Steven L. Beshear
Governor

Leonard K. Peters
Secretary
Energy and Environment Cabinet

Commonwealth of Kentucky
Public Service Commission
211 Sower Blvd.
P.O. Box 615
Frankfort, Kentucky 40602-0615
Telephone: (502) 564-3940
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psc.ky.gov

David L. Armstrong
Chairman

James W. Gardner
Vice Chairman

Charles R. Borders
Commissioner

June 28, 2011

PARTIES OF RECORD

Re: Case No. 2011-00161

Attached is a copy of the memorandum which is being filed in the record of the above-referenced case. If you have any comments you would like to make regarding the contents of the informal conference memorandum, please do so within five days of receipt of this letter. If you have any questions, please contact Richard Raff at 502-564-3940, Extension 263.

Sincerely,

Jeff Derouen
Executive Director

RR/kar

Attachment

INTRA-AGENCY MEMORANDUM

KENTUCKY PUBLIC SERVICE COMMISSION

TO: Case File

FROM: Richard Raff, Assistant General Counsel RGR

DATE: June 28, 2011

RE: Case No. 2011-00161
Kentucky Utilities Company

In accordance with the Commission's June 10, 2011 Order, an informal conference was held at the Commission's offices on June 16, 2011. A list of the attendees is attached hereto. The conference was held jointly with the parties to Case No. 2011-00162, which is the application of KU's affiliate, Louisville Gas and Electric Company ("LGE"). These cases are not consolidated, but both KU and LGE are requesting authorization to construct environmental facilities and approval of 2011 environmental compliance plans and rate surcharges, respectively.

At the beginning of the conference, Commission Staff announced that the Commission had decided to retain the services of a consultant to assist in the review of the evidence compiled during the course of these cases and to provide advice to the Commission. A request for proposals had been developed and the consultant was not anticipated to be filing testimony, although doing so was a possibility. One of the Commission's counsel, Richard Raff, also announced that his spouse was employed in an administrative position by the Kentucky Resources Council, an organization that had filed an intervention request on behalf of the Metropolitan Housing Coalition in Case No. 2011-00162. A full disclosure of this would be subsequently made in writing to all parties to Case No. 2011-00162, with an opportunity for parties to file comments.

Presentations were then made by KU and LGE personnel regarding the existing and proposed environmental requirements applicable to their respective generating stations, the existing environmental control facilities at their respective generating stations, the available options to meet the proposed environmental requirements, and the selected options to meet the proposed requirements, along with the basis for the selection. A copy of the presentation is also attached hereto.

At the conclusion of the KU/LGE presentation, Kentucky Industrial Utility Customers, Inc. ("KIUC"), an intervenor in both cases, made a brief presentation on the financial impacts of the proposed construction on the utilities and referred to a document prepared by the owner of KU and LGE, PPL Corporation. A copy of that document is also attached. KIUC suggested that the financial impacts could be lessened if the General Assembly would enact legislation authorizing utilities to issue securitized debt.

Attachments
cc: Parties of Record (with attendance list but not other attachments)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	CASE NO. 2011-00161

June 16, 2011

Please sign in:

NAME	REPRESENTING
RICHARD RAFF	PSC-LEGAL
DAVID C. BROWN	Kroger Co.
Larry Cook	OAG
Dennis Howard	"
Mike Kurtz	KIUC
Kimberly S. McCann	NAS
NATHANIEL K. ADAMS	NAS + KIUC
Kurt Boehm	KIUC
Dana Nickles	OAG
PATRICK HUGHES	OAG
Duncan Crosby	SKO for LG&E/KU
Shannon Charnas	LG&E/KU
Andrea Schroeder	LGE/KU

NAME	REPRESENTING
Fereydoon Gorjian	PSC/Engineering
JOHN SHUPP	PSC-ENGINEERING
Kimra Cole	PSC-Engineering
Ron Handziak	PSC-FA
Chris Whelan	PSC-FA
[illegible] R Riggs	SKO for LGE-KU
Lonnie Bellar	LGE/KU
John Voyles	LGE/KU
Robert Conroy	LG&E/KU
CHUCK SCHRAM	LG&E/KU
Gary Revlett	LG&E/KU
[illegible] B. Bowles	PSC-Legal
Quang D Nguyen	PSC
Appearing Telephonically by J.B.B. 6-16-11	
Iris Skidmore	Community Action Council
Dave Barberie	Lexington-Fayette Urban County Govt.
[illegible]	

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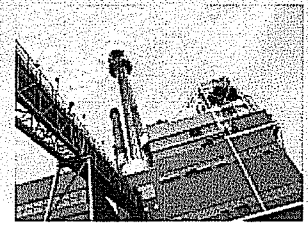
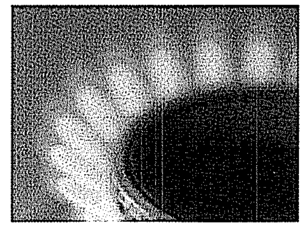
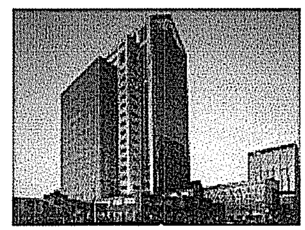
2011 Environmental Compliance Plans

Informal Conference
Case Nos. 2011-00161 and -00162
June 16, 2011





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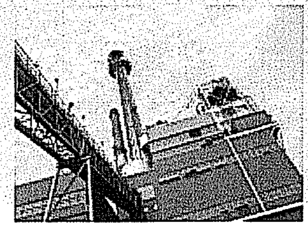
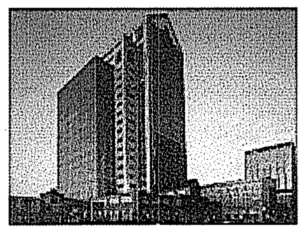
Environmental Regulations



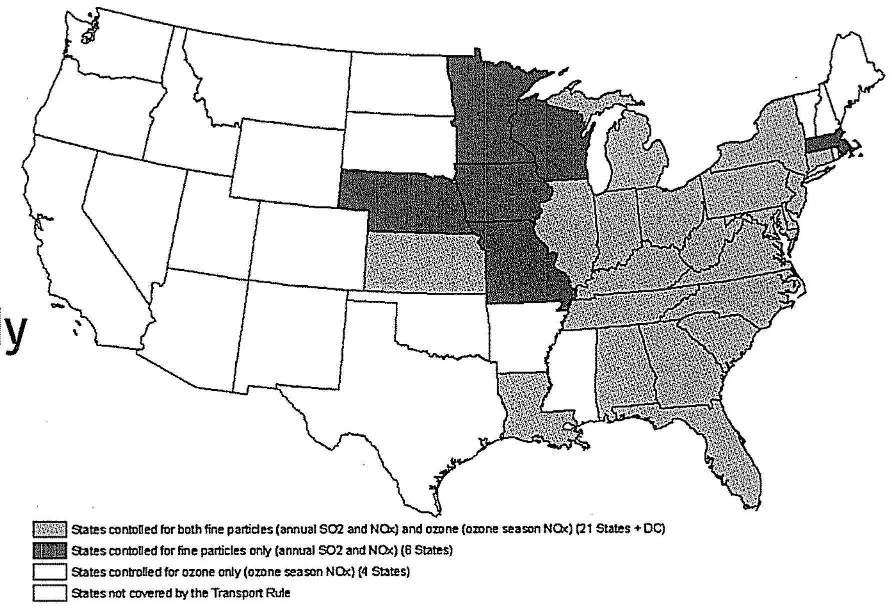


New air regulations - NAAQS

- National Ambient Air Quality Standards ***(NAAQS)***
  - *The federal Clean Air Act became law in 1970, authorized EPA to establish NAAQS for various emissions*
  - *NAAQS were first set to be achieved by 1975*
  - *Congress significantly strengthened Clean Air Act in 1990*
  - *Now, EPA has issued new 1-hour standard for SO_2 and NO_2*
  - *Compliance required by 2016 or 2017*
- Monitoring Data from 2010
  - *No monitors in Kentucky have exceeded the new 1-hour NO_2 NAAQS.*
  - *Jefferson Co. monitors have exceeded the new 75 ppb 1-hour SO_2 NAAQS (http://www.louisvilleky.gov/APCD/Monitoring/AmbientData.htm)*
  - *Kentucky has filed with the US EPA for non-attainment status as of June 2, 2011 and is required to implement plans to lower SO_2 emissions*
  - *Mill Creek and Cane Run are the two largest SO_2 emission sources in Jefferson Co.*

New air regulations – CATR

- Clean Air Transport Rule ***(CATR)***
  - *Successor regulation to Clean Air Interstate Rule (CAIR), but with more restrictive emissions limits and allowance trading regime*
  - *Court order required EPA to issue CATR to replace CAIR*
  - *Downwind air pollution effects on $PM_{2.5}$ and ozone*
  - *Regional transport of SO_2 and NO_x*
  - *Possible compliance dates of 2012 and 2014.*
- EPA has sent the rule to OMB for analysis
- Final rule expected to be issued in July
- CATR Allowance Proposal
  - *LG&E and KU combined allowances*
    - *Reduce NO_x by 15%*
    - *Reduce SO_2 by 40%*



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New air regulations - HAPs Rule

- National Emission Standards for Hazardous Air Pollutants from Electric Generating Units ***(HAPs Rule)***
  - *Successor to Clean Air Mercury Rule vacated by D.C. Circuit for not being sufficiently restrictive re existing generating units (EGUs)*
  - *Court order required EPA to issue new rule by March 16, 2011*
  - *Court order requires rule to be final by November 16, 2011*
  - *Mercury, Arsenic, Selenium, Acid aerosols*
  - *Plant-by-plant controls*
  - *Compliance by 2015 or 2016*
- Draft rule was issued March 16, 2011
- 60-Day comment period started May 3, 2011; ends July 5, 2011
- Math error found in mercury limit, but no material impact to mercury emission limit for EGUs
- Final rule still expected November 2011

New air regulations - HAPs Rule

Maximum Achievable Control Technology (MACT) Requirements

Electric Utility HAP Groups	Regulated Pollutant	Potential Surrogate	Proposed Surrogate Limit*
Non- mercury hazardous metals	As, Be, Cod, Co, Cr, Man, Ni, BP, Sib & Se - individually or total	Total Particulates (filterable PM + condensable** PM)	0.030 lbs/mmBtu or 0.30 lbs/MWh
Mercury	Mercury	none	1.2 lb/Tbtu or 0.013 lb/GWh
Acid gases	Hydrochloric acid (HCl)	Sulfur Dioxide (SO_2)	0.20 lb/mmBtu or 2.0 lbs/MWh
Hazardous organics	Numerous organic compounds	N/A	Annual emission test - No limit
Dioxin/Furan	Several congeners of both dioxin and furans	N/A	Annual emission test - No limit

* - Compliance can be based on a plant-wide average over a 12-month period

** - Condensable PM is primarily sulfuric acid mist

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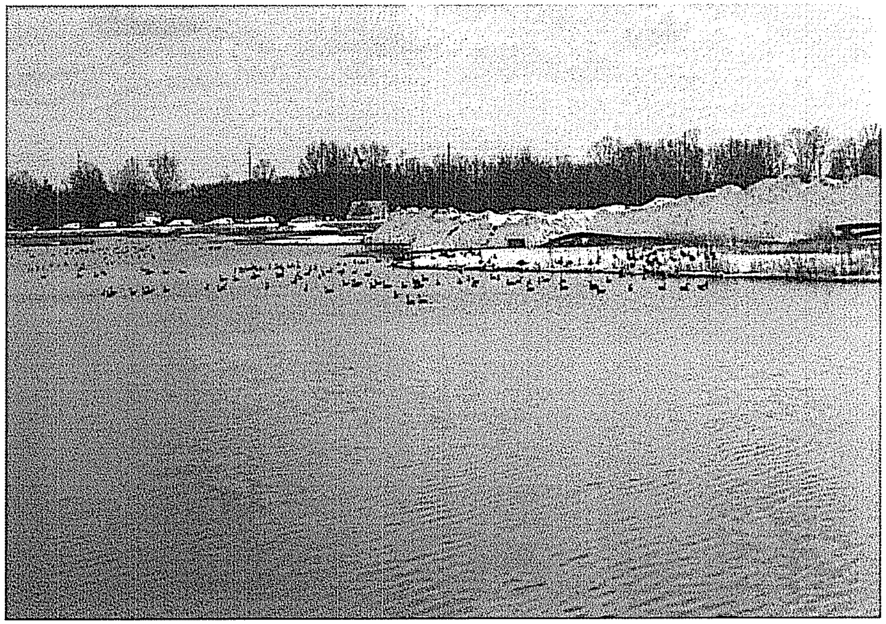
New coal combustion residuals



