η_{post}=Efficiency of the newly installed motor

$Hours$= Estimated annual operating hours for the motor; if unavailable, annual operational hours in Table 83 can be used

CF = Coincidence Factor = 0.74[204]

Table 87: Rewound Motor Efficiency Reduction Factors[205]

Motor Horsepower	**Efficiency Reduction Factor**
<40	0.01
≥40	0.005

For Years EUL - N through EUL:

Savings should be calculated exactly as they are for replace on burnout projects, referred to as $kWh_{SavingsROB}$.

Total lifetime savings for early retirement projects are then determined by adding the savings calculated under the two preceding equations as follows:

$$Lifetime\ kWh\ savings\ for\ Early\ Retirement\ Projects = \left(kWh_{savingsRUL} \times RUL\right) + \left[kWh_{savingsROB} \times (EUL - RUL)\right]$$

Where:

RUL= The Remaining Useful Life of the equipment, in years, see Table 86.

[204] Itron 2004-2005 DEER Update Study, Dec 2005; Table 3-25. http://www.deeresources.com/deer2005/downloads/DEER2005UpdateFinalReport_ItronVersion.pdf. Accessed May 2013.

[205] U.S. DOE, Preliminary Technical Support Document, "Energy Efficiency Program for Commercial Equipment: Energy Conservation Standards for Electric Motors, 2.7.2 Impact of Repair on Efficiency." July 23, 2012. http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/50. Download TSD at: http://www1.eere.energy.gov/buildings/appliance_standards/pdfs/em_preanalysis_tsdallchapters.pdf .

EUL = The Estimated Useful Life of the equipment, deemed at 15 years

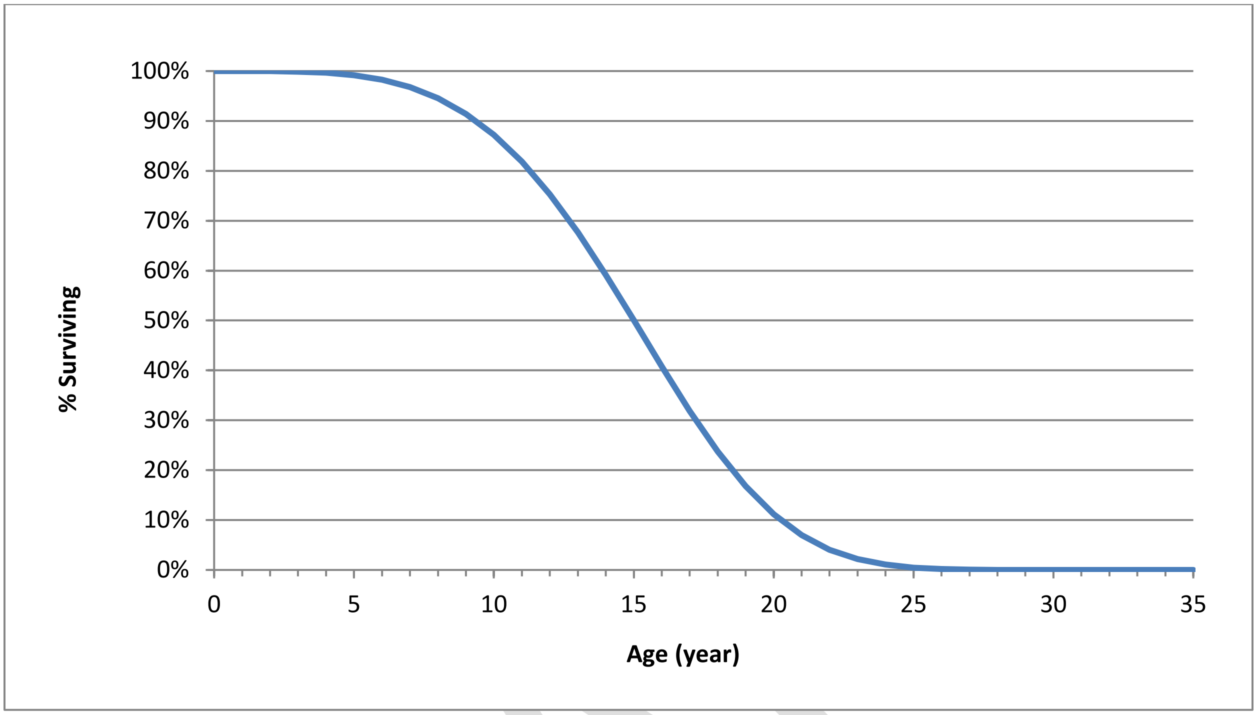

Figure 2: Survival Function for Premium Efficiency Motors[206]

The method used for estimating the RUL of a replaced system uses the age of the existing system to re-estimate the survival function shown in Figure 2. The age of the system being replaced is found on the horizontal axis and the corresponding percentage of surviving systems is determined from the chart. The surviving percentage value is then divided in half, creating a new percentage. Then the age (year) that corresponds to this new percentage is read from the chart. RUL is estimated as the difference between that age and the current age of the system being replaced.

C.1.3.5. Incremental Cost

Table 88: Motor Incremental Cost By Size[207]

[206] Source: Weibull distribution based on the Life Cycle Cost Analysis Spreadsheet, "lcc_cuac_hourly.xls".

http://www1.eere.energy.gov/buildings/appliance_standards/standards_test_procedures.html.

Motor Horsepower	*Incremental Cost*
5	$918
7.5	$918
10	$918
15	$918
20	$933
25	$1,012
30	$1,091
40	$1,300
50	$1,497
60	$1,796
75	$1,943
100	$2,389
125	$3,087
150	$3,784
200	$4,555
250	$4,655
300	$4,755
350	$4,855
400	$4,955
450	$5,055
500	$5,155

C.1.3.6. Future Studies

In Energy Smart and other utility portfolios, this is typically a low-volume measure. High-saving motor applications are more commonly found in custom applications. As a result, ADM does not advise funding future measure research, and recommend that the measure receive updated only when applicable codes or standards warrant it.

[207] Comprehensive Process and Impact Evaluation of the (Xcel Energy) Colorado Motor and Drive Efficiency Program, FINAL, March 28, 2011,TetraTech

C.2. Commercial Water Heating

C.2.1. Water Heater Replacement

C.2.1.1. Measure Description

This measure involves:

- The replacement of electric water heaters in commercial buildings by high efficiency electric resistance water heaters
- The replacement of electric water heaters in commercial buildings by heat pump water heaters
- The replacement of small (< 12 kW) electric water heaters in commercial buildings by electric tankless water heaters

Commercial water heater savings are measured per location and are calculated for new construction or replace-on-burnout. Storage tank models and tankless models, utilizing electricity are eligible.

C.2.1.2. Baseline and Efficiency Standards

The baseline standards for IECC 2009 are detailed in Table 89.

Table 89: Commercial Water Heaters – Water Heater Performance Requirements

Equipment Type	***Size Category (Input)***	***Subcategory or Rating Condition***	***Performance Required[208,209]***	***Test Procedure***
Water heaters, electric	≤ 12 kW	Resistance	IECC 2009: 0.97 - 0.00132V, EF	DOE 10 CFR Part 430
	> 12 kW		1.73V + 155, SL (Btu/hr)	ANSI Z21.10.3
	≤ 24 amps and ≤ 250 volts	Heat Pump	0.93 - 0.00132V, EF	DOE 10 CFR Part 430

For smaller water heaters where energy factor (EF) is used, EF takes into account the overall efficiency, including combustion efficiency and standby loss (SL). Regulated by DOE as "residential water heaters", these smaller water heaters

[208] Energy factor (EF) and thermal efficiency (E_t) are minimum requirements. In the EF equation, V is the rated volume in gallons.

[209] Standby loss (SL) is the maximum Btu/hr based on a nominal 70°F temperature difference between stored water and ambient requirements. In the SL equation, Q is the nameplate input rate in Btu/hr. In the SL equation for electric and gas water heaters and boilers, V is the rated volume in gallons.

manufactured on or after April 16, 2015 must comply with the amended standards found in the Code of Federal Regulations, 10 CFR 430.32(d), detailed in Table 90.

Table 90: Small Commercial Water Heaters – Standards and their Compliance Dates[210]

Product Class	***Energy Factor as of April 16, 2015***
Electric Water Heater	For Vs < 55 gallons: 0.960 – (0.0003V) For Vs > 55 gallons: 2.057 – (0.00113V)

For larger water heaters, thermal efficiency (Et) is used and does not factor into SL; however, a limitation on SL is noted.

The savings calculations consider the minimum water heater efficiency requirements listed in Table 89 to be the baseline.

C.2.1.3. Estimated Useful Life (EUL)

The estimated useful life (EUL) of this measure is dependent on the type of water heating. According to DEER 2008, the following measure lifetimes should be applied.[211]

- 10 years for Heat Pump Water Heater (HPWH)
- 15 years for High Efficiency Commercial Storage Water Heater
- 20 years for Commercial Tankless Water Heater

C.2.1.4. Calculation of Deemed Savings

Typically, two types of ratings exist for water heaters: energy factor (EF) for smaller units, and thermal efficiency (Et) for larger water heaters. Large heat pump water heaters may also be rated by a third method, coefficient of performance (COP), which is the ratio of heat energy output to electrical energy input, and is analogous to thermal efficiency. EF includes standby losses, while Et and COP only consider the amount of energy required to heat the water. Therefore, in the formulas below, the baseline and energy efficiency measure may be compared for each type of water heater.

The electricity savings for this measure are highly dependent on the estimated hot water consumption, which varies significantly by building type. The following tables list

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[210] Where V is the rated storage volume, which equals the water storage capacity of a water heater (in gallons), as certified by the manufacturer.

[211] http://www.deeresources.com/files/deer2008exante/downloads/EUL_Summary_10-1-08.xls

estimated hot water consumption for various building types by number of units, occupants, or building size.

Table 91: Hot Water Requirements by Building Type and System Capacity[212]

Building Type	***Annual Hot Water Consumption Per Gallon of Rated Capacity***
Convenience Store	489
Education	526
Grocery	489
Health	730
Large Office	474
Large Retail	489
Lodging	663
Multifamily	829
Nursing	623
Restaurant	577
Small Office	474
Small Retail	489
Warehouse	316
Other Commercial	316

Table 92 converts the values from Table 91 into per-1,000 square feet value based on the same CBECS 2012 data.

Table 92: Hot Water Requirements by Building Size[213]

[212] Methodology based on ADM analysis. Annual hot water usage in gallons based on CBECS (2012) and RECS (2009) consumption data of West South Central (removed outliers of 1,000 kBtuh or less) to calculate hot water usage. Annual hot water gallons per tank size gallons based on the tank sizing methodology found in ASHRAE 2011 HVAC Applications. Chapter 50 Service Water Heating. Demand assumptions (gallons per day) for each building type based on ASHRAE Chapter 50 and to LBNL White Paper. LBL-37398 Technology Data Characterizing Water Heating in Commercial Buildings: Application to End Use Forecasting. Assumes hot water heater efficiency of 80.

Building Type	*Annual Hot Water Consumption Per 1,000 square feet*
Convenience Store	4,255
Education	6,746
Grocery	646
Health	22,734
Large Office	1,686
Large Retail	1,254
Lodging	27,399
Multifamily	14,312
Nursing	28,279
Restaurant	41,224
Small Office	1,428
Small Retail	5,660
Warehouse	1,148
Other Commercial	3,652

C.2.1.4.1. Small Electric Storage Water Heaters

As small (≤ 12 kW) electric water heaters are typically rated by EF, this section of this measure includes both higher-efficiency resistance water heaters and small (≤ 24 amps and ≤ 250 volts) heat pump water heaters. Deemed annual energy savings for small electric water heater replacements are calculated by formulas as follows:

$$kWh_{Savings} = \frac{\rho \times C_p \times V \times \left(T_{SetPoint} - T_{Supply}\right) \times \left(EF_{pre} - EF_{post}\right)}{3{,}412\ Btu/kWh}$$

Where:

ρ = Water density = 8.33 lb/gal

C_p = Specific heat of water = 1 BTU/lb·°F

V = Average annual hot water use (gallons). See for Table 91 and Table 92 estimates of water consumption.

$T_{SetPoint}$ = Water heater set point (default value = 120°F)

[213] This is a conversion of the capacity values to a per-square foot value based on average building size in the CBECS.

T_{Supply} = Average New Orleans area supply water temperature, 74.8°F[214]

EF_{pre} = Calculated energy factor of existing water heater, based on the water heater tank volume; Table 89.

EF_{post} = Energy Factor of replacement water heater (taken from nameplate); the replacement water heater may be either a high efficiency electric storage water heater or a heat pump water heater

$Conversion\ Factor$ = 3,412 Btu/kWh

Deemed demand savings for small electric water heater replacements are calculated by formula as follows:

$$kW_{reduction} = \frac{\rho \times C_p \times V \times \left(T_{SetPoint} - T_{Supply}\right) \times \left(EF_{pre} - EF_{post}\right)}{3{,}412\ Btu/kWh} \times 1/24 \times 1/365$$

Where all variables are the same as in the energy equation and the average hourly ratio is a best estimate of peak coincidence for commercial hot water heater replacements.[215]

C.2.1.4.2. Large Electric Storage Water Heaters

Large (> 12 kW) electric resistance water heaters can be replaced with heat pump water heaters.

For replacement of large electric resistance water heaters with a heat pump water heater, deemed annual energy savings are calculated by the following formula:

$$kWh_{Savings} = \frac{\rho \times C_p \times GPD \times \left(T_{SetPoint} - T_{Supply}\right) \times \left(\frac{1}{E_{t,base}} - \frac{1}{COP_{post}}\right) \times Days/Year}{3{,}412\ Btu/kWh}$$

Where:

ρ = Water density = 8.33 lb/gal

C_p = Specific heat of water = 1 BTU/lb·°F

V = Average daily hot water use (gallons). See Table 91 and Table 92 for estimates of water consumption

$T_{SetPoint}$ = Water heater set point (default value = 120°F)

T_{Supply} = Average New Orleans area supply water temperature, 74.8°F

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[214] Calculated using area groundwater data. See Section C.2.1.1.

[215] For replacement with high-efficiency electric storage water heaters and tankless water heaters, the 1/24 peak coincidence factor accurately reflects that improvements in the efficiency of electric resistance storage water heaters are driven almost entirely by reductions in storage losses (conversion efficiency, RE, is close to 1), which are distributed evenly throughout the day.

$E_{t,base}$ = .98

COP_{post} = Coefficient of performance of new heat pump water heater

C.2.1.4.3. Demand Savings

Deemed demand savings for replacement of large electric resistance water heaters with a heat pump water heater are calculated by the following formula:

$$kW_{reduction} = \frac{\rho \times C_p \times GPD \times \left(T_{SetPoint} - T_{Supply}\right) \times \left(EF_{pre} - EF_{post}\right)}{3{,}412\ Btu/kWh} \times 1/24$$

Where all variables are the same as in the energy equation and the 1/24 ratio is a best estimate of peak coincidence for commercial hot water heater replacements.

C.2.1.4.4. Incremental Cost

The incremental cost for heat pump water heaters are as follows[216]:

- 50 Gallon: $1,050
- 80 Gallon: $1,050
- 100 Gallon: $1,950

C.2.1.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans businesses and updates for applicable codes.

Current DHW load estimates are based off of CBECS data for the West South region. If there is significant participation we recommend updating with actual participant loads. Further, a study of commercial DHW setpoints would be warranted.

[216] Cost information is based upon data from "2010-2012 WA017 Ex Ante Measure Cost Study Draft Report", Itron, February 28, 2014. See "NR HW Heater_WA017_MCS Results Matrix - Volume I.xls" for more information.

C.2.2. Commercial Faucet Aerators

C.2.2.1. Measure Description

This measure consists of installing low-flow faucet aerators in commercial facilities which reduce water usage and save energy associated with heating the water.

C.2.2.2. Baseline and Efficiency Standards

The savings values for low-flow faucet aerators are for the retrofit of existing operational faucet aerators with a flow rate of 2.2 gallons per minute or higher. Facilities that use both gas and electric water heaters are eligible for this measure.

The baseline faucet aerators are assumed to have a flow rate of 2.2 gallons per minute.[217] To qualify for this measure, the flow rate of installed low-flow faucet aerators must be at most 1.5 gallon per minute.[218]

C.2.2.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 10 years, according to DEER 2008.

C.2.2.4. Calculation of Deemed Savings

Annual kWh electric and peak kW savings can be calculated using the following equations:

$$kWh\ Savings = \frac{\rho \times C_P \times U \times (F_B - F_P) \times \left(T_H - T_{Supply}\right) \times \frac{1}{E_t} \times Days/Year}{3{,}412\ Btu/kWh}$$

$$kW_{reduction} = \frac{\rho \times C_P \times U \times (F_B - F_P) \times \left(T_H - T_{Supply}\right) \times \frac{1}{E_t} \times P}{3{,}412\ Btu/kWh}$$

Where:

[217] Maximum flow rate federal standard for lavatories and aerators set in Federal Energy Policy Act of 1992 and codified at 2.2 GPM at 60 psi in 10CFR430.32.

[218] "High-Efficiency Lavatory Faucet Specification." WaterSense. EPA. October 1, 2007. http://www.epa.gov/watersense/partners/faucets_final.html

Table 93: Commercial Aerator Savings Parameters

Parameter	Description	Value
F_B	Average baseline flow rate of aerator (GPM)	2.2
F_P	Average post measure flow rate of aerator (GPM)	≤1.5
Days/Year	Annual Building type operating days for the applications:	
	1.Hospital, Nursing home	365
	2. Dormitory	274[219]
	3. Multifamily	365
	4. Lodging	365
	5. Commercial	250
	6. School	200
T_{supply}	Average supply (cold) water temperature (^oF)	74.8
T_H	Average mixed water (after aerator) temperature (^oF)	120[220]
U	Baseline water usage duration, following applications	
	1. Hospital, Nursing home	3 min/day/unit
	2. Dormitory	30 min/day/unit
	3. Multifamily	3 min/day/unit
	4. Lodging	3 min/day/unit
	5. Commercial	30 min/day/unit
	6. School	30 min/day/unit
ρ	Unit conversion: 8.33 pounds/gallon	8.33
C_p	Heat capacity of water - 1 Btu/lb ^oF	1
E_t	Thermal Efficiency of water heater	Default Values: 0.98 for electric resistance, 2.2 (COP) for heat pump
	Hourly water consumption during peak period as a fraction of average daily consumption for applications:	
	2.Hospital, Nursing home	0.03
	3. Dormitory	0.04
	4. Multifamily	0.03
	5. Lodging	0.02

[219] Dormitories with few occupants in the summer: 365 x (9/12) = 274.

[220] Calculated based on area groundwater temps.

	6. Commercial	0.08
	7. School	0.05

Example: The following are gas and electric example calculations for a 1.0 GPM aerator replacement for a school using the previous equations and information. Example electric savings are based on heating water with a conventional electric resistance storage tank water heater.

$$\Delta kWh = [8.33\ x\ 30 minday\ x\ (2.2{-}1.0)\ GPM\ x\ (120{-}74.8°\text{F})\ x\ (1/.98) * 200 dayyear]/3412\ Btu/kWh = 811\ kWh$$

$$\Delta kW = [8.33\ x\ 30 minday\ x\ (2.2{-}1.0)\ GPM\ x\ (120{-}74.8°\text{F})\ \text{x}\ (1/.98)\ x\ .05]/3412\ Btu/kWh = 0.202\ kW$$

C.2.2.5. Incremental Cost

Program-actual costs should be used where available. If not available, the incremental cost of a faucet aerator is $8.00[221].

C.2.2.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans businesses and updates for applicable codes.

If there is significant participation we recommend updating with actual participant loads. Further, a study of commercial DHW setpoints would be warranted.

[221] Direct-install price per faucet assumes cost of aerator and install time. (2011, Market research average of $3 and assess and install time of $5 (20min @ $15/hr)

C.2.3. Commercial Low-Flow Showerheads

C.2.3.1. Measure Description

This measure consists of removing existing showerheads and installing low-flow showerheads at the following commercial building types: hospitals and nursing homes, lodging facilities, commercial facilities (offices or other commercial buildings in which showers are provided for employees), fitness centers, and schools.[222]

C.2.3.2. Baseline and Efficiency Standards

The savings values for low-flow showerheads are for the retrofit of existing operational showerheads with a flow rate of 2.5 gallons per minute (GPM) or higher.[223] Facilities must have electric water heating to qualify for this measure.

The baseline showerhead has an average flow rate of 2.5 GPM based on the current DOE standard. To qualify for the deemed savings, replacement showerheads must have a flow rate of 2.0 GPM or less.[224]

Existing showerheads that have been defaced so as to make the flow rating illegible are not eligible for replacement. Low flow shower heads that are easily tampered with should not be used. Removed showerheads shall be collected by the contractor and held for possible inspection by the utility until all inspections for invoiced installations have been completed.

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[222] This measure draws from multiple sources, including the residential low flow showerhead measure and commercial faucet aerator measure. Information specific to hot water use in commercial market sectors was drawn from CLEAResult, Inc. draft white paper: *Work Papers for Low Flow Shower Heads with Gas or Electric Water Heaters: Savings Calculation Methodology for Application in Arkansas Energy Efficiency Programs*, February 2014.

[223] 10 CFR Part 430, Energy Conservation Program for Consumer Products: Test Procedures and Certification and Enforcement Requirements for Plumbing Products; and Certification and Enforcement Requirements for Residential Appliances; Final Rule, March 1998. Online.Available: http://www.regulations.gov/#!documentDetail;D=EERE-2006-TP-0086-0003.

[224] The U.S. Environmental Protection Agency (EPA) WaterSense Program has a thorough specification for showerheads that meet a maximum flow rate of 2.0 gpm. The specification is available on the EPA website at: www.epa.gov/WaterSense/partners/showerhead_spec.html

Table 94: Low-Flow Showerhead – Baseline and Efficiency Standards

Measure	***New Showerhead Flow Rate[225] (GPM)***	***Existing Showerhead Baseline Flow Rate (GPM)***
2.0 GPM showerhead	2.0	2.5
1.75 GPM showerhead	1.75	2.5
1.5 GPM showerhead	1.5	2.5

The U.S. Environmental Protection Agency (EPA) WaterSense Program has implemented efficiency standards for showerheads requiring a maximum flow rate of 2.0 GPM[226].

C.2.3.3. Estimated Useful Life (EUL)

The average lifetime of this measure is 10 years, according to DEER 2014.

C.2.3.4. Calculation of Deemed Savings

Energy and demand savings are estimated as functions of the reduction in daily water use (ΔV) attributable to installation of low flow showerheads in a given commercial building type. Reduction in water use and deemed savings calculations make use of the data provided by building type in Table 95 and the New Orleans average water main temperature, 74.8.

Table 95: Showers per Day (per Showerhead) and Days of Operation by Building Type

Building Type	***Showers/Day***	***Days/Year***
Hospital/Nursing home	0.89	365
Hospitality	1.25	365
Commercial	0.97	250
Fitness Center	19.94	365
School	1.32	200

C.2.3.5. Estimated Hot Water Usage Reduction

Reduction in annual hot water usage is estimated based on the typical duration of a shower and the expected number of showers per year for an installed showerhead in a given facility.

225 All flow rate requirements listed here are the rated flow of the showerhead measured at 80 pounds per square inch of pressure (psi).

226 http://www1.eere.energy.gov/femp/program/waterefficiency_bmp7.html.

Reduction in daily hot water consumption is estimated on a per-showerhead basis using the following formula:

$$\Delta V = U \times N \times (Q_B - Q_P) \times F_{HW}$$

Where:

ΔV = Reduction in daily hot water use in gallons per day (GPD)

U = Typical shower duration of 7.8 (minutes/shower)

N = Number of showers per day (per showerhead); (N) is a function of the commercial building type, values for N are provided in Table 97.

Q_B = Baseline showerhead flow rate, 2.5 GPM

Q_P = Flow rate of installed showerhead (in GPM)

F_{HW} = Hot Water Fraction (share of water flowing through showerhead from the water heater, %)

The fraction of hot water is a function of the inlet water temperature (T_{supply}) the temperature of water from the hot water heater (T_{HW} = 120 ºF), and the desired temperature at the showerhead (T_{mixed} = 105 ºF).

Reduction in daily hot water usage is provided for reference in Table 96.

Table 96: Reduction in Daily Hot Water Usage, ΔV (GPD)

Flow Rate of installed showerhead	***Building Type***				
	Hospital/Nursing home	***Hospitality***	***Commercial (General) - Employee Shower***	***Fitness Center***	***Schools***
2.0 GPM	232	326	253	5,203	344
1.75 GPM	348	489	380	7,804	517
1.5 GPM	464	652	506	10,405	689

C.2.3.5.1. Energy Savings

The deemed energy savings are calculated as follows:

$$kWh_{savings} = \frac{\rho \times C_P \times \Delta V \times (T_{HW} - T_{Supply}) \times \left(\frac{1}{E_t}\right)}{Conversion\ Factor} \times \frac{days}{year}$$

Where:

ρ = Water density = 8.33 lb/gallon

C_P = Specific heat of water = 1 Btu/lb·°F

ΔV = gallons of hot water saved per day (GPD, calculated above identified in Table 96: Reduction in Daily Hot Water Usage, ΔV (GPD))

T_{HW} = Temperature to which water is heated in the water heater, 120°F

T_{Supply}= Average inlet water temperature (water mains temperature), 74.8.

E_t = Thermal efficiency of water heater (or in the case of heat pump water heaters, COP); if unknown, use 0.98 as a default for electric resistance water heaters, 2.2 for heat pump water heaters[227]

$Conversion\ Factor$ = 3,412 Btu/kWh for electric water heating or 100,000 Btu/therm for gas water heating

$days/year$ = annual operating days for the building type in which the retrofit is being implemented (see Table 95).

C.2.3.5.2. Demand Savings

The deemed demand savings are calculated as follows:

$$kW_{reduction} = \frac{\rho \times C_P \times \Delta V \times (T_{HW} - T_{Supply}) \times \left(\frac{1}{E_t}\right)}{Conversion\ Factor}\ x\ P$$

Where:

All inputs are the same as described in the Energy Savings Equation and

P = electric peak coincidence factors, as provided for each building type in Table 97. [228]

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[227] Default values based on median recovery efficiency of commercial water heaters by fuel type in the AHRI database as cited in previous iterations of the AR TRM. Online: available at http://cafs.ahrinet.org/gama_cafs/sdpsearch/search.jsp?table=CWH.

[228] For all building types except 24-Hour Fitness Centers, derived from *ASHRAE Handbook 2011. HVAC Applications.* American Society of Heating Refrigeration and Air Conditioning Engineers, Inc. (ASHRAE) 2011. ASHRAE, Inc., Atlanta, GA. The peak factor is the ratio of the gallons of hot water used during the peak times of 3pm to 6pm, to

C.2.3.5.3. Parameters for Annual Energy and Peak Demand Savings Calculations

Table 97: Parameters for Annual Energy and Peak Demand Savings Calculations

Parameter	Description	Value
U	Baseline shower duration[229] (min/shower)	7.8
N	Number of showers per day per showerhead[230] 1. Hospital, Nursing Home 2. Lodging 3. Commercial 4. 24-Hour Fitness Center 5. Schools	 0.89 1.25 0.97 19.94 1.32
Q_B	Average baseline flow rate of showerhead (GPM)	2.5
Q_P	Flow rate of installed showerhead (GPM)	≤ 2.0
F_{HW}	Share of water flowing through showerhead coming from the water heater (%)	66.9
ρ	Density of water (lb/gal)	8.33
Cp	Heat capacity of water (Btu/lb-ºF)	1
T_{HW}	Temperature to which water is heated by the water heater (ºF)[231]	120
T_{supply}	Average supply (cold) water temperature (ºF)	74.8
E_t	Thermal Efficiency of hot water heater: ▪ Conventional Electric Storage Water Heater ▪ Heat Pump Water Heater (COP)	 0.98 2.2

the total amount of hot water used during the day. 24-Hour Fitness Center is assigned the same value as Commercial.

[229] Hendron, R., & Engebrech, C. 2010, "*Building America Research Benchmark Definition, Updated December 2009, Technical Report NREL/TP-550-47246,* January. National Renewable Energy Laboratory The average shower duration taken from Table 12, p. 20.

[230] Primary source is Northwest Power and Conservation Council ProCost V2.3. The number of showers per day per showerhead is back-calculated for hospitals and nursing homes, lodging and commercial building types, coefficients from annual minutes per showerhead estimates. N = (Minutes/year) x (year/days) x (Shower/minutes) = Showers/day. For 24-hour fitness centers, minutes per year were taken from informal telephone survey of Fitness Centers in the Northwest, conducted by Northwest Power and Conservation Council Regional Technical Forum staff in June, 2013. The estimate for schools is derived from Water consumption from Planning and Management Consultants, Ltd., Aquacraft, Inc. and John Olaf Nelson, Water Resources Management. "*Commercial and Institutional End Uses of Water,"* American Water Works Association Research Foundation, 2000.

[231] ASHRAE Handbook 2011. HVAC Applications. American Society of Heating Refrigeration and Air Conditioning Engineers, Inc. (ASHRAE), Inc., Atlanta, GA.

Parameter	Description	Value
	▪ Gas Storage Water Heater	0.80
$Days/year$	Annual building type operating days for the applications:[232] 1. Hospital, Nursing Home 2. Lodging 3. Commercial 4. 24-Hour Fitness Center 5. School	 365 365 250 365 200
P	Peak Factor:[233] 1. Hospital, Nursing Home 2. Lodging 3. Commercial 4. 24-Hour Fitness Center 5. School	 0.03 0.02 0.08 0.08 0.05

C.2.3.6. Incremental Cost

Program-actual costs should be used where available. If not available, the incremental cost of a low flow showerhead is $12.00[234].

C.2.3.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans business and updates for applicable codes.

If there is significant participation we recommend updating with actual participant loads. Further, a study of commercial DHW setpoints would be warranted.

[232] All values except 24-Hour Fitness Center from Osman , S. & Koomey, J. Lawrence Berkeley National Laboratory 1995. *Technology Data Characterizing Water Heating in Commercial Buildings: Application to End-Use Forecasting.* December 1995. Value for 24-Hour Fitness Center based on observation.

[233] Derived from *ASHRAE Handbook 2011. HVAC Applications.* American Society of Heating Refrigeration and Air Conditioning Engineers, Inc. (ASHRAE) 2011. ASHRAE, Inc., Atlanta, GA. The peak factor is the ratio of the gallons of hot water used during the peak times of 3 pm to 6pm, to the total amount of hot water used during the day.

[234] Direct-install price per showerhead assumes cost of showerhead (Market research average of $7 and assess and install time of $5 (20min @ $15/hr)

C.2.4. Commercial Water Heater Pipe Insulation

C.2.4.1. Measure Description

This measure consists of installing water heater pipe insulation exceeding the IECC mandated standard (0.5-inch of insulation that delivers an R-value of at least 3.7 per inch) over at least the first 8 feet of exposed pipe in small commercial settings. Water heaters plumbed with heat traps or automatic-circulating systems are not eligible to receive incentives for this measure.[235]

C.2.4.2. Baseline and Efficiency Standards

Baseline insulation is R = 1.85 sq. ft. h °F/Btu, the mandated standard since IECC 2000.

C.2.4.3. Estimated Useful Life (EUL)

The estimated useful life (EUL) of this measure is the remaining service life of the water heater. If unknown, use one-third of the life of an electric resistant water heater, rounded down. This is a measure life of 4 years.[236]

C.2.4.4. Calculation of Deemed Savings

C.2.4.4.1. Energy Savings

$$kWh_{savings} = \left(U_{pre} - U_{post}\right) \times A \times \left(T_{Pipe} - T_{ambient}\right) \times \left(\frac{1}{E_t}\right) \times \frac{Hours_{Total}}{Conversion\ Factor}$$

Where:

U_{pre}= 1/(2.03[237]) = 0.49 BTU/h sq. ft. degree F

U_{post}= 1/(2.03+$R_{Insulation}$)

$R_{Insulation}$= R-value of installed insulation

A = Surface area in square feet (πDL) with L (length) and D pipe diameter in feet

T_{Pipe}(°F) = Average temperature of the pipe. Default value = 90 °F (average temperature of pipe between water heater and the wall)

$T_{ambient}$(°F) = 68.78°F (New Orleans TMY3 average hourly temperature)

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[235] A survey of several large online home-improvement retailers shows three general classes of commercially available pipe insulation: one around R-2.3 (typically 5/8" thick foam), another around R-3 (typically 1/2" thick rubber) and lastly high-end insulation in the R-6 to R-7 range (1" thick rubber).

[236] To see water heater EUL, go to Section B.2.1.3.

[237] 2.03 is the R-value representing the film coefficients between water and the inside of the pipe and between the surface and air. *Mark's Standard Handbook for Mechanical Engineers, 8th edition*.

Et = Thermal efficiency (or in the case of heat pump water heaters, COP); if unknown, use 0.98 as a default for electric water heaters, 2.2 for a heat pump water heater.[238]

$Hours_{Total}$ = 8,760 hr per year[239,240]

$Conversion\ Factor$ = 3,412 Btu/kWh for electric water heating or 100,000 Btu/Therm for gas water heating.

For example, deemed savings for water heater pipe insulation with an R-value of 3 installed on an electric water heater in New Orleans would be:

$$kWh_{savings} = (0.49 - 0.20) \times 2.1 \times (90 - 74.8) \times \left(\frac{1}{0.98}\right) \times \frac{8{,}760}{3{,}412} = 24.3\ kWh/yr$$

C.2.4.4.2. Demand Savings

Peak demand savings for hot water heaters installed in conditioned space can be calculated using the following formula for electric demand savings:

$$kW_{reduction} = \left(U_{pre} - U_{post}\right) \times A \times \left(T_{Pipe} - T_{ambientMAX}\right) \times \left(\frac{1}{E_t}\right) \times \frac{1}{3{,}412\ Btu/kWh}$$

Where:

U_{pre} = 1/(2.03) =0.49 BTU/h sq ft degree F

U_{post} = 1/(2.03+$R_{Insulation}$)

$R_{Insulation}$ = R-value of installed insulation

A = Surface area in square feet (πDL) with L (length) and D pipe diameter in feet

T_{Pipe}(°F) = Average temperature of the pipe. Default value = 90 °F (average temperature of pipe between water heater and the wall)

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238 Default values based on median recovery efficiency of residential water heaters by fuel type in the AHRI database, at https://www.ahridirectory.org/ahridirectory/pages/rwh/defaultSearch.aspx

239 Ontario Energy's Measures and Assumptions for Demand Side Management (DSM) Planning www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0346/Navigant_Appendix_C_substantiation_sheet_20090429.pdf

240 New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs Residential, Multi-Family, and Commercial/Industrial Measures http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/06f2fee55575bd8a852576e4006f9af7/$FILE/TechManualNYRevised10-15-10.pdf

$T_{ambientMAX}$(°F) =For water heaters installed in unconditioned basements, use an average ambient temperature of 68.78°F; for water heaters inside the thermal envelope, use an average ambient temperature of 78 °F

Et = Thermal efficiency (or in the case of heat pump water heaters, COP); if unknown, use 0.98 as a default for electric water heaters, 2.2 for a heat pump water heater.

C.2.4.5. Incremental Cost

The incremental cost of a Water Heater Pipe Insulation is equal to the full installed cost. If the cost is unknown, use $4.45 for ¾" pipe and $4.15 for ½" pipe per linear foot of insulation[241].

C.2.4.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using ENERGY STAR default values. If this measure is added to Energy Smart programs, the evaluation should include a review of actual efficiency levels and costs of units purchased by New Orleans businesses and updates for applicable codes.

[241] Illinois TRM

C.3. HVAC

C.3.1. Packaged Terminal AC/HP (PTAC/PTHP) Equipment

C.3.1.1. Measure Description

This measure requires the installation of a PTAC or PTHP. AHRI Test Standard 310/380-2004 defines a PTAC or PTHP as “a wall sleeve and a separate non-encased combination of heating and cooling assemblies specified by the manufacturer and intended for mounting through the wall. It includes refrigeration components, separable outdoor louvers, forced ventilation, and heating availability by purchaser’s choice of, at least, hot water, steam, or electrical resistance heat.” These definitions are consistent with federal code (10 CFR Part 431.92).

PTAC/PTHP equipment is available in standard and non-standard sizes. Standard size refers to PTAC/PTHP equipment with wall sleeve dimensions having an external opening greater than or equal to 16 inches high or greater than or equal to 42 inches wide, and a cross-sectional area greater than or equal to 670 square inches. Non-standard size refers to PTAC/PTHP equipment with existing wall sleeve dimensions having an external wall opening of less than 16 inches high or less than 42 inches wide, and a cross-sectional area less than 670 square inches.

C.3.1.2. Baseline and Efficiency Standards

The baseline for units that are used in new construction or are replaced on burnout is the current federal minimum standard,[242] which went into effect September 30, 2012 for standard sized units and September 30, 2010 for non-standard sized units (Table 98).

Table 98: PTAC/PTHP Equipment – Baseline Efficiency Levels

Equipment Type	***Size Category***	***Capacity (Btu/h)***	***Minimum Efficiency [243]***

[242] 2010 U.S. Code: Title 42, Chapter 77, Subchapter III, Part A-1, Section 6313.

Equipment Type	*Size Category*	*Capacity (Btu/h)*	*Minimum Efficiency* [243]
PTAC	Standard	< 7,000	EER = 11.7
		7,000 – 15,000	EER = 13.8 – (0.300 x CAP)
		> 15,000	EER = 9.3
	Non-Standard	< 7,000	EER = 9.4
		7,000 – 15,000	EER = 10.9 – (0.213 x CAP)
		> 15,000	EER = 7.7
PTHP	Standard	< 7,000	EER = 11.9 COP = 3.3
		7,000 – 15,000	EER = 14.0 – (0.300 x CAP) COP = 3.7 – (0.052 x CAP)
		> 15,000	EER = 9.5 COP = 2.9
	Non-Standard	< 7,000	EER = 9.3 COP = 2.7
		7,000 – 15,000	EER = 10.8 – (0.213 x CAP) COP = 2.9 – (0.026 x CAP)
		> 15,000	EER = 7.6 COP = 2.5

C.3.1.3. Estimated Useful Life (EUL)

The estimated useful life of the measure is 10 years, in accordance with the DOE's Packaged Terminal Air Conditioners and Heat Pumps Energy Conservation Standard Technical Support Document.[244]

[243] "Cap" refers to cooling capacity in thousand Btu/h.

[244] U.S. DOE, Technical Support Document: "*Packaged Terminal Air Conditioners and Heat Pumps, 3.2.7 Equipment Lifetime".* http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/45.

C.3.1.4. Calculation of Deemed Savings

Deemed peak demand and annual energy savings for PTAC/PTHP equipment should be calculated using the following formulas:

$$kW_{Savings} = CAP \times \frac{1\ kW}{1{,}000\ W} \times \left(\frac{1}{\eta_{base}} - \frac{1}{\eta_{post}}\right) \times CF$$

$$kWh_{Savings,PTAC} = CAP \times \frac{1\ kW}{1{,}000\ W} \times EFLH_C \times \left(\frac{1}{\eta_{base}} - \frac{1}{\eta_{post}}\right)$$

$$kWh_{Savings,PTHP,C} = CAP \times \frac{1\ kW}{1{,}000\ W} \times EFLH_C \times \left(\frac{1}{\eta_{base,C}} - \frac{1}{\eta_{post,C}}\right)$$

$$kWh_{Savings,PTHP,H} = CAP \times \frac{1\ kWh}{3{,}412\ \mathrm{BTU}} \times EFLH_H \times \left(\frac{1}{\eta_{base,H}} - \frac{1}{\eta_{post,H}}\right)$$

Where,

$CAPC$= Rated equipment cooling capacity of the new unit (BTU/hr)

$CAPH$= Rated equipment heating capacity of the new unit (BTU/hr)

$\eta base$, = Baseline energy efficiency rating of the baseline cooling equipment (EER)

(Table 250)

$\eta post$,= Nameplate energy efficiency rating of the installed cooling equipment (EER)

$\eta post$,= Nameplate energy efficiency rating of the installed heating equipment (COP)

Note: heating efficiencies expressed as a heating seasonal performance factor (HSPF) will need to be converted to a coefficient of performance (COP) using the following equation:

$$\mathrm{COP} = \mathrm{HSPF} \div 3.412$$

3,412 = Constant to convert from BTU/hr to kWh

CF= Coincidence factor (Table 100)

$EFLH_c$ = Equivalent full-load hours for cooling (Table 99)

$EFLH_h$= Equivalent full-load hours for heating (Table 99)

Table 99: Equivalent Full-Load Hours by building type

Building Type	***$EFLH_C$***	***$EFLH_H$***
Fast Food	2,375	272
Grocery	1,526	153
Health Clinic	1,989	115
Large Office	1,483	392
Lodging	2,095	409
Full Menu Restaurant	1,997	166
Retail	3,191	513
School	2,329	140
Small Office	2,060	255
University	1,510	604

Table 100: Commercial Coincidence Factors by Building Type[245]

Building Type	***Coincidence Factor***
Fast Food	0.78
Grocery	0.90
Health Clinic	0.85
Large Office	0.84
Lodging	0.77
Full Menu Restaurant	0.85
Retail	0.88
School	0.71
Small Office	0.84
College	0.84

[245] Values for Assembly and Religious Worship building types developed using an adjustment factor derived through a comparison of average CFs for College/University and Assembly/Religious Worship building types from the Texas state Technical Reference Manual. College/University was selected as a reference building type due to average alignment with Assembly/Religious worship building types in other TRMs, inclusion of a summer session, and increased evening usage.

C.3.1.5. Incremental Cost

The incremental cost for this equipment is $84/ton[246].

C.3.1.6. Future Studies

Though eligible for Energy Smart, this measure has had little-to-no participation. Until such time as participation produces a minimum of 500,000 kWh in a program year, it is recommended that updates be limited to those needed to reflect code changes.

If this threshold is met, we recommend focusing M&V to update EFLH estimates.

[246] DEER 2014.

C.3.2. Unitary and Split System AC/HP Equipment

C.3.2.1. Measure Description

This measure requires the installation of packaged or split system air conditioners (AC) or heat pumps (HP), excluding PTACs/PTHPs. Unitary or split system ACs/HPs consist of one or more factory-made assemblies that normally include an evaporator or cooling coil(s), compressor(s), and condenser(s). They provide the function of air cooling, and may include the functions of air heating, air circulation, air cleaning, dehumidifying, or humidifying.

C.3.2.2. Baseline and Efficiency Standards

The baseline for units that are used in new construction or are replaced on burnout is the current federal minimum standard,[247] which went into effect January 1, 2010 (Table 101).

As of January 1, 2015, split system heat pumps < 65,000 Btu/h must comply with 10 CFR 430.32(c)(3) for Residential Central Air Conditioners and Heat Pumps. Split systems are not explicitly covered by originally specified federal standard 10 CFR 431.97 for Commercial package air condition and heating equipment. Split system air conditioners are not affected because the existing SEER and HSPF values remain unchanged.

[247] 2010 U.S. Code: Title 42, Chapter 77, Subchapter III, Part A-1, Section 6313.

Table 101: Unitary AC/HP Equipment – Baseline Efficiency Levels[248]

Equipment Type	***Capacity (Btu/h)***	***Heating Section Type***	***Sub-Category***	***Minimum Efficiency***
Air Conditioners, Air Cooled	< 65,000	All	Split System & Single Package	11.2 EER[350] 13.0 SEER
	≥ 65,000 & <135,000	Electric Resistance (or none)	Split System & Single Package	11.2 EER 11.4 SEER
	≥ 65,000 & <135,000	All other	Split System & Single Package	11.0 EER 11.2 SEER
	≥ 135,000 & <240,000	Electric Resistance (or none)	Split System & Single Package	11.0 EER 11.2 SEER
	≥ 135,000 & <240,000	All other	Split System & Single Package	10.8 EER 11.0 SEER
	≥ 240,000 & <760,000	Electric Resistance (or none)	Split System & Single Package	10.0 EER 10.1 SEER
	≥ 240,000 & <760,000	All other	Split System & Single Package	9.8 EER 9.9 SEER
	≥ 760,000	Electric Resistance (or none)	Split System & Single Package	9.7 EER 9.8 SEER
	≥ 760,000	All other	Split System & Single Package	9.5 EER 9.6 SEER
Air Conditioners, Water and Evaporatively	< 65,000	All	Split System & Single Package	12.1 EER 12.3 IEER

[248] IECC 2012, Table C403.2.3(1) & C403.2.3(2); full-load efficiencies consistent with ASHRAE Standard 90.1-2007, Table 6.8.1A & 6.8.1B and compliant with the federal standard.

Cooled[351]	≥ 65,000 & <135,000	Electric Resistance (or none)	Split System & Single Package	11.5 EER 11.7 IEER
	≥ 65,000 & <135,000	All other	Split System & Single Package	11.3 EER 11.5 IEER
	≥ 135,000 & <240,000	Electric Resistance (or none)	Split System & Single Package	11.0 EER 11.2 IEER
	≥ 135,000 & <240,000	All other	Split System & Single Package	10.8 EER 11.0 IEER
	≥ 240,000	Electric Resistance (or none)	Split System & Single Package	11.0 EER 11.1 IEER
	≥ 240,000	All other	Split System & Single Package	10.8 EER 10.9 SEER
Heat Pumps, Air Cooled (Cooling Mode)	< 65,000	All	Single Package	11.2 EER[352] 13.0 SEER
			Single Package (before 1/1/2015)	11.2 EER[353] 13.0 SEER
			Single Package (after 1/1/2015)[354]	11.8 EER[355] 14.0 SEER
	≥65,000 & <135,000	Electric Resistance (or none)	Split System & Single Package	11.0 EER 11.2 IEER
	≥65,000 & <135,000	All other	Split System & Single Package	10.8 EER 11.0 IEER
	≥135,000 & <240,000	Electric Resistance (or none)	Split System & Single Package	10.6 EER 10.7 IEER
	≥135,000 & <240,000	All other	Split System & Single Package	10.4 EER

				10.5 IEER
	≥240,000	Electric Resistance (or none)	Split System & Single Package	9.5 EER 9.6 IEER
	≥240,000	All other	Split System & Single Package	9.3 EER 9.4 IEER
Heat Pumps, Air Cooled (Heating Mode)	<65,000	N/A	Single Package	7.7 HSPF
			Single Package (before 1/1/2015)	7.7 HSPF
			Single Package (after 1/1/2015)[356]	8.2 HSPF
	≥65,000 & <135,000	N/A	Split System & Single Package	3.3 COP
	≥135,000	N/A	Split System & Single Package	3.2 COP

C.3.2.3. Estimated Useful Life (EUL)

According to the DEER 2014, the EUL for this measure is 15 years.

A.1.2 Calculated Deemed Savings

Deemed peak demand and annual energy savings for unitary AC and HP equipment should be calculated as shown below. Note that these savings calculations are different depending on whether the measure is replace-on-burnout or early retirement.

$$kW_{Savings} = CAP \times \frac{1\ kW}{1{,}000\ W} \times \left(\frac{1}{\eta_{base}} - \frac{1}{\eta_{post}}\right) \times CF \tag{38}$$

$$kWh_{Savings,AC} = CAP \times \frac{1\ kW}{1{,}000\ W} \times EFLH_C \times \left(\frac{1}{\eta_{base}} - \frac{1}{\eta_{post}}\right) \tag{39}$$

$$kWh_{Savings,HP} = CAP \times \frac{1\ kW}{1{,}000\ W} \times \left[\left(\frac{EFLH_C}{\eta_{base,AC}} + \frac{EFLH_H}{\eta_{base,HP}} \right) - \left(\frac{EFLH_C}{\eta_{post,AC}} + \frac{EFLH_H}{\eta_{post,HP}} \right) \right] \tag{40}$$

Where,

CAP = Rated equipment cooling capacity of the new unit (BTU/hr)

$\eta_{base,AC/HP}$ = Baseline energy efficiency rating of the cooling/heating equipment (Table 101)

$\eta_{post,AC/HP}$= Nameplate energy efficiency rating of the installed cooling/heating equipment

Note: Use EER for kW savings calculations and SEER/IEER and HSPF for kWh savings calculations.

CF = Coincidence factor (Table 15)

$EFLH_c$ = Equivalent full-load hours for cooling (Table 102)

$EFLH_h$ = Equivalent full-load hours for heating (Table 103)

Table 102 Equivalent Full-Load Hours by building type

Building Type	***EFLH_C***	***EFLH_H***
Fast Food	2,375	272
Grocery	1,526	153
Health Clinic	1,989	115
Large Office	1,483	392
Lodging	2,095	409
Full Menu Restaurant	1,997	166
Retail	3,191	513
School	2,329	140
Small Office	2,060	255
University	1,510	604

Table 103 Commercial Coincidence Factors by Building Type[249]

Building Type	***Coincidence Factor***
Fast Food	0.78
Grocery	0.90
Health Clinic	0.85
Large Office	0.84
Lodging	0.77
Full Menu Restaurant	0.85
Retail	0.88
School	0.71
Small Office	0.84
College	0.84

C.3.2.4. Incremental Cost

Incremental cost is detailed in *Table 104* below.

Table 104 Unitary AC Incremental Cost

Capacity	***Cost Per Ton per 1.0 SEER above 14.0***
65,000 Btuh or less	$82
65,000 to 240,000 Btuh	$48
240,000 to 760,000 Btuh	$180
760,000 Btuh or more	$181

C.3.2.1. Future Studies

Though eligible for Energy Smart, this measure has had little-to-no participation. Until such time as participation produces a minimum of 500,000 kWh in a program year, it is recommended that updates be limited to those needed to reflect code changes.

249 Values for Assembly and Religious Worship building types developed using an adjustment factor derived through a comparison of average CFs for College/University and Assembly/Religious Worship building types from the Texas state Technical Reference Manual. College/University was selected as a reference building type due to average alignment with Assembly/Religious worship building types in other TRMs, inclusion of a summer session, and increased evening usage.

If this threshold is met, we recommend focusing M&V to update EFLH estimates.

C.3.3. Air- and Water-Cooled Chillers

C.3.3.1. Measure Description

This measure requires the installation of any air cooled or water cooled chilling package, referred to as a chiller. AHRI Test Standard 550/590-2003 defines a water-chilling package as “a factory-made and prefabricated assembly of one or more compressor, condensers, and evaporators, with interconnections and accessories, designed for the purpose of cooling water. It is a machine specifically designed to make use of a vapor compression refrigeration cycle to remove heat from water and reject the heat to a cooling medium, usually air or water.”

The most common applications are for larger cooling loads (e.g., 50 to 100 tons and greater). Chiller types include centrifugal, rotary, screw, scroll, reciprocating, and gas absorption. Absorption chillers are subject to a different AHRI test standard and not reviewed as part of this analysis. When a water-cooled chiller is replacing an air-cooled chiller, the additional auxiliary electrical loads for the condenser water pump and the cooling tower fan have to be considered. Thus a penalty factor is necessary as a downward adjustment to account for the peak demand and energy savings.

To qualify, the chiller must serve an HVAC load. Chillers used as part of industrial processes require custom analysis.

C.3.3.2. Baseline and Efficiency Standards

The baseline for units that are used in new construction or are replaced on burnout is the current state minimum standard,[250] which went into effect January 21, 2013 (Table 105).

[250] ASHRAE Standard 90.1-2007.

Table 105 Chillers – Baseline Efficiency Levels for Chilled Water Packages[251]

Equipment Type	Chiller Type	Capacity (Tons)	Minimum Efficiency
Air cooled	All	< 150	9.562 EER 12.5 IPLV
		≥ 150	9.562 EER 12.75 IPLV
Water cooled	Rotary/ Screw/Scroll/ Reciprocating	< 75	0.780 kW/ton 0.630 IPLV
		≥ 75 and < 150	0.775 kW/ton 0.615 IPLV
		≥ 150 and < 300	0.680 kW/ton 0.580 IPLV
		≥ 300	0.620 kW/ton 0.540 IPLV
Water cooled	Centrifugal	< 300	0.634 kW/ton 0.596 IPLV
		≥ 300 and < 600	0.576 kW/ton 0.549 IPLV
		≥ 600	0.570 kW/ton 0.539 IPLV

C.3.3.3. Estimated Useful Life (EUL)

For high-efficiency chillers, according to the DEER 2008, the estimated useful life (EUL) is 20 years.

C.3.3.4. Calculation of Deemed Savings

Deemed peak demand and annual energy savings for chillers should be calculated using the following formulas:

[251] The values in the table reflect IECC 2009, Table 503.2.3(7).

$$kW_{Savings} = CAP \times \left(\eta_{base} - \eta_{post}\right) \times CF$$

$$kWh_{savings} = CAP \times EFLH_C \times \left(\eta_{base} - \eta_{post}\right)$$

Where:

CAP = Rated equipment cooling capacity of the new unit (Tons)

η_{base} = Baseline energy efficiency rating of the baseline cooling equipment (kW/ton or EER converted to kW/ton)

η_{post}= Nameplate energy efficiency rating of the installed cooling equipment (kW/ton)

Note: use full-load efficiency (in units of kW/ton) for kW savings calculations and IPLV (in units of kW/ton) for kWh savings calculations. Cooling efficiencies expressed as an EER will need to be converted to kW/ton using the following equation:

$$\frac{kW}{Ton} = \frac{12}{EER}$$

CF= Coincidence factor (Table 15)

$EFLH_c$= Equivalent full-load hours for cooling (*Table 106*)

$EFLH_h$= Equivalent full-load hours for heating (*Table 107*)

Table 106: Equivalent Full-Load Hours by Building type

Building Type	***EFLH_C***	***EFLH_H***
Fast Food	2,375	272
Grocery	1,526	153
Health Clinic	1,989	115
Large Office	1,483	392
Lodging	2,095	409
Full Menu Restaurant	1,997	166
Retail	3,191	513
School	2,329	140
Small Office	2,060	255
University	1,510	604

Table 107: Commercial Coincidence Factors by Building Type[252]

Building Type	*Coincidence Factor*
Fast Food	0.78
Grocery	0.90
Health Clinic	0.85
Large Office	0.84
Lodging	0.77
Full Menu Restaurant	0.85
Retail	0.88
School	0.71
Small Office	0.84
College	0.84

C.3.3.5. Incremental Cost

Incremental cost is detailed in *Table 108* below.

[252] Values for Assembly and Religious Worship building types developed using an adjustment factor derived through a comparison of average CFs for College/University and Assembly/Religious Worship building types from the Texas state Technical Reference Manual. College/University was selected as a reference building type due to average alignment with Assembly/Religious worship building types in other TRMs, inclusion of a summer session, and increased evening usage.

Table 108: Chiller Incremental Cost

Equipment Type	***Capacity***	***Cost Per Ton***
Air-cooled	All capacities	$127/ton[253]
Water-cooled – reciprocating	All capacities	$22/ton[254]
Water-cooled – rotary & scroll	< 150 tons	$351/ton[255]
	>=150 and < 300 tons	$127/ton
	>= 300 tons	$87/ton

C.3.3.6. Future Studies

This is a low-volume, high-savings measure. ADM recommends that chiller projects be flagged for IPMVP Option C or D analysis when they occur.

[253] 2008 Database for Energy-Efficiency Resources (DEER), Version 2008.2.05, “Cost Values and Summary Documentation”, California Public Utilities Commission, December 16, 2008. Calculated as the simple average of screw and reciprocating air-cooled chiller incremental costs from DEER2008. This assumes that baseline shift from IECC 2012 to IECC 2015 carries the same incremental costs. Values should be verified during evaluation

[254] 2008 Database for Energy-Efficiency Resources (DEER), Version 2008.2.05, “Cost Values and Summary Documentation”

[255] Incremental costs for water-cooled, positive displacement (rotary screw and scroll) from the W017 Itron California Measure Cost Study, accessed via http://www.energydataweb.com/cpuc/search.aspx. The data is provided in a file named “MCS Results Matrix – Volume I”.

C.3.4. Commercial Air Conditioner and Heat Pump Tune-Up

C.3.4.1. Measure Description

This measure applies to central air conditioners and heat pumps. An AC tune-up, in general terms, involves checking, adjusting and resetting the equipment to factory conditions, such that it operates closer to the performance level of a new unit. For this measure, the service technician must complete the following tasks according to industry best practices:

- Inspect and clean condenser, evaporator coils, and blower.
- Inspect refrigerant level and adjust to manufacturer specifications.
- Measure the static pressure across the cooling coil to verify adequate system airflow and adjust to manufacturer specifications.
- Inspect, clean, or change air filters.
- Calibrate thermostat on/off setpoints based on building occupancy.
- Tighten all electrical connections, and measure voltage and current on motors.
- Lubricate all moving parts, including motor and fan bearings.
- Inspect and clean the condensate drain.
- Inspect controls of the system to ensure proper and safe operation. Check the starting cycle of the equipment to assure the system starts, operates, and shuts off properly.
- Provide documentation showing completion of the above checklist to the utility or the utility's representative.

C.3.4.2. Baseline and Efficiency Standards

The baseline is a system with demonstrated imbalances of refrigerant charge.

After the tune-up, the equipment must meet airflow and refrigerant charge requirements. To ensure the greatest savings when conducting tune-up services, the eligibility minimum requirement for airflow is the manufacturer specified design flow rate, or 350 CFM/ton, if unknown. Also, the refrigerant charge must be within +/- 3 degrees of target sub-cooling for units with thermal expansion valves (TXV) and +/- 5 degrees of target super heat for units with fixed orifices or a capillary.

The efficiency standard, or efficiency after the tune-up, is assumed to be the manufacturer specified energy efficiency ratio (EER) of the existing central air conditioner or heat pump. The efficiency improvement resulting from the refrigerant charge adjustment depends on the pre-adjustment refrigerant charge.

C.3.4.3. Estimated Useful Life (EUL)

According to DEER 2008, the estimated useful life (EUL) for refrigerant charge correction is 10 years.

C.3.4.4. Calculation of Deemed Savings

Deemed peak demand and annual energy savings for unitary AC/HP tune-up should be calculated using the following formulas:

$$kW_{savings,C} = CAP_C \times \frac{1\ kW}{1{,}000\ W} \times \left(\frac{1}{EER_{pre}} - \frac{1}{EER_{post}}\right) \times CF$$

$$kWh_{savings,C} = CAP_C \times \frac{1\ kW}{1{,}000\ W} \times EFLH_C \times \left(\frac{1}{EER_{pre}} - \frac{1}{EER_{post}}\right)$$

$$kWh_{savings,H} = CAP_H \times \frac{1\ kW}{1{,}000\ W} \times EFLH_H \times \left(\frac{1}{HSPF_{pre}} - \frac{1}{HSPF_{post}}\right)$$

$$kWh_{savings,AC} = kWh_{savings,C}$$

$$kWh_{savings,HP} = kWh_{savings,C} + kWh_{savings,H}$$

Where,

CAP_c= Rated equipment cooling capacity (BTU/hr)

CAP_h= Rated equipment heating capacity (BTU/hr)

EER_{pre}= Adjusted efficiency of the equipment for cooling before tune-up

EER_{post}= Nameplate efficiency of the existing equipment for cooling; if unknown, use default EER value from Table 111 and Table 112

Note: Site measurements may be substituted for EER_{pre} and EER_{post}, providing that the measurements are taken on the same site visit and under similar operating conditions using reliable, industry accepted techniques. If onsite measurements are used to measure savings for measures other than refrigerant charge, then the implementer should use an EUL of three years.

$HSPF_{pre}$ = Efficiency of the equipment for heating before tune-up

$HSPF_{post}$ = Nameplate efficiency of the existing equipment for heating; if unknown, use default HSPF value from Table 113.

CF= Coincidence factor (Table 115)

$EFLH_c$= Equivalent full-load hours for cooling (Table 114)

$EFLH_h$= Equivalent full-load hours for heating (Table 114)

$$EER_{pre} = (1 - EL) \times EER_{post}$$

Where,

EEF_{pre}= Adjusted efficiency of the cooling equipment before tune-up

EER_{post}= Nameplate efficiency of the existing cooling equipment; if unknown, use default EER value from Table 111 and Table 112.

EL = Efficiency Loss (Fixed Orifice: Table 109; TXV: Table 110) determined by averaging reported efficiency losses from multiple studies.[256,257,258,259,260] Interpolation of the efficiency loss values presented is allowed. Extrapolation is not allowed.

Table 109: Efficiency Loss Percentage by Refrigerant Charge Level (Fixed Orifice)

% Charged	EL
≤ 70	0.37
75	0.29
80	0.20
85	0.15
90	0.10
95	0.05
100	0.00
≥ 120	0.03

[256] Architectural Energy Corporation, managed by New Buildings Institute. “Small HVAC System Design Guide.” Prepared for the California Energy Commission. October 2003. Figure 11.

[257] Davis Energy Group. “HVAC Energy Efficiency Maintenance Study,” California Measurement Advisory Council (CALMAC). December 29, 2010. Figure 14.

[258] Proctor Engineering Group. “Innovative Peak Load Reduction Program CheckMe! Commercial and Residential AC Tune-Up Project.” California Energy Commission. November 6, 2003. Table 6-3.

[259] Proctor Engineering Group. PEG Tune-Up Calculations spreadsheet.

[260] Pennsylvania Technical Reference Manual (TRM). June 2012. Measure 3.3.2, Table 3-96.

Table 110: Efficiency Loss Percentage by Refrigerant Charge Level (TXV)

% Charged	EL
≤ 70	0.12
75	0.09
80	0.07
85	0.06
90	0.05
95	0.03
100	0.00
≥ 120	0.04

Table 111: Default Air Conditioner EER per Size Category[261]

Size Category (BTU/hr)	Default EER[262]
< 65,000	11.8
≥ 65,000 and < 135,000	11.0
≥ 135,000 and < 240,000	10.8
≥ 240,000 and < 760,000	9.8
≥ 760,000	9.5

[261] Code specified SEER or EER value from 2013 Addenda to ASHRAE 90.1-2010 (efficiency value effective January 1, 2015 for units < 65,000 Btu/hr and prior to January 1, 2010 for units ≥ 65,000 Btu/hr).

[261] Code specified SEER or EER value from ASHRAE 90.1-2010 (efficiency value effective January 1, 2015

[262] SEER values converted to EER using EER = -0.02 x SEER^2 + 1.12 x SEER. National Renewable Energy Laboratory (NREL). "Building America House Simulation Protocols." U.S. DOE. Revised October 2010. http://www.nrel.gov/docs/fy11osti/49246.pdf.

Table 112: Default Heat Pump EER per Size Category[263]

Size Category (BTU/hr)	Default EER
< 65,000	11.8
≥ 65,000 and < 135,000	10.8
≥ 135,000 and < 240,000	10.4
≥ 240,000	9.3

$$HSPF_{pre} = (HSPF_{post}) \times (1 - M)^{age} \quad (14)$$

Where,

$HSPF_{post}$= HSPF of pre-tune up equipment when new (use nameplate or default value from Table 113)

M = Maintenance factor[264], use 0.01 if annual maintenance conducted or 0.03 if maintenance is seldom

Age = Age of equipment in years, up to a maximum of 20 years, use a default of 10 years if unknown.

Table 113: Default Heat Pump HSPF per Size Category[265]

[263] Code specified SEER or EER value from 2013 Addenda to ASHRAE 90.1-2010 (efficiency value effective January 1, 2015 for units < 65,000 Btu/hr and prior to January 1, 2010 for units > 65,000 Btu/hr).

[264] "Building America House Simulation Protocols." U.S. DOE. Revised October 2010. Table 32. Page 40. http://www.nrel.gov/docs/fy11osti/49246.pdf.

Size Category (BTU/hr)	Subcategory or Rating Condition	Default HSPF[266]
< 65,000	Split System	8.2
	Single Package	8.0
≥ 65,000 and < 135,000	47°F db/43°F wb Outdoor Air	11.3
	17°F db/15°F wb Outdoor Air	7.7
≥ 135,000	47°F db/43°F wb Outdoor Air	10.9
	17°F db/15°F wb Outdoor Air	7.0

Table 114: Equivalent Full-Load Hours by Building type

Building Type	$EFLH_C$	$EFLH_H$
Fast Food	2,375	272
Grocery	1,526	153
Health Clinic	1,989	115
Large Office	1,483	392
Lodging	2,095	409
Full Menu Restaurant	1,997	166
Retail	3,191	513
School	2,329	140
Small Office	2,060	255
University	1,510	604

Table 115: Commercial Coincidence Factors by Building Type[267]

[265] Code specified HSPF or COP value from 2013 Addenda to ASHRAE 90.1-2010 (efficiency value effective January 1, 2015 for units < 65,000 Btu/hr and prior to January 1, 2010 for units > 65,000 Btu/hr).

[266] COP values converted to HSPF using COP=HSPF÷3.412

Building Type	*Coincidence Factor*
Fast Food	0.78
Grocery	0.90
Health Clinic	0.85
Large Office	0.84
Lodging	0.77
Full Menu Restaurant	0.85
Retail	0.88
School	0.71
Small Office	0.84
College	0.84

C.3.4.5. Incremental Cost

Program-actual costs should be used. If not available, use $35/ton[268].

