Company **Profile**



Forward-Looking Statement

All information contained in this FactBook is as of September 30, 2014 unless otherwise noted.

This FactBook includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "forecast," "will," "intend," "believe," "estimate" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements, which may include the following: the speed and nature of increased competition in the electric utility industry, in general, and the retail sales market in particular; the ability to experience growth in the Regulated Distribution and Regulated Transmission segments and to successfully implement our revised sales strategy in the Competitive Energy Services segment; the accomplishment of our regulatory and operational goals in connection with our transmission plan and pending distribution rate cases and the effectiveness of our repositioning strategy; the impact of the regulatory process on pending matters in the various states in which we do business including, but not limited to, matters related to rates and pending rate cases, and the Electric Security Plan IV in Ohio; the impact of the federal regulatory process on the Federal Energy Regulatory Commission (FERC) regulated entities and transactions, in particular FERC regulation of wholesale energy and capacity markets, including the PJM markets and also FERC-jurisdictional wholesale transactions, FERC regulation of cost-of-service rates, including FERC Opinion No. 531's revised Return on Equity methodology for FERC-jurisdictional wholesale generation and transmission utility service and FERC's compliance and enforcement activity, including compliance and enforcement activity related to NERC's mandatory reliability standards; the uncertainties of various cost recovery and cost allocation issues resulting from American Transmission Systems, Incorporated's realignment into PJM Interconnection, L.L.C.; economic or weather conditions affecting future sales and margins such as a polar vortex or other significant weather events, and all associated regulatory events or actions; regulatory outcomes associated with storm restoration costs, including but not limited to, Hurricane Sandy, Hurricane Irene and the October snowstorm of 2011; changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil, and their availability and impact on margins; the continued ability of our regulated utilities to recover their costs; costs being higher than anticipated and the success of our policies to control costs and to mitigate low energy, capacity and market prices; other legislative and regulatory changes, and revised environmental requirements, including, but not limited to, possible greenhouse gases emission, water discharge, and coal combustion residuals regulations, the potential impacts of Cross-State Air Pollution Rule, and the effects of the United States Environmental Protection Agency's Mercury and Air Toxics Standards rules including our estimated costs of compliance; the uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any litigation, including New Source Review litigation, or potential regulatory initiatives or rulemakings (including that such expenditures could result in our decision to deactivate or idle certain generating units); the uncertainties associated with the deactivation of certain older regulated and competitive fossil units, including the impact on vendor commitments, and the timing thereof as they relate to, among other things, Reliability Must Run arrangements and the reliability of the transmission grid; the impact of other future changes to the operational status or availability of our generating units; adverse regulatory or legal decisions and outcomes with respect to our nuclear operations (including, but not limited to the revocation or non-renewal of necessary licenses, approvals or operating permits by the Nuclear Regulatory Commission or as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant); issues arising from the indications of cracking in the shield building at Davis-Besse; the risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments; replacement power costs being higher than anticipated or not fully hedged; the ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates; changes in customers' demand for power, including, but not limited to, changes resulting from the implementation of state and federal energy efficiency and peak demand reduction mandates; the ability to accomplish or realize anticipated benefits from strategic and financial goals, including, but not limited to, the ability to continue to reduce costs and successfully execute our announced financial plans designed to improve our credit metrics and strengthen our balance sheet through, among other actions, our previously-implemented dividend reduction and our other proposed capital raising initiatives; our ability to improve electric commodity margins and the impact of, among other factors, the increased cost of fuel and fuel transportation on such margins; changing market conditions that could affect the measurement of certain liabilities and the value of assets held in our Nuclear Decommissioning Trusts, pension trusts and other trust funds, and cause us and/or our subsidiaries to make additional contributions sooner, or in amounts that are larger than currently anticipated; the impact of changes to material accounting policies; the ability to access the public securities and other capital and credit markets in accordance with our announced financial plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries; actions that may be taken by credit rating agencies that could negatively affect us and/or our subsidiaries' access to financing, increase the costs thereof, and increase requirements to post additional collateral to support outstanding commodity positions, letters of credit and other financial guarantees; changes in national and regional economic conditions affecting us, our subsidiaries and/or our major industrial and commercial customers and other counterparties with which we do business, including fuel suppliers; the impact of any changes in tax laws or regulations or adverse tax audit results or rulings; issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business; and the risks and other factors discussed from time to time in our United States Securities and Exchange Commission filings, and other similar factors. Dividends declared from time to time on FirstEnergy Corp.'s common stock during any period may in the aggregate vary from prior periods due to circumstances considered by FirstEnergy Corp.'s Board of Directors at the time of the actual declarations. A security rating is not a recommendation to buy or hold securities and is subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating. The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on FirstEnergy's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. FirstEnergy expressly disclaims any current intention to update, except as required by law, any forward-looking statements contained herein as a result of new information, future events or otherwise.

Non-GAAP Financial Matters

This FactBook contains references to non-GAAP financial measures including, among others, Operating earnings, Adjusted EBITDA, Adjusted Equity, Adjusted Debt, Adjusted Capitalization, Funds from Operations (FFO) and Free Cash Flow. In addition, Basic EPS and Basic EPS-Operating, each calculated on a segment basis, are also non-GAAP financial measures. Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with accounting principles generally accepted in the United States (GAAP). Operating earnings are not calculated in accordance with GAAP because they exclude the impact of "special items". Adjusted EBITDA also excludes the impact of special items and represents Operating earnings before interest expense, investment income, taxes, depreciation and amortization. Basic EPS for each segment is calculated by dividing segment net income (loss) on a GAAP basis by the basic weighted average shares outstanding for the period. Basic EPS-Operating for each segment is calculated by dividing segment Operating earnings, which exclude special items as discussed above, by the basic weighted average shares outstanding for the period. Management uses non-GAAP financial measures such as Operating earnings, Adjusted EBITDA, FFO and Free Cash Flow to evaluate the company's performance and manage its operations and frequently references these non-GAAP financial measures in its decision-making, using them to facilitate historical and ongoing performance comparisons. Additionally, management uses Basic EPS and Basic-EPS Operating by segment to further evaluate FirstEnergy's performance by segment and references these non-GAAP financial measures in its decision-making. Management believes that the non-GAAP financial measures of "Operating earnings," "Adjusted EBITDA," "Free Cash Flow," "Basic EPS" and "Basic EPS-Operating" provide consistent and comparable measures of performance of its businesses to help shareholders understand performance trends. Management uses Adjusted Equity, Adjusted Debt and Adjusted Capitalization to calculate and monitor its compliance with the debt to total capitalization financial covenant under the FirstEnergy credit facility and term loan. These financial measures, as calculated in accordance with the FirstEnergy credit facility and term loan, help shareholders understand compliance and provide a basis for understanding FirstEnergy's incremental debt capacity under the debt to total capitalization financial covenant. The financial covenant requires FirstEnergy to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. All of these non-GAAP financial measures are intended to complement, and are not considered as an alternative to, the most directly comparable GAAP financial measures. Also, the non-GAAP financial measures may not be comparable to similarly titled measures used by other entities.

Pursuant to the requirements of Regulation G, FirstEnergy has provided quantitative reconciliations within the presentation of the non-GAAP financial measures to the most directly comparable GAAP financial measures.

Acronyms

ABO	Accumulated Benefit Obligation
ACI	Activated Carbon Injection
AD	American Electric Power Dayton
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
BGS	Basic Generation Service
BPS	Basis Points
BPU	Board of Public Utilities
BRA	Base Residual Auction
CEMS	Continuous Emissions Monitoring System
CES	Competitive Energy Services
CIS	Customer Information System
COS	Combustion Optimization System
DOE	Department of Energy
DR	Demand Response
DSM	Demand Side Management
DSP	Default Service Plan
EDC	Electric Distribution Company
EE	Energy Efficiency
EHV	Extra High Voltage
EMAAC	EMAAC Locational Deliverability Area in PJM
ENEC	Expanded Net Energy Costs
EPA	United States Environmental Protection Agency
ESP	Electric Security Plan
FERC	Federal Energy Regulatory Commission
FRR	Fixed Resource Requirement
GA	Governmental Aggregation
GWH	Gigawatt-hour
HV	High Voltage
IGCC	Integrated Gasification Combined Cycle
ILB	Illinois Basin
ITC	Investment Tax Credit
kV	Kilovolt
kWh	Kilowatt-hour
LCI	Large Commercial / Industrial Customers
LNB	Low NOx Burners
Lo-S	Low Sulfur Coal
MAAC	MAAC Locational Deliverability Area in PJM
MATS	Mercury and Air Toxics Standards
MCI	Medium Commercial / Industrial Customers
MISO	Midcontinent Independent System Operator
MMBTU	Million British Thermal Unit
MW	Megawatt
MWH	Megawatt-hour
NAPP	Northern Appalachian Coal
NDC	Net Demonstrated Capacity
NDT	Nuclear Decommissioning Trust
NOX	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
OCI	Other Comprehensive Income
OFA	Separated Overfire Air
OPEB	Other Post-Employment Benefits
OVEC	Ohio Valley Electric Corporation
PAPUC	Pennsylvania Public Utility Commission
PBO	Projected Benefit Obligation
PIPP	Percentage of Income Payment Plan
PJM	PJM Interconnection, L.L.C.
POLR	Provider of Last Resort
PPA	Purchase Power Agreement
Precip	Electrostatic Precipitator
PSC	Maryland Public Service Commission
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
RD	Recommended Decision
RMR	Reliability Must Run
ROE	Return on Equity
RPM	Reliability Pricing Model
RPS	Renewables Portfolio Standard
RTEP	Regional Transmission Expansion Planning
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
SIP	Stock Investment Plan
SMIP	Smart Meter Technology Procurement and Installation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SSO	Standard Service Offer
SVC	Static VAR Compensator
VAR	Volt-Ampere Reactive
VVC	Voltage/VAR Control
WFGD	Wet Flue Gas Desulfurization
WV PSC	West Virginia Public Service Commission

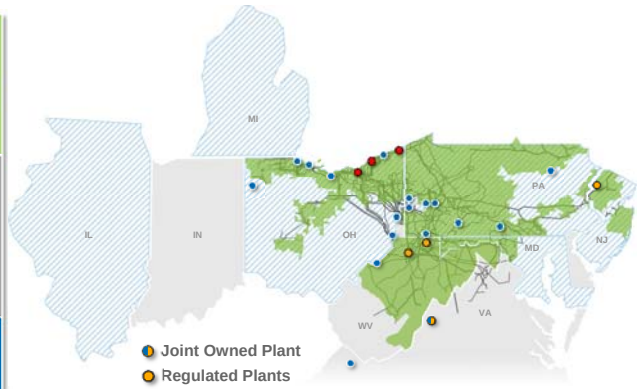
Strength in Our Diversity and Scale

Utilities
- Approximately 6M customers
- One of the largest contiguous service territories in the U.S. covering 65,000 square miles

Transmission
- Largest transmission system in PJM
- 24,000+ transmission miles
- Significant opportunity for growth

Competitive Operations
- One of the cleanest, lowest-cost generation fleets in the U.S.
- Long generation vs. sales strategy
- Focused on reducing overall business risk

*See slide 121



Going Forward … Growth Through Investments in Regulated Operations



Competitive Operations
- Reduced size of fleet and changed mix of assets to a much stronger platform of units
- Retain upside potential as markets improve, but limit downside from continued depressed conditions
- Targeting positive cash flow over the 2015 through 2018 period

Regulated Operations
- Increase transmission investments
- Target annual transmission earnings growth of 20%+ at ATSI and TrAILCo
- Grow predictable cash flow
- Seek opportunities in select rate case filings
- Continue to support a strong dividend

Regulated Business targeting 80%+ of EPS

FirstEnergy **Leadership**



Anthony J. Alexander
President and Chief Executive Officer



Leila L. Vespoli
Executive Vice President, Markets and Chief Legal Officer



Charles E. Jones
Executive Vice President and President, FirstEnergy Utilities



James F. Pearson
Senior Vice President and Chief Financial Officer



Lynn M. Cavalier
Senior Vice President, Human Resources



Michael J. Dowling
Senior Vice President, External Affairs



Bennett L. Gaines
Senior Vice President, Corporate Services and Chief Information Officer



James H. Lash
President
FirstEnergy Generation



Donald R. Schneider
President
FirstEnergy Solutions



Peter P. Sena III
President and Chief Nuclear Officer
FirstEnergy Nuclear Operating Company



Steven R. Staub
Vice President, Treasurer



K. Jon Taylor
Vice President, Controller and Chief Accounting Officer

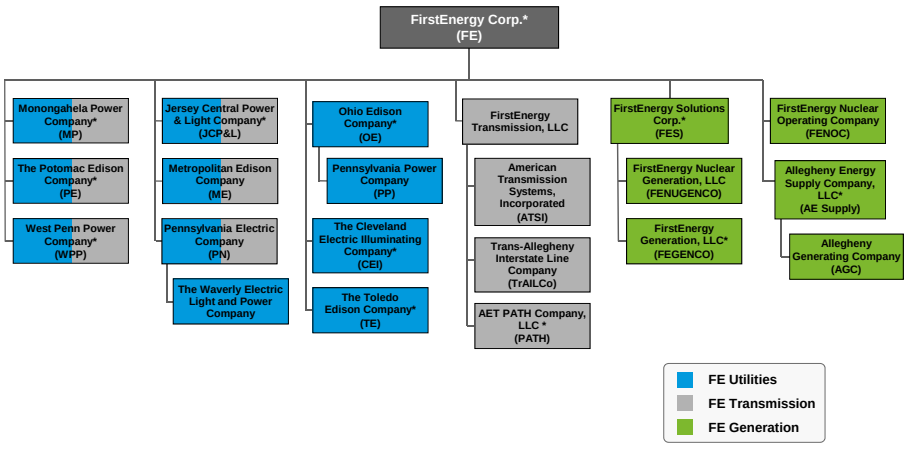


Irene M. Prezelj
Vice President, Investor Relations



John W. Judge
Vice President, Corporate Risk and Chief Risk Officer

Summary Organizational Structure



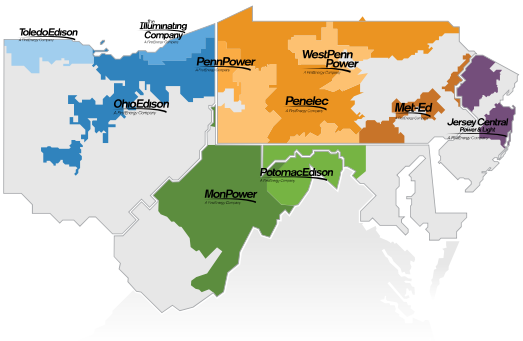
*Entity has subsidiaries that are not shown

FirstEnergy Corp. Segment Descriptions

Segment	
Regulated Distribution	Comprised of ten distribution companies serving ~6M customers in Ohio, Pennsylvania, New Jersey, West Virginia, Maryland and New York, making this one of the largest contiguous service territories in the U.S. Our regulated generation portfolio consists of 3,790 MW and serves primarily West Virginia. Net plant in-service as of 12/31/2013 was approximately $16.6B.
Regulated Transmission	The FirstEnergy transmission system spans a 65,000 square mile service territory and is the largest transmission system in PJM with over 24,000 transmission miles. The lines are owned by the distribution companies or FE's transmission companies, ATSI and TrAILCo. ATSI consists of the transmission systems formerly owned by OE, PP, CEI, and TE along with additions constructed by ATSI. TrAILCo consists of TrAIL, a 500-kV transmission line, and other transmission facilities constructed in the service areas of WPP, MP, PE, JCP&L, ME and PN. Net plant in-service as of 12/31/2013 was approximately $4.1B.
Competitive Energy Services (CES)	FES and AE Supply primarily comprise the Competitive Energy Services segment, which serves customers in the POLR, Governmental Aggregation, and selected large commercial-industrial sales channels. FirstEnergy's competitive generating portfolio consists of more than 13,000 MW* of diversified capacity. The segment is long generation vs. sales.
Corporate / Other	Corporate/Other primarily consists of interest on stand-alone holding company debt, non-core business related activity and corporate income taxes.

* Excludes RMR units and units scheduled to be deactivated by April 2015 (see slide 121)

Regulated **Distribution**



State	2013 Customers (in thousands)	2013 Distribution Sales (MWH in thousands)
Ohio	2,087	53,492
Pennsylvania	2,023	52,224
New Jersey	1,098	20,893
West Virginia	525	14,292
Maryland	256	6,987
New York	4	–
Total	**5,993**	**147,888**

As of December 31, 2013

Regulatory **Strategy**

State	Company	Regulatory Activity
New Jersey	JCP&L	• Filed distribution rate case November 30, 2012 • JCP&L distribution rate case resolution expected 2015Q1 • Generic Storm Proceeding stipulation approved March 19, 2014 • Generic Consolidated Tax Adjustment Proceeding order issued October 22, 2014
West Virginia	MP	• MP/PE Rate Case filed April 30, 2014; Amended filing made on June 13, 2014 • Rate Case settlement filed with the PSC on Nov 3, 2014; Hearing to be held Nov 7, 2014 • Settlement includes $15M increase in base rates and veg management surcharge of $48M • February 25, 2015: effective date of new base rates and veg management surcharge • August 29, 2014: ENEC case filed requesting $65.8M increase based on fuel and purchased power costs. Base rate case settlement delays rate change until February, 25, 2015.
	PE – WV	
Pennsylvania	PP	• Rate Case filings made for all four companies on August 4, 2014. Expected decision by May 2015. • Default Service Plan settlement for June 2015-May 2017 approved by PAPUC
	ME	
	PN	
	WPP	
Ohio	OE	• Base distribution rate freeze through May 2016 per ESP 3 • ESP IV (Powering Ohio's Progress) filed August 4, 2014. Requested decision by April 2015. • Alternative Energy Rider refund ruling appealed to the Supreme Court of Ohio in December 2013 • PUCO ruled no significantly excessive earnings in 2013
	CEI	
	TE	
Maryland	PE – MD	• No rate cases currently planned • Continue to monitor potential for Smart Meter and Incremental Investment Riders

Rate Base and Allowed ROEs

State	Company	Rates Effective	Rate Base ($M)	Allowed Debt /Equity	Allowed ROE
Ohio	OE	January 2009	$ 1,251	Debt 51.0% / Equity 49.0%	10.50%
	CEI	May 2009	$ 984	Debt 51.0% / Equity 49.0%	10.50%
	TE	January 2009	$ 414	Debt 51.0% / Equity 49.0%	10.50%
Pennsylvania	PP	May 1988	$ 654	Debt 62.6% / Equity 37.4%	12.90%
	ME	January 2007	$ 969	Debt 51.0% / Equity 49.0%	10.10%
	PN	January 2007	$ 1,068	Debt 51.0% / Equity 49.0%	10.10%
	WPP	December 1994	$ 1,830	Debt 54.5% / Equity 45.5%	11.50%
New Jersey	JCP&L	June 2005	$ 2,080	Debt 54.0% / Equity 46.0%	9.75%
West Virginia	PE – WV	May 2007	$ 1,184	Debt 54.0% / Equity 46.0%	10.50%
	MP	May 2007	$ 1,184	Debt 54.0% / Equity 46.0%	10.50%
Maryland	PE – MD	February 1993	$ 581	Debt 56.0% / Equity 44.0%	11.90%

As of the most recent fully litigated rate case approved by respective state commissions. Rate base can include distribution, transmission and generation assets but actual required revenues are adjusted to reflect current rate structure.

Note: Rate base of $1,184 is a combined value for PE-WV and MP

Summary of Rate Proceeding Requirements

	Ohio	Pennsylvania	New Jersey	West Virginia	Maryland
General					
Time Limitations Between Cases	No	No	No	No	No
Fuel Clause Renewal Frequency	N/A	N/A	N/A	Annually	N/A
Notice of Intent					
Prior Notice Required	Yes	Yes	No	Yes	Yes
Notice Period (Days)	30	30	N/A	30	30
Case Components					
Base Case Test Year	Hybrid (Historic/ Forecast)	12 Month Historic 12 Month Forecast 12 Month Fully Projected Future Test Year	Hybrid (Historic/ Forecast)	Historic	Hybrid (Historic/ Forecast)
Other					
Requested (but not approved) Rates Effective Subject to Refund	Yes*	Yes	Yes	No	Yes
Approximate number of months after filing to implement rates subject to refund	9 months	9 months	1-9 months	N/A	1-8 months
Default Service					
Term	ESP 3 through May 2016	Current DSP through May 2015**	Evergreen	N/A	Standard Offer Service (SOS)–Periodic Filing

* This provision is subject to other requirements including the filing of a bond or letter of credit
** DSP for June 2015-May 2017 delivery period approved on July 24, 2014

Summary of Recovery Mechanisms

Company	Purchased Power[1]/Fuel Rider	Storm Cost Recovery[2]	Incremental Capital Recovery	Energy Efficiency	Smart Meter / Smart Grid[7]	Alternative Energy[4,8]
OE	Annually	Base Rates	Quarterly	Semi Annually	Quarterly[3]	Quarterly
CEI	Annually	Base Rates	Quarterly	Semi Annually	Quarterly[3]	Quarterly
TE	Annually	Base Rates	Quarterly	Semi Annually	Quarterly[3]	Quarterly
PP	Quarterly	Base Rates	No	Annually	Annually	Annually
ME	Quarterly	Base Rates	No	Annually	Annually	Annually
PN	Quarterly	Base Rates	No	Annually	Annually	Annually
WPP	Quarterly	Base Rates	No	Annually	Annually	No-Supplier Obligation[5]
JCP&L	Annually	Base Rates	No	Annually	No	Annually
PE – WV	Annually	Base Rates	No	Annually	No	Yes
MP	Annually	Base Rates	No	Annually	No	Yes
PE – MD	Various[6]	Base Rates	No	Annually	No	No-Supplier Obligation

Notes:

1. Purchased Power is associated with competitive solicitations in all states except West Virginia. Ohio changes annually, reconciled quarterly.
2. Storm Costs that exceed baseline amounts are authorized to be deferred in New Jersey and Ohio. In other states, the company may seek deferral of costs.
3. Smart Meter in Ohio is currently a pilot program with a limited number of meters and equipment; 50% of funding from DOE.
4. Pennsylvania only recovers Solar Renewable Energy Credits. The non-solar obligation remains with the supplier. In Ohio, both solar and non-solar renewable energy credits are recovered. West Virginia requirement begins in 2015.
5. Less existing long-term Tier I Alternative Energy Credits that are recoverable through the Price To Compare.
6. Residential is updated twice a year. Commercial and Small Industrial change quarterly. Large industrial customers have Hourly Pricing Service.
7. Costs in New Jersey and Ohio for the Smart Grid Initiative are recovered through riders; 50% of funding from DOE.
8. New Jersey RPS requirements are the responsibility of the BGS suppliers.