- Coal Combustion Residuals (CCR)
  - *Hazardous or Non-hazardous*
  - *Wet ponds must have liners or convert to dry storage*
  - *Final rule expected in 2012*
  - *Compliance within approximately 5 years of final rule*

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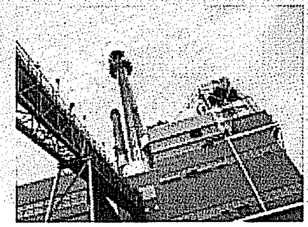
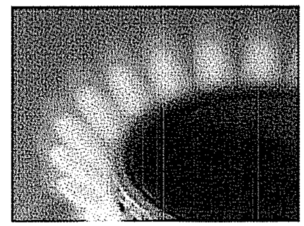
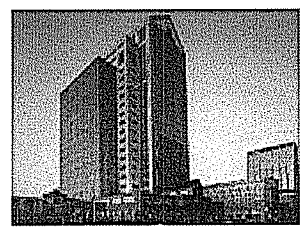
LG&E and KU System





Current LG&E and KU Control Technologies

		SO_2			NO_x		
	Net Summer Capacity (MW)	FGD Install	Emission Rate (lb/MMBtu)	Emission Control Efficiency	SCR Install	Emission Rate (lb/MMBtu)	Emission Control Efficiency
Brown	684	2010 (3 units)	0.12	98%	2012 (1 Unit)	0.38	90%
Ghent	1,918	2000 – 2009 (4 units)	0.17	94 – 98%	2003 – 2004 (3 Units)	0.12	80 - 90%
Green River	163	None	2.99	None	None	0.40	None
Tyrone	71	None	1.33	None	None	0.50	None
Cane Run	563	1976 – 1978 (3 units)	0.59	90 %	None	0.34	None
Mill Creek	1,472	1978 – 1982 (4 Units)	0.49	90 – 92%	2003 (2 Units)	0.16	85 - 87%
Trimble County 1	383	1990	0.12	98 %	2002	0.06	80 - 85%
Trimble County 2	549	2010	0.10	98 %	2010	0.04	90%

- All units have precipitators
- Trimble 1 and 2 capacities reflects 75% ownership

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Technology options for addressing air emissions

Technology	Targeted Pollutant	Regulation Addressed	Removal Rate
Flue Gas Desulfurization (FGD)	SO_2	CATR, NAAQS	98%
Selective Catalytic Reduction (SCR)	NO_x	CATR, NAAQS	90%
FGD + SCR (Hg Co-Benefit)	Hg	HAPs Rule	60-70%
Fabric Filter & PAC* Injection (with FGD and SCR)	Hg	HAPs Rule	greater than 90%
Sorbent Injection	SO_3 (SAM)	Opacity, BART	40-80%

* Powdered Activated Carbon

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Technology options for addressing air emissions at LG&E and KU Generating Stations

Station	Capacity (Net MW)	Options to Address Regulations
Brown	684	SCR, Fabric Filter Baghouse, PAC Injection, Lime Injection
Ghent	1,918	SCR, Fabric Filter Baghouse, PAC Injection
Green River	163	FGD, SCR, Fabric Filter Baghouse, PAC Injection
Cane Run	563	FGD, SCR, Fabric Filter Baghouse, PAC Injection, Lime Injection
Mill Creek	1,472	FGD, SCR, Fabric Filter Baghouse, Electrostatic Precipitator (ESP), PAC Injection, Lime Injection, Ammonia
Trimble County	932	Fabric Filter Baghouse, PAC Injection
Tyrone	71	FGD, SCR, Fabric Filter Baghouse, PAC Injection

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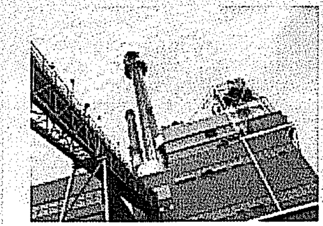
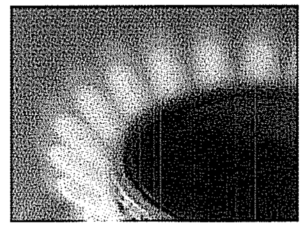
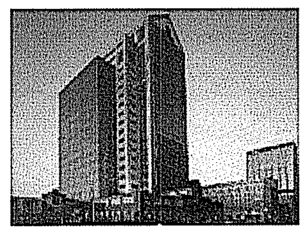
Methodology and Analysis





2010-11 Engineering Assessments

- Control equipment studies for all stations
- Existing Mill Creek scrubber (FGD) Performance Improvement study & structural review
- Existing precipitator (ESP) upgrade study
- Flow modeling studies for improving unit operation with the SCRs
- EW Brown study of a smaller ash pond, with delayed conversion to a landfill

Overview of Modeling Process

Inputs
- Unit Characteristics
- Fuel Costs
- Operating Costs
- Capital Costs
- Load Forecasts
- Future Resources

Modeling Tools

Outputs
- Unit & System Emissions
- Revenue Requirements
  - Production Costs
  - Capital for new units and/or controls

Modeled Least-Cost Plan

Reliability Considerations

Future Environmental Regulations

Compliance Margins

Business Decision

Units were evaluated in order of decreasing variable production cost

1. Tyrone 3
2. Green River 3
3. Brown 3
4. Cane Run 4
5. Cane Run 6
6. Brown 1-2
7. Cane Run 5
8. Ghent 3
9. Ghent 1
10. Green River 4
11. Mill Creek 4
12. Trimble County 1
13. Ghent 4
14. Mill Creek 3
15. Ghent 2
16. Mill Creek 1-2

Evaluate alternatives for Tyrone 3 to determine least cost approach

Install Controls (B)

- Capital and operating costs for existing generating units
- Capital and operating costs for expansion planning units
- Incremental capital and operating costs for controls
- Retirement assumptions:
  - None

Modeling Tool

NPVRR:
- Production costs
- Capital for new units
- Capital for controls

NPVRR Delta (A-B), $M	
Production Cost	(49)
Capital	36
Total	(13)

Retire & Replace Capacity (A)

Same assumptions as 'Install Controls' case except:
- **No controls on Tyrone 3**
- **Tyrone 3 retired in 2016**

Modeling Tool

NPVRR:
- Production costs
- Capital for new units
- Capital for controls (excluding Tyrone 3)

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Use Tyrone 3 outcome and continue analysis for Green River 3

Install Controls (B)

- Capital and operating costs for existing generating units
- Capital and operating costs for expansion planning units
- Incremental capital and operating costs for controls
- Retirement assumptions:
  - Tyrone 3 retired 2016

Modeling Tool

NPVRR:
- Production costs
- Capital for new units
- Capital for controls

NPVRR Delta (A-B), $M	
Production Cost	(122)
Capital	42
Total	(80)

Retire & Replace Capacity (A)

Same assumptions as 'Install Controls' case except:
- **No controls on Green River 3**
- **Green River 3 retired in 2016**

Modeling Tool

NPVRR:
- Production costs
- Capital for new units
- Capital for controls (excluding Green River 3)

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Continue analysis for Brown 3 . . .

Install Controls (B)

- Capital and operating costs for existing generating units
- Capital and operating costs for expansion planning units
- Incremental capital and operating costs for controls
- Retirement assumptions:
  -Tyrone 3 retired in 2016
  -Green River 3 retired in 2016

Modeling Tool

NPVRR:

- Production costs
- Capital for new units
- Capital for controls

NPVRR Delta (A-B), $M	
Production Cost	481
Capital	120
Total	601

Retire & Replace Capacity (A)

Same assumptions as 'Install Controls' case except:

- **No controls on Brown 3**
- **Brown 3 retired in 2016**

Modeling Tool

NPVRR:

- Production costs
- Capital for new units
- Capital for controls (excluding Brown 3)

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Modeling Analysis Results

Unit(s)	NPVRR Delta $M
Tyrone 3	($13)
Green River 3	($80)
Brown 3	$601
Cane Run 4	($88)
Cane Run 6	$8
Brown 1-2	$228
Cane Run 5	($58)
Ghent 3	$914
Ghent 1	$794
Green River 4	($110)
Mill Creek 4	$859
Trimble County 1	$993
Ghent 4	$1,155
Mill Creek 3	$756
Ghent 2	$1,139
Mill Creek 1-2	$1,022

Station	NPVRR Delta $M
Green River	($190)
Cane Run	($138)
Tyrone	($13)
Brown	$829
Trimble County*	$993
Mill Creek	$2,637
Ghent	$4,002

* TC Unit 1 only

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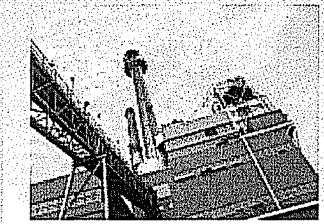
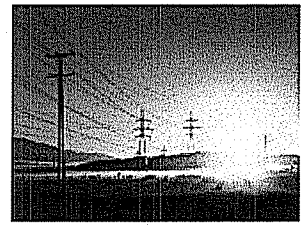
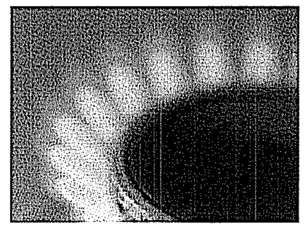
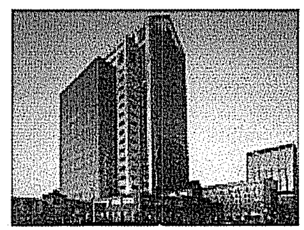
2011 ECR Projects





2011 ECR Compliance Plan

Project	CPCN	KU ECR Project	LG&E ECR Project	O&M Recovery Requested
Brown Landfill (conversion from wet to dry storage)		Project 29 (amended)		Yes
Brown Air Compliance	Yes	Project 34		Yes
Ghent Air Compliance	Yes	Project 35		Yes
Mill Creek Air Compliance	Yes		Project 26	Yes
Trimble County Unit 1 Air Compliance	Yes		Project 27	Yes

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Brown Landfill - KU Project 29 (amended)

- Amend existing KU Project 29
  - *Conversion of Main Ash Pond to Landfill*
  - *Accelerate construction of Auxiliary Pond to final approved Phase II height*
  - *Recovery of O&M associated with dry storage*
- Optimal timing to convert from planned wet storage to dry storage is now before early phase of ash pond is placed into service
  - *Landfill designed to meet proposed EPA rules*
  - *Maximize future vertical expansion opportunities and reduces final landfill height by using original Ash Pond footprint*
- Phase I of multi-phase project
  - *Estimated cost of Phase I is $59M*
  - *Expected in-service date is January 2014*