C.3.4.6. Future Studies

The incremental cost value is very sensitive to labor costs, and as such a New Orleans-specific cost study should be conducted to revise this value. Further, due to past realization rate issues with residential AC tune-up, if this offering is expanded to the commercial sector ADM strongly recommends a whole-program billing analysis to support savings estimates.

[267] Values for Assembly and Religious Worship building types developed using an adjustment factor derived through a comparison of average CFs for College/University and Assembly/Religious Worship building types from the Texas state Technical Reference Manual. College/University was selected as a reference building type due to average alignment with Assembly/Religious worship building types in other TRMs, inclusion of a summer session, and increased evening usage.

[268] Act on Energy Commercial Technical Reference Manual No. 2010-4

C.3.5. Guest Room Energy Management (GREM) Controls

C.3.5.1. Measure Description

Packaged terminal heat pumps (PTHP) and packaged terminal air conditioners (PTAC) are commonly installed in the hospitality industry to provide heating and cooling of individual guest rooms. Occupancy-based PTHP/PTAC controllers are a combination of a control unit and occupancy sensor that operate in conjunction with each other to provide occupancy-controlled heating and/or cooling. The control unit plugs into a wall socket and the PTHP/PTAC plugs into the control unit. The control unit is operated by an occupancy sensor that is mounted in the room and turns the PTHP/PTAC on and off. The most common application for occupancy-based PTHP/PTAC controls is hotel rooms.

To qualify for savings, equipment must have a setback of at least 5 degrees Fahrenheit. Setbacks greater than 8 degrees Fahrenheit are not recommended due to occupant comfort considerations.

C.3.5.2. Baseline and Efficiency Standards

There is no code requirement for installation of GREM systems. The baseline configuration is a PTAC/PTHP with a manually controlled thermostat.

C.3.5.3. Estimated Useful Life (EUL)

The average lifetime of this measure is eight years, in accordance with DEER 2008.

C.3.5.4. Calculation of Deemed Savings

Estimated gross annual energy savings is 355kWh/unit, based on numbers reported by Xcel Energy and scaled appropriately based on New Orleans weather data. There is no peak demand savings associated with this measure. As these savings estimates are based on a single reference, it is recommended that New Orleans work with early program participants to conduct actual pre- and post-measurement of energy use to verify the accuracy of these values.

C.3.5.5. Calculation of Deemed Savings

Only one reference was found that provided a comprehensive overview of estimated savings for this measure; 509 kWh/yr energy savings (Xcel Energy 2006).

C.3.5.6. Incremental Cost

The incremental cost is the difference between a GREM system and a manual thermostat, $260[269].

[269] DEER 2008 value for energy management systems

C.3.5.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values from other programs. If this measure is added to Energy Smart programs, the evaluation should include a metering study to support occupancy estimates.

C.4. Refrigeration

C.4.1. Door Heater Controls for Refrigerators and Freezers

C.4.1.1. Measure Description

This measure refers to the installation of anti-sweat door heater controls on glass doors for reach-in commercial refrigerators and freezers. The added control reduces both heater operation time and cooling load.

This measure only qualifies for retrofit applications. New construction applications are not allowed as this measure is standard practice for new construction and comes integrated on most modern glass-door refrigerators and freezers.

C.4.1.2. Baseline and Efficiency Standards

Qualifying equipment includes any controls that reduce the run time of door and frame heaters for refrigerated cases. The baseline efficiency case is a cooler or freezer door heater that operates 8,760 hours per year without any controls. The high efficiency case is a cooler (medium temperature) or freezer (low temperature) door heater connected to a heater control system. There are no state or federal codes or standards that govern the eligibility of equipment.

C.4.1.3. Estimated Useful Life (EUL)

The estimated useful life (EUL) is 12 years as defined in the DEER database.[270]

C.4.1.4. Calculation of Deemed Savings

C.4.1.4.1. Energy Savings

A door heater controller senses dew point (DP) temperature in the store and modulates power supplied to the heaters accordingly. DP inside a building is primarily dependent on the moisture content of outdoor ambient air. Because the outdoor DP varies between weather zones, weather data from each weather zone must be analyzed to obtain a DP profile.

Indoor dew point (t_{d-in}) is related to outdoor dew point (t_{d-out}) according to the following equation. Indoor dew point was calculated at each location for every hour in the year.[271]

$$t_{d-in} = 0.005379 \times t_{d-out}^2 + 0.171795 \times t_{d-out} + 19.870006$$

[270] California's Database for Energy Efficiency Resources (DEER 2008).

[271] Work Paper PGEREF108: Anti-Sweat Heat (ASH) Controls. Pacific Gas & Electric Company. May 29, 2009.

In the base case, the door heaters are all on and have a duty of 100% irrespective of the indoor DP temperature. For the post retrofit case, the duty for each hourly reading was calculated by assuming a linear relationship between indoor DP and duty cycle for each bin reading. It is assumed that the door heaters will be all off (duty cycle of 0%) at 42.89°F or lower DP and all on (duty cycle of 100%) at 52.87°F or higher DP for a typical supermarket. Between these values, the door heaters' duty cycle changes proportionally:

$$Door\ Heater\ ON\% = \frac{t_{d-in} - All\ OFF\ Setpt\ (42.89°F)}{All\ ON\ Setpt\ (52.87°F) - All\ OFF\ Setpt\ (42.89°F)}$$

Because the controller only changes the run-time of the heaters, instantaneous door heater power (kW_{ASH}) as a resistive load remains constant per linear foot of door heater at:

$$kW_{ASH} = \frac{kW}{ft} \times L_{DH}$$

Where kW/ft. = 0.0368 for medium temperature and 0.0780 for low temperature applications.

Door heater energy consumption for each hour of the year is a product of power and run-time:

$$kWh_{ASH-Hourly} = kW_{Ash} \times Door\ Heater\ ON\% \times 1\ hour$$

Total annual door heater energy consumption (kWh_{ASH}) is the sum of all hourly reading values:

$$kWh_{ASH} = \sum kWh_{ASH-Hourly}$$

Energy savings were also estimated for reduced refrigeration loads using average system efficiency and assuming that 35% of the anti-sweat heat becomes a load on the refrigeration system.[272] The cooling load contribution from door heaters can be given by:

$$Q_{ASH}(ton) = 0.35 \times kW_{ASH} \times \frac{3{,}412\ \frac{Btu/h}{ton}}{12{,}000\ \frac{Btu/h}{ton}} \times Door\ Heater\ ON\%$$

[272] Southern California Edison (SCE), 1999, *"A Study of Energy Efficient Solutions for Anti-Sweat Heaters."* Prepared for the Refrigeration Technology and Test Center (RTTC). December 14. https://www.sce.com/NR/rdonlyres/B1F7A3B4-719D-4CBB-87EB-E27F7CE7ECE0/0/Anti_Sweat_Heater_Report.pdf.

The compressor power requirements are based on calculated cooling load and energy-efficiency ratios obtained from the manufacturers' data. The compressor analysis is limited to the cooling load imposed by the door heaters, not the total cooling load of the refrigeration system.

The typical efficiency for a medium temperature case is 9 EER (1.33 kW/ton), and the typical efficiency for a low temperature case is 5 EER (2.40 kW/ton).[273]

Energy used by the compressor to remove heat imposed by the door heaters for each hourly reading is determined based on calculated cooling load and EER, as outlined below:

$$kWh_{Refrig-Hourly} = Q_{ASH} \times \frac{kW}{ton} \times 1\ hour$$

Total annual refrigeration energy consumption is the sum of all hourly reading values:

$$kWh_{Refrig} = \sum kWh_{Refrig-Hourly}$$

Total annual energy consumption (direct door heaters and indirect refrigeration) is the sum of all hourly reading values:

$$kWh_{Total} = kWh_{Refrig} + kWh_{ASH}$$

Once the annual energy consumption (direct door heaters and indirect refrigeration) has been determined for the baseline and post-retrofit case, the total energy savings are calculated by the following equation:

$$Annual\ Energy\ Savings = \Delta kWh = kWh_{Total-Baseline} - kWh_{Total-Post\ Retrofit}$$

C.4.1.4.2. Demand Savings

It is important to note that while there might be instantaneous demand savings as a result of the cycling of the door heaters, peak demand savings will only be due to the reduced refrigeration load. Peak demand savings was calculated by the equation shown below:

$$Peak\ Demand\ Savings = \Delta kW = \frac{kWh_{Refrig-Baseline} - kWh_{Refrig-Post\ Retrofit}}{8{,}760\ hr/yr}$$

C.4.1.5. Deemed Savings Values

Annual and peak energy savings due to anti-sweat door heater controls in medium and low temperature refrigerated cases for New Orleans. Deemed savings is calculated

[273] Chapter 15 of the 2010 ASHRAE Handbook for Refrigeration

using a ratio compared to El Dorado, AR (Zone 6) Savings provided in the table are per linear foot of glass door controlled heater.

Table 116: Anti-Sweat Heater Controls – Savings per Linear Foot of Case by Location

Weather Zone	Med-Temperature		Low-Temperature	
	Annual kWh/ft. Savings	kW/ft. Savings	Annual kWh/ft. Savings	kW/ft. Savings
New Orleans (Zone 3)	248	0.0046	259	0.0060

C.4.1.6. Incremental Cost

The full installed cost should be used for this measure. If not available, use $300 per circuit[274].

C.4.1.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure had low participation in Energy Smart programs. As a result, savings are calculated using weather-adjusted default values from other programs. If participation exceeds 500,000 kWh, the evaluation should include a metering study to support runtime estimates.

[274] Efficiency Vermont Technical Reference User Manual (TRM) Measure Savings Algorithms and Cost Assumptions, February, 19, 2010

C.4.2. Solid Door Refrigerators and Freezers

C.4.2.1. Measure Description

Commercial refrigerators and freezers are commonly found in restaurants and other food service industries. Reach-in, solid-door refrigerators and freezers are significantly more efficient than regular refrigerators and freezers due to better insulation and higher-efficiency components. These efficiency levels relate the volume of the appliance to its daily energy consumption.

C.4.2.2. Baseline and Efficiency Standards

Effective January 1, 2010, EPAct 2005 established new federal minimum efficiency levels for solid-door refrigerators and freezers (see Table 117 below). Also included are the minimum efficiency levels for the ENERGY STAR® specifications.

Table 117: Solid-Door Refrigerators and Freezers – Efficiency Levels

Equipment Type	***Efficiency Level***	***Maximum Daily Energy Consumption[275] (kWh/day)***
Refrigerator	Baseline	0.1V + 2.04
Refrigerator	ENERGY STAR®	0<V<15, 0.089V + 1.411
		15≤V<30, 0.037V + 2.2
		30≤V<50, 0.056V + 1.635
		50≤V, 0.060V + 1.416
Freezer	Baseline	0.4V + 1.38
Freezer	ENERGY STAR®	0<V<15, 0.250V + 1.250
		15≤V<30, 0.037V + 2.2
		30≤V<50, 0.163V
		50≤V, 0.158V + 6.333

The standard refrigerator/freezer efficiency is based on *Table 117* which contains the baseline annual energy consumption, and demand, for solid-door refrigerators and freezers.

[275] V is the volume of the refrigerator or freezer in cubic feet.

Table 118: Solid-Door Refrigerators and Freezers – Baseline Measure Information

Type	*Size Range*[276] *(Cubic Ft)*	*Annual Energy Consumption (kWh/unit)*	*Demand (kW/unit)*
Refrigerator	0-15	1,292	0.15
	15-30	1,840	0.21
	30-50	2,570	0.29
	≥50	3,300	0.38
Freezer	0-15	2,694	0.31
	15-30	4,884	0.56
	30-50	7,804	0.89
	≥50	10,724	1.22

To qualify for this measure, new solid-door refrigerators and freezers must meet ENERGY STAR® minimum efficiency requirements. Table 119 summarizes the estimated performance information for qualifying units.

Table 119. Solid-Door Refrigerators and Freezers – Qualifying Measure Information

Type	*Size Range*[277] *(Cubic Ft)*	*Annual Energy Consumption (kWh/unit)*	*Demand (kW/unit)*
Refrigerator	0-15	1,002	0.114
	15-30	1,208	0.138
	30-50	1,619	0.185
	≥50	2,050	0.234
Freezer	0-15	1,825	0.208
	15-30	4,015	0.458
	30-50	5,210	0.595
	≥50	6,348	0.725

[276] Solid-door refrigerators and freezers were evaluated for four different sizes or volumes (V), 15, 30, 50 and 70 cubic feet. The unit will be operated for 365 days per year.

[277] Ibid.

C.4.2.3. Estimated Useful Life (EUL)

According to DEER 2008, the estimated useful life (EUL) is 12 years.

C.4.2.4. Deemed Savings Values

Deemed measure savings for qualifying solid-door refrigerators and freezers are presented in Table 120.

Table 120: Solid-Door Refrigerators and Freezers – Deemed Savings Values

Type	***Size Range[278] (Cubic Ft)***	***Annual Energy Consumption (kWh/unit)***	***Demand (kW/unit)***
Refrigerator	0-15	290	0.03
	15-30	631	0.07
	30-50	951	0.11
	≥50	1,250	0.14
Freezer	0-15	869	0.10
	15-30	869	0.10
	30-50	2,593	0.30
	≥50	4,375	0.50

C.4.2.5. Measure Technology Review

Five primary resources contained data about solid-door refrigerators and freezers. The ENERGY STAR® website and the Consortium for Energy Efficiency (CEE) had the same maximum daily energy consumption levels for commercial food-grade refrigerators and freezers. The NPCC report and Ecotope studies gave savings and cost estimates, but did not include the volume of the appliances. NYSERDA's deemed savings and cost database (Nexant 2005) contained data for both refrigerators and freezers at common sizes.

[278] Solid-door refrigerators and freezers were evaluated for four different sizes or volumes (V), 15, 30, 50 and 70 cubic feet. The unit will be operated for 365 days per year.

Table 121: Solid-Door Refrigerators and Freezers – Review of Measure Information

Available Resource	Notes
PG&E 2005[41]	Energy savings and cost estimates for refrigerators and freezers at common sizes
DEER 2008[65]	Energy savings and cost estimates for refrigerators and freezers at common sizes
KEMA 2010[24]	Energy savings and cost estimates for refrigerators and freezers at common sizes
CEE[64]	Maximum daily energy consumption levels (kWh/day) for CEE-qualified commercial qualified food-grade refrigerators and freezers
ENERGY STAR®[69]	Maximum daily energy consumption levels (kWh/day) for commercial qualified food-grade refrigerators and freezers
NEXANT 2005[31]	Energy savings and cost estimates for refrigerators and freezers at common sizes
PacifiCorp 2009[44]	Unitary savings included in comprehensive potential study

Note: Italic numbers are endnotes not footnotes. (See Section 4.4 Commercial Measure Reference)

C.4.2.6. Incremental Cost

The incremental cost is provided in Table 122[279].

Table 122: Solid-Door Refrigerators and Freezers Incremental Costs

Type	***Incremental Cost***
Refrigerator	$143
	$164
	$164
	$249
Freezer	$142
	$166
	$166
	$407

C.4.2.7. Future Studies

This measure applies known values from ENERGY STAR; ADM does not recommend focused study for this measure. Parameters should be updated to correspond to the most recent ENERGY STAR specification.

[279] For the purposes of this characterization, assume and incremental cost adder of 5% on the full unit costs presented in Goldberg et al, State of Wisconsin Public Service Commission of Wisconsin, Focus on Energy Evaluation, Business Programs: Incremental Cost Study, KEMA, October 28, 2009.

C.4.3. Refrigerated Case Night Covers

C.4.3.1. Measure Description

This measure applies to the installation of night covers on otherwise open vertical (multi-deck) and horizontal (coffin-type) low-temperature (L) and medium temperature (M) display cases to decrease cooling load of the case during the night. It is recommended that these film-type covers have small, perforated holes to decrease the build-up of moisture.

Cases may be either: Self Contained (SC) having both evaporator and condenser coils, along with the compressor as part of the unit or Remote Condensing (RC) where the condensing unit and compressor are remotely located. Refrigerated case categories[280] are as follows:

- Vertical Open (VO): Equipment without doors and an air-curtain angle ≥ 0° and < 10°
- Semivertical Open (SVO): Equipment without doors and an air-curtain angle ≥ 10° and < 80°
- Horizontal Open (HO): Equipment without doors and an air-curtain angle ≥ 80°

This measure is only eligible for retrofit applications. The measure is standard practice in new construction.

C.4.3.2. Baseline and Efficiency Standards

The baseline standard for this measure is an open low-temperature or medium temperature refrigerated display case (vertical or horizontal) that is not equipped with a night cover.

The efficiency standard for this measure is any suitable material sold as a night cover. The cover must be applied for a period of at least six hours per night.

C.4.3.3. Estimated Useful Life (EUL)

According to the California Database of Energy Efficiency Resources (DEER 2014), refrigerated case night covers are assigned an EUL of 5 years.

C.4.3.4. Calculation of Deemed Savings

The following outlines the assumptions and approach used to estimate demand and energy savings due to installation of night covers on open low- and medium-temperature, vertical and horizontal, display cases. Heat transfer components of the

[280] U.S. DOE, Technical Support Document: Energy Efficiency Program for Consumer Products and Commercial Industrial Equipment, Commercial Refrigeration Equipment, Washington DC, p3-15

display case include infiltration (convection), transmission (conduction), and radiation. This deemed savings approach assumes that installing night covers on open display cases will only reduce the infiltration load on the case. Infiltration affects cooling load in the following ways:

- Infiltration accounts for approximately 80% of the total cooling load of open vertical (or multi-deck) display cases.[281]
- Infiltration accounts for approximately 24% of the total cooling load of open horizontal (coffin or tub style) display cases.[282]

Installing night covers for a period of 6 hours per night can reduce the cooling load due to infiltration. This was modeled by the U.S. Department of Energy (DOE) for Vertical and Semivertical cases.

Table 123: Vertical & Semivertical Refrigerated Case Savings

Case Type[283]	***VO.RC.M***	***VO.RC.L***	***VO.SC.M***	***SVO.RC.M***	***SVO.SC.M***
kWh per day- before Night Curtain	50.52	118.44	38.98	38.48	32.82
kWh per day - with Night Curtain	46.84	111.58	36.99	35.74	31.05
Percent kWh Savings per Day	7%	6%	5%	7%	5%
Annual kWh Savings	1,343	2,504	726	1,000	646
Test Case Length (ft.)	12	12	4	12	4

Table 124: Horizontal Refrigerated Case Savings

281 ASHRAE 2006. Refrigeration Handbook. Retail Food Store Refrigeration and Equipment. Atlanta, Georgia. pp. 46.1, 46.5, 46.10.

282 Ibid.

283 U.S. DOE, Technical Support Document: Energy Efficiency Program for Consumer Products and Commercial Industrial Equipment, Commercial Refrigeration Equipment, Washington DC, pp.5-43- 5-47, 5A-5, 5A-6

Case Type[284]	HO.RC.M	HO.RC.L	HO.SC.M	HO.SC.L
kWh per day- before Night Curtain[285]	15.44	34.23	16.06	35.02
kWh per day - with Night Curtain	14.05	31.15	14.61	31.87
Percent kWh Savings per Day[286]	9%	9%	9%	9%
Annual kWh Savings	507	1,124	528	1,150
Test Case Length (ft.)	12	12	4	4

While the DOE also modeled the energy consumption for horizontal open cases, there was not an efficient case modeled with a night cover. The 9% energy savings as found by Faramarzi & Woodworth-Szleper[6] was used to determine the post kWh per day.

C.4.3.5. Deemed Savings Values

Due to the relatively consistent summer dry-bulb temperature across the New Orleans weather zone, deemed savings values are only provided for the average dry-bulb temperature of 96°F.

Table 125: Refrigerated Case Night Covers – Deemed Savings Values (per Linear Foot)[287]

[284] U.S. DOE, Technical Support Document: Energy Efficiency Program for Consumer Products and Commercial Industrial Equipment, Commercial Refrigeration Equipment, Washington DC, pp. 5-48 - 5-51. The level AD3 was used for the baseline efficiency.

[285] Ibid.

[286] ASHRAE 1999 Effects of Low-E Shields on the Performance and Power Use of a Refrigerated Display Case. Faramarzi & Woodworth-Szleper, p.8

[287] Pacific Gas & Electric (PG&E), 2009, "*Night Covers for Open Vertical and Horizontal Display Cases (Low and Medium Temperature Cases),* May 29,.

Case Description	*Temperature Range (°F)*	*kWh Savings (kWh/ft.)*	*kW Savings (kW/ft.)*
Vertical Open, Remote Condensing Medium Temperature	10 – 35 °F	112	0.00
Vertical Open, Remote Condensing Low Temperature	< 10 °F	209	0.00
Vertical Open, Self-Contained Medium Temperature	10 – 35 °F	182	0.00
Semivertical Open, Remote Condensing Medium Temperature	10 – 35 °F	83	0.00
Semivertical Open, Self-Contained Medium Temperature	10 – 35 °F	162	0.00
Horizontal Open, Remote Condensing Medium Temperature	10 – 35 °F	42	0.00
Horizontal Open, Remote Condensing Low Temperature	< 10 °F	94	0.00
Horizontal Open, Self-Contained Medium Temperature	10 – 35 °F	132	0.00
Horizontal Open, Self-Contained Low Temperature	< 10 °F	288	0.00

C.4.3.1. Incremental Cost

The full measure cost should be used. When not available, use $42 per linear foot (CA DEER 2014).

C.4.3.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure had low participation in Energy Smart programs. As a result, savings are calculated using weather-adjusted default values from other programs. If participation exceeds 500,000 kWh, the evaluation should include a metering study to support coverage time estimates.

C.4.4. Zero Energy Doors

C.4.4.1. Measure Description

This measure applies to the installation of zero energy doors for refrigerated cases. Zero energy doors eliminate the need for anti-sweat heaters to prevent the formation of condensation on the glass surface by incorporating heat reflective coatings on the glass, gas inserted between the panes, non-metallic spacers to separate glass panes, and/or non-metallic frames.

This measure cannot be used in conjunction with anti-sweat heat (ASH) controls.

C.4.4.2. Baseline and Efficiency Standards

The baseline standard for this measure is a standard vertical reach-in refrigerated cooler or freezer with anti-sweat heaters on the glass surface of the doors.

The efficiency standard for this measure is a reach-in refrigerated cooler or freezer with special doors installed to eliminate the need for anti-sweat heaters. Doors must have either heat reflective treated glass, be gas-filled, or both.

C.4.4.3. Estimated Useful Life (EUL)

According to the California Database of Energy Efficiency Resources (DEER 2014), zero energy doors are assigned an EUL of 12 years.

C.4.4.4. Calculation of Deemed Savings

$$kW_{savings} = kW_{door} \times BF$$

$$kWh_{savings} = kW_{savings} \times 8760$$

Where:

kW_{door} = Connected load kW of a typical reach-in cooler or freezer door with a heater

BF = Bonus factor for reducing cooling load from eliminating heat generated by the door heater from entering the cooler or freezer

8760 = Annual operating hours

Table 126: Assumptions for Savings Calculations

Variable	Deemed Values
kW_{door}[288]	Cooler: 0.075 Freezer: 0.200
BF[289]	Low-Temp Freezer: 1.3 Medium-Temp Cooler: 1.2 High-Temp Cooler: 1.1

C.4.4.5. Deemed Savings Values

Table 127: Zero Energy Doors – Deemed Savings Values (per door)[290]

Measure	kWh Savings	kW Savings	Measure
Low-Temperature Freezer (< 25°F)	2,278	0.26	Low-Temperature Freezer (< 25°F)
Medium-Temperature Cooler (25° - 40°F)	2,102	0.24	Medium-Temperature Cooler (25° - 40°F)
High-Temperature Cooler (41° - 65°F)	723	0.08	High-Temperature Cooler (41° - 65°F)

C.4.4.6. Incremental Cost

The incremental cost is $290 per door.[291]

C.4.4.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. If this measure is added to Energy Smart, ADM recommends a baseline study to capture the market share of ASH-controlled doors versus uncontrolled doors.

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[288] Based on range of wattages from two manufacturers and metered data (cooler 50-130W, freezer 200-320W). Efficiency Vermont Commercial Master Technical Reference Manual No. 2005-37.

[289] Bonus factor (1+0.65/COP) assumes 2.0 COP for low temp, 3.5 COP for medium temp, and 5.4 COP for high temp, based on the average of standard reciprocating and discuss compressor efficiencies with Saturated Suction Temperatures of -20ºF, 20ºF, and 45ºF, respectively, and a condensing temperature of 90ºF, and manufacturers assumption that 65% of heat generated by door enters the refrigerated case. Efficiency Vermont Commercial Master Technical Reference Manual No. 2005-37.

[290] Temperature ranges based on Commercial Refrigeration Rebate Form, p, 3. Efficiency Vermont. https://www.efficiencyvermont.com/Media/Default/docs/rebates/forms/efficiency-vermont-commercial-refrigeration-rebate-form.pdf.

[291] Vermont TRM

C.4.5. Evaporator Fan Controls

C.4.5.1. Measure Description

This measure applies to the installation of evaporator fan controls. As walk-in cooler and freezer evaporators often run continuously, this measure consists of a control system that turns the fan on only when the unit's thermostat is calling for the compressor to operate.

C.4.5.2. Baseline and Efficiency Standards

The baseline standard for this measure is an existing shaded pole evaporator fan motor with no temperature controls with 8,760 annual operating hours.

The efficiency standard for this measure is an energy management system (EMS) or other electronic controls to modulate evaporator fan operation based on temperature of the refrigerated space.

C.4.5.3. Estimated Useful Life (EUL)

According to the California Database of Energy Efficiency Resources (DEER 2014), evaporator fan controls are assigned an EUL of 16 years.[292]

C.4.5.4. Calculation of Deemed Savings

The energy savings from the installation of evaporator fan controls are a result of savings due to the reduction in operation of the fan. The energy and demand savings are calculated using the following equations:

$$kW_{savings} = \left[\left(kW_{evap} \times n_{fans}\right) - kW_{circ}\right] \times \left(1 - DC_{comp}\right) \times DC_{evap} \times BF$$

$$kWh_{savings} = kW_{savings} \times 8760$$

Where:

kW_{evap} = Nameplate connected load kW of each evaporator fan = 0.123 kW (default) [293]

kW_{circ} = Nameplate connected load kW of the circulating fan = 0.035 kW (default) [294]

n_{fans} = Number of evaporator fans

DC_{comp} = Duty cycle of the compressor = 50% (default) [295]

DC_{evap} = Duty cycle of the evaporator fan = Coolers: 100%; Freezers: 94% (default) [296]

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[292] Database for Energy Efficient Resources (2014). http://www.deeresources.com/.

[293] Based on a weighted average of 80% shaded pole motors at 132 watts and 20% PSC motors at 88 watts.

[294] Wattage of fan used by Freeaire and Cooltrol.

[295] A 50% duty cycle is assumed based on examination of duty cycle assumptions from Richard Traverse (35%-65%), Control (35%-65%), Natural Cool (70%), Pacific Gas & Electric (58%). Also, manufacturers typically size equipment with a built-in 67% duty factor and contractors typically add another 25% safety factor, which results in a 50% overall duty factor.

BF = Bonus factor for reducing cooling load from replacing the evaporator fan with a lower wattage circulating fan when the compressor is not running = Low Temp.: 1.5, Medium Temp.: 1.3, High Temp.: 1.2 (default) [297]

8760 = Annual hours per year

C.4.5.5. Incremental Cost

The incremental cost is $291 per unit[298].

C.4.5.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure had low participation in Energy Smart programs. As a result, savings are calculated using weather-adjusted default values from other programs. If participation exceeds 500,000 kWh, the evaluation should include a metering study to support energy savings estimates.

[296] An evaporator fan in a cooler runs all the time, but a freezer only runs 8273 hours per year due to defrost cycles (4 20-min defrost cycles per day).

[297] Bonus factor (1+1/COP) assumes 2.0 COP for low temp, 3.5 COP for medium temp, and 5.4 COP for high temp, based on the average of standard reciprocating and discus compressor efficiencies with Saturated Suction Temperatures of -20°F, 20°F, and 45°F, respectively, and a condensing temperature of 90°F.

[298] CA DEER 2014

C.4.6. Beverage and Snack Machine Controls

C.4.6.1. Measure Description

This measure involves the installation of a beverage or snack machine control on an existing refrigerated beverage vending machine, refrigerated glass-front reach-in cooler, or non-refrigerated snack machine with a lighted display and no existing controls. Applicable control types include occupancy or schedule-based controls installed on the unit that will reduce energy consumption by powering down the refrigeration and lighting systems when the control does not detect human activity and by reducing the refrigeration process, while still maintaining product quality.

C.4.6.2. Baseline and Efficiency Standards

The baseline for this measure is an existing 120-volt single phase refrigerated or non-refrigerated beverage vending machine, refrigerated reach-in cooler, or non-refrigerated snack machine with a lighted display and no existing controls. Current federal regulations specify that refrigerated bottled or canned beverage vending machines manufactured on or after August 31, 2012 must meet increased energy conservation standards.[299,300] Therefore, any vending machine occupancy controls installed on refrigerated beverage vending machines must be installed on machines that were manufactured and purchased before August 31, 2012 to be eligible for this measure.

C.4.6.3. Estimated Useful Life (EUL)

The estimated useful life (EUL) for this measure for occupancy-based vending controls is five years.[301] The EUL for schedule-based controls is ten years.[302]

C.4.6.4. Calculation of Deemed Savings

C.4.6.4.1. Energy Savings

The following energy savings estimates align conservatively with various other vending miser energy savings studies.[303,304,305] Additionally, in comparing to savings calculation

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[299] U.S. DOE. Refrigerated Beverage Vending Machines: Standards and Test Procedures. http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/24.

[300] Refrigerated bottled or canned beverage vending machines manufactured on or after August 31, 2012 must meet the energy conservation standards specified in the Code of Federal Regulations, 10 CFR 421.296. http://www.gpo.gov/fdsys/pkg/CFR-2012-title10-vol3/pdf/CFR-2012-title10-vol3-sec431-292.pdf

[301] Database for Energy Efficiency Resources (DEER) 2014. Used value specified for Vending Machine Controllers.

[302] Energy & Resource Solutions (ERS), "Measure Life Study". Prepared for the Massachusetts Joint Utilities. November 17, 2005. Used median value specified for Novelty Cooler Shutoff.

[303] Deru, M., et. al. 2003, "*Analysis of NREL Cold-Drink Vending Machines for Energy Savings*". June. National Renewable Energy Laboratory (NREL). http://www.nrel.gov/docs/fy03osti/34008.pdf

methodologies for schedule-based controls from other TRMs, the energy savings factors defined in this measure produce energy savings that are more in line with expected savings percentages. This is likely due to the exclusion of a morning start-up penalty, used to represent the additional energy required to return to typical operating temperatures, from some TRMs.[306]

$$kWh_{Savings} = W_{CL} \times \frac{1\,kW}{1000\,W} \times AOH \times\ ESF$$

Where:

W_{CL} = Connected load of controlled beverage or snack machine; if unknown, use default values from Table 127.

AOH = Annual Operating Hours = 8,760 hours for occupancy-based controls; for schedule-based controls, assume one less hour than the number of hours that the installation location is closed per day

ESF = *Energy Savings Factor from Table 128*

Table 128: Default Connected Load by Machine Type

Machine Type	***Connected Load (W)***
Refrigerated beverage vending machine	400
Refrigerated glass-front reach-in cooler	460
Non-refrigerated snack vending machine	85

Table 129: Energy Savings Factor by Machine Type[307]

Machine Type	***ESF***
Refrigerated beverage vending machine	46%
Refrigerated glass-front reach-in cooler	30%
Non-refrigerated snack vending machine	46%

[304] Foster-Miller, Inc., "Vending Machine Energy Efficiency Device Engineering Evaluation and Test Report". June 1, 2000. Bayview Technology Group, Inc. http://www.energymisers.com/downloads/FosterMillerReportVMEnergyNoCover.pdf

[305] Ritter, J & Hugghins, J. 2000 Joel Hugghins, "Vending Machine Energy Consumption and Vending Miser Evaluation". October 31. Texas A&M Energy Systems Laboratory. http://repository.tamu.edu/bitstream/handle/1969.1/2006/ESL-TR-00-11-01.pdf

[306] Select Energy Services, Inc., "Analysis of Cooler Control Energy Conservation Measures: Final Report. March 3, 2004. Submitted to NSTAR Electric.

[307] Product data sheets from USA Technologies, Inc. http://www.energymisers.com.

C.4.6.4.2. Demand Savings

Metered data from a Sacramento Municipal Utility District (SMUD) program evaluation found an average demand impact of 0.030 kW/unit using a peak definition of 2 PM to 6 PM.[308] This impact equates to a 7.5% demand reduction, using the USA Technologies, Inc. controlled load estimate of 400 W for refrigerated beverage vending machines. Assuming a comparable load reduction for other equipment types, this measure estimates an average demand impact of 0.035 kW/unit for refrigerated reach-in coolers and 0.006 kW/unit for non-refrigerated snack vending machines.

No demand savings are claimed for schedule-based beverage and snack machine controls because energy savings typically occur during off-peak hours.

$$kW_{Savings} = W_{CL} \times \frac{1\ kW}{1000\ W} \times DSF$$

Where:

W_{CL} = Connected load of controlled beverage or snack machine; if unknown, use default values from Table 127.

DSF = Demand Savings Factor = 7.5% (occupancy controls); 0% (schedule controls)

C.4.6.5. Deemed Savings Values

Table 130: Occupancy-based Controls – Energy and Demand Savings by Machine Type

Machine Type	Annual Energy Savings (kWh/unit)	Peak Demand Savings (kW/unit)
Refrigerated beverage vending machine	1,612	0.030
Refrigerated glass-front reach-in cooler	1,209	0.035
Non-refrigerated snack vending machine	343	0.006

[308] Chappell, C., et. al. 2002 "Does It Keep The Drinks Cold and Reduce Peak Demand?: An Evaluation of a Vending Machine Control Program". Heschong Mahone Group, Sacramento Municipal Utility District (SMUD), RLW Analytics, Inc., and American Council for an Energy-Efficient Economy (ACEEE). http://aceee.org/proceedings-paper/ss02/panel10/paper05

Table 131: Schedule-based Controls – Energy and Demand Savings by Machine Type

Machine Type	Annual Energy Savings (kWh/unit)	Peak Demand Savings (kW/unit)
Refrigerated beverage vending machine	Use energy savings algorithms with site-specific annual operating hours	0
Refrigerated glass-front reach-in cooler		0
Non-refrigerated snack vending machine		0

C.4.6.6. Incremental Cost

Full measure cost should be used. If not available use $180 for refrigerated machines and $80 for non-refrigerated machines[309].

C.4.6.7. Future Studies

This measure has received significant metering in support of its California DEER savings estimate, and ADM has concluded that metering for New Orleans units would not add value to the precision of these savings estimates. Savings should be updated to correspond to CA DEER.

309 Illinois TRM, based on ComEd workpapers

C.4.7. Commercial Ice Makers

C.4.7.1. Measure Description

This measure applies to ENERGY STAR® air-cooled commercial ice makers in retrofit and new construction applications. Commercial ice makers are classified as either of two equipment types: batch type (also known as cube-type) and continuous type (also known as nugget or flakers). Both of these equipment types are eligible for ENERGY STAR® certification based on their configuration as ice-making heads (IMHs), remote condensing units (RCUs) and self-contained units (SCUs). Also eligible are remote condensing units designed for connection to a remote condenser rack.

The industry standard for energy and potable water use and performance of commercial ice makers is the Department of Energy (DOE) Standard 10 CFR Part 431 Subpart H[310] and AHRI Standard 810. Key parameters reported for ice makers include the Equipment Type, Harvest Rate (lbs. of ice/24hrs) and Energy Consumption Rate (kWh/100lbs of ice). The AHRI Directory of Certified Equipment[311] lists these values by equipment manufacturer and model number.

C.4.7.2. Baseline and Efficiency Standards

The ENERGY STAR®[312] criteria for ice makers define efficiency requirements for both energy and potable water use. The baseline standard for batch ice makers are current federal minimum levels that went into effect January 1, 2010. DOE recently published "trial" baseline levels for continuous ice makers.[313] Baseline and efficiency standards should be reviewed on an annual basis to reflect the latest requirements.

[310] 10 CFR Part 431 Subpart H, Automatic Commercial Ice Makers. 77 FR 1591. January 11, 2012.

[311] http://www.ahridirectory.org/ahridirectory/pages/acim/defaultSearch.aspx

[312] ENERGY STAR® Commercial Ice Makers Version 2.0, effective on February 1, 2013.

[313] U.S. DOE Report on Automatic Commercial Ice Machines (ACIM) on baseline values, http://www1.eere.energy.gov/buildings/appliance_standards/pdfs/acim_preliminary_tsd_ch5_engineering_2012_01_16.pdf

Table 132: Federal Minimum Standards for Air-Cooled Batch Ice Makers (H=Harvest Rate)

Equipment Type	Ice Harvest Rate (H) Range (lbs of ice/24 hrs)	Batch Ice Makers Energy Consumption Rate (kWh/100 lbs ice)
Ice Making Heads	<450	10.26 - 0.0086H
	≥450	6.89 - 0.0011H
Remote Condensing Units (w/out remote compressor)	<1,000	8.85 - 0.0038H
	≥1,000	5.1
Remote Condensing Units (w/ remote compressor)	<934	8.85 - 0.0038H
	≥934	5.3
Self-Contained Units	<175	18.0 - 0.0469H
	≥175	9.8

Table 133: DOE Trial Baseline Efficiency Levels for Air-Cooled Continuous Ice Makers (H=Harvest Rate)

Equipment Type	Ice Harvest Rate (H) Range (lbs. of ice/24 hrs.)	Batch Ice Makers Energy Consumption Rate (kWh/100 lbs. ice)
Ice Making Heads	<450	10.3 - 0.004H
	≥450	6.3
Remote Condensing Units (w/out remote compressor)	<1,000	9.5 - 0.004H
	≥1,000	5.5
Self-Contained Units	<175	18.0 - 0.0469H
	≥175	9.8

Table 134: ENERGY STAR® Requirements for Air-Cooled Batch Ice Makers (H = Harvest Rate)

Equipment Type	Ice Harvest Rate (H) Range (lbs. of ice/24 hrs.)	Batch Ice Makers Energy Consumption Rate (kWh/100 lbs ice)	Portable Water Use (gal/100 lbs. ice)
Ice Making Heads	<200 ≤ H ≤1600	$\leq 37.72 * H^{-0.298}$	≤20
Remote Condensing Units	<200 ≤ H ≤1600	$\leq 22.95 * H^{-0.258} + 1.00$	≤20
	<1600 ≤ H ≤4000	≤ -0.00011 * H + 4.60	
Self-Contained Units	<50 ≤ H ≤450	$\leq 48.66 * H^{-0.326 + 0.08}$	≤25

Table 135: ENERGY STAR® Requirements for Air-Cooled Continuous Ice Makers (H = Harvest Rate)

Equipment Type	Continuous Ice Makers Energy Consumption Rate (kWh/100 lbs. ice)	Portable Water Use (gal/100 lbs. ice)
Ice Making Heads	$\leq 9.18 * H^{-0.057}$	≤15
Remote Condensing Units	$\leq 6.00 * H^{-0.162} + 3.50$	≤15
Self-Contained Units	$\leq 59.45 * H^{-0.349} + 0.08$	≤15

C.4.7.3. Estimated Useful Life (EUL)

DEER 2011 database shows an estimated useful life (EUL) of 10 years for commercial ice makers.

C.4.7.4. Calculation of Deemed Savings

Annual electric savings can be calculated by determining the energy consumed for baseline ice makers compared against the energy consumed by the qualifying ENERGY STAR®[314] product using the harvest rate of the more efficient unit.

Peak demand savings can then be derived from the electric savings.

[314] As of July 19,2013 the ENERGY STAR® calculator has not been updated to reflect new efficiency levels adopted in February 1, 2013. Deemed savings should be calculated as described here.

$$\Delta kWh = \frac{\text{kWh base, per100lb} - \text{kWhee, per100lb}}{100} \times DC \times H \times 365$$

$$\Delta kW = \left(\frac{\Delta kWh}{HRS}\right) \times CF$$

Where:

ΔkWh = Annual energy savings

kWhbase,per100lb = Calculated based on the harvest rate and type of ice machine from the Federal Minimum Energy Consumption Rate relationships in Table 132: Federal Minimum Standards for Air-Cooled Batch Ice Makers

kWhee,per100lb = Qualifying energy efficient model consumption found in the AHRI directory of certified products by model information.; use the equations in AHRI Table 3 and Table 4 to qualify products be deriving the maximum efficiency performance level[315]

100 = conversion factor to convert kWhbase,per100lb and kWhee,per100lb into maximum kWh consumption per pound of ice

DC = Duty Cycle of the ice maker representing the percentage of time the ice machine is making ice = 0.50[316]

H = Harvest Rate[317] (lbs of ice made per day)

365 = days per year

HRS = Annual operating hours = 365 × 24 = 8760 hours/year

CF = 1.0[318]

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[315] AHRI Directory of Certified Automatic Commercial Ice Cube Machines (ACIM) can be found at http://www.ahridirectory.org/ahridirectory/pages/home.aspx.

[316] TRM assumptions from Vermont, Pennsylvania and Ohio use 40%, Wisconsin uses 50% and Ameren Missouri uses 75% (similar to ENERGY STAR® Commercial Kitchen Equipment Savings Calculator). A field study in California indicated an average duty cycle of 57% ("A Field Study to Characterize Water and Energy Use of Commercial Ice-Cube Machines and Quantify Saving Potential", Food Service Technology Center, December 2007). Conservative approach is to use 40%.

[317] Harvest Rate for all Ice Machines tested in accordance to AHRI 810-2007can be found at http://www.ahridirectory.org/ahridirectory/pages/home.aspx

[318] A New England study, *"Coincidence Factor Study for Residential and Commercial Industrial Lighting Measures", RLW Analytics,* Spring 2007 shows a CF of 0.775 for restaurants; California uses 0.9, Ameren Missouri and Wisconsin uses 1.0. Due to the applicability of this measure in other building types, 1.0 will be used.

C.4.7.5. Example Savings Calculations

Savings calculations for varying Harvest Rates (H) can be seen below based on the ice maker equipment type. The examples below are assuming the energy efficient commercial ice maker as having an energy usage at the ENERGY STAR® level. Actual energy usage can be found on the AHRI directory of certified products.

Table 136: Savings Calculation for Different Qualifying Types of Energy Efficient Commercial Ice Makers

Performance	Batch Type			Continuous Type		
	SCU	IMH	RCU	SCU	IMH	RCU
Ice Harvest Rate (lbs. per day)	150	200	750	150	200	750
Baseline Energy Usage (kWh/100lbs)	10.97	8.54	6	10.97	9.5	6.5
ENERGY STAR® Qualifying Energy Usage (kWh/100lbs)	9.58	7.78	5.16	10.42	6.79	5.55
Baseline Daily Consumption (kWh)	6.58	6.83	18	6.58	7.6	19.5
EE Daily Consumption (kWh)	5.75	6.22	15.48	6.25	5.43	16.66
Baseline Annual Consumption (kWh/yr.)	2,401	2,494	6,570	2,401	2,774	7,118
EE Annual Consumption (kWh/yr.)	2,098	2,271	5,649	2,283	1,982	6,081
Baseline Demand (kW)	0.27	0.28	0.75	0.27	0.32	0.81
EE Demand (kW)	0.24	0.26	0.64	0.26	0.23	0.69

Annual Energy Savings (kWh/yr.)	303	223	921	118	792	1,037
Estimated Demand Savings (kW)	0.03	0.03	0.11	0.01	0.09	0.12

C.4.7.6. Incremental Cost

Incremental costs are presented in Table 137[319]

Table 137: Commercial Icemaker Incremental costs

Harvest Rate	*Incremental Cost*
100-200 lbs.	$296
201-300 lbs.	$312
301-400 lbs.	$559
401-500 lbs.	$981
501-1,000 lbs.	$1,485
1,001-1,500 lbs.	$1,821
>1,500 lbs.	$2,194

C.4.7.1. Future Studies

This measure applies known values from ENERGY STAR; ADM does not recommend focused study for this measure. Parameters should be updated to correspond to the most recent ENERGY STAR specification.

[319] These values are from electronic work papers prepared in support of San Diego Gas & Electric's "Application for Approval of Electric and Gas Energy Efficiency Programs and Budgets for Years 2009-2011", SDGE, March 2, 2009. Accessed on 7/7/10 <http://www.sdge.com/regulatory/documents/ee2009-2011Workpapers/SW-ComB/Food%20Service/Food%20Service%20Electic%20Measure%20Workpapers%2011-08-05.DOC>.

C.5. Food Service

C.5.1. Commercial Griddles

C.5.1.1. Measure Description

This measure applies to ENERGY STAR® or its equivalent natural gas and electric commercial griddles in retrofit and new construction applications. This appliance is designed for cooking food in oil or its own juices by direct contact with either a flat, smooth, hot surface or a hot channeled cooking surface where plate temperature is thermostatically controlled.

Energy-efficient commercial electric griddles reduce energy consumption primarily through application of advanced controls and improved temperature uniformity. Energy efficient commercial gas griddles reduce energy consumption primarily through advanced burner design and controls.

C.5.1.2. Baseline and Efficiency Standards

Key parameters for defining griddle efficiency are Heavy Load Cooking Energy Efficiency and Idle Energy Rate. There are currently no federal minimum standards for Commercial Griddles, however, the American Society of Testing and Materials (ASTM) publishes Test Methods[320] that allow uniform procedures to be applied to each commercial cooking appliance for a fair comparison of performance results.

ENERGY STAR® efficiency requirements apply to single and double-sided griddles. The ENERGY STAR® criteria should be reviewed on an annual basis to reflect the latest requirements.

Table 138: ENERGY STAR® Criteria[321] for Electric and Gas Single and Double Sided Griddles

Performance Parameters	***Electric Griddles***
Heavy-Load Cooking Energy Efficiency	≥70%
Idle Energy Rate	≤320 watts per ft^2

[320] The industry standard for energy use and cooking performance of griddles are ASTM F1275-03: Standard Test Method for the Performance of Griddles and ASTM F1605-01: Standard Test Method for the Performance of Double-Sided Griddles

[321] ENERGY STAR® Commercial Griddles Program Requirements Version 1.1, effective May 2009 for gas griddles and effective January 1, 2011 for electric.

C.5.1.3. Estimated Useful Life (EUL)

According to DEER 2008, commercial griddles are assigned an estimated useful life (EUL) of 12 years.[322]

C.5.1.4. Calculation of Deemed Savings

Annual savings can be calculated by determining the energy consumed by a standard efficiency griddle as compared with an ENERGY STAR® rated griddle.

For electric savings,

$$\Delta \text{kWh} = \text{kWhbase} - \text{kWheff}$$

$$\text{kWh(base or eff)} = \text{kWhcooking} + \text{kWhidle} + \text{kWhpreheat}$$

$$\text{kWhcooking} = \left(\text{LBfood} \times \frac{\text{Efood}}{\text{CookEff}}\right) \times \text{Days}$$

$$\text{kWhidle} = \text{IdleEnergy} \times \left(\text{DailyHrs} - \frac{\text{LBfood}}{\text{Capacity}} - \frac{\text{PreheatTime}}{60}\right) \times \text{Days}$$

$$\text{kWhpreheat} = \text{PreheatEnergy} \times \text{Days}$$

Key parameters used to compute savings are defined in Table 139.

Table 139: Energy Consumption Related Parameters for Commercial Griddles[323]

[322] Database for Energy Efficient Resources, 2008, http://www.deeresources.com/deer0911planning/downloads/EUL_Summary_10-1-08.xls

Parameter	Description	Value	Source
Daily Hrs	Daily Operating Hours	12 hours	FSTC
Preheat Time	Time to Preheat (Min)	15 Minutes	FSTC
E_{food}	ASTM defined Energy to Food	0.139 kWh/lb, 475 Btu/ib	FSTC
Days	Number of Days of operation	365 Days	FSTC
CookEff	Cooking Energy Efficiency (%)	For Electric, see Table 414 For Gas, see Table 415	FSTC
IdleEnergy	Idle energy rate (kW), (Btu/h)		FSTC, ENERGY STAR®
Capacity	Production capacity (lbs/hr)		FSTC
Preheat Energy	kWh/day, Btu/day		FSTC
LB_{Food}	Food cooked per day (lb/day)		FSTC

General assumptions used for deriving deemed electric and gas savings are values are taken from the Food Service Technology Center (FSTC) work papers.[324] These deemed values assume that the griddles are 3 x 2 feet in size. Parameters in the table are per linear foot, with an assumed depth of 2 feet.

Table 140: Baseline and Efficient Assumptions for Electric Griddles

[323] Assumptions based on PG&E Commercial Griddles Work Paper developed by FSTC, May 22, 2012.

[324] FSTC food service equipment work papers submitted to CPUC for Energy Efficiency 2013-2014 Portfolio; document titled EnergyEfficiency2013-2014-Portfolio_Test_PGE_20120702_242194.zip

https://www.pge.com/regulation/EnergyEfficiency2013-2014-Portfolio/Testimony/PGE/2012/EnergyEfficiency2013-2014-Portfolio_Test_PGE_20120702_242194.zip.

Parameter	*Baseline Electric Griddles*	*Efficient Electric Griddles*
Preheat Energy (kWh/ft)	1.33	0.67
Idle Energy Rate (kW/ft)	0.8	0.64
Cooking Energy Efficiency (%)	65%	70%
Production Capacity (lbs/h/ft)	11.7	16.33
Lbs of food cooked/day/ft	33.33	33.33

Peak Demand Savings can be derived by dividing the annual energy savings by the operating Equivalent hours and multiplying by the Coincidence Factor.

$$\Delta \mathrm{kW} = \left(\frac{\Delta \mathrm{kWh}}{\mathrm{HOURS}}\right) \times \mathrm{CF}$$

Where:

ΔkWh = Annual energy savings (kWh)

4380 = Operating Equivalent hours = 365 x 12 = 4380 hours

0.84[325] = Coincidence Factor (CF)

C.5.1.5. Deemed Savings Values

Deemed savings based on the assumptions above are tabulated below per griddle, per linear foot.

Table 141: Deemed Savings for Electric and Gas Commercial Griddles per Linear Foot

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[325] Coincidence factors utilized in other jurisdictions for Commercial Griddles vary from 0.84 to 1.0. The KEMA report titled "Business Programs: Deemed Savings Parameter Development," November 2009 conducted for Wisconsin Focus on Energy lists Coincidence Factors by building type and identifies food service at 0.84.

Measure Description	Deemed Savings per Griddle per linear foot	
	kW	kWh
Griddle, Electric, ENERGY STAR®	0.15	758

C.5.1.6. Incremental Cost

The incremental cost is $60 per linear foot of width of the unit[326].

C.5.1.7. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values from FSTC. If this measure is added to Energy Smart programs, the evaluation should include an assessment of actual usage schedules to replace the default FSTC schedule values.

[326] Measure cost from ENERGY STAR which cites reference as "EPA research on available models using AutoQuotes, 2010" http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=COG

C.5.2. Convection Ovens

C.5.2.1. Measure Description

High efficiency ovens exhibit better baking uniformity and higher production capacities while also including high-quality components and controls.

C.5.2.2. Estimated Useful Life (EUL)

According to the California Database of Energy Efficiency Resources (DEER 2008), all commercial ovens are assigned an estimated useful life (EUL) of 12 years.[327]

C.5.2.3. Baseline and Efficiency Standards

Efficient convection ovens are defined by ENERGY STAR® or its equivalent and apply to electric full-size and half-size convection ovens and gas full-size convection ovens. Full size ovens accept a minimum of five pans measuring 18 x 26 x 1-inch. Half size ovens accept a minimum of five sheet pans measuring 18 x 13 x 1-inch. The ENERGY STAR® criteria should be reviewed on an annual basis to reflect the latest requirements.

There are currently no federal minimum standards for Commercial Convection Ovens, however, the American Society of Testing and Materials (ASTM) publishes Test Methods[328] that allow uniform procedures to be applied to each commercial cooking appliance for a fair comparison of performance results.

Table 142: ENERGY STAR® Criteria for Electric Convection Ovens[329]

Performance Parameters	***Half Size Electric Ovens***	***Full Size Electric Ovens***
Heavy-Load Cooking Energy Efficiency	≥71%	≥71%
Idle Energy Rate	≤1.0 kW	≤1.6 kW

[327] Database for Energy Efficient Resources, 2008, http://www.deeresources.com/deer0911planning/downloads/EUL_Summary_10-1-08.xls

[328] The industry standard for energy use and cooking performance of convection ovens is ASTM F-2861-10, Standard Test Method for Enhanced Performance of Combination Oven in Various Modes.

[329] ENERGY STAR® Commercial Ovens Version 1.1, effective May 2009; Version 2.0 is currently under development to be releas`qed by 2013. New efficiency levels will be identified and scope will add Combination Ovens.

C.5.2.4. Calculation of Deemed Savings

Annual savings can be calculated by determining the energy consumed by a standard efficiency convection oven as compared with an ENERGY STAR® rated convection oven.

$$\Delta kWh = kWhbase - kWheff$$

$$kWh(base\ or\ eff) = kWhcooking + kWhidle + kWhpreheat$$

$$kWhcooking = \left(LB \times \frac{Efood}{CookEff}\right) \times Days$$

$$kWhidle = IdleEnergy \times \left(DailyHrs - \frac{LB}{Capacity} - \frac{PreheatTime}{60}\right) \times Days$$

$$kWhpreheat = PreheatEnergy \times Days$$

General assumptions in Table 143 are from the ENERGY STAR® Commercial Kitchen Equipment Savings Calculator – Convection Ovens which refers to the Food Service Technology Center (FSTC) work papers and research.[330]

Table 143: Baseline and Efficient Assumptions for Electric Convection Ovens

Parameter	Half Size Electric Ovens		Full Size Electric Ovens	
	Baseline Model	Efficient Model	Baseline Model	Efficient Model
Preheat Energy (kWh/ft)	1	0.9	1.5	1
Idle Energy Rate (kW/ft)	1.5	1	2	1.6
Cooking Energy Efficiency (%)	65%	71%	65%	71%
Production Capacity (lbs/h/ft)	45	50	70	80
Lbs of food cooked/day/ft	100	100	100	100
Efood (kWh/lb)	0.0732	0.0732	0.0732	0.0732

330 FSTC food service equipment work papers submitted to CPUC for Energy Efficiency 2013-2014 Portfolio; document titled EnergyEfficiency2013-2014-Portfolio_Test_PGE_20120702_242194.zip

Peak Demand Savings can be derived by dividing the annual energy savings by the operating Equivalent hours and multiplying by the Coincidence Factor.

$$\Delta kW = \left(\frac{\Delta kWh}{HOURS}\right) \times CF$$

Where:

ΔkWh = Annual energy savings (kWh)

$HOURS$ = Operating Equivalent hours = 365 x 12 = 4,380 hours[331]

CF = Coincidence Factor = 0.84[332]

C.5.2.5. Deemed Savings Estimates for Convection Ovens

Deemed savings based on the assumptions above are tabulated below for electric convection ovens.

Table 144: Deemed Savings Estimates for Electric and Gas Convection Ovens

Measure Description	***Deemed Savings per Oven***	
	kW	***kWh***
Half Size Convection Oven, Electric, ENERGY STAR®	0.39	2,042
Half Size Convection Oven, Electric, ENERGY STAR®	0.37	1,933
Half Size Convection Oven, Electric, ENERGY STAR®	0	0

C.5.2.6. Incremental Cost

The incremental cost for this measure is $50.[333]

[331] ENERGY STAR® Commercial Kitchen Equipment Savings Calculator – Convection Ovens assumes an operating time of 12 hours.

[332] KEMA report titled "Business Programs: Deemed Savings Parameter Development," November 2009 conducted for Wisconsin Focus on Energy lists Coincidence Factors by building type and identifies food service at 0.84.

[333] Measure cost from ENERGY STAR which cites reference as "EPA research on available models using AutoQuotes, 2010" http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=COG

C.5.3. Combination Ovens

Combination ("Combi") ovens are convection ovens with a steam cooking mode.

C.5.3.1. Baseline and Efficiency Standards

There are currently no federal minimum standards for Commercial Combination Ovens, however, the American Society of Testing and Materials (ASTM) publishes Test Methods611 that allow uniform procedures to be applied to each commercial cooking appliance for a fair comparison of performance results.

As of January 1, 2014, efficient combination ovens are defined by ENERGY STAR® and apply to both electric and gas ovens. Combination ovens combines the function of hot air convection (oven mode), saturated and superheated steam heating (steam mode), and combination convection/steam mode for moist heating, to perform steaming, baking, roasting, rethermalizing, and proofing of various food products.

Table 145: High Efficiency Requirements for Electric and Gas Combination Ovens by Pan Capacity (P)

Mode	***Idle Rate***	***Cooking Efficiency (%)***
Electric, where P is ≥ 5 and ≤ 20		
Steam Mode	≤ 0.133P + 0.64 kW	≥ 55%
Convection Mode	≤ 0.08P + 0.4989 kW	≥ 76%

C.5.3.2. Calculation of Deemed Savings

Annual savings can be calculated by determining the energy consumed by a standard efficiency combination oven as compared with a high efficiency combination oven.

For electric savings,

$$\Delta kWh = kWhtotal, base - kWhtotal, eff$$

$$kWh(total, base\ or\ total, eff) = kWhoven + kWhsteam + kWhpreheat$$

$$kWh(oven\ or\ steam) = kWhcooking + kWhidle$$

$$kWhcooking\ (oven\ or\ steam) = (LBoven\ or\ steam \times \frac{Efood}{\text{CookEff}}) \times Days$$

Where $LB_{ove}n$ = LB × (1-% Steam) and LB_{steam} = LB × % Steam

$$kWhidle(oven) = (1 - \%Steam) \times IdleEnergy \times (DailyHrs - LBovenCapacity - nP \times PreheatTime60) \times Days$$

$$kWhidle(steam) = (\%Steam) \times IdleEnergy \times (DailyHrs - LBsteamCapacity - np \times PreheatTime60) \times Days$$

$$kWhpreheat = nP \times PreheatEnergy \times Days$$

Key parameters used to compute savings are listed in Table 430, Table 431, and Table 432.

Table 146: Energy Consumption Related Parameters for Commercial Combination Ovens

Parameter	***Description***	***Value***	***Source/Approach***
Daily Hrs	Daily Operating Hours	12 hours	ENERGY STAR® Commercial Kitchen Equipment Calculator
Preheat Time	Time to Preheat (Min)	15 min	FSTC Life Cycle & Energy Cost Calculator
nP	Number of Preheats per Day	1/day	FSTC Life Cycle & Energy Cost Calculator
$E_{food,oven}$	ASTM defined Energy to Food for Convection Ovens	0.0732 kWh/lb	ASTM
$E_{food,steam}$	ASTM defined Energy to Food for Steam Cookers	0.0308 kWh.lb,	ASTM
Days	Number of day of operation	365 days	ENERGY STAR® Commercial Kitchen Equipment Calculator
% Steam	Percent of time in Steam Mode	50%	ENERGY STAR® Commercial Kitchen Equipment Calculator
CookEff	Cooking energy efficiency (%)	See Table 147	Baseline: Average from ENERGY STAR® and FSTC Calculators[334]
IdleEnergy	Idle energy rate (kW),		

[334] Baseline cooking efficiencies and idle energy rates were averaged between the ENERGY STAR® Food Service Appliance Calculator and the FSTC food service life cycle cost calculator.

	(Btu/h)		
Capacity	Production capacity (lbs/hr)		Average from ENERGY STAR® Qualifying Products Listing
Preheat Energy	kWh/day, Btu/day		FSTC Life Cycle & Energy Cost Calculator ENERGY STAR® Products Listing
$LB_{oven,steam}$	Food cooked per day (lb/day) in steam mode or oven mode		ENERGY STAR® Commercial Kitchen Equipment Calculator

General assumptions used for deriving deemed electric and gas savings are defined in the following tables. These values were taken from the ENERGY STAR® Food Service Appliance Calculator as well as the Food Service Technology Center (FSTC) Life Cycle and Energy Cost Calculator.

C.5.3.3. Incremental Cost

The incremental cost is $800[335].

C.5.3.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values from FSTC. If this measure is added to Energy Smart programs, the evaluation should include an assessment of actual usage schedules to replace the default FSTC schedule values.

[335] ENERGY STAR Commercial Food Service Calculator

C.5.4. Commercial Fryers

C.5.4.1. Measure Description

This measure applies to ENERGY STAR® or its equivalent electric commercial open-deep fat fryers in retrofit and new construction applications. Commercial fryers consist of a reservoir of cooking oil that allows food to be fully submerged without touching the bottom of the vessel. Electric fryers use a heating element immersed in the cooking oil.

High efficiency standard and large vat fryers offer shorter cook times and higher production rates through the use of advanced burner and heat exchanger design. Standby losses are reduced in more efficient models through the use of fry pot insulation.

C.5.4.2. Baseline & Efficiency Standard

Key parameters for defining fryer efficiency are Heavy Load Cooking Energy Efficiency and Idle Energy Rate. ENERGY STAR® requirements apply to a standard fryer and a large vat fryer. A standard fryer measures 14 to 18 inches wide with a vat capacity from 25 to 60 pounds. A large vat fryer measures 18 inches to 24 inches wide with a vat capacity greater than 50 pounds. The ENERGY STAR® criteria should be reviewed on an annual basis to reflect the latest requirements.

There are currently no federal minimum standards for Commercial Fryers, however, ASTM publishes Test Methods[336] that allow uniform procedures to be applied to each commercial cooking appliance for a fair comparison of performance results.

Table 147: ENERGY STAR® Criteria[337] and FSTC Baseline for Open Deep-Fat Electric Fryers

Performance Parameters	***ENERGY STAR® Electric Fryer Criteria***	
	Standard Fryers	***Large Vat Fryers***
Heavy-Load Cooking Energy Efficiency	≥ 80%	≥ 80%
Idle Energy Rate	≤ 1.0 kW	≤ 1.1 kW

[336] The industry standards for energy use and cooking performance of fryers are ASTM Standard Test Method for the Performance of Open Deep Fat Fryers (F1361) and ASTM Standard Test Method for the Performance of Large Vat Fryers (FF2144).

[337]

C.5.4.3. Estimated Useful Life (EUL)

According to DEER 2008, commercial fryers are assigned an estimated useful life (EUL) of 12 years.[338]

C.5.4.4. Calculation of Deemed Savings

Annual savings can be calculated by determining the energy consumed by a standard efficiency fryer as compared with an ENERGY STAR® rated fryer.

$$\Delta kWh = kWhbase - kWheff$$

$$kWh(base\ or\ eff) = kWhcooking + kWhidle + kWhpreheat$$

$$kWhcooking = \left(LB \times \frac{Efood}{CookEff}\right) \times Days$$

$$kWhidle = IdleEnergy\ \times \left(DailyHrs - \frac{LB}{Capacity} - \frac{PreheatTime}{60}\right) \times Days$$

$$kWhpreheat = PreheatEnergy\ \times Days$$

Key parameters used to compute savings are defined in Table 148.

Table 148 Energy Consumption Related Parameters for Commercial Fryers[339]

[338] Database for Energy Efficient Resources, 2008, http://www.deeresources.com/deer0911planning/downloads/EUL_Summary_10-1-08.xls

Parameter	*Description*	*Value*	*Source*
Daily Hrs	Daily Operating Hours	12 hours	FSTC
Preheat Time	Time to Preheat (Min)	15 Minutes	FSTC
E_{food}	ASTM defined Energy to Food	0.167 kWh/lb, 570 Btu/ib	FSTC
Days	Number of Days of operation	365 Days	FSTC
CookEff	Cooking Energy Efficiency (%)	For Electric, see Table 437 For Gas, see Table 438	FSTC
IdleEnergy	Idle energy rate (kW), (Btu/h)		FSTC, ENERGY STAR®
Capacity	Production capacity (lbs/hr)		FSTC
Preheat Energy	kWh/day, Btu/day		FSTC
LB	Food cooked per day (lb/day)		FSTC

General assumptions used for deriving deemed electric and gas savings are defined in the following tables. These values are taken from the ENERGY STAR® Commercial Kitchen Equipment Savings Calculator as well as the Food Service Technology Center (FSTC) work papers and research.

Table 149: Baseline and Efficient Assumptions for Electric Standard and Large Vat Fryers

[339] Assumptions based on PG&E Commercial Fryers Work Paper developed by FSTC, June 13, 2012

Parameter	Baseline Electric Fryers		Efficient Electric Fryers	
	Standard	Large Vat	Standard	Large Vat
Preheat Energy (kWh/ft)	2.3	2.5	1.7	2.1
Idle Energy Rate (kW/ft)	1.05	1.35	1	1.1
Cooking Energy Efficiency (%)	75%	70%	80%	80%
Production Capacity (lbs/h/ft)	65	100	70	110
Lbs of food cooked/day/ft	150	150	150	150

Peak Demand Savings can be derived by dividing the annual energy savings by the operating Equivalent hours and multiplying by the Coincidence Factor.

$$\Delta kW = \left(\frac{\Delta kWh}{HOURS}\right) \times CF$$

Where:

ΔkWh = Annual energy savings (kWh)

$HOURS$ = Operating equivalent hours = 365 x 12 = 4,380

CF = Coincidence factor = 0.84[340]

C.5.4.5. Deemed Savings Values

Deemed savings using the assumptions above are tabulated below. These values are per installed unit based on the type of fryer.