Net Regulatory Asset Amortization (Deferral)

($ Millions)

State	2012A[2]	2013A[3]	2014F
Ohio	$131	$122	$65
Pennsylvania	$133	$362	($25)
New Jersey	($323)	$44	$30
West Virginia / Maryland[1]	($9)	$11	($75)
Total	**($68)**	**$539**	**($5)**

[1] Includes TrAILCo and PATH

[2] Includes $375M of deferred storm costs

[3] Includes $254M of regulatory asset impairment associated with deferred marginal transmission losses at ME and PN, and $51M of regulatory charges resulting from the PUCO's disallowance of renewable energy credit purchases at OE, CEI, TE which are included as regulatory charges on slide 155

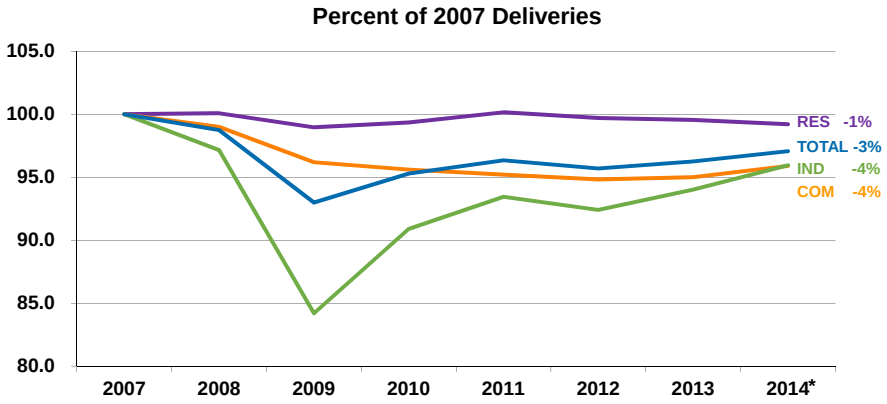
Renewable Energy Requirements

	OH	PA	NJ	WV	MD
Year	2026**	2021	2021	2025	2022
Requirements	12.5%	18.5%	23.85%	25%	20%
Class/Tier I – Non Solar	12.0%	8.0%	17.88%	–	18%
Solar	0.5%	0.5%	3.47%	–	2%
Class/Tier II	–	10.0%	2.5%	–	2.5% until 2018
Default Service RPS Obligations Fulfilled By	▪ 100% Company	▪ Company 100% solar for ME, PN & PP / Suppliers Tier I, Tier II & WPP solar	▪ Suppliers	▪ N/A – Fully Regulated	▪ Suppliers 100% residential & commercial / Company 100% industrial
Procurement Method / Market Incentive (NJ)	▪ RFP & limited spot	▪ RFP	▪ Financing Program / Auction sales to Suppliers	▪ Owned & PURPA generation	▪ Spot
Solar	▪ Solar PV and Solar Thermal	▪ Solar PV and Solar Thermal	▪ Solar PV and Solar Thermal	▪ Solar PV and Solar Thermal	▪ Solar PV, Solar Thermal & Solar Water Heating
Class/Tier I/ Renewable Energy Resources	▪ Solar ▪ Wind ▪ Hydro ▪ Geothermal ▪ Solid waste * ▪ Biomass ▪ Fuel cells ▪ Storage * ▪ Distributed generation* ▪ Certain advanced energy resources*	▪ Solar Photovoltaic ▪ Solar Thermal ▪ Wind ▪ Low-impact hydro ▪ Geothermal ▪ Biomass ▪ Methane gas* ▪ Coal-mine methane ▪ Fuel cells ▪ Wood byproducts* ▪ Large-scale hydro*	▪ Solar ▪ Wind ▪ Fuel Cells powered by Renewable fuels ▪ Wave / Tidal ▪ Geothermal technologies ▪ Methane Landfill gas ▪ Anaerobic Digestion ▪ Biomass (sustainable) ▪ In State hydro ≤3 with in service date >7/23/12	▪ Solar ▪ Wind ▪ Natural, Synthetic and Landfill Gas ▪ Hydroelectric ▪ Geothermal ▪ Fuel Cells ▪ Municipal Solid Waste ▪ Anaerobic Digestion ▪ Small Hydro ▪ Biodiesel ▪ Certain Advanced Coal Generation	▪ Solar ▪ Wind including Off-Shore* ▪ Biomass ▪ Landfill Gas ▪ Small Hydro ▪ Geothermal Electric ▪ Fuel Cells* ▪ Municipal Solid Waste ▪ Ocean ▪ Poultry litter incineration* ▪ Refuse derived
Class/Tier II Advanced/Alternative Energy Resources	▪ N/A	▪ Waste coal ▪ Distributed generation ▪ DSM ▪ Large hydro ▪ Muni solid waste ▪ Wood byproducts * ▪ IGCC coal ▪ Pumped-storage hydro	▪ Small hydro >3 and <30 ▪ Resource recovery	▪ N/A	▪ Hydro (excluding pumped storage) ▪ Waste-to energy ▪ Poultry litter incineration*
Renewable Energy Credit (REC) Life	5 years	3 years	Solar 5 Years, Class I 3 years & Class II 1 year	Unlimited	3 years
Other Provisions	Panel to review the RPS legislation	Quarterly Adjustments to Tier I Non-Solar %	Solar must be in-state	In-state or PJM territory	Solar must be in-state

*Additional restrictions and provisions apply

**Changes under SB310 extended RPS requirements from 2024 to 2026 due to freezing requirements barring outcome of panel review of legislation

Regulated Distribution Sales Trends

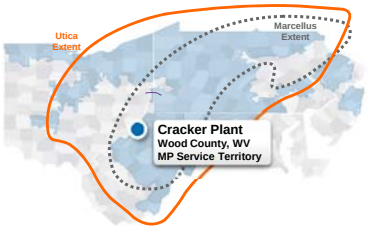


Distribution sales have not fully recovered from 2007 levels, but show improvement since 2011

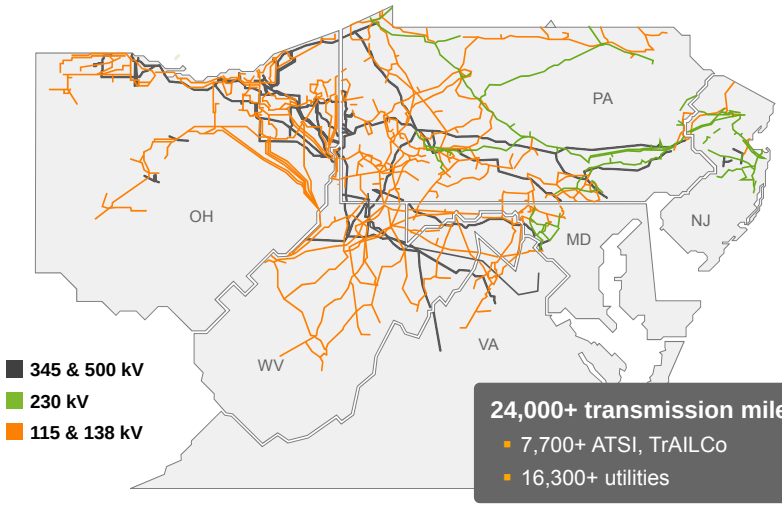
Assumes normal weather
* Reflects 9 months of actual and 3 months of forecast

Leveraging Industrial and Technological Developments in our Region

- **FE utility service territory overlays Marcellus and Utica shale region**
- **Although shale is in early stages of development, there are signs of load growth**
  - ~400 MW (Operational 2013 – 2014)
    - ~2.5M – 3.0M MWH of annual load growth
  - ~1,100 MW (2015 – 2019)
    - ~6.5 – 7.5M MWH of additional load growth
- **Shale development also creating other opportunities**
  - Steel and tubing companies benefit from large upstream infrastructure build
  - Midstream companies of substantial size being connected
  - Cracker plants that convert ethane and natural gas are being considered
  - Related supply chains being established



FirstEnergy Transmission – Overview



24,000+ transmission miles*
- 7,700+ ATSI, TrAILCo
- 16,300+ utilities

*Includes lines 23kV and above.

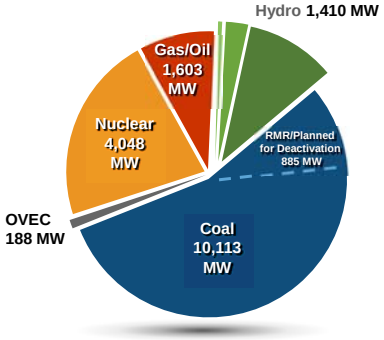
FirstEnergy Generation Portfolio

Nuclear	MW
Beaver Valley 1& 2	1,872
Perry	1,268
Davis-Besse	908
Total	**4,048**

Supercritical Coal	
Mansfield 1-3	2,490
Harrison 1-3 (R)	1,984
Pleasants 1-2	1,300
Sammis 6 & 7	1,200
Fort Martin 1 & 2 (R)	1,098
Total Supercritical Coal	**8,072**

Subcritical Coal	
Sammis 1-5	1,020
Eastlake 1-3 ⬣	396
Bay Shore 1	136
Lake Shore 18 ⬣	245
Ashtabula 5 ⬣	244
Subcritical Coal	**2,041**
OVEC (PR)	188
Regulated: 11 Competitive:177	
Total Subcritical Coal	**2,229**

Renewables 1,906 MW
Solar 20 MW
Wind 476 MW
Hydro 1,410 MW



Total Capacity	**17,858 MW**	
Competitive	**14,068 MW**	**(79%)**
Regulated	**3,790 MW**	**(21%)**

(R) Fully Regulated or (PR) Partially Regulated units
Long-term PPA
⬣ RMR Arrangements or Units scheduled to be deactivated by April 2015 (see slide 121)

Gas/Oil	MW
Springdale 1-5	638
West Lorain 1-6	545
Chambersburg 12 & 13	88
Gans 8 & 9	88
Forked River	86
Hunlock	45
Buchanan	43
Other	70
Total Gas/Oil	**1,603**

Hydro	
Bath County (PR)	1,200
Regulated: 487 Competitive: 713	
Yards Creek (R)	210
Total Hydro	**1,410**

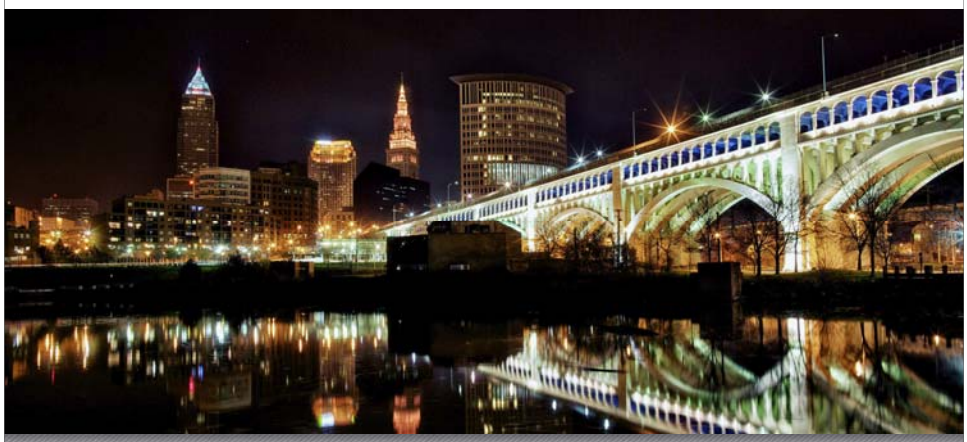
Wind	
Blue Creek	100
High Trail	99
Allegheny Ridge	80
N. Allegheny Ridge	70
Highland	62
Casselman	35
Meyersdale	30
Total Wind	**476**

Solar	
Maryland Solar	20
Total Solar	**20**

Coal Combustion By-Product Impoundments

- **FE operates coal combustion byproduct (CCB) impoundments and wastewater ponds in accordance with Federal, State, and Local regulatory requirements**
  - Requirements address design, construction, material placement, structural inspections, environmental monitoring, and final closure of facilities
- **Majority of FE CCBs are handled as dry material**
  - Typically sites consist of geotextile liners and or clay soil
  - Leachate and/or runoff is collected and treated
  - Wet CCB impoundments exist at Pleasants and Mansfield - Little Blue Run (LBR)
- **FE periodically removes CCB material from active wastewater ponds for placement in dry landfills**
  - All inactive CCB wastewater treatment ponds at retired plants have been stabilized and will be closed in accordance with state regulation
- **Closure permit issued by PA Department of Environmental Protection for LBR**
  - Site will stop receiving CCBs on December 31, 2016, and begin closure over a 12-year-period
  - A 30-year period of post closure monitoring will follow
  - Bonded closure cost is ~$170M
- **Pleasants is estimated to reach full capacity no sooner than 2021**
  - Closure plan expected to be developed and submitted to WV Department of Environmental Protection within 1-2 years of closure

Ohio Operations



Ohio – Customer Data

2013 Total Customers (thousands)	
Ohio Edison	1,034
The Illuminating Company (CEI)	745
Toledo Edison	308
Total	2,087

Typical Bill Comparison*	
Ohio	$/Month
Ohio Edison	$122.33
The Illuminating Company (CEI)	$118.21
Toledo Edison	$121.20
Statewide Avg. Bill	$126.75

* Typical bills are displayed on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2014. Ohio rates represent POLR bundled residential rates.



Major Metropolitan Areas	Population (thousands)
Cuyahoga County (Cleveland)	1,278
Summit County (Akron)	542
Lucas County (Toledo)	442
Mahoning/Trumbull Counties (Youngstown)	449
Total State of Ohio	11,545

Source: U.S. Census Bureau (2010)

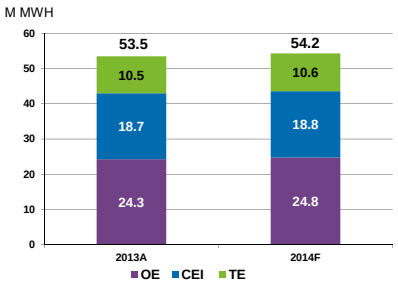
Principal Industries Served**
Primary Fabricated Metals
Automotive
Chemical
Plastic and Rubber
Petroleum

** Based on kWh sales

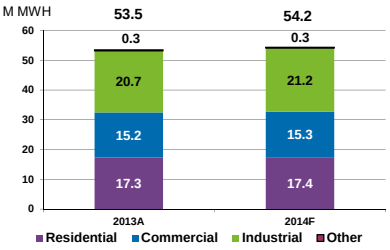
Ohio – **Distribution Sales**

State Unemployment Rates				
	2007	2011	2012	2013
OH	5.6%	8.7%	7.4%	7.3%

Source: Moody's Analytics



Note: Forecasted sales assume normal weather.
Includes forecast for state energy efficiency mandates.
(State mandate 4.2%. Approximately 2.3M MWH)



Gross Domestic Product Annualized Growth (Seasonally Adjusted Annualized Rate)				
	2007	2011	2012	2013
OH	0.3%	2.9%	2.2%	1.3%

Source: Moody's Analytics

Gross Domestic Product, in 2005 dollars ($ billions)				
	2007	2011	2012	2013
OH	$441	$426	$435	$441

Source: Moody's Analytics

Ohio – **Political Landscape**

Governor

Governor	Current Term
John Kasich (R)	Expires in 2015

Public Utilities Commission of Ohio (PUCO)

Commissioners	Current Term
Thomas W. Johnson, Chairman (R)	Expires in 2019
Asim Z. Haque, Vice Chairman (I)	Expires in 2016
Steven D. Lesser (D)	Expires in 2015
Lynn Slaby (R)	Expires in 2017
M. Beth Trombold (I)	Expires in 2018

Ohio – **Regulatory Update**

Ohio ESP 3

- **Approved by the PUCO on July 18, 2012**
- **Plan covers June 1, 2014, thru May 31, 2016**
- **Stabilizes pricing by modifying the previous POLR competitive bidding schedule**
- **Freezes base distribution rates through May 31, 2016**
- **Continues Delivery Capital Recovery rider to earn a return on and of incremental distribution plant in service since last rate case**
  - Up to $405M in revenue for period covered by ESP 3
- **Continues collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs**
- **Extends recovery period for RECs costs (with carrying charges) – reducing current monthly charges for non-shopping customers by more than 50%**
- **Provides PIPP customers with 6% discount off their price-to-compare with wholesale generation supply provided by FE Solutions**

Ohio – **Regulatory Update**

Ohio ESP 3 – Delivery Capital Recovery Rider

Recovery Period	Revenue Cap ($ Millions)
Jan 2012 – Dec 2012	$150
Jan 2013 – Dec 2013	$165
Jan 2014 – May 2014	$75
Jun 2014 – May 2015	$195
Jun 2015 – May 2016	$210

- **Individual company revenue caps are determined by the following percentages applied to the total revenue cap**
  - **CEI:** up to 70%
  - **OE:** up to 50%
  - **TE:** up to 30%
- **Any recovery period shortfall or overage will be applied to the subsequent period**

Ohio – **Regulatory Update**

Ohio ESP IV – Powering Ohio's Progress*
Continues to build upon the success of current and prior ESPs

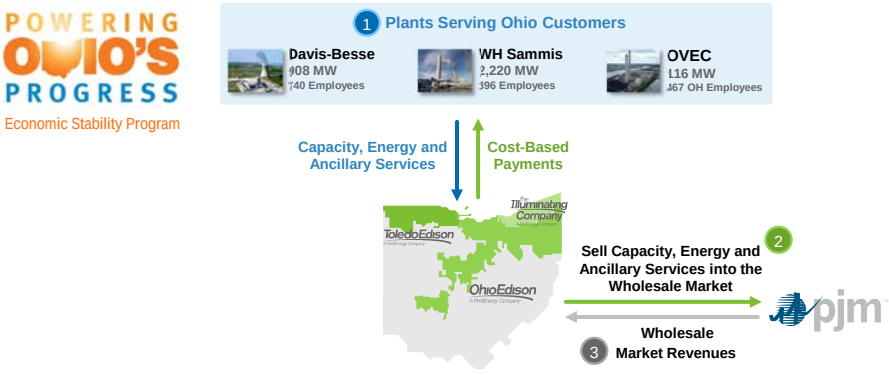
POWERING OHIO'S PROGRESS

- **Filed: August 4, 2014**
- **Term: June 1, 2016 – May 31, 2019**
- **As proposed:**
  - Continues successful competitive bid process for POLR load
  - Freezes base distribution rates through May 31, 2019
  - Continues Delivery Capital Recovery rider with revenue increase caps proposed at $30M per year
  - Continues collection of lost distribution revenue associated with energy efficiency and peak demand reduction programs
  - Includes Economic Stability Program

* Subject to regulatory approval

Ohio – **Regulatory Update**

POWERING OHIO'S PROGRESS
Economic Stability Program



1
- FE's Ohio utilities enter into a 15-year purchased power contract with FES
- Purchase power from Davis-Besse, Sammis and a portion of OVEC
- Utilities pay FES a cost-based rate for power

2
- Utilities sell power into wholesale market

3
- When wholesale market revenues exceed cost, customers receive credit
- When wholesale market revenues are less than cost, customers pay charge
- Cost-based arrangement protects all customers from retail price volatility

- Customers projected to save $2B over 15 years

Note:
- Non-shopping customers continue to receive generation from competitive auction process
- All customers retain option to shop for a competitive retail electric supplier

Ohio – Regulatory Update

- **Amended Energy Efficiency Filing**
  - Ohio Companies filed September 24, 2014, to amend their energy efficiency plan to reduce customers' costs while aligning with the state's recent action to freeze energy efficiency mandates for 2015-2016
  - Ohio Senate Bill 310 provides the opportunity to lower customers' costs while continuing to meet the state's energy efficiency requirements for 2015 and 2016
  - Certain large industrial customers will have the ability to opt out of utility-sponsored programs and implement their own energy efficiency initiatives
- **Alternative Energy Rider Case**
  - PUCO issued an Opinion and Order on August 7, 2013, disallowing $43.4M plus carrying costs in Renewable Energy Credit purchases
  - The Ohio Companies and Intervenors filed Applications for Rehearing on September 6, 2013
  - The PUCO granted the Applications for Rehearing for further consideration on September 18, 2013
  - A Second Entry on Rehearing from the PUCO was issued on December 18, 2013, denying the Application for Rehearing filed by the Ohio Companies and Intervenors
  - The Ohio Companies filed an appeal and motion to stay with the Supreme Court of Ohio on December 24, 2013. The stay was granted on February 10, 2014, and went into effect February 14, 2014.

Ohio – **Energy Efficiency**

Mandates and Progress

	Ohio
State Goals	Senate Bill 221*
Energy Efficiency	4.2% in 2014 (2,269 GWH) 4.2% in 2015 (2,266 GWH)* 4.2% in 2016 (2,288 GWH)*
Demand Response	4.75% in 2014 (566 MW) 4.75% in 2015 (552 MW)* 4.75% in 2016 (544 MW)*
Smart Meter	No state smart meter requirement

*Senate Bill 310, which became effective September 12, 2014, provides an alternative mandate structure by freezing the 2015 and 2016 energy efficiency and demand response requirements at 2014 levels (4.2% EE, 4.75% DR). FE Ohio utilities filed an Amended Energy Efficiency and Peak Reduction plan on September 24, 2014 in line with these updated targets. The PUCO has 60 days to consider the amended plan.

Status	
Smart Meter	PUCO approved Phase II pilot DR expansion for total up to 44,000 meters. Opt-in DR Pricing program available to most pilot customers in 2014.
Cost Recovery for Energy Efficiency	In place; semi-annual energy efficiency rider
Compliance	▪ 2013 EE & DR targets met ▪ On track to achieve 2014 EE & DR targets

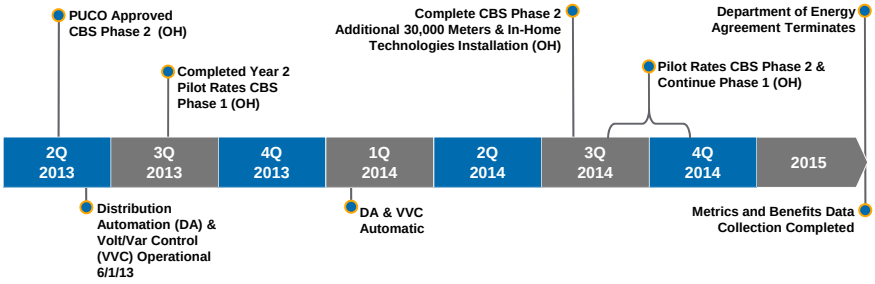
Smart Grid	
Cross-cutting** Technologies/Programs	CEI ($67M)
Distribution Automation	$27
Volt / VAR Control	$10
Consumer Behavior Study	$30

- **Period of performance = 60 months (June 2, 2010 – June 1, 2015)**
- **Implementation of all programs during 2014**
- **All just and reasonable costs are fully reimbursable via federal grant and state approved riders (subject to audit)**

**Cross-cutting describes a project that includes communications and control systems that support more than one component of the smart grid

Ohio – **Smart Grid Modernization Initiative Update**

- **Project Status: 93% Complete**
- **Remaining Work**
  - Consumer Behavior Study (CBS) Phase 2
  - Metrics & Benefits Reporting
- **$60M of $67M spent through 3Q 2014**



Ohio – **Procurement Schedule**

Ohio Edison, The Illuminating Company (CEI) and Toledo Edison

ESP 3		Delivery Period		
Auction	Tranches Bid*	June 2013 – May 2014	June 2014 – May 2015	June 2015 – May 2016
Oct-12	17	36 Months $60.90 / MWH		
Jan-13	17	36 Months $59.17 / MWH		
Oct-13	16		12 Months $50.91 / MWH	
	17		24 Months $59.99 / MWH	
Jan-14	16		12 Months $55.83 / MWH	
	17		24 Months $68.31 / MWH	
Oct-14	16			12 Months $73.82 / MWH
Jan-15	16			12 Months

*Each tranche represents 1% of the actual hourly energy and daily capacity required to serve SSO load; tranches are full-requirements products

Ohio – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
Ohio Edison	First Mortgage Bond	677347CG9	8.25%	10/15/2018	$25,000,000
	Senior Note	677347CE4	6.875%	7/15/2036	$350,000,000
	First Mortgage Bond	677347CF1	8.25%	10/15/2038	$275,000,000
				OE Total	**$650,000,000**
Ohio Edison Funding LLC	Phase-In Recovery Bond	33766QAA5	0.679%	1/15/2017*	$8,025,370
	Phase-In Recovery Bond	33766QAB3	1.726%	1/15/2020*	$10,202,000
	Phase-In Recovery Bond	33766QAC1	3.450%	1/15/2034*	$123,612,000
				OE Funding LLC Total	**$141,839,370**
The Illuminating Company (CEI)	Senior Note	186108CF1	5.7%	4/1/2017	$130,000,000
	Secured Note	186108BU9	7.88%	11/1/2017	$300,000,000
	First Mortgage Bond	186108CH7	8.875%	11/15/2018	$300,000,000
	First Mortgage Bond	186108CJ3	5.5%	8/15/2024	$300,000,000
	Senior Note	186108CE4	5.95%	12/15/2036	$300,000,000
				CEI Total	**$1,330,000,000**

* Expected Final Maturity Date

Ohio – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
CEI Funding LLC	Phase-In Recovery Bond	33766QAA5	0.679%	1/15/2017*	$42,387,863
	Phase-In Recovery Bond	33766QAB3	1.726%	1/15/2020*	$56,383,000
	Phase-In Recovery Bond	33766QAC1	3.450%	1/15/2034*	$103,160,000
				CEI Funding LLC Total	**$201,930,863**
Toledo Edison	Senior Secured Notes	889175BE4	7.25%	5/1/2020	$50,000,000
	Senior Secured Notes	889175BD6	6.15%	5/15/2037	$300,000,000
				TE Total	**$350,000,000**
Toledo Edison Funding LLC	Phase-In Recovery Bond	33766QAA5	0.679%	1/15/2017*	$2,796,264
	Phase-In Recovery Bond	33766QAB3	1.726%	1/15/2020*	$3,883,000
	Phase-In Recovery Bond	33766QAC1	3.450%	1/15/2034*	$35,711,000
				TE Funding LLC Total	**$42,390,264**

* Expected Final Maturity Date

Pennsylvania Operations



Pennsylvania – **Customer Data**

2013 Total Customers (thousands)	
Penelec (Includes NY – 4)	590
Met-Ed	556
Penn Power	161
West Penn Power	720
Total	2,027

Typical Bill Comparison*	
Pennsylvania	$/Month
Penelec	$118.82
Met-Ed	$125.81
Penn Power	$95.89
West Penn Power	$83.99
Statewide Avg. Bill	$126.29

* Typical bills are based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2014. Pennsylvania rates represent Default Service Provider bundled residential rates.