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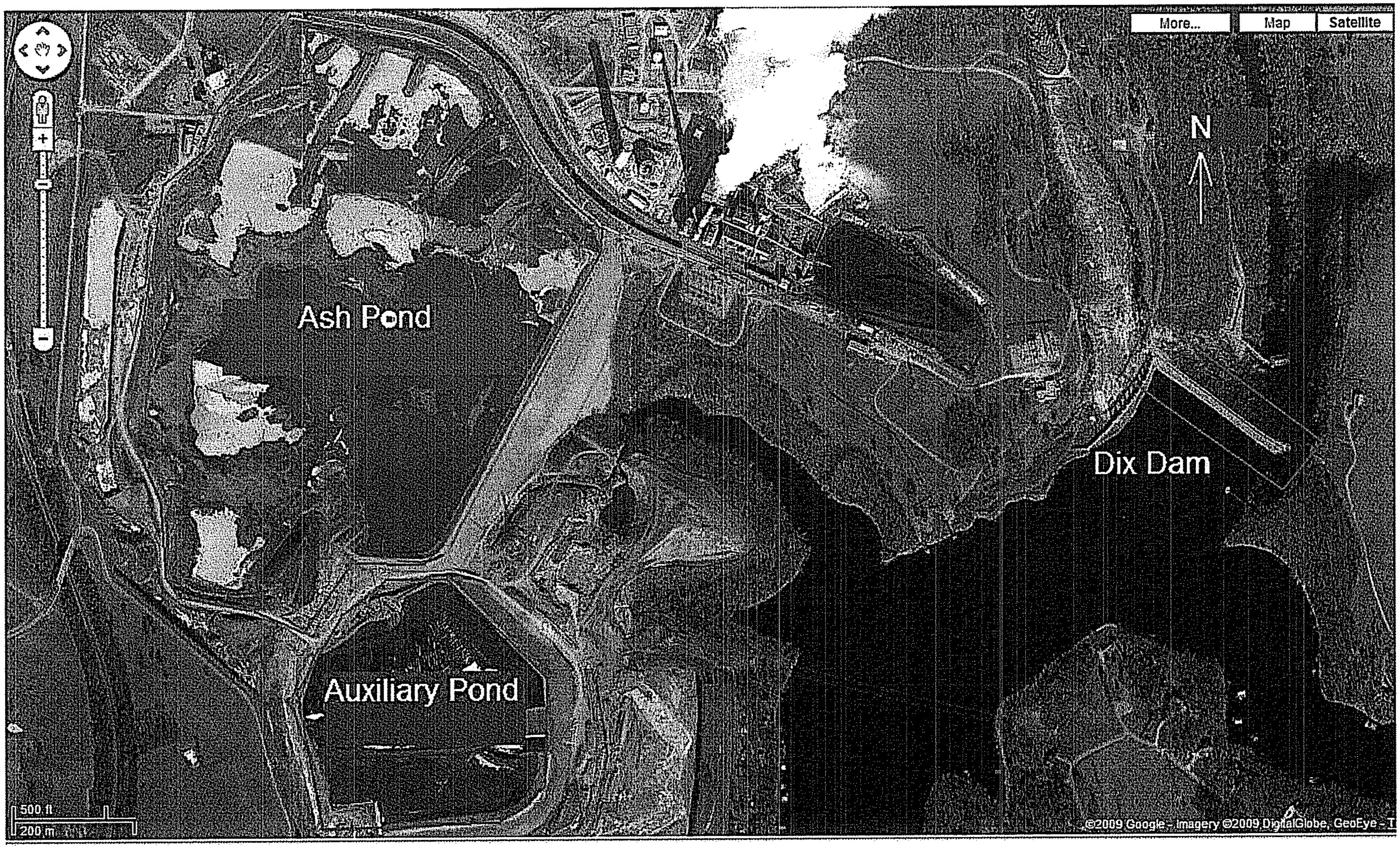
E. W. Brown Site



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Brown Air Compliance - KU Project 34

- Project 34 facilities include:
  - *Baghouse on Units 1, 2, and 3*
    - PAC Injection
    - Lime Injection to protect baghouse from SAM
  - *SAM Mitigation on Units 1 and 2*
- Estimated capital cost is $344M and associated O&M expense
- Expected in-service dates
  - *Unit 1 by late 2014*
  - *Unit 2 by late 2014*
  - *Unit 3 by mid-2015*

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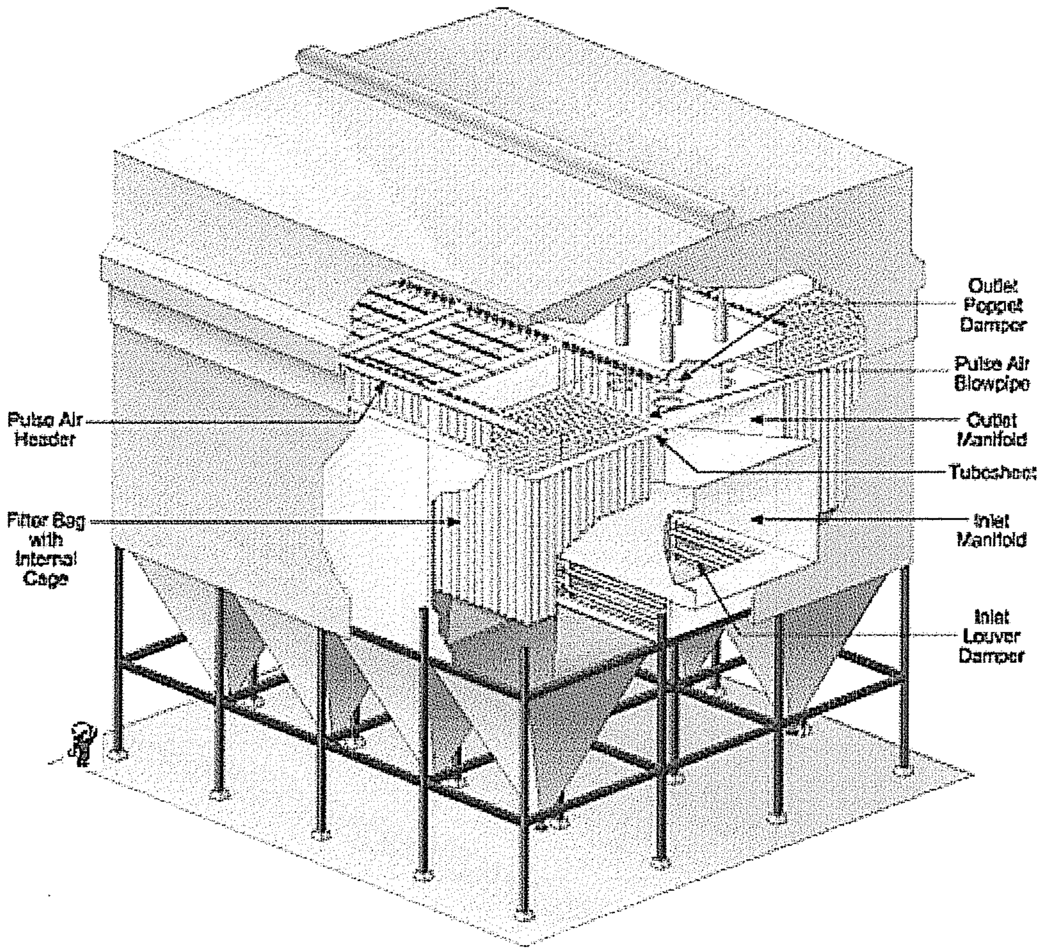
Pulse Jet Fabric Filter "Baghouse"



- Pulse Jet Fabric Filter, commonly referred to as "Baghouse"
- Integral component of a Particulate Matter Control System
- Addition of lime and PAC Injection Systems offer the best technology option to meet requirements for particulate matter and mercury removal

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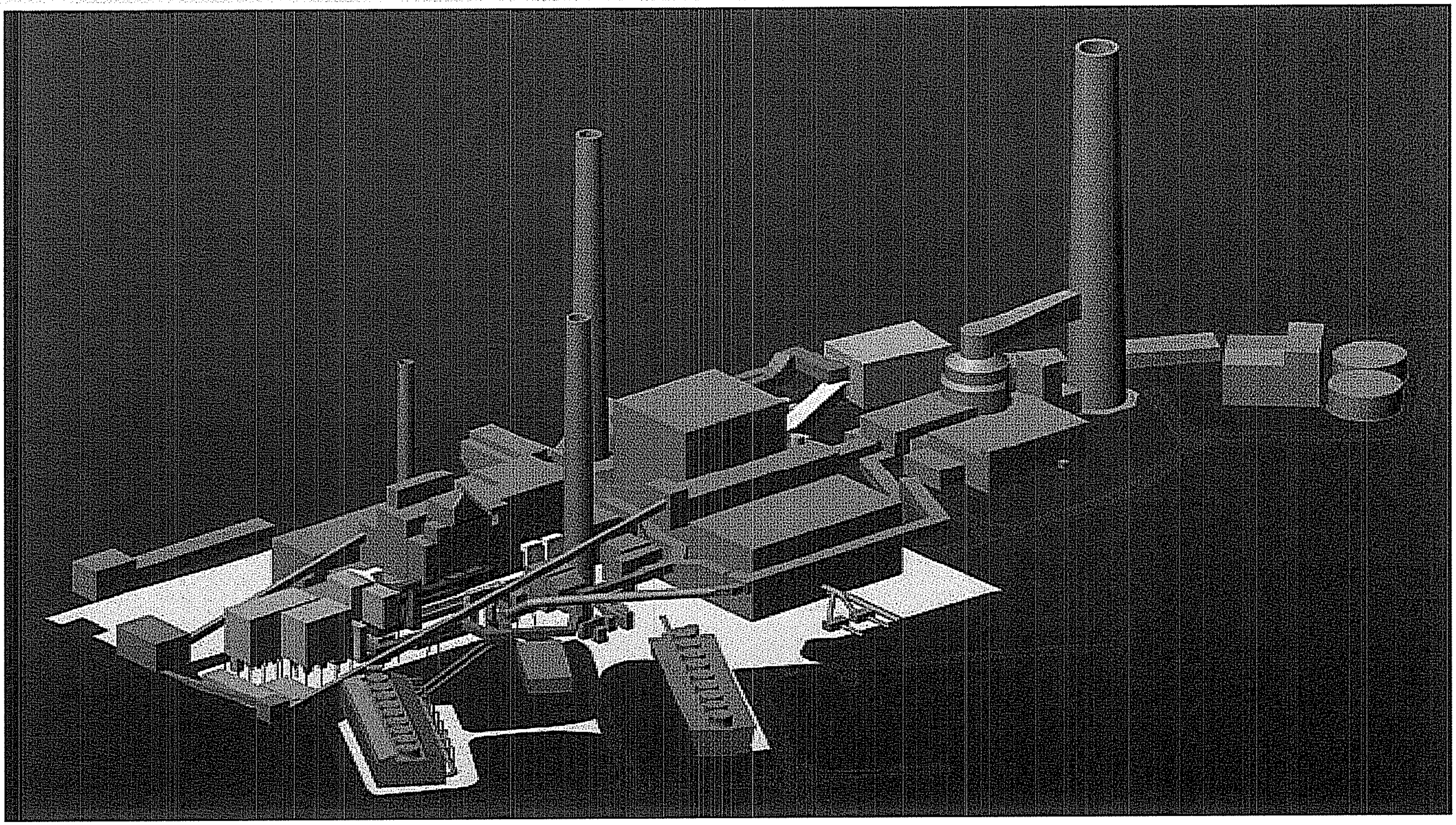
E.W. Brown Site Layout



Draft rendering subject to final detailed engineering design.