Table 150: Deemed Savings per Fryer Vat

Measure Description	Deemed Savings per

[340] Coincidence factors utilized in other jurisdictions for Commercial Fryers vary from 0.84 to 1.0. The KEMA report titled "Business Programs: Deemed Savings Parameter Development," November 2009 conducted for Wisconsin Focus on Energy lists Coincidence Factors by building type and identifies food service at 0.84.

	Fryer Vat	
	kWh	**kW**
Fryer, Electric, ENERGY STAR®	0.2	1,057
Fryer, Large Vat, Electric, ENERGY STAR®	0.51	2,659

C.5.4.6. Incremental Cost

The incremental cost is $1,200[341].

C.5.4.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values from FSTC. If this measure is added to Energy Smart programs, the evaluation should include an assessment of actual usage schedules to replace the default FSTC schedule values.

[341] cost from ENERGY STAR which cites reference as "EPA research on available models using AutoQuotes, 2010" http://www.energystar.gov/index.cfm?fuseaction=find_a_product.showProductGroup&pgw_code=COG

C.5.5. Commercial Steam Cookers

C.5.5.1. Measure Description

This measure applies to ENERGY STAR® or its equivalent electric steam cookers in retrofit and new construction applications. Commercial steam cookers, also known as "compartment steamers," vary in configuration and size based on the number of pans. High efficiency steam cookers offer shorter cook times, higher production rates and reduced heat loss due to better insulation and more efficient steam delivery system.

C.5.5.2. Baseline & Efficiency Standard

Key parameters for defining steam cookers efficiency are Heavy Load Cooking Energy Efficiency and Idle Energy Rate. ENERGY STAR® requirements apply to steam cookers based on the pan capacity. These criteria should be reviewed on an annual basis to reflect the latest ENERGY STAR® requirements.

There are currently no federal minimum standards for Commercial Steam Cookers, however, ASTM publishes Test Methods[342] that allow uniform procedures to be applied to each commercial cooking appliance for a fair comparison of performance results.

Table 151: ENERGY STAR® Criteria for Electric Steam Cookers[343]

Pan Capacity	Cooking Efficiency	Idle Rate (watts)
3-pan	50%	400
4-pan	50%	530
5-pan	50%	670
6-pan and larger	50%	800

Table 152: ENERGY STAR® Criteria for Gas Steam Cookers[344]

Pan Capacity	Cooking Efficiency	Idle Rate (Btu/h)
5-pan	38%	10,400

[342] The industry standard for steam cookers energy use and cooking performance is ASTM Standard F1484-99, Test Method for the Performance of Steam Cookers/

[343] ENERGY STAR® Commercial Steam Cookers Version 1.2, effective August 1, 2003.

[344] ENERGY STAR® provides criteria for 3-pan, 4-pan but availability of products in this range is limited or unavailable.

6-pan and larger	38%	12,500

C.5.5.3. Estimated Useful Life (EUL)

According to DEER 2008, steam cookers are assigned an estimated useful life (EUL) of 12 years.

C.5.5.4. Calculation of Deemed Savings

Energy savings for steam cookers is derived by determining the total energy consumed by standard steam cooker as compared with an ENERGY STAR® rated steam cooker. Total energy for a steam cooker includes the energy used during cooking, the energy used when the equipment is idling, the energy spent when set in a constant steam mode and the energy required during pre-heat.

$$\Delta Energy = Energybase, total - Energyeff, total$$

$$Energy(base, total\ or\ eff, total) = Energycooking + Energyidle + Energysteam + Energypreheat$$

where,

$$Energycooking = LB\ food \times EfoodCook\ Eff \times Days$$

$$Energyidle = (1 - \%Steam) \times IdleEnergy \times \left(DailyHrs - \frac{LBfood}{Capacity} - \frac{PreheatTime}{60}\right) \times Days$$

$$Energysteam = (\%Steam) \times \frac{Capacity \times Efood}{Cook\ Eff} \times \left(DailyHrs - \frac{LBfood}{Capacity} - \frac{PreheatTime}{60}\right) \times Days$$

$$Energypreheat = PreheatEnergy \times Days$$

General assumptions used for deriving deemed electric savings are defined in the following tables. These values are taken from the ENERGY STAR® Commercial Kitchen Equipment Savings Calculator as well as the Food Service Technology Center (FSTC) work papers and research.

Table 153: Energy Consumption Related Parameters for Commercial Steam Cookers

Parameter	***Description***	***Value***	***Source/Approach***
Daily Hrs	Daily Operating Hours	12 hours	FSTC
Preheat Time	Steam Cooker Preheat Time (Min)	15 min	FSTC
E_{food}	ASTM defined Energy to Food	0.0308 kWh/lb, 105 Btu/lb	FSTC
Days	Number of day of operation	365 days	FSTC
CookEff	Cooking energy efficiency (%)	For Electric, see Table 437 For Gas, see Table 438	FSTC
IdleEnergy	Idle energy rate (kW),(Btu/h)		FSTC, ENERGY STAR®
%Steam	Constant Steam energy use		FSTC
Capacity	Production capacity (lb/hr)		ENERGY STAR®
Preheat Energy	kWh/day, Btu/day		ENERGY STAR®
LB_{food}	Food cooked per day (lb/day)		ENERGY STAR®

Table 154: Deemed Savings Assumptions for Electric Steam Cookers

Parameter	***Baseline Model***	***Efficient Electric Model***
Cooking Efficiency (%)	26%	50%
Preheat Energy (Btu)	1.5	1.5
Constant Steam Mode Time (%)	0.9	0.1
Lbs of food Cooked/Day	100	100
Production Capacity (lbs/hr/pan)	23.33	16.67
Idle Energy Rate (kW/pan)	0.33	0.13

Peak Demand Savings can be derived by dividing the annual energy savings by the operating Equivalent hours and multiplying by the Coincidence Factor.

$$\Delta kW = \left(\frac{\Delta kWh}{HOURS}\right) \times CF$$

Where:

ΔkWh = Annual energy savings (kWh)

4380 = Operating Equivalent hours = 365 x 12 = 4380 hours

0.84[345] = Coincidence Factor (CF)

C.5.5.5. Deemed Savings Values

Deemed savings are per installed unit based on the number of pans per steam cooker.

[345] Coincidence factors utilized in other jurisdictions for Commercial Steam Cookers vary from 0.84 to 1.0. The KEMA report titled "Business Programs: Deemed Savings Parameter Development," November 2009 conducted for Wisconsin Focus on Energy lists Coincidence Factors by building type and identifies food service at 0.84.

Table 155: Deemed Savings for Steam Cookers

Measure Description	Deemed Savings	
	kW	kWh
Steam Cooker, Electric, 3-pan - ENERGY STAR®	5.4	28,214
Steam Cooker, Electric, 4-pan - ENERGY STAR®	7.3	38,081
Steam Cooker, Electric, 5-pan - ENERGY STAR®	9.2	47,948
Steam Cooker, Electric, 6-pan - ENERGY STAR®	11.1	57,815

C.5.5.1. Incremental Cost

The incremental cost is $2,490[346].

C.5.5.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. As a result, savings are calculated using default values from FSTC. If this measure is added to Energy Smart programs, the evaluation should include an assessment of actual usage schedules to replace the default FSTC schedule values.

[346] 32Source for efficient electric steamer incremental cost is $2,490 per 2009 PG&E Workpaper - PGECOFST104.1 - Commercial Steam Cooker - Electric and Gas as reference by KEMA in the ComEd C & I TRM.

C.5.6. Low-Flow Pre-Rinse Spray Valves

C.5.6.1. Measure Description

This measure consists of installing low-flow pre-rinse spray valves which reduce hot water use and save energy associated with heating the water. The low-flow pre-rinse spray valves have the same cleaning effect as the existing standard spray valves even though they use less water.

C.5.6.2. Baseline & Efficiency Standard

The savings values for low-flow pre-rinse spray valves are applicable for the retrofit of existing operational pre-rinse spray valves with an average flow rate of 1.9 gallons per minute. This average is based on an assumed combination of pre- and post-2006 PRSVs, which have code requirements of 2.25 and 1.6 GPM, respectively .

The maximum flow rate of qualifying low-flow pre-rinse spray valves is 1.28 gallons per minute.[347]. To qualify for savings the facility must have electric domestic hot water equipment.

C.5.6.3. Estimated Useful Life (EUL)

The effective useful life (EUL) for this measure is 5 years.[348]

C.5.6.4. Calculation of Deemed Savings

Annual gas savings and peak day gas savings can be calculated by using the following equations:

$$\Delta Therms = \frac{\rho \times CP \times U \times (FB - FP) \times (TH - TSupply) \times \frac{1}{Et} \times \frac{Days}{Year}}{100{,}000\ BTU/Therm}$$

$$\Delta Peak\ Therms = \frac{\Delta Therms}{\frac{\text{Days}}{\text{Year}}}$$

Annual kWh electric and peak kW savings can be calculated using the following equations and Table 156 summarizes the needed variables:

$$\Delta kWh = \frac{\rho \times CP \times U \times (FB - FP) \times (TH - TSupply) \times \frac{1}{Et} \times \frac{Days}{Year}}{3412 BTU/kWh}$$

[347] FEMP Performance Requirements for Federal Purchases of Pre-Rinse Spray Valves, Based on ASTM F2324-03: Standard Test Method for Pre-Rinse Spray Valves.

[348] FEMP Purchasing Specification for Energy-Efficiency Products, Pre-Rinse Spray Valves: http://www1.eere.energy.gov/femp/pdfs/pseep_spray_valves.pdf

$$\Delta kW = \frac{\rho \times CP \times U \times (FB - FP) \times (TH - TSupply) \times \frac{1}{Et} \times P}{3412BTU/kWh}$$

Table 156: Variables for the Deemed Savings Algorithm

Parameter	Description	Value
F_B	Average baseline flow rate of sprayer (GPM)	2.25
F_P	Average post measure flow rate of sprayer (GPM)	1.28
Days/Year	Annual Operating Days for the applications: See Table 451 for building type definitions:	
	1. Fast Food Restaurant	365[349]
	2. Casual Dining Restaurant	365
	3.Institutional	365
	4. Dormitory	274[350]
	5. K-12 School	200
T_{supply}	Average supply (cold) water temperature (°F)	74.8
T_H	Average mixed hot water (after spray valve) temperature (°F)	120[351]
U_B	Baseline water usage duration for the following applications:	
	1. Fast Food Restaurant (see Table 451 - small	45 min/day/unit[352]

[349] Osman S &. Koomey, J. G. , . Lawrence Berkeley National Laboratory 1995. *Technology Data Characterizing Water Heating in Commercial Buildings: Application to End-Use Forecasting.* December.

[350]For dormitories with few occupants in the summer: 365 x (9/12) = 274.

[351] According to ASTM F2324 03 Cleanability Test the optimal operating conditions are at 120ºF.

	service)	
	2. Casual Dining Restaurant (see Table 452 - medium service)	105 min/day/unit
	3. Institutional (see Table 452 - large service)	210 min/day/unit
	4. Dormitory (see Table 452 - large service)	210 min/day/unit
	5. K-12 School (see Table 452 - medium service)	105 min/day/unit[353]
ρ	Density of water 8.33 BTU/Gallon	8.33
C_P	Heat capacity of water	1
E_t	Thermal efficiency of water heater	Default value 0.98 for electric and 0.80 for gas
P	Hourly peak demand as a fraction of daily water consumption for the following applications:	
	1. Fast food restaurant (Fast Food)	0.05[354]
	2. Casual Dining Restaurant (Sit Down Rest.)	0.04[355]
	3. Institutional (Nursing Home)	0.03
	4. Dormitory (Sit Down Rest.)	0.04

[352] CEE Commercial Kitchens Initiative Program Guidance on Pre-Rinse Valves.

[353] School mealtime duration is assumed to be half of that of institutions, assuming that institutions (e.g. prisons, university dining halls, hospitals, nursing homes) serve three meals per day at 70 minutes each, and schools serve breakfast to half of the students and lunch to all, yielding 105 minutes per day.

[354] ASHRAE Handbook 2011. HVAC Applications. Chapter 50 –Service Water Heating. American Society of Heating Refrigeration and Air Conditioning Engineers, Inc. (ASHRAE) 2011. ASHRAE, Inc., Atlanta, GA.

[355] Maintenance factor of 0.01 is the average maintenance factor for gas furnaces taken from the October 2010 National Renewable Energy publication “Building America House Simulation Protocols,” Table 30

	5. K-12 School (High School)	0.05

Table 157: Building Type Definitions

Building Type	**Operating Days per Year**	**Representative PRSV Usage Examples**
1. Fast food restaurant	365	Establishments engaged in providing food services where patrons order and pay before eating. These facilities typically use disposable serving ware. PRSV are used for rinsing cooking ware, utensils, trays, etc. Examples: Fast food restaurant, supermarket food preparation and food service area, drive-ins, grills, luncheonettes, sandwich, and snack shops.
2. Casual dining restaurant	365	Establishments primarily engaged in providing food services to customers who order and are served while seated (i.e. waiter/waitress service). These facilities typically use chinaware and use the PRSV to rinse dishes, cooking ware, utensils, trays, etc. Example: Full meal restaurant.
3. Institutional	365	Establishments located in institutional facilities (e.g. nursing homes, hospitals, prisons, military) where food is prepared in large volumes and patrons order food before eating, such as in dining halls and cafeterias. These facilities typically use disposable serving ware and serving trays. PRSVs are used for rinsing cooking ware, utensils, tray, etc. Examples: Nursing home, hospital, prison cafeteria, and military barrack mess hall.
4. Dormitory	274	Establishments located in higher education facilities where food is prepared in large volumes and patrons order food before eating, such as in dining halls and cafeterias. These facilities typically use disposable serving ware and serving trays. PRSVs are used for rinsing cooking ware, utensils, trays, etc. Example:

		University dining halls.
5. K-12 School	200	Establishments located in K-12 schools where food is prepared in large volumes and patrons order food before eating, such as in dining halls and cafeterias. These facilities typically use disposable serving ware and serving trays. PRSVs are used for rinsing cooking ware, utensils, trays, etc. Example: K-12 school cafeterias

Table 158: Daily Operating Hours

Food Service Operation	Min (Min/Day)	Max (Min/Day)	Average (Min/Day)
Small Service (e.g., quick-service restaurants)	30	60	45
Medium Service (e.g., casual dining restaurants)	90	120	105
Large Service (e.g., institutional such as cafeterias in universities, prisons, and nursing homes)	180	240	210

The following are example calculations for a fast food restaurant in New Orleans using the previous equations.

$$\Delta kWh = \frac{8.33\ x\ 45\ minday\ x\ [1.9 - 1.28]GPM\ x\ (120 - 74.8°\mathrm{F})x\ \left(\frac{1}{0.98}\right)\ x\ \frac{365\ days}{year}}{3412\ BTU\ kWh}$$
$$= 1101\ kWh$$

$$\Delta kW = \frac{0.05\ x\ 8.33\ x\ 45\ minday\ x\ (1.9 - 1.28)GPM\ x\ (120 - 74.8°\mathrm{F})\ x\ \left(\frac{1}{0.98}\right)}{3412\ BTU\ kWh} = 0.15\ kW$$

C.5.6.5. Incremental Cost

When available program-actual costs should be used. If unknown, use a default value of \$92.90[356].

C.5.6.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. If this measure is incorporated into Energy Smart, ADM recommends studying the following parameters:

- DHW setpoint;
- Flow rate of installed PRSVs;
- Flow rate of baseline PRSVs (to be collected by the program implementer and sent to ADM for testing).

[356] Average of costs recognized by Ameren Missouri (\$85.8) and KCPL (\$100).

C.6. Commercial Lighting

C.6.1. Light Emitting Diode (LED) Traffic Signals

C.6.1.1. Measure Description

This measure involves the installation of LED traffic signals, typically available in red, yellow, green, and pedestrian format, at a traffic light serving any intersection in retrofit applications. New construction applications are not eligible for this measure, as incandescent traffic signals are not compliant with the current federal standard[357], effective January 1, 2006.

C.6.1.2. Baseline and Efficiency Standards

For all retrofit projects, the baseline is a standard incandescent fixture.

Due to the increased federal standard for traffic signals, the ENERGY STAR® LED Traffic Signal specification was suspended effective May 1, 2007.[358] ENERGY STAR® chose to suspend the specification rather than revise it due to minimal additional savings that would result from a revised specification. Because the ENERGY STAR® specification no longer exists, the efficiency standard is considered to be an equivalent LED fixture for the same application. The equivalent LED fixture must be compliant with the federal standard. There is no current federal standard for yellow "ball" or "arrow" fixtures.

[357] Current federal standards for traffic and pedestrian signals can be found at the DOE website at: http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/32.

[358] Memorandums related to this decision can be found on the ENERGY STAR® website at: https://www.energystar.gov/index.cfm?c=archives.traffic_signal_spec.

Table 159: Federal Standard Maximum Nominal Wattages[359] and Maximum Wattages[360]

Measure	***Nominal Wattage***	***Maximum Wattage***
12” Red Ball	17	11
12” Green Ball	15	15
8” Red Ball	13	8
8” Green Ball	12	12
12” Red Arrow	12	9
8” Green Arrow	11	11
Combination Walking Man/Hand	16	13
Walking Man	12	9
Orange Hand	16	13

Typical incandescent and LED traffic signal fixture wattages can be found in the following table. These fixture wattages should be used in the absence of project specific fixture wattages.

[359] Nominal wattage is defined as power consumed by the module when it is operated within a chamber at a temperature of 25 °C after the signal has been operated for 60 minutes.

[360] Maximum wattage is the wattage at which power consumed by the module after being operated for 60 minutes while mounted in a temperature testing chamber so that the lensed portion of the module is outside the chamber, all portions of the module behind the lens are within the chamber at a temperature of 74 °C, and the air temperature in front of the lens is maintained at a minimum of 49 °C.

Table 160: Incandescent/LED Traffic Signal Fixture Wattages

Measure	Incandescent. Wattage[361]	LED Wattage[362]
Replace 12" Red Incandescent Ball with 12" Red LED Ball		9
Replace 12" Yellow Incandescent Ball with 12" Yellow LED Ball	149	17
Replace 12" Green Incandescent Ball with 12" Green LED Ball		11
Replace 8" Red Incandescent Ball with 8" Red LED Ball		6
Replace 8" Yellow Incandescent Ball with 8" Yellow LED Ball	86	12
Replace 8" Green Incandescent Ball with 8" Green LED Ball		6
Replace 12" Red Incandescent Arrow with 12" Red LED Arrow		5
Replace 12" Yellow Incandescent Arrow with 12" Yellow LED Arrow	128	8
Replace 12" Green Incandescent Arrow with 12" Green LED Arrow		5
Replace Large (16"x18") Incandescent Pedestrian Signal with LED Pedestrian Signal (with Countdown)	149	17
Replace Small (12"x12") Incandescent Pedestrian Signal with LED Pedestrian Signal (with Countdown)	107	10
Replace Large (16"x18") Incandescent Pedestrian Signal with LED Pedestrian Signal (without Countdown)	116[363]	6
Replace Small (12"x12") Incandescent Pedestrian Signal with LED Pedestrian Signal (without Countdown)	68[364]	5

361 Northwest Power & Conservation Council: Regional Technical Forum. Commercial LED Traffic Signals measure workbook. http://rtf.nwcouncil.org/measures/measure.asp?id=114&decisionid=37.

362 Typical practice for estimating fixture wattages is to take an average of the three leading manufacturers: GE, Philips, and Sylvania. Of the three, GE is the only manufacturer providing LED traffic signals. Other manufacturers excluded from averages. http://www.gelightingsolutions.com/products--solutions/transportation-led-lighting/traffic-signals.

363 Average high wattage A19, A21, and A23 incandescent fixture from Philips and Sylvania.

364 Ibid.

C.6.1.3. Estimated Useful Life (EUL)

According to the Northwest Power & Conservation Council Regional Technical Forum, the estimated useful life (EUL) is 5 to 6 years, as shown in the following table.

Table 161: Estimated Useful Life by Measure

Measure	EUL[365] (Years)
Replace 12” Red Incandescent Ball with 12” Red LED Ball	6
Replace 12” Yellow Incandescent Ball with 12” Yellow LED Ball	
Replace 12” Green Incandescent Ball with 12” Green LED Ball	
Replace 8” Red Incandescent Ball with 8” Red LED Ball	
Replace 8” Yellow Incandescent Ball with 8” Yellow LED Ball	
Replace 8” Green Incandescent Ball with 8” Green LED Ball	
Replace 12” Red Incandescent Arrow with 12” Red LED Arrow	
Replace 12” Yellow Incandescent Arrow with 12” Yellow LED Arrow	
Replace 12” Green Incandescent Arrow with 12” Green LED Arrow	
Replace Large (16”x18”) Incandescent Pedestrian Signal with LED Pedestrian Signal	5
Replace Small (12”x12”) Incandescent Pedestrian Signal with LED Pedestrian Signal	

C.6.1.4. Measure Savings Calculation

$$kW_{savings} = \sum\left(\left[N_{fixt(i)}\ x\ \frac{W_{fixt(i)}}{1000}\right]_{pre} - \left[N_{fixt(i)}\ x\ \frac{W_{fixt(i)}}{1000}\right]_{post}\right) x\ CF$$

$$kWh_{savings} = \sum\left(\left[N_{fixt(i)}\ x\ \frac{W_{fixt(i)}}{1000}\right]_{pre} - \left[N_{fixt(i)}\ x\ \frac{W_{fixt(i)}}{1000}\right]_{post}\right) x\ AOH$$

[365] Northwest Power & Conservation Council: Regional Technical Forum. Commercial LED Traffic Signals measure workbook. http://rtf.nwcouncil.org/measures/measure.asp?id=114&decisionid=37. EUL is determined by LED Traffic Signal replacement schedule, which is set to precede earliest burnout. All fixtures will be replaced at the same time to minimize maintenance interruptions.

Where:

$N_{fixt(i),pre}$ = Pre-retrofit number of fixtures of type i.

$N_{fixt(i),post}$ = Post-retrofit number of fixtures of type i.

$W_{fixt(i),pre}$ = Rated wattage of pre-retrofit fixtures of type i (if unknown, use Table 160).

$W_{fixt(i),post}$ = Rated wattage of post-retrofit fixtures of type i (if unknown, use Table 160).

CF = Peak demand coincidence factor (Table 162).

AOH = Annual operating hours for specified measure type (Table 162).

Table 162: Coincidence Factor and Annual Operating Hours by Measure

Measure	CF[366]	AOH[367]
Replace 12" Red Incandescent Ball with 12" Red LED Ball	0.54	4,746
Replace 12" Yellow Incandescent Ball with 12" Yellow LED Ball	0.03	263
Replace 12" Green Incandescent Ball with 12" Green LED Ball	0.43	3,751
Replace 8" Red Incandescent Ball with 8" Red LED Ball	0.54	4,746
Replace 8" Yellow Incandescent Ball with 8" Yellow LED Ball	0.03	263
Replace 8" Green Incandescent Ball with 8" Green LED Ball	0.43	3,751
Replace 12" Red Incandescent Arrow with 12" Red LED Arrow	0.89	7,771
Replace 12" Yellow Incandescent Arrow with 12" Yellow LED Arrow	0.03	263
Replace 12" Green Incandescent Arrow with 12" Green LED Arrow	0.08	726
Replace Large (16"x18") Incandescent Pedestrian Signal with LED Pedestrian Signal	0.99	8,642
Replace Small (12"x12") Incandescent Pedestrian Signal with LED Pedestrian Signal	0.99	8,642

[366] CF = AOH / 8,760 hours

[367] Northwest Power & Conservation Council: Regional Technical Forum. Commercial LED Traffic Signals measure workbook. http://rtf.nwcouncil.org/measures/measure.asp?id=114&decisionid=37.

C.6.2. Lighting Controls

C.6.2.1. Measure Description

Automatic lighting controls save energy by switching off or dimming lights when they are not necessary. Some lighting control techniques, such as using photocell controls, can be coupled with a variety of control strategies, including daylighting controls, occupancy controls, timer controls, and time clocks.

C.6.2.1.1. Stepped Lighting Control Systems

When switching systems are used with entire circuits of lights, as opposed to individual light fixtures, the control protocol is usually described in terms of steps, with each "step" referring to a percentage of full lighting power. Stepped lighting control systems are a relatively inexpensive approach to controlling large individual spaces, but they can be distracting to occupants.

C.6.2.1.2. Continuous Dimming Control Systems

Continuous dimming control systems are designed to adjust electric lighting to maintain a designated light level. Continuous dimming systems eliminate distracting and abrupt changes in light levels, provide appropriate light levels at all times, and provide an increased range of available light level. Cost is the major disadvantage of this control.

C.6.2.1.3. Occupancy Sensors

Occupancy sensors use motion detection to control lights in response to the presence or absence of occupants in a space. Many different varieties of sensors are available, including passive infrared (PIR), Ultrasound detecting, dual-technology, and integral occupancy sensors. Occupancy sensors are most effective in spaces with sporadic or unpredictable occupancy levels.

C.6.2.1.4. Daylighting

Daylighting controls switch or dim electric lights in response to the presence or absence of daylight illumination in the space. Advanced daylighting controls incorporate occupancy and daylighting sensors into the same control.

C.6.2.2. Baseline and Efficiency Standards

IECC 2003 (Section 805.2) and IECC 2009 (Section 505.1) specify the conditions under which light reduction and automatic controls are mandatory for new construction and affected retrofit projects. See the Measure Baseline section under the lighting efficiency measure for a discussion of updated lighting fixture wattages.

There are no minimum efficiency requirements for lighting controls.

C.6.2.3. Estimated Useful Life (EUL)

According to DEER 2008, the estimated useful life (EUL) is eight years for Daylighting Sensors and eight years for Occupancy Sensors.

C.6.2.4. Calculation of Deemed Savings

C.6.2.4.1. *Measure/Technology Review*

There have been many in-depth studies performed on the energy savings associated with occupancy and daylighting controls. Research by various organizations – including the Illuminating Engineering Society (IES), Canada National Research Council (CNRC), New Buildings Institute (NBI), Lighting Research Center (LRC) and multiple utilities – was included in this review. A summary of the findings of these reports are located in Table 163 and Table 164.

Table 163: Lighting Controls – Energy Saving Estimates for Occupancy Sensors

Location	***IES[368]***	***CNRC[369]***	***NBI[370]***	***LRC[371]***
Break Room	22%	-	-	-
Classroom	45%	63%	25%	-
Conference Room	43%	-	-	-
Corridor	-	24%	-	-
Office	32%	44%	35-45%	43%
Restroom	41%	-	-	-

[368] IES HB-9-2000. *"Illuminating Engineering Society Lighting Handbook 9th Edition".* 2000.

[369] Canada National Research Center, *"Energy Savings from Photosensors and Occupant Sensors/Wall Switches".* September 2009.

[370] New Buildings Institute. 2010. http://buildings.newbuildings.org/.

[371] Lighting Research Center (LRC), Solid State Lighting Program. http://www.lrc.rpi.edu/researchareas/leds.asp.

Table 164: Lighting Controls – Energy Saving Estimates for Daylighting Sensors

Location	***CNRC***	***NBI***	***So Cal Edison***[372]	***LRC***
Classroom	16%	40%	-	-
Corridor	25%	-	-	-
Office	22%	35-40%	74%	24-59%
Grocery Stores	-	40%	-	-
Big Box Retail	-	60%	-	-

Lighting energy savings can be calculated using the following formula. The kWh savings for each combination of fixture type, fixture location, building type, and refrigeration type must be calculated separately:

$$kW_{savings} = N_{fixt} \times \frac{W_{fixt}}{1000} \times CF \times IEF_D$$

$$kWh_{savings} = N_{fixt} \times \frac{W_{fixt}}{1000} \times (1 - PAF) \times AOH \times IEF_E$$

Where:

N_{fixt} = Number of fixtures

W_{fixt} = Rated wattage of post-retrofit fixtures (Appendix E)

Note: If the fixture was retrofitted, use the installed fixture wattage; if fixture was not retrofitted, use the existing fixture wattage

PAF = Stipulated power adjustment factor based on control type (Table 165)

CF = Peak demand coincidence factor = 0.26[373]

AOH = Annual operating hours for specified building type (Table 171)

IEF_D = Interactive effects factor for demand savings (Table 172)

IEF_E = Interactive effects factor for energy savings (Table 172)

[372] Southern California Edison, "*Energy Design Resources: Design Brief Lighting Controls*". February 2000.

[373] RLW Analytics, "*2005 Coincidence Factor Study,*" Connecticut Energy Conservation Management Board. January 4, 2007. Default value applicable to all building types. This coincidence factor is a combination of the savings factor and peak coincidence factor.

Table 165: Lighting Controls – Power Adjustment Factors[374]

Control Type	Power Adjustment Factor (PAF)
No controls measures	1.00
Daylighting Control – Continuous Dimming	0.70
Daylighting Control – Multiple Step Dimming	0.80
Daylighting Control – ON/OFF (Indoor)	0.90
Daylighting Control – ON/OFF (Outdoor) 375	1.00
Occupancy Sensor	0.70
Occupancy Sensor w/ Daylighting Control – Continuous Dimming	0.60
Occupancy Sensor w/ Daylighting Control – Multiple Step Dimming	0.65
Occupancy Sensor w/ Daylighting Control – ON/OFF	0.65

C.6.2.5. Incremental Costs

Incremental costs for lighting controls should use the full project cost.

[374] ASHRAE 90.1-1989, Section 6.4.2.8 specifies that exterior lighting not intended for 24-hour continuous use shall be automatically switched by timer, photocell, or a combination of timer and photocell. This is consistent with current specifications in ASHRAE 90.1-2010, Section 9.4.1.3, which specifies that lighting for all exterior applications shall have automatic controls capable of turning off exterior lighting when sufficient daylight is available or when the lighting is not required during nighttime hours.

[375] ASHRAE 90.1-1989, Section 6.4.2.8 specifies that exterior lighting not intended for 24-hour continuous use shall be automatically switched by timer, photocell, or a combination of timer and photocell. This is consistent with current specifications in ASHRAE 90.1-2010, Section 9.4.1.3, which specifies that lighting for all exterior applications shall have automatic controls capable of turning off exterior lighting when sufficient daylight is available or when the lighting is not required during nighttime hours.

C.6.3. Lighting Efficiency

C.6.3.1. Measure Description

A variety of high-efficiency fixtures, ballasts and lamps exist in the market today, producing the same lighting level (in lumens) as their standard-efficiency counterparts while consuming less electricity. This measure provides energy and demand savings calculations for the replacement of commercial lighting equipment with energy efficient lamps or fixtures. The operating hours and demand factors for the different building types listed in this measure are based on a wide array of information available in the market.

C.6.3.2. Baseline & Efficiency Standard

The following sections explain the various codes, standards, and required processes to establish the applicability of the Lighting Efficiency savings calculation method.

C.6.3.2.1. State Commercial Energy Codes

Louisiana's state commercial energy code recognizes ASHRAE 90.1-2007[376] for commercial structures. These standards specify the maximum lighting power densities (LPDs) by building type (building area method) and interior space type (space-by-space method). LPDs apply to all new construction and major renovation projects. The ASHRAE 90.1-2007 LPDs for various building types are outlined in Appendix F. Agricultural lighting for animals will utilize recognized industry standards unique to the requirements of that animal to determine the LPD for the building housing those animals.

C.6.3.2.2. Retrofit Baseline Summary

For all retrofit projects, the baseline is the current federal efficacy standard. If the replacement system is a T8, then it must meet Consortium for Energy Efficiency (CEE) specification requirements for High Performance and Reduced Wattage T8 systems. Other high-performance systems, including but not limited to T5 and LED systems, are allowed. T12s are no longer an eligible baseline technology.

C.6.3.2.3. Federal Efficacy Standards

The Energy Independence and Security Act (EISA) of 2007 mandates minimum efficacy standards for general service incandescent lamps, modified spectrum general service incandescent lamps, incandescent reflector lamps, fluorescent lamps and metal halide lamps.

[376] Any references to any versions of this standard refer to the American National Standards Institute (ANSI) /American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE)/Illuminating Engineering Society of North America (IESNA) Standard 90.1

Effective January 1, 2010, EISA increased minimum ballast efficacy factors and established pulse-start metal halides (PSMHs) as the new industry standard baseline for the metal halide technology ($\leq$ 500 W). New construction projects must use PSMHs in metal halide applications.

Starting in 2012, baseline wattages for general service incandescent lamps (GSILs) should not exceed values specified by EISA. For convenience, Table 166 provides the lumens and wattages required to meet EISA standards for incandescent lamps.

Table 166: New Maximum Wattages for General Service Incandescent Lamps, 2012-2014

Old Standard Incandescent Wattage	***New Maximum Wattage (EISA 2007)***	***Rated Lumens***	***Effective Date***[377]
100	72	1490 - 2600	6/1/2012
75	53	1050 - 1489	6/1/2013
60	43	750 - 1049	6/1/2014
40	29	310 – 749	6/1/2014

The Energy Policy Act (EPAct) of 2005 and EISA of 2007 are two energy legislative rulings enacted to establish energy reduction targets for the United States. On July 14, 2009, the Department of Energy published a final rule for energy conservation standards for general service fluorescent lamps (GSFLs). These standards are shown in Table 167. As a result of this rule, all GSFLs manufactured in the United States, or imported for sale into the United States on or after July 14, 2012 (three years from the ruling date) must meet new, more stringent efficacy standards (measured in lumens per watt, LPW).

[377] Adjusted from January to June assuming continued market availability for a period of 6 months after the standard effective date.

Table 167: Lighting Efficiency – Current Federal Efficiency Standards for GSFLs

Lamp Type	***Nominal Lamp Wattage***	***Minimum Color Rendering Index (CRI)***	***Minimum Average Lamp Efficacy (Lumens/Watt, or LPW)***
4-foot Medium Bi-Pin	> 35W ≤ 35 W	69 45	75.0 75.0
2-foot U-Shaped	> 35W ≤ 35W	69 45	68.0 64.0
8-foot Slimline	> 65W ≤ 65W	69 45	80.0 80.0
8-foot High Output	> 100W ≤ 100W	69 45	80.0 80.0

Facilities with 4-foot and 8-foot T12s or with 2-foot U-Shaped T12s are still eligible to participate in lighting retrofit projects, but an assumed electronic T8 baseline should be used in place of the existing T12 equipment. These T12 fixtures will remain in the standard wattage table with the label “T12 (T8 baseline)” and will include adjusted wattages assumptions consistent with a T8 fixture with an equivalent length and lamp count. T12 fixtures not specified above will remain an eligible baseline technology.

Table 168: Adjusted Baseline Wattages for T12 Equipment

T12 Length	Lamp Count	Revised Lamp Wattage	Revised System Wattage
48 inch- Std, HO, and VHO (4 feet)	1	32	31
	2	32	58
	3	32	85
	4	32	112
	6	32	170
	8	32	224
96 inch-Std (8 feet) 60/75W	1	59	69
	2	59	110
	3	59	179
	4	59	219
	6	59	330
	8	59	438*
96 inch-HO and VHO (8 feet) 95/110W	1	86	101
	2	86	160
	3	86	261
	4	86	319
	6	86	481
	8	86	638
2 ft. U-Tube	1	32	32
	2	32	60
	3	32	89
* 8 lamp fixture wattage approximated by doubling 4 lamp fixture wattage.			
Key: HO = high output, VHO = very high output			

C.6.3.2.4. Fixture Qualification Process – High Performance and Reduced Wattage T-8 Equipment:

CEE develops and maintains energy specifications for High Performance and Reduced Wattage T8 equipment. CEE high performance and reduced wattage T8 specifications can be found at:

1) http://www.cee1.org/com/com-lt/com-lt-specs.pdf (High Performance products)
2) http://www.cee1.org/com/com-lt/lw-spec.pdf (Reduced Wattage products)

CEE compiles a list of approved lamps and ballasts for T8 systems that are eligible for incentives for retrofits which is available for download on CEE's website at http://library.cee1.org/content/commercial-lighting-qualifying-products-lists.

C.6.3.2.5. Fixture Qualification Process – CFL and LED Products:

CFL and LED products must be pre-qualified under one of the following options:

1) Product is on the ENERGY STAR® Qualified Product List or ENERGY STAR® Qualified Light Fixtures Product List (http://www.energystar.gov)
2) Product is on the Northeast Energy Efficiency Partnerships (NEEP) DesignLights Consortium™ (DLC) Qualified Products Listing (www.designlights.org)
3) Exceptions to the ENERGY STAR® and/or DLC requirements are allowed for unlisted lamps and fixtures that have already been submitted to either ENERGY STAR® or DLC for approval. If the lamp or fixture does not achieve approval within the AR DSM program year, however, then the lamp or fixture must immediately be withdrawn from the program. If withdrawn, savings may be claimed up to the point of withdrawal from the program. For Agricultural uses where the fixture is designed for animal use, if an LED bulb does not meet ENERGY STAR® and/or DLC requirements, the bulb can be utilized if a thorough review of the bulb is conducted and verified by the program evaluator.

C.6.3.3. Input Wattages

Input wattages for pre-retrofit and qualifying fixtures are included in the Standard Fixture Wattage Table (Appendix E). This is a relatively comprehensive list of both old and new lighting technologies that could be expected for inclusion in a project. If there are fixtures identified that are not included in this table, those fixtures should be submitted to the Independent Evaluation Monitor (IEM) for review and incorporation into subsequent TRM updates. Interim approval may be made for certain fixtures at the discretion of the IEM. However, there may be eligible products that are not on the list. If a product is not on the list, then manufacturer's data should be reviewed prior to accepting the product into a program. LED products should be approved by DLC or ENERGY STAR® before being recognized as an eligible product.

C.6.3.4. Estimated Useful Life (EUL)

Table 169: Estimated Useful Life by Lamp Type

Lamp Type	***EUL (years)***	***Source***[378]
Halogen	2.0	Based upon 5,000-hour manufacturer rated life and weighted-average 3,380 annual operating hours from Navigant U.S. Lighting Study. Rated life values assume the use of energy-efficient Halogen Infrared (IR) products.
High Intensity Discharge (HID)	16.0	Based upon 50,000 hour manufacturer rated life and weighted-average 3,205 annual operating hours from Navigant U.S. Lighting Study.
Integrated-Ballast Cold-Cathode Fluorescent Lamps (CCFL)	5.0	Based upon 25,000 hour manufacturer rated life and weighted-average 5,493 annual operating hours from Navigant U.S. Lighting Study.
Integrated-Ballast Compact Fluorescent Lamps (CFL)	2.025	Based upon 8,000 hour manufacturer rated life and weighted-average 3,253 annual operating hours from Navigant U.S. Lighting Study.
Integrated-Ballast LED Lamps	9.0	Based on 30,000 hour manufacturer rated life and weighted-average 3,260 annual operating hours from Navigant U.S. Lighting Study.
Light Emitting Diode (LED)	15.0	Based upon 50,000 hour manufacturer rated life and weighted-average 3,260 annual operating hours from Navigant U.S. Lighting Study.
Linear Fluorescents (T5, T8)	16.0	Based upon 50,000 hour manufacturer rated life and weighted-average 3,211 annual operating hours from Navigant U.S. Lighting Study.
Modular CFL and CCFL	16.0	Based upon 60,000 hour manufacturer rated life and weighted-average 3,251 annual operating hours from Navigant U.S. Lighting Study.

[378] Navigant Consulting, "U.S. Lighting Market Characterization, Volume I: National Lighting Inventory and Energy Consumption Estimate, Final Report." U.S. DOE. September 2002.

C.6.3.5. Calculation of Deemed Savings

C.6.3.5.1. New Construction:

$$kW_{savings} = \left(\left(SF \times \frac{LPD}{1000}\right) - \sum\left(\left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{post}\right)\right) \times CF \times IEF_D$$

(4)

$$kWh_{savings} = \left(\left(SF \times \frac{LPD}{1000}\right) - \sum\left(\left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{post}\right)\right) \times AOH \times IEF_E$$

Where:

SF = Total affected square footage of the new construction facility

LPD = Maximum allowable power density by building type (W/ft^2) (Table F1-F4)

$N_{fixt(i),post}$ = Post-retrofit # of fixtures of type i

$W_{fixt(i),post}$ = Rated wattage of post-retrofit fixtures of type i (Appendix E)

CF = Peak demand coincidence factor (Table 171)

AOH = Annual operating hours for specified building type (Table 171)

IEF_D = Interactive effects factor for demand savings (Table 172)

IEF_E = Interactive effects factor for energy savings (Table 172)

C.6.3.5.2. Retrofit with no existing controls:

$$kW_{savings} = \sum\left(\left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{pre} - \left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{post}\right) \times CF \times IEF_D$$

$$kWh_{savings} = \sum\left(\left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{pre} - \left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{post}\right) \times AOH \times IEF_E$$

C.6.3.5.3. Retrofit with existing controls:

Note: For lighting systems with existing controls, no additional control savings should be claimed with the savings specified by the equations below.

$$kW_{savings} = \sum\left(\left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{pre} - \left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{post}\right) \times IEF_D \times CF_{controls}$$

$$kWh_{savings} = \sum\left(\left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{pre} - \left[N_{fixt(i)} \times \frac{W_{fixt(i)}}{1000}\right]_{post}\right) \times IEF_E \times AOH \times PAF$$

Where:

$N_{fixt(i),pre}$ = Pre-retrofit number of fixtures of type i

$N_{fixt(i),post}$ = Post-retrofit number of fixtures of type i

$W_{fixt(i),pre}$ = Rated wattage of pre-retrofit fixtures of type i (Appendix E)

$W_{fixt(i),post}$ = Rated wattage of post-retrofit fixtures of type i (Appendix E)

CF = Peak demand coincidence factor (Table 171)

$CF_{controls}$ = Controls peak demand coincidence factor = 0.26[379]

AOH = Annual operating hours for specified building type (Table 171)

PAF = Power adjustment factor for specified control type (Table 165)

IEF_D = Interactive effects factor for demand savings (Table 172)

IEF_E = Interactive effects factor for energy savings (Table 172)

C.6.3.6. Operating Hours & Coincidence Factors (CF)

If the annual operating hours and/or CF for the specified building are not known, use the deemed average annual hours of operation and/or peak demand CF from Table 171.

Table 170 summarizes the general transferability ratings for the lighting end-use. Due to the low variability of schedules and weather for both indoor and outdoor lighting, there is a high degree of data transferability across regions and it is appropriate to assume very similar annual operating hours across different regions.[380] To the extent that utility system peak periods are similar, it is also appropriate to assume very similar peak CFs across different regions.

Table 170: Transferability of Data across Geographic Regions

Analysis Group	Schedule Variability	Weather Variability	Transferability Rating
Lighting – Exterior	Low	Low	High
Lighting – Interior	Low	Low	High

Operating hours are the number of hours that a particular equipment type is in use over the course of a year. For the purpose of these recommendations, raw building lighting operating hour data were adjusted by Frontier Associates according to the percentage

[379] RLW Analytics, "*2005 Coincidence Factor Study,"* Connecticut Energy Conservation Management Board. January 4, 2007. Default value applicable to all building types. This coincidence factor is a combination of the savings factor and peak coincidence factor.

[380] KEMA. *End-Use Load Data Update Project Final Report: Phase 1: Cataloguing Available End-Use and Efficiency Measure Load Data*. 2009. Prepared for the Northwest Power and Conservation Council and Northeast Energy Efficiency Partnerships, November.

of wattage consumed by each space within a building. Subsequently, weighted average operating hours (AOH) were developed for a range of building types.

The CF for lighting is the ratio of the lighting kW demand during the utility's peak period (New Orleans does not have a specific peak period definition, and CF values are assumed to reflect peak loads of similar utilities) to the connected lighting kW ($\sum(N_i \times W_i/1000)$ as defined above. Other issues are automatically accounted for, such as diversity and load factor. A portion of the CF values were arrived at through secondary research. In the cases where acceptable values were not available through other sources, Frontier Associates calculated values comprised of CF and building operating hour data available for the types of building spaces that would likely be found within that building type.

Deemed annual operating hours from the Arkansas TRM 6.0 were used as a basis for New Orleans AOH. These hours were originally developed by Frontier Associates for the AR TRM. ADM used these values in conjunction with on-site monitoring from facility types commonly found New Orleans commercial lighting program participant populations. Direct monitoring data was collected from 210 loggers placed in 59 New Orleans and other major Louisiana utility territories. A total of (14) facility types received updated hours, and (10) new generic space types common in New Orleans area-projects were created:

Table 171: Annual Operating Hours (AOH) and Coincidence Factors (CF)[381]

Facility or Space Type	AOH	CF
Bar Area	2,676	0.81
Corridor/Hallway/Stairwell	5,233	0.90
Education: College/University	3,577	0.69
Education: K-12	2,333	0.47
Education: K-12 (specialized room)	2,676	0.47
Exterior	4,319	-
Food Prep (Generic)	5,543	0.81
Food Sales: 24-Hour Supermarket	6,900	0.95
Food Sales: Non 24-Hour Supermarket	2,058	0.95

[381] Unless otherwise noted, deemed AOH and CF values are based on Frontier Associates on behalf of Electric Utility Marketing Managers of Texas (EUMMOT). "Petition to Revise Existing Measurement & Verification Guidelines for Lighting Measures for Energy Efficiency Programs: Docket No. 39146." Public Utility Commission of Texas. Approved June 6, 2011. http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgSearch.asp

Food Service: Fast Food	6,473	0.81
Food Service: Sit-Down Restaurant	4,731	0.81
Health Care: In-Patient	4,019	0.78
Health Care: Nursing Home	4,271	0.78
Health Care: Out-Patient	3,386	0.77
Kwik-E-Mart	4,245	0.90
Lodging (Hotel/Motel/Dorm): Common Areas	4,127	0.82
Lodging (Hotel/Motel/Dorm): Room	3,370	0.25
Manufacturing	5,740	0.73
Multi-family Housing: Common Areas	5,703	0.87
Non-Warehouse Storage (Generic)	4,207	0.77
Office	5,159	0.77
Office (attached to other facility)	4,728	0.77
Parking Structure	7,884	1.00
Public Assembly	2,638	0.56
Public Order and Safety	3,472	0.75
Religious Gathering	3,174	0.53
Restroom (Generic)	3,516	0.90
Retail: Enclosed Mall	4,813	0.93
Retail: Freestanding	3,515	0.90
Retail: Other	4,312	0.90
Retail: Strip Mall	3,965	0.90
Security Booth	4,389	0.75
Service: Excluding Food	3,406	0.90
Showroom Floor	4,057	0.90
Walk-In Cooler (Generic)	792	0.25
Warehouse: Non-Refrigerated	2,417	0.77
Warehouse: Refrigerated	3,798	0.84

C.6.3.7. Interactive Effects

Lighting in air conditioned and refrigerated spaces adds heat to the space, increasing the cooling requirement during the cooling season and decreasing the heating requirement during the heating season. The decrease in waste heat from lighting mitigates these effects, thus reducing electricity used for cooling and increasing electricity or gas used for heating.

Deemed interactive effects factors for both demand and energy savings are presented in Table 172. These factors represent the percentage increase or decrease in energy savings for the refrigeration system's electric load attributed to the heat dissipated by the more efficient lighting system. For example, a factor of 1.20 indicates a 20% savings. The methodology for applying these Interactive Effects Factors to calculate savings is discussed in the Calculation of Deemed Savings section.

A detailed description of the derivation of interactive effects is available in Appendix I.

Table 172: Commercial Conditioned and Refrigerated Space Interactive Effects Factors

<table>
<tr><th>Building Type</th><th>Temperature Description</th><th>Heating Type</th><th>IEF_D</th><th>IEF_E</th></tr>
<tr><td rowspan="6">All building types
(Except Outdoor
&
Parking Structure)</td><td rowspan="4">Air Conditioned Space –
Normal Temps. (> 41°F)</td><td>Gas</td><td rowspan="4">1.20</td><td>1.09</td></tr>
<tr><td>Electric Resistance</td><td>0.87</td></tr>
<tr><td>Heat Pump</td><td>1.02</td></tr>
<tr><td>Heating Unknown [382]</td><td>0.98</td></tr>
<tr><td>Refrigerated Space –
Med. Temps. (33-41°F)</td><td>All</td><td>1.25</td><td>1.25</td></tr>
<tr><td>Refrigerated Space –
Low Temps. (-10-10°F)</td><td>All</td><td>1.30</td><td>1.30</td></tr>
</table>

C.6.3.8. Incremental Costs

Incremental costs by lighting category are as follows.

C.6.3.8.1. Commercial CFLs

Incremental costs are[383]:

- < 2,600 Lumens: $1.20
- Over 2,600 Lumens: $5

[382] These values should be used for programs where heat type cannot be determined.

[383] Illinois TRM

C.6.3.8.2. High Performance and Reduced Wattage T8s

Incremental costs are detailed in Table 172[384]:

Table 173: T8 Linear Fluorescent Incremental Costs

EE Measure	Watts	Baseline	Incremental Cost
4-lamp HPT8 High-bay	128	200W Pulse Start MH	$75
4-lamp HPT8 High-bay	128	250W Pulse Start MH	$75
6-lamp HPT8 High-bay	192	320W Pulse Start MH	$75
6-lamp HPT8 High-bay	192	400W Pulse Start MH	$75
8-lamp HPT8 High-bay	256	320W Pulse Start MH	$75
8-lamp HPT8 High-bay	256	400W Pulse Start MH	$75
1-lamp HPT8 – 32W	32	1-lamp standard F328- Electronic ballast	$15
1-lamp HPT8 – 28W	28	1-lamp standard F328- Electronic ballast	$15
1-lamp HPT8 – 25W	25	1-lamp standard F328- Electronic ballast	$15
2-lamp HPT8 – 32W	64	2-lamp standard F328- Electronic ballast	$18
2-lamp HPT8 – 28W	56	2-lamp standard F328- Electronic ballast	$18
2-lamp HPT8 – 25W	50	2-lamp standard F328- Electronic ballast	$18
3-lamp HPT8 – 32W	96	3-lamp standard F328- Electronic ballast	$20
3-lamp HPT8 – 28W	84	3-lamp standard F328- Electronic ballast	$20
3-lamp HPT8 – 25W	75	3-lamp standard F328- Electronic ballast	$20
4-lamp HPT8 – 32W	128	4-lamp standard F328- Electronic ballast	$23
4-lamp HPT8 – 28W	112	4-lamp standard F328- Electronic ballast	$23
4-lamp HPT8 – 25W	100	4-lamp standard F328- Electronic ballast	$23
2-lamp HPT8 Troffer	64	3-lamp standard F328- Electronic ballast	$100
RW T8-F28 Lamp	28	F32 T8 Standard lamp	$2
RW T8-F28 Extra Life Lamp	28	F32 T8 Standard lamp	$2
RW T8-F32/25W Lamp	25	F32 T8 Standard lamp	$2
RW T8-F32/25 Extra Life Lamp	285	F32 T8 Standard lamp	$2
RWT8 F17T8 Lamp - 2 ft.	16	F17 T8 Standard lamp – 2 ft.	$2
RWT8 F25T8 Lamp - 3 ft.	23	F25 T8 Standard lamp – 3 ft.	$2

[384] Illinois TRM

RWT8 F30T8 Lamp - 6' Utube	30	F32 T8 Standard Utube	$2
RWT8 F29T8 Lamp - Utube	29	F32 T8 Standard Utube	$2
RWT8 F96T8 Lamp - 8 ft.	65	F96 T8 Standard lamp – 8 ft.	$2

C.6.3.8.3. T5 Linear Fluorescent Fixtures

Table 174: T5 Linear Fluorescent Incremental Costs

EE Measure	***Watts***	***Baseline***	***Incremental Cost***
2-lamp T5 High-bay	180	200W Pulse Start MH	$100
3-lamp T5 High-bay	180	200W Pulse Start MH	$100
4-lamp T5 High-bay	240	320W Pulse Start MH	$100
6- lamp T5 High-bay	192	320W Pulse Start MH	$100
1-lamp T5 Troffer	32	3-lamp T8	$40
2-lamp T5 Troffer	64	3-lamp T8	$80
1-lamp T5 Industrial/Strip	32	3-lamp T8	$30
2- lamp T5 Industrial/Strip	64	3-lamp T8	$60
3- lamp T5 Industrial/Strip	96	3-lamp T8	$90
4- lamp T5 Industrial/Strip	187	3-lamp T8	$120
1-lamp T5 Indirect	32	3-lamp T8	$30
2-lamp T5 Indirect	64	3-lamp T8	$60

C.6.3.8.4. LEDs

Table 175: Omnidirectional LED Incremental Costs

LED Measure Description	***LED Lamp Cost***	***Baseline Cost (EISA 2012-2014, EISA 2020)***	***Incremental Cost (EISA 2012-2014, EISA 2020)***
LED Screw and Pin-based Bulbs, Omnidirectional, <10W	$30.00	$0.34 ($1.25, $2.50)	$29.66 ($28.75, $27.50)
LED Screw and Pin-based Bulbs, Omnidirectional, >=10W	$40.00	$0.34 ($1.25, $2.50)	$39.66 ($38.75, $37.50)

LED Screw and Pin-based Bulbs, Decorative	$30.00	$1.00	$29.00

Table 176: LED Incremental Costs[385]

LED Category	EE Measure	Incremental Cost
LED Downlight Fixtures	LED Recessed, Surface, Pendant Downlights	$27
LED Interior Directional	LED Track Lighting	$59
	LED Wall-Wash Fixtures	$59
LED Display Case	LED Display Case Light Fixture	$11/ft.
	LED Undercabinet Shelf-Mounted Task Light Fixtures	$11/ft.
	LED Refrigerated/Freezer Case light	$11/ft.
LED Linear Replacement Lamps	LED 4’ Linear Replacement Lamp	$13
	LED 2’ Linear Replacement Lamp	$13
LED Troffers	LED 2x2 Recessed Light Fixture, 2,000-3,500 Lumens	$48
	LED 2x2 Recessed Light Fixture, 3,501-5,000 Lumens	$91
	LED 2x4 Recessed Light Fixture, 3,000-4,500 Lumens	$62
	LED 2x4 Recessed Light Fixture, 4,501-6,000 Lumens	$99
	LED 2x4 Recessed Light Fixture, 6,001-7,500 Lumens	$150
	LED 1x4 Recessed Light Fixture, 3,001-4,500 Lumens	$36
	LED 1x4 Recessed Light Fixture, 4,401-6,000 Lumens	$130
LED Linear Ambient Fixtures	LED Surface & Suspended Linear Fixture, <=3,000 Lumens	$54
	LED Surface & Suspended Linear Fixture, 3,001-4,500 Lumens	$104
	LED Surface & Suspended Linear Fixture, 4,501-6,000 Lumens	$158
	LED Surface & Suspended Linear Fixture, 6,001-7,500 Lumens	$215
	LED Surface & Suspended Linear Fixture, >7,500 Lumens	$374
LED Low Bay & High Bay Fixtures	LED Low-Bay Fixtures, <= 10,000 Lumens	$191
	LED High-Bay Fixtures, 10,001-15,000 Lumens	$331

385 Watt, lumen, lamp life, and ballast factor assumptions for efficient measures are based upon Consortium for Energy Efficiency (CEE) Commercial Lighting Qualifying Product Lists alongside past Efficiency Vermont projects and PGE refrigerated case study. Watt, lumen, lamp life, and ballast factor assumptions for baseline fixtures are based upon manufacturer specification sheets. Baseline cost data comes from lighting suppliers, past Efficiency Vermont projects, and professional judgment. Efficient cost data comes from 2012 DOE “Energy Savings Potential of Solid-State Lighting in General Illumination Applications”, Table A.1. See "LED Lighting Systems TRM Reference Tables.xlsx" for more information and specific product links.

	LED High-Bay Fixtures, 15,001-20,000 Lumens	$482
	LED High-Bay Fixtures, > 20,000 Lumens	$818
LED Agricultural Interior Fixtures	LED Ag Interior Fixtures, <= 2,000 Lumens	$33
	LED Ag Interior Fixtures, 2,001-4,000 Lumens	$54
	LED Ag Interior Fixtures, 4,001-6,000 Lumens	$125
	LED Ag Interior Fixtures, 6,001-8,000 Lumens	$190
	LED Ag Interior Fixtures, 8,001-12,000 Lumens	$298
	LED Ag Interior Fixtures, 12,001-16,000 Lumens	$450
	LED Ag Interior Fixtures, 16,001-20,000 Lumens	$595
	LED Ag Interior Fixtures, > ,000 Lumens	$998
LED Exterior Fixtures	LED Exterior Fixtures, <=5,000 Lumens	$190
	LED Exterior Fixtures, 5,001-10,000 Lumens	$287
	LED Exterior Fixtures, 10,001-15,000 Lumens	$391
	LED Exterior Fixtures, > 15,000 Lumens	$793

C.6.3.9. Future Studies

This measure category constitutes over 90% of C&I savings historically in Energy Smart. As a result this category should be a primary focus of EM&V research. ADM recommends the following:

- Conduct metering studies for commercial facilities not captured in EM&V to-date.
- Conduct a cost study to update incremental costs to reflect New Orleans prices, sales tax rates, and labor costs.
- Conduct focused metering for lighting that is not listed in Energy Start or CEE lists.
- Conduct a market assessment for advanced lighting controls; mature lighting programs have begun further incorporation of Wi-Fi-enabled control schemes where lighting is incorporated into the Energy Management System (EMS). ADM recommends a market assessment for advanced lighting control adoption in New Orleans.
- Conduct preliminary research to assess whether certain lighting categories would be better-served with a midstream program approach.

C.7. Other Measures

C.7.1. Plug Load Occupancy Sensors

C.7.1.1. Measure Description

Plug load occupancy sensors are devices that control low wattage devices (<150 watts) using an occupancy sensor. Common applications are computer monitors, desk lamps, printers, and other desktop equipment. Three wattage tiers were analyzed based on available products in the market: 25W, 50W, and 150W.

C.7.1.2. Baseline and Efficiency Standards

Table 177: Plug Load Without Occupancy Sensors– Baseline Data

Size (watts)	***Annual Energy Consumption[386] (kWh/ unit)***	***Annual Operating Hours***	***Demand (kW/unit)***
25	110	4,400	0.025
50	220	4,400	0.05
150	555	3,700	0.15

Table 133 contains the annual energy consumption and demand for plug load occupancy sensors.

Table 178: Plug Load Occupancy Sensors – Minimum Requirements

Size (watts)	***Annual Energy Consumption[387] (kWh/ unit)***	***Annual Operating Hours***	***Demand[1] (kW/ unit)***
25	45	1452	0.025
50	91	1452	0.050
150	234	1250	0.150

C.7.1.3. Estimated Useful Life (EUL)

According to DEER 2008, the estimated useful life (EUL) is eight years.

[386] Arkansas TRM

[387] Ibid.

C.7.1.4. Deemed Savings Values

Deemed measure costs and savings for various sized plug load occupancy sensors are provided in *Table 134*.

Table 179: Plug Load Occupancy Sensors – Deemed Savings Values

Measure	***Demand Savings[1] (kW/ unit)***	***Annual Energy Savings[1] (kWh/ unit)***
25W sensor	0.000	65
50W sensor	0.000	129
150W sensor	0.000	321

C.7.1.5. Calculation of Deemed Savings

Four resources contained information on plug load occupancy sensors. The energy savings and amount of equipment controlled per sensor varied widely. The values for energy and demand savings are given in Table 135.

Table 180: Review of Plug Load Occupancy Sensor Measure Information

Available Resource	***Type***	***Size***	***Annual Energy Saving (kWh/unit)***	***Demand Savings (kW/unit)***
PG&E 2003	Plug load occupancy sensor	150	300	0.124
Quantec 2005	Power strip occupancy sensor	N/A	27	0.012
DEER 2005	Plug load occupancy sensor	50	143	0.051
KEMA 2010	Plug load occupancy sensor	50	221	0.025
NPCC 2005	Cubicle occupancy sensor	25	55	0.025
PacifiCorp 2009	Unitary savings included in comprehensive potential study		196	0.00

C.7.1.6. Incremental Cost

The incremental cost is $70.[388]

C.7.1.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. If this measure is added to Energy Smart programs, the evaluation should include a field assessment to inventory the plug loads actually controlled.

[388] Ohio TRM.

C.7.2. Advanced Power Strips

C.7.2.1. Measure Description

This measure involves the installation of a multi-plug Advanced Power Strip (APS) that has the ability to automatically disconnect specific loads depending on the power draw of a specified or "master" load. A load sensor in the strip disconnects power from the control outlets when the master power draw is below a certain threshold. The energy savings calculated for this measure are derived by estimating the number of hours that devices in typical office workstations are in "off" or "standby" mode and the number of watts consumed by each device in each mode. When the master device (i.e. computer) is turned off, power supply is cut to other related equipment (i.e. monitors, printers, speakers, etc.), eliminating these loads.

Commercial deemed savings were developed based on reported plug load electricity consumption. The assumed mix of peripheral electronics, and related data, are presented in the following table.

Table 136 shows the assumed number of hours each device is typically in "off" mode. Given the assumption that the master device, a desktop computer, will only be in off mode during non-work hours, watts consumed by devices in standby-mode are not counted toward energy savings for a commercial APS. Workday and weekend day watts consumed in off mode are a function of hours multiplied by estimated watt consumption.

There are two deemed savings paths available: Savings can be estimated as follows: 1) per APS for an average complete system or 2) by individual peripheral device.

Table 181: Peripheral Watt Consumption Breakdown

Peripheral Device	Workday Daily Off Hours[389]	Weekend Daily Off Hours	Off Power (W)[390,391]	Workday (W-hr) [A]	Weekend (W-hr) [B]
Coffee Maker	16	24	1.14	18.24	27.36
Computer: Desktop	16	24	3.3	52.80	79.20
Computer: Laptop	16	24	4.4	70.40	105.60
Computer Monitor: CRT	16	24	1.5	24.00	36.00
Computer Monitor: LCD	16	24	1.1	17.60	26.40
Computer Speakers	16	24	2.3	36.80	55.20
Copier	16	24	1.5	24.00	36.00

[389] Commercial hours of operation based on typical 8-hour workday schedule.

[390] New York State Energy Research and Development Authority (NYSERDA), "Advanced Power Strip Research Report". August 2011.

[391] Standby Power Summary Table, Lawrence Berkeley National Laboratory. http://standby.lbl.gov/summary-table.html.

External Hard Drive	16	24	3.0	48.00	72.00
Fax Machine: Inkjet	16	24	5.3	84.80	127.20
Fax Machine: Laser	16	24	2.2	35.20	52.80
Media Player: Blu-Ray	16	24	0.1	1.60	2.40
Media Player: DVD	16	24	2.0	32.00	48.00
Media Player: DVD-R	16	24	3.0	48.00	72.00
Media Player: DVD/VCR	16	24	4.0	64.00	96.00
Media Player: VCR	16	24	3.0	48.00	72.00
Microwave	16	24	3.08	49.28	73.92
Modem: Cable	0	24	3.8	0.00	91.20
Modem: DSL	0	24	1.4	0.00	33.60
Multi-Function Printer: Inkjet	16	24	5.26	84.16	126.24
Multi-Function Printer: Laser	16	24	3.12	49.92	74.88
Phone with Voicemail	16	24	2.92	46.72	70.08
Printer: Inkjet	16	24	1.3	20.80	31.20
Printer: Laser	16	24	3.3	52.80	79.20
Router	16	24	1.7	27.20	40.80
Scanner	16	24	2.1	33.60	50.40
Television: CRT	16	24	1.6	25.60	38.40
Television: LCD	16	24	0.5	8.00	12.00
Television: Plasma	16	24	0.6	9.60	14.40
Television: Projection	16	24	7.0	112.00	168.00

C.7.2.2. Baseline and Efficiency Standards

The baseline case is the absence of an APS, where peripherals are plugged into a traditional surge protector or wall outlet. The baseline assumes a typical mix of office equipment, shown in Table 136

C.7.2.3. Estimated Useful Life (EUL)

The estimated useful life (EUL) is 10 years according to the New York State Energy Research and Development Authority (NYSERDA) Advanced Power Strip Research Report from August 2011.[392]

[392] New York State Energy Research and Development Authority (NYSERDA): Advanced Power Strip Research Report, p. 30. August 2011.

C.7.2.4. Calculation of Deemed Savings

C.7.2.4.1. Energy Savings

Energy savings for a 7-plug APS in use in a commercial setting are calculated using the following algorithm, where kWh saved are calculated and summed for all peripheral devices:

$$\Delta kWh = \frac{\sum(Workdays * \ A_i) + \sum\left((365 - Workdays) * \ B_i\right)}{1{,}000}$$

Where:

$Workdays$ = Average number of workdays per year[393] = 240 days

A = Watt-hours/day consumed in the "off" mode per workday

B = Watt-hours/day consumed in the "off" mode per weekend day

$1{,}000$ = Constant to convert watts to kilowatts

C.7.2.4.2. Demand Savings

No demand savings are awarded for this measure due to the assumption that typical office equipment will be operating throughout the workday.