Major Metropolitan Areas	Population (thousands)
York County (York)	436
Berks County (Reading)	412
Westmoreland County (Greensburg)	365
Erie County (Erie)	281
Total State of Pennsylvania	12,710

Source: U.S. Census Bureau (2010)

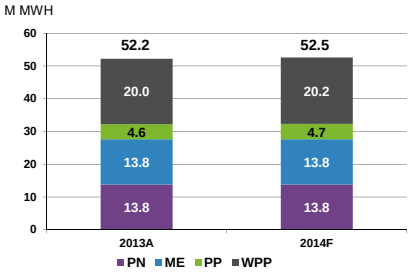
Principal Industries Served**
Primary and Fabricated Metals
Coal Mining
Chemical
Plastic and Rubber
Non-Metallic Minerals

** Based on kWh sales

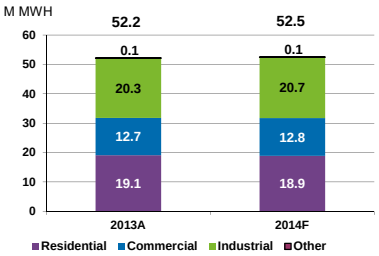
Pennsylvania – **Distribution Sales**

State Unemployment Rates (%)				
	2007	2011	2012	2013
PA	4.4%	8.0%	7.9%	7.4%

Source: Moody's Analytics



Note: Forecasted sales assume normal weather.
Includes forecast for state energy efficiency mandates
(State Mandate 3.0% by 5/31/13, ~1.6M MWH. Incrementally ~1.1M MWH by 5/31/16 ~1.1M)



Gross Domestic Product Annualized Growth (Seasonally Adjusted Annualized Rate)				
	2007	2011	2012	2013
PA	1.8%	1.9%	1.7%	1.2%

Source: Moody's Analytics

Gross Domestic Product, in 2005 dollars ($ billions)				
	2007	2011	2012	2013
PA	$497	$503	$511	$518

Source: Moody's Analytics

Pennsylvania – **Political Landscape**

Governor

Governor	Current Term
Tom Corbett (R)	Expires in 2015

Pennsylvania Public Utility Commission (PAPUC)

Commissioners	Current Term
Robert F. Powelson, Chairman (R)	Expires in 2019
John F. Coleman, Jr., Vice Chairman (R)	Expires in 2017
James H. Cawley (D)	Expires in 2015
Pamela A. Witmer (R)	Expires in 2016
Gladys M. Brown (D)	Expires in 2018

Pennsylvania – **Energy Efficiency**

	Pennsylvania
State Goals	**PA Act 129**
Energy Efficiency	**By 5/31/2016 (1,090 GWH) – Phase II of Act 129** – ME +2.3% (338 GWH) – PN +2.2% (319 GWH) – PP +2.0% (96 GWH) – WPP +1.6% (338 GWH)
Demand Response	**No peak demand reduction targets in Phase II, 6/2013 through 5/2016**
Smart Meter	**Smart Meter full deployment** ▪ **Mandatory deployment within 15 year depreciation cycle**
Status	
Smart Meter	**Commission approval received June 5, 2014, on the Revised Smart Meter Deployment Plan** **Deployment began in July 2014 of 170,000 smart meters in PP by the end of 2015 and nearly all PA FE customers by mid-2019.**
Cost Recovery for Energy Efficiency	**In place; annual energy efficiency rider**
Compliance	**On track to achieve 2016 EE targets**

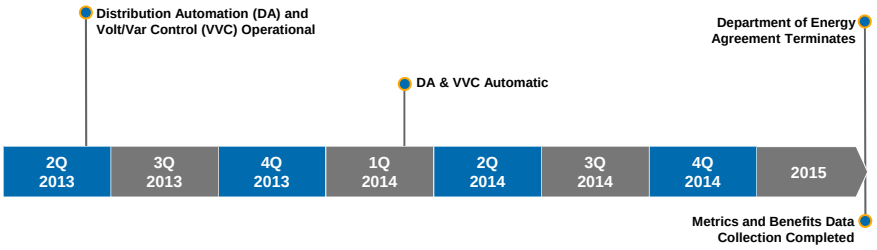
Smart Grid	
Cross-cutting* Technologies/ Programs	**ME ($33M)**
Distribution Automation	**$9**
Volt / VAR Control	**$5**
Integrated Distributed Energy Resource Direct Load Control	**$19**

- **Period of performance = 60 months (June 2, 2010 – June 1, 2015)**
- **Implementation of all programs during 2014**
- **All just and reasonable costs are fully reimbursable via federal grant and state approved riders (subject to audit)**

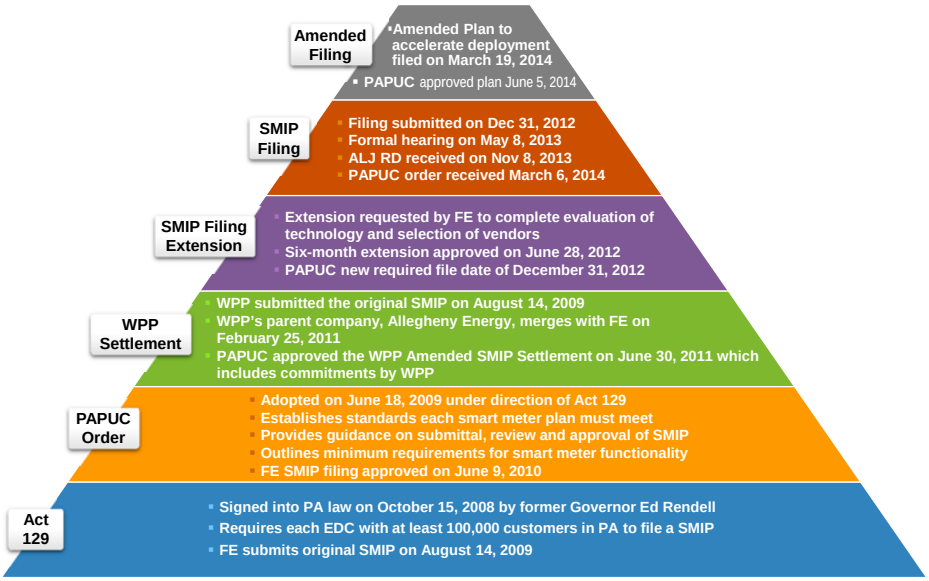
*Cross-cutting describes a project that includes communications and control systems that support more than one component of the smart grid

Pennsylvania – **Smart Grid Modernization Initiative Update**

- **Project Status: 98% Complete**
- **Remaining Work**
  - Metrics & Benefits Reporting
- **$32M of $33M spent through 3Q 2014**



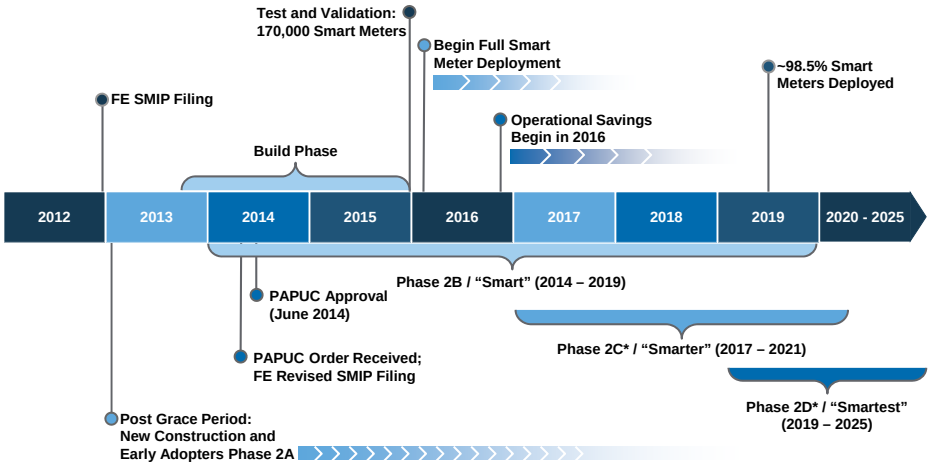
Pennsylvania – **Smart Meter Update**



Pennsylvania – **Smart Meter Update**

- **Commission Approval Received on June 5, 2014**
  - Order approves the Revised Smart Meter Deployment Plan
  - Deployment began in July 2014
- **Revised Deployment Plan Timeframe**
  - 2014 - 2015: PP rolls out test program using 170,000 meters
  - 2016 - 2019: Four-year deployment schedule to install approximately two million meters in remaining Pennsylvania Operating Companies
    - Full-scale deployment expected to begin with most densely populated areas deployed first
- **Financial Impacts**
  - 20-Year Cost: $1.26B
    - Deployment cost Included in Total Cost: $815M
  - Estimated Operational Savings: $417M
    - Meter Reading: $383M
    - Meter Services: $13M
    - Contact Center: $2M
    - Back Office: $19M
- **Cost Recovery Mechanism: Smart Meter Technologies Charge**
  - The calculation of cost savings achieved from the deployment of smart meters will be addressed as part of the PA base rate cases

Pennsylvania – **Smart Meter Update**



*Smarter and Smartest Phases are not included in the Business Case

Pennsylvania – **Regulatory Update**

	Rate Case Summary			
	Met-Ed	Penelec	Penn Power	West Penn Power
Case Docket #	R-2014-2428745	R-2014-2428743	R-2014-2428744	R-2014-2428742
Capital Structure	50.00% Debt, 50.00% Equity 5.21% Cost of Debt	50.10% Debt, 49.90% Equity 5.72% Cost of Debt	49.90% Debt, 50.10% Equity 6.12% Cost of Debt	49.90% Debt, 50.10% Equity 5.38% Cost of Debt
Requested ROE	10.90%	10.90%	10.90%	10.90%
Proposed Overall Return	8.05%	8.31%	8.51%	8.14%
Percentage Change Over Revenues At Existing Rates[1]	11.5%	8.6%	8.7%	8.4%
($ Thousands)				
Distribution Base Rates	$149,328	$116,499	$25,379	$66,825
USC Rider	–	–	–	29,565
DSS and HPS Riders	(716)	(524)	(1,074)	7,351
Smart Meter	3,315	3,817	4,178	11,794
Total Revenue Increase	$151,927	$119,792	$28,483	$115,535

[1]The percentage was calculated based on total estimated revenue for the fully projected future test year consisting of distribution revenue as well as generation service revenue, with the latter reflecting generation rates equivalent to the Companies' prices for applicable default service.

Supporting documents filed by ME, PN, PP, and WPP are available at www.puc.state.pa.us

Proposed / Updated Riders

- **Storm Rider – a charge or credit on customers' bills to reflect the difference between storm related expenses in base rates and actual storm related expenses**
  - Eliminates risk by providing for timely recovery of actual storm costs
  - Rate filed annually on December 1
  - Calculated separately for each rate class
  - Similar to Storm Rider recently approved for PPL Electric Utilities Corporation
- **WPP Universal Service Rider – makes the WPP's Universal Service cost recovery consistent with ME, PN, and PP**
  - Enable WPP to increase expenditures and enhance existing programs in response to changes in economic conditions
  - Rate filed annually on December 1
  - Charged to residential customers only
- **Default Service Support (DSS)/Hourly Pricing Service (HPS) rider changes – Uncollectibles normalized**
  - Update WPP DSS rider to include default service and purchase of receivable-related uncollectible expense
  - Collect industrial default service related uncollectibles through the HPS rider
- **Time-of-Use**
  - Elimination of time-of-use distribution rates (Rate Schedule Residential Time of Day) for ME and PN
  - Creation of Time-of-Use Riders for Residential Price-to-Compare charge for ME and PN

Pennsylvania – Regulatory Update

- **Met-Ed, Penelec, Penn Power and West Penn Power Default Service Programs for June 2015 – May 2017**
  - Default Service Programs filed on November 3, 2013
  - A settlement was reached with all intervening parties on all but one issue
  - Settlement Documents and Initial Briefs filed March 27, 2014, and Reply Briefs filed April 10, 2014
  - ALJ RD was issued May 7, 2014
  - PAPUC approved settlement July 24, 2014
  - Changes and new rates for Price to Compare Default Service Riders and Default Service Support Riders become effective on June 1, 2015

Pennsylvania – **Procurement Schedule**

ME Default Service Supply Plan • June 1, 2013 to May 31, 2015

Residential Full Requirements Tranche Procurement Schedule*

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Jan-13	12	24 months - $67.71 / MWH							
Feb-13	12	12 months - $71.34 / MWH							
Jan-14	12					12 months - $63.24 / MWH			

Commercial Full Requirements Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Jan-13	11	6 months - $66.34 / MWH							
Feb-13	12	12 months - $69.16 / MWH							
Sep-13	11			12 months - $63.49 / MWH					
Jan-14	12					12 months - $63.09 / MWH			
Sep-14	11							6 months - $80.23 / MWH	

Hourly Pricing Service Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Sep-13	11			18 months - $18.46 / MWH					

* Schedule does not reflect four additional existing fixed block energy only tranches procured during the January 2010 auction which terminate on May 31, 2015

Pennsylvania – **Procurement Schedule**

PN Default Service Supply Plan • June 1, 2013 to May 31, 2015

Residential Full Requirements Tranche Procurement Schedule*

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Jan-13	9	24 months – $61.14 / MWH							
Feb-13	9	12 months - $64.39 / MWH							
Jan-14	9					12 months - $58.36 / MWH			

Commercial Full Requirements Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Jan-13	10	6 months - $63.05 / MWH							
Feb-13	10	12 months – $65.18 / MWH							
Sep-13	10			12 months – $60.89 / MWH					
Jan-14	10					12 months - $60.92 / MWH			
Sep-14	10							6 months - $74.79 / MWH	

Hourly Pricing Service Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Sep-13	11			18 months - $12.99 / MWH					

* Schedule does not reflect four additional existing fixed block energy only tranches procured during the January 2010 auction which terminate on May 31, 2015.

Pennsylvania – **Procurement Schedule**

PP Default Service Supply Plan • June 1, 2013 to May 31, 2015

Residential Full Requirements Tranche Procurement Schedule*

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Jan-13	3	24 months - $52.22 / MWH							
Feb-13	3	12 months - $45.45 / MWH							
Jan-14	3					12 months - $58.04 / MWH			

Commercial Full Requirements Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Jan-13	3	6 months - $47.19 / MWH							
Feb-13	4	12 months – $48.19 / MWH							
Sep-13	3			12 months – $55.72 / MWH					
Jan-14	4					12 months - $63.42 / MWH			
Sep-14	3							6 months - $73.73 / MWH	

Hourly Pricing Service Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Sep-13	3			18 months - $10.22 / MWH					

* Schedule does not reflect four additional existing fixed block energy only tranches procured during the January 2010 auction which terminate on May 31, 2015

Pennsylvania – **Procurement Schedule**

WPP Default Service Supply Plan • June 1, 2013 to May 31, 2015

Residential Full Requirements Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Jan-13	15	24 months - $51.04 / MWH							
Feb-13	15	12 months - $46.53 / MWH							
Jan-14	15					12 months - $57.36 / MWH			

Commercial Full Requirements Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Jan-13	9	6 months - $45.05 / MWH							
Feb-13	10	12 months - $45.92 / MWH							
Sep-13	9			12 months - $49.46 / MWH					
Jan-14	10					12 months - $57.29 / MWH			
Sep-14	9							6 months - $68.99 / MWH	

Industrial Hourly Pricing Service Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Sep-13	12			18 months - $5.68 / MWH					

Pennsylvania – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
Penn Power	First Mortgage Bond	7090689O0	9.74%	11/1/2019	$5,390,000
	First Mortgage Bond	709068JN6	6.09%	6/30/2022	$100,000,000
				PP Total	**$105,390,000**
Penelec	Senior Note	708696BU2	6.05%	9/1/2017	$300,000,000
	Senior Note	708696BM0	6.625%	4/1/2019	$125,000,000
	Senior Note	708696BW8	5.2%	4/1/2020	$250,000,000
	Senior Note	708696BX6	4.15%	4/15/2025	$200,000,000
	Senior Note	708696BV0	6.15%	10/1/2038	$250,000,000
				PN Total	**$1,125,000,000**

Pennsylvania – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
Met-Ed	Senior Note	591894BX7	7.7%	1/15/2019	$300,000,000
	Senior Note	591894BY5	3.5%	3/15/2023	$300,000,000
	Senior Note	591894CB4	4.0%	4/15/2025	$250,000,000
				ME Total	**$850,000,000**
West Penn Power	First Mortgage Bond	955278BG0	5.875%	8/15/2016	$145,000,000
	First Mortgage Bond	955278BH8	5.95%	12/15/2017	$275,000,000
	First Mortgage Bond	Private Placement	3.34%	4/15/2022	$100,000,000
				WPP Total	**$520,000,000**

New Jersey Operations

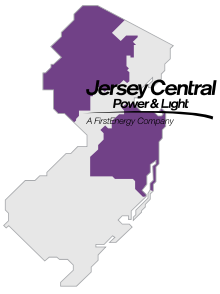


New Jersey – Customer Data

2013 Total Customers (thousands)	
JCP&L	1,098

Typical Bill Comparison*	
New Jersey	$/Month
JCP&L	$134.48
Statewide Avg. Bill	$157.44

* Typical bills are based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2014. New Jersey rates represent POLR bundled residential rates



Major Metropolitan Areas	Population (thousands)
Monmouth County (Middleton Township)	631
Ocean County (Lakewood Township)	578
Morris County (Parsippany)	493
Somerset County (Franklin Township)	324
Total State of New Jersey	8,803

Source: U.S. Census Bureau (2010)

Principal Industries Served**
Chemical
Primary and Fabricated Metals
Plastic and Rubber

** Based on kWh sales

New Jersey – **Distribution Sales**

State Unemployment Rates (%)				
	2007	2011	2012	2013
NJ	4.3%	9.3%	9.3%	8.2%

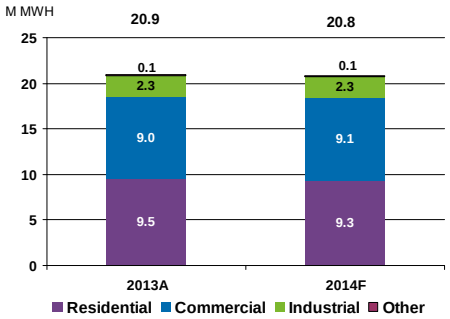
Source: Moody's Analytics

Gross Domestic Product Annualized Growth (Seasonally Adjusted Annualized Rate)				
	2007	2011	2012	2013
NJ	0.7%	0.2%	1.3%	2.3%

Source: Moody's Analytics

Gross Domestic Product, in 2005 dollars ($ billions)				
	2007	2011	2012	2013
NJ	$444	$432	$438	$448

Source: Moody's Analytics



Note: Forecasted sales assume normal weather. Includes forecast for state energy efficiency mandates. (NJ Mandate state goal of 20% usage reduction by 2020).