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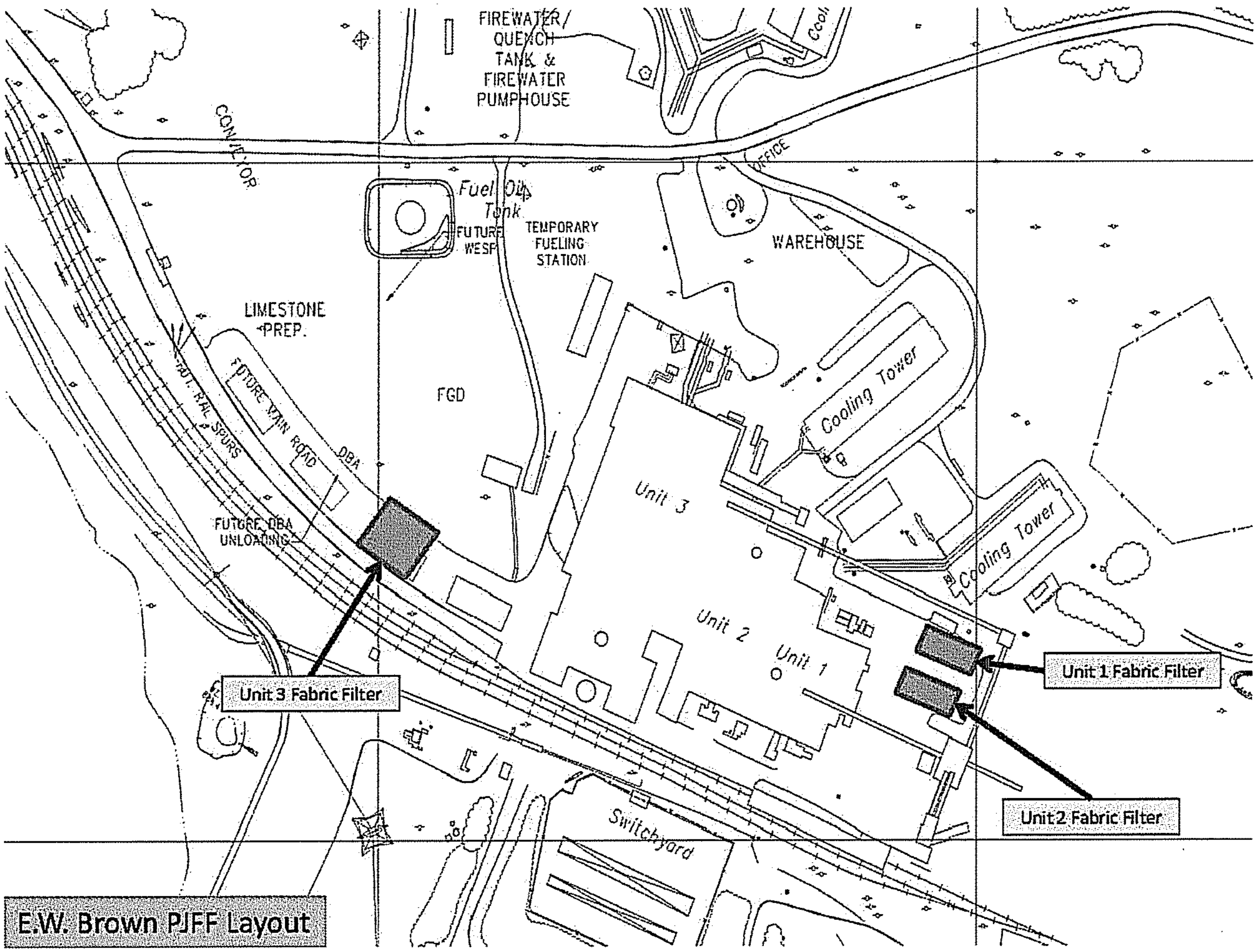
Brown Air Compliance Site Plan



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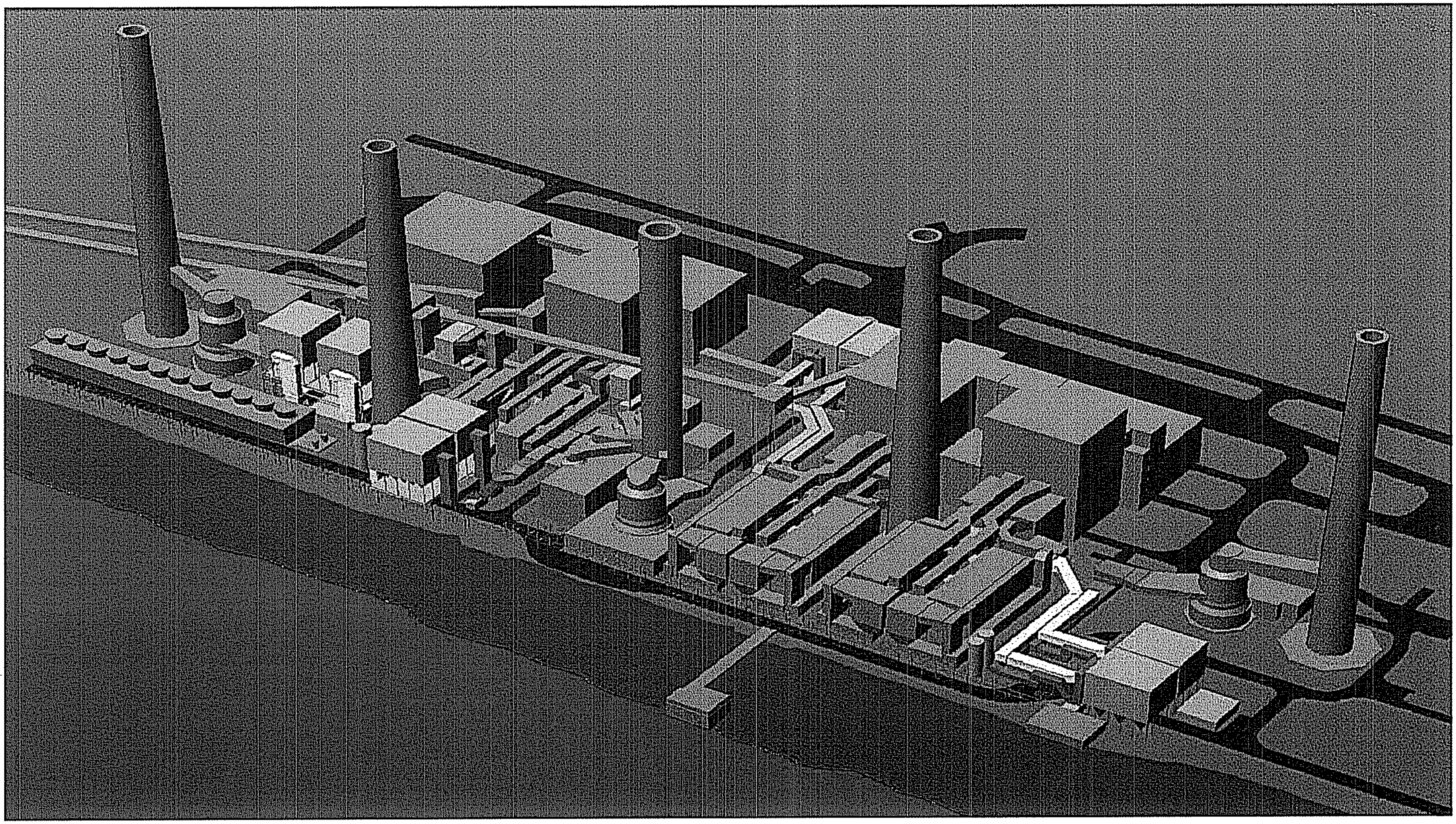
Ghent Air Compliance – KU Project 35

- Project 35 facilities include:
  - — *Baghouse on Units 1, 2, 3 and 4*
    - PAC Injection
    - Lime Injection to protect baghouse from SAM
  - — *SAM Mitigation on Units 1, 2, 3 and 4*
  - — *SCR Turn-down on Units 1, 3, and 4*
- Estimated capital cost is $711M and associated O&M expense
- Expected in-service dates
  - — *Unit 1 by mid-2014*
  - — *Unit 2 by late 2014*
  - — *Units 3 and 4 by late 2015*

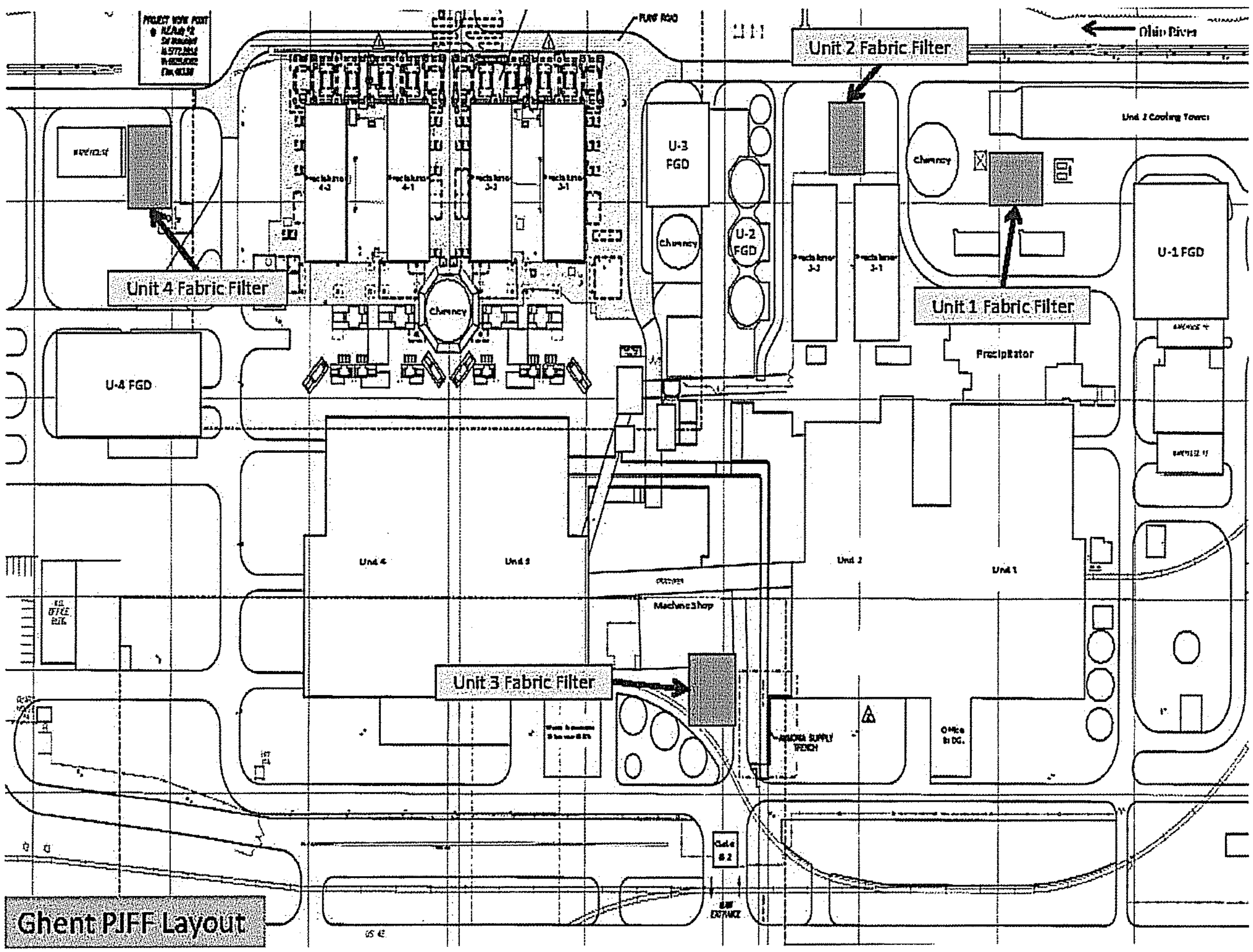
Ghent Site Layout



Draft rendering subject to final detailed engineering design.