C.7.2.5. Deemed Savings Values

Energy savings from an APS in an office setting are estimated to be 71.4 kWh using the above equation and assuming six unique peripheral devices. Energy savings per peripheral device are also available in the following table.

Table 182: Advanced Power Strips – Deemed Savings Values

Peripheral Device	***kWh Savings***
Coffee Maker	7.8
Computer: Desktop	22.6
Computer: Laptop	30.1
Computer Monitor: CRT	10.3
Computer Monitor: LCD	7.5
Computer Speakers	15.7
Copier	10.3
External Hard Drive	20.5
Fax Machine: Inkjet	36.3
Fax Machine: Laser	15.0
Media Player: Blu-Ray	0.7

[393] Assuming 50 working weeks, deducting 2 weeks for federal holidays and another 2 weeks for vacation; 48 weeks x 5 days/week = 240 days

Media Player: DVD	13.7
Media Player: DVD-R	20.5
Media Player: DVD/VCR	27.4
Media Player: VCR	20.5
Microwave	21.1
Modem: Cable	11.4
Modem: DSL	4.2
Multi-Function Printer: Inkjet	36.0
Multi-Function Printer: Laser	21.3
Phone with Voicemail	20.0
Printer: Inkjet	8.9
Printer: Laser	22.6
Router	11.6
Scanner	14.4
Television: CRT	10.9
Television: LCD	3.4
Television: Plasma	4.1
Television: Projection	47.9
Average APS: Small Business Whole System[394]	**61.2**

C.7.2.6. Incremental Cost

For this measure, program administrators should use the full installed cost.

C.7.2.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. If this measure is added to Energy Smart programs, the evaluation should include a field assessment to inventory the plug loads actually controlled.

[394] Assuming Computer Monitor: LCD, Computer Speakers, Modem: Average, Printer: Average, and Scanner. Computer not included because it is assumed to be the controlling load. This average value is meant to apply to a typical small business application and should not be applied in other applications. For other applications, calculate the savings for each individual equipment type. kWh savings = 7.5 + 15.7 + [(11.4 + 4.2) ÷ 2] + [(8.9 + 22.6) ÷ 2] + 14.4 = 61.2 kWh.

C.7.3. Computer Power Management

C.7.3.1. Measure Description

Computer Power Management (CPM) is the automated control of the power, or “sleep” settings of network desktop and notebook computer equipment. CPM involves using built-in features or add-on software programs to switch off displays and enable computers to enter a low power setting called sleep mode during periods of non-use. This measure applies to both ENERGY STAR® and conventional computer equipment, and assumes that the same computer equipment is being used before and after CPM settings are activated. The power draw of a computer is assumed to be roughly equivalent during active and idle periods, so for the purposes of calculating savings, we will combine the terms active and idle as “active/idle” throughout the document.

C.7.3.2. Baseline and Efficiency Standards

The baseline conditions are the estimated number of hours that the computer spends in idle and sleep mode before the power settings are actively managed. The efficient conditions are the estimated number of hours that the computer spends in active/idle and sleep mode after the power settings are actively managed. Operating hours may be estimated from metering, or the default hours provided in the calculation of deemed savings may be used.

C.7.3.3. Calculation of Deemed Savings

Deemed demand and annual savings are based on the ENERGY STAR® Low Carbon IT Savings calculator. The coincidence factor, default equipment wattages in Table 138, and the active/idle and sleep hours are taken from assumptions in the ENERGY STAR® calculator with all equipment set to enter sleep mode after 15 minutes of inactivity.

$$kWh_{savings} = \frac{W_{active/idle}\left(hours_{active/idle_{pre}} - hours_{active/idle_{post}}\right) + W_{sleep}\left(hours_{sleep_{pre}} - hours_{sleep_{post}}\right)}{1{,}000} \tag{5}$$

$$kW_{savings} = \frac{(W_{active/idle} - W_{sleep}) * CF}{1{,}000} \tag{6}$$

Where:

$W_{active/idle}$ = total wattage of the equipment, including computer and monitor, in active/idle mode; see Table 138

$Hours_{active\_idle\_pre}$ = annual number of hours the computer is in active/idle mode before computer management software is installed = 6,293

$Hours_{active\_idle\_post}$ = annual number of hours the computer is in active/idle mode after computer management software is installed = 1,173

W_{sleep}= total wattage of the equipment, including computer and monitor, in sleep mode; see Table 138

$Hours_{sleep\_pre}$= annual number of hours the computer is in sleep mode before computer management software is installed = 0

$Hours_{sleep\_post}$ = annual number of hours the computer is in sleep mode after computer management software is installed = 5,120

CF= Coincidence Factor[395] = 0.25

1,000 = W/kW conversion

Table 183: Computer Power Management - Equipment Wattages

Equipment	W_{sleep}	$W_{active/idle}$
Conventional LCD Monitor	1	32
Conventional Computer	3	69
Conventional Notebook (including display)	2	21

Table 184: Computer Power Management - Deemed Savings Values

Equipment	***kWh savings***	***kW savings***
Conventional LCD Monitor	158.72	0.008
Conventional Computer	337.92	0.017
Conventional Notebook (including display)	97.28	0.005

C.7.3.4. Estimated Useful Life (EUL)

The EUL of this measure is based on the useful life of the computer equipment which is being controlled. Computer technology may continue to function long after technological

[395] The coincidence factor is the percentage of time the computer is assumed to be not in use during the hours 3pm to 6pm from the ENERGY STAR® calculator modeling study.

advances have diminished the usefulness of the equipment. The EUL for Computer Power Management is 4 years.[396]

C.7.3.5. Incremental Cost

The incremental cost is $29 per computer, including labor.[397]

C.7.3.1. Future Studies

At the time of authorship of the New Orleans TRM Version 1.0, this measure was not implemented in Energy Smart programs. If this measure is added to Energy Smart programs, the evaluation should include a field assessment to inventory the plug loads actually controlled.

[396] The Regional Technical Forum, Measure workbook for Commercial: Non-Res Network Computer Power Management. http://rtf.nwcouncil.org/measures/measure.asp?id=95. Accessed August 2013.

[397] Work Paper WPSCNROE0003 Revision 1, Power Management Software for Networked Computers. Southern California Edison

Appendix: Inputs

Residential

ENERGY STAR© Appliances

Unless otherwise noted, deemed savings values and inputs were derived form and found in the Energy Star calculators: https://www.energystar.gov/products/appliances.

Domestic Hot Water

Ambient Water Main (Tin) and Ambient Air Temperature (Tamb) Calculations based on New Orleans City Climate

Ambient Water Main (Tin) and Outside Air Temperature (Tamb) Calculations based on TMY3 New Orleans climate data

New Orleans	*Jan*	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*	*Nov*	*Dec*	*Annual Avg*
Month	1	2	3	4	5	6	7	8	9	10	11	12	
Outside Air Temperature (T_{air})	49.9	55.6	64.1	69.4	75.1	80.7	81.6	82.3	77.7	68.2	65.6	54.5	**68.7**
Water Heater Inlet Water Temperature, (T_{in})	66.0	64.2	65.2	68.6	73.6	78.9	83.1	85.2	84.4	81.2	76.3	70.9	**74.8**
offset (district water) =	6.00												
ratio =	0.647												
lag =	34.8												

Estimated Hot Water Usage (By Tank Size)

The values in Table 22 are based off Table 136: Estimated Annual Hot Water Use (gal), Arkansas TRM 5.0, page 137.

Tanks Size (gal) of Replaced Water Heater	*40*	*50*	*65*	*80*
El Dorado Estimated Annual Hot Water Use (gal)	17,815	20,245	24,293	29,152

ADM created a correction factor to compensate for the difference in the average water main temperatures between the two cities.

$$\textbf{Correction Factor} = \frac{\textbf{El Dorado Average Water Main Temperature}}{\textbf{New Orleans Average Water Main Temperature}} = \frac{\mathbf{70.1}}{\mathbf{74.8}} = \mathbf{.937166}$$

The correction factor was applied to existing El Dorado hot water usage estimates resulting on values appropriate for New Orleans:

Tanks Size (gal) of Replaced Water Heater	***40***	***50***	***65***	***80***
New Orleans Estimated Annual Hot Water Use (gal)	16,696	18,973	22,767	27,320

Estimated Average Ambient Temperatures by Water Heater Installation Location

Average ambient air temperature, New Orleans (TMY3)	68.78
Number of heating degree days, New Orleans (TMY3, base 65)	126
Number of cooling degree days, New Orleans (TMY3, base 65)	239
Ratio of conditioned/unconditioned	1.00549

Heat Pump Water Heater Adjustment Factor

	Count	***% of year***
Heating Days	126	35%
Cooling Days	239	65%

PA% for conditioned space: 2.784%

	COP-Heating	***COP-Cooling***	***Calculated F Adj***	***Calculated Adj***	***Estimated Adj***
Gas	20	3	1.201	0.856	**0.917**
Heat Pump	2	3	1.046	0.983	**1.201**
Elec.Resistance	0.89	3	0.830	1.238	**1.395**

Water Heater Jackets Deemed Savings Values

Estimated hot water usage (by tank size) Deemed water heating jacket savings are Table 143: Water Heater Jackets – Electric Heating Deemed Savings Values Arkansas TRM 5.0, page 144.

Annual Average Daily Isolation

Daily Total Insolation (BTU/ft2/day) (AR TRM 5.0)	1,601
Average solar radiation El Dorado, AR (NREL)	1,407
Average solar radiation New Orleans, LA (NREL)	1,405
Correction factor	1.137
New Orleans Solar radiation x Correction Factor =	**1,598**

Weather Zone Localization Factor for SEF

Average solar radiation New Orleans, LA (NREL): 4.33 kWh/m2/day = 1,405.254 BTU/ft2/day

Average solar radiation El Dorado, AR (AR TRM 5.0): 1,601 BTU/ft2/day

Latitude correction factor: 1.137

Envelope

Appendix A: Prototype Building Characteristics

Various building energy usage computer models have been used in development of deemed savings included in the TRM according to several factors:

- Building Type and Use. Prototype buildings support deemed savings development for measures to be implemented in the following building types: residential, converted residence (CR), commercial, and small commercial (SC).
- Model Vintage. Original prototypes date back to deemed savings developed in 2007/08 for use in the QuickStart programs. Prototype inputs have been updated for more recent models.
- Measure being modeled. Specific changes to a prototype are introduced to represent the specific measure being implemented in a given building.

In this Appendix, “top level” tables – those tables with the letter A followed only by a number in their table name (e.g. Table A1) provide the general characteristics of a given model prototype. “Supplemental tables” – (e.g. Table A1.a) – provide the specific changes introduced to a given prototype for the modeling of specific measures.

The following table applies to the Attic Knee Wall Insulation, Ceiling Insulation, Wall Insulation, Floor Insulation, Roof Deck Insulation, Air Infiltration, Radiant Barriers, ENERGY STAR® Windows, and Window Film measures. Unique modifications for each specific measure are listed in supplemental Tables A3.a through A3.h. BEopt™ – a residential building modeling platform developed by NREL – was used to estimate energy savings for these measures using the U.S. DOE EnergyPlus simulation engine.

Residential Envelope Measures – Prototype Home Characteristics

Shell Characteristic	Value	Source(s)
Site/Layout		
Conditioned Floor Area	1,764ft^2	Average square footage of conditioned (heated) space between one story home and all SFD homes in 2009 RECS microdata for AR/LA/OK.[398]
Orientation	Square building with faces on each cardinal direction	LBNL: Nationally Representative Housing Sample[399]
Number of Stories	Single story with unfinished attic	Preponderance of SFD homes in 2009 RECS microdata are single story
Building Envelope		
Foundation	Slab-on-ground, no edge insulation	Preponderance of SFD homes in 2009 RECS microdata (62%) have slab foundation Also a conservative assumption for base energy usage.
Slab Insulation	None – no perimeter, under-slab, or above-slab insulation	Not part of standard practice, also no requirement for slab insulation in residential code for relevant weather regions except the NW corner of state in IECC Climate Zone 4.
Ceiling Insulation	R-12	Table 25 of BA Home Simulation Protocols suggests R-9 is appropriate for homes closed rafter roofs built with 2 x 6 beams, R-15 for 2 x 10. Suspect 2 x 6 is more likely, but some share of homes will have had ceiling insulation replaced/added. Select R-12 based

[398] 2009 RECS, Available at: http://www.eia.gov/consumption/residential/data/2009/

[399] Simulating a Nationally Representative Housing Sample Using EnergyPlus*,* Available at: http://www.osti.gov/scitech/servlets/purl/1012239

		on the above information and engineering judgment.[400]
Wall Insulation	R-11	BAHSP, p. 35 – value for homes built 1980-1989
Air Leakage	0.9 ACH	Median ACH for older, low income housing.[401]
Fenestration		
Window Area	15% opf wall area	American Housing Survey 2007 and 2008 was used to inform the value for likely participants.
Window U-value	0.81	2009 ASHRAE Fundamentals, Ch. 15 Table 4. Value for double-pane, metal frame, fixed, clear glass window.
Window SHGC	0.64	2009 ASHRAE Fundamentals, Ch. 15 Table 10. Value for double-pane, metal frame, fixed, clear glass window.
HVAC		
Efficiency Rating, Air Conditioner	10 SEER	Federal Standard in effect from 1990-2006. Representative of low-efficiency program participant homes.
Efficiency Rating Space Heating (Gas Furnace)	78% AFUE	Annual Fuel Utilization Efficiency – base gas furnace efficiency
Efficiency Rating Space Heating (Electric Resistance Heat)	COP 1.0	Coefficient of Performance for central electric resistance heating systems
Efficiency Rating Space Heating (Heat Pump)	HSPF = 7.25	Average of Federal Standards: 1992 – 1/2006: 6.8 HSPF 1/2006 – 1/2015: 7.7 HSPF
Thermostat Settings	Heating: 71 F Cooling 76 F	BAHSP, p. 49
Duct Losses	20%	Lower tier of air leakage for typical homes as cited by ENERGY

[400] Building America Home Simulation Protocols (BAHSP), Available at: http://www.nrel.gov/docs/fy11osti/49246.pdf

[401] Referenced information is from 2009 ASHRAE Fundamentals, Section 16.17 Residential Ventilation.

		STAR®[402]
Duct Insulation	R-4	
Domestic Hot Water		
Energy Factor, Electric Storage	0.9	BAHSP (p. 42) EWH with 50 gal tank, 3-inch insulation.
Energy Factor, Gas Storage	0.59	BAHSP (p. 42), midpoint between options 2 and 3
Lighting		
Share of Lighting by Type	Lamps are 66% incandescent, 21% CFL, 13% T-8 linear fluorescent	BAHSP (p. 16)

Shell Characteristic	Value	Source(s)
Ceiling Construction	2 foot wide vaulted ceiling around the perimeter of the conditioned floor area	This modeling approach reduces simulation distortions introduced by a large vaulted ceiling area, while still exposing the attic knee walls to the conditioned living space.
Base Knee Wall Insulation	No existing insulation	Encountered insulation level drives eligibility for this measure
Improved Knee Wall Insulation	(1) Insulate to R-19, or (2) Insulate to R-30	Efficiency Measure

Ceiling Insulation – Prototype Home Characteristics

Shell Characteristic	Value	Source(s)
Base Ceiling Insulation	Five ranges of encountered ceiling insulation: R-0 to R-1 R-2 to R-4 R-5 to R-8 R-9 to R-14 R-15 to R-22	Insulation level as encountered by the EESP drives eligibility for this measure
Improved Ceiling Insulation	Insulate to R-38 & R-49	Efficiency measure – retrofit insulation level

Wall Insulation – Prototype Home Characteristics

[402] ENERGY STAR®, Duct Sealing: http://www.energystar.gov/?c=home_improvement.hm_improvement_ducts

Shell Characteristic	Value	Source(s)
Base Wall Insulation	R-0	Insulation level as encountered by the EESP drives eligibility for this measure
Improved Wall Insulation	R-13 & R-23	3.5" of fiberglass batt at R-3.7/in provides R-13 Full thickness of 4" cavity with open cell foam provides R-13 Full thickness of 4" cavity with open cell foam provides R-13

Floor Insulation – Prototype Home Characteristics

Shell Characteristic	Value	Source(s)
Foundation	Pier and beam with vented crawlspace	Floor Insulation not a relevant measure for homes with slab foundation
Base Floor Insulation	R-0	Insulation level as encountered by the EESP drives eligibility for this measure
Change Floor Insulation	R-19	This brings existing homes in compliance with IECC 2009.
Crawlspace Insulation	R-13	This brings existing homes in compliance with IECC 2009.

Air Infiltration – Prototype Home Characteristics

Shell Characteristic	Value	Source(s)
Base Air Leakage	0.9 ACH	Median infiltration value of older low-income housing sample:
Change Air Leakage	.035 ACH	Minimum allowable air exchanges assuming a 1,764 ft2 and 3 bedroom prototype home: ASHRAE 62.2 P - 2010

Radiant Barriers – Prototype Home Characteristics

Shell Characteristic	Value	Source(s)

Ceiling Insulation Case 1	≤ R-19	Assumed existing insulation level
Ceiling Insulation Case 2	> R-19	Assumed existing insulation level
Base roof deck	No radiant barrier	Existing condition applicable for this measure
Change roof deck	Double-Sided, Foil: Installed radiant barrier meeting ENERGY STAR® standards	Efficiency Measure

Window Film – Prototype Home Characteristics

Shell Characteristic	Value	Source(s)
Baseline Window Characteristics – double-pane model	0.81 U-value/0.64 SHGC	U-value assuming metal framed, double-pane clear glass windows 2009 ASHRAE Fundamentals, Ch.15 Tables 4 and 10
Baseline Window Characteristics – single-pane model	1.12 U-value/0.79 SHGC	U-value assuming metal framed, single-pane clear glass windows 2009 ASHRAE Fundamentals, Ch.15 Tables 4 and 10
Change Case Window Characteristics – double-pane model	0.81 U-value/0.49 SHGC	Efficiency Measure – values based on 3M product performance and technical data
Change Case Window Characteristics – single-pane model	1.12 U-value/0.40 SHGC	Efficiency Measure – values based on 3M product performance and technical data

Ambient Water Main (Tin) and Ambient Air Temperature (T_{amb}) Calculations based on New Orleans City Climate

Ambient Water Main (Tin) and Outside Air Temperature (T_{amb}) Calculations based on TMY3 New Orleans climate data

New Orleans	***Jan***	***Feb***	***Mar***	***Apr***	***May***	***Jun***	***Jul***	***Aug***	***Sep***	***Oct***	***Nov***	***Dec***	***Annual Avg***
Month	1	2	3	4	5	6	7	8	9	10	11	12	
Outside Air Temperature (T_{air})	49.9	55.6	64.1	69.4	75.1	80.7	81.6	82.3	77.7	68.2	65.6	54.5	**68.7**
Water Heater Inlet Water Temperature, (T_{in})	66.0	64.2	65.2	68.6	73.6	78.9	83.1	85.2	84.4	81.2	76.3	70.9	**74.8**
offset (district water) =	6.00												
ratio =	0.647												
lag =	34.8												

Duct Efficiency Improvements, Duct Insulation (SC), Cool Roofs, & Window Awnings (SC) – Prototype Building Characteristics

Building Characteristic	Building Type		
	Small Office	Stand-Alone Retail	Strip Mall
General			
Ground Area (Sq. Ft.)	7,500	15,000	7,500
# of Stories	2	1	1
Floor Area (Sq. Ft.)	15,000	15,000	7,500
Roof			
Construction	Metal Frame, > 24 in. o.c.	Metal Frame, > 24 in. o.c.	Metal Frame, > 24 in. o.c.
Ext. Finish	Roof, Built up	Roof, Built up	Roof, Built up
Ext. Color	Med (abs = 0.6)	Med (abs = 0.6)	Med (abs = 0.6)
Ext. Insulation	Varied	Varied	Varied
Add'l Insulation	No batt or radiant barrier	No batt or radiant barrier	No batt or radiant barrier
Walls			
Construction	Metal Frame, 2x6, 24 in. o.c.	Metal Frame, 2x6, 16 in. o.c.	Metal Frame, 2x4, 16 in. o.c.
Ext. Finish	Wood/Plywood	CMU	Stucco/Gunite
Ext. Color	Med (abs = 0.6)	Med (abs = 0.6)	Med (abs = 0.6)
Ext. Insulation	3/4 in. fiber bd sheathing (R-2)	3/4 in. fiber bd sheathing (R-2)	1/2 in. fiber bd sheathing (R-1.3)

Building Characteristic	Building Type		
	Small Office	Stand-Alone Retail	Strip Mall
Add'l Insulation	R-19 batt	R-11 batt	R-11 batt
Ceiling			
Construction	Acoustic Tile	Acoustic Tile	Acoustic Tile
Insulation	varied	varied	varied
Windows			
Glass Category	Double Clr/Tint 1/4", 1/2" air	Double Clr/Tint 1/4", 1/2" air	Double Clr/Tint 1/4", 1/2" air
Window Area	70% of all walls	70% of North wall; all others 0%	70% of East wall; all others 0%
Lighting			
Lighting Density (W/Sq. Ft.)	1.330	2.030	2.030
HVAC			
Cooling Source	DX Coils	DX Coils	DX Coils
System Type	Packaged Single Zone	Packaged Single Zone	Packaged Single Zone
Typ. Unit Size	11.25 – 20 tons	5.4 – 7.5 tons	< 5.4 tons
EER (Base)	8.50 EER	8.90 EER	9.70 SEER
Heating Source	Furnace	Furnace	Furnace
Typ. Unit Size	> 225 kBTUh	< 225 kBTUh	< 225 kBTUh
Efficiency (AFUE)	0.806	0.780	0.780
Fans			
Min. Design Flow (cfm/ft^2)	0.50	0.50	0.50
Cycle Fans at Night?	Cycle Fans (no OA at night)	Cycle Fans (no OA at night)	Cycle Fans (no OA at night)
DHW			
Fuel	Natural Gas	Natural Gas	Natural Gas
Type	Storage	Storage	Storage
Tank Insulation R-Value	12.00	12.00	12.00
Tank Capacity (gal)	39	21	11

HVAC

The tables below provide the eQuest Equivalent Full Load Hours (EFLH) model results for various building types found in New Orleans. EFLH values developed in eQuest were then normalized with El Dorado, AR EFLH,.

eQuest Model EFLH Results

Building Type	El Dorado EFLH$_c$	El Dorado EFLH$_h$	New Orleans EFLH$_c$	New Orleans EFLH$_h$
Fast Food	2,111	411	3,013	178
Grocery	1,544	537	1,703	285
Health Clinic	1,317	510	1,451	325
Large Office	1,684	879	1,598	501
Lodging	5,833	588	7,647	372
Full Menu Restaurant	2,070	509	2,900	217
Retail	2,424	588	3,305	372
School	1,209	420	1,672	167
Small Office	1,564	115	2,098	37
University	1,755	771	1,799	602

EFHL Normalized Multipliers

Building Type	El Dorado EFLH$_c$	El Dorado EFLH$_h$	New Orleans EFLH$_c$	New Orleans EFLH$_h$
Fast Food	1.00	1.00	1.43	0.43
Grocery	1.00	1.00	1.10	0.53
Health Clinic	1.00	1.00	1.10	0.64
Large Office	1.00	1.00	0.95	0.57
Lodging	1.00	1.00	1.31	0.63
Full Menu Restaurant	1.00	1.00	1.40	0.43
Retail	1.00	1.00	1.36	0.63
School	1.00	1.00	1.38	0.40
Small Office	1.00	1.00	1.34	0.33
University	1.00	1.00	1.02	0.78

Lighting

The table below shows logger counts, standard deviations, and compare original AR TRM6 hours with figures derived from direct monitoring.

Commercial Lighting Updates

Facility or Space Type	***Count of Loggers***	***ARM TRM 6 hours***	***New Orleans Recommended Value***
Bar Area	12		2,676.0
Corridor/Hallway/Stairwell	39		5,537.3
Education: College/University		3,577.0	3,577.0

Education: K-12	9	2,777.0	2,333.5
Exterior		3,996.0	4,319.0
Food Prep (Generic)	9		5,543.2
Food Sales: 24-Hour Supermarket		6,900.0	6,900.0
Food Sales: Non 24-Hour Supermarket	5	4,706.0	2,058.2
Food Service: Fast Food	11	6,188.0	6,473.4
Food Service: Sit-Down Restaurant	13	4,368.0	4,730.6
Health Care: In-Patient	3	5,730.0	4,019.4
Health Care: Nursing Home		4,271.0	4,271.0
Health Care: Out-Patient		3,386.0	3,386.0
K-12 (specialized room)	9		3,248.1
Kwik-E-Mart	22		4,244.8
Lodging (Hotel/Motel/Dorm): Common Areas	22	6,630.0	4,126.9
Lodging (Hotel/Motel/Dorm): Room	13	3,055.0	3,369.9
Manufacturing		5,740.0	5,740.0
Multi-family Housing: Common Areas	24	4,772.0	5,703.4
Non-Warehouse Storage (Generic)	11		4,206.5
Office	27	3,737.0	5,158.5
Office (attached to other facility)	36		4,728.4
Parking Structure		7,884.0	7,884.0
Public Assembly		2,638.0	2,638.0
Public Order and Safety		3,472.0	3,472.0
Religious Gathering	8	1,824.0	3,174.3
Restroom (Generic)	11		3,515.6
Retail: Enclosed Mall		4,813.0	4,813.0
Retail: Freestanding	52	3,668.0	3,514.8
Retail: Other	4	4,527.0	4,311.8
Retail: Strip Mall		3,965.0	3,965.0
Security Booth	5		4,389.2
Service: Excluding Food		3,406.0	3,406.0
Showroom Floor	14		4,057.1
Walk-In Cooler (Generic)	6		792.3
Warehouse: Non-Refrigerated	9	3,501.0	2,416.7
Warehouse: Offices	4		2,791.8
Warehouse: Refrigerated		3,798.0	3,798.0

The table below presents standard wattages.

Standard Wattage Table

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED-SCRW		Integrated Ballast LEDs						
LED001-SCRW	LEDINT1W	Integrated Ballast LED, (1) 1W screw-in lamp/base, any bulb shape	1W LED - Int. Ballast	Electronic	N/A	N/A	1	9
LED002-SCRW	LEDINT2W	Integrated Ballast LED, (1) 2W screw-in lamp/base, any bulb shape	2W LED - Int. Ballast	Electronic	N/A	N/A	2	9
LED003-SCRW	LEDINT3W	Integrated Ballast LED, (1) 3W screw-in lamp/base, any bulb shape	3W LED - Int. Ballast	Electronic	N/A	N/A	3	9
LED004-SCRW	LEDINT4W	Integrated Ballast LED, (1) 4W screw-in lamp/base, any bulb shape	4W LED - Int. Ballast	Electronic	N/A	N/A	4	9
LED005-SCRW	LEDINT5W	Integrated Ballast LED, (1) 5W screw-in lamp/base, any bulb shape	5W LED - Int. Ballast	Electronic	N/A	N/A	5	9
LED006-SCRW	LEDINT6W	Integrated Ballast LED, (1) 6W screw-in lamp/base, any bulb shape	6W LED - Int. Ballast	Electronic	N/A	N/A	6	9
LED007-SCRW	LEDINT7W	Integrated Ballast LED, (1) 7W screw-in lamp/base, any bulb shape	7W LED - Int. Ballast	Electronic	N/A	N/A	7	9
LED008-SCRW	LEDINT8W	Integrated Ballast LED, (1) 8W screw-in lamp/base, any bulb shape	8W LED - Int. Ballast	Electronic	N/A	N/A	8	9
LED009-SCRW	LEDINT9W	Integrated Ballast LED, (1) 9W screw-in lamp/base, any bulb shape	9W LED - Int. Ballast	Electronic	N/A	N/A	9	9

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED010-SCRW	LEDINT10W	Integrated Ballast LED, (1) 10W screw-in lamp/base, any bulb shape	10W LED - Int. Ballast	Electronic	N/A	N/A	10	9
LED011-SCRW	LEDINT11W	Integrated Ballast LED, (1) 11W screw-in lamp/base, any bulb shape	11W LED - Int. Ballast	Electronic	N/A	N/A	11	9
LED012-SCRW	LEDINT12W	Integrated Ballast LED, (1) 12W screw-in lamp/base, any bulb shape	12W LED - Int. Ballast	Electronic	N/A	N/A	12	9
LED013-SCRW	LEDINT13W	Integrated Ballast LED, (1) 13W screw-in lamp/base, any bulb shape	13W LED - Int. Ballast	Electronic	N/A	N/A	13	9
LED014-SCRW	LEDINT14W	Integrated Ballast LED, (1) 14W screw-in lamp/base, any bulb shape	14W LED - Int. Ballast	Electronic	N/A	N/A	14	9
LED015-SCRW	LEDINT15W	Integrated Ballast LED, (1) 15W screw-in lamp/base, any bulb shape	15W LED - Int. Ballast	Electronic	N/A	N/A	15	9
LED016-SCRW	LEDINT16W	Integrated Ballast LED, (1) 16W screw-in lamp/base, any bulb shape	16W LED - Int. Ballast	Electronic	N/A	N/A	16	9
LED017-SCRW	LEDINT17W	Integrated Ballast LED, (1) 17W screw-in lamp/base, any bulb shape	17W LED - Int. Ballast	Electronic	N/A	N/A	17	9
LED018-SCRW	LEDINT18W	Integrated Ballast LED, (1) 18W screw-in lamp/base, any bulb shape	18W LED - Int. Ballast	Electronic	N/A	N/A	18	9
LED019-SCRW	LEDINT19W	Integrated Ballast LED, (1) 19W screw-in lamp/base, any bulb shape	19W LED - Int. Ballast	Electronic	N/A	N/A	19	9
LED020-SCRW	LEDINT20W	Integrated Ballast LED, (1) 20W screw-in lamp/base, any bulb shape	20W LED - Int. Ballast	Electronic	N/A	N/A	20	9
LED021-SCRW	LEDINT21W	Integrated Ballast LED, (1) 21W screw-in lamp/base, any bulb shape	21W LED - Int. Ballast	Electronic	N/A	N/A	21	9
LED022-SCRW	LEDINT22W	Integrated Ballast LED, (1) 22W screw-in lamp/base, any bulb shape	22W LED - Int. Ballast	Electronic	N/A	N/A	22	9

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED023-SCRW	LEDINT23W	Integrated Ballast LED, (1) 23W screw-in lamp/base, any bulb shape	23W LED - Int. Ballast	Electronic	N/A	N/A	23	9
LED024-SCRW	LEDINT24W	Integrated Ballast LED, (1) 24W screw-in lamp/base, any bulb shape	24W LED - Int. Ballast	Electronic	N/A	N/A	24	9
LED025-SCRW	LEDINT25W	Integrated Ballast LED, (1) 25W screw-in lamp/base, any bulb shape	25W LED - Int. Ballast	Electronic	N/A	N/A	25	9
LED026-SCRW	LEDINT26W	Integrated Ballast LED, (1) 26W screw-in lamp/base, any bulb shape	26W LED - Int. Ballast	Electronic	N/A	N/A	26	9
LED027-SCRW	LEDINT27W	Integrated Ballast LED, (1) 27W screw-in lamp/base, any bulb shape	27W LED - Int. Ballast	Electronic	N/A	N/A	27	9
LED028-SCRW	LEDINT28W	Integrated Ballast LED, (1) 28W screw-in lamp/base, any bulb shape	28W LED - Int. Ballast	Electronic	N/A	N/A	28	9
LED029-SCRW	LEDINT29W	Integrated Ballast LED, (1) 29W screw-in lamp/base, any bulb shape	29W LED - Int. Ballast	Electronic	N/A	N/A	29	9
LED030-SCRW	LEDINT30W	Integrated Ballast LED, (1) 30W screw-in lamp/base, any bulb shape	30W LED - Int. Ballast	Electronic	N/A	N/A	30	9
LED031-SCRW	LEDINT31W	Integrated Ballast LED, (1) 31W screw-in lamp/base, any bulb shape	31W LED - Int. Ballast	Electronic	N/A	N/A	31	9
LED032-SCRW	LEDINT32W	Integrated Ballast LED, (1) 32W screw-in lamp/base, any bulb shape	32W LED - Int. Ballast	Electronic	N/A	N/A	32	9
LED033-SCRW	LEDINT33W	Integrated Ballast LED, (1) 33W screw-in lamp/base, any bulb shape	33W LED - Int. Ballast	Electronic	N/A	N/A	33	9
LED034-SCRW	LEDINT34W	Integrated Ballast LED, (1) 34W screw-in lamp/base, any bulb shape	34W LED - Int. Ballast	Electronic	N/A	N/A	34	9
LED035-SCRW	LEDINT35W	Integrated Ballast LED, (1) 35W screw-in lamp/base, any bulb shape	35W LED - Int. Ballast	Electronic	N/A	N/A	35	9

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED036-SCRW	LEDINT36W	Integrated Ballast LED, (1) 36W screw-in lamp/base, any bulb shape	36W LED - Int. Ballast	Electronic	N/A	N/A	36	9
LED037-SCRW	LEDINT37W	Integrated Ballast LED, (1) 37W screw-in lamp/base, any bulb shape	37W LED - Int. Ballast	Electronic	N/A	N/A	37	9
LED038-SCRW	LEDINT38W	Integrated Ballast LED, (1) 38W screw-in lamp/base, any bulb shape	38W LED - Int. Ballast	Electronic	N/A	N/A	38	9
LED039-SCRW	LEDINT39W	Integrated Ballast LED, (1) 39W screw-in lamp/base, any bulb shape	39W LED - Int. Ballast	Electronic	N/A	N/A	39	9
LED040-SCRW	LEDINT40W	Integrated Ballast LED, (1) 40W screw-in lamp/base, any bulb shape	40W LED - Int. Ballast	Electronic	N/A	N/A	40	9
LED041-SCRW	LEDINT41W	Integrated Ballast LED, (1) 41W screw-in lamp/base, any bulb shape	41W LED - Int. Ballast	Electronic	N/A	N/A	41	9
LED042-SCRW	LEDINT42W	Integrated Ballast LED, (1) 42W screw-in lamp/base, any bulb shape	42W LED - Int. Ballast	Electronic	N/A	N/A	42	9
LED043-SCRW	LEDINT43W	Integrated Ballast LED, (1) 43W screw-in lamp/base, any bulb shape	43W LED - Int. Ballast	Electronic	N/A	N/A	43	9
LED044-SCRW	LEDINT44W	Integrated Ballast LED, (1) 44W screw-in lamp/base, any bulb shape	44W LED - Int. Ballast	Electronic	N/A	N/A	44	9
LED045-SCRW	LEDINT45W	Integrated Ballast LED, (1) 45W screw-in lamp/base, any bulb shape	45W LED - Int. Ballast	Electronic	N/A	N/A	45	9
LED046-SCRW	LEDINT46W	Integrated Ballast LED, (1) 46W screw-in lamp/base, any bulb shape	46W LED - Int. Ballast	Electronic	N/A	N/A	46	9
LED047-SCRW	LEDINT47W	Integrated Ballast LED, (1) 47W screw-in lamp/base, any bulb shape	47W LED - Int. Ballast	Electronic	N/A	N/A	47	9
LED048-SCRW	LEDINT48W	Integrated Ballast LED, (1) 48W screw-in lamp/base, any bulb shape	48W LED - Int. Ballast	Electronic	N/A	N/A	48	9