New Jersey – **Political Landscape**

Governor

Governor	Current Term
Christopher J Christie (R)	Expires in 2018

New Jersey Board of Public Utilities (BPU)

Commissioners	Current Term
President Richard S. Mroz (R)	Expires in 2015
Dianne Solomon (R)	Expires in 2018
Joseph L. Fiordaliso (D)	Expires in 2019*
Upendra Chivukula (D)	Expires in 2020
Mary-Anna Holden (R)	Expires in 2017

*Pending Senate confirmation

New Jersey – **Regulatory Update**

JCP&L Distribution Rate Case/Regulatory Proceedings

- **November 30, 2012: Distribution Rate Case filed**
- **January 23, 2013: BPU established a generic proceeding to review the consolidated tax adjustment policy**
- **February 22, 2013: Filing updated to include Hurricane Sandy costs**
- **March 20, 2013: BPU established a generic proceeding to review prudency of storm costs for 2011 and 2012**
- **April 4, 2013: JCP&L filed a Motion for Reconsideration to leave storm costs in the base rate case**
- **May 31, 2013: BPU issued "Clarifying Order" stating rate treatment for 2011 Storm costs would be applied in JCP&L's existing rate case. A Phase II of the rate case or some other rate treatment would be utilized relating to the 2012 Storm costs**
- **June 14, 2013: Filed update to incorporate the results of the BPU-Ordered Depreciation Study, the amended Cash Working Capital Testimony, and removed 2012 storm costs and other revisions identified during discovery**
- **August 7, 2013: Rebuttal testimony filed and reflected a revision to the proposed ROE**
- **September 12, 2013: Evidentiary hearings continued through November**
- **January 27, 2014: Briefs submitted by parties**

New Jersey – **Regulatory Update**

JCP&L Distribution Rate Case/Regulatory Proceedings (Continued)

- **February 24, 2014: Reply briefs submitted**
- **February 24, 2014: JCP&L, BPU Staff, Division of Rate Counsel entered into a stipulated agreement in the generic storm proceedings to allow recovery of $736M out of $744M for 2011 and 2012 significant weather events**
  - $156M of 2011 costs to be recovered in the pending JCP&L rate case: $74M Capital, $82M Deferred O&M
  - Recovery mechanism and timing of 2012 costs of $580M is to be determined: $333M Capital, $247M Deferred O&M
- **March 19, 2014: Generic storm proceeding settlement approved**
- **May 5, 2014: JCP&L filed updated schedules to reflect the results of the generic storm cost proceeding and revised the debt rate to 5.93%**
- **June 18, 2014: BPU Staff proposed that the current Consolidated Tax Adjustment (CTA) policy remain in effect except as amended by the following:**
  - Calculation would look back 5 years from the beginning of the test year
  - Allocation of the calculated savings would be 75% to the company and 25% ratepayers; and
  - Transmission assets of the EDCs would not be included in the calculation of the CTA
- **June 30, 2014: ALJ closed record in base rate case**
- **October, 22, 2014: BPU issued an order approving Staff's proposal. Following an initial decision of the Administrative Law Judge (ALJ), the BPU would reopen the record in JCP&L's pending base rate case for the limited purpose of adding a CTA calculation reflecting this modified policy and allow parties the opportunity to comment.**
- **2015Q1: Resolution of base rate case expected**

	November 30, 2012	August 7, 2013	May 5, 2014
JCP&L Filing*	Including 2011 Storm Costs	Including 2011 Storm Costs	Including 2011 Storm Costs
Rate Increase	$31M, 1.4%**	$11M, 0.50%**	$9.1M, 0.40%**
Debt/Equity Ratio	46% / 54%	46% / 54%	46% / 54%
Return on Equity	11.53%	11.00%	11.00%
Rate Base	$2.040B	$2.024B	$2.021B

*Excludes June 14, 2013 filing. See slide 58.
**Residential Rate Impact

New Jersey – **Energy Efficiency**

	New Jersey
State Goals	Energy Master Plan (EMP)
Energy Efficiency	2011 modified EMP goal of 20% usage reduction by 2020 (State Goal), subject to modification
Demand Response	17% reduction by 2020 of 2011 PJM Demand Forecast (State Goal)
Smart Grid	Smart Grid DR program 2011. DOE funded circuit automation pilot for 2014
Cost Recovery for Energy Efficiency	In place; annual energy efficiency rider
Compliance	▪ Current EE programs run by the State's Office of Clean Energy

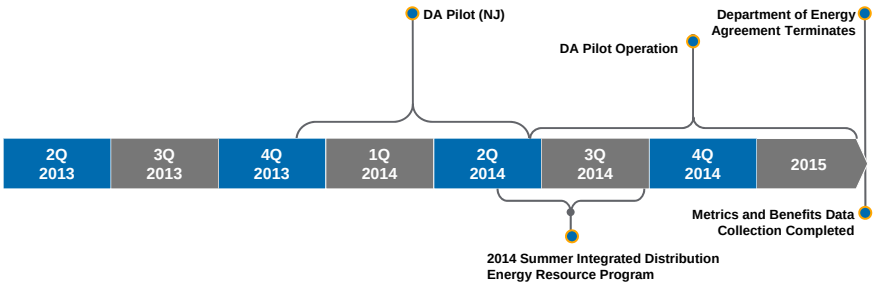
Smart Grid	
Cross-cutting* Technologies/ Programs	JCP&L ($15M)
Distribution Automation	$1
Integrated Distributed Energy Resource Direct Load Control	$14

- **Period of performance = 60 months (June 2, 2010 – June 1, 2015)**
- **Expected implementation of all programs during 2014**
- **All just and reasonable costs are fully reimbursable via federal grant and state approved riders (subject to audit)**

*Cross-cutting describes a project that includes communications and control systems that support more than one component of the smart grid

New Jersey – **Smart Grid Modernization Initiative Update**

- **Project Status: 99% Complete**
- **Remaining Work**
  - Distribution Automation (DA) Pilot
  - Metrics & Benefits Reporting
- **$14.8M of $15M spent through 3Q 2014**



New Jersey – **Procurement Schedule**

JCP&L Generation Service Supply Plan
State-wide procurement process

Approximately 33.3% load annually - 100 MW Fixed Price Full Requirements Tranches – Residential & Small Commercial

		Delivery Period					
Auction	Tranches Bid	June 2014	June 2015	June 2016	May 2017	May 2018	May 2019
Feb-14	15	36 months - $84.44 / MWH					
Feb-15	20		36 months				
Feb-16	18			36 months			

100% load annually - 75 MW Hourly Priced Full Requirements Tranches – Large Commercial Industrial

		Delivery Period					
Auction	Tranches Bid	June 2014 – May 2015		June 2015 – May 2016		June 2016 – May 2017	
Feb-14	13	12 months - $254.79 / MW Day					
Feb-15	16			12 months			
Feb-16	13					12 months	

New Jersey – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
JCP&L	Senior Note	476556CM5	5.625%	5/1/2016	$300,000,000
	Senior Note	476556CW3	5.65%	6/1/2017	$250,000,000
	Senior Note	476556CK9	4.8%	6/15/2018	$150,000,000
	Senior Note	476556DA0	7.35%	2/1/2019	$300,000,000
	Senior Note	476556DB8	4.7%	4/1/2024	$500,000,000
	Senior Note	476556CP8	6.4%	5/15/2036	$200,000,000
	Senior Note	476556CT0	6.15%	6/1/2037	$300,000,000
				JCP&L Total	$2,000,000,000
JCP&L Transition Funding LLC	Transition Bond	47214TAD1	6.16%	6/5/2017*	$79,956,722
	Transition Bond	47215BAC1	5.52%	6/5/2018*	$48,264,173
	Transition Bond	47215BAD9	5.61%	6/5/2021*	$51,139,000
				JCP&L Transition Funding LLC Total	$179,359,895

* Expected Final Maturity Date

West Virginia/Maryland Operations





West Virginia/Maryland – **Customer Data**

2013 Total Customers (thousands)	
MP	388
PE	393
Total	781

Typical Bill Comparison*	
West Virginia/Maryland	$/Month
MP	$92.62
PE	$95.08
WV Statewide Avg. Bill	$93.23
MD Statewide Avg. Bill	$131.20

* Typical bills are based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of January 1, 2014. MD/WV rates represent POLR bundled residential rates



Principal Industries Served**
Chemical
Coal Mining
Non-Metallic Minerals
Primary and Fabricated Metals
Oil and Gas Extractions

** Based on kWh sales



Major Metropolitan Areas	Population (thousands)
Berkeley County (Martinsburg)	105
Monongalia County (Morgantown)	97
Wood County (Parkersburg)	87
Total State of West Virginia	1,854

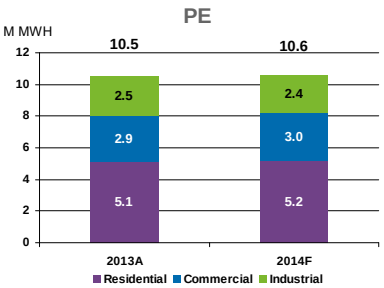
Major Metropolitan Areas	Population (thousands)
Frederick County	234
Washington County (Hagerstown)	148
Allegany County (Cumberland)	75
Total State of Maryland	5,787

Source: U.S. Census Bureau (2010)

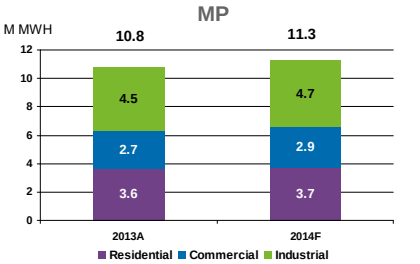
West Virginia/Maryland – **Distribution Sales**

State Unemployment Rates				
	2007	2011	2012	2013
WV	4.2%	7.9%	7.3%	6.5%
MD	3.4%	7.3%	6.9%	6.6%

Source: Moody's Analytics



Note: Forecasted sales assume normal weather.
Includes forecast for state energy efficiency mandates.
(MD Mandate 10% per capita by 12/31/15, ~0.4M MWH)



Note: Forecasted sales assume normal weather. Includes forecast for state energy efficiency mandates. (WV Mandate 0.5% of 2009 sales by 12/31/16, ~0.1M MWH. Plus incremental 0.5% of 2013 Sales by May 2018)

Gross Domestic Product Annualized Growth (Seasonally Adjusted Annualized Rate)				
	2007	2011	2012	2013
WV	-0.7%	1.9%	3.3%	1.4%
MD	1.6%	1.6%	2.4%	1.6%

Source: Moody's Analytics

Gross Domestic Product, in 2005 dollars ($ billions)				
	2007	2011	2012	2013
WV	$52	$55	$56	$57
MD	$255	$268	$275	$279

Source: Moody's Analytics

West Virginia/Maryland – **Political Landscape**

West Virginia

Governor

Governor	Current Term
Earl Ray Tomblin (D)	Expires in 2017

Public Service Commission of West Virginia (WV PSC)

Commissioners	Current Term
Michael A. Albert, Chairman (R)	Expires in 2019
Jon W. McKinney (D)	Until Reappointed or Replaced
Vacant	

Maryland

Governor

Governor	Current Term
Martin J. O'Malley (D)	Expires in 2015

Maryland Public Service Commission (PSC)

Commissioners	Current Term
W. Kevin Hughes, Chairman (D)	Expires in 2018
Harold D. Williams (D)	Expires in 2017
Lawrence Brenner (D)	Expires in 2015
Kelly Speakes-Backman (D)	Until Reappointed or Replaced
Anne E. Hoskins (D)	Expires in 2016

West Virginia – **Regulatory Update**

Rate Case

- **April 30, 2014: Base Rate Case Filed (Case # 14-0702-E-42T)**
  - $95.7M (9.27%) base rate increase (2013 historic test year), inclusive of depreciation rate increase
    - $144.1M (14.0%) overall increase including vegetation management plan surcharge
  - 11% return on equity
  - Depreciation case filed concurrently ($17M reflected in overall increase)
- **June 13, 2014: Amendment to Base Rate Case**
  - Amendment filed due to WV PSC order requiring MP and PE-WV to begin reading customer meters on a monthly basis no later than July 1, 2015 (i.e., convert bimonthly meter reads to monthly meter reads)
  - Annual incremental increase of $7.5M
  - Amended rate impact: $103.2M (9.99%) base rate increase, inclusive of depreciation rate increase
    - $151.6M (14.7%) overall increase including vegetation management program and monthly meter reading
- **November 3, 2014: Joint Settlement filed with the WV PSC**
  - Hearing on the joint settlement scheduled for November 7, 2014
  - Joint settlement includes:
    - $15M (1.43%) base rate increase
    - Vegetation Management Surcharge of $48M (4.52%) in 2015
    - Vegetation Management Surcharge along with the base rate increase results in an overall increase of $63M (5.95%)
    - Collection of $46M of 2012 storm costs, amortized over 5 years
    - Depreciation rates remain unchanged from current value
    - Delay in ENEC rate change until Feb 25, 2015
    - Deferral of 2016-2017 MATS capital costs
    - Black box settlement does not provide ROE and income tax rate in base rates
  - February 25, 2015: Effective date of new rates and surcharge

Base Rate Change	**$ 124.3M**
Elimination of Harrison Surcharge	**$ (109.3)**
Vegetation Management Surcharge	**$ 47.6**
Total Settlement Increase	**$ 62.6M**

West Virginia – **Regulatory Update**

West Virginia Vegetation Maintenance Program & MATS Compliance
Pursuant to pending settlement

- **Vegetation Management Surcharge**
  - Permits timely recovery of cycle-based end-to-end vegetation management plan approved by the WV PSC on April 14, 2014
  - Reconcilable surcharge to recover 100% of vegetation management O&M and capital costs between base rate cases
    - 2015 O&M = $44.9M
    - 2015 Capital = $51.5M (equates to a $2.7M revenue requirement)
  - Deferral of incremental O&M costs (incurred from April 14, 2014 PSC order date through Feb 25, 2015 effective date of new rates) to be included in September 2015 reconciliation filing for rates effective January 1, 2016
  - Includes $15M previously in O&M in base rates
- **MATS Compliance Capital Recovery**
  - New base rates include collection of MATS compliance capital projects placed in service by Dec 31, 2015
  - Establishes regulatory asset for MATS compliance capital projects placed in service during 2016-2017. Expected to total approximately $55M for Harrison and Fort Martin
    - Regulatory asset includes depreciation expense and a pre-tax return of 8.19%
  - Recovery of the regulatory asset in the next base rate case

Maryland – **Procurement Schedule**

			Delivery Period **		
Load Type	Tranches Bid *	Auction Date	June 2014 - May 2015	June 2015 - May 2016	June 2016 - May 2017
Residential	1	October 2013	12 Months		
	1		24 Months		
Residential	2	January 2014	12 Months		
	2		24 Months		
Residential	1	April 2014		12 Months	
	1			24 Months	
Residential	1	June 2014		12 Months	
	1			24 Months	

			Delivery Period **
Load Type	Tranches Bid *	Auction Date	June 2014 - May 2016
Small C&I	1	October 2013	24 Months
Small C&I	1	January 2014	24 Months

			Delivery Period **			
Load Type	Tranches Bid *	Auction Date	Dec 2013 – Feb 2014	March 2014 – May 2014	June 2014 – Aug 2014	Sept 2014 – Nov 2014
Medium C&I	3	October 2013	3 Months			
Medium C&I	3	January 2014		3 Months		
Medium C&I	3	April 2014			3 Months	
Medium C&I	3	June 2014				3 Months

*All tranches are for full requirements service.
**The Maryland PSC does not release bid or winning prices. However, a list of bidders who submitted bids and a list of winning bidders can be found at https://www.firstenergycorp.com/content/fecorp/upp/md/power_procurements/2014sosrfp/archive.html

West Virginia/Maryland – **Energy Efficiency**

	Maryland	West Virginia
State Goals	**EmPower MD**	**Base Rate Case and Merger Settlements**
Energy Efficiency	10.0% per capita by 12/31/2015 (415 GWH)[1]	0.5% of 2009 Sales by 12/31/2016 (67 GWH) Plus incremental 0.5% of 2013 Sales by May 2018 (71 GWH)
Demand Response	15.0% per capita by 12/31/2015 (21 MW)	0.5% of 2009 Demand by 12/31/2016 (14 MW)
Smart Meter	No state smart meter requirement	No state smart meter requirement
Cost Recovery for Energy Efficiency	In place – 5 year amortization schedule with carrying costs and annual reconciliation	In place – annual energy efficiency rider
Compliance	On track to achieve EE/DR 2015 targets	On track to achieve EE/DR 2016 targets

[1]On 9/30/14, PE filed a 2015-2017 EE/PDR Plan that is under MD PSC Review.

West Virginia/Maryland – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
Mon Power	Pollution Control Note	41524CAU8	5.5%	10/15/2037	$73,500,000
	First Mortgage Bond	610202BK8	5.375%	10/15/2015	$70,000,000
	First Mortgage Bond	610202BL6	5.7%	3/15/2017	$150,000,000
	First Mortgage Bond	610202BN2	4.1%	4/15/2024	$400,000,000
	First Mortgage Bond	610202BP7	5.4%	12/15/2043	$600,000,000
				MP Total	**$1,293,500,000**
Mon Power Environmental Funding LLC	Environmental Control Bond	553214AB3	5.233%	7/15/2019*	$75,427,062
	Environmental Control Bond	553214AC1	5.463%	7/15/2026*	$153,250,000
	Environmental Control Bond	553214AD9	5.523%	7/15/2027*	$29,025,000
	Environmental Control Bond	553214AE7	5.127%	1/15/2031*	$64,380,000
				Mon Power Environmental Funding LLC Total	**$322,082,062**

* Expected Final Maturity Date

West Virginia/Maryland – **Long-Term Debt Schedules**

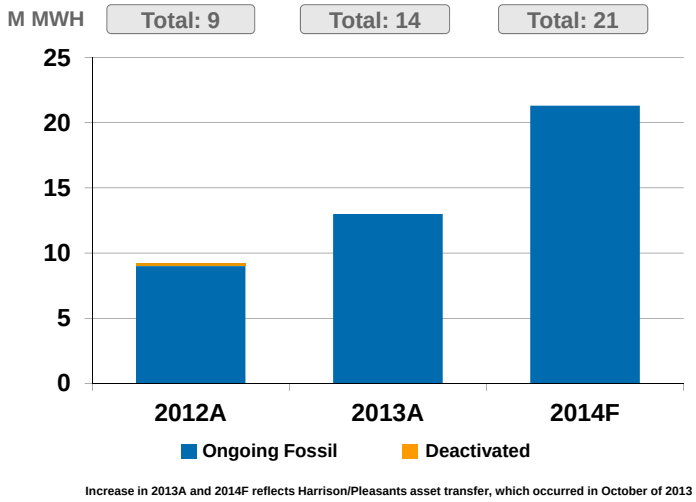
Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
Potomac Edison	First Mortgage Bond	737662BP0	5.35%	11/15/2014	$175,000,000
	First Mortgage Bond	737662BR6	5.125%	8/15/2015	$145,000,000
	First Mortgage Bond	737662BS4	5.8%	10/15/2016	$100,000,000
				PE Total	**$420,000,000**
Potomac Edison Environmental Funding LLC	Environmental Control Bond	69336NAB5	5.233%	7/15/2019*	$25,328,396
	Environmental Control Bond	69336NAC3	5.463%	7/15/2026*	$50,700,000
	Environmental Control Bond	69336NAD1	5.523%	7/15/2027*	$9,975,000
	Environmental Control Bond	69336NAE9	5.127%	1/15/2031*	$21,510,000
				Potomac Edison Environmental Funding LLC Total	**$107,513,396**

* Expected Final Maturity Date

Regulated Generation



Regulated Generation – **2012 - 2014 Output**



Increase in 2013A and 2014F reflects Harrison/Pleasants asset transfer, which occurred in October of 2013

Regulated Generation

Fuel

			Total Fleet – Coal Sources		
	Plants	Units	NAPP	Western	ILB
Supercritical Units	Harrison	1-3	✓		
	Fort Martin	1-2	✓	✓	✓

Fossil Environmental Controls

	Plant	NDC	NOx Controls				SO_2 Controls		Particulate	Cooling Towers
			SCR	SNCR	LNB	OFA	Scrubbers[1]	Lo-S Fuel	Electro/Other[2]	
Supercritical	Harrison 1-3	1,984	✓		✓		✓		✓	✓
	Fort Martin 1 & 2	1,098		✓	✓	✓	✓	✓	✓	✓
	Sub-total	3,082								

[1]Scrubbed coal units have FGD (Flue Gas Desulfurization - equipment to remove sulfur from flue gas after combustion)
[2]Particulate Controls can include Venturi Scrubber or Electrostatic Precipitator

Regulated Generation – **Plant Deactivations**

- **660 MW deactivated as of September 1, 2012**

Regulated	NDC MW	2012 M MWH	2012 Capacity Factor (%)	Deactivation Date
Albright	292	0.2	10	9/1/2012
Rivesville	126	0.0	0	9/1/2012
Willow Island	242	0.0	1	9/1/2012
Total	660	0.2		

Regulated Generation – **MATS Overview**

- **MATS**
  - Total compliance cost estimate of $192M

Plant	Technologies
Harrison 1-3	**Precip Changes, FGD changes, SCR Catalyst, Duct Repairs, CEMS**
Fort Martin 1-2	**GORE Mercury Control System, Duct Repairs, CEMS**

Regulated Generation – **Plant Details**

Plant	PJM Zone	State	Utility	Fuel Type	Units	Net Maximum Capacity (MW)	Year Plant Commissioned
Bath County	Rest of RTO	VA	MP	Hydro	6	487*	1985
Fort Martin	Rest of RTO	WV	MP	Coal	2	1,098	1967
Harrison	Rest of RTO	WV	MP	Coal	3	1,984	1972
OVEC	Rest of RTO	Multiple	MP	Coal	Multiple	11**	
					Rest of RTO Total	**3,580**	
Yards Creek	EMAAC	NJ	JCP&L	Hydro	3	210	1965
					EMAAC Total	**210**	
					Regulated Generation Total	**3,790**	

*Represents MP's approximate 41% shareholder interest in AGC, which owns a 40% interest in Bath County, a pumped-storage hydroelectric station. The station is operated by 60% owner Virginia Electric and Power Company
**Represents MP's 0.49% entitlement based on its participation in OVEC

Transmission



Transmission – **Enhancing** Transmission Reliability for Customers

"Energizing the Future"

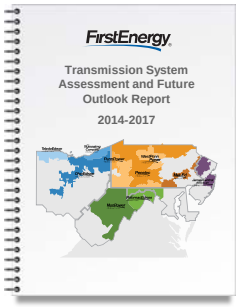
- **FirstEnergy's overall transmission program**
- **Includes all investments in ATSI, TrAILCo and other utility operating companies within the FirstEnergy footprint**

2014-2017 Growth Program

- **$4.2B plan initially focused primarily in ATSI and extending east over time**

Benefits

- **Focused on smaller-scale projects with near-term completion dates**
  - Majority of projects located in the ATSI region, target 69kV lines, and outside of the RTEP approval process
  - Construction to occur on land where most rights-of-way are already secured
- **Enhanced system reliability and customer service**
- **Older equipment replaced with updated technology**
- **Decreased maintenance costs by converting to condition-based maintenance program that allows for equipment replacement using real-time data**
- **Local employment opportunities for ~1,100 contractors annually**



2018 and Beyond

- **$15B in incremental opportunities for reliability enhancement**

Transmission – Energizing the Future

Energizing the FUTURE

To increase system reliability and capacity for existing and new customers

Reliability Enhancements	**$1.6B**	▪ **Upgrade condition / health of the system** ▪ **Increase operating flexibility/margin** • Outage scheduling • System/storm restoration • Load serving capability for existing and new customers ▪ **Increase system performance/reliability** • Decrease exposure to outages • Decrease outage time ▪ **Increase automation and communication within the system** ▪ **Improve dynamic performance** ▪ **Reduce future transmission investment costs**
Regulatory Required	**$2.6B**	▪ **Preserves the reliability of PJM's transmission system** ▪ **Formula rate recoverable in both ATSI and TrAILCo** ▪ **RTEP approved projects (PJM requested to support grid reliability)** ▪ **Generator deactivation projects** ▪ **Enables future markets** ▪ **Emerging shale gas projects**

$4.2B plan initially focused primarily in ATSI and extending east over time

Transmission – **Formula Rate Summary**

	ATSI	TrAILCo
Jurisdiction	FERC	FERC
Filing Month	May	May
FERC approved ROE	**12.38%**	**12.70% TrAIL the Line & Black Oak SVC** **11.70% All other projects**
Rate Base	**$0.9B***	**$1.2B****
Transmission system locations	**OE, PP, CEI, and TE**	**WPP, MP, and PE. Also some portions of JCP&L, ME, and PN**
Timing	**Projects in plan for 2014-2017**	**Projects in plan for 2014-2017**
Term	June – Following May	June – Following May
Test Year	**Historical:** based on most recent calendar year in FERC Form 1; Network Service Peak Load updated effective January 1***	**Forward-Looking**: Utilizes prior year plant-in-service from FERC Form 1 and adds capital additions projected to be in service within current calendar year
True-up Mechanism	No	Yes
Calculation	Separate Annual Network Rates:**** ▪ 138kV and above ▪ Below 138kV	Revenue Requirement by project: ▪ TrAIL the Line ▪ Individual RTEP projects