LG&E KU
PPL companies

Ghent Air Compliance Site Plan



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Mill Creek Air Compliance - LG&E Project 26

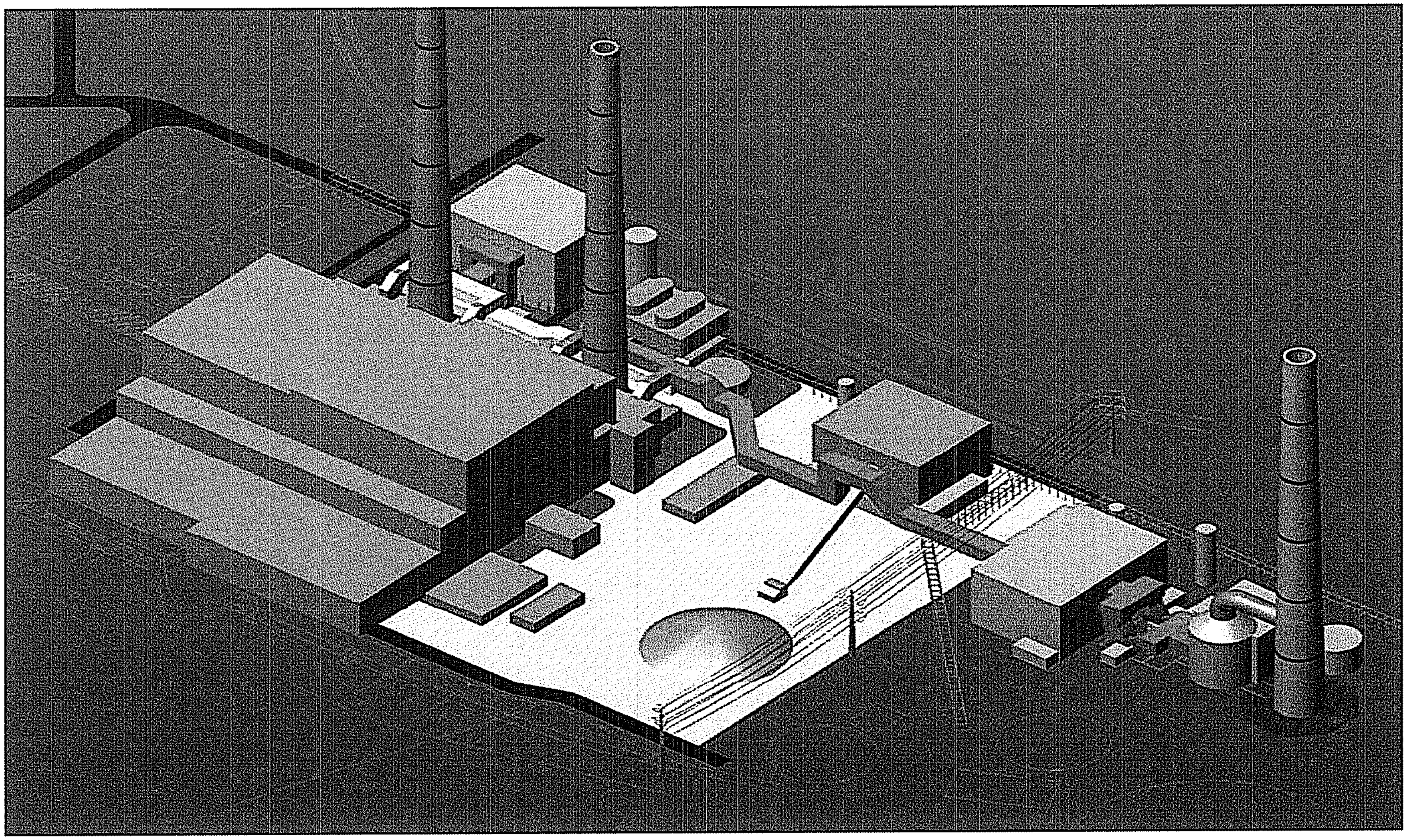
- Project 26 facilities include:
  - *New FGD - combined Units 1 and 2, Unit 4*
  - *Upgrade and tie-in existing Unit 4 FGD to Unit 3*
  - *Baghouse on Units 1, 2, 3 and 4*
    - PAC Injection
    - Lime Injection to protect baghouse from SAM
  - *SCR Turn-down on Units 3 and 4*
  - *SCR Upgrade on Unit 4*
- Estimated capital cost is $1.3B and associated O&M expense
- Filed construction permit application with LMAPCD on June 13, 2011 to construct new pollution control facilities at Mill Creek Station
- Expected in-service dates
  - *Units 1 and 2 FGD and Baghouse by mid-2015*
  - *Unit 3 FGD tie-in by late 2014, Baghouse by late 2015*
  - *Unit 4 FGD and Baghouse by late 2014*

Mill Creek Retirements and O&M

- Existing FGDs on Mill Creek Units 1, 2, and 3 to be retired; existing Unit 4 FGD to be upgraded and tied-in to Unit 3
  - *Existing to be demolished once new FGDs are in-service*
  - *Net book value as of October 31, 2009 (most recent test-year-end) of existing Units 1, 2, and 3 FGDs included in base rates will be an offset to Project 26 capital costs on ES Form 2.10*
- Annual O&M expense associated with existing FGDs included in base rates will be subtracted from total FGD O&M expenses
  - *As of October 31, 2009, annual Mill Creek scrubber O&M expense in base rates is $8.85M*
  - *Amount will be updated in future base rate proceedings*

PPL companies

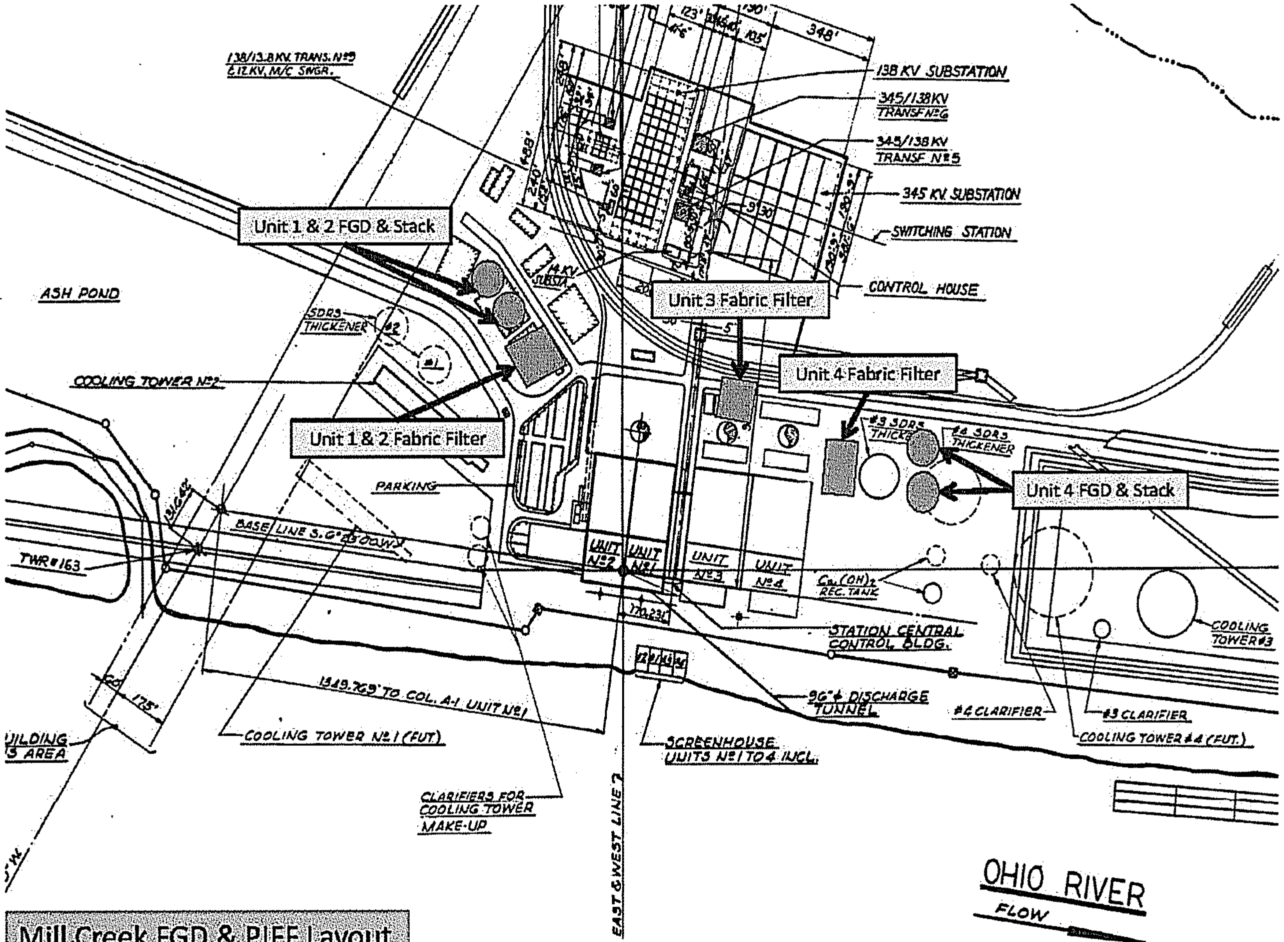
Mill Creek 3 and 4 Site Layout



Draft rendering subject to final detailed engineering design.

LG&E KU
PPL companies

Mill Creek Air Compliance Site Plan



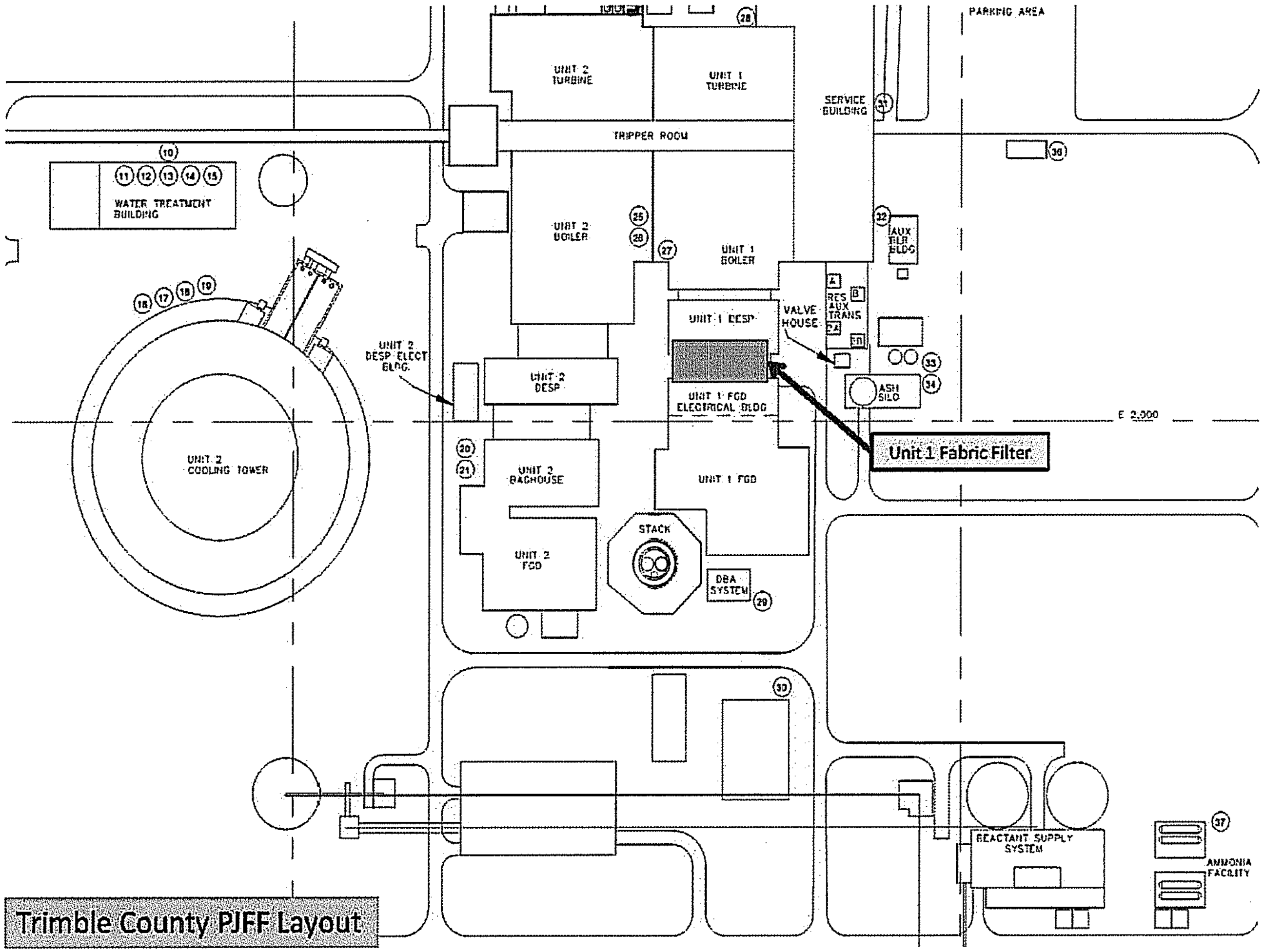
Mill Creek FGD & PJFF Layout

LG&E KU
PPL companies

Trimble County Unit 1 Air Compliance - LG&E Project 27

- Project 27 facilities include:
  - *Baghouse on Unit 1*
    - PAC Injection
    - Lime Injection to protect baghouse from SAM
- Estimated capital cost is $124M and associated O&M expense
- Expected in-service date is late 2015

Trimble County Unit 1 Air Compliance Site Plan



LG&E KU
PPL companies

ECR Compliance Plans

Questions ?