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED049-SCRW	LEDINT49W	Integrated Ballast LED, (1) 49W screw-in lamp/base, any bulb shape	49W LED - Int. Ballast	Electronic	N/A	N/A	49	9
LED050-SCRW	LEDINT50W	Integrated Ballast LED, (1) 50W screw-in lamp/base, any bulb shape	50W LED - Int. Ballast	Electronic	N/A	N/A	50	9
LED-FIXT		Non-Integrated Ballast LEDs						
LED001-FIXT	LED1W	Non-Integrated Ballast LED, 1W, any bulb shape, any application	1W LED - Non-Int. Ballast	Electronic	N/A	N/A	1	15
LED002-FIXT	LED2W	Non-Integrated Ballast LED, 2W, any bulb shape, any application	2W LED - Non-Int. Ballast	Electronic	N/A	N/A	2	15
LED003-FIXT	LED3W	Non-Integrated Ballast LED, 3W, any bulb shape, any application	3W LED - Non-Int. Ballast	Electronic	N/A	N/A	3	15
LED004-FIXT	LED4W	Non-Integrated Ballast LED, 4W, any bulb shape, any application	4W LED - Non-Int. Ballast	Electronic	N/A	N/A	4	15
LED005-FIXT	LED5W	Non-Integrated Ballast LED, 5W, any bulb shape, any application	5W LED - Non-Int. Ballast	Electronic	N/A	N/A	5	15
LED006-FIXT	LED6W	Non-Integrated Ballast LED, 6W, any bulb shape, any application	6W LED - Non-Int. Ballast	Electronic	N/A	N/A	6	15
LED007-FIXT	LED7W	Non-Integrated Ballast LED, 7W, any bulb shape, any application	7W LED - Non-Int. Ballast	Electronic	N/A	N/A	7	15
LED008-FIXT	LED8W	Non-Integrated Ballast LED, 8W, any bulb shape, any application	8W LED - Non-Int. Ballast	Electronic	N/A	N/A	8	15
LED009-FIXT	LED9W	Non-Integrated Ballast LED, 9W, any bulb shape, any application	9W LED - Non-Int. Ballast	Electronic	N/A	N/A	9	15
LED010-FIXT	LED10W	Non-Integrated Ballast LED, 10W, any bulb shape, any application	10W LED - Non-Int. Ballast	Electronic	N/A	N/A	10	15
LED011-FIXT	LED11W	Non-Integrated Ballast LED, 11W, any bulb shape, any application	11W LED - Non-Int. Ballast	Electronic	N/A	N/A	11	15
LED012-FIXT	LED12W	Non-Integrated Ballast LED, 12W, any bulb shape, any application	12W LED - Non-Int. Ballast	Electronic	N/A	N/A	12	15
LED013-FIXT	LED13W	Non-Integrated Ballast LED, 13W, any bulb shape, any application	13W LED - Non-Int. Ballast	Electronic	N/A	N/A	13	15
LED014-FIXT	LED14W	Non-Integrated Ballast LED, 14W, any bulb shape, any application	14W LED - Non-Int. Ballast	Electronic	N/A	N/A	14	15
LED015-FIXT	LED15W	Non-Integrated Ballast LED, 15W, any bulb shape, any application	15W LED - Non-Int. Ballast	Electronic	N/A	N/A	15	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED016-FIXT	LED16W	Non-Integrated Ballast LED, 16W, any bulb shape, any application	16W LED - Non-Int. Ballast	Electronic	N/A	N/A	16	15
LED017-FIXT	LED17W	Non-Integrated Ballast LED, 17W, any bulb shape, any application	17W LED - Non-Int. Ballast	Electronic	N/A	N/A	17	15
LED018-FIXT	LED18W	Non-Integrated Ballast LED, 18W, any bulb shape, any application	18W LED - Non-Int. Ballast	Electronic	N/A	N/A	18	15
LED019-FIXT	LED19W	Non-Integrated Ballast LED, 19W, any bulb shape, any application	19W LED - Non-Int. Ballast	Electronic	N/A	N/A	19	15
LED020-FIXT	LED20W	Non-Integrated Ballast LED, 20W, any bulb shape, any application	20W LED - Non-Int. Ballast	Electronic	N/A	N/A	20	15
LED021-FIXT	LED21W	Non-Integrated Ballast LED, 21W, any bulb shape, any application	21W LED - Non-Int. Ballast	Electronic	N/A	N/A	21	15
LED022-FIXT	LED22W	Non-Integrated Ballast LED, 22W, any bulb shape, any application	22W LED - Non-Int. Ballast	Electronic	N/A	N/A	22	15
LED023-FIXT	LED23W	Non-Integrated Ballast LED, 23W, any bulb shape, any application	23W LED - Non-Int. Ballast	Electronic	N/A	N/A	23	15
LED024-FIXT	LED24W	Non-Integrated Ballast LED, 24W, any bulb shape, any application	24W LED - Non-Int. Ballast	Electronic	N/A	N/A	24	15
LED025-FIXT	LED25W	Non-Integrated Ballast LED, 25W, any bulb shape, any application	25W LED - Non-Int. Ballast	Electronic	N/A	N/A	25	15
LED026-FIXT	LED26W	Non-Integrated Ballast LED, 26W, any bulb shape, any application	26W LED - Non-Int. Ballast	Electronic	N/A	N/A	26	15
LED027-FIXT	LED27W	Non-Integrated Ballast LED, 27W, any bulb shape, any application	27W LED - Non-Int. Ballast	Electronic	N/A	N/A	27	15
LED028-FIXT	LED28W	Non-Integrated Ballast LED, 28W, any bulb shape, any application	28W LED - Non-Int. Ballast	Electronic	N/A	N/A	28	15
LED029-FIXT	LED29W	Non-Integrated Ballast LED, 29W, any bulb shape, any application	29W LED - Non-Int. Ballast	Electronic	N/A	N/A	29	15
LED030-FIXT	LED30W	Non-Integrated Ballast LED, 30W, any bulb shape, any application	30W LED - Non-Int. Ballast	Electronic	N/A	N/A	30	15
LED031-FIXT	LED31W	Non-Integrated Ballast LED, 31W, any bulb shape, any application	31W LED - Non-Int. Ballast	Electronic	N/A	N/A	31	15
LED032-FIXT	LED32W	Non-Integrated Ballast LED, 32W, any bulb shape, any application	32W LED - Non-Int. Ballast	Electronic	N/A	N/A	32	15
LED033-FIXT	LED33W	Non-Integrated Ballast LED, 33W, any bulb shape, any application	33W LED - Non-Int. Ballast	Electronic	N/A	N/A	33	15
LED034-FIXT	LED34W	Non-Integrated Ballast LED, 34W, any bulb shape, any application	34W LED - Non-Int. Ballast	Electronic	N/A	N/A	34	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED035-FIXT	LED35W	Non-Integrated Ballast LED, 35W, any bulb shape, any application	35W LED - Non-Int. Ballast	Electronic	N/A	N/A	35	15
LED036-FIXT	LED36W	Non-Integrated Ballast LED, 36W, any bulb shape, any application	36W LED - Non-Int. Ballast	Electronic	N/A	N/A	36	15
LED037-FIXT	LED37W	Non-Integrated Ballast LED, 37W, any bulb shape, any application	37W LED - Non-Int. Ballast	Electronic	N/A	N/A	37	15
LED038-FIXT	LED38W	Non-Integrated Ballast LED, 38W, any bulb shape, any application	38W LED - Non-Int. Ballast	Electronic	N/A	N/A	38	15
LED039-FIXT	LED39W	Non-Integrated Ballast LED, 39W, any bulb shape, any application	39W LED - Non-Int. Ballast	Electronic	N/A	N/A	39	15
LED040-FIXT	LED40W	Non-Integrated Ballast LED, 40W, any bulb shape, any application	40W LED - Non-Int. Ballast	Electronic	N/A	N/A	40	15
LED041-FIXT	LED41W	Non-Integrated Ballast LED, 41W, any bulb shape, any application	41W LED - Non-Int. Ballast	Electronic	N/A	N/A	41	15
LED042-FIXT	LED42W	Non-Integrated Ballast LED, 42W, any bulb shape, any application	42W LED - Non-Int. Ballast	Electronic	N/A	N/A	42	15
LED043-FIXT	LED43W	Non-Integrated Ballast LED, 43W, any bulb shape, any application	43W LED - Non-Int. Ballast	Electronic	N/A	N/A	43	15
LED044-FIXT	LED44W	Non-Integrated Ballast LED, 44W, any bulb shape, any application	44W LED - Non-Int. Ballast	Electronic	N/A	N/A	44	15
LED045-FIXT	LED45W	Non-Integrated Ballast LED, 45W, any bulb shape, any application	45W LED - Non-Int. Ballast	Electronic	N/A	N/A	45	15
LED046-FIXT	LED46W	Non-Integrated Ballast LED, 46W, any bulb shape, any application	46W LED - Non-Int. Ballast	Electronic	N/A	N/A	46	15
LED047-FIXT	LED47W	Non-Integrated Ballast LED, 47W, any bulb shape, any application	47W LED - Non-Int. Ballast	Electronic	N/A	N/A	47	15
LED048-FIXT	LED48W	Non-Integrated Ballast LED, 48W, any bulb shape, any application	48W LED - Non-Int. Ballast	Electronic	N/A	N/A	48	15
LED049-FIXT	LED49W	Non-Integrated Ballast LED, 49W, any bulb shape, any application	49W LED - Non-Int. Ballast	Electronic	N/A	N/A	49	15
LED050-FIXT	LED50W	Non-Integrated Ballast LED, 50W, any bulb shape, any application	50W LED - Non-Int. Ballast	Electronic	N/A	N/A	50	15
LED051-FIXT	LED51W	Non-Integrated Ballast LED, 51W, any bulb shape, any application	51W LED - Non-Int. Ballast	Electronic	N/A	N/A	51	15
LED052-FIXT	LED52W	Non-Integrated Ballast LED, 52W, any bulb shape, any application	52W LED - Non-Int. Ballast	Electronic	N/A	N/A	52	15
LED053-FIXT	LED53W	Non-Integrated Ballast LED, 53W, any bulb shape, any application	53W LED - Non-Int. Ballast	Electronic	N/A	N/A	53	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED054-FIXT	LED54W	Non-Integrated Ballast LED, 54W, any bulb shape, any application	54W LED - Non-Int. Ballast	Electronic	N/A	N/A	54	15
LED055-FIXT	LED55W	Non-Integrated Ballast LED, 55W, any bulb shape, any application	55W LED - Non-Int. Ballast	Electronic	N/A	N/A	55	15
LED056-FIXT	LED56W	Non-Integrated Ballast LED, 56W, any bulb shape, any application	56W LED - Non-Int. Ballast	Electronic	N/A	N/A	56	15
LED057-FIXT	LED57W	Non-Integrated Ballast LED, 57W, any bulb shape, any application	57W LED - Non-Int. Ballast	Electronic	N/A	N/A	57	15
LED058-FIXT	LED58W	Non-Integrated Ballast LED, 58W, any bulb shape, any application	58W LED - Non-Int. Ballast	Electronic	N/A	N/A	58	15
LED059-FIXT	LED59W	Non-Integrated Ballast LED, 59W, any bulb shape, any application	59W LED - Non-Int. Ballast	Electronic	N/A	N/A	59	15
LED060-FIXT	LED60W	Non-Integrated Ballast LED, 60W, any bulb shape, any application	60W LED - Non-Int. Ballast	Electronic	N/A	N/A	60	15
LED061-FIXT	LED61W	Non-Integrated Ballast LED, 61W, any bulb shape, any application	61W LED - Non-Int. Ballast	Electronic	N/A	N/A	61	15
LED062-FIXT	LED62W	Non-Integrated Ballast LED, 62W, any bulb shape, any application	62W LED - Non-Int. Ballast	Electronic	N/A	N/A	62	15
LED063-FIXT	LED63W	Non-Integrated Ballast LED, 63W, any bulb shape, any application	63W LED - Non-Int. Ballast	Electronic	N/A	N/A	63	15
LED064-FIXT	LED64W	Non-Integrated Ballast LED, 64W, any bulb shape, any application	64W LED - Non-Int. Ballast	Electronic	N/A	N/A	64	15
LED065-FIXT	LED65W	Non-Integrated Ballast LED, 65W, any bulb shape, any application	65W LED - Non-Int. Ballast	Electronic	N/A	N/A	65	15
LED066-FIXT	LED66W	Non-Integrated Ballast LED, 66W, any bulb shape, any application	66W LED - Non-Int. Ballast	Electronic	N/A	N/A	66	15
LED067-FIXT	LED67W	Non-Integrated Ballast LED, 67W, any bulb shape, any application	67W LED - Non-Int. Ballast	Electronic	N/A	N/A	67	15
LED068-FIXT	LED68W	Non-Integrated Ballast LED, 68W, any bulb shape, any application	68W LED - Non-Int. Ballast	Electronic	N/A	N/A	68	15
LED069-FIXT	LED69W	Non-Integrated Ballast LED, 69W, any bulb shape, any application	69W LED - Non-Int. Ballast	Electronic	N/A	N/A	69	15
LED070-FIXT	LED70W	Non-Integrated Ballast LED, 70W, any bulb shape, any application	70W LED - Non-Int. Ballast	Electronic	N/A	N/A	70	15
LED071-FIXT	LED71W	Non-Integrated Ballast LED, 71W, any bulb shape, any application	71W LED - Non-Int. Ballast	Electronic	N/A	N/A	71	15
LED072-FIXT	LED72W	Non-Integrated Ballast LED, 72W, any bulb shape, any application	72W LED - Non-Int. Ballast	Electronic	N/A	N/A	72	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED073-FIXT	LED73W	Non-Integrated Ballast LED, 73W, any bulb shape, any application	73W LED - Non-Int. Ballast	Electronic	N/A	N/A	73	15
LED074-FIXT	LED74W	Non-Integrated Ballast LED, 74W, any bulb shape, any application	74W LED - Non-Int. Ballast	Electronic	N/A	N/A	74	15
LED075-FIXT	LED75W	Non-Integrated Ballast LED, 75W, any bulb shape, any application	75W LED - Non-Int. Ballast	Electronic	N/A	N/A	75	15
LED076-FIXT	LED76W	Non-Integrated Ballast LED, 76W, any bulb shape, any application	76W LED - Non-Int. Ballast	Electronic	N/A	N/A	76	15
LED077-FIXT	LED77W	Non-Integrated Ballast LED, 77W, any bulb shape, any application	77W LED - Non-Int. Ballast	Electronic	N/A	N/A	77	15
LED078-FIXT	LED78W	Non-Integrated Ballast LED, 78W, any bulb shape, any application	78W LED - Non-Int. Ballast	Electronic	N/A	N/A	78	15
LED079-FIXT	LED79W	Non-Integrated Ballast LED, 79W, any bulb shape, any application	79W LED - Non-Int. Ballast	Electronic	N/A	N/A	79	15
LED080-FIXT	LED80W	Non-Integrated Ballast LED, 80W, any bulb shape, any application	80W LED - Non-Int. Ballast	Electronic	N/A	N/A	80	15
LED081-FIXT	LED81W	Non-Integrated Ballast LED, 81W, any bulb shape, any application	81W LED - Non-Int. Ballast	Electronic	N/A	N/A	81	15
LED082-FIXT	LED82W	Non-Integrated Ballast LED, 82W, any bulb shape, any application	82W LED - Non-Int. Ballast	Electronic	N/A	N/A	82	15
LED083-FIXT	LED83W	Non-Integrated Ballast LED, 83W, any bulb shape, any application	83W LED - Non-Int. Ballast	Electronic	N/A	N/A	83	15
LED084-FIXT	LED84W	Non-Integrated Ballast LED, 84W, any bulb shape, any application	84W LED - Non-Int. Ballast	Electronic	N/A	N/A	84	15
LED085-FIXT	LED85W	Non-Integrated Ballast LED, 85W, any bulb shape, any application	85W LED - Non-Int. Ballast	Electronic	N/A	N/A	85	15
LED086-FIXT	LED86W	Non-Integrated Ballast LED, 86W, any bulb shape, any application	86W LED - Non-Int. Ballast	Electronic	N/A	N/A	86	15
LED087-FIXT	LED87W	Non-Integrated Ballast LED, 87W, any bulb shape, any application	87W LED - Non-Int. Ballast	Electronic	N/A	N/A	87	15
LED088-FIXT	LED88W	Non-Integrated Ballast LED, 88W, any bulb shape, any application	88W LED - Non-Int. Ballast	Electronic	N/A	N/A	88	15
LED089-FIXT	LED89W	Non-Integrated Ballast LED, 89W, any bulb shape, any application	89W LED - Non-Int. Ballast	Electronic	N/A	N/A	89	15
LED090-FIXT	LED90W	Non-Integrated Ballast LED, 90W, any bulb shape, any application	90W LED - Non-Int. Ballast	Electronic	N/A	N/A	90	15
LED091-FIXT	LED91W	Non-Integrated Ballast LED, 91W, any bulb shape, any application	91W LED - Non-Int. Ballast	Electronic	N/A	N/A	91	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED092-FIXT	LED92W	Non-Integrated Ballast LED, 92W, any bulb shape, any application	92W LED - Non-Int. Ballast	Electronic	N/A	N/A	92	15
LED093-FIXT	LED93W	Non-Integrated Ballast LED, 93W, any bulb shape, any application	93W LED - Non-Int. Ballast	Electronic	N/A	N/A	93	15
LED094-FIXT	LED94W	Non-Integrated Ballast LED, 94W, any bulb shape, any application	94W LED - Non-Int. Ballast	Electronic	N/A	N/A	94	15
LED095-FIXT	LED95W	Non-Integrated Ballast LED, 95W, any bulb shape, any application	95W LED - Non-Int. Ballast	Electronic	N/A	N/A	95	15
LED096-FIXT	LED96W	Non-Integrated Ballast LED, 96W, any bulb shape, any application	96W LED - Non-Int. Ballast	Electronic	N/A	N/A	96	15
LED097-FIXT	LED97W	Non-Integrated Ballast LED, 97W, any bulb shape, any application	97W LED - Non-Int. Ballast	Electronic	N/A	N/A	97	15
LED098-FIXT	LED98W	Non-Integrated Ballast LED, 98W, any bulb shape, any application	98W LED - Non-Int. Ballast	Electronic	N/A	N/A	98	15
LED099-FIXT	LED99W	Non-Integrated Ballast LED, 99W, any bulb shape, any application	99W LED - Non-Int. Ballast	Electronic	N/A	N/A	99	15
LED100-FIXT	LED100W	Non-Integrated Ballast LED, 100W, any bulb shape, any application	100W LED - Non-Int. Ballast	Electronic	N/A	N/A	100	15
LED101-FIXT	LED101W	Non-Integrated Ballast LED, 101W, any bulb shape, any application	101W LED - Non-Int. Ballast	Electronic	N/A	N/A	101	15
LED102-FIXT	LED102W	Non-Integrated Ballast LED, 102W, any bulb shape, any application	102W LED - Non-Int. Ballast	Electronic	N/A	N/A	102	15
LED103-FIXT	LED103W	Non-Integrated Ballast LED, 103W, any bulb shape, any application	103W LED - Non-Int. Ballast	Electronic	N/A	N/A	103	15
LED104-FIXT	LED104W	Non-Integrated Ballast LED, 104W, any bulb shape, any application	104W LED - Non-Int. Ballast	Electronic	N/A	N/A	104	15
LED105-FIXT	LED105W	Non-Integrated Ballast LED, 105W, any bulb shape, any application	105W LED - Non-Int. Ballast	Electronic	N/A	N/A	105	15
LED106-FIXT	LED106W	Non-Integrated Ballast LED, 106W, any bulb shape, any application	106W LED - Non-Int. Ballast	Electronic	N/A	N/A	106	15
LED107-FIXT	LED107W	Non-Integrated Ballast LED, 107W, any bulb shape, any application	107W LED - Non-Int. Ballast	Electronic	N/A	N/A	107	15
LED108-FIXT	LED108W	Non-Integrated Ballast LED, 108W, any bulb shape, any application	108W LED - Non-Int. Ballast	Electronic	N/A	N/A	108	15
LED109-FIXT	LED109W	Non-Integrated Ballast LED, 109W, any bulb shape, any application	109W LED - Non-Int. Ballast	Electronic	N/A	N/A	109	15
LED110-FIXT	LED110W	Non-Integrated Ballast LED, 110W, any bulb shape, any application	110W LED - Non-Int. Ballast	Electronic	N/A	N/A	110	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED111-FIXT	LED111W	Non-Integrated Ballast LED, 111W, any bulb shape, any application	111W LED - Non-Int. Ballast	Electronic	N/A	N/A	111	15
LED112-FIXT	LED112W	Non-Integrated Ballast LED, 112W, any bulb shape, any application	112W LED - Non-Int. Ballast	Electronic	N/A	N/A	112	15
LED113-FIXT	LED113W	Non-Integrated Ballast LED, 113W, any bulb shape, any application	113W LED - Non-Int. Ballast	Electronic	N/A	N/A	113	15
LED114-FIXT	LED114W	Non-Integrated Ballast LED, 114W, any bulb shape, any application	114W LED - Non-Int. Ballast	Electronic	N/A	N/A	114	15
LED115-FIXT	LED115W	Non-Integrated Ballast LED, 115W, any bulb shape, any application	115W LED - Non-Int. Ballast	Electronic	N/A	N/A	115	15
LED116-FIXT	LED116W	Non-Integrated Ballast LED, 116W, any bulb shape, any application	116W LED - Non-Int. Ballast	Electronic	N/A	N/A	116	15
LED117-FIXT	LED117W	Non-Integrated Ballast LED, 117W, any bulb shape, any application	117W LED - Non-Int. Ballast	Electronic	N/A	N/A	117	15
LED118-FIXT	LED118W	Non-Integrated Ballast LED, 118W, any bulb shape, any application	118W LED - Non-Int. Ballast	Electronic	N/A	N/A	118	15
LED119-FIXT	LED119W	Non-Integrated Ballast LED, 119W, any bulb shape, any application	119W LED - Non-Int. Ballast	Electronic	N/A	N/A	119	15
LED120-FIXT	LED120W	Non-Integrated Ballast LED, 120W, any bulb shape, any application	120W LED - Non-Int. Ballast	Electronic	N/A	N/A	120	15
LED121-FIXT	LED121W	Non-Integrated Ballast LED, 121W, any bulb shape, any application	121W LED - Non-Int. Ballast	Electronic	N/A	N/A	121	15
LED122-FIXT	LED122W	Non-Integrated Ballast LED, 122W, any bulb shape, any application	122W LED - Non-Int. Ballast	Electronic	N/A	N/A	122	15
LED123-FIXT	LED123W	Non-Integrated Ballast LED, 123W, any bulb shape, any application	123W LED - Non-Int. Ballast	Electronic	N/A	N/A	123	15
LED124-FIXT	LED124W	Non-Integrated Ballast LED, 124W, any bulb shape, any application	124W LED - Non-Int. Ballast	Electronic	N/A	N/A	124	15
LED125-FIXT	LED125W	Non-Integrated Ballast LED, 125W, any bulb shape, any application	125W LED - Non-Int. Ballast	Electronic	N/A	N/A	125	15
LED126-FIXT	LED126W	Non-Integrated Ballast LED, 126W, any bulb shape, any application	126W LED - Non-Int. Ballast	Electronic	N/A	N/A	126	15
LED127-FIXT	LED127W	Non-Integrated Ballast LED, 127W, any bulb shape, any application	127W LED - Non-Int. Ballast	Electronic	N/A	N/A	127	15
LED128-FIXT	LED128W	Non-Integrated Ballast LED, 128W, any bulb shape, any application	128W LED - Non-Int. Ballast	Electronic	N/A	N/A	128	15
LED129-FIXT	LED129W	Non-Integrated Ballast LED, 129W, any bulb shape, any application	129W LED - Non-Int. Ballast	Electronic	N/A	N/A	129	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED130-FIXT	LED130W	Non-Integrated Ballast LED, 130W, any bulb shape, any application	130W LED - Non-Int. Ballast	Electronic	N/A	N/A	130	15
LED131-FIXT	LED131W	Non-Integrated Ballast LED, 131W, any bulb shape, any application	131W LED - Non-Int. Ballast	Electronic	N/A	N/A	131	15
LED132-FIXT	LED132W	Non-Integrated Ballast LED, 132W, any bulb shape, any application	132W LED - Non-Int. Ballast	Electronic	N/A	N/A	132	15
LED133-FIXT	LED133W	Non-Integrated Ballast LED, 133W, any bulb shape, any application	133W LED - Non-Int. Ballast	Electronic	N/A	N/A	133	15
LED134-FIXT	LED134W	Non-Integrated Ballast LED, 134W, any bulb shape, any application	134W LED - Non-Int. Ballast	Electronic	N/A	N/A	134	15
LED135-FIXT	LED135W	Non-Integrated Ballast LED, 135W, any bulb shape, any application	135W LED - Non-Int. Ballast	Electronic	N/A	N/A	135	15
LED136-FIXT	LED136W	Non-Integrated Ballast LED, 136W, any bulb shape, any application	136W LED - Non-Int. Ballast	Electronic	N/A	N/A	136	15
LED137-FIXT	LED137W	Non-Integrated Ballast LED, 137W, any bulb shape, any application	137W LED - Non-Int. Ballast	Electronic	N/A	N/A	137	15
LED138-FIXT	LED138W	Non-Integrated Ballast LED, 138W, any bulb shape, any application	138W LED - Non-Int. Ballast	Electronic	N/A	N/A	138	15
LED139-FIXT	LED139W	Non-Integrated Ballast LED, 139W, any bulb shape, any application	139W LED - Non-Int. Ballast	Electronic	N/A	N/A	139	15
LED140-FIXT	LED140W	Non-Integrated Ballast LED, 140W, any bulb shape, any application	140W LED - Non-Int. Ballast	Electronic	N/A	N/A	140	15
LED141-FIXT	LED141W	Non-Integrated Ballast LED, 141W, any bulb shape, any application	141W LED - Non-Int. Ballast	Electronic	N/A	N/A	141	15
LED142-FIXT	LED142W	Non-Integrated Ballast LED, 142W, any bulb shape, any application	142W LED - Non-Int. Ballast	Electronic	N/A	N/A	142	15
LED143-FIXT	LED143W	Non-Integrated Ballast LED, 143W, any bulb shape, any application	143W LED - Non-Int. Ballast	Electronic	N/A	N/A	143	15
LED144-FIXT	LED144W	Non-Integrated Ballast LED, 144W, any bulb shape, any application	144W LED - Non-Int. Ballast	Electronic	N/A	N/A	144	15
LED145-FIXT	LED145W	Non-Integrated Ballast LED, 145W, any bulb shape, any application	145W LED - Non-Int. Ballast	Electronic	N/A	N/A	145	15
LED146-FIXT	LED146W	Non-Integrated Ballast LED, 146W, any bulb shape, any application	146W LED - Non-Int. Ballast	Electronic	N/A	N/A	146	15
LED147-FIXT	LED147W	Non-Integrated Ballast LED, 147W, any bulb shape, any application	147W LED - Non-Int. Ballast	Electronic	N/A	N/A	147	15
LED148-FIXT	LED148W	Non-Integrated Ballast LED, 148W, any bulb shape, any application	148W LED - Non-Int. Ballast	Electronic	N/A	N/A	148	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED149-FIXT	LED149W	Non-Integrated Ballast LED, 149W, any bulb shape, any application	149W LED - Non-Int. Ballast	Electronic	N/A	N/A	149	15
LED150-FIXT	LED150W	Non-Integrated Ballast LED, 150W, any bulb shape, any application	150W LED - Non-Int. Ballast	Electronic	N/A	N/A	150	15
LED151-FIXT	LED151W	Non-Integrated Ballast LED, 151W, any bulb shape, any application	151W LED - Non-Int. Ballast	Electronic	N/A	N/A	151	15
LED152-FIXT	LED152W	Non-Integrated Ballast LED, 152W, any bulb shape, any application	152W LED - Non-Int. Ballast	Electronic	N/A	N/A	152	15
LED153-FIXT	LED153W	Non-Integrated Ballast LED, 153W, any bulb shape, any application	153W LED - Non-Int. Ballast	Electronic	N/A	N/A	153	15
LED154-FIXT	LED154W	Non-Integrated Ballast LED, 154W, any bulb shape, any application	154W LED - Non-Int. Ballast	Electronic	N/A	N/A	154	15
LED155-FIXT	LED155W	Non-Integrated Ballast LED, 155W, any bulb shape, any application	155W LED - Non-Int. Ballast	Electronic	N/A	N/A	155	15
LED156-FIXT	LED156W	Non-Integrated Ballast LED, 156W, any bulb shape, any application	156W LED - Non-Int. Ballast	Electronic	N/A	N/A	156	15
LED157-FIXT	LED157W	Non-Integrated Ballast LED, 157W, any bulb shape, any application	157W LED - Non-Int. Ballast	Electronic	N/A	N/A	157	15
LED158-FIXT	LED158W	Non-Integrated Ballast LED, 158W, any bulb shape, any application	158W LED - Non-Int. Ballast	Electronic	N/A	N/A	158	15
LED159-FIXT	LED159W	Non-Integrated Ballast LED, 159W, any bulb shape, any application	159W LED - Non-Int. Ballast	Electronic	N/A	N/A	159	15
LED160-FIXT	LED160W	Non-Integrated Ballast LED, 160W, any bulb shape, any application	160W LED - Non-Int. Ballast	Electronic	N/A	N/A	160	15
LED161-FIXT	LED161W	Non-Integrated Ballast LED, 161W, any bulb shape, any application	161W LED - Non-Int. Ballast	Electronic	N/A	N/A	161	15
LED162-FIXT	LED162W	Non-Integrated Ballast LED, 162W, any bulb shape, any application	162W LED - Non-Int. Ballast	Electronic	N/A	N/A	162	15
LED163-FIXT	LED163W	Non-Integrated Ballast LED, 163W, any bulb shape, any application	163W LED - Non-Int. Ballast	Electronic	N/A	N/A	163	15
LED164-FIXT	LED164W	Non-Integrated Ballast LED, 164W, any bulb shape, any application	164W LED - Non-Int. Ballast	Electronic	N/A	N/A	164	15
LED165-FIXT	LED165W	Non-Integrated Ballast LED, 165W, any bulb shape, any application	165W LED - Non-Int. Ballast	Electronic	N/A	N/A	165	15
LED166-FIXT	LED166W	Non-Integrated Ballast LED, 166W, any bulb shape, any application	166W LED - Non-Int. Ballast	Electronic	N/A	N/A	166	15
LED167-FIXT	LED167W	Non-Integrated Ballast LED, 167W, any bulb shape, any application	167W LED - Non-Int. Ballast	Electronic	N/A	N/A	167	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED168-FIXT	LED168W	Non-Integrated Ballast LED, 168W, any bulb shape, any application	168W LED - Non-Int. Ballast	Electronic	N/A	N/A	168	15
LED169-FIXT	LED169W	Non-Integrated Ballast LED, 169W, any bulb shape, any application	169W LED - Non-Int. Ballast	Electronic	N/A	N/A	169	15
LED170-FIXT	LED170W	Non-Integrated Ballast LED, 170W, any bulb shape, any application	170W LED - Non-Int. Ballast	Electronic	N/A	N/A	170	15
LED171-FIXT	LED171W	Non-Integrated Ballast LED, 171W, any bulb shape, any application	171W LED - Non-Int. Ballast	Electronic	N/A	N/A	171	15
LED172-FIXT	LED172W	Non-Integrated Ballast LED, 172W, any bulb shape, any application	172W LED - Non-Int. Ballast	Electronic	N/A	N/A	172	15
LED173-FIXT	LED173W	Non-Integrated Ballast LED, 173W, any bulb shape, any application	173W LED - Non-Int. Ballast	Electronic	N/A	N/A	173	15
LED174-FIXT	LED174W	Non-Integrated Ballast LED, 174W, any bulb shape, any application	174W LED - Non-Int. Ballast	Electronic	N/A	N/A	174	15
LED175-FIXT	LED175W	Non-Integrated Ballast LED, 175W, any bulb shape, any application	175W LED - Non-Int. Ballast	Electronic	N/A	N/A	175	15
LED176-FIXT	LED176W	Non-Integrated Ballast LED, 176W, any bulb shape, any application	176W LED - Non-Int. Ballast	Electronic	N/A	N/A	176	15
LED177-FIXT	LED177W	Non-Integrated Ballast LED, 177W, any bulb shape, any application	177W LED - Non-Int. Ballast	Electronic	N/A	N/A	177	15
LED178-FIXT	LED178W	Non-Integrated Ballast LED, 178W, any bulb shape, any application	178W LED - Non-Int. Ballast	Electronic	N/A	N/A	178	15
LED179-FIXT	LED179W	Non-Integrated Ballast LED, 179W, any bulb shape, any application	179W LED - Non-Int. Ballast	Electronic	N/A	N/A	179	15
LED180-FIXT	LED180W	Non-Integrated Ballast LED, 180W, any bulb shape, any application	180W LED - Non-Int. Ballast	Electronic	N/A	N/A	180	15
LED181-FIXT	LED181W	Non-Integrated Ballast LED, 181W, any bulb shape, any application	181W LED - Non-Int. Ballast	Electronic	N/A	N/A	181	15
LED182-FIXT	LED182W	Non-Integrated Ballast LED, 182W, any bulb shape, any application	182W LED - Non-Int. Ballast	Electronic	N/A	N/A	182	15
LED183-FIXT	LED183W	Non-Integrated Ballast LED, 183W, any bulb shape, any application	183W LED - Non-Int. Ballast	Electronic	N/A	N/A	183	15
LED184-FIXT	LED184W	Non-Integrated Ballast LED, 184W, any bulb shape, any application	184W LED - Non-Int. Ballast	Electronic	N/A	N/A	184	15
LED185-FIXT	LED185W	Non-Integrated Ballast LED, 185W, any bulb shape, any application	185W LED - Non-Int. Ballast	Electronic	N/A	N/A	185	15
LED186-FIXT	LED186W	Non-Integrated Ballast LED, 186W, any bulb shape, any application	186W LED - Non-Int. Ballast	Electronic	N/A	N/A	186	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED187-FIXT	LED187W	Non-Integrated Ballast LED, 187W, any bulb shape, any application	187W LED - Non-Int. Ballast	Electronic	N/A	N/A	187	15
LED188-FIXT	LED188W	Non-Integrated Ballast LED, 188W, any bulb shape, any application	188W LED - Non-Int. Ballast	Electronic	N/A	N/A	188	15
LED189-FIXT	LED189W	Non-Integrated Ballast LED, 189W, any bulb shape, any application	189W LED - Non-Int. Ballast	Electronic	N/A	N/A	189	15
LED190-FIXT	LED190W	Non-Integrated Ballast LED, 190W, any bulb shape, any application	190W LED - Non-Int. Ballast	Electronic	N/A	N/A	190	15
LED191-FIXT	LED191W	Non-Integrated Ballast LED, 191W, any bulb shape, any application	191W LED - Non-Int. Ballast	Electronic	N/A	N/A	191	15
LED192-FIXT	LED192W	Non-Integrated Ballast LED, 192W, any bulb shape, any application	192W LED - Non-Int. Ballast	Electronic	N/A	N/A	192	15
LED193-FIXT	LED193W	Non-Integrated Ballast LED, 193W, any bulb shape, any application	193W LED - Non-Int. Ballast	Electronic	N/A	N/A	193	15
LED194-FIXT	LED194W	Non-Integrated Ballast LED, 194W, any bulb shape, any application	194W LED - Non-Int. Ballast	Electronic	N/A	N/A	194	15
LED195-FIXT	LED195W	Non-Integrated Ballast LED, 195W, any bulb shape, any application	195W LED - Non-Int. Ballast	Electronic	N/A	N/A	195	15
LED196-FIXT	LED196W	Non-Integrated Ballast LED, 196W, any bulb shape, any application	196W LED - Non-Int. Ballast	Electronic	N/A	N/A	196	15
LED197-FIXT	LED197W	Non-Integrated Ballast LED, 197W, any bulb shape, any application	197W LED - Non-Int. Ballast	Electronic	N/A	N/A	197	15
LED198-FIXT	LED198W	Non-Integrated Ballast LED, 198W, any bulb shape, any application	198W LED - Non-Int. Ballast	Electronic	N/A	N/A	198	15
LED199-FIXT	LED199W	Non-Integrated Ballast LED, 199W, any bulb shape, any application	199W LED - Non-Int. Ballast	Electronic	N/A	N/A	199	15
LED200-FIXT	LED200W	Non-Integrated Ballast LED, 200W, any bulb shape, any application	200W LED - Non-Int. Ballast	Electronic	N/A	N/A	200	15
LED201-FIXT	LED201W	Non-Integrated Ballast LED, 201W, any bulb shape, any application	201W LED - Non-Int. Ballast	Electronic	N/A	N/A	201	15
LED202-FIXT	LED202W	Non-Integrated Ballast LED, 202W, any bulb shape, any application	202W LED - Non-Int. Ballast	Electronic	N/A	N/A	202	15
LED203-FIXT	LED203W	Non-Integrated Ballast LED, 203W, any bulb shape, any application	203W LED - Non-Int. Ballast	Electronic	N/A	N/A	203	15
LED204-FIXT	LED204W	Non-Integrated Ballast LED, 204W, any bulb shape, any application	204W LED - Non-Int. Ballast	Electronic	N/A	N/A	204	15
LED205-FIXT	LED205W	Non-Integrated Ballast LED, 205W, any bulb shape, any application	205W LED - Non-Int. Ballast	Electronic	N/A	N/A	205	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED206-FIXT	LED206W	Non-Integrated Ballast LED, 206W, any bulb shape, any application	206W LED - Non-Int. Ballast	Electronic	N/A	N/A	206	15
LED207-FIXT	LED207W	Non-Integrated Ballast LED, 207W, any bulb shape, any application	207W LED - Non-Int. Ballast	Electronic	N/A	N/A	207	15
LED208-FIXT	LED208W	Non-Integrated Ballast LED, 208W, any bulb shape, any application	208W LED - Non-Int. Ballast	Electronic	N/A	N/A	208	15
LED209-FIXT	LED209W	Non-Integrated Ballast LED, 209W, any bulb shape, any application	209W LED - Non-Int. Ballast	Electronic	N/A	N/A	209	15
LED210-FIXT	LED210W	Non-Integrated Ballast LED, 210W, any bulb shape, any application	210W LED - Non-Int. Ballast	Electronic	N/A	N/A	210	15
LED211-FIXT	LED211W	Non-Integrated Ballast LED, 211W, any bulb shape, any application	211W LED - Non-Int. Ballast	Electronic	N/A	N/A	211	15
LED212-FIXT	LED212W	Non-Integrated Ballast LED, 212W, any bulb shape, any application	212W LED - Non-Int. Ballast	Electronic	N/A	N/A	212	15
LED213-FIXT	LED213W	Non-Integrated Ballast LED, 213W, any bulb shape, any application	213W LED - Non-Int. Ballast	Electronic	N/A	N/A	213	15
LED214-FIXT	LED214W	Non-Integrated Ballast LED, 214W, any bulb shape, any application	214W LED - Non-Int. Ballast	Electronic	N/A	N/A	214	15
LED215-FIXT	LED215W	Non-Integrated Ballast LED, 215W, any bulb shape, any application	215W LED - Non-Int. Ballast	Electronic	N/A	N/A	215	15
LED216-FIXT	LED216W	Non-Integrated Ballast LED, 216W, any bulb shape, any application	216W LED - Non-Int. Ballast	Electronic	N/A	N/A	216	15
LED217-FIXT	LED217W	Non-Integrated Ballast LED, 217W, any bulb shape, any application	217W LED - Non-Int. Ballast	Electronic	N/A	N/A	217	15
LED218-FIXT	LED218W	Non-Integrated Ballast LED, 218W, any bulb shape, any application	218W LED - Non-Int. Ballast	Electronic	N/A	N/A	218	15
LED219-FIXT	LED219W	Non-Integrated Ballast LED, 219W, any bulb shape, any application	219W LED - Non-Int. Ballast	Electronic	N/A	N/A	219	15
LED220-FIXT	LED220W	Non-Integrated Ballast LED, 220W, any bulb shape, any application	220W LED - Non-Int. Ballast	Electronic	N/A	N/A	220	15
LED221-FIXT	LED221W	Non-Integrated Ballast LED, 221W, any bulb shape, any application	221W LED - Non-Int. Ballast	Electronic	N/A	N/A	221	15
LED222-FIXT	LED222W	Non-Integrated Ballast LED, 222W, any bulb shape, any application	222W LED - Non-Int. Ballast	Electronic	N/A	N/A	222	15
LED223-FIXT	LED223W	Non-Integrated Ballast LED, 223W, any bulb shape, any application	223W LED - Non-Int. Ballast	Electronic	N/A	N/A	223	15
LED224-FIXT	LED224W	Non-Integrated Ballast LED, 224W, any bulb shape, any application	224W LED - Non-Int. Ballast	Electronic	N/A	N/A	224	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED225-FIXT	LED225W	Non-Integrated Ballast LED, 225W, any bulb shape, any application	225W LED - Non-Int. Ballast	Electronic	N/A	N/A	225	15
LED226-FIXT	LED226W	Non-Integrated Ballast LED, 226W, any bulb shape, any application	226W LED - Non-Int. Ballast	Electronic	N/A	N/A	226	15
LED227-FIXT	LED227W	Non-Integrated Ballast LED, 227W, any bulb shape, any application	227W LED - Non-Int. Ballast	Electronic	N/A	N/A	227	15
LED228-FIXT	LED228W	Non-Integrated Ballast LED, 228W, any bulb shape, any application	228W LED - Non-Int. Ballast	Electronic	N/A	N/A	228	15
LED229-FIXT	LED229W	Non-Integrated Ballast LED, 229W, any bulb shape, any application	229W LED - Non-Int. Ballast	Electronic	N/A	N/A	229	15
LED230-FIXT	LED230W	Non-Integrated Ballast LED, 230W, any bulb shape, any application	230W LED - Non-Int. Ballast	Electronic	N/A	N/A	230	15
LED231-FIXT	LED231W	Non-Integrated Ballast LED, 231W, any bulb shape, any application	231W LED - Non-Int. Ballast	Electronic	N/A	N/A	231	15
LED232-FIXT	LED232W	Non-Integrated Ballast LED, 232W, any bulb shape, any application	232W LED - Non-Int. Ballast	Electronic	N/A	N/A	232	15
LED233-FIXT	LED233W	Non-Integrated Ballast LED, 233W, any bulb shape, any application	233W LED - Non-Int. Ballast	Electronic	N/A	N/A	233	15
LED234-FIXT	LED234W	Non-Integrated Ballast LED, 234W, any bulb shape, any application	234W LED - Non-Int. Ballast	Electronic	N/A	N/A	234	15
LED235-FIXT	LED235W	Non-Integrated Ballast LED, 235W, any bulb shape, any application	235W LED - Non-Int. Ballast	Electronic	N/A	N/A	235	15
LED236-FIXT	LED236W	Non-Integrated Ballast LED, 236W, any bulb shape, any application	236W LED - Non-Int. Ballast	Electronic	N/A	N/A	236	15
LED237-FIXT	LED237W	Non-Integrated Ballast LED, 237W, any bulb shape, any application	237W LED - Non-Int. Ballast	Electronic	N/A	N/A	237	15
LED238-FIXT	LED238W	Non-Integrated Ballast LED, 238W, any bulb shape, any application	238W LED - Non-Int. Ballast	Electronic	N/A	N/A	238	15
LED239-FIXT	LED239W	Non-Integrated Ballast LED, 239W, any bulb shape, any application	239W LED - Non-Int. Ballast	Electronic	N/A	N/A	239	15
LED240-FIXT	LED240W	Non-Integrated Ballast LED, 240W, any bulb shape, any application	240W LED - Non-Int. Ballast	Electronic	N/A	N/A	240	15
LED241-FIXT	LED241W	Non-Integrated Ballast LED, 241W, any bulb shape, any application	241W LED - Non-Int. Ballast	Electronic	N/A	N/A	241	15
LED242-FIXT	LED242W	Non-Integrated Ballast LED, 242W, any bulb shape, any application	242W LED - Non-Int. Ballast	Electronic	N/A	N/A	242	15
LED243-FIXT	LED243W	Non-Integrated Ballast LED, 243W, any bulb shape, any application	243W LED - Non-Int. Ballast	Electronic	N/A	N/A	243	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED244-FIXT	LED244W	Non-Integrated Ballast LED, 244W, any bulb shape, any application	244W LED - Non-Int. Ballast	Electronic	N/A	N/A	244	15
LED245-FIXT	LED245W	Non-Integrated Ballast LED, 245W, any bulb shape, any application	245W LED - Non-Int. Ballast	Electronic	N/A	N/A	245	15
LED246-FIXT	LED246W	Non-Integrated Ballast LED, 246W, any bulb shape, any application	246W LED - Non-Int. Ballast	Electronic	N/A	N/A	246	15
LED247-FIXT	LED247W	Non-Integrated Ballast LED, 247W, any bulb shape, any application	247W LED - Non-Int. Ballast	Electronic	N/A	N/A	247	15
LED248-FIXT	LED248W	Non-Integrated Ballast LED, 248W, any bulb shape, any application	248W LED - Non-Int. Ballast	Electronic	N/A	N/A	248	15
LED249-FIXT	LED249W	Non-Integrated Ballast LED, 249W, any bulb shape, any application	249W LED - Non-Int. Ballast	Electronic	N/A	N/A	249	15
LED250-FIXT	LED250W	Non-Integrated Ballast LED, 250W, any bulb shape, any application	250W LED - Non-Int. Ballast	Electronic	N/A	N/A	250	15
LED251-FIXT	LED251W	Non-Integrated Ballast LED, 251W, any bulb shape, any application	251W LED - Non-Int. Ballast	Electronic	N/A	N/A	251	15
LED252-FIXT	LED252W	Non-Integrated Ballast LED, 252W, any bulb shape, any application	252W LED - Non-Int. Ballast	Electronic	N/A	N/A	252	15
LED253-FIXT	LED253W	Non-Integrated Ballast LED, 253W, any bulb shape, any application	253W LED - Non-Int. Ballast	Electronic	N/A	N/A	253	15
LED254-FIXT	LED254W	Non-Integrated Ballast LED, 254W, any bulb shape, any application	254W LED - Non-Int. Ballast	Electronic	N/A	N/A	254	15
LED255-FIXT	LED255W	Non-Integrated Ballast LED, 255W, any bulb shape, any application	255W LED - Non-Int. Ballast	Electronic	N/A	N/A	255	15
LED256-FIXT	LED256W	Non-Integrated Ballast LED, 256W, any bulb shape, any application	256W LED - Non-Int. Ballast	Electronic	N/A	N/A	256	15
LED257-FIXT	LED257W	Non-Integrated Ballast LED, 257W, any bulb shape, any application	257W LED - Non-Int. Ballast	Electronic	N/A	N/A	257	15
LED258-FIXT	LED258W	Non-Integrated Ballast LED, 258W, any bulb shape, any application	258W LED - Non-Int. Ballast	Electronic	N/A	N/A	258	15
LED259-FIXT	LED259W	Non-Integrated Ballast LED, 259W, any bulb shape, any application	259W LED - Non-Int. Ballast	Electronic	N/A	N/A	259	15
LED260-FIXT	LED260W	Non-Integrated Ballast LED, 260W, any bulb shape, any application	260W LED - Non-Int. Ballast	Electronic	N/A	N/A	260	15
LED261-FIXT	LED261W	Non-Integrated Ballast LED, 261W, any bulb shape, any application	261W LED - Non-Int. Ballast	Electronic	N/A	N/A	261	15
LED262-FIXT	LED262W	Non-Integrated Ballast LED, 262W, any bulb shape, any application	262W LED - Non-Int. Ballast	Electronic	N/A	N/A	262	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED263-FIXT	LED263W	Non-Integrated Ballast LED, 263W, any bulb shape, any application	263W LED - Non-Int. Ballast	Electronic	N/A	N/A	263	15
LED264-FIXT	LED264W	Non-Integrated Ballast LED, 264W, any bulb shape, any application	264W LED - Non-Int. Ballast	Electronic	N/A	N/A	264	15
LED265-FIXT	LED265W	Non-Integrated Ballast LED, 265W, any bulb shape, any application	265W LED - Non-Int. Ballast	Electronic	N/A	N/A	265	15
LED266-FIXT	LED266W	Non-Integrated Ballast LED, 266W, any bulb shape, any application	266W LED - Non-Int. Ballast	Electronic	N/A	N/A	266	15
LED267-FIXT	LED267W	Non-Integrated Ballast LED, 267W, any bulb shape, any application	267W LED - Non-Int. Ballast	Electronic	N/A	N/A	267	15
LED268-FIXT	LED268W	Non-Integrated Ballast LED, 268W, any bulb shape, any application	268W LED - Non-Int. Ballast	Electronic	N/A	N/A	268	15
LED269-FIXT	LED269W	Non-Integrated Ballast LED, 269W, any bulb shape, any application	269W LED - Non-Int. Ballast	Electronic	N/A	N/A	269	15
LED270-FIXT	LED270W	Non-Integrated Ballast LED, 270W, any bulb shape, any application	270W LED - Non-Int. Ballast	Electronic	N/A	N/A	270	15
LED271-FIXT	LED271W	Non-Integrated Ballast LED, 271W, any bulb shape, any application	271W LED - Non-Int. Ballast	Electronic	N/A	N/A	271	15
LED272-FIXT	LED272W	Non-Integrated Ballast LED, 272W, any bulb shape, any application	272W LED - Non-Int. Ballast	Electronic	N/A	N/A	272	15
LED273-FIXT	LED273W	Non-Integrated Ballast LED, 273W, any bulb shape, any application	273W LED - Non-Int. Ballast	Electronic	N/A	N/A	273	15
LED274-FIXT	LED274W	Non-Integrated Ballast LED, 274W, any bulb shape, any application	274W LED - Non-Int. Ballast	Electronic	N/A	N/A	274	15
LED275-FIXT	LED275W	Non-Integrated Ballast LED, 275W, any bulb shape, any application	275W LED - Non-Int. Ballast	Electronic	N/A	N/A	275	15
LED276-FIXT	LED276W	Non-Integrated Ballast LED, 276W, any bulb shape, any application	276W LED - Non-Int. Ballast	Electronic	N/A	N/A	276	15
LED277-FIXT	LED277W	Non-Integrated Ballast LED, 277W, any bulb shape, any application	277W LED - Non-Int. Ballast	Electronic	N/A	N/A	277	15
LED278-FIXT	LED278W	Non-Integrated Ballast LED, 278W, any bulb shape, any application	278W LED - Non-Int. Ballast	Electronic	N/A	N/A	278	15
LED279-FIXT	LED279W	Non-Integrated Ballast LED, 279W, any bulb shape, any application	279W LED - Non-Int. Ballast	Electronic	N/A	N/A	279	15
LED280-FIXT	LED280W	Non-Integrated Ballast LED, 280W, any bulb shape, any application	280W LED - Non-Int. Ballast	Electronic	N/A	N/A	280	15
LED281-FIXT	LED281W	Non-Integrated Ballast LED, 281W, any bulb shape, any application	281W LED - Non-Int. Ballast	Electronic	N/A	N/A	281	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED282-FIXT	LED282W	Non-Integrated Ballast LED, 282W, any bulb shape, any application	282W LED - Non-Int. Ballast	Electronic	N/A	N/A	282	15
LED283-FIXT	LED283W	Non-Integrated Ballast LED, 283W, any bulb shape, any application	283W LED - Non-Int. Ballast	Electronic	N/A	N/A	283	15
LED284-FIXT	LED284W	Non-Integrated Ballast LED, 284W, any bulb shape, any application	284W LED - Non-Int. Ballast	Electronic	N/A	N/A	284	15
LED285-FIXT	LED285W	Non-Integrated Ballast LED, 285W, any bulb shape, any application	285W LED - Non-Int. Ballast	Electronic	N/A	N/A	285	15
LED286-FIXT	LED286W	Non-Integrated Ballast LED, 286W, any bulb shape, any application	286W LED - Non-Int. Ballast	Electronic	N/A	N/A	286	15
LED287-FIXT	LED287W	Non-Integrated Ballast LED, 287W, any bulb shape, any application	287W LED - Non-Int. Ballast	Electronic	N/A	N/A	287	15
LED288-FIXT	LED288W	Non-Integrated Ballast LED, 288W, any bulb shape, any application	288W LED - Non-Int. Ballast	Electronic	N/A	N/A	288	15
LED289-FIXT	LED289W	Non-Integrated Ballast LED, 289W, any bulb shape, any application	289W LED - Non-Int. Ballast	Electronic	N/A	N/A	289	15
LED290-FIXT	LED290W	Non-Integrated Ballast LED, 290W, any bulb shape, any application	290W LED - Non-Int. Ballast	Electronic	N/A	N/A	290	15
LED291-FIXT	LED291W	Non-Integrated Ballast LED, 291W, any bulb shape, any application	291W LED - Non-Int. Ballast	Electronic	N/A	N/A	291	15
LED292-FIXT	LED292W	Non-Integrated Ballast LED, 292W, any bulb shape, any application	292W LED - Non-Int. Ballast	Electronic	N/A	N/A	292	15
LED293-FIXT	LED293W	Non-Integrated Ballast LED, 293W, any bulb shape, any application	293W LED - Non-Int. Ballast	Electronic	N/A	N/A	293	15
LED294-FIXT	LED294W	Non-Integrated Ballast LED, 294W, any bulb shape, any application	294W LED - Non-Int. Ballast	Electronic	N/A	N/A	294	15
LED295-FIXT	LED295W	Non-Integrated Ballast LED, 295W, any bulb shape, any application	295W LED - Non-Int. Ballast	Electronic	N/A	N/A	295	15
LED296-FIXT	LED296W	Non-Integrated Ballast LED, 296W, any bulb shape, any application	296W LED - Non-Int. Ballast	Electronic	N/A	N/A	296	15
LED297-FIXT	LED297W	Non-Integrated Ballast LED, 297W, any bulb shape, any application	297W LED - Non-Int. Ballast	Electronic	N/A	N/A	297	15
LED298-FIXT	LED298W	Non-Integrated Ballast LED, 298W, any bulb shape, any application	298W LED - Non-Int. Ballast	Electronic	N/A	N/A	298	15
LED299-FIXT	LED299W	Non-Integrated Ballast LED, 299W, any bulb shape, any application	299W LED - Non-Int. Ballast	Electronic	N/A	N/A	299	15
LED300-FIXT	LED300W	Non-Integrated Ballast LED, 300W, any bulb shape, any application	300W LED - Non-Int. Ballast	Electronic	N/A	N/A	300	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED301-FIXT	LED301W	Non-Integrated Ballast LED, 301W, any bulb shape, any application	301W LED - Non-Int. Ballast	Electronic	N/A	N/A	301	15
LED302-FIXT	LED302W	Non-Integrated Ballast LED, 302W, any bulb shape, any application	302W LED - Non-Int. Ballast	Electronic	N/A	N/A	302	15
LED303-FIXT	LED303W	Non-Integrated Ballast LED, 303W, any bulb shape, any application	303W LED - Non-Int. Ballast	Electronic	N/A	N/A	303	15
LED304-FIXT	LED304W	Non-Integrated Ballast LED, 304W, any bulb shape, any application	304W LED - Non-Int. Ballast	Electronic	N/A	N/A	304	15
LED305-FIXT	LED305W	Non-Integrated Ballast LED, 305W, any bulb shape, any application	305W LED - Non-Int. Ballast	Electronic	N/A	N/A	305	15
LED306-FIXT	LED306W	Non-Integrated Ballast LED, 306W, any bulb shape, any application	306W LED - Non-Int. Ballast	Electronic	N/A	N/A	306	15
LED307-FIXT	LED307W	Non-Integrated Ballast LED, 307W, any bulb shape, any application	307W LED - Non-Int. Ballast	Electronic	N/A	N/A	307	15
LED308-FIXT	LED308W	Non-Integrated Ballast LED, 308W, any bulb shape, any application	308W LED - Non-Int. Ballast	Electronic	N/A	N/A	308	15
LED309-FIXT	LED309W	Non-Integrated Ballast LED, 309W, any bulb shape, any application	309W LED - Non-Int. Ballast	Electronic	N/A	N/A	309	15
LED310-FIXT	LED310W	Non-Integrated Ballast LED, 310W, any bulb shape, any application	310W LED - Non-Int. Ballast	Electronic	N/A	N/A	310	15
LED311-FIXT	LED311W	Non-Integrated Ballast LED, 311W, any bulb shape, any application	311W LED - Non-Int. Ballast	Electronic	N/A	N/A	311	15
LED312-FIXT	LED312W	Non-Integrated Ballast LED, 312W, any bulb shape, any application	312W LED - Non-Int. Ballast	Electronic	N/A	N/A	312	15
LED313-FIXT	LED313W	Non-Integrated Ballast LED, 313W, any bulb shape, any application	313W LED - Non-Int. Ballast	Electronic	N/A	N/A	313	15
LED314-FIXT	LED314W	Non-Integrated Ballast LED, 314W, any bulb shape, any application	314W LED - Non-Int. Ballast	Electronic	N/A	N/A	314	15
LED315-FIXT	LED315W	Non-Integrated Ballast LED, 315W, any bulb shape, any application	315W LED - Non-Int. Ballast	Electronic	N/A	N/A	315	15
LED316-FIXT	LED316W	Non-Integrated Ballast LED, 316W, any bulb shape, any application	316W LED - Non-Int. Ballast	Electronic	N/A	N/A	316	15
LED317-FIXT	LED317W	Non-Integrated Ballast LED, 317W, any bulb shape, any application	317W LED - Non-Int. Ballast	Electronic	N/A	N/A	317	15
LED318-FIXT	LED318W	Non-Integrated Ballast LED, 318W, any bulb shape, any application	318W LED - Non-Int. Ballast	Electronic	N/A	N/A	318	15
LED319-FIXT	LED319W	Non-Integrated Ballast LED, 319W, any bulb shape, any application	319W LED - Non-Int. Ballast	Electronic	N/A	N/A	319	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED320-FIXT	LED320W	Non-Integrated Ballast LED, 320W, any bulb shape, any application	320W LED - Non-Int. Ballast	Electronic	N/A	N/A	320	15
LED321-FIXT	LED321W	Non-Integrated Ballast LED, 321W, any bulb shape, any application	321W LED - Non-Int. Ballast	Electronic	N/A	N/A	321	15
LED322-FIXT	LED322W	Non-Integrated Ballast LED, 322W, any bulb shape, any application	322W LED - Non-Int. Ballast	Electronic	N/A	N/A	322	15
LED323-FIXT	LED323W	Non-Integrated Ballast LED, 323W, any bulb shape, any application	323W LED - Non-Int. Ballast	Electronic	N/A	N/A	323	15
LED324-FIXT	LED324W	Non-Integrated Ballast LED, 324W, any bulb shape, any application	324W LED - Non-Int. Ballast	Electronic	N/A	N/A	324	15
LED325-FIXT	LED325W	Non-Integrated Ballast LED, 325W, any bulb shape, any application	325W LED - Non-Int. Ballast	Electronic	N/A	N/A	325	15
LED326-FIXT	LED326W	Non-Integrated Ballast LED, 326W, any bulb shape, any application	326W LED - Non-Int. Ballast	Electronic	N/A	N/A	326	15
LED327-FIXT	LED327W	Non-Integrated Ballast LED, 327W, any bulb shape, any application	327W LED - Non-Int. Ballast	Electronic	N/A	N/A	327	15
LED328-FIXT	LED328W	Non-Integrated Ballast LED, 328W, any bulb shape, any application	328W LED - Non-Int. Ballast	Electronic	N/A	N/A	328	15
LED329-FIXT	LED329W	Non-Integrated Ballast LED, 329W, any bulb shape, any application	329W LED - Non-Int. Ballast	Electronic	N/A	N/A	329	15
LED330-FIXT	LED330W	Non-Integrated Ballast LED, 330W, any bulb shape, any application	330W LED - Non-Int. Ballast	Electronic	N/A	N/A	330	15
LED331-FIXT	LED331W	Non-Integrated Ballast LED, 331W, any bulb shape, any application	331W LED - Non-Int. Ballast	Electronic	N/A	N/A	331	15
LED332-FIXT	LED332W	Non-Integrated Ballast LED, 332W, any bulb shape, any application	332W LED - Non-Int. Ballast	Electronic	N/A	N/A	332	15
LED333-FIXT	LED333W	Non-Integrated Ballast LED, 333W, any bulb shape, any application	333W LED - Non-Int. Ballast	Electronic	N/A	N/A	333	15
LED334-FIXT	LED334W	Non-Integrated Ballast LED, 334W, any bulb shape, any application	334W LED - Non-Int. Ballast	Electronic	N/A	N/A	334	15
LED335-FIXT	LED335W	Non-Integrated Ballast LED, 335W, any bulb shape, any application	335W LED - Non-Int. Ballast	Electronic	N/A	N/A	335	15
LED336-FIXT	LED336W	Non-Integrated Ballast LED, 336W, any bulb shape, any application	336W LED - Non-Int. Ballast	Electronic	N/A	N/A	336	15
LED337-FIXT	LED337W	Non-Integrated Ballast LED, 337W, any bulb shape, any application	337W LED - Non-Int. Ballast	Electronic	N/A	N/A	337	15
LED338-FIXT	LED338W	Non-Integrated Ballast LED, 338W, any bulb shape, any application	338W LED - Non-Int. Ballast	Electronic	N/A	N/A	338	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED339-FIXT	LED339W	Non-Integrated Ballast LED, 339W, any bulb shape, any application	339W LED - Non-Int. Ballast	Electronic	N/A	N/A	339	15
LED340-FIXT	LED340W	Non-Integrated Ballast LED, 340W, any bulb shape, any application	340W LED - Non-Int. Ballast	Electronic	N/A	N/A	340	15
LED341-FIXT	LED341W	Non-Integrated Ballast LED, 341W, any bulb shape, any application	341W LED - Non-Int. Ballast	Electronic	N/A	N/A	341	15
LED342-FIXT	LED342W	Non-Integrated Ballast LED, 342W, any bulb shape, any application	342W LED - Non-Int. Ballast	Electronic	N/A	N/A	342	15
LED343-FIXT	LED343W	Non-Integrated Ballast LED, 343W, any bulb shape, any application	343W LED - Non-Int. Ballast	Electronic	N/A	N/A	343	15
LED344-FIXT	LED344W	Non-Integrated Ballast LED, 344W, any bulb shape, any application	344W LED - Non-Int. Ballast	Electronic	N/A	N/A	344	15
LED345-FIXT	LED345W	Non-Integrated Ballast LED, 345W, any bulb shape, any application	345W LED - Non-Int. Ballast	Electronic	N/A	N/A	345	15
LED346-FIXT	LED346W	Non-Integrated Ballast LED, 346W, any bulb shape, any application	346W LED - Non-Int. Ballast	Electronic	N/A	N/A	346	15
LED347-FIXT	LED347W	Non-Integrated Ballast LED, 347W, any bulb shape, any application	347W LED - Non-Int. Ballast	Electronic	N/A	N/A	347	15
LED348-FIXT	LED348W	Non-Integrated Ballast LED, 348W, any bulb shape, any application	348W LED - Non-Int. Ballast	Electronic	N/A	N/A	348	15
LED349-FIXT	LED349W	Non-Integrated Ballast LED, 349W, any bulb shape, any application	349W LED - Non-Int. Ballast	Electronic	N/A	N/A	349	15
LED350-FIXT	LED350W	Non-Integrated Ballast LED, 350W, any bulb shape, any application	350W LED - Non-Int. Ballast	Electronic	N/A	N/A	350	15
LED351-FIXT	LED351W	Non-Integrated Ballast LED, 351W, any bulb shape, any application	351W LED - Non-Int. Ballast	Electronic	N/A	N/A	351	15
LED352-FIXT	LED352W	Non-Integrated Ballast LED, 352W, any bulb shape, any application	352W LED - Non-Int. Ballast	Electronic	N/A	N/A	352	15
LED353-FIXT	LED353W	Non-Integrated Ballast LED, 353W, any bulb shape, any application	353W LED - Non-Int. Ballast	Electronic	N/A	N/A	353	15
LED354-FIXT	LED354W	Non-Integrated Ballast LED, 354W, any bulb shape, any application	354W LED - Non-Int. Ballast	Electronic	N/A	N/A	354	15
LED355-FIXT	LED355W	Non-Integrated Ballast LED, 355W, any bulb shape, any application	355W LED - Non-Int. Ballast	Electronic	N/A	N/A	355	15
LED356-FIXT	LED356W	Non-Integrated Ballast LED, 356W, any bulb shape, any application	356W LED - Non-Int. Ballast	Electronic	N/A	N/A	356	15
LED357-FIXT	LED357W	Non-Integrated Ballast LED, 357W, any bulb shape, any application	357W LED - Non-Int. Ballast	Electronic	N/A	N/A	357	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED358-FIXT	LED358W	Non-Integrated Ballast LED, 358W, any bulb shape, any application	358W LED - Non-Int. Ballast	Electronic	N/A	N/A	358	15
LED359-FIXT	LED359W	Non-Integrated Ballast LED, 359W, any bulb shape, any application	359W LED - Non-Int. Ballast	Electronic	N/A	N/A	359	15
LED360-FIXT	LED360W	Non-Integrated Ballast LED, 360W, any bulb shape, any application	360W LED - Non-Int. Ballast	Electronic	N/A	N/A	360	15
LED361-FIXT	LED361W	Non-Integrated Ballast LED, 361W, any bulb shape, any application	361W LED - Non-Int. Ballast	Electronic	N/A	N/A	361	15
LED362-FIXT	LED362W	Non-Integrated Ballast LED, 362W, any bulb shape, any application	362W LED - Non-Int. Ballast	Electronic	N/A	N/A	362	15
LED363-FIXT	LED363W	Non-Integrated Ballast LED, 363W, any bulb shape, any application	363W LED - Non-Int. Ballast	Electronic	N/A	N/A	363	15
LED364-FIXT	LED364W	Non-Integrated Ballast LED, 364W, any bulb shape, any application	364W LED - Non-Int. Ballast	Electronic	N/A	N/A	364	15
LED365-FIXT	LED365W	Non-Integrated Ballast LED, 365W, any bulb shape, any application	365W LED - Non-Int. Ballast	Electronic	N/A	N/A	365	15
LED366-FIXT	LED366W	Non-Integrated Ballast LED, 366W, any bulb shape, any application	366W LED - Non-Int. Ballast	Electronic	N/A	N/A	366	15
LED367-FIXT	LED367W	Non-Integrated Ballast LED, 367W, any bulb shape, any application	367W LED - Non-Int. Ballast	Electronic	N/A	N/A	367	15
LED368-FIXT	LED368W	Non-Integrated Ballast LED, 368W, any bulb shape, any application	368W LED - Non-Int. Ballast	Electronic	N/A	N/A	368	15
LED369-FIXT	LED369W	Non-Integrated Ballast LED, 369W, any bulb shape, any application	369W LED - Non-Int. Ballast	Electronic	N/A	N/A	369	15
LED370-FIXT	LED370W	Non-Integrated Ballast LED, 370W, any bulb shape, any application	370W LED - Non-Int. Ballast	Electronic	N/A	N/A	370	15
LED371-FIXT	LED371W	Non-Integrated Ballast LED, 371W, any bulb shape, any application	371W LED - Non-Int. Ballast	Electronic	N/A	N/A	371	15
LED372-FIXT	LED372W	Non-Integrated Ballast LED, 372W, any bulb shape, any application	372W LED - Non-Int. Ballast	Electronic	N/A	N/A	372	15
LED373-FIXT	LED373W	Non-Integrated Ballast LED, 373W, any bulb shape, any application	373W LED - Non-Int. Ballast	Electronic	N/A	N/A	373	15
LED374-FIXT	LED374W	Non-Integrated Ballast LED, 374W, any bulb shape, any application	374W LED - Non-Int. Ballast	Electronic	N/A	N/A	374	15
LED375-FIXT	LED375W	Non-Integrated Ballast LED, 375W, any bulb shape, any application	375W LED - Non-Int. Ballast	Electronic	N/A	N/A	375	15
LED376-FIXT	LED376W	Non-Integrated Ballast LED, 376W, any bulb shape, any application	376W LED - Non-Int. Ballast	Electronic	N/A	N/A	376	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED377-FIXT	LED377W	Non-Integrated Ballast LED, 377W, any bulb shape, any application	377W LED - Non-Int. Ballast	Electronic	N/A	N/A	377	15
LED378-FIXT	LED378W	Non-Integrated Ballast LED, 378W, any bulb shape, any application	378W LED - Non-Int. Ballast	Electronic	N/A	N/A	378	15
LED379-FIXT	LED379W	Non-Integrated Ballast LED, 379W, any bulb shape, any application	379W LED - Non-Int. Ballast	Electronic	N/A	N/A	379	15
LED380-FIXT	LED380W	Non-Integrated Ballast LED, 380W, any bulb shape, any application	380W LED - Non-Int. Ballast	Electronic	N/A	N/A	380	15
LED381-FIXT	LED381W	Non-Integrated Ballast LED, 381W, any bulb shape, any application	381W LED - Non-Int. Ballast	Electronic	N/A	N/A	381	15
LED382-FIXT	LED382W	Non-Integrated Ballast LED, 382W, any bulb shape, any application	382W LED - Non-Int. Ballast	Electronic	N/A	N/A	382	15
LED383-FIXT	LED383W	Non-Integrated Ballast LED, 383W, any bulb shape, any application	383W LED - Non-Int. Ballast	Electronic	N/A	N/A	383	15
LED384-FIXT	LED384W	Non-Integrated Ballast LED, 384W, any bulb shape, any application	384W LED - Non-Int. Ballast	Electronic	N/A	N/A	384	15
LED385-FIXT	LED385W	Non-Integrated Ballast LED, 385W, any bulb shape, any application	385W LED - Non-Int. Ballast	Electronic	N/A	N/A	385	15
LED386-FIXT	LED386W	Non-Integrated Ballast LED, 386W, any bulb shape, any application	386W LED - Non-Int. Ballast	Electronic	N/A	N/A	386	15
LED387-FIXT	LED387W	Non-Integrated Ballast LED, 387W, any bulb shape, any application	387W LED - Non-Int. Ballast	Electronic	N/A	N/A	387	15
LED388-FIXT	LED388W	Non-Integrated Ballast LED, 388W, any bulb shape, any application	388W LED - Non-Int. Ballast	Electronic	N/A	N/A	388	15
LED389-FIXT	LED389W	Non-Integrated Ballast LED, 389W, any bulb shape, any application	389W LED - Non-Int. Ballast	Electronic	N/A	N/A	389	15
LED390-FIXT	LED390W	Non-Integrated Ballast LED, 390W, any bulb shape, any application	390W LED - Non-Int. Ballast	Electronic	N/A	N/A	390	15
LED391-FIXT	LED391W	Non-Integrated Ballast LED, 391W, any bulb shape, any application	391W LED - Non-Int. Ballast	Electronic	N/A	N/A	391	15
LED392-FIXT	LED392W	Non-Integrated Ballast LED, 392W, any bulb shape, any application	392W LED - Non-Int. Ballast	Electronic	N/A	N/A	392	15
LED393-FIXT	LED393W	Non-Integrated Ballast LED, 393W, any bulb shape, any application	393W LED - Non-Int. Ballast	Electronic	N/A	N/A	393	15
LED394-FIXT	LED394W	Non-Integrated Ballast LED, 394W, any bulb shape, any application	394W LED - Non-Int. Ballast	Electronic	N/A	N/A	394	15
LED395-FIXT	LED395W	Non-Integrated Ballast LED, 395W, any bulb shape, any application	395W LED - Non-Int. Ballast	Electronic	N/A	N/A	395	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED396-FIXT	LED396W	Non-Integrated Ballast LED, 396W, any bulb shape, any application	396W LED - Non-Int. Ballast	Electronic	N/A	N/A	396	15
LED397-FIXT	LED397W	Non-Integrated Ballast LED, 397W, any bulb shape, any application	397W LED - Non-Int. Ballast	Electronic	N/A	N/A	397	15
LED398-FIXT	LED398W	Non-Integrated Ballast LED, 398W, any bulb shape, any application	398W LED - Non-Int. Ballast	Electronic	N/A	N/A	398	15
LED399-FIXT	LED399W	Non-Integrated Ballast LED, 399W, any bulb shape, any application	399W LED - Non-Int. Ballast	Electronic	N/A	N/A	399	15
LED400-FIXT	LED400W	Non-Integrated Ballast LED, 400W, any bulb shape, any application	400W LED - Non-Int. Ballast	Electronic	N/A	N/A	400	15
LED401-FIXT	LED401W	Non-Integrated Ballast LED, 401W, any bulb shape, any application	401W LED - Non-Int. Ballast	Electronic	N/A	N/A	401	15
LED402-FIXT	LED402W	Non-Integrated Ballast LED, 402W, any bulb shape, any application	402W LED - Non-Int. Ballast	Electronic	N/A	N/A	402	15
LED403-FIXT	LED403W	Non-Integrated Ballast LED, 403W, any bulb shape, any application	403W LED - Non-Int. Ballast	Electronic	N/A	N/A	403	15
LED404-FIXT	LED404W	Non-Integrated Ballast LED, 404W, any bulb shape, any application	404W LED - Non-Int. Ballast	Electronic	N/A	N/A	404	15
LED405-FIXT	LED405W	Non-Integrated Ballast LED, 405W, any bulb shape, any application	405W LED - Non-Int. Ballast	Electronic	N/A	N/A	405	15
LED406-FIXT	LED406W	Non-Integrated Ballast LED, 406W, any bulb shape, any application	406W LED - Non-Int. Ballast	Electronic	N/A	N/A	406	15
LED407-FIXT	LED407W	Non-Integrated Ballast LED, 407W, any bulb shape, any application	407W LED - Non-Int. Ballast	Electronic	N/A	N/A	407	15
LED408-FIXT	LED408W	Non-Integrated Ballast LED, 408W, any bulb shape, any application	408W LED - Non-Int. Ballast	Electronic	N/A	N/A	408	15
LED409-FIXT	LED409W	Non-Integrated Ballast LED, 409W, any bulb shape, any application	409W LED - Non-Int. Ballast	Electronic	N/A	N/A	409	15
LED410-FIXT	LED410W	Non-Integrated Ballast LED, 410W, any bulb shape, any application	410W LED - Non-Int. Ballast	Electronic	N/A	N/A	410	15
LED411-FIXT	LED411W	Non-Integrated Ballast LED, 411W, any bulb shape, any application	411W LED - Non-Int. Ballast	Electronic	N/A	N/A	411	15
LED412-FIXT	LED412W	Non-Integrated Ballast LED, 412W, any bulb shape, any application	412W LED - Non-Int. Ballast	Electronic	N/A	N/A	412	15
LED413-FIXT	LED413W	Non-Integrated Ballast LED, 413W, any bulb shape, any application	413W LED - Non-Int. Ballast	Electronic	N/A	N/A	413	15
LED414-FIXT	LED414W	Non-Integrated Ballast LED, 414W, any bulb shape, any application	414W LED - Non-Int. Ballast	Electronic	N/A	N/A	414	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED415-FIXT	LED415W	Non-Integrated Ballast LED, 415W, any bulb shape, any application	415W LED - Non-Int. Ballast	Electronic	N/A	N/A	415	15
LED416-FIXT	LED416W	Non-Integrated Ballast LED, 416W, any bulb shape, any application	416W LED - Non-Int. Ballast	Electronic	N/A	N/A	416	15
LED417-FIXT	LED417W	Non-Integrated Ballast LED, 417W, any bulb shape, any application	417W LED - Non-Int. Ballast	Electronic	N/A	N/A	417	15
LED418-FIXT	LED418W	Non-Integrated Ballast LED, 418W, any bulb shape, any application	418W LED - Non-Int. Ballast	Electronic	N/A	N/A	418	15
LED419-FIXT	LED419W	Non-Integrated Ballast LED, 419W, any bulb shape, any application	419W LED - Non-Int. Ballast	Electronic	N/A	N/A	419	15
LED420-FIXT	LED420W	Non-Integrated Ballast LED, 420W, any bulb shape, any application	420W LED - Non-Int. Ballast	Electronic	N/A	N/A	420	15
LED421-FIXT	LED421W	Non-Integrated Ballast LED, 421W, any bulb shape, any application	421W LED - Non-Int. Ballast	Electronic	N/A	N/A	421	15
LED422-FIXT	LED422W	Non-Integrated Ballast LED, 422W, any bulb shape, any application	422W LED - Non-Int. Ballast	Electronic	N/A	N/A	422	15
LED423-FIXT	LED423W	Non-Integrated Ballast LED, 423W, any bulb shape, any application	423W LED - Non-Int. Ballast	Electronic	N/A	N/A	423	15
LED424-FIXT	LED424W	Non-Integrated Ballast LED, 424W, any bulb shape, any application	424W LED - Non-Int. Ballast	Electronic	N/A	N/A	424	15
LED425-FIXT	LED425W	Non-Integrated Ballast LED, 425W, any bulb shape, any application	425W LED - Non-Int. Ballast	Electronic	N/A	N/A	425	15
LED426-FIXT	LED426W	Non-Integrated Ballast LED, 426W, any bulb shape, any application	426W LED - Non-Int. Ballast	Electronic	N/A	N/A	426	15
LED427-FIXT	LED427W	Non-Integrated Ballast LED, 427W, any bulb shape, any application	427W LED - Non-Int. Ballast	Electronic	N/A	N/A	427	15
LED428-FIXT	LED428W	Non-Integrated Ballast LED, 428W, any bulb shape, any application	428W LED - Non-Int. Ballast	Electronic	N/A	N/A	428	15
LED429-FIXT	LED429W	Non-Integrated Ballast LED, 429W, any bulb shape, any application	429W LED - Non-Int. Ballast	Electronic	N/A	N/A	429	15
LED430-FIXT	LED430W	Non-Integrated Ballast LED, 430W, any bulb shape, any application	430W LED - Non-Int. Ballast	Electronic	N/A	N/A	430	15
LED431-FIXT	LED431W	Non-Integrated Ballast LED, 431W, any bulb shape, any application	431W LED - Non-Int. Ballast	Electronic	N/A	N/A	431	15
LED432-FIXT	LED432W	Non-Integrated Ballast LED, 432W, any bulb shape, any application	432W LED - Non-Int. Ballast	Electronic	N/A	N/A	432	15
LED433-FIXT	LED433W	Non-Integrated Ballast LED, 433W, any bulb shape, any application	433W LED - Non-Int. Ballast	Electronic	N/A	N/A	433	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED434-FIXT	LED434W	Non-Integrated Ballast LED, 434W, any bulb shape, any application	434W LED - Non-Int. Ballast	Electronic	N/A	N/A	434	15
LED435-FIXT	LED435W	Non-Integrated Ballast LED, 435W, any bulb shape, any application	435W LED - Non-Int. Ballast	Electronic	N/A	N/A	435	15
LED436-FIXT	LED436W	Non-Integrated Ballast LED, 436W, any bulb shape, any application	436W LED - Non-Int. Ballast	Electronic	N/A	N/A	436	15
LED437-FIXT	LED437W	Non-Integrated Ballast LED, 437W, any bulb shape, any application	437W LED - Non-Int. Ballast	Electronic	N/A	N/A	437	15
LED438-FIXT	LED438W	Non-Integrated Ballast LED, 438W, any bulb shape, any application	438W LED - Non-Int. Ballast	Electronic	N/A	N/A	438	15
LED439-FIXT	LED439W	Non-Integrated Ballast LED, 439W, any bulb shape, any application	439W LED - Non-Int. Ballast	Electronic	N/A	N/A	439	15
LED440-FIXT	LED440W	Non-Integrated Ballast LED, 440W, any bulb shape, any application	440W LED - Non-Int. Ballast	Electronic	N/A	N/A	440	15
LED441-FIXT	LED441W	Non-Integrated Ballast LED, 441W, any bulb shape, any application	441W LED - Non-Int. Ballast	Electronic	N/A	N/A	441	15
LED442-FIXT	LED442W	Non-Integrated Ballast LED, 442W, any bulb shape, any application	442W LED - Non-Int. Ballast	Electronic	N/A	N/A	442	15
LED443-FIXT	LED443W	Non-Integrated Ballast LED, 443W, any bulb shape, any application	443W LED - Non-Int. Ballast	Electronic	N/A	N/A	443	15
LED444-FIXT	LED444W	Non-Integrated Ballast LED, 444W, any bulb shape, any application	444W LED - Non-Int. Ballast	Electronic	N/A	N/A	444	15
LED445-FIXT	LED445W	Non-Integrated Ballast LED, 445W, any bulb shape, any application	445W LED - Non-Int. Ballast	Electronic	N/A	N/A	445	15
LED446-FIXT	LED446W	Non-Integrated Ballast LED, 446W, any bulb shape, any application	446W LED - Non-Int. Ballast	Electronic	N/A	N/A	446	15
LED447-FIXT	LED447W	Non-Integrated Ballast LED, 447W, any bulb shape, any application	447W LED - Non-Int. Ballast	Electronic	N/A	N/A	447	15
LED448-FIXT	LED448W	Non-Integrated Ballast LED, 448W, any bulb shape, any application	448W LED - Non-Int. Ballast	Electronic	N/A	N/A	448	15
LED449-FIXT	LED449W	Non-Integrated Ballast LED, 449W, any bulb shape, any application	449W LED - Non-Int. Ballast	Electronic	N/A	N/A	449	15
LED450-FIXT	LED450W	Non-Integrated Ballast LED, 450W, any bulb shape, any application	450W LED - Non-Int. Ballast	Electronic	N/A	N/A	450	15
LED451-FIXT	LED451W	Non-Integrated Ballast LED, 451W, any bulb shape, any application	451W LED - Non-Int. Ballast	Electronic	N/A	N/A	451	15
LED452-FIXT	LED452W	Non-Integrated Ballast LED, 452W, any bulb shape, any application	452W LED - Non-Int. Ballast	Electronic	N/A	N/A	452	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED453-FIXT	LED453W	Non-Integrated Ballast LED, 453W, any bulb shape, any application	453W LED - Non-Int. Ballast	Electronic	N/A	N/A	453	15
LED454-FIXT	LED454W	Non-Integrated Ballast LED, 454W, any bulb shape, any application	454W LED - Non-Int. Ballast	Electronic	N/A	N/A	454	15
LED455-FIXT	LED455W	Non-Integrated Ballast LED, 455W, any bulb shape, any application	455W LED - Non-Int. Ballast	Electronic	N/A	N/A	455	15
LED456-FIXT	LED456W	Non-Integrated Ballast LED, 456W, any bulb shape, any application	456W LED - Non-Int. Ballast	Electronic	N/A	N/A	456	15
LED457-FIXT	LED457W	Non-Integrated Ballast LED, 457W, any bulb shape, any application	457W LED - Non-Int. Ballast	Electronic	N/A	N/A	457	15
LED458-FIXT	LED458W	Non-Integrated Ballast LED, 458W, any bulb shape, any application	458W LED - Non-Int. Ballast	Electronic	N/A	N/A	458	15
LED459-FIXT	LED459W	Non-Integrated Ballast LED, 459W, any bulb shape, any application	459W LED - Non-Int. Ballast	Electronic	N/A	N/A	459	15
LED460-FIXT	LED460W	Non-Integrated Ballast LED, 460W, any bulb shape, any application	460W LED - Non-Int. Ballast	Electronic	N/A	N/A	460	15
LED461-FIXT	LED461W	Non-Integrated Ballast LED, 461W, any bulb shape, any application	461W LED - Non-Int. Ballast	Electronic	N/A	N/A	461	15
LED462-FIXT	LED462W	Non-Integrated Ballast LED, 462W, any bulb shape, any application	462W LED - Non-Int. Ballast	Electronic	N/A	N/A	462	15
LED463-FIXT	LED463W	Non-Integrated Ballast LED, 463W, any bulb shape, any application	463W LED - Non-Int. Ballast	Electronic	N/A	N/A	463	15
LED464-FIXT	LED464W	Non-Integrated Ballast LED, 464W, any bulb shape, any application	464W LED - Non-Int. Ballast	Electronic	N/A	N/A	464	15
LED465-FIXT	LED465W	Non-Integrated Ballast LED, 465W, any bulb shape, any application	465W LED - Non-Int. Ballast	Electronic	N/A	N/A	465	15
LED466-FIXT	LED466W	Non-Integrated Ballast LED, 466W, any bulb shape, any application	466W LED - Non-Int. Ballast	Electronic	N/A	N/A	466	15
LED467-FIXT	LED467W	Non-Integrated Ballast LED, 467W, any bulb shape, any application	467W LED - Non-Int. Ballast	Electronic	N/A	N/A	467	15
LED468-FIXT	LED468W	Non-Integrated Ballast LED, 468W, any bulb shape, any application	468W LED - Non-Int. Ballast	Electronic	N/A	N/A	468	15
LED469-FIXT	LED469W	Non-Integrated Ballast LED, 469W, any bulb shape, any application	469W LED - Non-Int. Ballast	Electronic	N/A	N/A	469	15
LED470-FIXT	LED470W	Non-Integrated Ballast LED, 470W, any bulb shape, any application	470W LED - Non-Int. Ballast	Electronic	N/A	N/A	470	15
LED471-FIXT	LED471W	Non-Integrated Ballast LED, 471W, any bulb shape, any application	471W LED - Non-Int. Ballast	Electronic	N/A	N/A	471	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED472-FIXT	LED472W	Non-Integrated Ballast LED, 472W, any bulb shape, any application	472W LED - Non-Int. Ballast	Electronic	N/A	N/A	472	15
LED473-FIXT	LED473W	Non-Integrated Ballast LED, 473W, any bulb shape, any application	473W LED - Non-Int. Ballast	Electronic	N/A	N/A	473	15
LED474-FIXT	LED474W	Non-Integrated Ballast LED, 474W, any bulb shape, any application	474W LED - Non-Int. Ballast	Electronic	N/A	N/A	474	15
LED475-FIXT	LED475W	Non-Integrated Ballast LED, 475W, any bulb shape, any application	475W LED - Non-Int. Ballast	Electronic	N/A	N/A	475	15
LED476-FIXT	LED476W	Non-Integrated Ballast LED, 476W, any bulb shape, any application	476W LED - Non-Int. Ballast	Electronic	N/A	N/A	476	15
LED477-FIXT	LED477W	Non-Integrated Ballast LED, 477W, any bulb shape, any application	477W LED - Non-Int. Ballast	Electronic	N/A	N/A	477	15
LED478-FIXT	LED478W	Non-Integrated Ballast LED, 478W, any bulb shape, any application	478W LED - Non-Int. Ballast	Electronic	N/A	N/A	478	15
LED479-FIXT	LED479W	Non-Integrated Ballast LED, 479W, any bulb shape, any application	479W LED - Non-Int. Ballast	Electronic	N/A	N/A	479	15
LED480-FIXT	LED480W	Non-Integrated Ballast LED, 480W, any bulb shape, any application	480W LED - Non-Int. Ballast	Electronic	N/A	N/A	480	15
LED481-FIXT	LED481W	Non-Integrated Ballast LED, 481W, any bulb shape, any application	481W LED - Non-Int. Ballast	Electronic	N/A	N/A	481	15
LED482-FIXT	LED482W	Non-Integrated Ballast LED, 482W, any bulb shape, any application	482W LED - Non-Int. Ballast	Electronic	N/A	N/A	482	15
LED483-FIXT	LED483W	Non-Integrated Ballast LED, 483W, any bulb shape, any application	483W LED - Non-Int. Ballast	Electronic	N/A	N/A	483	15
LED484-FIXT	LED484W	Non-Integrated Ballast LED, 484W, any bulb shape, any application	484W LED - Non-Int. Ballast	Electronic	N/A	N/A	484	15
LED485-FIXT	LED485W	Non-Integrated Ballast LED, 485W, any bulb shape, any application	485W LED - Non-Int. Ballast	Electronic	N/A	N/A	485	15
LED486-FIXT	LED486W	Non-Integrated Ballast LED, 486W, any bulb shape, any application	486W LED - Non-Int. Ballast	Electronic	N/A	N/A	486	15
LED487-FIXT	LED487W	Non-Integrated Ballast LED, 487W, any bulb shape, any application	487W LED - Non-Int. Ballast	Electronic	N/A	N/A	487	15
LED488-FIXT	LED488W	Non-Integrated Ballast LED, 488W, any bulb shape, any application	488W LED - Non-Int. Ballast	Electronic	N/A	N/A	488	15
LED489-FIXT	LED489W	Non-Integrated Ballast LED, 489W, any bulb shape, any application	489W LED - Non-Int. Ballast	Electronic	N/A	N/A	489	15
LED490-FIXT	LED490W	Non-Integrated Ballast LED, 490W, any bulb shape, any application	490W LED - Non-Int. Ballast	Electronic	N/A	N/A	490	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED491-FIXT	LED491W	Non-Integrated Ballast LED, 491W, any bulb shape, any application	491W LED - Non-Int. Ballast	Electronic	N/A	N/A	491	15
LED492-FIXT	LED492W	Non-Integrated Ballast LED, 492W, any bulb shape, any application	492W LED - Non-Int. Ballast	Electronic	N/A	N/A	492	15
LED493-FIXT	LED493W	Non-Integrated Ballast LED, 493W, any bulb shape, any application	493W LED - Non-Int. Ballast	Electronic	N/A	N/A	493	15
LED494-FIXT	LED494W	Non-Integrated Ballast LED, 494W, any bulb shape, any application	494W LED - Non-Int. Ballast	Electronic	N/A	N/A	494	15
LED495-FIXT	LED495W	Non-Integrated Ballast LED, 495W, any bulb shape, any application	495W LED - Non-Int. Ballast	Electronic	N/A	N/A	495	15
LED496-FIXT	LED496W	Non-Integrated Ballast LED, 496W, any bulb shape, any application	496W LED - Non-Int. Ballast	Electronic	N/A	N/A	496	15
LED497-FIXT	LED497W	Non-Integrated Ballast LED, 497W, any bulb shape, any application	497W LED - Non-Int. Ballast	Electronic	N/A	N/A	497	15
LED498-FIXT	LED498W	Non-Integrated Ballast LED, 498W, any bulb shape, any application	498W LED - Non-Int. Ballast	Electronic	N/A	N/A	498	15
LED499-FIXT	LED499W	Non-Integrated Ballast LED, 499W, any bulb shape, any application	499W LED - Non-Int. Ballast	Electronic	N/A	N/A	499	15
LED500-FIXT	LED500W	Non-Integrated Ballast LED, 500W, any bulb shape, any application	500W LED - Non-Int. Ballast	Electronic	N/A	N/A	500	15
LED505-FIXT	LED505W	Non-Integrated Ballast LED, 505W, any bulb shape, any application	505W LED - Non-Int. Ballast	Electronic	N/A	N/A	505	15
LED510-FIXT	LED510W	Non-Integrated Ballast LED, 510W, any bulb shape, any application	510W LED - Non-Int. Ballast	Electronic	N/A	N/A	510	15
LED515-FIXT	LED515W	Non-Integrated Ballast LED, 515W, any bulb shape, any application	515W LED - Non-Int. Ballast	Electronic	N/A	N/A	515	15
LED520-FIXT	LED520W	Non-Integrated Ballast LED, 520W, any bulb shape, any application	520W LED - Non-Int. Ballast	Electronic	N/A	N/A	520	15
LED525-FIXT	LED525W	Non-Integrated Ballast LED, 525W, any bulb shape, any application	525W LED - Non-Int. Ballast	Electronic	N/A	N/A	525	15
LED530-FIXT	LED530W	Non-Integrated Ballast LED, 530W, any bulb shape, any application	530W LED - Non-Int. Ballast	Electronic	N/A	N/A	530	15
LED535-FIXT	LED535W	Non-Integrated Ballast LED, 535W, any bulb shape, any application	535W LED - Non-Int. Ballast	Electronic	N/A	N/A	535	15
LED540-FIXT	LED540W	Non-Integrated Ballast LED, 540W, any bulb shape, any application	540W LED - Non-Int. Ballast	Electronic	N/A	N/A	540	15
LED545-FIXT	LED545W	Non-Integrated Ballast LED, 545W, any bulb shape, any application	545W LED - Non-Int. Ballast	Electronic	N/A	N/A	545	15