* Represents rate base from its annual update on May 1, 2014 to be utilized for rates effective June 1, 2014
** Represents projected rate base from its annual update on May 15, 2014 for rates effective June 1, 2014
*** On October 31, 2014 ATSI submitted a rate filing to FERC to amend its formula rate to a forward-looking test year (see slide 84)
**** On October 8, 2014 ATSI submitted a FERC-required compliance filing to convert to a single network voltage rate effective January 1, 2015

Transmission – **ATSI Filing**

ATSI

- Wholly owned indirect subsidiary of FE Corp.
- Owns, operates and maintains over 7,390 circuit-miles of transmission lines, substations and other transmission facilities operated at nominal voltages of 345 kV, 138 kV and 69 kV
- Footprint includes the OE, PP, CEI, and TE utilities
- Only provides transmission services; does not provide retail utility services or own generation assets

Forward-looking rate structure request

- On October 31, 2014, ATSI filed a proposal with the Federal Energy Regulatory Commission (FERC Case Number ER15-303) requesting a "forward looking" transmission formula rate
- The change would impact the timing of recovery for expenditures, allowing ATSI to capture planned expenditures within its large infrastructure closer to the time of spend
- Requested FERC approval of the proposal with an effective date of January 1, 2015

	Existing Structure	Proposal
Rate Year	June 1 to May 31	January 1 to December 31
Date Projected Revenue Requirement is posted	May 1	November 1
ROE	12.38%	12.38%
Test Year	Historical: Based on most recent calendar year in FERC Form 1; Network Service Peak Load updated effective January 1	Forward-Looking: Utilizes prior year plant-in-service from FERC Form 1 and adds capital additions projected to be in service within current calendar year based on a 13 month average. Also utilizes projected operating expenses for the year.
True-up Mechanism • Date Actual Revenue Requirement and True Up filed	No • N/A	Yes • May 1

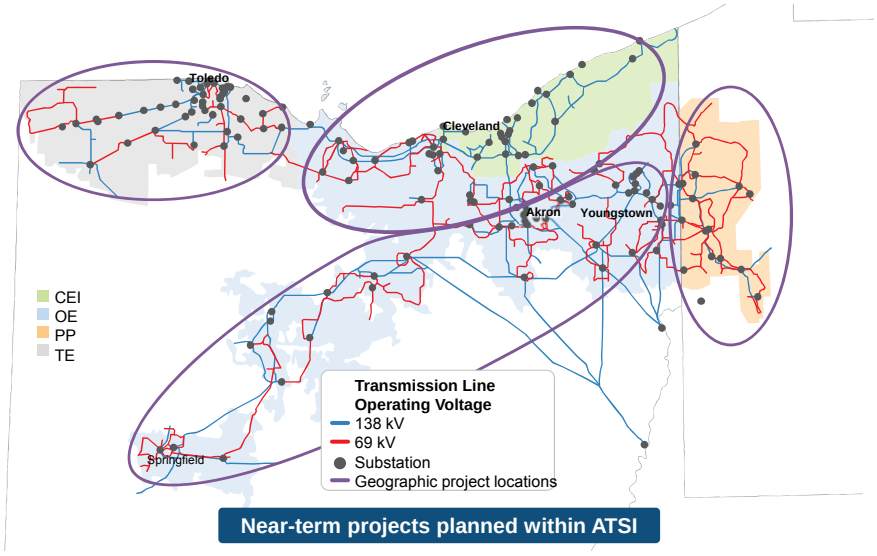
Transmission – **Enhancing** Transmission Reliability

- **$4.2B over 2014-2017: Majority of near-term projects in ATSI**
- **Funding Strategy: FET up to 65% Debt, ATSI & TrAILCo up to 40% Debt**



Transmission – **Enhancing** Transmission Reliability

ATSI 69kV – 138kV System Network

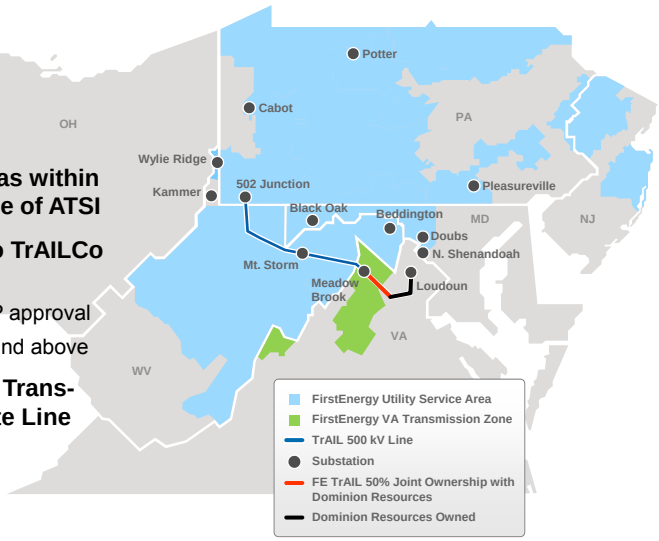


Near-term projects planned within ATSI

Transmission – **TrAILCo** Footprint

TrAILCo
A FirstEnergy Company

- **Projects target areas within FE footprint outside of ATSI**
- **Assets assigned to TrAILCo must:**
  - Receive PJM RTEP approval
  - Operate at 100kV and above
- **Owns the 150-mile Trans-Allegheny Interstate Line (TrAIL)**



Transmission – **Enhancing** Transmission Reliability

	2014F	2015F	2016F	2017F
Formula Rate Recoverable Projects designed to upgrade and enhance system conditions, performance, capacity and reliability. Receive ATSI or TrAILCo formula rates.	$1,150M	$830M	$810M	$725M
Baseline Planned capital projects at operating companies (JCP&L, ME, MP, PN, PE, and WPP).	$200M	$160M	$200M	$125M
Total	$1,350M	$990M	$1,010M	$850M

Expected ATSI & TrAILCo annual earnings growth of 20+%

Transmission – **Upgrade Condition of the System**

- **Replace oil, single-pressure and two-pressure, gas-insulated circuit breakers with new single-pressure, gas-insulated circuit breakers due to deteriorating condition. New EHV circuit breakers will also include on-line diagnostic systems with capabilities to provide data to the new Asset Health System**
- **Replace power transformers due to deterioration of internal insulation with new transformers that include on-line diagnostic systems with capabilities to provide data to the new Asset Health System**
- **Evaluate and rebuild aging EHV and HV transmission lines (~2,500 circuit miles of 69kV and ~5,000 circuit miles of 138kV and 345kV)**
- **Based on the initial reliability review, anticipate rebuilding approximately 50% of the 69kV and 20% of the 138kV lines; however these percentages may increase as overall condition assessment of the ATSI transmission system is completed**



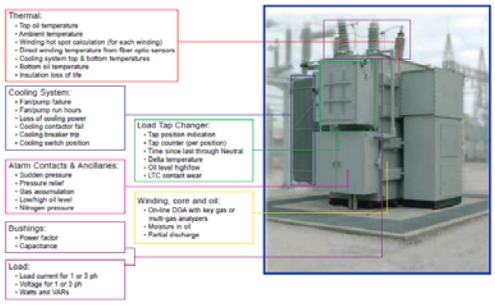
Oil pressure gas insulated circuit breaker (on left), replaced by gas-insulated circuit breaker (on right)



New transformers will provide data to the Asset Health System

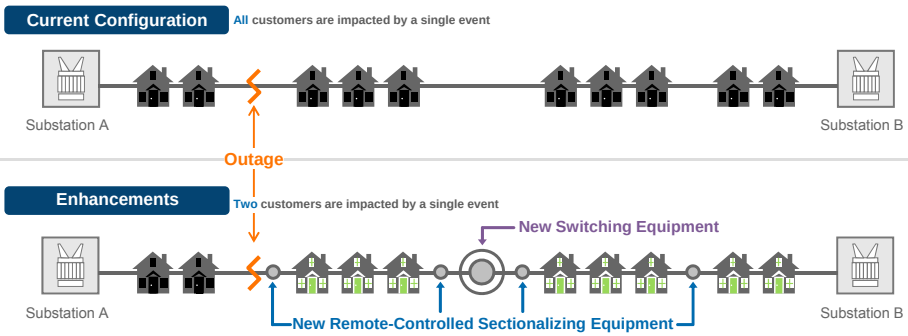
Transmission – **Enhance System Performance**

- **Implement an Asset Health System**
  - Provide situational awareness through real-time, consolidated data on asset condition
  - Reduce maintenance by enabling real-time data event analysis and condition assessment
- **Physical Security Enhancements**
  - Replace existing chain link perimeter fencing with no cut/no climb product to prevent entry
  - Expand use of perimeter video, thermal imaging and virtual inspection
- **Expand FirstEnergy's fiber and core network to critical transmission facilities**
  - Reduce/eliminate dependence on third-party communication assets



Transmission – **Add Operating Flexibility and Capacity**

- **Rebuild existing single-circuit transmission lines as double-circuit transmission lines**
- **Build line segments to create parallel paths (loop feeds) to existing substations**
- **Reconfigure longer transmission lines with high customer loads to decrease the number of customers impacted by a single operational event**

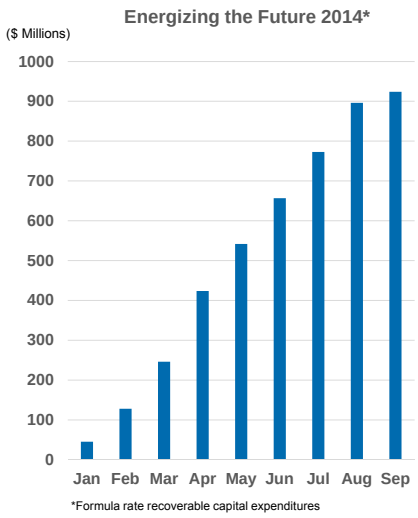


Transmission Program Status

- **Burns & McDonnell hired to manage engineering, procurement, construction and completion of capital portfolio created for Energizing the Future**
  - Currently staffed with approximately 330 employees
    - 143 Design staff
    - 125 Program and construction managers
    - 62 Other support staff
    - 150 of 330 employees located in the Akron office
  - Design engineering in process, with several local Ohio firms supplementing Burns & McDonnell
  - A four-year project list has been established (construction underway on numerous projects), and coordination of future outages and construction is in progress
- **Quanta Services augmenting physical labor (linemen and substation electricians) required to perform reliability-based work**
  - ~ 800 Quanta affiliated linemen and electricians currently working on Energizing the Future program and other FirstEnergy projects
- **Manufacturer production and deliveries to support construction activities through 2014 and 2015; Equipment includes:**
  - 750 HV circuit breakers
  - 60 HV power transformers
  - 25 EHV power transformers
- **Working with International Brotherhood of Electrical Workers to anticipate and plan for adequate workforce availability, timing and deployment of resources throughout FE service area to support Energizing the Future**

Transmission Program Status

- **By Year-End 2014**
  - Approximately:
    - 550 pieces of substation equipment replaced
    - 300 miles of Transmission line projects completed
  - Physical Security Upgrade projects completed at approximately 50 Substations
  - One Synchronous Condenser conversion and three Static Var Compensators (SVC) projects in-service
    - Provides ~1,900 MVAR of support
  - Approximately 70 Communication Upgrade projects completed
- **2015 Projects**
  - Over 1,000 pieces of substation equipment slated for replacement/upgrades including:
    - 60+ transformers, 17 capacitor banks, 80+ breakers
  - Approximately 300 miles of Transmission line projects
  - Telecom/IT projects
  - Three Synchronous Condenser conversion projects and seven SVC Projects



*Formula rate recoverable capital expenditures

Transmission – **Political Landscape**

Federal Energy Regulatory Commission (FERC)

Commissioners	Current Term
Cheryl A. LaFleur (D)- Chairman*	Expires in 2019
Philip D. Moeller (R)	Expires in 2015
Tony Clark (R)	Expires in 2016
Colette D. Honorable**	Expires in 2017
Norman C. Bay (D)*	Expires in 2018

*Commissioner Bay will become Chairman of the FERC on April 15, 2015. LaFleur has announced that she will step down from Chair but will remain as a Commissioner through the end of her term in 2019.

** President Obama nominated Arkansas PSC Chairman Colette D. Honorable (D) to the vacant seat on August 28, 2014.

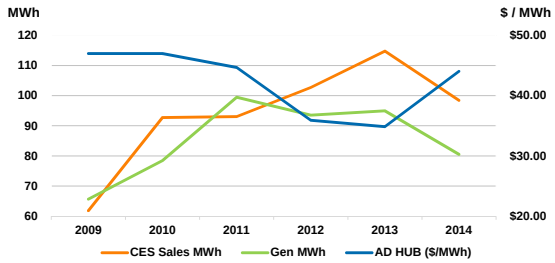
Transmission – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
FET	Senior Note	33767BAB5	4.35%	1/15/2025	$600,000,000
	Senior Note	33767BAA7	5.45%	7/15/2044	$400,000,000
				FET Total	$1,000,000,000
ATSI	Senior Note	030288AA2	5.25%	1/15/2022	$400,000,000
	Senior Note	030288AB0	5.00%	9/1/2044	$400,000,000
				ATSI Total	$800,000,000
TrAILCo	Senior Note	893045AC8	4.00%	1/15/2015	$450,000,000

Competitive Operations



Taking Our Generation to the Competitive Market



2009 - 2011

- **FirstEnergy builds a significant competitive portfolio gaining experience and knowledge**
- **Retail market conditions are stable and predictable**

2012 - Present

- **Significant drop in wholesale prices following recession**
- **Risk premiums no longer cover increasing risks associated with retail markets**

While our focus on a retail strategy during the last several years has created profitable margins and stable prices for customers, a fundamental change in the markets is underway

Includes actual generation output each year and AE Supply generation output post merger only (2011)

Taking Our Generation to the Competitive Market

In recent years, FirstEnergy has taken aggressive action to mitigate market risks …

Risk	FirstEnergy Action
MATS	▪ Announced intent to deactivate 4,769 MW in 2012/2013; All units deactivated with the exception of 885 MW currently running under RMR status or planned to be deactivated by April 2015*
Increased reliance on demand response	▪ Advocated for policy changes stimulating a more competitive market ▪ Filed a complaint with FERC in response to D.C. Circuit Court's finding that FERC does not have jurisdiction to regulate (compensate) demand response in wholesale energy markets
Volatility of energy markets in 1Q 2014 and scarcity pricing	▪ Increased risk premiums on all future retail contracts ▪ Took deliberate action to close small unhedged position remaining for 2014 ▪ Layered in further hedges to supplement retail load in summer months ▪ Purchased outage insurance for larger generation units in summer 2014 ▪ Passed PJM ancillary charges to commercial and industrial customers ▪ Re-evaluated sales targets for future years

We believe several drivers will increase future volatility

- **Increased dependence on less reliable resources**
  - Interruptible natural gas
  - Degrading coal plants
  - New builds of gas where construction has not started
- **PJM focus on summer events when modeling a full year**
- **Narrowed reserve margins after baseload generation deactivations due to MATS**

Given current state of capacity and energy markets along with increased risks associated with retail sales, CES will leave 10 - 20M MWH of its 80 - 85M MWH of generation resources open for spot sales

*See slide 121

Taking Our Generation to the Competitive Market



Taking Our Generation to the Competitive Market

- **Utilize strong competitive knowledge**
- **Take advantage of flexibility given current committed position**

Effectively hedge generation

- Flexibility to continue POLR, Governmental Aggregation, and selected large commercial-industrial sales
- Enables the use of retail margin uplift to hedge during periods of low wholesale prices
- Employ a variety of hedging tools, including existing retail sales commitments, traditional forward wholesale sales and potentially Utility PPAs
- Strong focus on portfolio optimization and risk management

- **Leverage clean, efficient generation portfolio**
- **Mitigate risk**
- **Maximize margins**

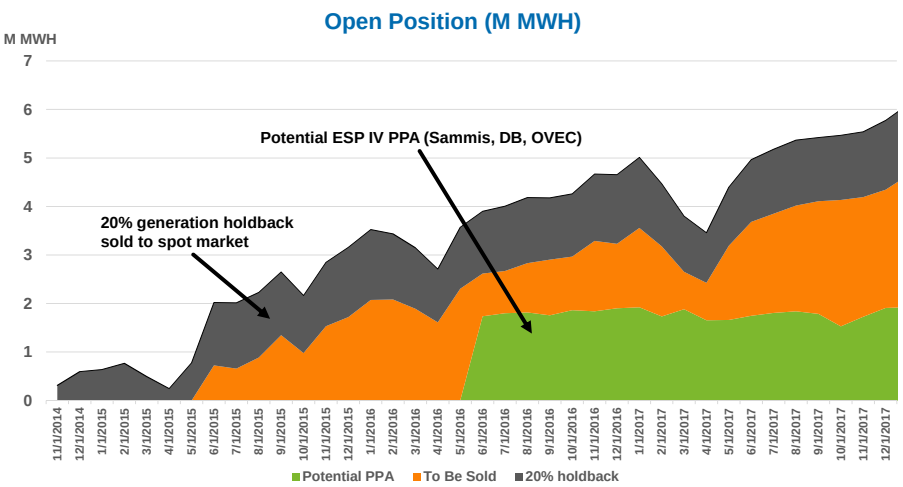
"Long" generating strategy

Annual generation resources of 80-85M MWH

- Benefit from established baseline of higher margin Governmental Aggregation load (13M MWH) and natural attrition of selected channels through 2019
- Reserve 10-20M MWH to protect weather-sensitive loads and to take advantage of opportunities resulting from scarcity pricing
- Target 10-45M MWH annually through POLR, Governmental Aggregation and selected large commercial-industrial sales
- Balance remainder of portfolio for sales in the wholesale market and potentially Utility PPAs

Adapt Competitive Operations to changing market dynamics

Flexible Hedging Platform to Bring Our Generation to Market

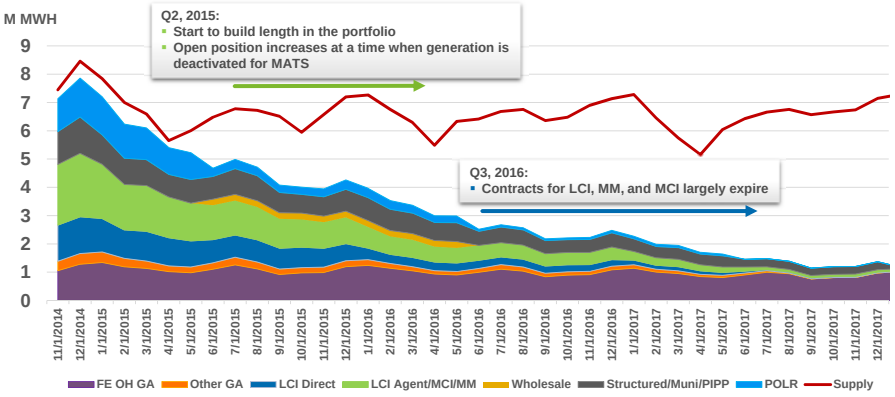


Significant level of committed sales through mid-2015

Existing Committed Sales

- **Retain POLR, GA, and selected large commercial-industrial contracts**
- **Exit MCI, MM and certain LCI contracts by natural attrition**

Committed Load by Segment



Expected significant level of uncommitted sales beginning mid-2015 provides flexibility

Optionality and Variety of Hedging Resources

Channel	Description	Value
Wholesale Sales	Sales in forward power markets made to hedge generation	Provides flexibility in volume and timing of hedge
GA	Buying group formed by communities which choose electric supplier for all members in the group. Pricing is fixed or is a percentage discount off the price to compare, which is determined through utility default service auctions. Current contracts run through 2019.	Higher margin load, pricing of majority of sales moves with market, minimal acquisition cost, minimizes risk of POLR
POLR	Tranches of non-shopping load that is won through utilities' default service auctions	Higher margin load, minimal acquisition cost and flexibility of participation
Structured	Includes municipality sales, co-operative sales, bilateral sales, and unique transactions	Higher margin wholesale transactions made for strategic purposes
LCI	Selected/strategic direct sales to large commercial and industrial customers	Higher load factors, less weather sensitive, flexibility of term; a wholesale-type load with better margins
Utility PPA	Dedicated plant output (MW) to distribution utilities through PPA	Full cost-based recovery with a rate of return; provides revenue certainty
Spot Market Sales	Sales in day-ahead or real-time to take advantage of market volatility/scarcity pricing	Having a reserve dedicated to spot provides flexibility to manage weather sensitive loads and take advantage of market volatility
MCI and MM Sales	No new sales. Small Commercial and Residential customers. Contracts expire naturally through 2018.	High cost to acquire and support customers; highly weather sensitive

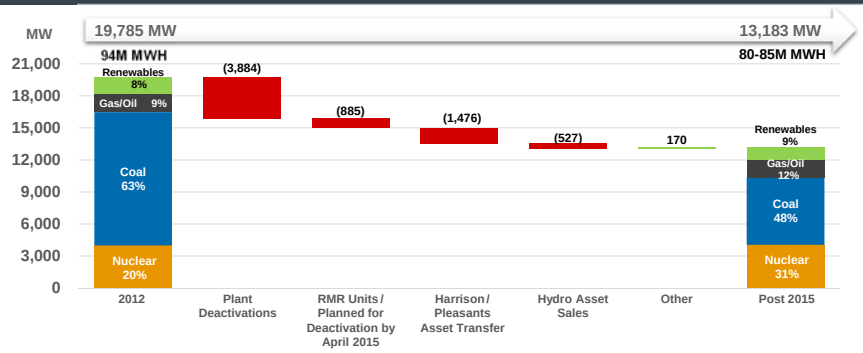
Target Portfolio Mix

Weather Sensitive		Annual Load (M MWH)
✔	GA	10-15
✔	POLR	0-10
✔ / ✖	LCI Direct*	0-20
✖	Block Wholesale	10-20
✖	Spot Wholesale	10-20

Annual Generation Resources = 80-85M MWH

*LCI Direct is less weather sensitive than GA and POLR

Repositioning our Competitive Fleet Over Time



Current generation output of 75-80M MWH; additional resources of 0-5M MWH (includes Wind/Solar/OVEC)

The character and operation of our fleet has changed over the past several years

- 3,884 MW deactivated
- 885 MW additional deactivations by April 2015*
- Changed operating status of Sammis to cold storage for a period of 4 months
- 1,833 MW includes asset transfer and sales and other actions including net uprates (110 MW), additional wind and solar PPA agreements (120 MW), less deactivation of Mad River plant (60 MW)

In 2015, the competitive generation portfolio will operate similar to a natural gas portfolio in that ~100% of the power generated will come from low or non-emitting sources yet also offer a diverse platform of resources

Generation output of 75-80M MWH; additional resources of ~2M MWH (includes Wind/Solar/OVEC)
*See slide 121

2015F CES Adjusted EBITDA

	Closed			Open			Total		
	M MWH	Rate	$M	M MWH	Rate	$M	M MWH	Rate	$M
Sales:									
LCI/MCI/MM	24.8	$56	$1,390				24.8	$56	$1,390
GA & POLR	23.2	$66	$1,530				23.2	$66	$1,530
Structured & Muni	9.8	$45	$440				9.8	$45	$440
Wholesale	1.5	$41	$60	21.6	$39.60	$855	23.1	$39.60	$915
Other	2.8						2.8		
Capacity Revenue - BRA			$890						$890
Total Revenues	62.1		$4,310	21.6	$39.60	$855	83.7		$5,165
Expenses:									
Capacity & Delivery Expenses			($1,115)			($60)			($1,175)
Purchased Power	6.2	($45)	($280)				6.2	($45)	($280)
Nuclear Fuel	30.6	($7.00)	($215)				30.6	($7.00)	($215)
Fossil Fuel	25.3	($27.50)	($695)	21.6	($27.50)	($595)	46.9	($27.50)	($1,290)
Total Expenses	62.1		($2,305)	21.6		($655)	83.7		($2,960)
Commodity Margin			**$2,005**			**$200**			**$2,205**
Commodity Margin (excl. Capacity Revenue)		**~$18**	**$1,115**		**~$9**	**$200**		**~$16**	**$1,315**

Closed Contribution	+	Open Contribution	=	CES Adjusted EBITDA[1] – 2015F
$700-$800		$200		$900 -$1,000

Please see slide 108 for additional notes describing "Sales" and "Expenses"

[1] Total CES 2015F Adjusted EBITDA, a non-GAAP financial measure, is reconciled to 2015F CES Net Income on slide 136, and is based on market prices as of October 21, 2014. The "Closed contribution" to Adjusted EBITDA is based on committed sales whereas the "Open contribution" to Adjusted EBITDA is based on currently uncommitted sales that are assumed to be sold in the wholesale market assuming market prices as of October 21, 2014. The purpose of the table above is to summarize the impact on Adjusted EBITDA of changes in market prices on currently uncommitted sales.