KIUC Presentation On Securitization Financing

(June 16, 2011)

Introduction to Securitization

Since the 1990s, utility companies have used securitization as a form of asset-based financing to reduce the costs to utilities and their ratepayers of plant and other investments that otherwise would be financed through a combination of debt and equity at a much greater cost as measured by the utility's grossed-up overall rate of return. Initially, securitizations were used as a vehicle to allow utilities to recover their "stranded" costs. More recently, securitization has been used as a lower cost alternative to finance the construction and installation of environmental equipment on existing generation, to recover costs resulting from storm damage, and to recover deferred power procurement costs. With new and proposed EPA regulations relating to coal generation facilities likely requiring Kentucky electric utilities to invest billions of dollars in environmental compliance measures within the next several years, lower cost forms of financing, such as securitization, have become increasingly attractive, and indeed necessary, to mitigate the effects on consumers of the rate increases necessary for the utilities to recover their costs of environmental compliance.

Benefits of Securitization

Securitization provides benefits for both the utility and ratepayers. For the utility, all costs are recovered upfront through the sale of bonds or through recovery that is guaranteed by the regulator or by a state agency, thus eliminating any recovery risk. In addition, this type of financing preserves credit metrics and lessens the pressure to issue additional equity because the securitization debt, if retained or consolidated on the utility's accounting books, is ignored by the rating agencies in rating the utility's other debt and is ignored by for ratemaking purposes other than recovery of the debt service through a surcharge. Even though the securitization debt may appear on the utility's consolidated balance sheet, rating agencies generally ignore the debt for credit analysis purposes because it is an obligation of the special-purpose entity issuer or guaranteed by a surcharge revenue stream, not the utility itself or general rate revenues. However, the utility loses the ability to include the investment in general rate base and earn a grossed up overall rate of return on it.

At the same time, securitization results in lower costs to be recovered from customers, both because the higher credit ratings on securitization debt result in lower interest rates than traditional utility debt and because the investment is funded 100% by the securitization bonds and, therefore, the customer pays for only this debt cost, without the more expensive equity component and the related income taxes included in a traditional rate base return.

How it Works

There are three key components in the structure of a utility securitization: (1) state legislation that authorizes the utility to finance the recovery of certain costs through the issuance of securitization bonds and contains a pledge that the state will not interfere with the utility's right to recover from customers the amounts necessary to service the securitization bonds; (2) a financing order issued by the state utility commission pursuant to the state legislation which, among other things, creates the right to impose certain non-bypassable charges on utility customers in the utility's service territory; and (3) a bankruptcy-remote, special-purpose entity, created by the utility, to issue the securitization bonds. The non-bypassable charges are collected from ratepayers and used to make payments when due on the securitization bonds. The state legislation specifically provides that the charges are subject to adjustment to ensure the collection of adequate funds to provide for timely payments on the securitization bonds. The financing order is generally irrevocable.

Dozens of States have used Securitization to Finance Utility Capital Investments

- **-Securitization of Pollution Control Investments**

As mentioned above, in the late 1990s securitization statutes directed at the utility sector began to emerge in order to address the financing of stranded costs.[1] Recently, utilities have used securitization to finance government mandated pollution-control equipment. Wisconsin was the first state to extend securitization techniques to mandated pollution-control requirements in 2004 with the enactment of 2003 Wisconsin Act 152. This Act authorizes Wisconsin utilities to use environmental trust bonds to finance environmental improvements on utility facilities.

Shortly thereafter, West Virginia enacted West Virginia Code §24-2-4e. This statute allows West Virginia public utilities to issue bonds that are secured by the obligation of the utility's customers to repay the bonds in order to provide money for the utility to construct and install environmental control equipment.

In support of this statute, the West Virginia Legislature explained that the significant costs of pollution control equipment may make the use of traditional utility mechanisms to finance the construction and installation environmental equipment difficult. This may cause

[1] See CAL. PUB. UTIL. CODE § 844(a) (West 2004) (enacted 1996); CONN. GEN. STAT. ANN. § 16-245k(h) (West 2007) (enacted 1998); 220 ILL. COMP. STAT. ANN. 5/18-108 (West 2007) (enacted 1997); MASS. GEN. LAWS ANN. ch.164, § 1H(f) (West 2003) (enacted 1997); MICH. COMP. LAWS SERV. § 460.101 (LexisNexis 2001) (enacted 2000); MONT. CODE ANN. § 69-8-503 (2007) (enacted 1997); N.H. REV. STAT. ANN. § 369-B:6 (Supp. 2007) (enacted 2000); N.J. STAT. ANN. § 48:3-72 (West 2008) (enacted 1999); 66 PA. CONS. STAT. ANN. § 2812(e) (West 2000) (enacted 1996); R.I. GEN. LAWS § 39-1-59 (2006) (enacted 1997); TEX. UTIL. CODE ANN. § 39.308 (Vernon 2007) (enacted 1999).

utilities to defer the installation of the equipment, incur higher financing costs, or to use financing alternatives that are less favorable to the state and its citizens.[2] The Legislature stated that securitization is an appropriate vehicle to address this problem because it can result in lower costs to customers. The West Virginia Legislature found that:

> *"it is in the interest of the state and its citizens to encourage and facilitate the use of alternative financing mechanisms that will enable certain utilities to finance the construction and installation of emission control equipment at electric-generating facilities in the state under certain conditions and to empower the Commission to review and approve alternative financing mechanisms as being consistent with the public interest..."*[3]

- **-Other Uses of Securitization By Utility Companies**

The latest trend in securitization statutes allows utilities to issue securitization bonds in order to recover the costs of remediation of hurricane and storm damage. FLA. STAT. ANN. § 366.8260(c) (West 2008) (enacted 2005); LA. REV. STAT. ANN. § 45:1230 (Supp. 2008) (enacted 2006); LA. REV. STAT. ANN. § 45:1320 (Supp. 2008) (enacted 2007). For other uses, see CAL. PUB. UTIL. CODE § 848.4 (West 2004) (enacted 2004) (securitization of tariffs allowed to be charged by Pacific Gas & Electric Co. to amortize a multibillion-dollar "regulatory asset" it was permitted to book in order to finance its emergence from bankruptcy); IDAHO CODE ANN. § 61-1506 (2002) (enacted 2001) (securitization by public utilities of tariffs charged for certain energy cost adjustments); IDAHO CODE ANN. § 61-1606 (Supp. 2008) (enacted 2005) (similar); IND. CODE ANN. § 8-1-8.9-15 (West Supp. 2007) (enacted 2007) (securitization by public utilities of tariffs charged to recover for the costs of purchasing natural gas produced by coal gasification); MD. CODE ANN., PUB. UTIL. COS. § 7-539 (LexisNexis

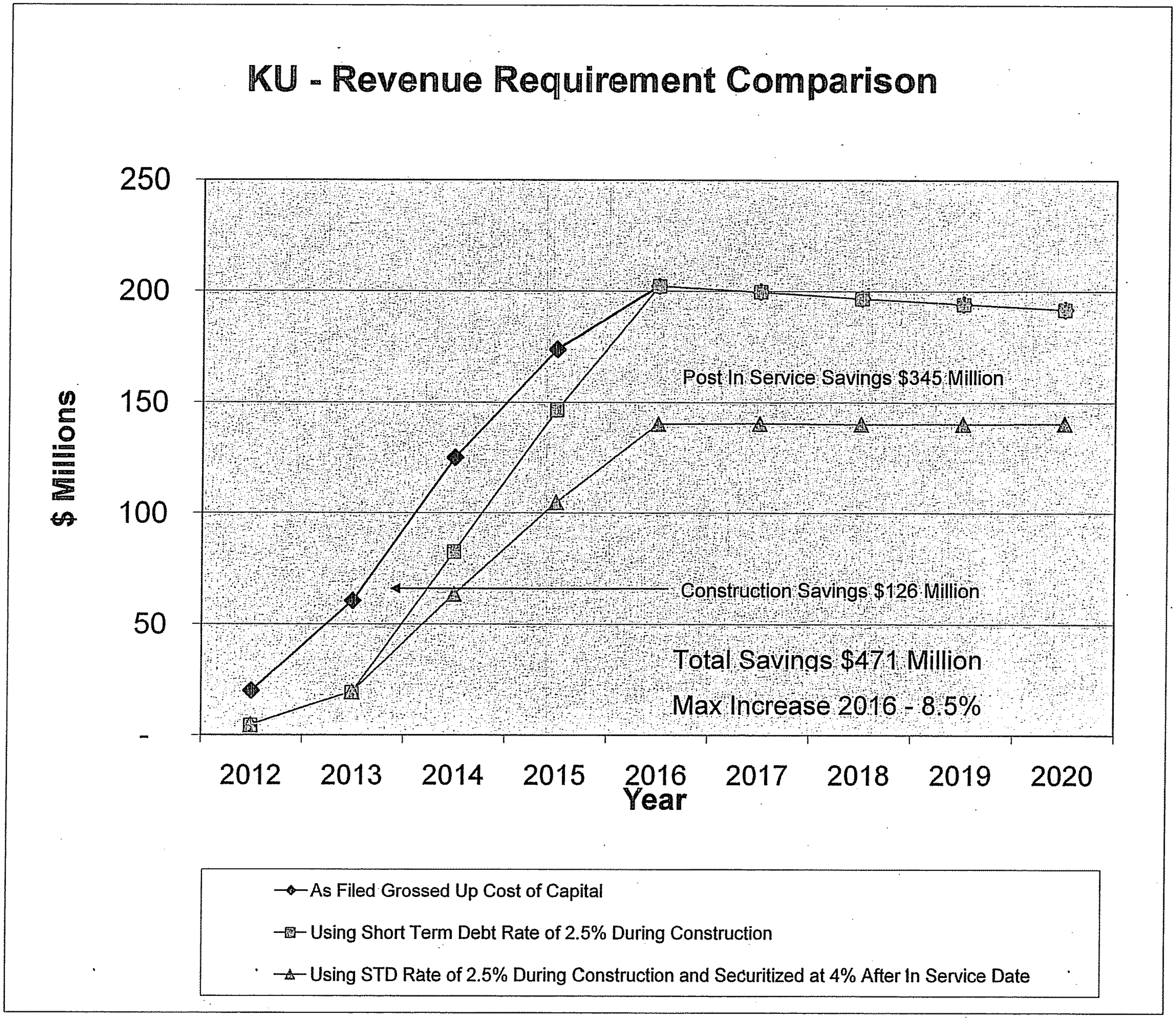
[2] W. Va. Code, Section 24-2-4e(1).

[3] W. Va. Code, Section 24-2-4e.

2008) (enacted 2006) (securitization by electric utilities of tariffs charged to smooth a sharp increase of rates following the end of a regulatory freeze).

Conclusion

With new and proposed EPA regulations likely requiring billions of dollars in capital investments by Kentucky electric utilities in the next several years, finding least-cost ways to finance these expenditures will be critical to Kentucky's goals of retaining and attracting industry and providing low-cost power to its residents. Securitization is a proven, low-cost financing technique that should be considered, along with other alternatives. It may be possible to combine securitization with more traditional financing techniques, allowing utilities to earn a rate-of-return on a portion of their costs, while financing the other portion through securitization.