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
LED550-FIXT	LED550W	Non-Integrated Ballast LED, 550W, any bulb shape, any application	550W LED - Non-Int. Ballast	Electronic	N/A	N/A	550	15
CF		Compact Fluorescent Fixtures						
CF2/1-SCRW	CF2W	Compact Fluorescent, (1) 2W screw-in lamp/base w/ permanent disk installed, any bulb shape	2W CFL	Mag. or Elec.	1	2	2	2.5
CF3/1-SCRW	CF3W	Compact Fluorescent, (1) 3W screw-in lamp/base w/ permanent disk installed, any bulb shape	3W CFL	Mag. or Elec.	1	3	3	2.5
CF4/1-SCRW	CF4W	Compact Fluorescent, (1) 4W screw-in lamp/base w/ permanent disk installed, any bulb shape	4W CFL	Mag. or Elec.	1	4	4	2.5
CF5/1-SCRW	CF5W	Compact Fluorescent, (1) 5W screw-in lamp/base w/ permanent disk installed, any bulb shape	5W CFL	Mag. or Elec.	1	5	5	2.5
CF6/1-SCRW	CF6W	Compact Fluorescent, (1) 6W screw-in lamp/base w/ permanent disk installed, any bulb shape	6W CFL	Mag. or Elec.	1	6	6	2.5
CF7/1-SCRW	CF7W	Compact Fluorescent, (1) 7W screw-in lamp/base w/ permanent disk installed, any bulb shape	7W CFL	Mag. or Elec.	1	7	7	2.5
CF8/1-SCRW	CF8W	Compact Fluorescent, (1) 8W screw-in lamp/base w/ permanent disk installed, any bulb shape	8W CFL	Mag. or Elec.	1	8	8	2.5
CF9/1-SCRW	CF9W	Compact Fluorescent, (1) 9W screw-in lamp/base w/ permanent disk installed, any bulb shape	9W CFL	Mag. or Elec.	1	9	9	2.5
CF10/1-SCRW	CF10W	Compact Fluorescent, (1) 10W screw-in lamp/base w/ permanent disk installed, any bulb shape	10W CFL	Mag. or Elec.	1	10	10	2.5
CF11/1-SCRW	CF11W	Compact Fluorescent, (1) 11W screw-in lamp/base w/ permanent disk installed, any bulb shape	11W CFL	Mag. or Elec.	1	11	11	2.5
CF12/1-SCRW	CF12W	Compact Fluorescent, (1) 12W screw-in lamp/base w/ permanent disk installed, any bulb shape	12W CFL	Mag. or Elec.	1	12	12	2.5
CF13/1-SCRW	CF13W	Compact Fluorescent, (1) 13W screw-in lamp/base w/ permanent disk installed, any bulb shape	13W CFL	Mag. or Elec.	1	13	13	2.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
CF14/1-SCRW	CF14W	Compact Fluorescent, (1) 14W screw-in lamp/base w/ permanent disk installed, any bulb shape	14W CFL	Mag. or Elec.	1	14	14	2.5
CF15/1-SCRW	CF15W	Compact Fluorescent, (1) 15W screw-in lamp/base w/ permanent disk installed, any bulb shape	15W CFL	Mag. or Elec.	1	15	15	2.5
CF16/1-SCRW	CF16W	Compact Fluorescent, (1) 16W screw-in lamp/base w/ permanent disk installed, any bulb shape	16W CFL	Mag. or Elec.	1	16	16	2.5
CF17/1-SCRW	CF17W	Compact Fluorescent, (1) 17W screw-in lamp/base w/ permanent disk installed, any bulb shape	17W CFL	Mag. or Elec.	1	17	17	2.5
CF18/1-SCRW	CF18W	Compact Fluorescent, (1) 18W screw-in lamp/base w/ permanent disk installed, any bulb shape	18W CFL	Mag. or Elec.	1	18	18	2.5
CF19/1-SCRW	CF19W	Compact Fluorescent, (1) 19W screw-in lamp/base w/ permanent disk installed, any bulb shape	19W CFL	Mag. or Elec.	1	19	19	2.5
CF20/1-SCRW	CF20W	Compact Fluorescent, (1) 20W screw-in lamp/base w/ permanent disk installed, any bulb shape	20W CFL	Mag. or Elec.	1	20	20	2.5
CF21/1-SCRW	CF21W	Compact Fluorescent, (1) 21W screw-in lamp/base w/ permanent disk installed, any bulb shape	21W CFL	Mag. or Elec.	1	21	21	2.5
CF22/1-SCRW	CF22W	Compact Fluorescent, (1) 22W screw-in lamp/base w/ permanent disk installed, any bulb shape	22W CFL	Mag. or Elec.	1	22	22	2.5
CF23/1-SCRW	CF23W	Compact Fluorescent, (1) 23W screw-in lamp/base w/ permanent disk installed, any bulb shape	23W CFL	Mag. or Elec.	1	23	23	2.5
CF24/1-SCRW	CF24W	Compact Fluorescent, (1) 24W screw-in lamp/base w/ permanent disk installed, any bulb shape	24W CFL	Mag. or Elec.	1	24	24	2.5
CF25/1-SCRW	CF25W	Compact Fluorescent, (1) 25W screw-in lamp/base w/ permanent disk installed, any bulb shape	25W CFL	Mag. or Elec.	1	25	25	2.5
CF26/1-SCRW	CF26W	Compact Fluorescent, (1) 26W screw-in lamp/base w/ permanent disk installed, any bulb shape	26W CFL	Mag. or Elec.	1	26	26	2.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
CF27/1-SCRW	CF27W	Compact Fluorescent, (1) 27W screw-in lamp/base w/ permanent disk installed, any bulb shape	27W CFL	Mag. or Elec.	1	27	27	2.5
CF28/1-SCRW	CF28W	Compact Fluorescent, (1) 28W screw-in lamp/base w/ permanent disk installed, any bulb shape	28W CFL	Mag. or Elec.	1	28	28	2.5
CF29/1-SCRW	CF29W	Compact Fluorescent, (1) 29W screw-in lamp/base w/ permanent disk installed, any bulb shape	29W CFL	Mag. or Elec.	1	29	29	2.5
CF30/1-SCRW	CF30W	Compact Fluorescent, (1) 30W screw-in lamp/base w/ permanent disk installed, any bulb shape	30W CFL	Mag. or Elec.	1	30	30	2.5
CF31/1-SCRW	CF31W	Compact Fluorescent, (1) 31W screw-in lamp/base w/ permanent disk installed, any bulb shape	31W CFL	Mag. or Elec.	1	31	31	2.5
CF32/1-SCRW	CF32W	Compact Fluorescent, (1) 32W screw-in lamp/base w/ permanent disk installed, any bulb shape	32W CFL	Mag. or Elec.	1	32	32	2.5
CF33/1-SCRW	CF33W	Compact Fluorescent, (1) 33W screw-in lamp/base w/ permanent disk installed, any bulb shape	33W CFL	Mag. or Elec.	1	33	33	2.5
CF34/1-SCRW	CF34W	Compact Fluorescent, (1) 34W screw-in lamp/base w/ permanent disk installed, any bulb shape	34W CFL	Mag. or Elec.	1	34	34	2.5
CF35/1-SCRW	CF35W	Compact Fluorescent, (1) 35W screw-in lamp/base w/ permanent disk installed, any bulb shape	35W CFL	Mag. or Elec.	1	35	35	2.5
CF36/1-SCRW	CF36W	Compact Fluorescent, (1) 36W screw-in lamp/base w/ permanent disk installed, any bulb shape	36W CFL	Mag. or Elec.	1	36	36	2.5
CF37/1-SCRW	CF37W	Compact Fluorescent, (1) 37W screw-in lamp/base w/ permanent disk installed, any bulb shape	37W CFL	Mag. or Elec.	1	37	37	2.5
CF38/1-SCRW	CF38W	Compact Fluorescent, (1) 38W screw-in lamp/base w/ permanent disk installed, any bulb shape	38W CFL	Mag. or Elec.	1	38	38	2.5
CF39/1-SCRW	CF39W	Compact Fluorescent, (1) 39W screw-in lamp/base w/ permanent disk installed, any bulb shape	39W CFL	Mag. or Elec.	1	39	39	2.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
CF40/1-SCRW	CF40W	Compact Fluorescent, (1) 40W screw-in lamp/base w/ permanent disk installed, any bulb shape	40W CFL	Mag. or Elec.	1	40	40	2.5
CF41/1-SCRW	CF41W	Compact Fluorescent, (1) 41W screw-in lamp/base w/ permanent disk installed, any bulb shape	41W CFL	Mag. or Elec.	1	41	41	2.5
CF42/1-SCRW	CF42W	Compact Fluorescent, (1) 42W screw-in lamp/base w/ permanent disk installed, any bulb shape	42W CFL	Mag. or Elec.	1	42	42	2.5
CF43/1-SCRW	CF43W	Compact Fluorescent, (1) 43W screw-in lamp/base w/ permanent disk installed, any bulb shape	43W CFL	Mag. or Elec.	1	43	43	2.5
CF44/1-SCRW	CF44W	Compact Fluorescent, (1) 44W screw-in lamp/base w/permanent disk installed, any bulb shape	44W CFL	Mag. or Elec.	1	44	44	2.5
CF45/1-SCRW	CF45W	Compact Fluorescent, (1) 45W screw-in lamp/base w/permanent disk installed, any bulb shape	45W CFL	Mag. or Elec.	1	45	45	2.5
CF46/1-SCRW	CF46W	Compact Fluorescent, (1) 46W screw-in lamp/base w/permanent disk installed, any bulb shape	46W CFL	Mag. or Elec.	1	46	46	2.5
CF47/1-SCRW	CF47W	Compact Fluorescent, (1) 47W screw-in lamp/base w/permanent disk installed, any bulb shape	47W CFL	Mag. or Elec.	1	47	47	2.5
CF48/1-SCRW	CF48W	Compact Fluorescent, (1) 48W screw-in lamp/base w/permanent disk installed, any bulb shape	48W CFL	Mag. or Elec.	1	48	48	2.5
CF49/1-SCRW	CF49W	Compact Fluorescent, (1) 49W screw-in lamp/base w/permanent disk installed, any bulb shape	49W CFL	Mag. or Elec.	1	49	49	2.5
CF50/1-SCRW	CF50W	Compact Fluorescent, (1) 50W screw-in lamp/base w/permanent disk installed, any bulb shape	50W CFL	Mag. or Elec.	1	50	50	2.5
CF51/1-SCRW	CF51W	Compact Fluorescent, (1) 51W screw-in lamp/base w/permanent disk installed, any bulb shape	51W CFL	Mag. or Elec.	1	51	51	2.5
CF52/1-SCRW	CF52W	Compact Fluorescent, (1) 52W screw-in lamp/base w/permanent disk installed, any bulb shape	52W CFL	Mag. or Elec.	1	52	52	2.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
CF53/1-SCRW	CF53W	Compact Fluorescent, (1) 53W screw-in lamp/base w/permanent disk installed, any bulb shape	53W CFL	Mag. or Elec.	1	53	53	2.5
CF54/1-SCRW	CF54W	Compact Fluorescent, (1) 54W screw-in lamp/base w/permanent disk installed, any bulb shape	54W CFL	Mag. or Elec.	1	54	54	2.5
CF55/1-SCRW	CF55W	Compact Fluorescent, (1) 55W screw-in lamp/base w/permanent disk installed, any bulb shape	55W CFL	Mag. or Elec.	1	55	55	2.5
CF56/1-SCRW	CF56W	Compact Fluorescent, (1) 56W screw-in lamp/base w/permanent disk installed, any bulb shape	56W CFL	Mag. or Elec.	1	56	56	2.5
CF57/1-SCRW	CF57W	Compact Fluorescent, (1) 57W screw-in lamp/base w/permanent disk installed, any bulb shape	57W CFL	Mag. or Elec.	1	57	57	2.5
CF58/1-SCRW	CF58W	Compact Fluorescent, (1) 58W screw-in lamp/base w/permanent disk installed, any bulb shape	58W CFL	Mag. or Elec.	1	58	58	2.5
CF59/1-SCRW	CF59W	Compact Fluorescent, (1) 59W screw-in lamp/base w/permanent disk installed, any bulb shape	59W CFL	Mag. or Elec.	1	59	59	2.5
CF60/1-SCRW	CF60W	Compact Fluorescent, (1) 60W screw-in lamp/base w/permanent disk installed, any bulb shape	60W CFL	Mag. or Elec.	1	60	60	2.5
CF61/1-SCRW	CF61W	Compact Fluorescent, (1) 61W screw-in lamp/base w/permanent disk installed, any bulb shape	61W CFL	Mag. or Elec.	1	61	61	2.5
CF62/1-SCRW	CF62W	Compact Fluorescent, (1) 62W screw-in lamp/base w/permanent disk installed, any bulb shape	62W CFL	Mag. or Elec.	1	62	62	2.5
CF63/1-SCRW	CF63W	Compact Fluorescent, (1) 63W screw-in lamp/base w/permanent disk installed, any bulb shape	63W CFL	Mag. or Elec.	1	63	63	2.5
CF64/1-SCRW	CF64W	Compact Fluorescent, (1) 64W screw-in lamp/base w/permanent disk installed, any bulb shape	64W CFL	Mag. or Elec.	1	64	64	2.5
CF65/1-SCRW	CF65W	Compact Fluorescent, (1) 65W screw-in lamp/base w/permanent disk installed, any bulb shape	65W CFL	Mag. or Elec.	1	65	65	2.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
CF66/1-SCRW	CF66W	Compact Fluorescent, (1) 66W screw-in lamp/base w/permanent disk installed, any bulb shape	66W CFL	Mag. or Elec.	1	66	66	2.5
CF67/1-SCRW	CF67W	Compact Fluorescent, (1) 67W screw-in lamp/base w/permanent disk installed, any bulb shape	67W CFL	Mag. or Elec.	1	67	67	2.5
CF68/1-SCRW	CF68W	Compact Fluorescent, (1) 68W screw-in lamp/base w/permanent disk installed, any bulb shape	68W CFL	Mag. or Elec.	1	68	68	2.5
CF69/1-SCRW	CF69W	Compact Fluorescent, (1) 69W screw-in lamp/base w/permanent disk installed, any bulb shape	69W CFL	Mag. or Elec.	1	69	69	2.5
CF70/1-SCRW	CF70W	Compact Fluorescent, (1) 70W screw-in lamp/base w/permanent disk installed, any bulb shape	70W CFL	Mag. or Elec.	1	70	70	2.5
CF71/1-SCRW	CF71W	Compact Fluorescent, (1) 71W screw-in lamp/base w/permanent disk installed, any bulb shape	71W CFL	Mag. or Elec.	1	71	71	2.5
CF72/1-SCRW	CF72W	Compact Fluorescent, (1) 72W screw-in lamp/base w/permanent disk installed, any bulb shape	72W CFL	Mag. or Elec.	1	72	72	2.5
CF73/1-SCRW	CF73W	Compact Fluorescent, (1) 73W screw-in lamp/base w/permanent disk installed, any bulb shape	73W CFL	Mag. or Elec.	1	73	73	2.5
CF74/1-SCRW	CF74W	Compact Fluorescent, (1) 74W screw-in lamp/base w/permanent disk installed, any bulb shape	74W CFL	Mag. or Elec.	1	74	74	2.5
CF75/1-SCRW	CF75W	Compact Fluorescent, (1) 75W screw-in lamp/base w/permanent disk installed, any bulb shape	75W CFL	Mag. or Elec.	1	75	75	2.5
CF80/1-SCRW	CF80W	Compact Fluorescent, (1) 80W screw-in lamp/base w/permanent disk installed, any bulb shape	80W CFL	Mag. or Elec.	1	80	80	2.5
CF85/1-SCRW	CF85W	Compact Fluorescent, (1) 85W screw-in lamp/base w/permanent disk installed, any bulb shape	85W CFL	Mag. or Elec.	1	85	85	2.5
CF100/1-SCRW	CF100W	Compact Fluorescent, (1) 100W screw-in lamp/base w/ permanent disk installed, any bulb shape	100W CFL	Mag. or Elec.	1	100	100	2.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
CF125/1-SCRW	CF125W	Compact Fluorescent, (1) 125W screw-in lamp/base w/ permanent disk installed, any bulb shape	125W CFL	Mag. or Elec.	1	125	125	2.5
CF150/1-SCRW	CF150W	Compact Fluorescent, (1) 150W screw-in lamp/base w/ permanent disk installed, any bulb shape	150W CFL	Mag. or Elec.	1	150	150	2.5
CF200/1-SCRW	CF200W	Compact Fluorescent, (1) 200W screw-in lamp/base w/ permanent disk installed, any bulb shape	200W CFL	Mag. or Elec.	1	200	200	2.5
CFC2/1-SCRW	CFC2W	Compact Fluorescent, Cold Cathode, (1) 2W screw-in lamp/base w/ permanent locking device, any bulb shape	2W Cold Cathode	Electronic	1	2	2	4.5
CFC2/2-SCRW	CFC2W	Compact Fluorescent, Cold Cathode, (2) 2W screw-in lamp/base w/ permanent locking device, any bulb shape	4W Cold Cathode	Electronic	2	2	4	4.5
CFC3/1-SCRW	CFC3W	Compact Fluorescent, Cold Cathode, (1) 3W screw-in lamp/base w/ permanent locking device, any bulb shape	3W Cold Cathode	Electronic	1	3	3	4.5
CFC3/2-SCRW	CFC3W	Compact Fluorescent, Cold Cathode, (2) 3W screw-in lamp/base w/ permanent locking device, any bulb shape	6W Cold Cathode	Electronic	2	3	6	4.5
CFC4/1-SCRW	CFC4W	Compact Fluorescent, Cold Cathode, (1) 4W screw-in lamp/base w/ permanent locking device, any bulb shape	4W Cold Cathode	Electronic	1	4	4	4.5
CFC4/2-SCRW	CFC4W	Compact Fluorescent, Cold Cathode, (2) 4W screw-in lamp/base w/ permanent locking device, any bulb shape	8W Cold Cathode	Electronic	2	4	8	4.5
CFC5/1-SCRW	CFC5W	Compact Fluorescent, Cold Cathode, (1) 5W screw-in lamp/base w/ permanent locking device, any bulb shape	5W Cold Cathode	Electronic	1	5	5	4.5
CFC5/2-SCRW	CFC5W	Compact Fluorescent, Cold Cathode, (2) 5W screw-in lamp/base w/ permanent locking device, any bulb shape	10W Cold Cathode	Electronic	2	5	10	4.5
CFC8/1-SCRW	CFC8W	Compact Fluorescent, Cold Cathode, (1) 8W screw-in lamp/base w/ permanent locking device, any bulb shape	8W Cold Cathode	Electronic	1	8	8	4.5
CFC8/2-SCRW	CFC8W	Compact Fluorescent, Cold Cathode, (2) 8W screw-in lamp/base w/ permanent locking device, any bulb shape	16W Cold Cathode	Electronic	2	8	16	4.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
CFC13/1-SCRW	CFC13W	Compact Fluorescent, Cold Cathode, (1) 13W screw-in lamp/base w/ permanent locking device, any bulb shape	13W Cold Cathode	Electronic	1	13	13	4.5
CFC18/1-SCRW	CFC18W	Compact Fluorescent, Cold Cathode, (1) 18W screw-in lamp/base w/ permanent locking device, any bulb shape	18W Cold Cathode	Electronic	1	18	18	4.5
CFD10/1	CFD10W	Compact Fluorescent, 2D, (1) 10W lamp	1-Lamp 10W CFL 2D	Mag-STD	1	10	16	16
CFD10/1-L	CFD10W	Compact Fluorescent, 2D, (1) 10W lamp	1-Lamp 10W CFL 2D	Electronic	1	10	14	16
CFD16/1	CFD16W	Compact Fluorescent, 2D, (1) 16W lamp	1-Lamp 16W CFL 2D	Mag-STD	1	16	26	16
CFD16/1-L	CFD16W	Compact Fluorescent, 2D, (1) 16W lamp	1-Lamp 16W CFL 2D	Electronic	1	16	18	16
CFD21/1	CFD21W	Compact Fluorescent, 2D, (1) 21W lamp	1-Lamp 21W CFL 2D	Mag-STD	1	21	26	16
CFD21/1-L	CFD21W	Compact Fluorescent, 2D, (1) 21W lamp	1-Lamp 21W CFL 2D	Electronic	1	21	22	16
CFD28/1	CFD28W	Compact Fluorescent, 2D, (1) 28W lamp	1-Lamp 28W CFL 2D	Mag-STD	1	28	35	16
CFD28/1-L	CFD28W	Compact Fluorescent, 2D, (1) 28W lamp	1-Lamp 28W CFL 2D	Electronic	1	28	29	16
CFD38/1	CFD38W	Compact Fluorescent, 2D, (1) 38W lamp	1-Lamp 38W CFL 2D	Mag-STD	1	38	46	16
CFD38/1-L	CFD38W	Compact Fluorescent, 2D, (1) 38W lamp	1-Lamp 38W CFL 2D	Electronic	1	38	32	16
CFG13/1-L	CFG13W	Compact Fluorescent, Multi, GU24 with Integrated Ballast, (1) 13W lamp	1-Lamp 13W CFL Multi	Electronic	1	13	13	16
CFG18/1-L	CFG18W	Compact Fluorescent, Multi, GU24 with Integrated Ballast, (1) 18W lamp	1-Lamp 18W CFL Multi	Electronic	1	18	18	16
CFG23/1-L	CFG23W	Compact Fluorescent, Multi, GU24 with Integrated Ballast, (1) 23W lamp	1-Lamp 23W CFL Multi	Electronic	1	23	23	16
CFG26/1-L	CFG26W	Compact Fluorescent, Multi, GU24 with Integrated Ballast, (1) 26W lamp	1-Lamp 26W CFL Multi	Electronic	1	26	26	16
CFG32/1-L	CFG32W	Compact Fluorescent, Multi, GU24 with Integrated Ballast, (1) 32W lamp	1-Lamp 32W CFL Multi	Electronic	1	32	32	16
CFG42/1-L	CFG42W	Compact Fluorescent, Multi, GU24 with Integrated Ballast, (1) 42W lamp	1-Lamp 42W CFL Multi	Electronic	1	42	42	16

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
CFM13/1-L	CFM13W	Compact Fluorescent, Multi, 4-pin, (1) 13W lamp	1-Lamp 13W CFL Multi 4-Pin	Electronic	1	13	16	16
CFM13/2-L	CFM13W	Compact Fluorescent, Multi, 4-pin, (2) 13W lamps	2-Lamp 13W CFL Multi 4-Pin	Electronic	2	13	30	16
CFM15/1-L	CFM15W	Compact Fluorescent, Multi, 4-pin, (1) 15W lamp	1-Lamp 15W CFL Multi 4-Pin	Electronic	1	15	18	16
CFM18/1-L	CFM18W	Compact Fluorescent, Multi, 4-pin, (1) 18W lamp	1-Lamp 18W CFL Multi 4-Pin	Electronic	1	18	20	16
CFM18/2-L	CFM18W	Compact Fluorescent, Multi, 4-pin, (2) 18W lamps	2-Lamp 18W CFL Multi 4-Pin	Electronic	2	18	40	16
CFM21/1-L	CFM21W	Compact Fluorescent, Multi, 4-pin, (1) 21W lamp	1-Lamp 21W CFL Multi 4-Pin	Electronic	1	21	23	16
CFM26/1-L	CFM26W	Compact Fluorescent, Multi, 4-pin, (1) 26W lamp	1-Lamp 26W CFL Multi 4-Pin	Electronic	1	26	29	16
CFM26/2-L	CFM26W	Compact Fluorescent, Multi, 4-pin, (2) 26W lamps	2-Lamp 26W CFL Multi 4-Pin	Electronic	2	26	51	16
CFM28/1-L	CFM28W	Compact Fluorescent, Multi, 4-pin, (1) 28W lamp	1-Lamp 28W CFL Multi 4-Pin	Electronic	1	28	31	16
CFM32/1-L	CFM32W	Compact Fluorescent, Multi, 4-pin, (1) 32W lamp	1-Lamp 32W CFL Multi 4-Pin	Electronic	1	32	35	16
CFM42/1-L	CFM42W	Compact Fluorescent, Multi, 4-pin, (1) 42W lamp	1-Lamp 42W CFL Multi 4-Pin	Electronic	1	42	46	16
CFM42/2-L	CFM42W	Compact Fluorescent, Multi, 4-pin, (2) 42W lamps	2-Lamp 42W CFL Multi 4-Pin	Electronic	2	42	93	16
CFM42/8-L	CFM42W	Compact Fluorescent, Multi, 4-pin, (8) 42W lamps, (4) 2-lamp ballasts	8-Lamp 42W CFL Multi 4-Pin	Electronic	8	42	372	16
CFM57/1-L	CFM57W	Compact Fluorescent, Multi, 4-pin, (1) 57W lamp	1-Lamp 57W CFL Multi 4-Pin	Electronic	1	57	59	16
CFM60/1-L	CFM60W	Compact Fluorescent, Multi, 4-pin, (1) 60W lamp	1-Lamp 60W CFL Multi 4-Pin	Electronic	1	60	70	16
CFM70/1-L	CFM70W	Compact Fluorescent, Multi, 4-pin, (1) 70W lamp	1-Lamp 70W CFL Multi 4-Pin	Electronic	1	70	73	16
CFM85/1-L	CFM85W	Compact Fluorescent, Multi, 4-pin, (1) 85W lamp	1-Lamp 85W CFL Multi 4-Pin	Electronic	1	85	96	16
CFM120/1-L	CFM120W	Compact Fluorescent, Multi, 4-pin, (1) 120W lamp	1-Lamp 120W CFL Multi 4-Pin	Electronic	1	120	135	16
CFQ9/1	CFQ9W	Compact Fluorescent, Quad, (1) 9W lamp	1-Lamp 9W CFL Quad	Mag-STD	1	9	14	16

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
CFQ9/2	CFQ9W	Compact Fluorescent, Quad, (2) 9W lamps	2-Lamp 9W CFL Quad	Mag-STD	2	9	23	16
CFQ10/1	CFQ10W	Compact Fluorescent, quad, (1) 10W lamp	1-Lamp 10W CFL Quad	Mag-STD	1	10	15	16
CFQ13/1	CFQ13W	Compact Fluorescent, quad, (1) 13W lamp	1-Lamp 13W CFL Quad	Mag-STD	1	13	17	16
CFQ13/1-L	CFQ13W	Compact Fluorescent, quad, (1) 13W lamp, BF=1.05	1-Lamp 13W CFL Quad	Electronic	1	13	15	16
CFQ13/2	CFQ13W	Compact Fluorescent, quad, (2) 13W lamps	2-Lamp 13W CFL Quad	Mag-STD	2	13	31	16
CFQ13/2-L	CFQ13W	Compact Fluorescent, quad, (2) 13W lamps, BF=1.0	2-Lamp 13W CFL Quad	Electronic	2	13	28	16
CFQ13/3	CFQ13W	Compact Fluorescent, quad, (3) 13W lamps	3-Lamp 13W CFL Quad	Mag-STD	3	13	48	16
CFQ15/1	CFQ15W	Compact Fluorescent, quad, (1) 15W lamp	1-Lamp 15W CFL Quad	Mag-STD	1	15	20	16
CFQ17/1	CFQ17W	Compact Fluorescent, quad, (1) 17W lamp	1-Lamp 17W CFL Quad	Mag-STD	1	17	24	16
CFQ17/2	CFQ17W	Compact Fluorescent, quad, (2) 17W lamps	2-Lamp 17W CFL Quad	Mag-STD	2	17	48	16
CFQ18/1	CFQ18W	Compact Fluorescent, quad, (1) 18W lamp	1-Lamp 18W CFL Quad	Mag-STD	1	18	26	16
CFQ18/1-L	CFQ18W	Compact Fluorescent, quad, (1) 18W lamp, BF=1.0	1-Lamp 18W CFL Quad	Electronic	1	18	20	16
CFQ18/2	CFQ18W	Compact Fluorescent, quad, (2) 18W lamps	2-Lamp 18W CFL Quad	Mag-STD	2	18	45	16
CFQ18/2-L	CFQ18W	Compact Fluorescent, quad, (2) 18W lamp, BF=1.0	2-Lamp 18W CFL Quad	Electronic	2	18	38	16
CFQ18/4	CFQ18W	Compact Fluorescent, quad, (4) 18W lamps	4-Lamp 18W CFL Quad	Mag-STD	2	18	90	16
CFQ20/1	CFQ20W	Compact Fluorescent, quad, (1) 20W lamp	1-Lamp 20W CFL Quad	Mag-STD	1	20	23	16
CFQ20/2	CFQ20W	Compact Fluorescent, quad, (2) 20W lamps	2-Lamp 20W CFL Quad	Mag-STD	2	20	46	16
CFQ22/1	CFQ22W	Compact Fluorescent, Quad, (1) 22W lamp	1-Lamp 22W CFL Quad	Mag-STD	1	22	24	16
CFQ22/2	CFQ22W	Compact Fluorescent, Quad, (2) 22W lamps	2-Lamp 22W CFL Quad	Mag-STD	2	22	48	16

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
CFQ22/3	CFQ22W	Compact Fluorescent, Quad, (3) 22W lamps	3-Lamp 22W CFL Quad	Mag-STD	3	22	72	16
CFQ23/1	CFQ23W	Compact Fluorescent, Quad, (1) 23W lamp	1-Lamp 23W CFL Quad	Mag-STD	1	23	27	16
CFQ25/1	CFQ25W	Compact Fluorescent, Quad, (1) 25W lamp	1-Lamp 25W CFL Quad	Mag-STD	1	25	33	16
CFQ25/2	CFQ25W	Compact Fluorescent, Quad, (2) 25W lamps	2-Lamp 25W CFL Quad	Mag-STD	2	25	66	16
CFQ26/1	CFQ26W	Compact Fluorescent, quad, (1) 26W lamp	1-Lamp 26W CFL Quad	Mag-STD	1	26	33	16
CFQ26/1-L	CFQ26W	Compact Fluorescent, quad, (1) 26W lamp, BF=0.95	1-Lamp 26W CFL Quad	Electronic	1	26	27	16
CFQ26/2	CFQ26W	Compact Fluorescent, quad, (2) 26W lamps	2-Lamp 26W CFL Quad	Mag-STD	2	26	66	16
CFQ26/2-L	CFQ26W	Compact Fluorescent, quad, (2) 26W lamps, BF=0.95	2-Lamp 26W CFL Quad	Electronic	2	26	50	16
CFQ26/3	CFQ26W	Compact Fluorescent, quad, (3) 26W lamps	3-Lamp 26W CFL Quad	Mag-STD	3	26	99	16
CFQ26/6-L	CFQ26W	Compact Fluorescent, quad, (6) 26W lamps, BF=0.95	6-Lamp 26W CFL Quad	Electronic	6	26	150	16
CFQ28/1	CFQ28W	Compact Fluorescent, quad, (1) 28W lamp	1-Lamp 28W CFL Quad	Mag-STD	1	28	33	16
CFQ28/1-L	CFQ28W	Compact Fluorescent, quad, (1) 28W lamp	1-Lamp 28W CFL Quad	Electronic	1	28	31	16
CFQ28/2-L	CFQ28W	Compact Fluorescent, quad, (2) 28W lamps	2-Lamp 28W CFL Quad	Electronic	2	28	60	16
CFT5/1	CFT5W	Compact Fluorescent, twin, (1) 5W lamp	1-Lamp 5W CFL Twin	Mag-STD	1	5	9	16
CFT5/2	CFT5W	Compact Fluorescent, long twin, (2) 5W lamps	2-Lamp 5W CFL Twin	Mag-STD	2	5	18	16
CFT7/1	CFT7W	Compact Fluorescent, twin, (1) 7W lamp	1-Lamp 7W CFL Twin	Mag-STD	1	7	10	16
CFT7/2	CFT7W	Compact Fluorescent, twin, (2) 7W lamps	2-Lamp 7W CFL Twin	Mag-STD	2	7	21	16
CFT9/1	CFT9W	Compact Fluorescent, twin, (1) 9W lamp	1-Lamp 9W CFL Twin	Mag-STD	1	9	12	16
CFT9/2	CFT9W	Compact Fluorescent, twin, (2) 9W lamps	2-Lamp 9W CFL Twin	Mag-STD	2	9	23	16

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
CFT9/3	CFT9W	Compact Fluorescent, twin, (3) 9 W lamps	3-Lamp 9W CFL Twin	Mag-STD	3	9	34	16
CFT13/1	CFT13W	Compact Fluorescent, twin, (1) 13W lamp	1-Lamp 13W CFL Twin	Mag-STD	1	13	17	16
CFT13/1-L	CFT13W	Compact Fluorescent, twin, (1) 13W lamp	1-Lamp 13W CFL Twin	Electronic	1	13	15	16
CFT13/2	CFT13W	Compact Fluorescent, twin, (2) 13W lamps	2-Lamp 13W CFL Twin	Mag-STD	2	13	31	16
CFT13/2-L	CFT13W	Compact Fluorescent, twin, (2) 13W lamps	2-Lamp 13W CFL Twin	Electronic	2	13	28	16
CFT13/3	CFT13W	Compact Fluorescent, twin, (3) 13 W lamps	3-Lamp 13W CFL Twin	Mag-STD	3	13	48	16
CFT18/1	CFT18W	Compact Fluorescent, Long twin., (1) 18W lamp	1-Lamp 18W CFL Twin	Mag-STD	1	18	24	16
CFT18/1-L	CFT18W	Compact Fluorescent, twin, (1) 18W lamp	1-Lamp 18W CFL Twin	Electronic	1	18	20	16
CFT18/2	CFT18W	Compact Fluorescent, twin, (2) 18 W lamps	2-Lamp 18W CFL Twin	Mag-STD	2	18	38	16
CFT22/1	CFT22W	Compact Fluorescent, twin, (1) 22W lamp	1-Lamp 22W CFL Twin	Mag-STD	1	22	27	16
CFT22/2	CFT22W	Compact Fluorescent, twin, (2) 22W lamps	2-Lamp 22W CFL Twin	Mag-STD	2	22	54	16
CFT22/4	CFT22W	Compact Fluorescent, twin, (4) 22W lamps	4-Lamp 22W CFL Twin	Mag-STD	4	22	108	16
CFT24/1	CFT24W	Compact Fluorescent, long twin, (1) 24W lamp	1-Lamp 24W CFL Twin	Mag-STD	1	24	32	16
CFT26/1	CFT26W	Compact Fluorescent, twin, (1) 26W lamp	1-Lamp 26W CFL Twin	Mag-STD	1	26	32	16
CFT26/1-L	CFT26W	Compact Fluorescent, twin, (1) 26W lamp	1-Lamp 26W CFL Twin	Electronic	1	26	27	16
CFT26/2-L	CFT26W	Compact Fluorescent, twin, (2) 26W lamps	2-Lamp 26W CFL Twin	Electronic	2	26	51	16
CFT28/1	CFT28W	Compact Fluorescent, twin, (1) 28W lamp	1-Lamp 28W CFL Twin	Mag-STD	1	28	33	16
CFT28/2	CFT28W	Compact Fluorescent, twin, (2) 28W lamps	2-Lamp 28W CFL Twin	Mag-STD	2	28	66	16
CFT32/1-L	CFT32W	Compact Fluorescent, twin, (1) 32W lamp	1-Lamp 32W CFL Twin	Electronic	1	32	34	16

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
CFT32/2-L	CFT32W	Compact Fluorescent, twin, (2) 32W lamps	2-Lamp 32W CFL Twin	Electronic	2	32	62	16
CFT32/6-L	CFT32W	Compact Fluorescent, twin, (6) 32W lamps	6-Lamp 32W CFL Twin	Electronic	6	32	186	16
CFT36/1	CFT36W	Compact Fluorescent, long twin, (1) 36W lamp	1-Lamp 36W CFL Long Twin	Mag-STD	1	36	51	16
CFT40/1	CFT40W	Compact Fluorescent, long twin, (1) 40W lamp	1-Lamp 40W CFL Long Twin	Mag-STD	1	40	46	16
CFT40/1-L	CFT40W	Compact Fluorescent, long twin, (1) 40W lamp	1-Lamp 40W CFL Long Twin	Electronic	1	40	43	16
CFT40/2	CFT40W	Compact Fluorescent, long twin, (2) 40W lamps	2-Lamp 40W CFL Long Twin	Mag-STD	2	40	85	16
CFT40/2-L	CFT40W	Compact Fluorescent, long twin, (2) 40W lamps	2-Lamp 40W CFL Long Twin	Electronic	2	40	72	16
CFT40/3	CFT40W	Compact Fluorescent, long twin, (3) 40 W lamps	3-Lamp 40W CFL Long Twin	Mag-STD	3	40	133	16
CFT40/3-L	CFT40W	Compact Fluorescent, long twin, (3) 40W lamps	3-Lamp 40W CFL Long Twin	Electronic	3	40	105	16
CFT40/5-L	CFT40W	Compact Fluorescent, long twin, (5) 40W lamps	5-Lamp 40W CFL Long Twin	Electronic	5	40	177	16
CFT50/1-L	CFT50W	Compact Fluorescent, long twin, (1) 50W lamp	1-Lamp 50W CFL Long Twin	Electronic	1	50	54	16
CFT50/2-L	CFT50W	Compact Fluorescent, long twin, (2) 50W lamps	1-Lamp 50W CFL Long Twin	Electronic	1	50	108	16
CFT55/1-L	CFT55W	Compact Fluorescent, long twin, (1) 55W lamp	1-Lamp 55W CFL Long Twin	Electronic	1	55	58	16
CFT55/2-L	CFT55W	Compact Fluorescent, long twin, (2) 55W lamps	2-Lamp 55W CFL Long Twin	Electronic	2	55	108	16
CFT55/3-L	CFT55W	Compact Fluorescent, long twin, (3) 55W lamps	3-Lamp 55W CFL Long Twin	Electronic	3	55	168	16
CFT55/4-L	CFT55W	Compact Fluorescent, long twin, (4) 55W lamps	4-Lamp 55W CFL Long Twin	Electronic	4	55	220	16
CFT80/1-L	CFT80W	Compact Fluorescent, long twin, (1) 80W lamp	1-Lamp 80W CFL Long Twin	Electronic	1	80	90	16
ECF		EXIT Sign Fixtures						
ECF5/1	CFT5W	EXIT Compact Fluorescent, (1) 5W lamp	1-Lamp 5W CFL Exit	Mag-STD	1	5	9	16