2016F CES Adjusted EBITDA

	Closed			Open			Total		
	M MWH	Rate	$M	M MWH	Rate	$M	M MWH	Rate	$M
Sales:									
LCI/MCI/MM	9.5	$58	$555				9.5	$58	$555
GA & POLR	15.5	$64	$985				15.5	$64	$985
Structured & Muni	7.0	$44	$305				7.0	$44	$305
Wholesale	1.1	$41	$45	45.4	$39.90	$1,810	46.5	$39.90	$1,855
Other	2.4						2.4		
Capacity Revenue			$665						$665
Total Revenues	35.5		$2,555	45.4	$39.90	$1,810	80.9		$4,365
Expenses:									
Capacity & Delivery Expenses			($525)			($140)			($665)
Purchased Power	3.1	($51)	($160)				3.1	($51)	($160)
Nuclear Fuel	32.4	($7.15)	($230)				32.4	($7.15)	($230)
Fossil Fuel				45.4	($27.60)	($1,250)	45.4	($27.60)	($1,250)
Total Expenses	35.5		($915)	45.4		($1,390)	80.9		($2,305)
Commodity Margin			**$1,640**			**$420**			**$2,060**
Commodity Margin (excl. Capacity Revenue)		**~$28**	**$975**		**~$9**	**$420**		**~$17**	**$1,395**

Closed Contribution	+	Open Contribution	=	CES Adjusted EBITDA[1] – 2016F
$430 - $530		$420		$850 - $950

Please see slide 109 for additional notes describing "Sales" and "Expenses"

[1] Total CES 2016F Adjusted EBITDA, a non-GAAP financial measure, is reconciled to 2016F CES Net Income on slide 136, and is based on market prices as of October 21, 2014. The "Closed contribution" to Adjusted EBITDA is based on committed sales whereas the "Open contribution" to Adjusted EBITDA is based on currently uncommitted sales that are assumed to be sold in the wholesale market assuming market prices as of October 21, 2014. The purpose of the table above is to summarize the impact on Adjusted EBITDA of changes in market prices on currently uncommitted sales.

2015 CES Adjusted EBITDA Notes

- **Sales:**
  - Volume in all channels, with the exception of wholesale, is subject to fluctuations due to weather and customer behavior.
  - When wholesale volumes are committed they will be categorized as “Closed” and moved to the appropriate channel. Additional retail channel sales could include an operating margin of ~$2 to $3 per MWH.
  - Wholesale “Open” position is based on forward market prices at AD Hub as of October 21, 2014. The “Closed” position represents physical and financial transactions executed to reduced market price risk.
  - “Other” sales include distribution losses and pumping for Hydro units.
- **Expenses:**
  - Capacity expense is the cost associated with serving load, net of incremental capacity auctions and bilateral transactions and credits associated with serving load, Capacity Transfer Rights or CTRs.
  - Delivery expenses, net of delivery revenues, include congestion, losses, ancillaries, Network Integration Transmission Service and the cost of Financial Transmission Rights. Can vary based on delivery location, channel and market conditions.
    - A delivery expense of ~$2 – $3/MWH is incurred to serve wholesale load
    - A delivery expense of ~$3 – $6/MWH is incurred to serve retail load
  - Generation volume is committed in the following order: (1) Purchased Power, which includes Renewables/OVEC of ~2M MWH and additional Bilateral/Spot Purchases, (2) Nuclear, and (3) Fossil.
  - Fossil Fuel expense includes Coal, Gas, and Hydro.
  - Nuclear Fuel expense reflects the reduction of the DOE nuclear fuel disposal fee.
  - Total Adjusted EBITDA includes other operating expenses such as, O&M, Non Income Taxes, as well as variability (+/- $50M) in other revenues and expenses such as, customer usage, weather, planned generation output, and spot purchases.

2016 CES Adjusted EBITDA Notes

- **Sales:**
  - Volume in all channels, with the exception of wholesale, is subject to fluctuations due to weather and customer behavior.
  - When wholesale volumes are committed they will be categorized as “Closed” and moved to the appropriate channel. Additional retail channel sales could include an operating margin of ~$2 to $3 per MWH.
  - Wholesale “Open” position is based on forward market prices at AD Hub as of October 21, 2014. The “Closed” position represents physical and financial transactions executed to reduced market price risk.
  - “Other” sales include distribution losses and pumping for Hydro units.
  - Capacity Revenue includes revenues from the BRA as well as the results of incremental capacity auctions, bilateral transactions and credits associated with serving load (CTRs).
- **Expenses:**
  - Capacity expense is the cost associated with serving load.
  - Delivery expenses, net of delivery revenues, include congestion, losses, ancillaries, Network Integration Transmission Service and the cost of Financial Transmission Rights. Can vary based on delivery location, channel and market conditions.
    - A delivery expense of ~$2 – $3/MWH is incurred to serve wholesale load
    - A delivery expense of ~$3 – $6/MWH is incurred to serve retail load
  - Generation volume is committed in the following order: (1) Purchased Power, which includes Renewables/OVEC of ~2M MWH and additional Bilateral/Spot Purchases, (2) Nuclear, and (3) Fossil.
  - Fossil Fuel expense includes Coal, Gas, and Hydro.
  - Nuclear Fuel expense reflects the reduction of the DOE nuclear fuel disposal fee.
  - Total Adjusted EBITDA includes other operating expenses such as, O&M, Non Income Taxes, as well as variability (+/- $50M) in other revenues and expenses such as, customer usage, weather, planned generation output, and spot purchases.

CES Commodity Margin Current Assumptions

		2014	2015	2016
Energy Prices	**AD Hub Forwards** (On-peak/Off-peak $/MWH)	**$41 / $32**	**$45 / $30**	**$44 / $31**
	PJM West Forwards (On-peak/Off-peak $/MWH)	**$46 / $35**	**$50 / $33**	**$48 / $33**
	Ind Hub (On-peak/Off-peak $/MWH)	**$39 / $30**	**$43 / $28**	**$43 / $29**
Fuel Prices	**Henry Hub Natural Gas** ($/MMBTU)	**$3.72**	**$3.74**	**$3.91**
	Dominion South Natural Gas ($/MMBTU)	**$2.34**	**$2.48**	**$2.83**

	Impact to Commodity Margin/Adjusted EBITDA	
Sensitivities*	**2015**	**2016**
+ / - $5/MWH RTC Energy Prices	**- / + $110M**	**- / + $225M**
Fuel Cost Exposure		
+ / - $1/MMBTU Natural Gas	**- / + $23M**	**- / + $31M**
+ / - $5/Ton Eastern Coal	**- / + $10M**	**- / + $41M**
+ / - $5/Ton Western Coal	**- / + $2M**	**- / + $2M**

As of 10/21/2014

*RTC energy price sensitivities relate to the impact of the change in prices on CES' open position. Gas and coal sensitivities relate to the impact of the change in prices on CES' open gas and coal position.

Committed Sales by Zone

Calendar Year	2013A			2014F			2015F			2016F		
Committed Sales	**M MWH**	**$ M**	**$/MWH**	**M MWH**	**$ M**	**$/MWH**	**M MWH**	**$ M**	**$/MWH**	**M MWH**	**$ M**	**$/MWH**
ATSI	40	$2,155	$54	33	$1,900	$57	24	$1,530	$63	17	$1,050	$60
Rest of RTO	49	2,450	50	45	2,340	52	25	1,300	52	13	680	51
MAAC	12	755	65	11	735	67	5	335	66	1	100	71
EMAAC	2	160	75	2	170	74	1	85	74	1	20	77
MISO	6	285	47	7	305	46	4	170	45	1	40	50
Total Committed Sales	109	$5,805	$53	98	$5,450	$56	59	$3,420	$58	33	$1,890	$57

Planning Year	PY 13/14A			PY 14/15F			PY 15/16F			PY 16/17F		
Committed Sales	**M MWH**	**$ M**	**$/MWH**	**M MWH**	**$ M**	**$/MWH**	**M MWH**	**$ M**	**$/MWH**	**M MWH**	**$ M**	**$/MWH**
ATSI	39	$2,120	$54	28	$1,670	$60	22	$1,480	$66	14	$815	$58
Rest of RTO	49	2,485	50	38	1,990	52	18	945	51	10	520	51
MAAC	11	760	67	9	605	65	3	180	69	1	70	70
EMAAC	2	180	75	2	145	74	1	45	75	<1	15	78
MISO	7	305	46	6	255	46	2	110	46	1	30	52
Total Committed Sales	109	$5,850	$54	83	$4,665	$56	46	$2,760	$60	26	$1,450	$55

Numbers may not foot due to rounding

Beginning June 2016 FE Ohio GA rate has been forecasted based on projected PTC

Committed Sales by Channel

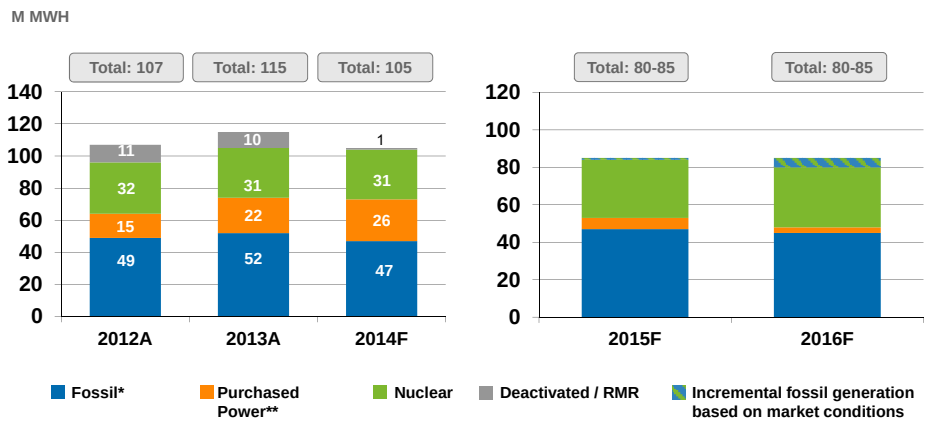
Calendar Year	2014F			2015F			2016F		
Committed Sales	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH
MM	7	$460	$67	4	$245	$68	2	$130	$70
MCI	3	220	63	2	110	66	1	55	64
LCI	40	2,130	53	19	1,035	53	6	370	55
GA	20	1,190	61	15	1,080	70	14	860	63
POLR	16	890	57	8	450	59	2	125	65
Structured	12	560	44	10	440	45	7	305	44
Wholesale	-	-	-	1.5	60	41	1	45	41
Total Committed Sales	98	$5,450	$56	59	$3,420	$58	33	$1,890	$57

Planning Year	PY 14/15F						PY 15/16F						PY 16/17F					
	Jun - Dec 14			Jan - May 15			Jun - Dec 15			Jan - May 16			Jun - Dec 16			Jan - May 17		
Committed Sales	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH
MM	4	$250	$67	2	$125	$67	2	$120	$69	1	$65	$69	1	$65	$68	<1	$25	$77
MCI	2	125	66	<1	60	67	1	50	63	<1	25	64	<1	30	66	<1	15	59
LCI	20	1,100	52	10	525	53	9	510	53	3	180	55	3	190	54	1	70	55
GA	11	705	65	7	430	62	8	650	75	6	420	71	8	440	57	5	325	65
POLR	8	495	59	6	315	57	2	135	66	1	90	65	1	35	69	<1	25	69
Structured	8	345	45	5	190	44	5	250	46	4	160	44	3	145	42	2	85	42
Wholesale	-	-	-	-	-	-	2	60	39	1	45	41	-	-	-	-	-	-
Total Committed Sales	53	$3,020	$55	30	$1,645	$59	29	$1,775	$57	17	$985	$60	16	$905	$55	10	$545	$55

Numbers may not foot due to rounding

Beginning June 2016 FE Ohio GA rate has been forecasted based on projected PTC

CES Generation Portfolio



Planned ongoing generation resources of 80- 85M MWH annually

* Fossil includes Coal, Gas, and Hydro excluding pumping; excludes deactivated and RMR units

** Purchased Power includes Renewables/OVEC and additional Bilateral/Spot Purchases

Competitive Fuel Sources

	2013A*	2014F	2015F	2016F
Fossil (M MWH)	52	47	47	45
Nuclear (M MWH)	31	31	31	32
Total	83	78	78	78
Hedged Fossil		100%	85%-90%	80%-85%
Hedged Nuclear		100%	100%	100%
Fossil $/MWH	$26.69	~$28.00	~$27.50	~$27.50
Nuclear $/MWH	$7.79	~$7.50**	~$7.00**	~$7.00**
Total Competitive Fleet $/MWH	$19.61	~$19.50	~$19.00	~$19.00

			2014F Total Fleet - Coal Sources		
	Plants	Units	NAPP	Western	Petcoke
Supercritical Units	Mansfield	1-3	✓		
	Pleasants	1-2	✓		
	Sammis	6-7	✓	✓	
Subcritical Units	Sammis	1-5	✓	✓	
	Bay Shore	1			✓

Coal Consumption	2014F	M Tons	16	1	1
	2013A	M Tons	21	2	1

*Fossil includes Coal, Gas, and Hydro excluding pumping; excludes deactivated and RMR units

**Adjusted for termination of the DOE spent nuclear fuel fee

Reliability Pricing Model Capacity

Auction Results
Price Per Megawatt-Day

		RTO		MAAC	EMAAC
		ATSI	Rest of RTO		
2011 – 2012	FRR Integration Auction	$108.89	–	–	–
2012 – 2013	FRR Integration Auction	$20.46	–	–	–
2010-2011	BRA	N/A	$174.29	$174.29	$174.29
2011-2012	BRA	N/A	$110.00	$110.00	$110.00
2012-2013	BRA	N/A	$16.46	$133.37	$139.73
2013-2014	BRA	$27.73	$27.73	$226.15	$245.00
2014-2015	BRA	$125.99	$125.99	$136.50	$136.50
2015-2016	BRA	$357.00	$136.00	$167.46	$167.46
2016-2017	BRA	$114.23	$59.37	$119.13	$119.13
2017 - 2018	BRA	$120.00	$120.00	$120.00	$120.00

Future Capacity Auctions

	Base Residual	First Incremental	Second Incremental	Third Incremental
2015 - 2016	–	–	–	February 2015
2016 - 2017	–	–	July 2015	February 2016
2017 - 2018	–	September 2015	July 2016	February 2017
2018 - 2019	May 2015	September 2016	July 2017	February 2018

- **First Incremental Auction for 2016-2017 held in September 2014**
  - 500 MW of FE Competitive Generation cleared at ~$100/MWD

This schedule does not incorporate any potential changes from a PJM filing for transitional auctions for their Capacity Performance Product

PJM Capacity Revenues

BRA Cleared/Current Available MW

	13/14	14/15	15/16	16/17		17/18	
	Cleared	Cleared	Cleared	Cleared	Available	Cleared	Available
ATSI	6,830	5,645	7,070	3,845	2,490	4,285	2,455
RTO	5,670	4,720	5,040	3,460	275	4,515	-
MAAC	85	85	80	80	-	75	-
EMAAC	55	55	55	55	-	55	-
TOTAL – CLEARED/AVAILABLE	12,640	10,505	12,245	7,440	2,765	8,930	2,455
Total Capacity Revenue ($M)	$140	$485	$1,185	$240		$390	

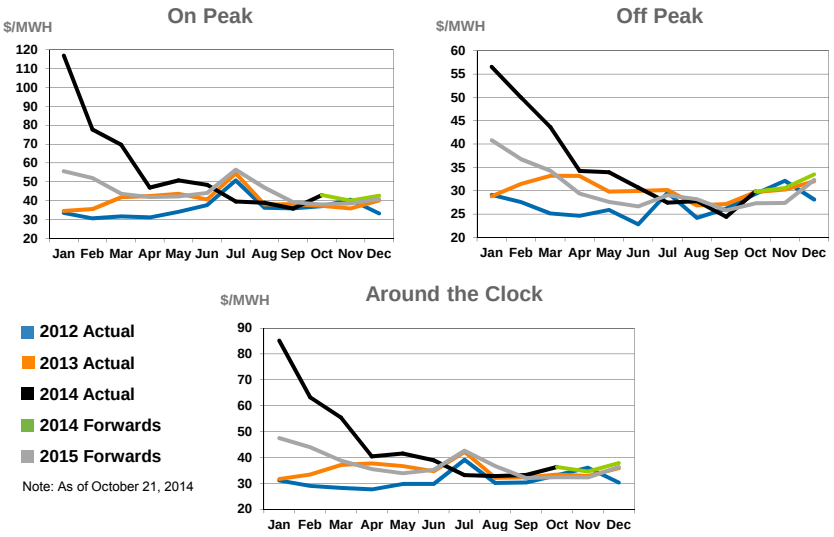
PJM BRA Capacity Revenues ($ Millions)

	2014	2015	2016	2017
ATSI	$180	$645	$480	$175
RTO	$150	$235	$145	$145
MAAC	$5	$5	$5	$5
EMAAC	$5	$5	$5	$5
Total Cleared Revenue	$340	$890	$635	$330

- **The "Cleared" MW and Revenues above reflect only results from the PJM Base Residual Auction**
- **Units that have been deactivated are included for years in which they cleared as their capacity obligations will be met with sources that did not clear or with purchased replacement capacity**
- **Units that have been sold/transferred are excluded from MW and capacity revenues**
- **PY 14/15 includes:**
  - MW and revenues from the portion of Pleasants transferred to CES
  - RMR unit revenues
- **"Available" MW:**
  - Include MW that did not clear the BRA or incremental auctions and can be offered into future incremental auctions
  - If "Available" MW cleared at $50/MWD in incremental auctions, would produce additional ~$50M in revenues for PY 16/17, ~$45M in revenues for PY 17/18

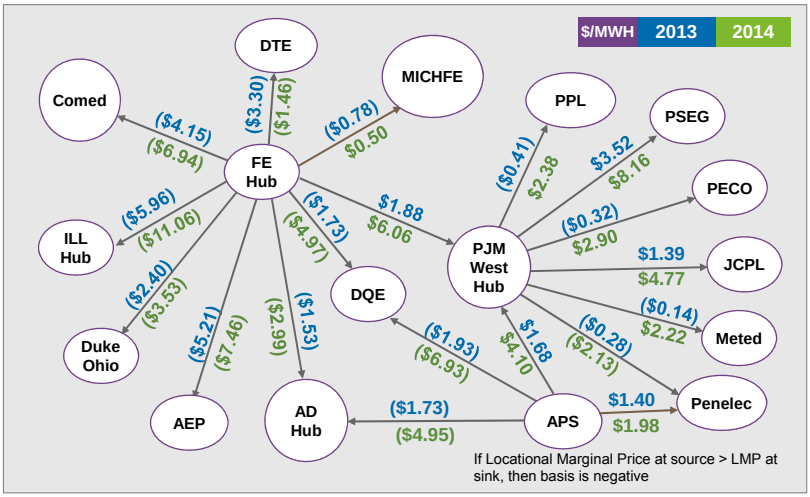
Power Price Trends

AD Hub



Note: As of October 21, 2014

Commodity Operations – **Basis Risk**



- **Basis risk mitigated by limiting geographic scope of sales obligation**
- **Basis risk hedged with basis and financial swaps as well as power transactions at the zones**
- **Values shown are around-the-clock, day-ahead average basis values**

Commodity Operations – **Annual Historical Basis Values**

A negative value means the Locational Marginal Price (LMP)* at the source is greater than the LMP at the sink

Source	Sink	2012 ($/MWH)	2013 ($/MWH)	2014 ($/MWH)
FE Hub	Ill Hub	(5.04)	(5.96)	(11.06)
FE Hub	Comed	(3.31)	(4.15)	(6.94)
FE Hub	DTE	(1.33)	(3.30)	(1.46)
FE Hub	MichFE	(0.57)	(0.78)	0.50
FE Hub	PJM West Hub	1.78	1.88	6.06
FE Hub	DQE	(0.58)	(1.73)	(4.97)
FE Hub	AD Hub	(0.88)	(1.53)	(2.99)
FE Hub	AEP	(4.39)	(5.21)	(7.46)
FE Hub	Duke Ohio	(1.56)	(2.40)	(3.53)
APS	AD Hub	(1.60)	(1.73)	(4.95)
APS	DQE	(1.29)	(1.93)	(6.93)
APS	PJM West Hub	1.07	1.68	4.10
APS	Penelec	0.59	1.40	1.98
PJM West Hub	PPL	(0.70)	(0.41)	2.38
PJM West Hub	PSEG	0.86	3.52	8.16
PJM West Hub	PECO	0.12	(0.32)	2.90
PJM West Hub	JCP&L	0.35	1.39	4.77
PJM West Hub	Met-Ed	(0.21)	(0.14)	2.22
PJM West Hub	Penelec	(0.48)	(0.28)	(2.13)

*Values shown are around-the-clock, day-ahead average basis values

Repositioning Our Competitive Generation Portfolio
2012 - 2015

Deactivations

Competitive	NDC MW	RMR/Planned Deactivation MW	2012 M MWH	2012 Capacity Factor (%)	Deactivation Date
Eastlake 1-5	1,233	396 (1-3)	4.5	53	9/1/2012 (4-5); 4/15/2015 (1-3)*
Bay Shore 2-4	495	–	0.4	12	9/1/2012
Armstrong	356	–	0.3	16	9/1/2012
Lake Shore 18	245	245	0.2	9	4/15/2015*
Ashtabula 5	244	244	0.2	12	Under RMR status until 4/15/2015
R. Paul Smith 3-4	116	–	0.1	12	9/1/2012
Hatfield 1-3	1,710	–	9.7	64	10/9/2013
Mitchell 2-3	370	–	1.2	47	10/9/2013
Total	4,769	885	16.6		

*Units were under RMR status until September 15, 2014 and are now included in CES Generation and planned to be deactivated by April 15, 2015

Transfers and Sales

Competitive	NDC MW	Date
Harrison / Pleasants Asset Transfer	1,476	10/9/2013
Hydro Asset Sales	527	2/12/2014
Total	2,003	