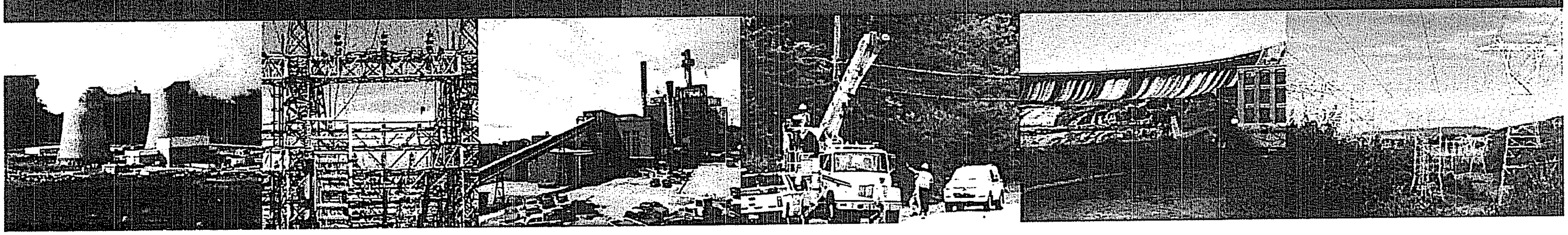


KU - Revenue Requirement Comparison
250
200
150
100
50
-
$ Millions
Post In Service Savings $345 Million
Construction Savings $126 Million
Total Savings $471 Million
Max Increase 2016 - 8.5%
2012
2013
2014
2015
2016
2017
2018
2019
2020
Year
As Filed Grossed Up Cost of Capital
Using Short Term Debt Rate of 2.5% During Construction
Using STD Rate of 2.5% During Construction and Securitized at 4% After In Service Date

DRAFT 5/6/2011 3:00 p.m.

Deutsche Bank Conference

PPL Corporation
May 11, 2011



Cautionary Statements and Factors That May Affect Future Results

Any statements made in this presentation about future operating results or other future events are forward-looking statements under the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. Actual results may differ materially from such forward-looking statements. A discussion of factors that could cause actual results or events to vary is contained in the Appendix to this presentation and in the Company's SEC filings.

Investment Highlights

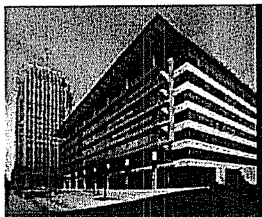
- Predominantly rate regulated company with significant growth prospects
  - Operations in constructive jurisdictions
  - Approximately two-thirds of regulated capital expenditures earn real-time or near real-time returns
  - ~ 9% compound annual growth in rate base from 2011 to 2015
  - Expect 75% of 2013 EBITDA from regulated businesses
- Highly attractive generation fleet
  - Competitively positioned nuclear, hydro and efficient coal
    - Complemented by flexible dispatch gas fired units
    - No significant exposure to currently proposed environmental regulations
  - Multiple drivers of significant upside
    - Increasing natural gas prices
    - Increasing heat rates
    - Environmental regulation
- Business Risk Profile rated "Excellent" by S&P
  - Stable ratings outlooks
- Secure dividend with strong potential for future growth

PPL has a highly attractive and differentiated position in the electric industry

ppl™

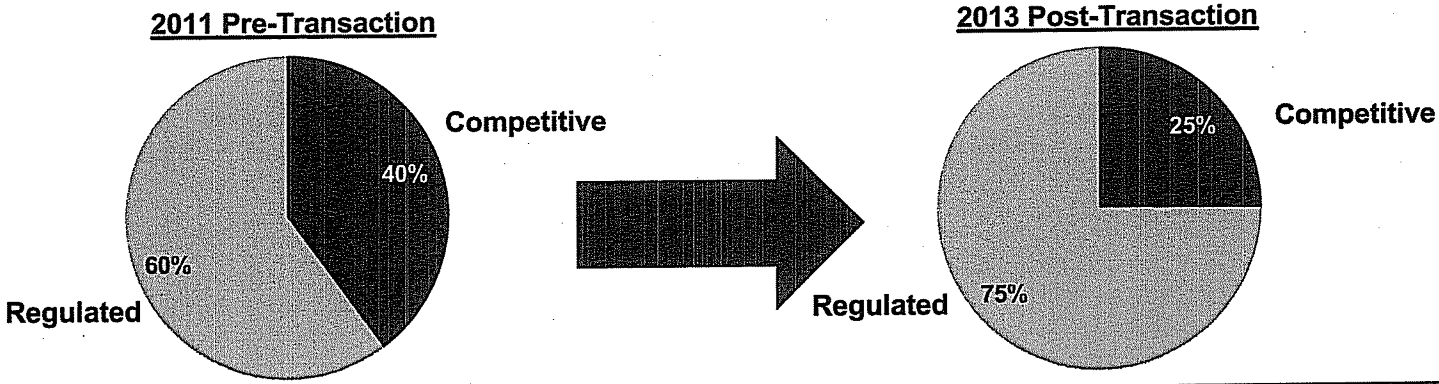
Our Strengths

- Strong regulatory relationships
- Best in class reliability, customer service
- Strong operating performance – regulated and competitive
- Strong carbon and other environmental position
- Excellent cost-management
- Knowledgeable, dedicated employees

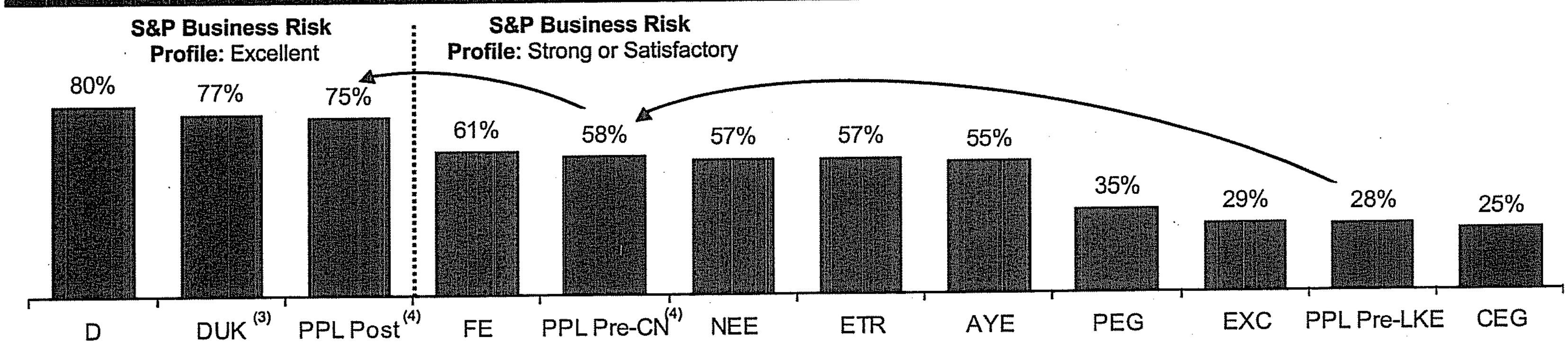


Predominantly Regulated Business Mix

EBITDA Projection (1)



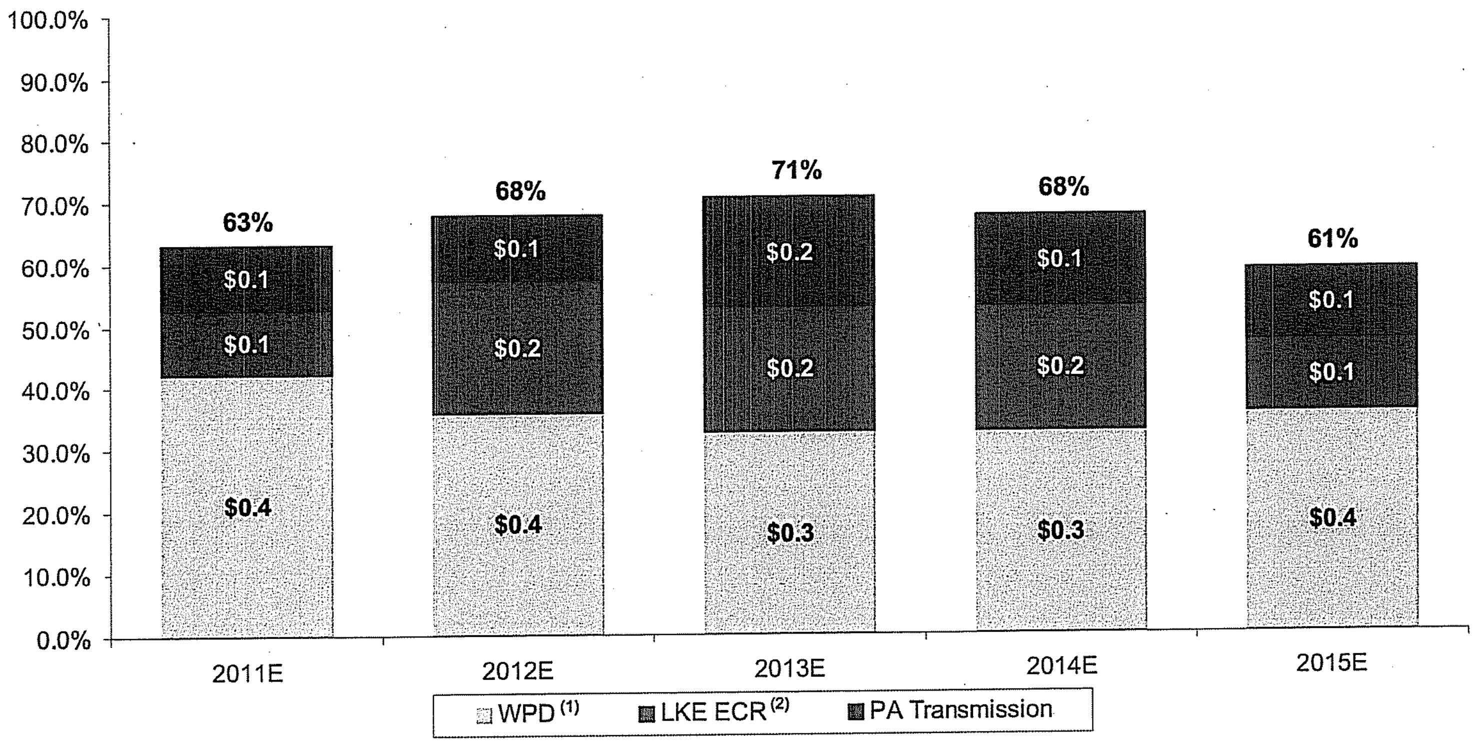
Regulated Cash Flow (2)



(1) *Approximate projections.*
(2) *"Does The Shale Gas Glut Pose A Threat To U.S. Integrated Power Merchants' Credit Quality?" Standard & Poor's, October 22, 2010.*
(3) *Based on EBIT estimate from company presentation.*
(4) *PPL estimates; CN pre-transaction figure based on 2011 FFO; post-transaction figure based on 2013 FFO for the combined entity, which includes full realization of synergies.*

Real-Time Recovery of Majority of Regulated Capex Spending

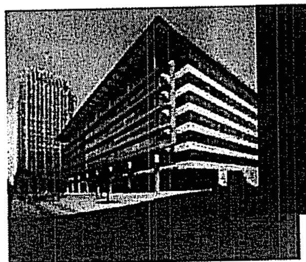
Approximately two-thirds of regulated capital expenditures earn returns subject to minimal or no regulatory lag