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
ECF5/2	CFT5W	EXIT Compact Fluorescent, (2) 5W lamps	2-Lamp 5W CFL Exit	Mag-STD	2	5	20	16
ECF6/1	CFT6W	EXIT Compact Fluorescent, (1) 6W lamp	1-Lamp 6W CFL Exit	Mag-STD	1	6	13	16
ECF6/2	CFT6W	EXIT Compact Fluorescent, (2) 6W lamps, (2) ballasts	2-Lamp 6W CFL Exit	Mag-STD	2	6	26	16
ECF7/1	CFT7W	EXIT Compact Fluorescent, (1) 7W lamp	1-Lamp 7W CFL Exit	Mag-STD	1	7	10	16
ECF7/2	CFT7W	EXIT Compact Fluorescent, (2) 7W lamps	2-Lamp 7W CFL Exit	Mag-STD	2	7	21	16
ECF9/1	CFT9W	EXIT Compact Fluorescent, (1) 9W lamp	1-Lamp 9W CFL Exit	Mag-STD	1	9	12	16
ECF9/2	CFT9W	EXIT Compact Fluorescent, (2) 9W lamps	2-Lamp 9W CFL Exit	Mag-STD	2	9	20	16
EF2/2	F2T1	EXIT Sub-miniature T-1 Fluorescent, (2) lamps	2-Lamp 2W T-1 Exit	Electronic	2	2	5	16
EF6/1	F6T5	EXIT Miniature Bi-pin Fluorescent, (1) 6W lamp, (1) ballast	1-Lamp 6W Bi-Pin Fluorescent Exit	Mag-STD	1	6	9	16
EF6/2	F6T5	EXIT Miniature Bi-pin Fluorescent, (2) 6W lamps, (2) ballasts	2-Lamp 6W Bi-Pin Fluorescent Exit	Mag-STD	2	6	18	16
EF8/1	F8T5	EXIT T5 Fluorescent, (1) 8W lamp	1-Lamp 8W T-5 Exit	Mag-STD	1	8	12	16
EF8/2	F8T5	EXIT T5 Fluorescent, (2) 8W lamps	2-Lamp 8W T-5 Exit	Mag-STD	2	8	24	16
EI5/1	I5	EXIT Incandescent, (1) 5W lamp	1-Lamp 5W incandescent Exit		1	5	5	1.5
EI5/2	I5	EXIT Incandescent, (2) 5W lamps	2-Lamp 5W incandescent Exit		2	5	10	1.5
EI7.5/1	I7.5	EXIT Tungsten, (1) 7.5 W lamp	1-Lamp 7.5W Tungsten Exit		1	7.5	8	1.5
EI7.5/2	I7.5	EXIT Tungsten, (2) 7.5 W lamps	2-Lamp 7.5W Tungsten Exit		2	7.5	15	1.5
EI10/2	I10	EXIT Incandescent, (2) 10W lamps	2-Lamp 10W incandescent Exit		2	10	20	1.5
EI15/1	I15	EXIT Incandescent, (1) 15W lamp	1-Lamp 15W incandescent Exit		1	15	15	1.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
EI15/2	I15	EXIT Incandescent, (2) 15W lamps	2-Lamp 15W incandescent Exit		2	15	30	1.5
EI20/1	I20	EXIT Incandescent, (1) 20W lamp	1-Lamp 20W incandescent Exit		1	20	20	1.5
EI20/2	I20	EXIT Incandescent, (2) 20W lamps	2-Lamp 20W incandescent Exit		2	20	40	1.5
EI25/1	I25	EXIT Incandescent, (1) 25W lamp	1-Lamp 25W incandescent Exit		1	25	25	1.5
EI25/2	I25	EXIT Incandescent, (2) 25W lamps	2-Lamp 25W incandescent Exit		2	25	50	1.5
EI34/1	I34	EXIT Incandescent, (1) 34W lamp	1-Lamp 34W incandescent Exit		1	34	34	1.5
EI34/2	I34	EXIT Incandescent, (2) 34W lamps	2-Lamp 34W incandescent Exit		2	34	68	1.5
EI40/1	I40	EXIT Incandescent, (1) 40W lamp	1-Lamp 40W incandescent Exit		1	40	40	1.5
EI40/2	I40	EXIT Incandescent, (2) 40W lamps	2-Lamp 40W incandescent Exit		2	40	80	1.5
EI50/2	I50	EXIT Incandescent, (2) 50W lamps	2-Lamp 50W incandescent Exit		2	50	100	1.5
EI6/1	6S6	EXIT Incandescent, (1) 6 W lamp	1-Lamp 6W incandescent Exit		1	6	6	1.5
EI6/2	6S6	EXIT Incandescent, (2) 6 W lamps	2-Lamp 6W incandescent Exit		2	6	12	1.5
ELED2/1	LED2W	EXIT Light Emitting Diode, (1) 2W lamp, Single Sided	1-Lamp 2W LED Exit		1	2	6	15
ELED2/2	LED2W	EXIT Light Emitting Diode, (2) 2W lamps, Dual Sided	2-Lamp 2W LED Exit		2	2	9	15
ELED3	LED3W	EXIT Light Emitting Diode, (1) 3W lamp, Single Sided	1-Lamp 3W LED Exit		1	3	3	15
EP	P0W	EXIT Photoluminescent, 0W	Photoluminescent Exit Sign		0	0	0	15
FT5		T5 Linear Fluorescent Systems						
F22PS	F13T5	Fluorescent, (2) 21", Preheat T5 lamps, (1) Magnetic ballasts with integral starter, (BF=0.80)	2' 2-Lamp T5	Mag-STD	2	13	26	15.5
F24PS	F13T5	Fluorescent, (4) 21", Preheat T5 lamps, (2) Magnetic ballasts with integral starter (BF=0.80)	2' 4-Lamp T5	Mag-STD	4	13	53	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F21GPL-H	F14T5	Fluorescent (1) 22" (563mm) T-5 lamp; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	2' 1-Lamp T5	PRS Elec.	1	14	18	15.5
F22GPL-H	F14T5	Fluorescent (2) 22" (563mm) T-5 lamps; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	2' 2-Lamp T5	PRS Elec.	2	14	33	15.5
F23GPL-H	F14T5	Fluorescent (3) 22" (563mm)T-5 lamps; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	2' 3-Lamp T5	PRS Elec.	3	14	50	15.5
F23GPL/2-H	F14T5	Fluorescent (3) 22" (563mm)T-5 lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	2' 3-Lamp T5	PRS Elec.	3	14	51	15.5
F24GPL/2-H	F14T5	Fluorescent (4) 22" (563mm)T-5 lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	2' 4-Lamp T5	PRS Elec.	4	14	66	15.5
F31GPL-H	F21T5	Fluorescent (1) 34" (863mm) T-5 lamp; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	3' 1-Lamp T5	PRS Elec.	1	21	25	15.5
F32GPL-H	F21T5	Fluorescent (2) 34" (863mm) T-5 lamps; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	3' 2-Lamp T5	PRS Elec.	2	21	48	15.5
F33GPL/2-H	F21T5	Fluorescent (3) 34" (863mm)T-5 lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	3' 3-Lamp T5	PRS Elec.	3	21	73	15.5
F34GPL/2-H	F21T5	Fluorescent (4) 34" (863mm)T-5 lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	3' 4-Lamp T5	PRS Elec.	4	21	96	15.5
F21GPHL-H	F24T5/HO	Fluorescent (1) 22" (563mm) T-5 HO lamp; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	2' 1-Lamp T5HO	PRS Elec.	1	24	27	15.5
F22GPHL-H	F24T5/HO	Fluorescent (2) 22" (563mm) T-5 HO lamps; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	2' 2-Lamp T5HO	PRS Elec.	2	24	52	15.5
F23GPHL/2-H	F24T5/HO	Fluorescent (3) 22" (563mm)T-5 HO lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	2' 3-Lamp T5HO	PRS Elec.	3	24	79	15.5
F24GPHL/2-H	F24T5/HO	Fluorescent (4) 22" (563mm)T-5 HO lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	2' 4-Lamp T5HO	PRS Elec.	4	24	104	15.5
F26GPHL/3-H	F24T5/HO	Fluorescent (4) 22" (563mm) T-5 HO lamps; (3) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	2' 6-Lamp T5HO	PRS Elec.	6	24	156	15.5
F41GPL-H	F28T5	Fluorescent (1) 45.8" (1163mm) T-5 lamp; (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 1-Lamp T5	PRS Elec.	1	28	33	15.5
F41GPL/T2-H	F28T5	Fluorescent (1) 45.8" (1163mm) T-5 lamp; Tandem 2-lamp PRS Ballast,HLO (.95 < BF < 1.1)	4' 1-Lamp T5	PRS Elec.	1	28	32	15.5
F42GPL-H	F28T5	Fluorescent (2) 45.8" (1163mm) T-5 lamps; (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 2-Lamp T5	PRS Elec.	2	28	63	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F43GPL/2-H	F28T5	Fluorescent (3) 45.8" (1163mm)T-5 lamps; (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 3-Lamp T5	PRS Elec.	3	28	96	15.5
F44GPL/2-H	F28T5	Fluorescent (4) 45.8" (1163mm)T-5 lamps; (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 4-Lamp T5	PRS Elec.	4	28	126	15.5
F51GPL-H	F35T5	Fluorescent (1) 57.6" (1463mm) T-5 lamp; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	5' 1-Lamp T5	PRS Elec.	1	35	40	15.5
F52GPL-H	F35T5	Fluorescent (2) 57.6" (1463mm) T-5 lamps; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	5' 2-Lamp T5	PRS Elec.	2	35	78	15.5
F53GPL/2-H	F35T5	Fluorescent (3) 57.6" (1463mm)T-5 lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	5' 3-Lamp T5	PRS Elec.	3	35	118	15.5
F54GPL/2-H	F35T5	Fluorescent (4) 57.6" (1463mm)T-5 lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	5' 4-Lamp T5	PRS Elec.	4	35	156	15.5
F31GPHL-H	F39T5/HO	Fluorescent (1) 34" (863mm) T-5 HO lamp; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	3' 1-Lamp T5	PRS Elec.	1	39	44	15.5
F32GPHL-H	F39T5/HO	Fluorescent (2) 34" (863mm) T-5 HO lamps; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	3' 2-Lamp T5	PRS Elec.	2	39	86	15.5
F33GPHL/2-H	F39T5/HO	Fluorescent (3) 34" (863mm)T-5 HO lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	3' 3-Lamp T5	PRS Elec.	3	39	130	15.5
F34GPHL/2-H	F39T5/HO	Fluorescent (4) 34" (863mm)T-5 HO lamps; (2) Prog.Start or PRS Ballasts, HLO (.95 < BF < 1.1)	3' 4-Lamp T5	PRS Elec.	4	39	172	15.5
F46GPRL/2-H	F45T5/HO-RW	Fluorescent, (6) 45.8" T-5 HO reduced-wattage lamps, (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 6-Lamp T5HO	PRS Elec.	6	54	332	15.5
F46GPRL/3-H	F45T5/HO-RW	Fluorescent, (6) 45.8" T-5 HO reduced-wattage lamps, (3) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 6-Lamp T5HO	PRS Elec.	6	54	330	15.5
F41GPHL-H	F54T5/HO	Fluorescent (1) 45.8" T-5 HO lamp, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 1-Lamp T5HO	PRS Elec.	1	54	64	15.5
F41GPHL/T2-H	F54T5/HO	Fluorescent (1) 45.8" T-5 HO lamp, Tandem 2-lamp PRS Ballast, HLO (.95 < BF < 1.1)	4' 1-Lamp T5HO	PRS Elec.	1	54	59	15.5
F42GPHL-H	F54T5/HO	Fluorescent (2) 45.8" T-5 HO lamps, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 2-Lamp T5HO	PRS Elec.	2	54	117	15.5
F43GPHL-H	F54T5/HO	Fluorescent, (3) 45.8" T-5 HO lamps, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 3-Lamp T5HO	PRS Elec.	3	54	181	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F43GPHL/2-H	F54T5/HO	Fluorescent (3) 45.8" T-5 HO lamps, (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 3-Lamp T5HO	PRS Elec.	3	54	181	15.5
F44GPHL-H	F54T5/HO	Fluorescent, (4) 45.8" T-5 HO lamps, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 4-Lamp T5HO	PRS Elec.	4	54	230	15.5
F44GPHL/2-H	F54T5/HO	Fluorescent (4) 45.8" T-5 HO lamps, (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 4-Lamp T5HO	PRS Elec.	4	54	234	15.5
F45GPHL/2-H	F54T5/HO	Fluorescent (5) 45.8" T-5 HO lamps, (2) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 5-Lamp T5HO	PRS Elec.	5	54	298	15.5
F45GPRL/2-H	F54T5/HO-RW	Fluorescent (5) 45.2" T-5 HO reduced-wattage lamp, (2) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 5-Lamp T5HO	PRS Elec.	5	47-51	276	15.5
F46GPHL/2-H	F54T5/HO	Fluorescent, (6) 45.8" T-5 HO lamps, (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 6-Lamp T5HO	PRS Elec.	6	54	362	15.5
F46GPHL/3-H	F54T5/HO	Fluorescent, (6) 45.8" T-5 HO lamps, (3) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 6-Lamp T5HO	PRS Elec.	6	54	351	15.5
F48GPHL/2-H	F54T5/HO	Fluorescent, (8) 45.8" T-5 HO lamps, (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 8-Lamp T5HO	PRS Elec.	8	54	460	15.5
F48GPHL/4-H	F54T5/HO	Fluorescent, (8) 45.8" T-5 HO lamps, (4) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 8-Lamp T5HO	PRS Elec.	8	54	468	15.5
F410GPHL/3-H	F54T5/HO	Fluorescent, (10) 45.8" T-5 HO lamps, (3) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 10L T5HO	PRS Elec.	10	54	577	15.5
F410GPHL/5-H	F54T5/HO	Fluorescent, (10) 45.8" T-5 HO lamps, (5) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 10L T5HO	PRS Elec.	10	54	585	15.5
F412GPHL/3-H	F54T5/HO	Fluorescent, (12) 45.8" T-5 HO lamps, (3) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 12 T5HO	PRS Elec.	12	54	690	15.5
F412GPHL/6-H	F54T5/HO	Fluorescent, (12) 45.8" T-5 HO lamps, (6) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 12-Lamp T5HO	PRS Elec.	12	54	702	15.5
F41GPRL-H	F54T5/HO-RW	Fluorescent (1) 45.2" T-5 HO reduced-wattage lamp, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 1-Lamp T5HO	PRS Elec.	1	47-51	61	15.5
F42GPRL-H	F54T5/HO-RW	Fluorescent (2) 45.2" T-5 HO reduced-wattage lamp, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 2-Lamp T5HO	PRS Elec.	2	47-51	110	15.5
F43GPRL-H	F54T5/HO-RW	Fluorescent (3) 45.2" T-5 HO reduced-wattage lamp, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 3-Lamp T5HO	PRS Elec.	3	47-51	166	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F44GPRL-H	F54T5/HO-RW	Fluorescent (4) 45.2" T-5 HO reduced-wattage lamp, (1) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 4-Lamp T5HO	PRS Elec.	4	47-51	211	15.5
F48GPRL/2-H	F54T5/HO-RW	Fluorescent, (8) 45.8" T-5 HO reduced-wattage lamps, (2) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 8-Lamp T5HO	PRS Elec.	8	50	428	15.5
F48GPRL/4-H	F54T5/HO-RW	Fluorescent, (8) 45.8" T-5 HO reduced-wattage lamps, (4) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 8-Lamp T5HO	PRS Elec.	8	50	436	15.5
F410GPRL/3-H	F54T5/HO-RW	Fluorescent, (10) 45.8" T-5 HO reduced-wattage lamps, (3) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 10L T5HO	PRS Elec.	10	50	537	15.5
F410GPRL/5-H	F54T5/HO-RW	Fluorescent, (10) 45.8" T-5 HO reduced-wattage lamps, (5) PRS Electronic Ballast, HLO (.95 < BF < 1.1)	4' 10L T5HO	PRS Elec.	10	50	545	15.5
F412GPRL/3-H	F54T5/HO-RW	Fluorescent, (12) 45.8" T-5 HO reduced-wattage lamps, (3) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 12-Lamp T5HO	PRS Elec.	12	50	642	15.5
F412GPRL/6-H	F54T5/HO-RW	Fluorescent, (12) 45.8" T-5 HO reduced-wattage lamps, (6) PRS Electronic Ballasts, HLO (.95 < BF < 1.1)	4' 12-Lamp T5HO	PRS Elec.	12	50	654	15.5
F51GPHL-H	F80T5/HO	Fluorescent (1) 57.6" (1463mm) T-5 HO lamp; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	5' 1-Lamp T5HO	PRS Elec.	1	80	90	15.5
F52GPHL/2-H	F80T5/HO	Fluorescent (2) 57.6" (1463mm) T-5 HO lamps; (1) Prog.Start or PRS Ballast, HLO (.95 < BF < 1.1)	5' 2-Lamp T5HO	PRS Elec.	2	80	180	15.5
FT8		T8 Linear Fluorescent Systems						
F1.51LS	F15T8	Fluorescent, (1) 18" T-8 lamp	1.5' 1-Lamp T8	Mag-STD	1	15	19	15.5
F1.52LS	F15T8	Fluorescent, (2) 18" T-8 lamps	1.5' 2-Lamp T8	Mag-STD	2	15	36	15.5
F21GLL	F17T8	Fluorescent (1) 24" T-8 lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	PRS Elec.	1	17	18	15.5
F21ILL	F17T8	Fluorescent, (1) 24", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	18	15.5
F21ILL-R	F17T8	Fluorescent, (1) 24", T-8 lamp, Instant Start Ballast, RLO (BF< 0.85)	2' 1-Lamp T8 RLO	Electronic	1	17	17	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F21ILL/T2	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	17	15.5
F21ILL/T2-R	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 2-lamp IS Ballast, RLO (BF< 0.85)	2' 1-Lamp T8 RLO	Electronic	1	17	15	15.5
F21ILL/T3	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 3-lamp IS Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	16	15.5
F21ILL/T3-R	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	2' 1-Lamp T8 RLO	Electronic	1	17	14	15.5
F21ILL/T4	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	15	15.5
F21ILL/T4-R	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	2' 1-Lamp T8 RLO	Electronic	1	17	13	15.5
F21ILU	F17T8	Fluorescent, (1) 24", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	17	15.5
F21ILU-R	F17T8	Fluorescent, (1) 24", T-8 lamp, Instant Start Ballast, RLO (BF< 0.85)	2' 1-Lamp T8 RLO	Electronic	1	17	15	15.5
F21ILU-V	F17T8	Fluorescent, (1) 24", T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	2' 1-Lamp T8 VHLO	Electronic	1	17	22	15.5
F21LL	F17T8	Fluorescent, (1) 24", T-8 lamp, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	16	15.5
F21LL-R	F17T8	Fluorescent, (1) 24", T-8 lamp, Rapid Start Ballast, RLO (BF< 0.85)	2' 1-Lamp T8 RLO	Electronic	1	17	15	15.5
F21LL/T2	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 2-Lamp RS Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	16	15.5
F21LL/T3	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 3-Lamp RS Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	17	15.5
F21LL/T4	F17T8	Fluorescent, (1) 24", T-8 lamp, Tandem 4-Lamp RS Ballast, NLO (0.85 < BF < 0.95)	2' 1-Lamp T8	Electronic	1	17	17	15.5
F21SL	F17T8	Fluorescent, (1) 24", T-8 lamp, Standard Ballast	2' 1-Lamp T8	Mag-STD	1	17	24	15.5
F22GLL	F17T8	Fluorescent (2) 24" T-8 lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	2' 2-Lamp T8	PRS Elec.	2	17	31	15.5
F22ILL	F17T8	Fluorescent, (2) 24", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 2-Lamp T8	Electronic	2	17	33	15.5
F22ILL-R	F17T8	Fluorescent, (2) 24", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	2' 2-Lamp T8 RLO	Electronic	2	17	30	15.5
F22ILL/T4	F17T8	Fluorescent, (2) 24", T-8 lamps, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	2' 2-Lamp T8	Electronic	2	17	30	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F22ILL/T4-R	F17T8	Fluorescent, (2) 24", T-8 lamps, Tandem 4-lamp IS Ballast, RLO (BF<.85)	2' 2-Lamp T8 RLO	Electronic	2	17	27	15.5
F22ILU	F17T8	Fluorescent, (2) 24", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 2-Lamp T8	Electronic	2	17	30	15.5
F22ILU-R	F17T8	Fluorescent, (2) 24", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	2' 2-Lamp T8 RLO	Electronic	2	17	27	15.5
F22ILU-V	F17T8	Fluorescent, (2) 24", T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	2' 2-Lamp T8 VHLO	Electronic	2	17	41	15.5
F22ILU/T4-R	F17T8	Fluorescent, (2) 24", T-8 lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	2' 2-Lamp T8 RLO	Electronic	2	17	26	15.5
F22LL	F17T8	Fluorescent, (2) 24", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	2' 2-Lamp T8	Electronic	2	17	31	15.5
F22LL-R	F17T8	Fluorescent, (2) 24", T-8 lamps, Rapid Start Ballast, RLO (BF< 0.85)	2' 2-Lamp T8 RLO	Electronic	2	17	28	15.5
F22LL/T4	F17T8	Fluorescent, (2) 24", T-8 lamps, Tandem 4-lamp RS Ballast, NLO (0.85 < BF < 0.95)	2' 2-Lamp T8	Electronic	2	17	34	15.5
F23GLL	F17T8	Fluorescent (3) 24" T-8 lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	2' 3-Lamp T8	PRS Elec.	3	17	47	15.5
F23ILL	F17T8	Fluorescent, (3) 24", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 3-Lamp T8	Electronic	3	17	47	15.5
F23ILL-H	F17T8	Fluorescent, (3) 24", T-8 lamps, Instant Start Ballast, HLO (0.95 < BF < 1.1)	2' 3-Lamp T8 HLO	Electronic	3	17	51	15.5
F23ILL-R	F17T8	Fluorescent, (3) 24", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	2' 3-Lamp T8 RLO	Electronic	3	17	41	15.5
F23ILU	F17T8	Fluorescent, (3) 24", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 3-Lamp T8	Electronic	3	17	45	15.5
F23ILU-R	F17T8	Fluorescent, (3) 24", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	2' 3-Lamp T8 RLO	Electronic	3	17	40	15.5
F23ILU-V	F17T8	Fluorescent, (3) 24", T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	2' 3-Lamp T8 VHLO	Electronic	3	17	59	15.5
F23LL	F17T8	Fluorescent, (3) 24", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	2' 3-Lamp T8	Electronic	3	17	52	15.5
F23LL-R	F17T8	Fluorescent, (3) 24", T-8 lamps, Rapid Start Ballast, RLO (BF< 0.85)	2' 3-Lamp T8 RLO	Electronic	3	17	41	15.5
F24GLL	F17T8	Fluorescent (4) 24" T-8 lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	2' 4-Lamp T8	PRS Elec.	4	17	59	15.5
F24ILL	F17T8	Fluorescent, (4) 24", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 4-Lamp T8	Electronic	4	17	59	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F24ILL-R	F17T8	Fluorescent, (4) 24", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	2' 4-Lamp T8 RLO	Electronic	4	17	53	15.5
F24ILU	F17T8	Fluorescent, (4) 24", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	2' 4-Lamp T8	Electronic	4	17	57	15.5
F24ILU-R	F17T8	Fluorescent, (4) 24", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	2' 4-Lamp T8 RLO	Electronic	4	17	52	15.5
F24LL	F17T8	Fluorescent, (4) 24", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	2' 4-Lamp T8	Electronic	4	17	68	15.5
F24LL-R	F17T8	Fluorescent, (4) 24", T-8 lamps, Rapid Start Ballast, RLO (BF< 0.85)	2' 4-Lamp T8 RLO	Electronic	4	17	57	15.5
F31ILL	F25T8	Fluorescent, (1) 36", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	26	15.5
F31ILL-H	F25T8	Fluorescent, (1) 36", T-8 lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	3' 1-Lamp T8 HLO	Electronic	1	25	28	15.5
F31ILL-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Instant Start Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	22	15.5
F31ILL/T2	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	23	15.5
F31ILL/T2-H	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 3-lamp IS Ballast, 1 lead capped, HLO (0.95 < BF < 1.1)	3' 1-Lamp T8	Electronic	1	25	26	15.5
F31ILL/T2-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 2-lamp IS Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	21	15.5
F31ILL/T3	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 3-lamp IS Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	23	15.5
F31ILL/T3-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	20	15.5
F31ILL/T4	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	22	15.5
F31ILL/T4-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	20	15.5
F31ILU	F25T8	Fluorescent, (1) 36", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	23	15.5
F31ILU-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Instant Start Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	20	15.5
F31ILU/T2	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	22	15.5
F31ILU/T2-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 2-lamp IS Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	20	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F31ILU/T3-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	19	15.5
F31ILU/T4-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	19	15.5
F31LL	F25T8	Fluorescent, (1) 36", T-8 lamp, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	24	15.5
F31LL-H	F25T8	Fluorescent, (1) 36", T-8 lamp, Rapid Start Ballast, HLO (0.95 < BF < 1.1)	3' 1-Lamp T8 HLO	Electronic	1	25	26	15.5
F31LL-R	F25T8	Fluorescent, (1) 36", T-8 lamp, Rapid Start Ballast, RLO (BF< 0.85)	3' 1-Lamp T8 RLO	Electronic	1	25	23	15.5
F31LL/T2	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 2-lamp RS Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	23	15.5
F31LL/T3	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 3-lamp RS Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	24	15.5
F31LL/T4	F25T8	Fluorescent, (1) 36", T-8 lamp, Tandem 4-lamp RS Ballast, NLO (0.85 < BF < 0.95)	3' 1-Lamp T8	Electronic	1	25	22	15.5
F32ILL	F25T8	Fluorescent, (2) 36", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 2-Lamp T8	Electronic	2	25	46	15.5
F32ILL-H	F25T8	Fluorescent, (2) 36", T-8 lamps, Instant Start Ballast, HLO (0.95 < BF < 1.1)	3' 2-Lamp T8 HLO	Electronic	2	25	52	15.5
F32ILL-R	F25T8	Fluorescent, (2) 36", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	3' 2-Lamp T8 RLO	Electronic	2	25	42	15.5
F32ILL/2-R	F25T8	Fluorescent, (2) 36", T-8 lamps, (2) Instant Start Ballasts, RLO (BF< 0.85)	3' 2-Lamp T8 RLO	Electronic	2	25	44	15.5
F32ILL/T4	F25T8	Fluorescent, (2) 36", T-8 lamps, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	3' 2-Lamp T8	Electronic	2	25	44	15.5
F32ILL/T4-R	F25T8	Fluorescent, (2) 36", T-8 lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	3' 2-Lamp T8 RLO	Electronic	2	25	39	15.5
F32ILU	F25T8	Fluorescent, (2) 36", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 2-Lamp T8	Electronic	2	25	44	15.5
F32ILU-R	F25T8	Fluorescent, (2) 36", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	3' 2-Lamp T8 RLO	Electronic	2	25	39	15.5
F32ILU/T4-R	F25T8	Fluorescent, (2) 36", T-8 lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	3' 2-Lamp T8 RLO	Electronic	2	25	39	15.5
F32LL	F25T8	Fluorescent, (2) 36", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	3' 2-Lamp T8	Electronic	2	25	46	15.5
F32LL-H	F25T8	Fluorescent, (2) 36", T-8 lamps, Rapid Start Ballast, HLO (0.95 < BF < 1.1)	3' 2-Lamp T8 HLO	Electronic	2	25	50	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F32LL-R	F25T8	Fluorescent, (2) 36", T-8 lamps, Rapid Start Ballast, RLO (BF< 0.85)	3' 2-Lamp T8 RLO	Electronic	2	25	42	15.5
F32LL-V	F25T8	Fluorescent, (2) 36", T-8 lamps, Rapid Start Ballast, VHLO (BF > 1.1)	3' 2-Lamp T8 VHLO	Electronic	2	25	70	15.5
F32LL/T4	F25T8	Fluorescent, (2) 36", T-8 lamps, Tandem 4-lamp RS Ballast, NLO (0.85 < BF < 0.95)	3' 2-Lamp T8	Electronic	2	25	45	15.5
F33ILL	F25T8	Fluorescent, (3) 36", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 3-Lamp T8	Electronic	3	25	68	15.5
F33ILL-R	F25T8	Fluorescent, (3) 36", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	3' 3-Lamp T8 RLO	Electronic	3	25	61	15.5
F33ILU	F25T8	Fluorescent, (3) 36", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 3-Lamp T8	Electronic	3	25	65	15.5
F33ILU-R	F25T8	Fluorescent, (3) 36", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	3' 3-Lamp T8 RLO	Electronic	3	25	58	15.5
F33LL	F25T8	Fluorescent, (3) 36", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	3' 3-Lamp T8	Electronic	3	25	72	15.5
F33LL-R	F25T8	Fluorescent, (3) 36", T-8 lamps, Rapid Start Ballast, RLO (BF< 0.85)	3' 3-Lamp T8 RLO	Electronic	3	25	62	15.5
F34ILL	F25T8	Fluorescent, (4) 36", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 4-Lamp T8	Electronic	4	25	88	15.5
F34ILL-R	F25T8	Fluorescent, (4) 36", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	3' 4-Lamp T8 RLO	Electronic	4	25	78	15.5
F34ILL/2-R	F25T8	Fluorescent, (4) 36", T-8 lamps, (2) Instant Start Ballasts, RLO (BF< 0.85)	3' 4-Lamp T8 RLO	Electronic	4	25	84	15.5
F34ILU	F25T8	Fluorescent, (4) 36", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	3' 4-Lamp T8	Electronic	4	25	86	15.5
F34ILU-R	F25T8	Fluorescent, (4) 36", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	3' 4-Lamp T8 RLO	Electronic	4	25	77	15.5
F34LL	F25T8	Fluorescent, (4) 36", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	3' 4-Lamp T8	Electronic	4	25	89	15.5
F34LL-R	F25T8	Fluorescent, (4) 36", T-8 lamps, Rapid Start Ballast, RLO (BF< 0.85)	3' 4-Lamp T8 RLO	Electronic	4	25	84	15.5
F36ILL/2	F25T8	Fluorescent, (6) 36", T-8 lamps, (2) Instant Start Ballasts, NLO (0.85 < BF < 0.95)	3' 6-Lamp T8	Electronic	6	25	135	15.5
F36ILL/2-R	F25T8	Fluorescent, (6) 36", T-8 lamps, (2) Instant Start Ballasts, RLO (BF< 0.85)	3' 6-Lamp T8 RLO	Electronic	6	25	121	15.5
F42GRLL-V	F28T8	Fluorescent, (2) 48", T-8 lamps, Prog. Start or PRS Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 28W VLHO	PRS Elec.	2	28	66	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F43GRLL-V	F28T8	Fluorescent, (3) 48", T-8 lamps, Prog. Start or PRS Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 28W VLHO	PRS Elec.	3	28	92	15.5
F41GLL	F32T8	Fluorescent (1) 48" T-8 lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	PRS Elec.	1	32	30	15.5
F41GLL-R	F32T8	Fluorescent (1) 48" T-8 lamp, Prog. Start or PRS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	PRS Elec.	1	32	25	15.5
F41ILL	F32T8	Fluorescent, (1) 48", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	31	15.5
F41ILL-H	F32T8	Fluorescent, (1) 48", T-8 lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 HLO	Electronic	1	32	36	15.5
F41ILL-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Instant Start Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	27	15.5
F41ILL/T2	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	29	15.5
F41ILL/T2-H	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp IS Ballast, 1 lead capped, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 HLO	Electronic	1	32	33	15.5
F41ILL/T2-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 2-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	26	15.5
F41ILL/T3	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	28	15.5
F41ILL/T3-H	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp IS Ballast, 1 lead capped, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 HLO	Electronic	1	32	31	15.5
F41ILL/T3-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	25	15.5
F41ILL/T4	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	28	15.5
F41ILL/T4-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	25	15.5
F41ILU	F32T8	Fluorescent, (1) 48", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	28	15.5
F41ILU-H	F32T8	Fluorescent, (1) 48", T-8 lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 HLO	Electronic	1	32	35	15.5
F41ILU-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Instant Start Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	25	15.5
F41ILU/T2	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	27	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F41ILU/T2-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 2-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	24	15.5
F41ILU/T3	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	27	15.5
F41ILU/T3-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	24	15.5
F41ILU/T4	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	27	15.5
F41ILU/T4-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	24	15.5
F41LE	F32T8	Fluorescent, (1) 48", T-8 lamp	4' 1-Lamp T8	Mag-ES	1	32	35	15.5
F41LL	F32T8	Fluorescent, (1) 48", T-8 lamp, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	32	15.5
F41LL-H	F32T8	Fluorescent, (1) 48", T-8 lamp, Rapid Start Ballast, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 HLO	Electronic	1	32	39	15.5
F41LL-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Rapid Start Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	27	15.5
F41LL/T2	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 2-lamp RS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	30	15.5
F41LL/T2-H	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp RS Ballast, 1 lead capped, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 HLO	Electronic	1	32	35	15.5
F41LL/T2-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 2-lamp RS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	27	15.5
F41LL/T3	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp RS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	31	15.5
F41LL/T3-H	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp RS Ballast, 1 lead capped, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 HLO	Electronic	1	32	33	15.5
F41LL/T3-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 3-lamp RS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	25	15.5
F41LL/T4	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp RS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8	Electronic	1	32	30	15.5
F41LL/T4-R	F32T8	Fluorescent, (1) 48", T-8 lamp, Tandem 4-lamp RS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 RLO	Electronic	1	32	26	15.5
F42GLL	F32T8	Fluorescent (2) 48" T-8 lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	PRS Elec.	2	32	59	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F42GLL-R	F32T8	Fluorescent (2) 48" T-8 lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 2-Lamp T8 RLO	PRS Elec.	2	32	47	15.5
F42GLL-V	F32T8	Fluorescent, (2) 48" T-8 lamps, Prog. Start or PRS Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 VHLO	PRS Elec.	2	32	74	15.5
F42ILL	F32T8	Fluorescent, (2) 48", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	58	15.5
F42ILL-H	F32T8	Fluorescent, (2) 48", T-8 lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 2-Lamp T8 HLO	Electronic	2	32	66	15.5
F42ILL-R	F32T8	Fluorescent, (2) 48", T-8 lamps, Instant Start Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 RLO	Electronic	2	32	51	15.5
F42ILL-V	F32T8	Fluorescent, (2) 48", T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 VHLO	Electronic	2	32	77	15.5
F42ILL/2	F32T8	Fluorescent, (2) 48", T-8 lamps, (2) 1-lamp Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	62	15.5
F42ILL/2-R	F32T8	Fluorescent, (2) 48" T-8 lamps, (2) 1-lamp Instant Start Ballasts, RLO (BF< 0.85)	4' 2-Lamp T8 RLO	Electronic	2	32	54	15.5
F42ILL/T4	F32T8	Fluorescent, (2) 48", T-8 lamps, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	56	15.5
F42ILL/T4-R	F32T8	Fluorescent, (2) 48", T-8 lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 RLO	Electronic	2	32	49	15.5
F42ILU	F32T8	Fluorescent, (2) 48", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	54	15.5
F42ILU-H	F32T8	Fluorescent, (2) 48", T-8 lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 2-Lamp T8 HLO	Electronic	2	32	64	15.5
F42ILU-R	F32T8	Fluorescent, (2) 48", T-8 lamps, Instant Start, RLO (BF< 0.85)	4' 2-Lamp T8 RLO	Electronic	2	32	48	15.5
F42ILU-V	F32T8	Fluorescent, (2) 48", T-8 lamps, Instant Start, VHLO (BF> 1.1)	4' 2-Lamp T8 VHLO	Electronic	2	32	73	15.5
F42ILU/T4	F32T8	Fluorescent, (2) 48", T-8 lamps, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	54	15.5
F42ILU/T4-R	F32T8	Fluorescent, (2) 48", T-8 lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 RLO	Electronic	2	32	48	15.5
F42LE	F32T8	Fluorescent, (2) 48", T-8 lamp	4' 2-Lamp T8	Mag-ES	2	32	71	15.5
F42LL	F32T8	Fluorescent, (2) 48", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	60	15.5
F42LL-H	F32T8	Fluorescent, (2) 48", T-8 lamp, Rapid Start Ballast, HLO (0.95 < BF < 1.1)	4' 2-Lamp T8 HLO	Electronic	2	32	70	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F42LL-R	F32T8	Fluorescent, (2) 48", T-8 lamp, Rapid Start Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 RLO	Electronic	2	32	54	15.5
F42LL-V	F32T8	Fluorescent, (2) 48", T-8 lamp, Rapid Start Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 HLO	Electronic	2	32	85	15.5
F42LL/2	F32T8	Fluorescent, (2) 48", T-8 lamps, (2) 1-lamp Rapid Start Ballasts, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	64	15.5
F42LL/T4	F32T8	Fluorescent, (2) 48", T-8 lamps, Tandem 4-lamp RS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8	Electronic	2	32	59	15.5
F42LL/T4-R	F32T8	Fluorescent, (2) 48", T-8 lamp, Tandem 4-lamp RS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 RLO	Electronic	2	32	53	15.5
F43GLL	F32T8	Fluorescent (3) 48" T-8 lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8	PRS Elec.	3	32	88	15.5
F43GLL-R	F32T8	Fluorescent (3) 48" T-8 lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 RLO	PRS Elec.	3	32	72	15.5
F43GLL-V	F32T8	Fluorescent, (3) 48" T-8 lamps, Prog. Start or PRS Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 VHLO	Electronic	3	32	108	15.5
F43ILL	F32T8	Fluorescent, (3) 48" T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8	Electronic	3	32	85	15.5
F43ILL-H	F32T8	Fluorescent, (3) 48" T-8 lamps, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 3-Lamp T8 HLO	Electronic	3	32	93	15.5
F43ILL-R	F32T8	Fluorescent, (3) 48" T-8 lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 RLO	Electronic	3	32	76	15.5
F43ILL-V	F32T8	Fluorescent, (3) 48" T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 VHLO	Electronic	3	32	112	15.5
F43ILL/2	F32T8	Fluorescent, (3) 48" T-8 lamps, (2) Instant Start Ballasts, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8	Electronic	3	32	89	15.5
F43ILL/2-H	F32T8	Fluorescent (3) 48" T-8 lamps, (1) 2-lamp and (1) 3-lamp IS Ballast,1 lead capped, HLO (0.95 < BF < 1.1)	4' 3-Lamp T8 HLO	Electronic	3	32	102	15.5
F43ILL/2-R	F32T8	Fluorescent, (3) 48" T-8 lamps, (1) 1-lamp and (1) 2-lamp IS Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 RLO	Electronic	3	32	78	15.5
F43ILU	F32T8	Fluorescent, (3) 48" T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8	Electronic	3	32	81	15.5
F43ILU-H	F32T8	Fluorescent, (3) 48", T-8 lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 3-Lamp T8 HLO	Electronic	3	32	92	15.5
F43ILU-R	F32T8	Fluorescent, (3) 48" T-8 lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 RLO	Electronic	3	32	72	15.5
F43ILU-V	F32T8	Fluorescent, (3) 48" T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 VHLO	Electronic	3	32	108	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F43LE	F32T8	Fluorescent, (3) 48", T-8 lamp	4' 3-Lamp T8	Mag-ES	3	32	110	15.5
F43LL	F32T8	Fluorescent, (3) 48", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8	Electronic	3	32	93	15.5
F43LL-H	F32T8	Fluorescent, (3) 48", T-8 lamp, Rapid Start Ballast, HLO (.95 < BF < 1.1)	4' 3-Lamp T8 HLO	Electronic	3	32	98	15.5
F43LL-R	F32T8	Fluorescent, (3) 48", T-8 lamp, Rapid Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 RLO	Electronic	3	32	76	15.5
F43LL/2	F32T8	Fluorescent, (3) 48", T-8 lamps, (1) 1-lamp and (1) 2-lamp RS Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8	Electronic	3	32	92	15.5
F44GLL	F32T8	Fluorescent (4) 48" T-8 lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8	PRS Elec.	4	32	115	15.5
F44GLL-R	F32T8	Fluorescent (4) 48" T-8 lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 RLO	PRS Elec.	4	32	92	15.5
F44GLL-V	F32T8	Fluorescent, (4) 48" T-8 lamps, Prog. Start or PRS Ballast, VHLO (BF > 1.1)	4' 4-Lamp T8 VHLO	PRS Elec.	4	32	144	15.5
F44ILL	F32T8	Fluorescent, (4) 48", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8	Electronic	4	32	112	15.5
F44ILL-R	F32T8	Fluorescent, (4) 48", T-8 lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 RLO	Electronic	4	32	98	15.5
F44ILL-V	F32T8	Fluorescent, (4) 48", T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 4-Lamp T8 VHLO	Electronic	4	32	151	15.5
F44ILL/2	F32T8	Fluorescent, (4) 48", T-8 lamps, (2) 2-lamp IS Ballasts, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8	Electronic	4	32	116	15.5
F44ILL/2-H	F32T8	Fluorescent, (4) 48", T-8 lamps, (2) 3-lamp IS Ballasts, 1 lead capped, HLO (.95 < BF < 1.1)	4' 4-Lamp T8 HLO	Electronic	4	32	132	15.5
F44ILL/2-R	F32T8	Fluorescent, (4) 48", T-8 lamps, (2) 2-lamp IS Ballasts, RLO (BF < 0.85)	4' 4-Lamp T8 RLO	Electronic	4	32	102	15.5
F44ILL/2-V	F32T8	Fluorescent, (4) 48", T-8 lamps, (2) 2-lamp IS Ballasts, VHLO (BF > 1.1)	4' 4-Lamp T8 VHLO	Electronic	4	32	154	15.5
F44ILU	F32T8	Fluorescent, (4) 48", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8	Electronic	4	32	107	15.5
F44ILU-H	F32T8	Fluorescent, (4) 48", T-8 lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 4-Lamp T8 HLO	Electronic	4	32	121	15.5
F44ILU-R	F32T8	Fluorescent, (4) 48", T-8 lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 RLO	Electronic	4	32	95	15.5
F44ILU-V	F32T8	Fluorescent, (4) 48", T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 4-Lamp T8 VHLO	Electronic	4	32	146	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F44LE	F32T8	Fluorescent, (4) 48", T-8 lamps	4' 4-Lamp T8	Mag-ES	4	32	142	15.5
F44LL	F32T8	Fluorescent, (4) 48", T-8 lamps, Rapid Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8	Electronic	4	32	118	15.5
F44LL-R	F32T8	Fluorescent, (4) 48", T-8 lamps, Rapid Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 RLO	Electronic	4	32	105	15.5
F44LL/2	F32T8	Fluorescent, (4) 48", T-8 lamps, (2) 2-lamp Rapid Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8	Electronic	4	32	120	15.5
F45ILL/2	F32T8	Fluorescent, (5) 48", T-8 lamps, (1) 3-lamp and (1) 2-lamp IS ballast, NLO (0.85 < BF < 0.95)	4' 5-Lamp T8	Electronic	5	32	143	15.5
F45GLL/2-V	F32T8	Fluorescent, (5) 48", T-8 lamps, (1) 3-lamp and (1) 2-lamp Prog. Start Ballast, VHLO (BF > 1.1)	4' 5-Lamp T8 VHLO	Electronic	5	32	182	15.5
F46GLL/2	F32T8	Fluorescent (6) 48" T-8 lamps, (2) Prog. Start or PRS Ballasts, NLO (0.85 < BF < 0.95)	4' 6-Lamp T8	PRS Elec.	6	32	175	15.5
F46GLL/2-R	F32T8	Fluorescent (6) 48" T-8 lamps, (2) Prog. Start or PRS Ballasts, RLO (BF < 0.85)	4' 6-Lamp T8 RLO	PRS Elec.	6	32	142	15.5
F46GLL/2-V	F32T8	Fluorescent (6) 48" T-8 lamps, (2) Prog. Start or PRS Ballasts, VHLO (BF > 1.1)	4' 6-Lamp T8 VHLO	PRS Elec.	6	32	217	15.5
F46ILL/2	F32T8	Fluorescent, (6) 48", T-8 lamps, (2) IS Ballasts, NLO (0.85 < BF < 0.95)	4' 6-Lamp T8	Electronic	6	32	170	15.5
F46ILL/2-R	F32T8	Fluorescent, (6) 48", T-8 lamps, (2) IS Ballasts, RLO (BF < 0.85)	4' 6-Lamp T8 RLO	Electronic	6	32	151	15.5
F46ILL/2-V	F32T8	Fluorescent (6) 48" T-8 lamps, (2) IS Ballasts, VHLO (BF > 1.1)	4' 6-Lamp T8 VHLO	Electronic	6	32	226	15.5
F46ILU/2	F32T8	Fluorescent (6) 48" T-8 lamps, (2) IS Ballasts, NLO (0.85 < BF < 0.95)	4' 6-Lamp T8	Electronic	6	32	162	15.5
F46ILU/2-R	F32T8	Fluorescent (6) 48" T-8 lamps, (2) IS Ballasts, RLO (BF < 0.85)	4' 6-Lamp T8 RLO	Electronic	6	32	144	15.5
F46ILU/2-V	F32T8	Fluorescent (6) 48" T-8 lamps, (2) IS Ballasts, VHLO (BF > 1.1)	4' 6-Lamp T8 VHLO	Electronic	6	32	218	15.5
F465LL/2	F32T8	Fluorescent, (6) 48", T-8 lamps, (2) Rapid Start Ballasts, NLO (0.85 < BF < 0.95)	4' 6-Lamp T8	Electronic	6	32	182	15.5
F48GLL/2	F32T8	Fluorescent (8) 48" T-8 lamps, (2) Prog. Start or PRS Ballasts, NLO (0.85 < BF < 0.95)	4' 8-Lamp T8	PRS Elec.	8	32	230	15.5
F48GLL/2-R	F32T8	Fluorescent (8) 48" T-8 lamps, (2) Prog. Start or PRS Ballasts, RLO (BF < 0.85)	4' 8-Lamp T8 RLO	PRS Elec.	8	32	184	15.5
F48GLL/2-V	F32T8	Fluorescent (8) 48" T-8 lamps, (2) Prog. Start or PRS Ballasts, VHLO (BF > 1.1)	4' 8-Lamp T8 VHLO	PRS Elec.	8	32	288	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F48ILL/2	F32T8	Fluorescent, (8) 48", T-8 lamps, (2) 4-lamp IS Ballasts, NLO (0.85 < BF < 0.95)	4' 8-Lamp T8	Electronic	8	32	224	15.5
F48ILL/2-R	F32T8	Fluorescent, (8) 48", T-8 lamps, (2) 4-lamp IS Ballasts, RLO (BF < 0.85)	4' 8-Lamp T8 RLO	Electronic	8	32	196	15.5
F48ILU/2	F32T8	Fluorescent, (8) 48", T-8 lamps, (2) 4-lamp IS Ballasts, NLO (0.85 < BF < 0.95)	4' 8-Lamp T8	Electronic	8	32	214	15.5
F48ILU/2-R	F32T8	Fluorescent, (8) 48", T-8 lamps, (2) 4-lamp IS Ballasts, RLO (BF < 0.85)	4' 8-Lamp T8 RLO	Electronic	8	32	190	15.5
F48ILU/2-V	F32T8	Fluorescent, (8) 48", T-8 lamps, (2) 4-lamp IS Ballasts, VHLO (BF > 1.1)	4' 8-Lamp T8 VHLO	Electronic	8	32	292	15.5
F41GNLL	F32T8-25W	Fluorescent (1) 48" T-8 @ 25W lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 25W	PRS Elec.	1	25	24	15.5
F41GNLL-R	F32T8-25W	Fluorescent (1) 48" T-8 @ 25W lamp, Prog. Start or PRS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 25W RLO	PRS Elec.	1	25	21	15.5
F41INLL	F32T8-25W	Fluorescent, (1) 48", T-8 @ 25W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 25W	Electronic	1	25	24	15.5
F41INLU	F32T8-25W	Fluorescent, (1), T-8 @ 25W lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 25W	Electronic	1	25	23	15.5
F41INLU-R	F32T8-25W	Fluorescent, (1), T-8 @ 25W lamp, Instant Start Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 25W RLO	Electronic	1	25	21	15.5
F41INLU-V	F32T8-25W	Fluorescent, (1), T-8 @ 25W lamp, Instant Start Ballast, VHLO (BF > 1.1)	4' 1-Lamp T8 25W VHLO	Electronic	1	25	32	15.5
F41INLU/T3-R	F32T8-25W	Fluorescent, (1) 48", T-8 @ 25W lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 25W RLO	Electronic	1	25	19	15.5
F41INLU/T4-R	F32T8-25W	Fluorescent, (1) 48", T-8 @ 25W lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 25W RLO	Electronic	1	25	19	15.5
F42GNLL	F32T8-25W	Fluorescent (2) 48" T-8 @ 25W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 25W	PRS Elec.	2	25	44	15.5
F42GNLL-R	F32T8-25W	Fluorescent (2) 48" T-8 @ 25W lamps, Prog. Start or PRS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 25W RLO	PRS Elec.	2	25	38	15.5
F42INLL	F32T8-25W	Fluorescent, (2) 48", T-8 @ 25W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 25W	Electronic	2	25	46	15.5
F42INLL-V	F32T8-25W	Fluorescent, (2) 48" T-8 @ 25W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 25W VHLO	Electronic	2	25	65	15.5
F42INLU	F32T8-25W	Fluorescent, (2), T-8 @ 25W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 25W	Electronic	2	25	43	15.5
F42INLU-R	F32T8-25W	Fluorescent (2) 48" T8 @ 25W lamps, Instant Start Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 25W RLO	Electronic	2	25	38	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F42INLU-V	F32T8-25W	Fluorescent, (2) 48", T-8 @ 25W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 25W VHLO	Electronic	2	25	60	15.5
F42INLU/T4-R	F32T8-25W	Fluorescent, (2) 48", T-8 @ 25W lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 25W RLO	Electronic	2	25	38	15.5
F43GNLL	F32T8-25W	Fluorescent (3) 48" T-8 @ 25W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 25W	PRS Elec.	3	25	66	15.5
F43GNLL-R	F32T8-25W	Fluorescent, (3) 48" T-8 @ 25W lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 25W RLO	PRS Elec.	3	25	56	15.5
F43INLL	F32T8-25W	Fluorescent, (3) 48" T-8 @ 25W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 25W	Electronic	3	25	66	15.5
F43INLL-V	F32T8-25W	Fluorescent, (3) 48" T-8 @ 25W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 25W VHLO	Electronic	3	25	95	15.5
F43INLU	F32T8-25W	Fluorescent, (3) 48" T-8 lamps @ 25W, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 25W	Electronic	3	25	64	15.5
F43INLU-R	F32T8-25W	Fluorescent, (3) 48" T-8 @ 25W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 25W RLO	Electronic	3	25	57	15.5
F43INLU-V	F32T8-25W	Fluorescent, (3) 48" T-8 @ 25W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 25W VHLO	Electronic	3	25	93	15.5
F44GNLL	F32T8-25W	Fluorescent (4) 48" T-8 @ 25W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 25W	PRS Elec.	4	25	85	15.5
F44GNLL-R	F32T8-25W	Fluorescent (4) 48" T-8 @ 25W lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 25W RLO	PRS Elec.	4	25	73	15.5
F44INLL	F32T8-25W	Fluorescent, (4) 48", T-8 @ 25W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 25W	Electronic	4	25	86	15.5
F44INLU	F32T8-25W	Fluorescent, (4) 48", T-8 @ 25W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 25W	Electronic	4	25	85	15.5
F44INLU-R	F32T8-25W	Fluorescent, (4) 48" T-8 @ 25W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 25W RLO	Electronic	4	25	75	15.5
F44INLU-V	F32T8-25W	Fluorescent, (4) 48" T-8 @ 25W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 4-Lamp T8 25W VHLO	Electronic	4	25	122	15.5
F46INLU/2-R	F32T8-25W	Fluorescent (6) 48" T-8 @ 25W lamps, (2) IS Ballasts, RLO (BF < 0.85)	4' 6-Lamp T8 25W RLO	Electronic	6	25	114	15.5
F46INLU/2-V	F32T8-25W	Fluorescent (6) 48" T-8 @ 25W lamps, (2) IS Ballasts, VHLO (BF > 1.1)	4' 6-Lamp T8 25W VHLO	Electronic	6	25	184	15.5
F41GRLL	F32T8-28W	Fluorescent (1) 48" T-8 @ 28W lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 28W	PRS Elec.	1	28	26	15.5
F41GRLL-R	F32T8-28W	Fluorescent (1) 48" T-8 @ 28W lamp, Prog. Start or PRS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 28W RLO	PRS Elec.	1	28	22	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F41IRLL	F32T8-28W	Fluorescent, (1) 48" T-8 @ 28W lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 28W	Electronic	1	28	27	15.5
F41IRLL-V	F32T8-28W	Fluorescent, (1) 48" T-8 @ 28W lamp, Instant Start Ballast, VHLO (BF > 1.1)	4' 1-Lamp T8 28W VHLO	Electronic	1	28	35	15.5
F41IRLU	F32T8-28W	Fluorescent, (1), T-8 @ 28W lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 28W	Electronic	1	28	25	15.5
F41IRLU-R	F32T8-28W	Fluorescent, (1), T-8 @ 28W lamp, Instant Start Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 28W RLO	Electronic	1	28	22	15.5
F41IRLU-V	F32T8-28W	Fluorescent, (1), T-8 @ 28W lamp, Instant Start Ballast, VHLO (BF > 1.1)	4' 1-Lamp T8 28W VHLO	Electronic	1	28	33	15.5
F41IRLU/T3-R	F32T8-28W	Fluorescent, (1) 48", T-8 @ 28W lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 28W RLO	Electronic	1	28	21	15.5
F41IRLU/T4-R	F32T8-28W	Fluorescent, (1) 48", T-8 @ 28W lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 28W RLO	Electronic	1	28	21	15.5
F42GRLL	F32T8-28W	Fluorescent (2) 48" T-8 @ 28W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 28W	PRS Elec.	2	28	49	15.5
F42GRLL-R	F32T8-28W	Fluorescent (2) 48" T-8 @ 28W lamps, Prog. Start or PRS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 28W RLO	PRS Elec.	2	28	40	15.5
F42IRLL	F32T8-28W	Fluorescent, (2) 48", T-8 @ 28W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 28W NLO	Electronic	2	28	52	15.5
F42IRLL-V	F32T8-28W	Fluorescent, (2) 48" T-8 @ 28W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 28W VHLO	Electronic	2	28	68	15.5
F42IRLU	F32T8-28W	Fluorescent, (2), T-8 @ 28W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 28W	Electronic	2	28	48	15.5
F42IRLU-R	F32T8-28W	Fluorescent, (2) 48", T-8 @ 28W lamps, Instant Start Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 28W RLO	Electronic	2	28	43	15.5
F42IRLU-V	F32T8-28W	Fluorescent, (2) 48", T-8 @ 28W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 2-Lamp T8 28W VHLO	Electronic	2	28	65	15.5
F42IRLU/T4-R	F32T8-28W	Fluorescent, (2) 48", T-8 @ 28W lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 28W RLO	Electronic	2	28	42	15.5
F43GRLL	F32T8-28W	Fluorescent (3) 48" T-8 @ 28W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 28W	PRS Elec.	3	28	75	15.5
F43GRLL-R	F32T8-28W	Fluorescent, (3) 48" T-8 @ 28W lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 28W RLO	PRS Elec.	3	28	62	15.5
F43IRLL	F32T8-28W	Fluorescent, (3) 48" T-8 @ 28W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 28W	Electronic	3	28	76	15.5
F43IRLL-H	F32T8-28W	Fluorescent, (3) 48" T-8 @ 28W lamps, Instant Start Ballast, HLO (.95 < BF < 1.1)	4' 3-Lamp T8 28W HLO	Electronic	3	28	82	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F43IRLL-V	F32T8-28W	Fluorescent, (3) 48" T-8 @ 28W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 28W VHLO	Electronic	3	28	97	15.5
F43IRLU	F32T8-28W	Fluorescent, (3) 48" T-8 lamps @ 28W, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 28W	Electronic	3	28	72	15.5
F43IRLU-R	F32T8-28W	Fluorescent, (3) 48" T-8 @ 28W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 28W RLO	Electronic	3	28	63	15.5
F43IRLU-V	F32T8-28W	Fluorescent, (3) 48" T-8 @ 28W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 28W VHLO	Electronic	3	28	96	15.5
F44GRLL	F32T8-28W	Fluorescent (4) 48" T-8 @ 28W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 28W	PRS Elec.	4	28	99	15.5
F44GRLL-R	F32T8-28W	Fluorescent (4) 48" T-8 @ 28W lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 28W RLO	PRS Elec.	4	28	80	15.5
F44IRLL	F32T8-28W	Fluorescent, (4) 48", T-8 @ 28W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 28W	Electronic	4	28	99	15.5
F44IRLL-R	F32T8-28W	Fluorescent, (4) 48", T-8 @ 28W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 28W RLO	Electronic	4	28	85	15.5
F44IRLU	F32T8-28W	Fluorescent, (4) 48", T-8 @ 28W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 28W	Electronic	4	28	94	15.5
F44IRLU-R	F32T8-28W	Fluorescent, (4) 48" T-8 @ 28W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 28W RLO	Electronic	4	28	83	15.5
F44IRLU-V	F32T8-28W	Fluorescent, (4) 48" T-8 @ 28W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 4-Lamp T8 28W VHLO	Electronic	4	28	131	15.5
F46IRLU/2-R	F32T8-28W	Fluorescent (6) 48" T-8 @ 28W lamps, (2) IS Ballasts, RLO (BF < 0.85)	4' 6-Lamp T8 28W	Electronic	6	28	126	15.5
F46IRLU/2-V	F32T8-28W	Fluorescent (6) 48" T-8 @ 28W lamps, (2) IS Ballasts, VHLO (BF > 1.1)	4' 6-Lamp T8 28W VHLO	Electronic	6	28	194	15.5
F48IRLU/2-V	F32T8-28W	Fluorescent (8) 48" T-8 @ 28W lamps, (2) IS Ballasts, VHLO (BF > 1.1)	4' 6-Lamp T8 28W VHLO	Electronic	8	28	250	15.5
F41GELL	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	PRS Elec.	1	30	28	15.5
F41GELL-R	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 1-Lamp T8 30W RLO	PRS Elec.	1	30	24	15.5
F41IELL	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	29	15.5
F41IELL-H	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 30W HLO	Electronic	1	30	34	15.5
F41IELL-R	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Instant Start Ballast, RLO (BF < 0.85)	4' 1-Lamp T8 30W RLO	Electronic	1	30	26	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F41IELL/T2	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	28	15.5
F41IELL/T3	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 3-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	27	15.5
F41IELL/T4	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	27	15.5
F41IELU	F32T8-30W	Fluorescent, (1) 48", T-8 @ 30W lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	27	15.5
F41IELU-H	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 1-Lamp T8 30W HLO	Electronic	1	30	32	15.5
F41IELU-R	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Instant Start Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 30W RLO	Electronic	1	30	24	15.5
F41IELU/T2	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	26	15.5
F41IELU/T2-R	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 2-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 30W RLO	Electronic	1	30	23	15.5
F41IELU/T3	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 3-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	26	15.5
F41IELU/T3-R	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 3-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 30W RLO	Electronic	1	30	23	15.5
F41IELU/T4	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 30W	Electronic	1	30	25	15.5
F41IELU/T4-R	F32T8-30W	Fluorescent (1) 48" T-8 @ 30W lamp, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 1-Lamp T8 30W RLO	Electronic	1	30	22	15.5
F42GELL	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 30W	PRS Elec.	2	30	56	15.5
F42GELL-R	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 2-Lamp T8 30W RLO	PRS Elec.	2	30	43	15.5
F42IELL	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 30W	Electronic	2	30	55	15.5
F42IELL-H	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 2-Lamp T8 30W HLO	Electronic	2	30	62	15.5
F42IELL-R	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Instant Start Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 30W RLO	Electronic	2	30	49	15.5
F42IELL/T4	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 30W	Electronic	2	30	53	15.5
F42IELL/T4-R	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 30W RLO	Electronic	2	30	46	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F42IELU	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 30W	Electronic	2	30	52	15.5
F42IELU-R	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Instant Start, RLO (BF< 0.85)	4' 2-Lamp T8 30W RLO	Electronic	2	30	45	15.5
F42IELU-V	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Instant Start, VHLO (BF > 1.1)	4' 2-Lamp T8 30W HLO	Electronic	2	30	70	15.5
F42IELU/T4	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 30W	Electronic	2	30	51	15.5
F42IELU/T4-R	F32T8-30W	Fluorescent (2) 48" T-8 @ 30W lamps, Tandem 4-lamp IS Ballast, RLO (BF< 0.85)	4' 2-Lamp T8 30W RLO	Electronic	2	30	45	15.5
F43GELL	F32T8-30W	Fluorescent (3) 48" T-8 @ 30W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 30W	PRS Elec.	3	30	83	15.5
F43GELL-R	F32T8-30W	Fluorescent (3) 48" T-8 @ 30W lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 30W RLO	PRS Elec.	3	30	67	15.5
F43IELL	F32T8-30W	Fluorescent (3) 48" T-8 @ 30 W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 30W	Electronic	3	30	81	15.5
F43IELL-H	F32T8-30W	Fluorescent (3) 48" T-8 @ 30 W lamps, Instant Start Ballast, HLO (0.95 < BF < 1.1)	4' 3-Lamp T8 30W HLO	Electronic	3	30	86	15.5
F43IELL-R	F32T8-30W	Fluorescent (3) 48" T-8 @ 30 W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 30W RLO	Electronic	3	30	71	15.5
F43IELL/2	F32T8-30W	Fluorescent (3) 48" T-8 @ 30 W lamps, (1) 1-lamp and (1) 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 30W	Electronic	3	30	84	15.5
F43IELL/2-H	F32T8-30W	Fluorescent (3) 48" T-8 @ 30 W lamps, (1) 2-lamp, (1) 3-lamp IS Ballast, 1 lead capped, HLO (0.95 < BF < 1.1)	4' 3-Lamp T8 30W HLO	Electronic	3	30	96	15.5
F43IELL/2-R	F32T8-30W	Fluorescent (3) 48" T-8 @ 30 W lamps, (1) 1-lamp and (1) 2-lamp IS Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 30W RLO	Electronic	3	30	75	15.5
F43IELU	F32T8-30W	Fluorescent (3) 48" T-8 @ 30W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 30W	Electronic	3	30	77	15.5
F43IELU-R	F32T8-30W	Fluorescent (3) 48" T-8 @ 30W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T8 30W RLO	Electronic	3	30	68	15.5
F43IELU-V	F32T8-30W	Fluorescent (3) 48" T-8 @ 30W lamps, Instant Start Ballast, VHLO (BF > 1.1)	4' 3-Lamp T8 30W VHLO	Electronic	3	30	104	15.5
F44GELL	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Prog. Start or PRS Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 30W	PRS Elec.	4	30	109	15.5
F44GELL-R	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Prog. Start or PRS Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 30W RLO	PRS Elec.	4	30	86	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F44IELL	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 30W	Electronic	4	30	106	15.5
F44IELL-R	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 30W RLO	Electronic	4	30	92	15.5
F44IELL/2	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, (2) 2-lamp IS Ballasts, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 30W	Electronic	4	30	110	15.5
F44IELL/2-H	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, (2) 3-lamp IS Ballasts, 1 lead capped, HLO (.95 < BF < 1.1)	4' 4-Lamp T8 30W HLO	Electronic	4	30	124	15.5
F44IELL/2-R	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, (2) 2-lamp IS Ballasts, RLO (BF< 0.85)	4' 4-Lamp T8 30W RLO	Electronic	4	30	98	15.5
F44IELU	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 30W	Electronic	4	30	101	15.5
F44IELU-R	F32T8-30W	Fluorescent (4) 48" T-8 @ 30W lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T8 30W RLO	Electronic	4	30	89	15.5
F46IELU/2	F32T8-30W	Fluorescent (6) 48" T-8 @ 30W lamps, (2) IS Ballasts, NLO (0.85 < BF < 0.95)	4' 6-Lamp T8 30W	Electronic	6	30	154	15.5
F46IELU/2-R	F32T8-30W	Fluorescent (6) 48" T-8 @ 30W lamps, (2) IS Ballasts, RLO (BF < 0.85)	4' 6-Lamp T8 30W RLO	Electronic	6	30	135	15.5
F51ILL	F40T8	Fluorescent, (1) 60", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	5' 1-Lamp T8	Electronic	1	40	36	15.5
F51ILL-R	F40T8	Fluorescent, (1) 60", T-8 lamp, Instant Start Ballast, RLO (BF < 0.85)	5' 1-Lamp T8 RLO	Electronic	1	40	43	15.5
F51ILL/T2	F40T8	Fluorescent, (1) 60", T-8 lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	5' 1-Lamp T8	Electronic	1	40	36	15.5
F51ILL/T3	F40T8	Fluorescent, (1) 60", T-8 lamp, Tandem 3-lamp IS Ballast, NLO (0.85 < BF < 0.95)	5' 1-Lamp T8	Electronic	1	40	35	15.5
F51ILL/T4	F40T8	Fluorescent, (1) 60", T-8 lamp, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	5' 1-Lamp T8	Electronic	1	40	34	15.5
F52ILL	F40T8	Fluorescent, (2) 60", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	5' 2-Lamp T8	Electronic	2	40	72	15.5
F52ILL-H	F40T8	Fluorescent, (2) 60", T-8 lamps, Instant Start Ballast, HILO (.95 < BF < 1.1)	5' 2-Lamp T8 HLO	Electronic	2	40	80	15.5
F52ILL-R	F40T8	Fluorescent, (2) 60", T-8 lamps, Instant Start Ballast, RLO (BF < 0.85)	5' 2-Lamp T8 RLO	Electronic	2	40	73	15.5
F52ILL/T4	F40T8	Fluorescent, (2) 60", T-8 lamps, Tandem 4-lamp IS Ballast, NLO (0.85 < BF < 0.95)	5' 2-Lamp T8	Electronic	2	40	67	15.5
F53ILL	F40T8	Fluorescent, (3) 60", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	5' 3-Lamp T8	Electronic	3	40	106	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F53ILL-H	F40T8	Fluorescent, (3) 60", T-8 lamps, Instant Start Ballast, HILO (.95 < BF < 1.1)	5' 3-Lamp T8 HLO	Electronic	3	40	108	15.5
F54ILL	F40T8	Fluorescent, (4) 60", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	5' 4-Lamp T8	Electronic	4	40	134	15.5
F54ILL-H	F40T8	Fluorescent, (4) 60", T-8 lamps, Instant Start Ballast, HLO (.95 < BF < 1.1)	5' 4-Lamp T8 HLO	Electronic	4	40	126	15.5
F41LHL	F48T8/HO	Fluorescent, (1) 48", T-8 HO lamps, (1) Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 1-Lamp T8 44W HO	Electronic	1	44	59	15.5
F42LHL	F48T8/HO	Fluorescent, (2) 48", T-8 HO lamps, (1) Instant Start Ballast, NLO (0.85 < BF < 0.95)	4' 2-Lamp T8 44W HO	Electronic	2	44	98	15.5
F43LHL	F48T8/HO	Fluorescent, (3) 48", T-8 HO lamps, (2) Instant Start Ballasts, NLO (0.85 < BF < 0.95)	4' 3-Lamp T8 44W HO	Electronic	3	44	141	15.5
F44LHL	F48T8/HO	Fluorescent, (4) 48", T-8 HO lamps, (2) Instant Start Ballasts, NLO (0.85 < BF < 0.95)	4' 4-Lamp T8 44W HO	Electronic	4	44	168	15.5
F81ILL	F96T8	Fluorescent, (1) 96", T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 1-Lamp T8	Electronic	1	59	69	15.5
F81ILL-H	F96T8	Fluorescent, (1) 96", T-8 lamp, Instant Start Ballast, HILO (.95 < BF < 1.1)	8' 1-Lamp T8 HLO	Electronic	1	59	70	15.5
F81ILL-R	F96T8	Fluorescent, (1) 96", T-8 lamp, Instant Start Ballast, RLO (BF < 0.85)	8' 1-Lamp T8 RLO	Electronic	1	59	67	15.5
F81ILL-V	F96T8	Fluorescent, (1) 96", T-8 lamp, Instant Start Ballast, VHLO (BF > 1.1)	8' 1-Lamp T8 VHLO	Electronic	1	59	72	15.5
F81ILL/T2	F96T8	Fluorescent, (1) 96", T-8 lamp, Tandem 2-lamp IS Ballast, NLO (0.85 < BF < 0.95)	8' 1-Lamp T8	Electronic	1	59	55	15.5
F81ILL/T2-R	F96T8	Fluorescent, (1) 96", T-8 lamp, Tandem 2-lamp IS Ballast, RLO (BF < 0.85)	8' 1-Lamp T8 RLO	Electronic	1	59	50	15.5
F81ILU	F96T8	Fluorescent, (1) 96" T-8 lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 1-Lamp T8	Electronic	1	59	67	15.5
F82ILL	F96T8	Fluorescent, (2) 96", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 2-Lamp T8	Electronic	2	59	110	15.5
F82ILL-R	F96T8	Fluorescent, (2) 96", T-8 lamps, Instant Start Ballast, RLO (BF < 0.85)	8' 2-Lamp T8 RLO	Electronic	2	59	100	15.5
F82ILL-V	F96T8	Fluorescent, (2) 96", T-8 lamps, Instant Start Ballast, VHLO (BF > 1.1)	8' 2-Lamp T8 VHLO	Electronic	2	59	149	15.5
F82ILU	F96T8	Fluorescent, (2) 96" T-8 ES lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 2-Lamp T8	Electronic	2	59	107	15.5
F83ILL	F96T8	Fluorescent, (3) 96", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 3-Lamp T8	Electronic	3	59	179	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F84ILL	F96T8	Fluorescent, (4) 96", T-8 lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 4-Lamp T8	Electronic	4	59	219	15.5
F84ILL/2-V	F96T8	Fluorescent, (4) 96", T-8 lamps, (2) Instant Start Ballasts, VHLO (BF > 1.1)	8' 4-Lamp T8 VHLO	Electronic	4	59	298	15.5
F86ILL	F96T8	Fluorescent, (6) 96", T-8 lamps, (2) 3-lamp IS Ballasts, NLO (0.85 < BF < 0.95)	8' 6-Lamp T8	Electronic	6	59	330	15.5
F81LHL/T2	F96T8/HO	Fluorescent, (1) 96", T-8 HO lamp, Tandem 2-lamp Ballast	8' 1-Lamp T8 86W HO	Electronic	1	86	80	15.5
F82LHL	F96T8/HO	Fluorescent, (2) 96", T-8 HO lamps	8' 2-Lamp T8 86W HO	Electronic	2	86	160	15.5
F84LHL	F96T8/HO	Fluorescent, (4) 96", T-8 HO lamps	8' 4-Lamp T8 86W HO	Electronic	4	86	320	15.5
F81IERU	F96T8-RW	Fluorescent, (1) 96" T-8 reduced-wattage lamp, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 1-Lamp T8 54W	Electronic	1	54	61	15.5
F82IERU	F96T8-RW	Fluorescent, (2) 96" T-8 @ reduced-wattage lamps, Instant Start Ballast, NLO (0.85 < BF < 0.95)	8' 2-Lamp T8 54W	Electronic	2	54	93	15.5
FT12		T12 and Other Linear Fluorescent Systems						
F1.51SS	F15T12	Fluorescent, (1) 18" T12 lamp	1.5' 1-Lamp T12 15W	Mag-STD	1	15	19	8.5
F1.52SS	F15T12	Fluorescent, (2) 18", T12 lamps	1.5' 2-Lamp T12 15W	Mag-STD	2	15	36	8.5
F21SS	F20T12	Fluorescent, (1) 24", STD lamp	2' 1-Lamp T12 20W	Mag-STD	1	20	25	8.5
F22SS	F20T12	Fluorescent, (2) 24", STD lamps	2' 2-Lamp T12 20W	Mag-STD	2	20	50	8.5
F23SS	F20T12	Fluorescent, (3) 24", STD lamps	2' 3-Lamp T12 20W	Mag-STD	3	20	71	8.5
F24SS	F20T12	Fluorescent, (4) 24", STD lamps	2' 4-Lamp T12 20W	Mag-STD	4	20	100	8.5
F26SS/2	F20T12	Fluorescent, (6) 24", STD lamps, (2) ballasts	2' 6-Lamp T12 20W	Mag-STD	6	20	146	8.5
F21HS	F24T12/HO	Fluorescent, (1) 24", HO lamp	2' 1-Lamp T12HO	Mag-STD	1	35	62	8.5
F22HS	F24T12/HO	Fluorescent, (2) 24", HO lamps	2' 2-Lamp T12HO	Mag-STD	2	35	90	8.5
F32EL/T4	F25T12	Fluorescent, (2) 36" ES lamps, Tandem 4-lamp ballast, NLO (0.85 < BF < 0.95)	3' 2-Lamp T12ES	Electronic	2	25	50	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F41IAL	F25T12	Fluorescent, (1) 48", F25T12 lamp, Instant Start Ballast	4' 1-Lamp T12 25W	Electronic	1	25	25	15.5
F41IAL/T2-R	F25T12	Fluorescent, (1) 48", F25T12 lamp, Tandem 2-Lamp IS ballast, RLO (BF < 0.85)	4' 1-Lamp T12 25W RLO	Electronic	1	25	19	15.5
F41IAL/T3-R	F25T12	Fluorescent, (1) 48", F25T12 lamp, Tandem 3-Lamp IS ballast, RLO (BF < 0.85)	4' 1-Lamp T12 25W RLO	Electronic	1	25	20	15.5
F41IAL/T4-R	F25T12	Fluorescent, (1) 48", F25T12 lamp, Tandem 4-Lamp IS ballast, RLO (BF < 0.85)	4' 1-Lamp T12 25W RLO	Electronic	1	25	20	15.5
F42IAL-R	F25T12	Fluorescent, (2) 48", F25T12 lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 2-Lamp T12 25W RLO	Electronic	2	25	39	15.5
F42IAL/T4-R	F25T12	Fluorescent, (2) 48", F25T12 lamps, Tandem 4-lamp IS Ballast, RLO (BF < 0.85)	4' 2-Lamp T12 25W RLO	Electronic	2	25	40	15.5
F43IAL-R	F25T12	Fluorescent, (3) 48", F25T12 lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 3-Lamp T12 25W RLO	Electronic	3	25	60	15.5
F44IAL-R	F25T12	Fluorescent, (4) 48", F25T12 lamps, Instant Start Ballast, RLO (BF < 0.85)	4' 4-Lamp T12 25W RLO	Electronic	4	25	80	15.5
F31SE/T2	F30T12	Fluorescent, (1) 36", STD lamp, Tandem 2-lamp ballast	3' 1-Lamp T12	Mag-ES	1	30	37	8.5
F31SL	F30T12	Fluorescent, (1) 36", STD lamp	3' 1-Lamp T12	Electronic	1	30	31	15.5
F31SS	F30T12	Fluorescent, (1) 36", STD lamp	3' 1-Lamp T12	Mag-STD	1	30	46	8.5
F31SS/T2	F30T12	Fluorescent, (1) 36", STD lamp, Tandem 2-lamp ballast	3' 1-Lamp T12	Mag-STD	1	30	41	8.5
F32SE	F30T12	Fluorescent, (2) 36", STD lamps	3' 2-Lamp T12	Mag-ES	2	30	74	8.5
F32SL	F30T12	Fluorescent, (2) 36", STD lamps	3' 2-Lamp T12	Electronic	2	30	58	15.5
F32SS	F30T12	Fluorescent, (2) 36", STD lamps	3' 2-Lamp T12	Mag-STD	2	30	75	8.5
F33SE	F30T12	Fluorescent, (3) 36", STD lamps, (1) STD ballast and (1) ES ballast	3' 3-Lamp T12	Mag-ES	3	30	120	8.5
F33SS	F30T12	Fluorescent, (3) 36", STD lamps	3' 3-Lamp T12	Mag-STD	3	30	127	8.5
F34SE	F30T12	Fluorescent, (4) 36", STD lamps	3' 4-Lamp T12	Mag-ES	4	30	148	8.5
F34SL	F30T12	Fluorescent, (4) 36", STD lamps	3' 4-Lamp T12	Electronic	4	30	116	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F34SS	F30T12	Fluorescent, (4) 36", STD lamps	3' 4-Lamp T12	Mag-STD	4	30	150	8.5
F36SE	F30T12	Fluorescent, (6) 36", STD lamps	3' 6-Lamp T12ES	Mag-ES	6	30	213	8.5
F36SS	F30T12	Fluorescent, (6) 36", STD lamps	3' 6-Lamp T12	Mag-STD	6	30	225	8.5
F31EE/T2	F30T12/ES	Fluorescent, (1) 36", ES lamp, Tandem 2-lamp ballast	3' 1-Lamp T12ES	Mag-ES	1	25	33	8.5
F31EL	F30T12/ES	Fluorescent, (1) 36", ES lamp	3' 1-Lamp T12ES	Electronic	1	25	26	15.5
F31ES	F30T12/ES	Fluorescent, (1) 36", ES lamp	3' 1-Lamp T12ES	Mag-STD	1	25	42	8.5
F31ES/T2	F30T12/ES	Fluorescent, (1) 36", ES lamp, Tandem 2-lamp ballast	3' 1-Lamp T12ES	Mag-STD	1	25	33	8.5
F32EE	F30T12/ES	Fluorescent, (2) 36", ES lamps	3' 1-Lamp T12ES	Mag-ES	2	25	66	8.5
F32EL	F30T12/ES	Fluorescent, (2) 36", ES lamps	3' 1-Lamp T12ES	Electronic	2	25	50	15.5
F32ES	F30T12/ES	Fluorescent, (2) 36", ES lamps	3' 1-Lamp T12ES	Mag-STD	2	25	73	8.5
F33ES	F30T12/ES	Fluorescent, (3) 36", ES lamps	3' 2-Lamp T12ES	Mag-STD	3	25	115	8.5
F34EE	F30T12/ES	Fluorescent, (4) 36", ES lamps	3' 4-Lamp T12ES	Mag-ES	4	25	132	8.5
F36EE	F30T12/ES	Fluorescent, (6) 36", ES lamps	3' 6-Lamp T12ES	Mag-ES	6	30	198	8.5
F36ES	F30T12/ES	Fluorescent, (6) 36", ES lamps	3' 6-Lamp T12ES	Mag-STD	6	30	219	8.5
F31SHS	F36T12/HO	Fluorescent, (1) 36", HO lamp	3' 1-Lamp T5HO	Mag-STD	1	50	70	8.5
F32SHS	F36T12/HO	Fluorescent, (2) 36", HO, lamps	3' 2-Lamp T12HO	Mag-STD	2	50	114	8.5
F41SIL	F40T12	Fluorescent, (1) 48", STD IS lamp, Electronic ballast	4' 1-Lamp T12	Electronic	1	39	46	15.5
F41SIL/T2	F40T12	Fluorescent, (1) 48", STD IS lamp, Tandem 2-lamp IS ballast	4' 1-Lamp T12	Electronic	1	39	37	15.5
F42SIL	F40T12	Fluorescent, (2) 48", STD IS lamps, Electronic ballast	4' 2-Lamp T12IS	Electronic	2	39	74	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F43SIL	F40T12	Fluorescent, (3) 48", STD IS lamps, Electronic ballast	4' 3-Lamp T12IS	Electronic	3	39	120	15.5
F44SIL	F40T12	Fluorescent, (4) 48", STD IS lamps, Electronic ballast	4' 4-Lamp T12IS	Electronic	4	39	148	15.5
F46SL	F40T12	Fluorescent, (6) 48", STD lamps	4' 4-Lamp T12	Electronic	6	40	186	15.5
F41TS	F40T10	Fluorescent, (1) 48", T-10 lamp	4' 1-Lamp T10	Mag-STD	1	40	51	8.5
F41EE	F40T12/ES	Fluorescent, (1) 48", ES lamp	4' 1-Lamp T12ES	Mag-ES	1	34	43	8.5
F41EE/2	F40T12/ES	Fluorescent, (1) 48", ES lamp, 2 ballast	4' 1-Lamp T12ES	Mag-ES	1	34	43	8.5
F41EE/T2	F40T12/ES	Fluorescent, (1) 48", ES lamp, Tandem 2-lamp ballast	4' 1-Lamp T12ES	Mag-ES	1	34	36	8.5
F41EL	F40T12/ES	Fluorescent, (1) 48", T12 ES lamp, Electronic Ballast	4' 1-Lamp T12ES	Electronic	1	34	32	15.5
F42EE	F40T12/ES	Fluorescent, (2) 48", ES lamp	4' 2-Lamp T12ES	Mag-ES	2	34	72	8.5
F42EE/2	F40T12/ES	Fluorescent, (2) 48", ES lamps, (2) 1-lamp ballasts	4' 2-Lamp T12ES	Mag-ES	2	34	86	8.5
F42EE/D2	F40T12/ES	Fluorescent, (2) 48", ES lamps, 2 Ballasts (delamped)	4' 2-Lamp T12ES	Mag-ES	2	34	76	8.5
F42EL	F40T12/ES	Fluorescent, (2) 48", T12 ES lamps, Electronic Ballast	4' 2-Lamp T12ES	Electronic	2	34	60	15.5
F43EE	F40T12/ES	Fluorescent, (3) 48", ES lamps	4' 3-Lamp T12ES	Mag-ES	3	34	115	8.5
F43EE/T2	F40T12/ES	Fluorescent, (3) 48", ES lamps, Tandem 2-lamp ballasts	4' 3-Lamp T12ES	Mag-ES	3	34	108	8.5
F43EL	F40T12/ES	Fluorescent, (3) 48", T12 ES lamps, Electronic Ballast	4' 3-Lamp T12ES	Electronic	3	34	92	15.5
F44EE	F40T12/ES	Fluorescent, (4) 48", ES lamps	4' 3-Lamp T12ES	Mag-ES	4	34	144	8.5
F44EE/D3	F40T12/ES	Fluorescent, (4) 48", ES lamps, 3 Ballasts (delamped)	4' 4-Lamp T12ES	Mag-ES	4	34	148	8.5
F44EE/D4	F40T12/ES	Fluorescent, (4) 48", ES lamps, 4 Ballasts (delamped)	4' 3-Lamp T12ES	Mag-ES	4	34	152	8.5
F44EL	F40T12/ES	Fluorescent, (4) 48", T12 ES lamps, Electronic Ballast	4' 4-Lamp T12ES	Electronic	4	34	120	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F46EE	F40T12/ES	Fluorescent, (6) 48", ES lamps	4' 6-Lamp T12ES	Mag-ES	6	34	216	8.5
F46EL	F40T12/ES	Fluorescent, (6) 48", ES lamps	4' 6-Lamp T12ES	Electronic	6	34	180	15.5
F48EE	F40T12/ES	Fluorescent, (8) 48", ES lamps	4' 8-Lamp T12ES	Mag-ES	8	34	288	8.5
F42EHS	F42T12/HO/ES	Fluorescent, (2) 42", HO lamps (3.5' lamp)	4' 2-Lamp T12HO	Mag-STD	2	55	135	8.5
F43EHS	F42T12/HO/ES	Fluorescent, (3) 42", HO lamps (3.5' lamp)	4' 3-Lamp T12ES HO	Mag-STD	3	55	215	8.5
F41EIS	F48T12/ES	Fluorescent, (1) 48" ES Instant Start lamp. Magnetic ballast	4' 1-Lamp T12ES	Mag-STD	1	40	51	8.5
F42EIS	F48T12/ES	Fluorescent, (2) 48" ES Instant Start lamps. Magnetic ballast	4' 2-Lamp T12ES	Mag-STD	2	40	82	8.5
F43EIS	F48T12/ES	Fluorescent, (3) 48" ES Instant Start lamps. Magnetic ballast	4' 3-Lamp T12ES	Mag-STD	3	40	133	8.5
F44EIS	F48T12/ES	Fluorescent, (4) 48" ES Instant Start lamps. Magnetic ballast	4' 4-Lamp T12IS	Mag-STD	4	40	164	8.5
F41SHS	F48T12/HO	Fluorescent, (1) 48", STD HO lamp	4' 1-Lamp T12HO	Mag-STD	1	60	85	8.5
F42SHS	F48T12/HO	Fluorescent, (2) 48", STD HO lamps	4' 2-Lamp T12HO	Mag-STD	2	60	145	8.5
F43SHS	F48T12/HO	Fluorescent, (3) 48", STD HO lamps	4' 3-Lamp T12HO	Mag-STD	3	60	230	8.5
F44SHS	F48T12/HO	Fluorescent, (4) 48", STD HO lamps	4' 4-Lamp T12HO	Mag-STD	4	60	290	8.5
F41EHS	F48T12/HO/ES	Fluorescent, (1) 48", ES HO lamp	4' 1-Lamp T12HO	Mag-STD	1	55	80	8.5
F44EHS	F48T12/HO/ES	Fluorescent, (4) 48", ES HO lamps	4' 3-Lamp T12ES HO	Mag-STD	4	55	270	8.5
F41SVS	F48T12/VHO	Fluorescent, (1) 48", STD VHO lamp	4' 1-Lamp T12VHO	Mag-STD	1	110	140	8.5
F42SVS	F48T12/VHO	Fluorescent, (2) 48", STD VHO lamps	4' 2-Lamp T12VHO	Mag-STD	2	110	252	8.5
F43SVS	F48T12/VHO	Fluorescent, (3) 48", STD VHO lamps	4' 3-Lamp T12VHO	Mag-STD	3	110	377	8.5
F44SVS	F48T12/VHO	Fluorescent, (4) 48", STD VHO lamps	4' 4-Lamp T12VHO	Mag-STD	4	110	484	8.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F44EVS	F48T12/VHO/ ES	Fluorescent, (4) 48", VHO ES lamps	4' 4-Lamp T12VHO	Mag-STD	4	100	420	8.5
F51SL	F60T12	Fluorescent, (1) 60", STD lamp	5' 1-Lamp T12	Electronic	1	50	44	15.5
F51SS	F60T12	Fluorescent, (1) 60", STD lamp	5' 1-Lamp T12	Mag-STD	1	50	63	8.5
F52SL	F60T12	Fluorescent, (2) 60", STD lamps	5' 2-Lamp T12	Electronic	2	50	88	15.5
F52SS	F60T12	Fluorescent, (2) 60", STD lamps	5' 2-Lamp T12	Mag-STD	2	50	128	8.5
F51SHE	F60T12/HO	Fluorescent, (1) 60", STD HO lamp	5' 1-Lamp T12HO	Mag-ES	1	75	88	8.5
F51SHL	F60T12/HO	Fluorescent, (1) 60", STD HO lamp	5' 1-Lamp T12HO	Electronic	1	75	69	15.5
F51SHS	F60T12/HO	Fluorescent, (1) 60", STD HO lamp	5' 1-Lamp T12HO	Mag-STD	1	75	92	8.5
F52SHE	F60T12/HO	Fluorescent, (2) 60", STD HO lamps	5' 2-Lamp T12HO	Mag-ES	2	75	176	8.5
F52SHL	F60T12/HO	Fluorescent, (2) 60", STD HO lamps	5' 2-Lamp T12HO	Electronic	2	75	138	15.5
F52SHS	F60T12/HO	Fluorescent, (2) 60", STD HO lamps	5' 2-Lamp T12HO	Mag-STD	2	75	168	8.5
F51SVS	F60T12/VHO	Fluorescent, (1) 60", VHO ES lamp	5' 1-Lamp T12VHO	Mag-STD	1	135	165	8.5
F52SVS	F60T12/VHO	Fluorescent, (2) 60", VHO ES lamps	5' 2-Lamp T12VHO	Mag-STD	2	135	310	8.5
F61ISL	F72T12	Fluorescent, (1) 72", STD lamp, IS electronic ballast	6' 1-Lamp T12	Electronic	1	55	68	15.5
F61SS	F72T12	Fluorescent, (1) 72", STD lamp	6' 1-Lamp T12	Mag-STD	1	55	76	8.5
F62ISL	F72T12	Fluorescent, (2) 72", STD lamps, IS electronic ballast	6' 2-Lamp T12IS	Electronic	2	55	108	15.5
F62SE	F72T12	Fluorescent, (2) 72", STD lamps	6' 2-Lamp T12	Mag-ES	2	55	122	8.5
F62SL	F72T12	Fluorescent, (2) 72", STD lamps	6' 2-Lamp T12	Electronic	2	55	108	15.5
F62SS	F72T12	Fluorescent, (2) 72", STD lamps	6' 2-Lamp T12	Mag-STD	2	55	142	8.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F63ISL	F72T12	Fluorescent, (3) 72", STD lamps, IS electronic ballast	6' 3-Lamp T12IS	Electronic	3	55	176	15.5
F63SS	F72T12	Fluorescent, (3) 72", STD lamps	6' 3-Lamp T12	Mag-STD	3	55	202	8.5
F64ISL	F72T12	Fluorescent, (4) 72", STD lamps, IS electronic ballast	6' 4-Lamp T12IS	Electronic	4	55	216	15.5
F64SE	F72T12	Fluorescent, (4) 72", STD lamps	6' 4-Lamp T12	Mag-ES	4	55	244	8.5
F64SS	F72T12	Fluorescent, (4) 72", STD lamps	6' 4-Lamp T12	Mag-STD	4	56	244	8.5
F61SHS	F72T12/HO	Fluorescent, (1) 72", STD HO lamp	6' 1-Lamp T12HO	Mag-STD	1	85	106	8.5
F62SHE	F72T12/HO	Fluorescent, (2) 72", STD HO lamps	6' 2-Lamp T12HO	Mag-ES	2	85	194	8.5
F62SHL	F72T12/HO	Fluorescent, (2) 72", STD HO lamps	6' 2-Lamp T12HO	Electronic	2	85	167	15.5
F62SHS	F72T12/HO	Fluorescent, (2) 72", STD HO lamps	6' 2-Lamp T12HO	Mag-STD	2	85	200	8.5
F64SHE	F72T12/HO	Fluorescent, (4) 72", HO lamps	6' 4-Lamp T12HO	Mag-ES	4	85	388	8.5
F61SVS	F72T12/VHO	Fluorescent, (1) 72", VHO lamp	6' 1-Lamp T12VHO	Mag-STD	1	160	180	8.5
F62SVS	F72T12/VHO	Fluorescent, (2) 72", VHO lamps	6' 2-Lamp T12VHO	Mag-STD	2	160	330	8.5
F71HS	F84T12/HO	Fluorescent, (1) 84", HO lamp	7' 1-Lamp T12HO	Mag-ES	1	100	104	8.5
F72HS	F84T12/HO	Fluorescent, (2) 84", HO lamp	7' 2-Lamp T12HO	Mag-ES	2	100	198	8.5
F81SL	F96T12	Fluorescent, (1) 96", STD lamp	8' 1-Lamp T12	Electronic	1	75	69	15.5
F81SL/T2	F96T12	Fluorescent, (1) 96", STD lamp, Tandem 2-lamp ballast	8' 1-Lamp T12	Electronic	1	75	55	15.5
F82SL	F96T12	Fluorescent, (2) 96", STD lamps	8' 2-Lamp T12	Electronic	2	75	110	15.5
F83SL	F96T12	Fluorescent, (3) 96", STD lamps	8' 3-Lamp T12	Electronic	3	75	179	15.5
F84SL	F96T12	Fluorescent, (4) 96", STD lamps	8' 4-Lamp T12	Electronic	4	75	220	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F81EE	F96T12/ES	Fluorescent, (1) 96" ES lamp	8' 4-Lamp T12ES	Mag-ES	1	60	75	8.5
F81EE/T2	F96T12/ES	Fluorescent, (1) 96", ES lamp, Tandem 2-lamp ballast	8' 1-Lamp T12ES	Mag-ES	1	60	62	8.5
F81EL	F96T12/ES	Fluorescent, (1) 96", ES lamp	8' 1-Lamp T12ES	Electronic	1	60	69	15.5
F81EL/T2	F96T12/ES	Fluorescent, (1) 96", ES lamp, Tandem 2-lamp ballast	8' 1-Lamp T12ES	Electronic	1	60	55	15.5
F82EE	F96T12/ES	Fluorescent, (2) 96", ES lamps	8' 2-Lamp T12ES	Mag-ES	2	60	123	8.5
F82EL	F96T12/ES	Fluorescent, (2) 96", ES lamps	8' 2-Lamp T12ES	Electronic	2	60	110	15.5
F83EE	F96T12/ES	Fluorescent, (3) 96", ES lamps	8' 3-Lamp T12ES	Mag-ES	3	60	198	8.5
F83EL	F96T12/ES	Fluorescent, (3) 96", ES lamps	8' 3-Lamp T12ES	Electronic	3	60	179	15.5
F84EE	F96T12/ES	Fluorescent, (4) 96", ES lamps	8' 4-Lamp T12ES	Mag-ES	4	60	246	8.5
F84EL	F96T12/ES	Fluorescent, (4) 96", ES lamps	8' 4-Lamp T12ES	Electronic	4	60	220	15.5
F86EE	F96T12/ES	Fluorescent, (6) 96", ES lamps	8' 6-Lamp T12ES	Mag-ES	6	60	369	8.5
F81SHS	F96T12/HO	Fluorescent, (1) 96", STD HO lamp	8' 1-Lamp T12HO	Mag-STD	1	110	121	8.5
F82SHE	F96T12/HO	Fluorescent, (2) 96", STD HO lamps	8' 2-Lamp T12HO	Mag-ES	2	110	207	8.5
F82SHL	F96T12/HO	Fluorescent, (2) 96", STD HO lamps	8' 2-Lamp T12HO	Electronic	2	110	173	15.5
F82SHS	F96T12/HO	Fluorescent, (2) 96", STD HO lamps	8' 2-Lamp T12HO	Mag-STD	2	110	207	8.5
F83SHE	F96T12/HO	Fluorescent, (3) 96", STD HO lamps	8' 3-Lamp T12HO	Mag-ES	3	110	319	8.5
F83SHS	F96T12/HO	Fluorescent, (3) 96", STD HO lamps	8' 3-Lamp T12HO	Mag-STD	3	110	319	8.5
F84SHE	F96T12/HO	Fluorescent, (4) 96", STD HO lamps	8' 4-Lamp T12HO	Mag-ES	4	110	414	8.5
F84SHL	F96T12/HO	Fluorescent, (4) 96", STD HO lamps	8' 4-Lamp T12HO	Electronic	4	110	346	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F84SHS	F96T12/HO	Fluorescent, (4) 96", STD HO lamps	8' 4-Lamp T12HO	Mag-STD	4	110	414	8.5
F88SHS	F96T12/HO	Fluorescent, (8) 96", STD HO lamps	8' 8-Lamp T12HO	Mag-STD	8	110	828	8.5
F81EHL	F96T12/HO/ES	Fluorescent, (1) 96", ES HO lamp	8' 1-Lamp T12ES HO	Electronic	1	95	80	15.5
F81EHS	F96T12/HO/ES	Fluorescent, (1) 96", ES HO lamp	8' 1-Lamp T12ES HO	Mag-STD	1	95	113	8.5
F82EHE	F96T12/HO/ES	Fluorescent, (2) 96", ES HO lamps	8' 2-Lamp T12ES HO	Mag-ES	2	95	207	8.5
F82EHL	F96T12/HO/ES	Fluorescent, (2) 96", ES HO lamps	8' 2-Lamp T12ES HO	Electronic	2	95	173	15.5
F82EHS	F96T12/HO/ES	Fluorescent, (2) 96", ES HO lamps	8' 2-Lamp T12ES HO	Mag-STD	2	95	207	8.5
F83EHE	F96T12/HO/ES	Fluorescent, (3) 96", ES HO lamps, (1) 2-lamp ES Ballast and (1) 1-lamp STD Ballast	8' 3-Lamp T12ES HO	Mag-ES/STD	3	95	319	8.5
F83EHS	F96T12/HO/ES	Fluorescent, (3) 96", ES HO lamps	8' 3-Lamp T12ES HO	Mag-STD	3	95	319	8.5
F84EHE	F96T12/HO/ES	Fluorescent, (4) 96", ES HO lamps	8' 4-Lamp T12ES HO	Mag-ES	4	95	414	8.5
F84EHL	F96T12/HO/ES	Fluorescent, (4) 96", ES HO lamps	8' 4-Lamp T12ES HO	Electronic	4	95	346	15.5
F84EHS	F96T12/HO/ES	Fluorescent, (4) 96", ES HO lamps	8' 4-Lamp T12ES HO	Mag-STD	4	95	414	8.5
F86EHS	F96T12/HO/ES	Fluorescent, (6) 96", ES HO lamps	8' 6-Lamp T12ES HO	Mag-STD	6	95	519	8.5
F88EHE	F96T12/HO/ES	Fluorescent, (8) 96", ES HO lamps	8' 8-Lamp T12ES HO	Mag-ES	8	95	828	8.5
F81SVS	F96T12/VHO	Fluorescent, (1) 96", STD VHO lamp	8' 1-Lamp T12VHO	Mag-STD	1	215	205	8.5
F82SVS	F96T12/VHO	Fluorescent, (2) 96", STD VHO lamps	8' 2-Lamp T12VHO	Mag-STD	2	215	380	8.5
F83SVS	F96T12/VHO	Fluorescent, (3) 96", STD VHO lamps	8' 3-Lamp T12VHO	Mag-STD	3	215	585	8.5
F84SVS	F96T12/VHO	Fluorescent, (4) 96", STD VHO lamps	8' 4-Lamp T12VHO	Mag-STD	4	215	760	8.5
F81EVS	F96T12/VHO/ ES	Fluorescent, (1) 96", ES VHO lamp	8' 1-Lamp T12ES VHO	Mag-STD	1	185	205	8.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
F82EVS	F96T12/VHO/ ES	Fluorescent, (2) 96", ES VHO lamps	8' 2-Lamp T12ES VHO	Mag-STD	2	195	380	8.5
F83EVS	F96T12/VHO/ ES	Fluorescent, (3) 96", ES VHO lamps	8' 3-Lamp T12ES VHO	Mag-STD	3	185	585	8.5
F84EVS	F96T12/VHO/ ES	Fluorescent, (4) 96", ES VHO lamps	8' 4-Lamp T12ES VHO	Mag-STD	4	185	760	8.5
F81SGS	F96T17	Fluorescent, (1) 96", T17 Grooved lamp	8' 1-Lamp T12	Mag-STD	1	215	235	8.5
F40SE/D1	None	Fluorescent, (0) 48" lamps, Completely delamped fixture with (1) hot ballast		Mag-ES	1	0	4	8.5
F40SE/D2	None	Fluorescent, (0) 48" lamps, Completely delamped fixture with (2) hot ballast		Mag-ES	1	0	8	8.5
FC		Circline Fluorescent Fixtures						
FC6/1	FC6T9	Fluorescent, (1) 6" circular lamp, RS ballast	6" 1-Lamp T9 Cir	Mag-STD	1	20	25	15.5
FC8/1	FC8T9	Fluorescent, (1) 8" circular lamp, RS ballast	8" 1-Lamp T9 Cir	Mag-STD	1	22	26	15.5
FC8/2	FC8T9	Fluorescent, (2) 8" circular lamps, RS ballast	8" 2-Lamp T9 Cir	Mag-STD	2	22	52	15.5
FC20	FC6T9	Fluorescent, Circline, (1) 20W lamp, preheat ballast	20W 1-Lamp T9 Cir	Mag-STD	1	20	20	15.5
FC22	FC8T9	Fluorescent, Circline, (1) 22W lamp, preheat ballast	22W 1-Lamp T9 Cir	Mag-STD	1	22	20	15.5
FC12/1	FC12T9	Fluorescent, (1) 12" circular lamp, RS ballast	12" 1-Lamp T9 Cir	Mag-STD	1	32	31	15.5
FC12/2	FC12T9	Fluorescent, (2) 12" circular lamps, RS ballast	12" 2-Lamp T9 Cir	Mag-STD	2	32	62	15.5
FC32	FC12T9	Fluorescent, Circline, (1) 32W lamp, preheat ballast	32W 1-Lamp T9 Cir	Mag-STD	1	32	40	15.5
FC16/1	FC16T9	Fluorescent, (1) 16" circular lamp	16" 1-Lamp T9 Cir	Mag-STD	1	40	35	15.5
FC40	FC16T9	Fluorescent, Circline, (1) 32W lamp, preheat ballast	40W 1-Lamp T9 Cir	Mag-STD	1	32	42	15.5
FEI		Fluorescent Electrodeless Induction Fixtures						