Competitive Generation – **Plant Details**

Plant Name	PJM Zone	State	Fuel Type	Units	Net Maximum Capacity (MW)	Year Plant Commissioned
Ashtabula	ATSI	OH	Coal	1	244	1958
Bay Shore	ATSI	OH	Coal, Oil	2	153	1955
Davis-Besse	ATSI	OH	Nuclear	1	908	1977
Eastlake	ATSI	OH	Coal, Oil	4	425	1953
Lake Shore	ATSI	OH	Coal, Oil	2	249	1962
Mansfield	ATSI	PA	Coal	3	2,490	1976
Perry	ATSI	OH	Nuclear	1	1,268	1987
R.E. Burger	ATSI	OH	Oil	1	7	1972
Sammis	ATSI	OH	Coal, Oil	8	2,233	1959
West Lorain	ATSI	OH	Natural Gas, Oil	2	545	1973
Total ATSI Zone Generation					**8,522**	
Forked River*	EMAAC	NJ	Natural Gas		86	
Total EMAAC Zone Generation					**86**	

*Long-term PPA

Competitive Generation – **Plant Details** (Continued)

Plant Name	PJM Zone	State	Fuel Type	Units	Net Maximum Capacity (MW)	Year Plant Commissioned
Hunlock	MAAC	PA	Natural Gas	1	45	2000
Wind Farms*	MAAC	Multiple	Wind	Multiple	277	
Total MAAC Zone Generation					**322**	
Bath County	Rest of RTO	VA	Hydro	6	713	1985
Beaver Valley	Rest of RTO	PA	Nuclear	2	1,872	1976
Buchanan	Rest of RTO	VA	Natural Gas	1	43	2002
Chambersburg	Rest of RTO	PA	Natural Gas	1	88	2001
Gans	Rest of RTO	PA	Natural Gas	1	88	2000
Maryland Solar*	Rest of RTO	MD	Solar	Multiple	20	
OVEC*	Rest of RTO	Multiple	Coal	Multiple	177**	
Pleasants	Rest of RTO	WV	Coal	2	1,300	1979
Springdale	Rest of RTO	PA	Natural Gas	5	638	1999
Wind Farms*	Rest of RTO	Multiple	Wind	Multiple	199	
Total Rest of RTO Generation					**5,138**	
Total Competitive Generation					**14,068**	

*Long-term PPA
**Represents FES' 4.85% and AE Supply's 3.01% entitlement

Fossil **Environmental Controls**

	Plant	NDC	NOx Controls					SO_2 Controls		Particulate		Cooling Towers
			SCR	SNCR	COS	LNB	OFA	Scrubbers[1]	Lo-S Fuel	Baghouse	Electro/Other[2]	
Supercritical	Mansfield 1-3	2,490	✔		✔	✔	✔	✔			✔	✔
	Pleasants 1-2	1,300	✔			✔		✔			✔	✔
	Sammis 6 & 7	1,200	✔	✔	✔	✔	✔	✔			✔	
	Sub-total	4,990										
Subcritical	Sammis 1 - 4	720		✔	✔	✔	✔	✔		✔		
	Sammis 5	300		✔	✔	✔	✔	✔			✔	
	Bay Shore 1 (CFB [3])	136				[3]		[3]		✔		
	Sub-total	1,156										
RMR/Planned Deactivations[4]	Ashtabula 5	244				✔					✔	
	Eastlake 1	132				✔	✔				✔	
	Eastlake 2	132				✔	✔				✔	
	Eastlake 3	132				✔	✔				✔	
	Lake Shore 18	245							✔		✔	
	Sub-total	885										

[1]Scrubbed coal units have FGD (Flue Gas Desulfurization - equipment to remove sulfur from flue gas after combustion)
[2]Particulate Controls can include Venturi Scrubber or Electrostatic Precipitator
[3]CFB (Circulating Fluidized Bed) Boiler is inherently low emitting for NOx and SO_2
[4]See slide 121

In 2015, nearly 100% of the power the competitive portfolio generates is expected to come from low-or non-emitting sources, including nuclear, natural gas, scrubbed coal and renewable energy

MATS Overview

- **MATS**
  - Total compliance cost estimate of $178M

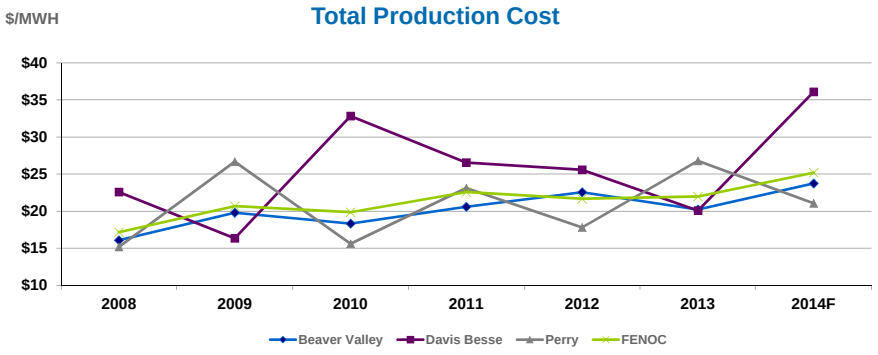
Plant	Technologies
Bay Shore 1	Baghouse Fabric Filter changes, Mini ACI system, CEMS
Sammis 1-7	Precip Controls, CEMS
Mansfield 1-3	WFGD Changes, SCR Changes, CEMS
Pleasants 1-2	Precip Changes, FGD Changes, SCR Catalyst, Duct Repairs, CEMS

Nuclear **Key Events**

Key Events	Beaver Valley 1 (939 MW)	Beaver Valley 2 (933 MW)	Davis-Besse (908 MW)	Perry (1,268 MW)
License Expiration	2036	2047	2017*	2026**
2012	▪ **Completed planned outage**	▪ **Completed planned outage** – Low-pressure turbine rotor replacement	▪ **Completed planned outage** – Perform additional shield building monitoring	▪ **Implemented dry cask fuel storage** ▪ **Supplemental NRC inspection (95002)**
2013	▪ **Completed planned outage**	▪ **Completed fuel pool rerack**	▪ **Relicensing process** – NRC issued final Safety Evaluation Report (SER) in license renewal process	▪ **Completed planned outage** ▪ **Supplemental NRC inspection (95002) completed satisfactorily**
2014	▪ **Implement dry fuel storage**	▪ **Planned outage** – Refueling	▪ **Completed planned outage** – Refueling – Steam generator replacement ▪ **Relicensing process** – NRC scheduled to issue Supplemental Environmental Impact Statement (SEIS)	▪ **Prepare for License Renewal Application submittal**
2015	▪ **Planned outage** – Refueling	▪ **Planned outage** – Refueling		▪ **Submit License Renewal Application** ▪ **Planned outage** – Refueling
2016	▪ **Planned outage** – Refueling		▪ **Planned outage** – Refueling	
2017		▪ **Planned outage** – Refueling	▪ **Implement dry fuel storage**	▪ **Planned outage** – Refueling

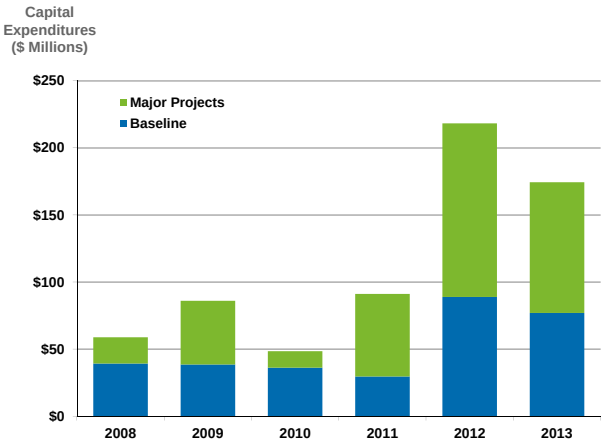
*License Renewal Application submitted in 2010 **Submit License Renewal Application in 2015

Nuclear **Operating Costs**



FENOC	2008	2009	2010	2011	2012	2013	2014F
O&M ($/MWH)	$13	→	→	→	→	→	$17
Fuel ($/MWH)	$5	→	→	→	→	→	$8
Generation (M MWH)	32.2	29.2	30.9	29.8	31.8	30.9	31.1

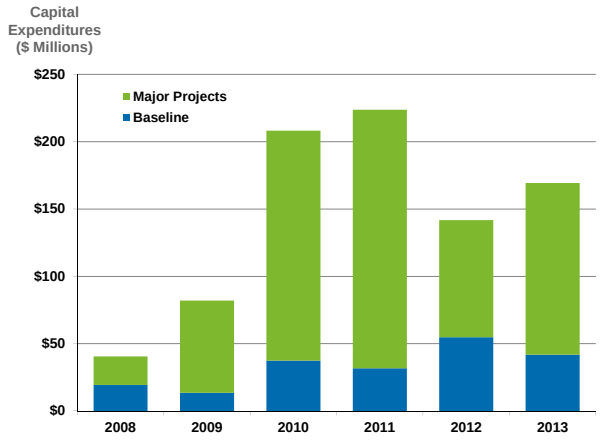
Beaver Valley



Major projects include:

- Steam Generator Replacement
- Low-Pressure Turbine Rotor Replacement
- Reactor Vessel Head Replacement

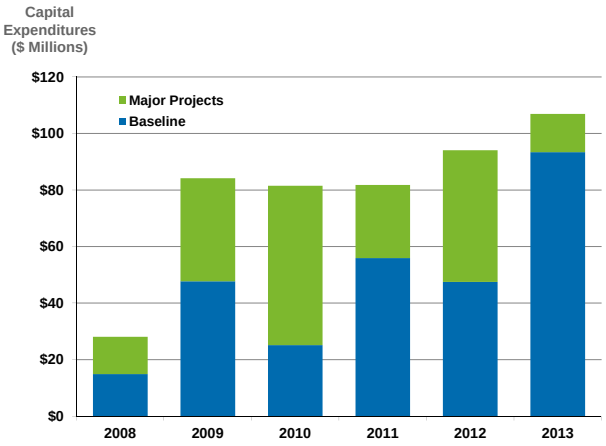
Davis-Besse



Major projects include:

- Reactor Vessel Head Replacement
- Steam Generator Replacement
- Main Generator Rewind
- Alloy 600 Mitigation

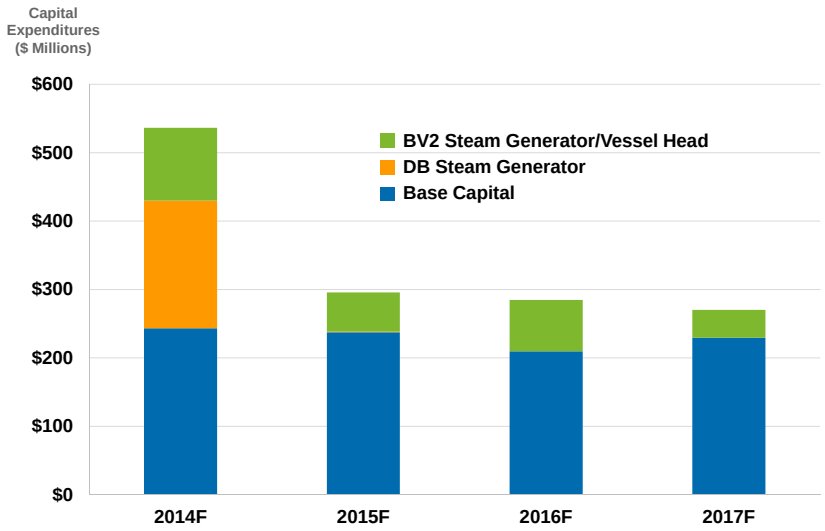
Perry



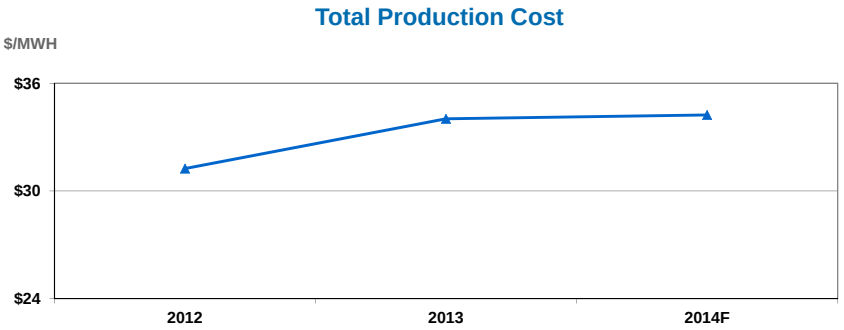
Major projects include:

- Low-Pressure Turbine Rotor Replacement
- Main Generator Rewind
- Alternate Decay Heat Removal System Replacement

Nuclear **Fleet Capital**

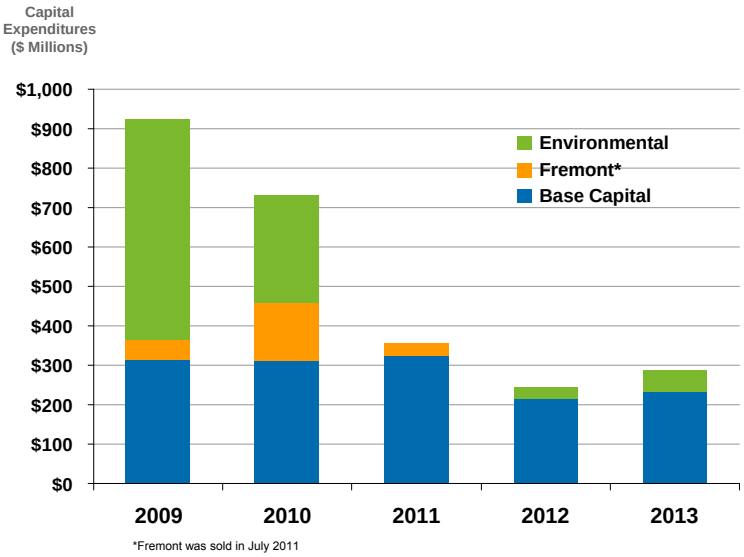


Fossil **Operating Costs**

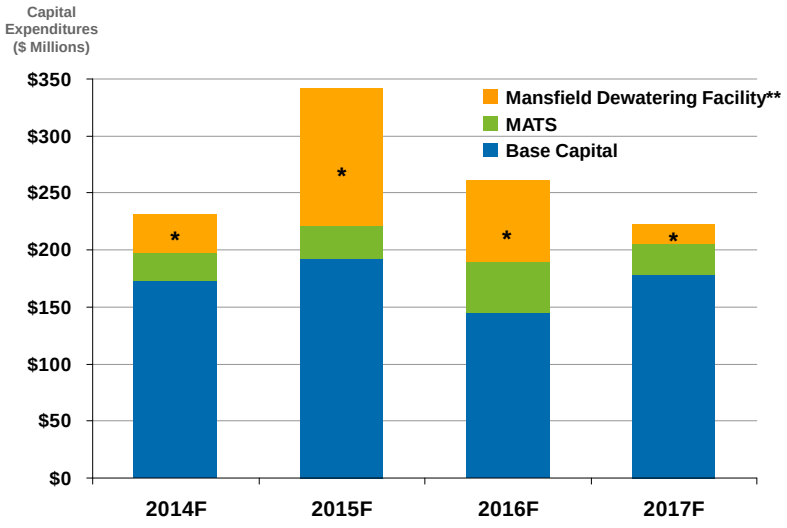


Fossil	2012	2013	2014F
O&M ($/MWH)	$6	$6	$6
Fuel ($/MWH)	$26	$28	$28
Generation (M MWH)	64.7	61.1	47.0

Fossil **Fleet Capital**

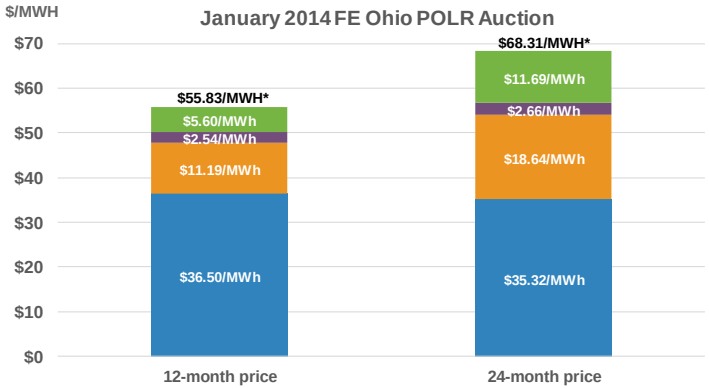


Fossil **Fleet Capital**



*To Be Determined
**Due to closure of LBR by end of December 2016, Mansfield's CCBs must be converted to a dry product for disposal.

Illustration of POLR Components



The following components are estimated and for illustrative purposes only:

Energy:	Energy price at AD Hub on 1/29/2014 for FE Ohio slice of system load shape
Capacity:	RPM Capacity expense for product
Delivery:	Contains all non-energy; non-capacity RTO expenses. In OH, Network Integration Transmission Service is excluded.
Risk Premium:	Contains margin and risk premiums associated with load shape and price volatility

*Represents the actual OH POLR Clearing Price

Competitive Operations
Net Income(Loss) to Adjusted EBITDA* Reconciliation

($ Millions)	2014F	2015F	2016F
Net Income(Loss) – GAAP	$(320) – $(235)	$150 – $270	$95 – $205
Special Items (after tax)*	385 – 340	60 – 40	40 – 30
Operating Earnings	$65 - $105	$210 - $310	$135 - $235
Income Taxes	40 – 60	125 – 180	80 – 140
Interest Expense, Net	155 – 145	165 – 150	155 – 140
Depreciation & Amortization **	460 – 450	475 – 460	525 – 500
Other Income	(80)	(75) – (100)	(45) – (65)
Adjusted EBITDA*	$640 – $680	$900 – $1,000	$850 – $950

* Adjusted EBITDA represents GAAP net income adjusted for the special items listed on slide 137 and the addition of income taxes; interest expense, net; depreciation and amortization and other income

**Does not include nuclear fuel amortization of approximately $220 M in 2014, 2015, and 2016

Competitive Operations – **Special Items**

($ Millions)	2014F	2015F	2016F
Pre-tax items			
Total Securities Impairment	$9	$ –	$ –
Merger Accounting – Commodity Contracts	40	40 – 45	40 – 45
Non-Core Asset Sales/Impairments	(110)	10 – 20	10 – 20
Plant Closing Costs	205	–	–
Loss on Debt Redemptions	8	–	–
Mark to Market Adjustments			
Pension/OPEB actuarial assumption*	235 - 300	–	–
Other	68	–	–
Retail Repositioning Charges	70	15 - 30	–
Subtotal	$525 - $590	$65 - $95	$50 - $65
Income Taxes	(185) – (205)	(25) – (35)	(20) – (25)
After Tax Effect – Special Items	$340 – $385	$40 – $60	$30 – $40

*Based on current discount rates ranging from 4.50% to 4.25% and an expected return on plan assets of 7.75%.

Competitive Operations – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
FEGENCO	Pollution Control Note	677660UC4	Variable*	10/1/2018	$2,805,000
	Pollution Control Note	677525UZ8	Variable*	10/1/2018	$2,985,000
	Pollution Control Note	074876HE6	Variable*	10/1/2047	$46,300,000
	Pollution Control Note	708686DX5	Variable*	6/1/2028	$15,000,000
	Pollution Control Note	074876HK2	Variable*	6/1/2028	$25,000,000
	Pollution Control Note	677525VK0	3.75%**	12/1/2023	$234,520,000
	Pollution Control Note	708686DA5	3.375%**	12/1/2040	$43,000,000
	Pollution Control Note	677660UE0	2.25%**	8/1/2029	$6,450,000
	Pollution Control Note	677525VB0	2.25%**	8/1/2029	$100,000,000
	Pollution Control Note	074876HF3	2.15%**	3/1/2017	$28,525,000
	Pollution Control Note	074876HJ5	2.5%**	12/1/2041	$129,610,000
	Pollution Control Note	677525TF4	5.625%	6/1/2018	$141,260,000
	Pollution Control Note	708686DB3	2.55%**	11/1/2041	$26,000,000

* Subject to mandatory redemption upon expiration of associated letter of credit; may later be remarketed, subject to market and other conditions
** Currently a fixed rate subject to mandatory put prior to maturity; may later be remarketed, subject to market and other conditions
Note: FES' debt obligations are guaranteed by its subsidiaries, FEGENCO and FENUGENCO, and FES guarantees the debt obligations of FEGENCO and FENUGENCO

Competitive Operations – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
FEGENCO	Pollution Control Note	074876HL0	3.5%**	11/1/2041	$56,600,000
	Pollution Control Note	677525TK3	5.7%	8/1/2020	$177,000,000
	Pollution Control Note	677525VP9	3.1%**	3/1/2023	$50,000,000
	Pollution Control Note	677660UL4	3.0%	5/15/2019	$90,140,000
				FEGENCO Total	**$1,175,195,000**
FENUGENCO	Pollution Control Note	677525VR5	3.625%**	10/1/2033	$9,100,000
	Pollution Control Note	677660UM2	3.625%**	10/1/2033	$20,450,000
	Pollution Control Note	677660UN0	3.95%**	11/1/2032	$33,000,000
	Pollution Control Note	677525VS3	3.95%**	11/1/2032	$23,000,000
	Pollution Control Note	677660UJ9	4.0%**	12/1/2033	$135,550,000
	Pollution Control Note	677660UK6	4.0%**	6/1/2033	$46,500,000
	Pollution Control Note	677525UA3	3.75%**	6/1/2033	$26,000,000
	Pollution Control Note	677525TY3	3.375%**	7/1/2033	$8,000,000

** Currently a fixed rate subject to mandatory put prior to maturity; may later be remarketed, subject to market and other conditions
Note: FES' debt obligations are guaranteed by its subsidiaries, FEGENCO and FENUGENCO, and FES guarantees the debt obligations of FEGENCO and FENUGENCO

Competitive Operations – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
FENUGENCO	Pollution Control Note	677660TV4	3.375%**	7/1/2033	$99,100,000
	Pollution Control Note	677525TZ0	3.375%**	1/1/2034	$7,200,000
	Pollution Control Note	677660TU6	3.375%**	1/1/2034	$82,800,000
	Pollution Control Note	074876GX5	3.375%**	1/1/2035	$72,650,000
	Pollution Control Note	677660TP7	5.875%**	6/1/2033	$107,500,000
	Pollution Control Note	677525TE7	5.75%**	6/1/2033	$62,500,000
	Pollution Control Note	677660UF7	2.2%**	6/1/2033	$54,600,000
	Pollution Control Note	677525VQ7	3.625%**	12/1/2033	$15,500,000
	Pollution Control Note	074876HG1	2.2%**	1/1/2035	$60,000,000
	Pollution Control Note	074876HH9	2.7%**	4/1/2035	$98,900,000
	Pollution Control Note	074876HM8	3.5%**	12/1/2035	$163,965,000

** Currently a fixed rate subject to mandatory put prior to maturity; may later be remarketed, subject to market and other conditions
Note: FES' debt obligations are guaranteed by its subsidiaries, FEGENCO and FENUGENCO, and FES guarantees the debt obligations of FEGENCO and FENUGENCO