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
FEI40/1	CFT40W	Electrodeless Fluorescent System, (1) 40W lamp	1-Lamp 40W Induction	Electronic	1	40	44	15.5
FEI55/1	CFT55W	Electrodeless Fluorescent System, (1) 55W lamp	1-Lamp 55W Induction	Electronic	1	55	59	15.5
FEI60/1	CFT60W	Electrodeless Fluorescent System, (1) 60W lamp	1-Lamp 60W Induction	Electronic	1	60	64	15.5
FEI70/1	CFT70W	Electrodeless Fluorescent System, (1) 70W lamp	1-Lamp 70W Induction	Electronic	1	70	74	15.5
FEI80/1	CFT80W	Electrodeless Fluorescent System, (1) 80W lamp	1-Lamp 80W Induction	Electronic	1	80	84	15.5
FEI85/1	CFT85W	Electrodeless Fluorescent System, (1) 85W lamp	1-Lamp 85W Induction	Electronic	1	85	89	15.5
FEI100/1	CFT100W	Electrodeless Fluorescent System, (1) 100W lamp	1-Lamp 100W Induction	Electronic	1	100	105	15.5
FEI125/1	CFT125W	Electrodeless Fluorescent System, (1) 125W lamp	1-Lamp 125W Induction	Electronic	1	125	131	15.5
FEI150/1	CFT150W	Electrodeless Fluorescent System, (1) 150W lamp	1-Lamp 150W Induction	Electronic	1	150	157	15.5
FEI165/1	CFT165W	Electrodeless Fluorescent System, (1) 165W lamp	1-Lamp 165W Induction	Electronic	1	165	173	15.5
FEI200/1	CFT200W	Electrodeless Fluorescent System, (1) 200W lamp	1-Lamp 200W Induction	Electronic	1	200	210	15.5
FEI250/1	CFT250W	Electrodeless Fluorescent System, (1) 250W lamp	1-Lamp 250W Induction	Electronic	1	250	263	15.5
FEI300/1	CFT300W	Electrodeless Fluorescent System, (1) 300W lamp	1-Lamp 300W Induction	Electronic	1	300	315	15.5
FEI400/1	CFT400W	Electrodeless Fluorescent System, (1) 400W lamp	1-Lamp 400W Induction	Electronic	1	400	420	15.5
FU		U-Tube Fluorescent Fixtures						
FU1ILL	FU31T8/6	Fluorescent, (1) U-Tube, T-8 lamp, Instant Start ballast	1-Lamp T8 U-Tube	Electronic	1	32	31	15.5
FU1LL	FU31T8/6	Fluorescent, (1) U-Tube, T-8 lamp	1-Lamp T8 U-Tube	Electronic	1	32	32	15.5
FU1LL-R	FU31T8/6	Fluorescent, (1) U-Tube, T-8 lamp, RLO (BF < 0.85)	1-Lamp T8 U-Tube	Electronic	1	31	27	15.5
FU2ILL	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps, Instant Start Ballast	1-Lamp T8 U-Tube	Electronic	2	32	59	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
FU2ILL-H	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps, Instant Start HLO Ballast	2-Lamp T8 HLO U-Tube	Electronic	2	32	65	15.5
FU2ILL-R	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps, Instant Start RLO Ballast	2-Lamp T8 RLO U-Tube	Electronic	2	32	52	15.5
FU2ILL/T4	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps, Instant Start Ballast, Tandem 4-lamp ballast	2-Lamp T8 U-Tube	Electronic	2	32	56	15.5
FU2ILL/T4-R	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps, Instant Start Ballast, RLO, Tandem 4-lamp ballast	2-Lamp T8 RLO U-Tube	Electronic	2	32	49	15.5
FU2LL	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps	2-Lamp T8 U-Tube	Electronic	2	32	60	15.5
FU2LL-R	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps, RLO (BF < 0.85)	2-Lamp T8 RLO U-Tube	Electronic	2	31	54	15.5
FU2LL/T2	FU31T8/6	Fluorescent, (2) U-Tube, T-8 lamps, Tandem 4-lamp ballast	2-Lamp T8 U-Tube	Electronic	2	32	59	15.5
FU3ILL	FU31T8/6	Fluorescent, (3) U-Tube, T-8 lamps, Instant Start Ballast	3-Lamp T8 U-Tube	Electronic	3	32	89	15.5
FU3ILL-R	FU31T8/6	Fluorescent, (3) U-Tube, T-8 lamps, Instant Start RLO Ballast	3-Lamp T8ES U-Tube	Electronic	3	32	78	15.5
FU1ILU	FU32T8/6	Fluorescent, (1) 6" spacing U-Tube, T-8 lamp, IS Ballast, NLO (0.85 < BF < 0.95)	1-Lamp T8 6" Spacing U-Tube	Electronic	1	32	29	15.5
FU1ILU-H	FU32T8/6	Fluorescent, (1) 6" spacing U-Tube, T-8 lamp, IS Ballast, HLO (.95 < BF < 1.1)	1-Lamp T8 6" Spacing U-Tube HLO	Electronic	1	32	34	15.5
FU2ILU	FU32T8/6	Fluorescent, (2) 6" spacing U-Tube, T-8 lamps, IS Ballast, NLO (0.85 < BF < 0.95)	2-Lamp T8 6" Spacing U-Tube	Electronic	2	32	55	15.5
FU2ILU-R	FU32T8/6	Fluorescent, (2) 6" spacing U-Tube, T-8 lamps, IS Ballast, RLO (BF < 0.85)	2-Lamp T8 6" Spacing U-Tube RLO	Electronic	2	32	48	15.5
FU2ILU-V	FU32T8/6	Fluorescent, (2) 6" spacing U-Tube, T-8 lamps, IS Ballast, VHLO (BF > 1.1)	2-Lamp T8 6" Spacing U-Tube VHLO	Electronic	2	32	73	15.5
FU3ILU	FU32T8/6	Fluorescent, (3) 6" spacing U-Tube, T-8 lamps, IS Ballast, NLO (0.85 < BF < 0.95)	3-Lamp T8 6" Spacing U-Tube	Electronic	3	32	81	15.5
FU3ILU-R	FU32T8/6	Fluorescent, (3) 6" spacing U-Tube, T-8 lamps, IS Ballast, RLO (BF < 0.85)	3-Lamp T8 6" Spacing U-Tube RLO	Electronic	3	32	73	15.5
FU1SE	FU40T12	Fluorescent, (1) U-Tube, STD lamp	1-Lamp T12 U-Tube	Mag-ES	1	40	43	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
FU1SS	FU40T12	Fluorescent, (1) U-Tube, ES Lamp	1-Lamp T12 U-Tube ES	Mag-STD	1	40	43	8.5
FU2SE	FU40T12	Fluorescent, (2) U-Tube, STD lamps	2-Lamp T12 U-Tube	Mag-ES	2	40	72	15.5
FU2SL	FU40T12	Fluorescent (2) 48" U-bent Standard lamps, Electronic ballast, NLO (0.85 < BF < 0.95)	2-Lamp T12 U-Tube	Electronic	2	40	63	15.5
FU2SS	FU40T12	Fluorescent, (1) U-Tube, STD lamp, STD Mag Ballast	2-Lamp T12 U-Tube	Mag-STD	2	40	72	8.5
FU3SE	FU40T12	Fluorescent, (3) U-Tube, STD lamps	3-Lamp T12 U-Tube	Mag-ES	3	40	115	15.5
FU1EE	FU40T12/ES	Fluorescent, (1) U-Tube, ES lamp	1-Lamp T12ES U-Tube	Mag-ES	1	35	43	15.5
FU1ES	FU40T12/ES	Fluorescent, (1) U-Tube, ES Lamp	1-Lamp T12ES U-Tube	Mag-STD	1	34	43	8.5
FU2EE	FU40T12/ES	Fluorescent, (2) U-Tube, ES lamps	1-Lamp T12ES U-Tube	Mag-ES	2	35	72	15.5
FU2EL	FU40T12/ES	Fluorescent (2) 48" U-bent ES lamps, Electronic ballast, NLO (0.85 < BF < 0.95)	1-Lamp T12ES U-Tube	Electronic	2	34	63	15.5
FU2ES	FU40T12/ES	Fluorescent, (2) U-Tube, ES lamps	1-Lamp T12ES U-Tube	Mag-STD	1	35	72	8.5
FU3EE	FU40T12/ES	Fluorescent, (3) U-Tube, ES lamps	3-Lamp T12ES U-Tube	Mag-ES	3	35	115	15.5
H		Halogen Incandescent Fixtures						
H20/1	H20	Halogen, (1) 20W lamp	20W 1-Lamp Halogen		1	20	20	1.5
H21/1	H21	Halogen, (1) 21W lamp	21W 1-Lamp Halogen		1	21	21	1.5
H22/1	H22	Halogen, (1) 22W lamp	22W 1-Lamp Halogen		1	22	22	1.5
H23/1	H23	Halogen, (1) 23W lamp	23W 1-Lamp Halogen		1	23	23	1.5
H24/1	H24	Halogen, (1) 24W lamp	24W 1-Lamp Halogen		1	24	24	1.5
H25/1	H25	Halogen, (1) 25W lamp	25W 1-Lamp Halogen		1	25	25	1.5
H26/1	H26	Halogen, (1) 26W lamp	26W 1-Lamp Halogen		1	26	26	1.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
H27/1	H27	Halogen, (1) 27W lamp	27W 1-Lamp Halogen		1	27	27	1.5
H28/1	H28	Halogen, (1) 28W lamp	28W 1-Lamp Halogen		1	28	28	1.5
H29/1	H29	Halogen, (1) 29W lamp	29W 1-Lamp Halogen		1	29	29	1.5
H30/1	H30	Halogen, (1) 30W lamp	30W 1-Lamp Halogen		1	30	30	1.5
H31/1	H31	Halogen, (1) 31W lamp	31W 1-Lamp Halogen		1	31	31	1.5
H32/1	H32	Halogen, (1) 32W lamp	32W 1-Lamp Halogen		1	32	32	1.5
H33/1	H33	Halogen, (1) 33W lamp	33W 1-Lamp Halogen		1	33	33	1.5
H34/1	H34	Halogen, (1) 34W lamp	34W 1-Lamp Halogen		1	34	34	1.5
H35/1	H35	Halogen, (1) 35W lamp	35W 1-Lamp Halogen		1	35	35	1.5
H36/1	H36	Halogen, (1) 36W lamp	36W 1-Lamp Halogen		1	36	36	1.5
H37/1	H37	Halogen, (1) 37W lamp	37W 1-Lamp Halogen		1	37	37	1.5
H38/1	H38	Halogen, (1) 38W lamp	38W 1-Lamp Halogen		1	38	38	1.5
H39/1	H39	Halogen, (1) 39W lamp	39W 1-Lamp Halogen		1	39	39	1.5
H40/1	H40	Halogen, (1) 40W lamp	40W 1-Lamp Halogen		1	40	40	1.5
H41/1	H41	Halogen, (1) 41W lamp	41W 1-Lamp Halogen		1	41	41	1.5
H42/1	H42	Halogen, (1) 42W lamp	42W 1-Lamp Halogen		1	42	42	1.5
H43/1	H43	Halogen, (1) 43W lamp	43W 1-Lamp Halogen		1	43	43	1.5
H44/1	H44	Halogen, (1) 44W lamp	44W 1-Lamp Halogen		1	44	44	1.5
H45/1	H45	Halogen, (1) 45W lamp	45W 1-Lamp Halogen		1	45	45	1.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
H46/1	H46	Halogen, (1) 46W lamp	46W 1-Lamp Halogen		1	46	46	1.5
H47/1	H47	Halogen, (1) 47W lamp	47W 1-Lamp Halogen		1	47	47	1.5
H48/1	H48	Halogen, (1) 48W lamp	48W 1-Lamp Halogen		1	48	48	1.5
H49/1	H49	Halogen, (1) 49W lamp	49W 1-Lamp Halogen		1	49	49	1.5
H50/1	H50	Halogen, (1) 50W lamp	50W 1-Lamp Halogen		1	50	50	1.5
H51/1	H51	Halogen, (1) 51W lamp	51W 1-Lamp Halogen		1	51	51	1.5
H52/1	H52	Halogen, (1) 52W lamp	52W 1-Lamp Halogen		1	52	52	1.5
H53/1	H53	Halogen, (1) 53W lamp	53W 1-Lamp Halogen		1	53	53	1.5
H54/1	H54	Halogen, (1) 54W lamp	54W 1-Lamp Halogen		1	54	54	1.5
H55/1	H55	Halogen, (1) 55W lamp	55W 1-Lamp Halogen		1	55	55	1.5
H56/1	H56	Halogen, (1) 56W lamp	56W 1-Lamp Halogen		1	56	56	1.5
H57/1	H57	Halogen, (1) 57W lamp	57W 1-Lamp Halogen		1	57	57	1.5
H58/1	H58	Halogen, (1) 58W lamp	58W 1-Lamp Halogen		1	58	58	1.5
H59/1	H59	Halogen, (1) 59W lamp	59W 1-Lamp Halogen		1	59	59	1.5
H60/1	H60	Halogen, (1) 60W lamp	60W 1-Lamp Halogen		1	60	60	1.5
H61/1	H61	Halogen, (1) 61W lamp	61W 1-Lamp Halogen		1	61	61	1.5
H62/1	H62	Halogen, (1) 62W lamp	62W 1-Lamp Halogen		1	62	62	1.5
H63/1	H63	Halogen, (1) 63W lamp	63W 1-Lamp Halogen		1	63	63	1.5
H64/1	H64	Halogen, (1) 64W lamp	64W 1-Lamp Halogen		1	64	64	1.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
H65/1	H65	Halogen, (1) 65W lamp	65W 1-Lamp Halogen		1	65	65	1.5
H66/1	H66	Halogen, (1) 66W lamp	66W 1-Lamp Halogen		1	66	66	1.5
H67/1	H67	Halogen, (1) 67W lamp	67W 1-Lamp Halogen		1	67	67	1.5
H68/1	H68	Halogen, (1) 68W lamp	68W 1-Lamp Halogen		1	68	68	1.5
H69/1	H69	Halogen, (1) 69W lamp	69W 1-Lamp Halogen		1	69	69	1.5
H70/1	H70	Halogen, (1) 70W lamp	70W 1-Lamp Halogen		1	70	70	1.5
H71/1	H71	Halogen, (1) 71W lamp	71W 1-Lamp Halogen		1	71	71	1.5
H72/1	H72	Halogen, (1) 72W lamp	72W 1-Lamp Halogen		1	72	72	1.5
H73/1	H73	Halogen, (1) 73W lamp	73W 1-Lamp Halogen		1	73	73	1.5
H74/1	H74	Halogen, (1) 74W lamp	74W 1-Lamp Halogen		1	74	74	1.5
H75/1	H75	Halogen, (1) 75W lamp	75W 1-Lamp Halogen		1	75	75	1.5
H80/1	H80	Halogen, (1) 80W lamp	80W 1-Lamp Halogen		1	80	80	1.5
H90/1	H90	Halogen, (1) 90W lamp	90W 1-Lamp Halogen		1	90	90	1.5
H100/1	H100	Halogen, (1) 100W lamp	100W 1-Lamp Halogen		1	100	100	1.5
H150/1	H150	Halogen, (1) 150W lamp	150W 1-Lamp Halogen		1	150	150	1.5
H250/1	H250	Halogen, (1) 250W lamp	250W 1-Lamp Halogen		1	250	250	1.5
H300/1	H300	Halogen, (1) 300W lamp	300W 1-Lamp Halogen		1	300	300	1.5
H500/1	H500	Halogen, (1) 500W lamp	500W 1-Lamp Halogen		1	500	500	1.5
HPS		High Pressure Sodium Fixtures						

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
HPS35/1	HPS35	High Pressure Sodium, (1) 35W lamp	35W HPS		1	35	46	15.5
HPS50/1	HPS50	High Pressure Sodium, (1) 50W lamp	50W HPS		1	50	66	15.5
HPS70/1	HPS70	High Pressure Sodium, (1) 70W lamp	70W HPS		1	70	95	15.5
HPS100/1	HPS100	High Pressure Sodium, (1) 100W lamp	100W HPS		1	100	138	15.5
HPS150/1	HPS150	High Pressure Sodium, (1) 150W lamp	150W HPS		1	150	188	15.5
HPS200/1	HPS200	High Pressure Sodium, (1) 200W lamp	200W HPS		1	200	250	15.5
HPS250/1	HPS250	High Pressure Sodium, (1) 250W lamp	250W HPS		1	250	295	15.5
HPS310/1	HPS310	High Pressure Sodium, (1) 310W lamp	310W HPS		1	310	365	15.5
HPS360/1	HPS360	High Pressure Sodium, (1) 360W lamp	360W HPS		1	360	414	15.5
HPS400/1	HPS400	High Pressure Sodium, (1) 400W lamp	400W HPS		1	400	465	15.5
HPS1000/1	HPS1000	High Pressure Sodium, (1) 1000W lamp	1000W HPS		1	1000	1100	15.5
I		Standard Incandescent Fixtures						
I7.5/1	I7.5	Tungsten exit light, (1) 7.5 W lamp, used in night light application	7.5W incandescent		1	7.5	8	1.5
I10/1	I10	Incandescent, (1) 10W lamp	10W incandescent		1	10	10	1.5
I11/1	I11	Incandescent, (1) 11W lamp	11W incandescent		1	11	11	1.5
I12/1	I12	Incandescent, (1) 12W lamp	12W incandescent		1	12	12	1.5
I13/1	I13	Incandescent, (1) 13W lamp	13W incandescent		1	13	13	1.5
I14/1	I14	Incandescent, (1) 14W lamp	14W incandescent		1	14	14	1.5
I15/1	I15	Incandescent, (1) 15W lamp	15W incandescent		1	15	15	1.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
I16/1	I16	Incandescent, (1) 16W lamp	16W incandescent		1	16	16	1.5
I17/1	I17	Incandescent, (1) 17W lamp	17W incandescent		1	17	17	1.5
I18/1	I18	Incandescent, (1) 18W lamp	18W incandescent		1	18	18	1.5
I19/1	I19	Incandescent, (1) 19W lamp	19W incandescent		1	19	19	1.5
I20/1	I20	Incandescent, (1) 20W lamp	20W incandescent		1	20	20	1.5
I21/1	I21	Incandescent, (1) 21W lamp	21W incandescent		1	21	21	1.5
I22/1	I22	Incandescent, (1) 22W lamp	22W incandescent		1	22	22	1.5
I23/1	I23	Incandescent, (1) 23W lamp	23W incandescent		1	23	23	1.5
I24/1	I24	Incandescent, (1) 24W lamp	24W incandescent		1	24	24	1.5
I25/1	I25	Incandescent, (1) 25W lamp	25W incandescent		1	25	25	1.5
I26/1	I26	Incandescent, (1) 26W lamp	26W incandescent		1	26	26	1.5
I27/1	I27	Incandescent, (1) 27W lamp	27W incandescent		1	27	27	1.5
I28/1	I28	Incandescent, (1) 28W lamp	28W incandescent		1	28	28	1.5
I29/1	I29	Incandescent, (1) 29W lamp	29W incandescent		1	29	29	1.5
I30/1	I30	Incandescent, (1) 30W lamp	30W incandescent		1	30	30	1.5
I31/1	I31	Incandescent, (1) 31W lamp	31W incandescent		1	31	31	1.5
I32/1	I32	Incandescent, (1) 32W lamp	32W incandescent		1	32	32	1.5
I33/1	I33	Incandescent, (1) 33W lamp	33W incandescent		1	33	33	1.5
I34/1	I34	Incandescent, (1) 34W lamp	34W incandescent		1	34	34	1.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
I35/1	I35	Incandescent, (1) 35W lamp	35W incandescent		1	35	35	1.5
I36/1	I36	Incandescent, (1) 36W lamp	36W incandescent		1	36	36	1.5
I37/1	I37	Incandescent, (1) 37W lamp	37W incandescent		1	37	37	1.5
I38/1	I38	Incandescent, (1) 38W lamp	38W incandescent		1	38	38	1.5
I39/1	I39	Incandescent, (1) 39W lamp	39W incandescent		1	39	39	1.5
I40/1	I40	Incandescent, (1) 40W lamp	40W incandescent		1	40	40	1.5
I40E/1	I40/ES	Incandescent, (1) 40W ES lamp	40W incandescent		1	29	29	1.5
I40EL/1	I40/ES/LL	Incandescent, (1) 40W ES/LL lamp	40W incandescent		1	34	34	1.5
I41/1	I41	Incandescent, (1) 41W lamp	41W incandescent		1	41	41	1.5
I42/1	I42	Incandescent, (1) 42W lamp	42W incandescent		1	42	42	1.5
I43/1	I43	Incandescent, (1) 43W lamp	43W incandescent		1	43	43	1.5
I44/1	I44	Incandescent, (1) 44W lamp	44W incandescent		1	44	44	1.5
I45/1	I45	Incandescent, (1) 45W lamp	45W incandescent		1	45	45	1.5
I46/1	I46	Incandescent, (1) 46W lamp	46W incandescent		1	46	46	1.5
I47/1	I47	Incandescent, (1) 47W lamp	47W incandescent		1	47	47	1.5
I48/1	I48	Incandescent, (1) 48W lamp	48W incandescent		1	48	48	1.5
I49/1	I49	Incandescent, (1) 49W lamp	49W incandescent		1	49	49	1.5
I50/1	I50	Incandescent, (1) 50W lamp	50W incandescent		1	50	50	1.5
I51/1	I51	Incandescent, (1) 51W lamp	51W incandescent		1	51	51	1.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
I52/1	I52	Incandescent, (1) 52W lamp	52W incandescent		1	52	52	1.5
I53/1	I53	Incandescent, (1) 53W lamp	53W incandescent		1	53	53	1.5
I54/1	I54	Incandescent, (1) 54W lamp	54W incandescent		1	54	54	1.5
I55/1	I55	Incandescent, (1) 55W lamp	55W incandescent		1	55	55	1.5
I56/1	I56	Incandescent, (1) 56W lamp	56W incandescent		1	56	56	1.5
I57/1	I57	Incandescent, (1) 57W lamp	57W incandescent		1	57	57	1.5
I58/1	I58	Incandescent, (1) 58W lamp	58W incandescent		1	58	58	1.5
I59/1	I59	Incandescent, (1) 59W lamp	59W incandescent		1	59	59	1.5
I60/1	I60	Incandescent, (1) 60W lamp	60W incandescent		1	60	60	1.5
I60E/1	I60/ES	Incandescent, (1) 60W ES lamp	60W incandescent		1	43	43	1.5
I60EL/1	I60/ES/LL	Incandescent, (1) 60W ES/LL lamp	60W incandescent		1	52	52	1.5
I61/1	I61	Incandescent, (1) 61W lamp	61W incandescent		1	61	61	1.5
I62/1	I62	Incandescent, (1) 62W lamp	62W incandescent		1	62	62	1.5
I63/1	I63	Incandescent, (1) 63W lamp	63W incandescent		1	63	63	1.5
I64/1	I64	Incandescent, (1) 64W lamp	64W incandescent		1	64	64	1.5
I65/1	I65	Incandescent, (1) 65W lamp	65W incandescent		1	65	65	1.5
I66/1	I66	Incandescent, (1) 66W lamp	66W incandescent		1	66	66	1.5
I67/1	I67	Incandescent, (1) 67W lamp	67W incandescent		1	67	67	1.5
I68/1	I68	Incandescent, (1) 68W lamp	68W incandescent		1	68	68	1.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
I69/1	I69	Incandescent, (1) 69W lamp	69W incandescent		1	69	69	1.5
I70/1	I70	Incandescent, (1) 70W lamp	70W incandescent		1	70	70	1.5
I71/1	I71	Incandescent, (1) 71W lamp	71W incandescent		1	71	71	1.5
I72/1	I72	Incandescent, (1) 72W lamp	72W incandescent		1	72	72	1.5
I73/1	I73	Incandescent, (1) 73W lamp	73W incandescent		1	73	73	1.5
I74/1	I74	Incandescent, (1) 74W lamp	74W incandescent		1	74	74	1.5
I75/1	I75	Incandescent, (1) 75W lamp	75W incandescent		1	75	75	1.5
I75E/1	I75/ES	Incandescent, (1) 75W ES lamp	75W incandescent		1	53	53	1.5
I75EL/1	I75/ES/LL	Incandescent, (1) 75W ES/LL lamp	75W incandescent		1	67	67	1.5
I80/1	I80	Incandescent, (1) 80W lamp	80W incandescent		1	80	80	1.5
I85/1	I85	Incandescent, (1) 85W lamp	85W incandescent		1	85	85	1.5
I90/1	I90	Incandescent, (1) 90W lamp	90W incandescent		1	90	90	1.5
I93/1	I93	Incandescent, (1) 93W lamp	93W incandescent		1	93	93	1.5
I95/1	I95	Incandescent, (1) 95W lamp	95W incandescent		1	95	95	1.5
I100/1	I100	Incandescent, (1) 100W lamp	100W incandescent		1	100	100	1.5
I100E/1	I100/ES	Incandescent, (1) 100W ES lamp	100W incandescent		1	72	72	1.5
I100EL/1	I100/ES/LL	Incandescent, (1) 100W ES/LL lamp	100W incandescent		1	90	90	1.5
I110/1	I110	Incandescent, (1) 110W lamp	110W incandescent		1	110	110	1.5
I116/1	I116	Incandescent, (1) 116W lamp	116W incandescent		1	116	116	1.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
I120/1	I120	a	120W incandescent		1	120	120	1.5
I125/1	I125	Incandescent, (1) 125W lamp	125W incandescent		1	125	125	1.5
I130/1	I130	Incandescent, (1) 130W lamp	130W incandescent		1	130	130	1.5
I135/1	I135	Incandescent, (1) 135W lamp	135W incandescent		1	135	135	1.5
I150/1	I150	Incandescent, (1) 150W lamp	150W incandescent		1	150	150	1.5
I150E/1	I150/ES	Incandescent, (1) 150W ES lamp	150W incandescent		1	135	135	1.5
I150EL/1	I150/ES/LL	Incandescent, (1) 150W ES/LL lamp	150W incandescent		1	135	135	1.5
I160/1	I160	Incandescent, (1) 160W lamp	160W incandescent		1	160	160	1.5
I170/1	I170	Incandescent, (1) 170W lamp	170W incandescent		1	170	170	1.5
I200/1	I200	Incandescent, (1) 200W lamp	200W incandescent		1	200	200	1.5
I200L/1	I200/LL	Incandescent, (1) 200W LL lamp	200W incandescent		1	200	200	1.5
I250/1	I250	Incandescent, (1) 250W lamp	250W incandescent		1	250	250	1.5
I300/1	I300	Incandescent, (1) 300W lamp	300W incandescent		1	300	300	1.5
I400/1	I400	Incandescent, (1) 400W lamp	400W incandescent		1	400	400	1.5
I448/1	I448	Incandescent, (1) 448W lamp	448W incandescent		1	448	448	1.5
I500/1	I500	Incandescent, (1) 500W lamp	500W incandescent		1	500	500	1.5
I750/1	I750	Incandescent, (1) 750W lamp	750W incandescent		1	750	750	1.5
I1000/1	I1000	Incandescent, (1) 1000W lamp	1000W incandescent		1	1000	1000	1.5
I1500/1	I1500	Incandescent, (1) 1500W lamp	1500W incandescent		1	1500	1500	1.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
I2000/1	I2000	Incandescent, (1) 2000W lamp	2000W incandescent		1	2000	2000	1.5
MH		Metal Halide Fixtures - Standard, Pulse Start, or Ceramic						
MH20/1-L	MH20	Metal Halide, (1) 20W lamp	20W Metal Halide	Electronic	1	20	23	15.5
MH22/1-L	MH22	Metal Halide, (1) 22W lamp	22W Metal Halide	Electronic	1	22	26	15.5
MH32/1	MH32	Metal Halide, (1) 32W lamp, Magnetic ballast	32W Metal Halide	Magnetic	1	32	42	15.5
MH39/1	MH39	Metal Halide, (1) 39W lamp, Magnetic ballast	39W Metal Halide	Magnetic	1	39	51	15.5
MH39/1-L	MH39	Metal Halide, (1) 39W lamp	39W Metal Halide	Electronic	1	39	44	15.5
MH50/1	MH50	Metal Halide, (1) 50W lamp, Magnetic ballast	50W Metal Halide	Magnetic	1	50	64	15.5
MH50/1-L	MH50	Metal Halide, (1) 50W lamp	50W Metal Halide	Electronic	1	50	56	15.5
MH70/1	MH70	Metal Halide, (1) 70W lamp, Magnetic ballast	70W Metal Halide	Magnetic	1	70	91	15.5
MH70/1-L	MH70	Metal Halide, (1) 70W lamp	70W Metal Halide	Electronic	1	70	78	15.5
MH100/1	MH100	Metal Halide, (1) 100W lamp, Magnetic ballast	100W Metal Halide	Magnetic	1	100	124	15.5
MH100/1-L	MH100	Metal Halide, (1) 100W lamp	100W Metal Halide	Electronic	1	100	108	15.5
MH125/1	MH125	Metal Halide, (1) 125W lamp, Magnetic ballast	125W Metal Halide	Magnetic	1	125	148	15.5
MH150/1	MH150	Metal Halide, (1) 150W lamp, Magnetic ballast	150W Metal Halide	Magnetic	1	150	183	15.5
MH150/1-L	MH150	Metal Halide, (1) 150W lamp	150W Metal Halide	Electronic	1	150	163	15.5
MH175/1	MH175	Metal Halide, (1) 175W lamp, Magnetic ballast	175W Metal Halide	Magnetic	1	175	208	15.5
MH175/1-L	MH175	Metal Halide, (1) 175W lamp	175W Metal Halide	Electronic	1	175	196	15.5
MH200/1	MH200	Metal Halide, (1) 200W lamp, Magnetic ballast	200W Metal Halide	Magnetic	1	200	228	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
MH200/1-L	MH200	Metal Halide, (1) 200W lamp	200W Metal Halide	Electronic	1	200	219	15.5
MH250/1	MH250	Metal Halide, (1) 250W lamp, Magnetic ballast	250W Metal Halide	Magnetic	1	250	288	15.5
MH250/1-L	MH250	Metal Halide, (1) 250W lamp	250W Metal Halide	Electronic	1	250	275	15.5
MH320/1	MH320	Metal Halide, (1) 320W lamp, Magnetic ballast	320W Metal Halide	Magnetic	1	320	362	15.5
MH320/1-L	MH320	Metal Halide, (1) 320W lamp	320W Metal Halide	Electronic	1	320	343	15.5
MH350/1	MH350	Metal Halide, (1) 350W lamp, Magnetic ballast	350W Metal Halide	Magnetic	1	350	391	15.5
MH350/1-L	MH350	Metal Halide, (1) 350W lamp	350W Metal Halide	Electronic	1	350	375	15.5
MH360/1	MH360	Metal Halide, (1) 360W lamp, Magnetic ballast	360W Metal Halide	Magnetic	1	360	418	15.5
MH400/1	MH400	Metal Halide, (1) 400W lamp, Magnetic ballast	400W Metal Halide	Magnetic	1	400	453	15.5
MH400/1-L	MH400	Metal Halide, (1) 400W lamp	400W Metal Halide	Electronic	1	400	429	15.5
MH450/1	MH450	Metal Halide, (1) 450W lamp, Magnetic ballast	450W Metal Halide	Magnetic	1	450	499	15.5
MH450/1-L	MH450	Metal Halide, (1) 450W lamp	450W Metal Halide	Electronic	1	450	486	15.5
MH575/1	MH575	Metal Halide, (1) 575W lamp, Magnetic ballast	575W Metal Halide	Magnetic	1	575	630	15.5
MH750/1	MH750	Metal Halide, (1) 750W lamp, Magnetic ballast	750W Metal Halide	Magnetic	1	750	812	15.5
MH775/1	MH775	Metal Halide, (1) 775W lamp, Magnetic ballast	775W Metal Halide	Magnetic	1	775	843	15.5
MH875/1	MH875	Metal Halide, (1) 875W lamp	875W Metal Halide	Magnetic	1	875	939	15.5
MH1000/1	MH1000	Metal Halide, (1) 1000W lamp, Magnetic ballast	1000W Metal Halide	Magnetic	1	1000	1078	15.5
MH1000/1-L	MH1000	Metal Halide, (1) 1000W lamp	1000W Metal Halide	Electronic	1	1000	1067	15.5
MH1500/1	MH1500	Metal Halide, (1) 1500W lamp, Magnetic ballast	1500W Metal Halide	Magnetic	1	1500	1605	15.5

Fixture Code	LAMP CODE	DESCRIPTION	Layman Term	BALLAST	LAMP / FIXT	W / LAMP	W / FIXT	EUL
MH1650/1	MH1650	Metal Halide, (1) 1650W lamp	1650W Metal Halide	Magnetic	1	1650	1765	15.5
MH2000/1	MH2000	Metal Halide, (1) 2000W lamp	2000W Metal Halide	Magnetic	1	2000	2140	15.5
MV		Mercury Vapor Fixtures						
MV40/1	MV40	Mercury Vapor, (1) 40W lamp	40W Mercury Vapor		1	40	50	15.5
MV50/1	MV50	Mercury Vapor, (1) 50W lamp	50W Mercury Vapor		1	50	74	15.5
MV75/1	MV75	Mercury Vapor, (1) 75W lamp	75W Mercury Vapor		1	75	93	15.5
MV100/1	MV100	Mercury Vapor, (1) 100W lamp	100W Mercury Vapor		1	100	125	15.5
MV160/1	MV160-SB	Mercury Vapor, Self-Ballasted, (1) 160W self-ballasted lamp	160W Mercury Vapor		1	160	160	15.5
MV175/1	MV175	Mercury Vapor, (1) 175W lamp	175W Mercury Vapor		1	175	205	15.5
MV250/1	MV250	Mercury Vapor, (1) 250W lamp	250W Mercury Vapor		1	250	290	15.5
MV400/1	MV400	Mercury Vapor, (1) 400W lamp	400W Mercury Vapor		1	400	455	15.5
MV700/1	MV700	Mercury Vapor, (1) 700W lamp	700W Mercury Vapor		1	700	780	15.5
MV1000/1	MV1000	Mercury Vapor, (1) 1000W lamp	1000W Mercury Vapor		1	1000	1075	15.5

THE COUNCIL OF THE CITY OF NEW ORLEANS, LA

REQUEST FOR QUALIFICATIONS STATEMENTS

FOR

DEMAND SIDE MANAGEMENT CONSULTANT

ISSUED SEPTEMBER 15, 2017

APPENDIX V

ENTERGY NEW ORLEANS' APPLICATION TO DEPLOY

ADVANCED METERING INFRASTRUCTURE

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, REQUEST FOR COST RECOVERY AND RELATED RELIEF

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:

INTRODUCTION

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.

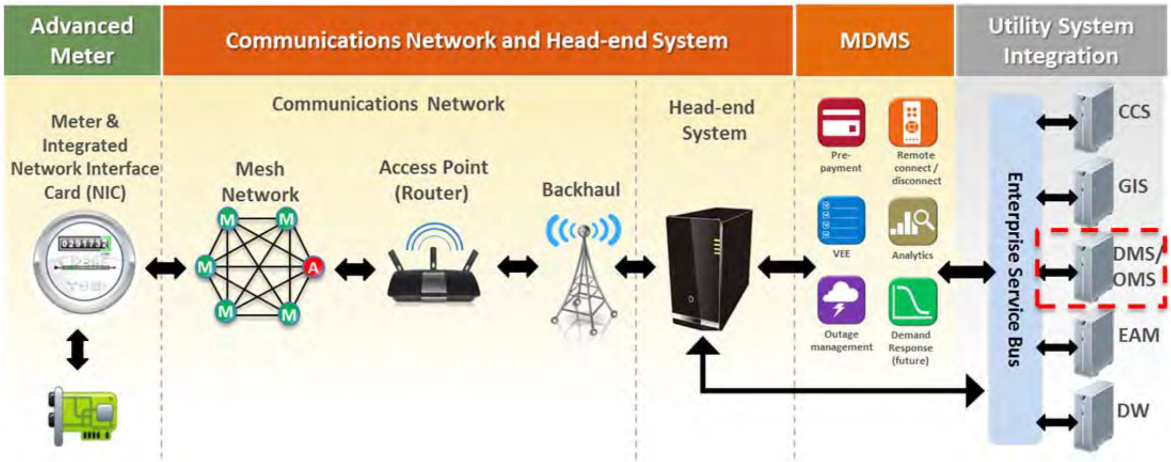
- **Dr. Ahmad Faruqui –** Dr. Faruqui is a Principal with The Brattle Group who offers an external viewpoint on the state of AMI deployment in the utility industry, as well as his opinions on ENO's assumptions in quantifying benefits associated with the Company's AMI deployment. His analysis of the estimated 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
New Orleans, Louisiana 70113
Telephone: (504) 576-2603
Facsimile: (504) 576-5579

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

[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

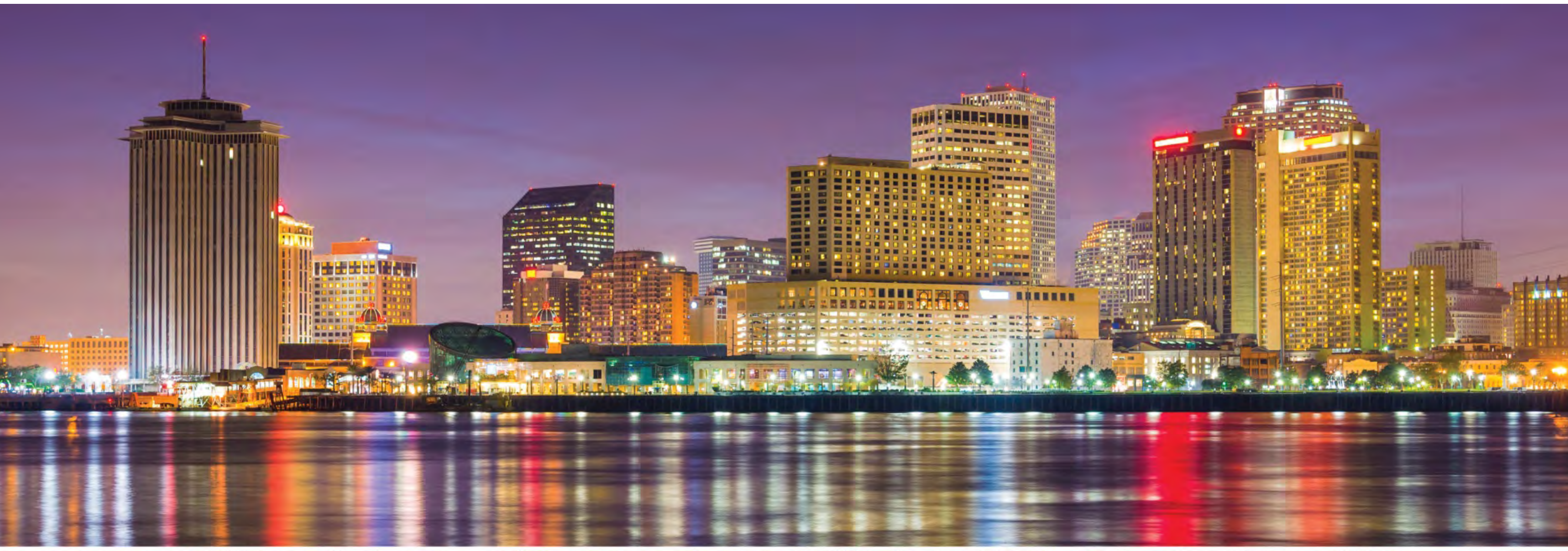
My commission expires: at death

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.



WE POWER LIFE℠

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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

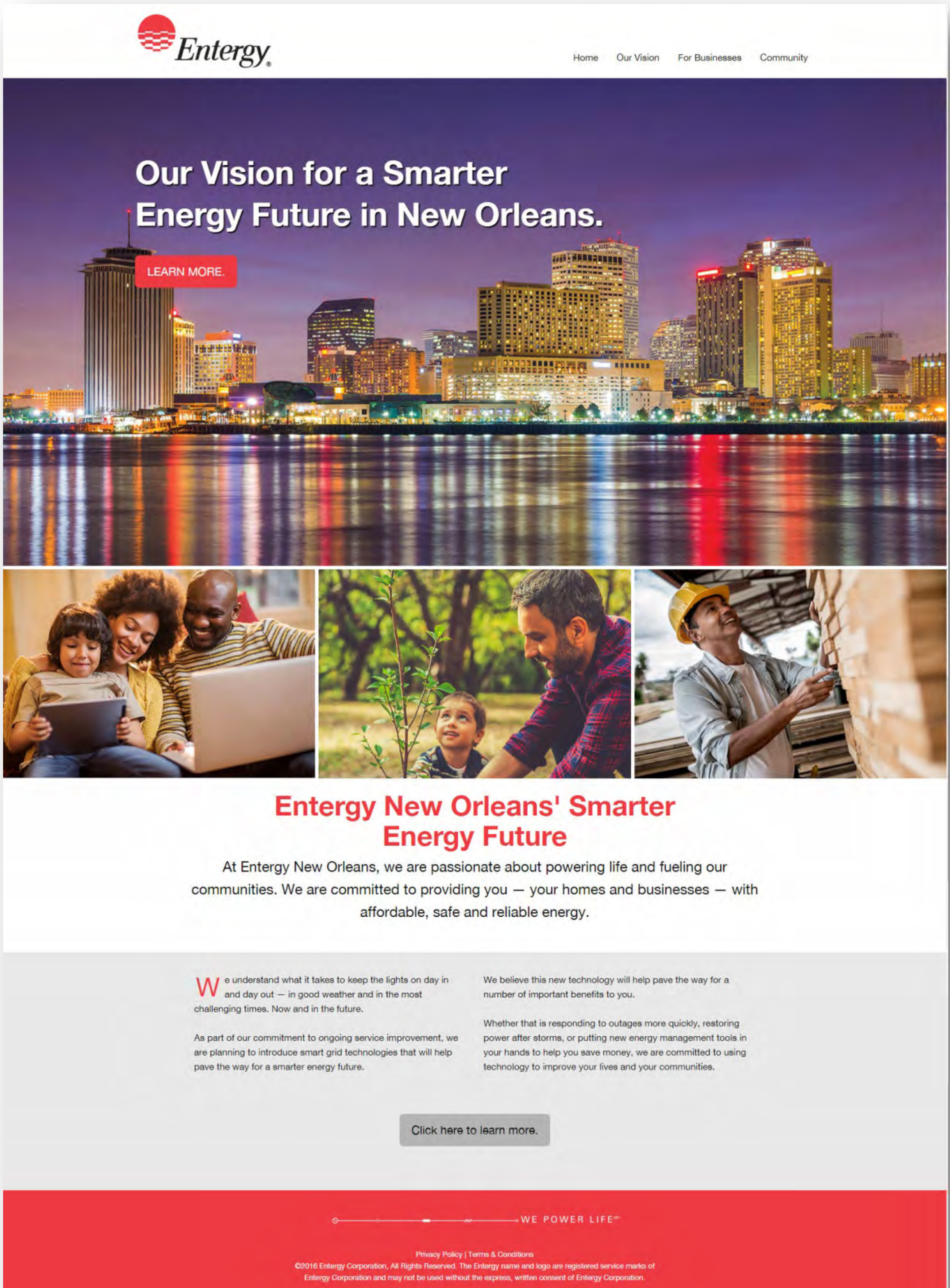
	enable customers to find information about AMI generally, and ENO's AMI deployment in particular, when using web search engines.
Door hangers	Door hangers will be developed to use during meter installation. The door hangers will notify customers if their advanced meter was successfully installed or whether 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

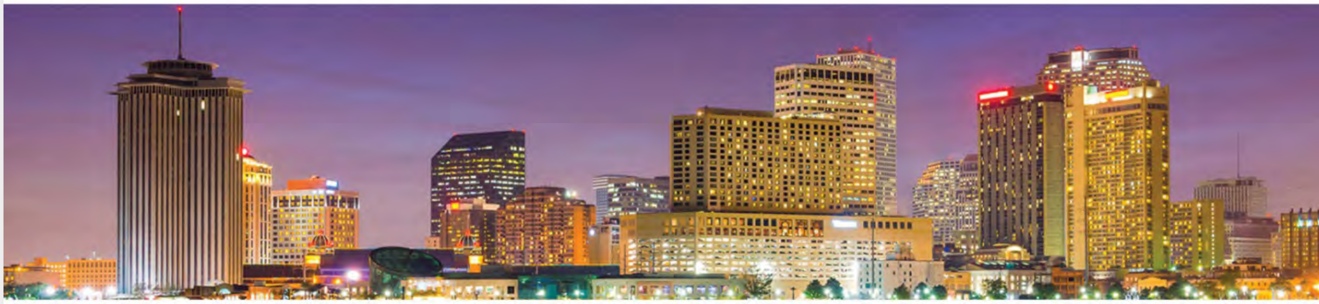
This section provides samples of educational materials for **illustrative purposes**. Actual information will be adjusted prior to dissemination based on design phase decisions and feedback from customers.

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)

For illustrative purposes only

Building a Smarter Energy Future

Starts with a meter.

Entergy is upgrading our energy infrastructure to improve our communities. These upgrades begin with the installation of advanced meters.

Benefits include:

- Faster outage restoration after storms
- New tools to help you understand and manage your energy use more effectively
- Improved customer service

To learn more about our smarter energy future, visit energyfutureneworleans.com or call us at XXX-XXX-XXXX with questions.

Entergy®

WE POWER LIFE℠

For illustrative purposes only

We Were Here

to upgrade your meter.

Date: ______________________

Time: ______________________

During our visit:

___ We upgraded your meter successfully

We were unable to upgrade your meter for one of the reasons below:

___ Need access to electric and/or gas meter

___ Meter blocked and/or obstructed

___ Locked fence or gate

___ Dog in the yard

___ Safety issue

___ Damaged equipment

___ Other:______________________

Please call us at XXX-XXX-XXXX to return at a convenient time.

Entergy®

Installation Direct Mail (Residential Customers)

IT ALL STARTS
WITH A METER.

Entergy is installing new advanced meters as the foundation for new technology and programs to empower our communities.

Benefits of the new technology include:

- Faster outage restoration after storms
- New tools to help you understand and manage your energy use more effectively
- Improved customer service

We will let you know when we'll be in your neighborhood. To learn more about our smarter energy future, visit energyfutureneworleans.com or call us at XXX-XXX-XXXX with questions.

For illustrative purposes only

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

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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

[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.

[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.

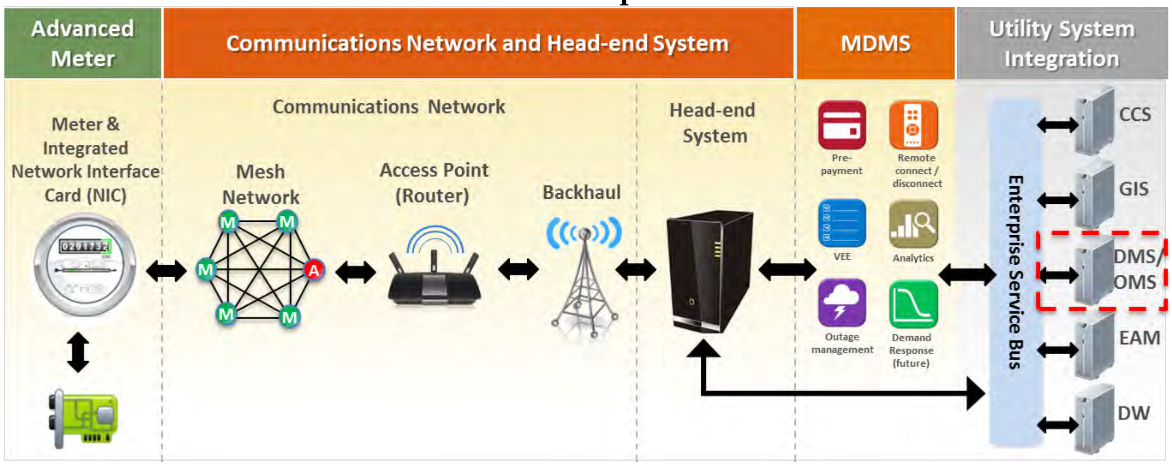
Finally, ENO established a comprehensive cost estimate for the design and deployment of AMI, incorporating vendor cost information from a competitive bidding process, internal Company costs associated with executing the AMI project control environment, and an appropriate and reasonable contingency. The 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.

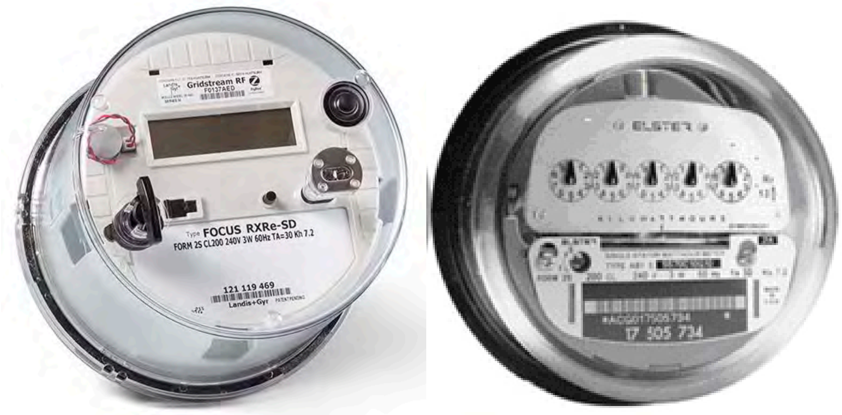
B. AMI Components

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.

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[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.

[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

PUBLIC VERSION

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

OCTOBER 2016

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DIRECT TESTIMONY

OF

MICHELLE P. BOURG

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

OCTOBER 2016

TABLE OF CONTENTS

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,

[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.

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[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

[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.

[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 FOR COST RECOVERY AND RELATED RELIEF	)))))	**DOCKET NO. UD-16-___**

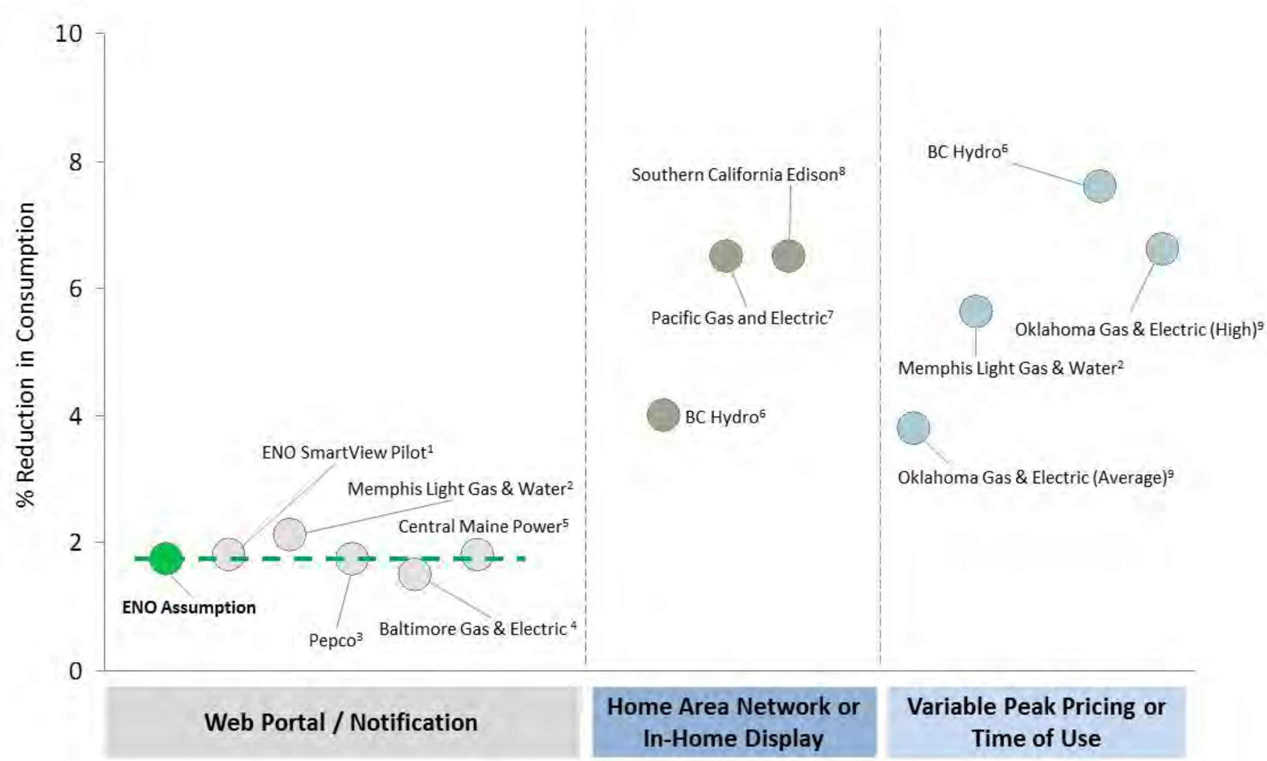
EXHIBIT JAL-2

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

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[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?

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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

[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?

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[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

[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

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[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?

[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,

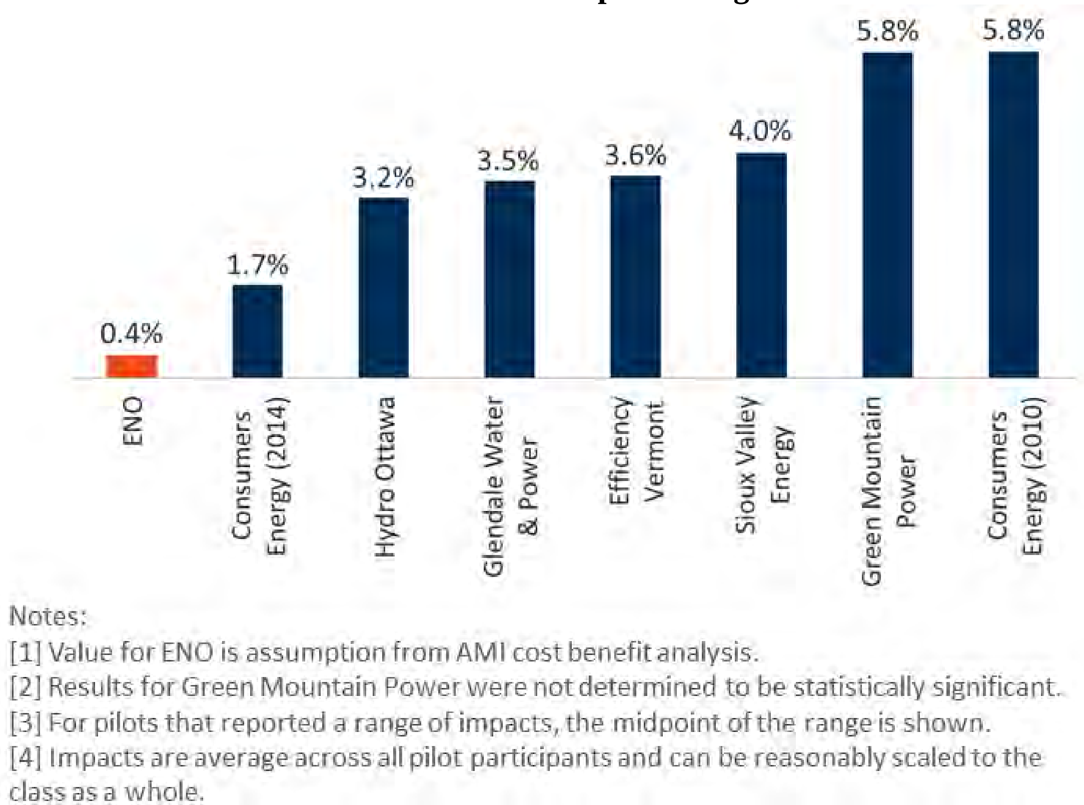
[28] *See* Kassia Micek, "CAISO Calls on Consumers to Conserve Electricity," *Platts*, June 20, 2016, *available at* http://www.platts.com/latest-news/electric-power/houston/caiso-calls-on-consumers-to-conserve-electricity-21758647, last accessed September 2, 2016.

[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



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

[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.

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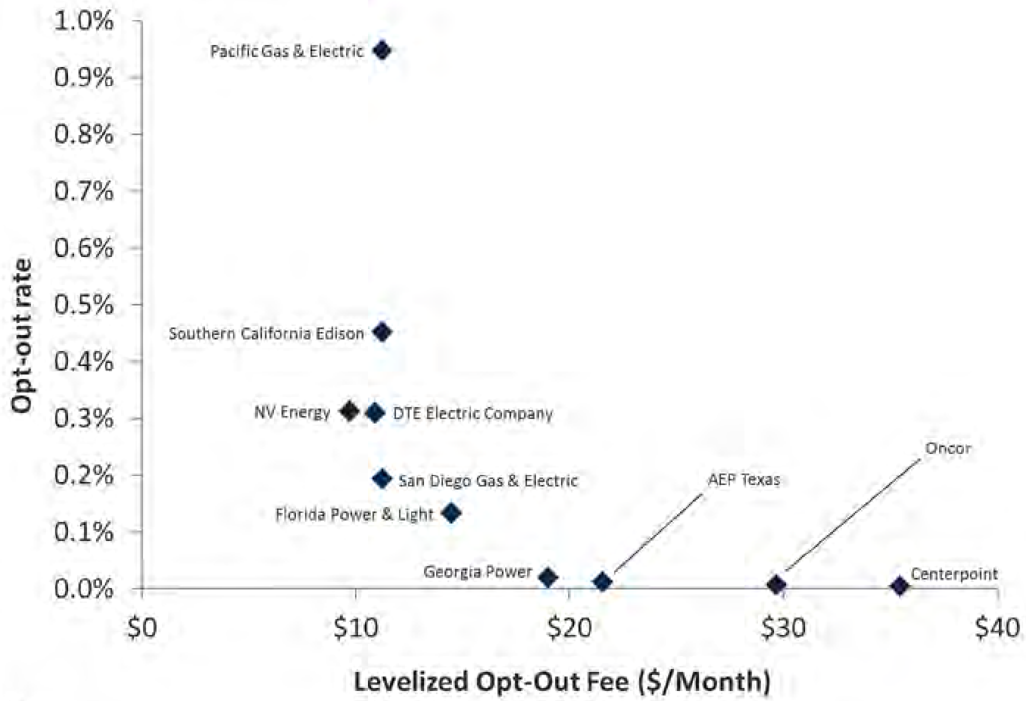
[37] That is 52,205 customers who were enrolled in PG&E's SmartMeter Opt-Out Program as of October 2015 out of a total of 5,518,718 customers. *See California Smart Grid – Annual Report to the Governor and the Legislature, in Compliance with Public Utilities Code 913.2, California Public Utilities Commission* (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.

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Pennsylvania

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Arkansas

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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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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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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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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.

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[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

[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