Competitive Operations – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
FENUGENCO	Collateralized Lease Bonds	N/A	9.12%	5/30/2016	$17,161,000
	Collateralized Lease Bonds	N/A	8.83%	5/30/2016	$1,233,000
	Collateralized Lease Bonds	N/A	9.0%	6/1/2017	$17,054,000
	Collateralized Lease Bonds	N/A	12.0%	6/1/2017	$505,604
	Collateralized Lease Bonds	N/A	8.89%	6/1/2017	$78,310,000
	Collateralized Lease Bonds	N/A	8.68%	6/1/2017	$17,058,000
				FENUGENCO Total	**$1,257,636,604**

Competitive Operations – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
FES	Senior Note	33766JAD5	6.05%	8/15/2021	$332,305,000
	Senior Note	33766JAF0	6.8%	8/15/2039	$363,281,000
	Term Note	N/A	5.15%	7/1/2015	$17,732,775
				FES Total	**$713,318,775**
AE Supply	Pollution Control Note	41524CAU8	5.5%	10/15/2037	$73,500,000*
	Pollution Control Note	728896CF6	5.25%	10/15/2037	$142,000,000
	Senior Note	017363AK8	5.75%	10/15/2019	$155,532,000
	Senior Note	017363AM4	6.75%	10/15/2039	$150,034,000
				AE Supply Total	**$521,066,000**
AGC	Senior Note	Private Placement	5.06%	7/15/2021	$100,000,000
				AGC Total	**$100,000,000**

*Mon Power assumed primary liability for this Note in connection with the Harrison transfer

Note: FES' debt obligations are guaranteed by its subsidiaries, FEGENCO and FENUGENCO, and FES guarantees the debt obligations of FEGENCO and FENUGENCO

Financial



Financial – **Liquidity**

Available Liquidity
($ Millions)

	FEG	FET	FEU	FE Corp.	FE Consolidated
Revolving Credit Facility	**$ 1,500**	**$ 1,000**	**$ 3,500**		**$ 6,000**
Short-term borrowings	–	(75)	(100)	(1,300)	**(1,475)**
Letters of Credit (LOC)	(48)	–	–	(6)	**(54)**
Total Utilization	**$ (48)**	**$ (75)**	**($1,406)**		**$ (1,529)**
Available External Credit Capacity	**$ 1,452**	**$ 925**	**$2,094**		**$ 4,471**
Cash & Investments	–	59	–	38	**97**
Available Liquidity	**$ 1,452**	**$ 984**	**$2,132**		**$ 4,568**

As of October 31, 2014

Financial – **Parental Guarantees**

	FirstEnergy Corp. Parent					
	Competitive		Regulated		Corp/Other	
	$M	Expiration	$M	Expiration	$M	Expiration
Energy Related Contracts	$41	2020-2030	–	–	–	–
Fuel Related Contracts	$37	2021-2031	–	–	–	–
Retail Contracts	$99	2014-2016	–	–	–	–
Benefit Related Programs	$124	–	$155	–	$200	–
Other	$10	2015	$4	2030	$3	–
Total FE Guarantee on behalf of subsidiaries	**$311**		**$159**		**$203**	

As of October 31, 2014

Financial – **Collateral Dependent on Investment Grade Rating**

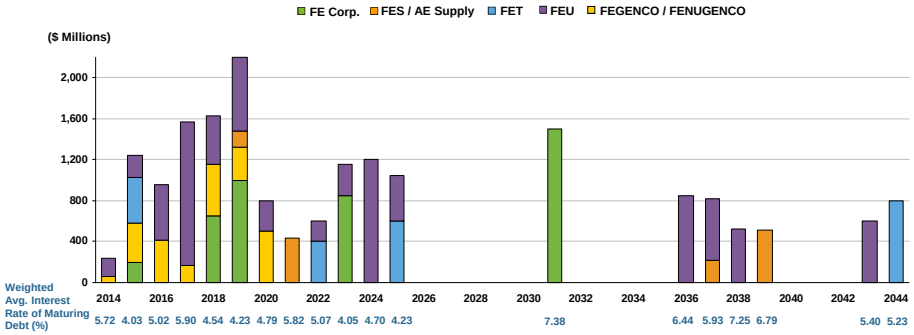
($ Millions)

Collateral Provisions As of September 30, 2014	FES* (tied to FE Corp. rating)	FES* (tied to FES rating)	Utilities	Total
Split Rating (One Rating Agency below investment grade)	**$124****	**$376**	**$52**	**$552**
Non-Investment Grade Ratings (All Rating Agencies at or below BB+/Ba1)	**$130**	**$413**	**$52**	**$595**
Total Exposure from Contractual Obligations	**$238**	**$618**	**$90**	**$946**

*Includes AE Supply

**Exists due to FE Corp's current Unsecured Rating of BB+ by Standard & Poors

Consolidated Long-Term Debt Maturities



Excludes variable rate tax-exempt debt and securitization bonds

Financial – **Debt Targets**

Segment	FirstEnergy Utilities (FEU)	FirstEnergy Transmission (FET)		Competitive Energy Services (CES)
		HoldCo	OpCo	
Target Adjusted Debt Ratios*	**55%**	**65%**	**40%**	**≤40%**

FEU = OE, PP, CEI, TE, JCP&L, ME, PN, MP, PE, WPP

FET = FET, ATSI, TrAILCo

CES = FES, AE Supply

Outstanding debt at FE Corp is not reflected above

*Calculated per rating agency view shown on slide 165

Financial – **FirstEnergy Corp. Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
FirstEnergy Corp.	Term Loan	N/A	Variable	12/31/2015	$200,000,000
	Term Loan	N/A	Variable	3/31/2019	$1,000,000,000
	Unsecured Notes	337932AE7	2.75%	3/15/2018	$650,000,000
	Unsecured Notes	337932AF4	4.25%	3/15/2023	$850,000,000
	Unsecured Notes	337932AC1	7.375%	11/15/2031	$1,500,000,000
				FirstEnergy Corp. Total	**$4,200,000,000**

Financial – **Credit Ratings**

As of 10/31/2014	Corporate Credit Rating (S&P) / Issuer Rating (Moody's) / Issuer Default (Fitch)			Senior Secured			Senior Unsecured			Outlook		
	S&P	Moodys	Fitch	S&P	Moodys	Fitch	S&P	Moodys	Fitch	S&P	Moodys	Fitch
FirstEnergy Corp.	BBB-	Baa3	BB+	-	-	-	BB+	Baa3	BB+	stable	stable	stable
FirstEnergy Solutions	BBB-	Baa3	-	-	-	-	BBB-	Baa3	-	stable	stable	-
Allegheny Energy Supply	BBB-	Baa3	-	-	-	-	BBB-	Baa3	-	stable	stable	-
Allegheny Generating Co.	BBB-	Baa3	-	-	-	-	BBB-	Baa3	-	stable	stable	-
American Transmission Systems Inc.	BBB-	Baa2	-	-	-	-	BBB-	Baa2	-	stable	stable	-
Cleveland Electric Illuminating	BBB-	Baa3	-	BBB+	Baa1	-	BBB-	Baa3	-	stable	stable	-
FirstEnergy Transmission	BBB-	Baa3	-	-	-	-	BB+	Baa3	-	stable	stable	-
Jersey Central Power & Light	BBB-	Baa2	-	-	-	-	BBB-	Baa2	-	stable	negative	-
Metropolitan Edison	BBB-	Baa1	-	-	-	-	BBB-	Baa1	-	stable	stable	-
Monongahela Power	BBB-	Baa2	-	BBB+	A3	-	-	-	-	stable	stable	-
Ohio Edison Co.	BBB-	Baa1	-	BBB+	A2	-	BBB-	Baa1	-	stable	stable	-
Pennsylvania Electric Co.	BBB-	Baa2	-	-	-	-	BBB-	Baa2	-	stable	stable	-
Pennsylvania Power Co.	BBB-	Baa1	-	BBB+	A2	-	-	-	-	stable	stable	-
Potomac Edison Co.	BBB-	Baa2	-	BBB+	A3	-	-	-	-	stable	stable	-
Toledo Edison Co.	BBB-	Baa3	-	BBB	Baa1	-	-	-	-	stable	stable	-
Trans-Allegheny Interstate Line Co.	BBB-	A3	-	-	-	-	BBB-	A3	-	stable	stable	-
West Penn Power Co.	BBB-	Baa1	-	BBB+	A2	-	-	-	-	stable	stable	-

Financial – **2014 Financial Plan**

- **Revised annual dividend level of $1.44 per share**
  - Dividend level aligned with FE's targeted business mix (80+% regulated, <20% competitive)
  - Fully supported by earnings and cash flows from regulated businesses
  - Provides balance sheet capacity to invest in transmission reliability projects
- **Focus on FE Transmission growth**
  - To support transmission reliability program issued long-term debt
    - $1B at FET HoldCo
    - $400M at ATSI
  - Debt authority obtained at TrAILCo of $850M
- **Continued focus on strengthening FES/AE Supply balance sheets**
  - $394M sale of hydro assets completed on February 12, 2014
  - Refinanced certain debt at FEGENCO and FENUGENCO
- **Continued focus on strengthening FE Utilities balance sheets**
  - Refinancing of maturing debt at certain utilities*
  - Reduce short-term borrowings through refinancings
  - $250M debt authority remains at JCP&L
- **Improved liquidity by restructuring existing credit facilities**
  - Extended maturity of facilities by one year to March 2019
  - Upsized FE Corp/FEU facility to $3.5B while reducing FES/AE Supply facility to $1.5B
  - FE Corp. entered into a new $1B 5-year term loan
- **Continue to issue equity – program targets ~$75M** in 2014 through stock investment/employee benefit plans, as available**

Committed to maintain investment grade metrics at each business unit and improve metrics at FE Corp. over time consistent with business profile

*Subject to market and other conditions. ** Varies based on participation and market conditions

Financial – 2013 Financial Accomplishments

- **Strengthened FES/AE Supply's balance sheet**
  - $1.5B equity infusion from FE Corp.
  - $1.5B debt reduction at FES / AE Supply
  - $1.1B transfer of Harrison/Pleasants
- **Strengthened Utilities' balance sheet**
  - $1.1B+ debt redeemed at Ohio utilities
  - Issued securitized debt of ~$445M
  - Refinanced maturing utility debt and reduced short-term borrowings
  - Harrison asset transfer financed with a mix of debt and equity infusion from FE Corp.
- **Issued $1.5B FE Corp. Notes**
- **Extended maturity of existing credit facilities to May 2018 and upsized FE/Utilities facility by $500M**
- **Launched equity program through stock investment plan and employee benefits plans**
  - $11M issued in 2013

Financial – **Credit Providers**

31 financial institutions provide ~$7.5B aggregate credit commitment

($ Milions)	
Revolving Credit Facilities	**$6,000**
Term Loans	**1,200**
SUB-TOTAL	**$7,200**
Letters of Credit (LOC)	**93**
Vehicle Leases	**216**
Sale Leaseback LOC	**34**
TOTAL	**$7,543**

Bank of America	JP Morgan Chase
Bank of New York Mellon	Keybank
Bank of Nova Scotia	Mizuho
Barclays Bank	Morgan Stanley
BBVA	National Cooperative Services
BNP Paribas	PNC
CIBC	Regions Bank
Citibank	Royal Bank of Canada
CoBank	Royal Bank of Scotland
Credit Agricole	Satander
Credit Suisse	Sumitomo Mitsui
Fifth Third Bank	TD Bank
First National Bank	Union Bank/Bank of Tokyo Mitsubishi
G.E. Capital	US Bank
Goldman Sachs	Wells Fargo
Huntington National Bank	

Financial – **2014 Operating Earnings**[1] Guidance by Segment

Operating EPS[1] – Basic	Guidance May 2014	Guidance November 2014
Regulated Distribution	**$1.98 - $2.04**	**$1.90 - $1.96**
Regulated Transmission	**$0.52 - $0.56**	**$0.52 - $0.56**
Sub-total	**$2.50 - $2.60**	**$2.42 - $2.52**
Competitive Energy Services	**$0.12 - $0.22**	**$0.15 - $0.25**
Corporate / Other	**($0.22)**	**($0.17)**
FirstEnergy Consolidated	**$2.40 - $2.60**	**$2.40 - $2.60**

[1]See GAAP to Operating earnings reconciliation on slide 156

As of November 4, 2014

Financial – **2013 GAAP** to **Operating Earnings* Reconciliation**

(In Millions, except per share amounts)	FirstEnergy Consolidated 2013A	Regulated Distribution 2013A	Regulated Transmission 2013A	Competitive Energy Services 2013A	Corporate/ Other 2013A
Net Income(Loss) – GAAP	$392	$501	$214	($220)	($103)
Basic EPS (average shares outstanding 418)	$0.94	$1.20	$0.51	($0.52)	($0.25)
Excluding Special Items:					
Plant Deactivation Costs	1.03	0.01	–	0.97	0.05
Regulatory Charges	0.54	0.53	–	0.03	(0.02)
Merger Accounting – Commodity Contracts	0.08	–	–	0.08	–
Non-core Asset Sales/Impairments	0.03	–	–	0.03	–
Debt Redemption Costs	0.20	–	–	0.23	(0.03)
WV Asset Transfer Charges	0.51	0.52	–	–	(0.01)
Restructuring Costs	0.01	–	–	0.01	–
Trust Securities Impairment	0.12	0.01	–	0.11	–
Mark-to-Market Adjustments					
Pension/OPEB actuarial assumptions	(0.38)	(0.22)	–	(0.16)	–
Other	(0.04)	–	–	(0.04)	–
Basic EPS – Operating (Non-GAAP)	$3.04	$2.05	$0.51	$0.74	($0.26)

* Operating earnings exclude special items as described in the reconciliation table above and is a non-GAAP financial measure

Financial – **2014 GAAP** to **Operating Earnings**[1] **Reconciliation**

(In Millions, except per share amounts)	FirstEnergy Consolidated 2014F	Regulated Distribution 2014F	Regulated Transmission 2014F	Competitive Energy Services 2014F	Corporate/ Other 2014F
Net Income(Loss) – GAAP	$340M - $530M	$510M - $595M	$215M - $235M	($320M)-($235M)	($65M)
Basic EPS (average shares outstanding 420M)	$0.81 - $1.26	$1.21 – $1.42	$0.52 - $0.56	($0.76)–($0.56)	($0.16)
Excluding Special Items[2]:					
Plant Deactivation Costs	0.31	–	–	0.31	–
Trust Securities Impairment	0.02	–	–	0.02	–
Regulatory Charges	0.05	0.05	–	–	–
Litigation resolution	(0.01)	–	–	–	(0.01)
Loss on Debt Redemptions	0.01	–	–	0.01	–
Mark-to-market adjustments					
Pension/OPEB actuarial assumptions[3]	0.85 – 1.10	0.49 – 0.64	–	0.36 – 0.46	–
Other	0.10	–	–	0.10	–
Merger Accounting – Commodity Contracts	0.06	–	–	0.06	–
Non-core Asset Sales/Impairments	(0.16)	–	–	(0.16)	–
Retail Repositioning Charges	0.11	–	–	0.11	–
Total Special Items[2]	$1.34 – $1.59	$0.54 – $0.69	–	$0.81 - $0.91	($0.01)
Basic EPS – Operating (Non-GAAP) (average shares outstanding 420M)	$2.40 – $2.60	$1.90 - $1.96	$0.52 - $0.56	$0.15 - $0.25	($0.17)

[1]Operating earnings exclude special items as described in the reconciliation table above and is a non-GAAP financial measure
[2]Per share amounts for the special items above are based on the after tax effect of each item divided by the weighted average shares outstanding for the period
[3]Based on current discount rates ranging from 4.50% to 4.25% and an assumed expected return on plan assets of 7.75%

Financial – **2013 Capital Expenditures**

Capital Expenditures ($ Millions)	Regulated Distribution	Regulated Transmission	CES[1]	Corporate/ Other	FirstEnergy Consolidated[2]
Baseline Capital	$584	$118	$414	$66	$1,182
Formula Rate Recoverable	252	339	–	–	591
Major Projects					
Generation Projects	–	–	278	–	278
MATS	14	–	56	–	70
JCP&L LITE	6	34	–	–	40
Storms	47	5	–	–	52
Total	$903	$496	$748	$66	$2,213

[1] Excludes nuclear fuel

[2] Includes adjustment of approximately ($130M) related to the capital component of the mark-to-market adjustment for pension and OPEB costs

Financial – **2014F Capital Expenditures**

Capital Expenditures ($ Millions)	Regulated Distribution	Regulated Transmission	CES[1]	Corporate/ Other	FirstEnergy Consolidated[2]
Baseline Capital	$685	$145	$355	$85	$1,270
Formula Rate Recoverable	335	1,150	–	–	1,485
Major Projects					
Generation Projects	–	–	405	–	405
MATS	40	–	30	–	70
JCP&L LITE	10	55	–	–	65
Storms	40	–	–	–	40
Total	$1,110	$1,350	$790	$85	$3,335

[1] Excludes nuclear fuel

[2] Excludes estimate related to the capital component of the mark-to-market adjustment for Pension and OPEB costs. Based on current discount rates ranging from 4.50% to 4.25% and an assumed expected return on plan assets of 7.75%, the estimated adjustment that would increase capital ranges from $350M to $450M.

2013 Free Cash Flow

($ Millions)	FirstEnergy Consolidated
Funds From Operations (FFO)[1]	**$3,157**
Capital expenditures	(2,343)
Nuclear fuel	(228)
Cash Before Other Items	**$586**
Hurricane Sandy[2]	(358)
Debt Premiums	(260)
Other	(266)
Cash Before Dividends and Equity	**($298)**
Dividends @ $2.20/share	(920)
Equity (SIP and other employee benefit plans)	11
Free Cash Flow [3]	**($1,207)**

[1] Non-GAAP figure; see GAAP to FFO reconciliation on slide 161
[2] Represents 2013 capital and maintenance expenditures associated with 2012 storm restoration activities
[3] Excludes cash items related to financing activity

2014F Free Cash Flow

($ Millions)	FirstEnergy Consolidated
Funds From Operations (FFO)[1]	**$2,430 - $2,480**
Capital expenditures	(3,335)
Nuclear fuel	(225)
Cash Before Other Items	**($1,130) – ($1,080)**
Hydro Asset Sales	394
Collateral	(140)
Working Capital	(194)
Cash Before Dividends and Equity	**($1,070) – ($1,020)**
Dividends @ $1.44/share	(605)
Equity (SIP and other employee benefit plans)	75
Free Cash Flow [2]	**($1,600) – ($1,550)**

[1]Non-GAAP figure; See GAAP to FFO reconciliation on slide 161
[2] Excludes cash items related to financing activity

Financial – **Funds** from **Operations Reconciliation**

FirstEnergy Consolidated ($ millions)	2013	2014F
Net Income – GAAP	**$392**	**$340 - $530**
Depreciation	1,202	1,225
Amortization	539	(5)
Nuclear Fuel Amortization	209	220
Deferred Taxes and ITC	243	180 - 190
Deferred Purchased Power	(76)	(110)
Retirement Benefits	(57)	(5)
Pension and OPEB MTM	(256)	750 - 550
NDT Impairments and Gains	34	(40)
Impairments of Long-lived Assets	795	–
Loss on Debt Redemptions	132	8
Gain on Asset Sales	–	(142)
Other	–	9 - 59
Funds from Operations (FFO)	**$3,157**	**$2,430 - $2,480**

Financial – **Qualified Pension Status Overview**

Pension Plan ($ Millions)	2012	2013	2014 Assumptions
Assumptions* - Pension Costs			
Expected Return on Assets	7.75%	7.75%	7.75%
Discount Rate	5.00%	4.25%	5.00%
Pension Funding (Year End)			
Plan Assets	$6,671	$6,171	
ABO Liability	$8,047	$7,554	
ABO Funding Ratio	83%	82%	

($ Millions)	2012	2013	2014F
Contributions during the year	$600	$ -	$ -

- **Projected Benefit Obligation (PBO) Liability as of December 2013 was $7,953M**
  - A 25 bps increase in the discount rate decreases the PBO liability by ~$220-250M
- **At year end, there is an annual income statement impact based on mark-to-market accounting. Based on interest rate levels as of October 31, 2014, discount rates would range from 4.50% to 4.25%. The combined EPS impact of the discount rate change and new mortality tables is expected to be $0.85-$1.10.**

* Assumptions relate to net periodic pension costs as opposed to the pension benefit obligation. Year-end liabilities are valued based on the end-of-year discount rate.

2015 vs. 2014 Earnings Drivers

Regulated Distribution	
Distribution Revenue	↑
Rate Case Outcomes	↑
O&M	↓
Depreciation	↓
Interest	↓
Effective Income Tax Rate	↓

Regulated Transmission	
Transmission Revenue	↑
Depreciation	↓
General Taxes	↓
Interest	↓
Effective Income Tax Rate	↓

Competitive Energy Services	
Commodity Margin	↑
Sales Revenue	↓
Capacity Revenue	↑
Purchased Power	↑
Capacity Expense	↓
Fuel	↑
O&M	↓
General Taxes	↑
Depreciation	↓
Effective Income Tax Rate	↓

Corporate/Other	
Interest	↓
Effective Income Tax Rate	↓

2016 vs. 2015 Earnings Drivers

Regulated Distribution	
Distribution Revenue	↑
O&M	↔
Depreciation	↓
Interest	↓
Effective Tax Rate	↔

Regulated Transmission	
Transmission Revenue	↑
Depreciation	↓
General Tax	↓
Interest	↓
Effective Tax Rate	↔

Competitive Energy Services	
Commodity Margin	↓
Sales Revenue	↓
Capacity Revenue	↓
Capacity Expense	↑
Purchased Power	↑
Fuel	↔
O&M	↑
General Taxes	↑
Depreciation	↓
Effective Tax Rate	↔

Financial – **Credit Metrics Calculations**

FFO Calculation

Net Income
Add back non-cash items:
+ Depreciation, amortization (incl. nuclear fuel, Pension/OPEB MTM adjustment and lease amortization), and deferral of regulatory assets
+ Deferred purchased power and other costs
+ Deferred income taxes and investment tax credits
+ Investment impairments
+ Deferred rents and lease market valuation liability
+ Retirement benefits
+ Loss on Debt Redemptions
- AFUDC
+ Operating Lease Debt Adjustment
+ Other
= Funds from Operations (FFO)

FFO Interest Coverage

$$= \frac{\text{FFO + Adjusted Interest}}{\text{Adjusted Interest}}$$

Adjusted Interest:
+ Interest Expense (before AFUDC)
+ Interest portion of leases
- Securitization bond interest expense
= Adjusted Interest

Debt / Capitalization Ratio

Rating Agency View	*Covenant View*
Debt: Long-term debt + Short-term borrowings + Operating lease debt equivalent* + Post-retirement benefit obligations** + Other debt - Securitization debt	Debt: Long-term debt + Short-term borrowings - Securitization debt + Guarantees of Indebtedness + Reimbursement Obligations
= Adjusted Debt	= Adjusted Debt
Capitalization: + Adjusted debt + Total equity	Capitalization: + Adjusted Debt + Total Equity - Accumulated OCI + Non-cash charges***
= Adjusted Capitalization	= Adjusted Capitalization

FFO-to-Debt Ratio

$$= \frac{\text{FFO}}{\text{Adjusted Debt}}$$

Adjusted debt:
+ Short-term borrowings
+ Long-term debt
+ Operating lease debt equivalent*
+ Post-retirement benefit obligations**
+ Other debt
- Securitization debt
= Adjusted Debt

* Net Present Value of future lease payments using discount rate of 7%
** After-tax unfunded Pension/OPEB obligation
*** Includes historical (2011-2013) and forward-looking non-cash charges

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