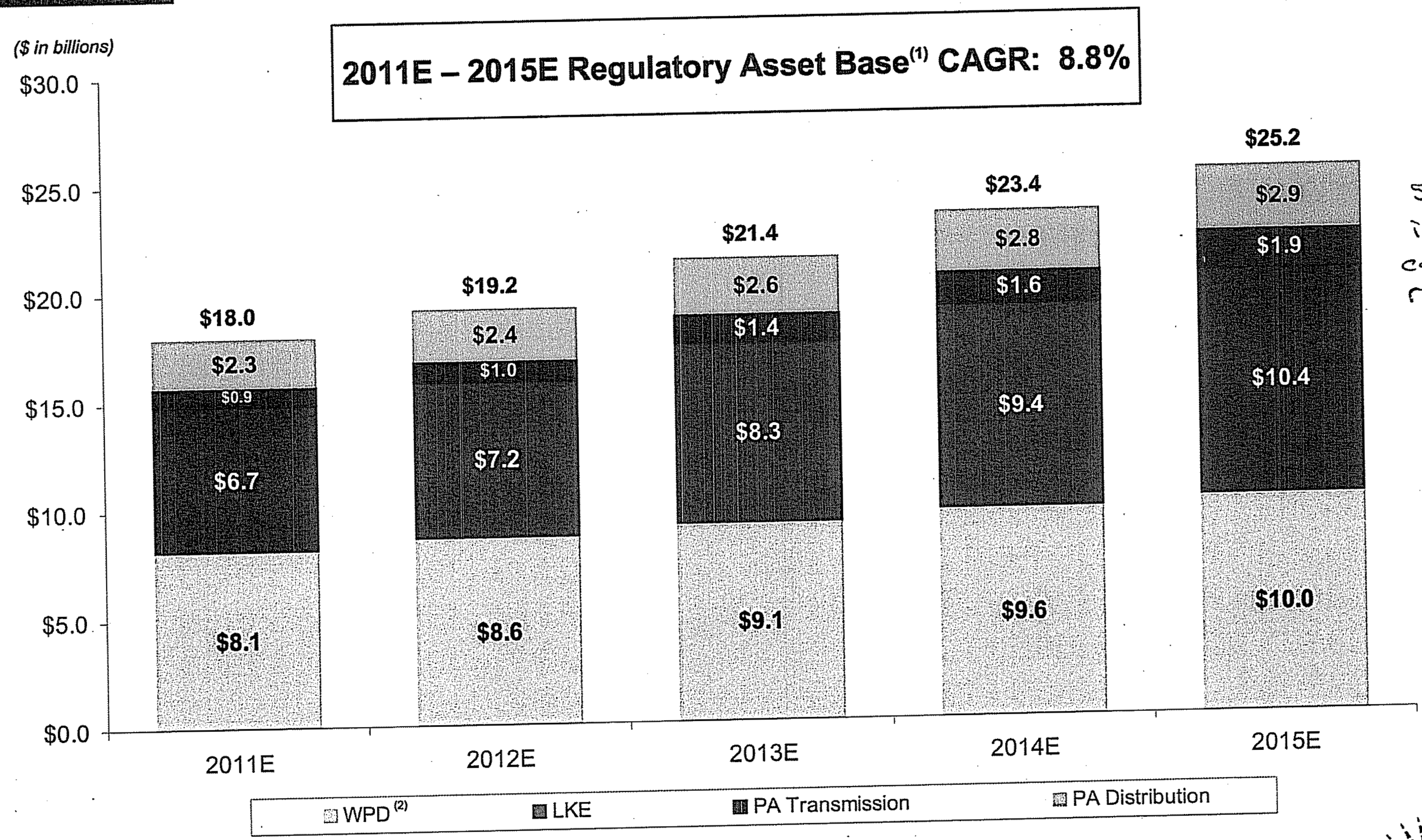
Note: *$ in billions.*

(1) *Figures based on assumed exchange rate of $1.60 / GBP. Includes capex for WPD Midlands.*

(2) *Assumes approximately 85% of timely returns via ECR mechanism based on historical experience.*

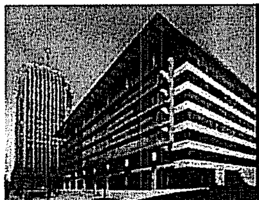


Regulated Rate Base Growth



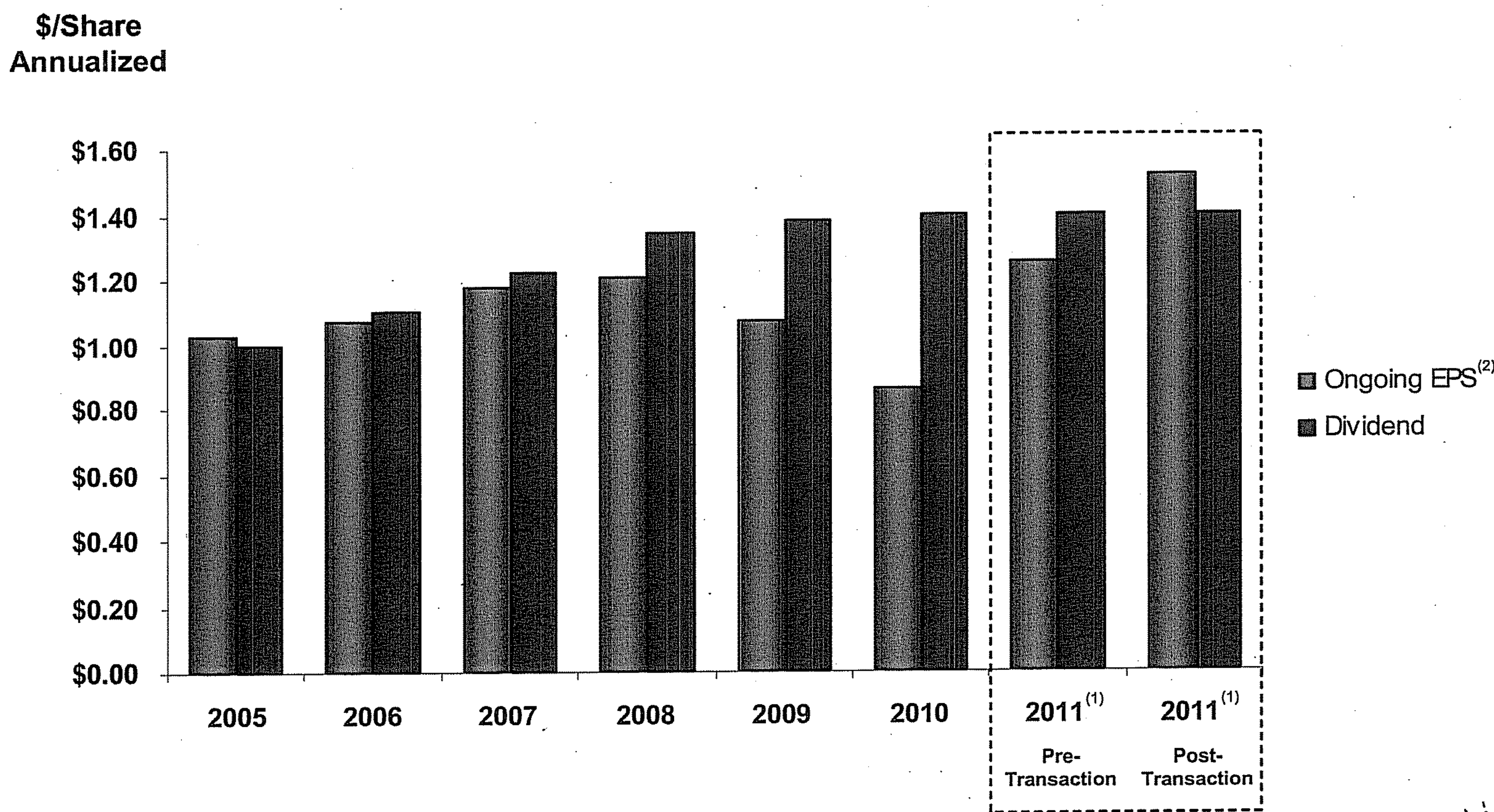
55 % increase in Kentucky capitalization/ rate base

(1) Represents capitalization for LKE, as LG&E and KU rate constructs are based on capitalization. Represents Regulatory Asset Value (RAV) for WPD.
(2) Includes RAV for WPD Midlands. Figures based on assumed exchange rate of $1.60 / GBP and are as of year-end December 31.



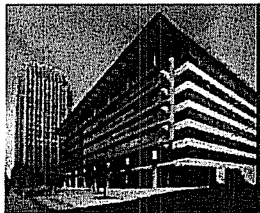
Dividend Profile

A significantly more rate-regulated business mix provides strong support for current dividend and a platform for future growth

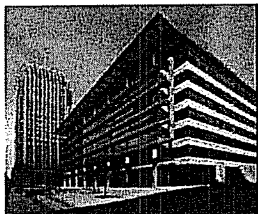


(1) *Ongoing EPS based on mid-point of forecast. Annualized dividend based on 1st quarter declaration. Actual dividends to be determined by Board of Directors.*

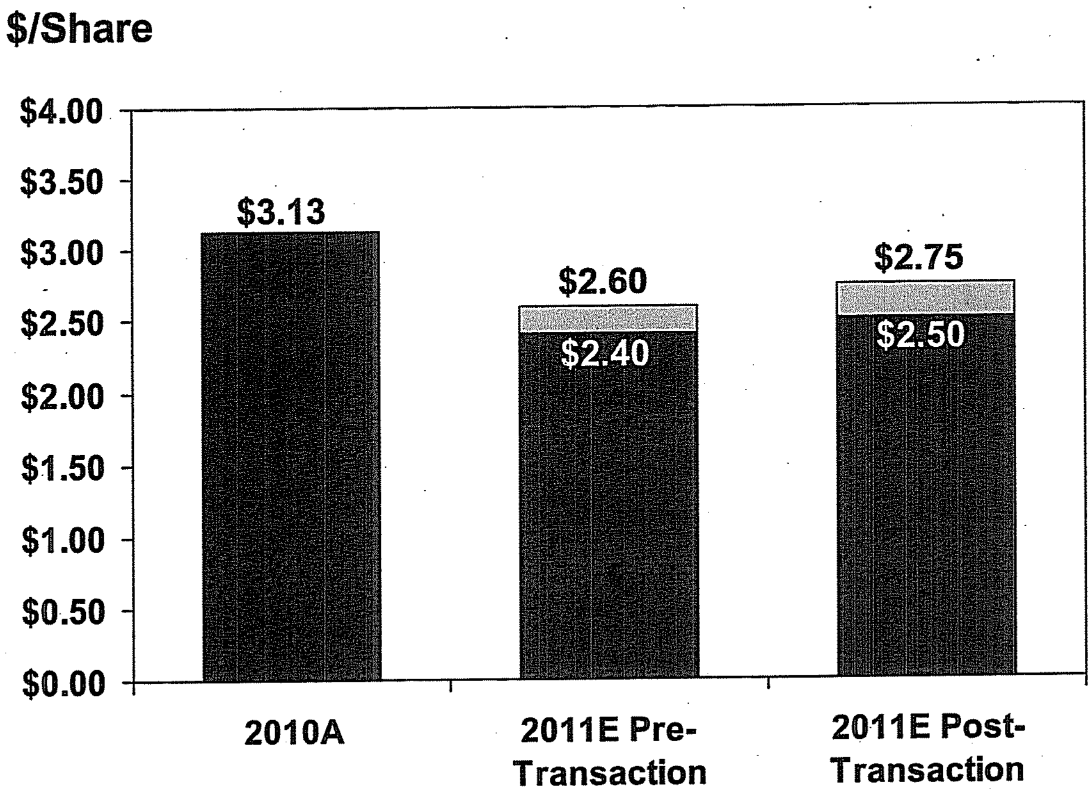
(2) *From only regulated segments.*

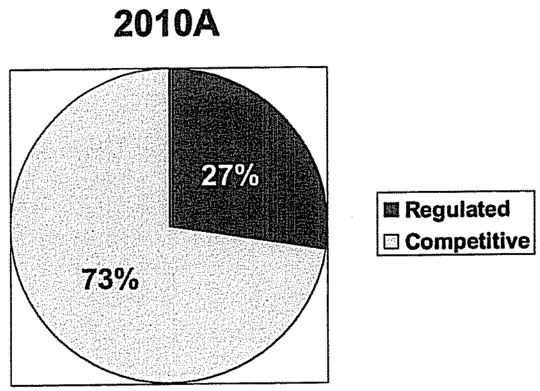


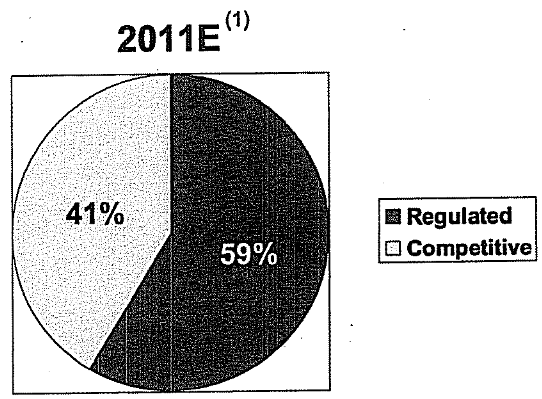
Appendix



2011 Earnings from Ongoing Operations Forecast

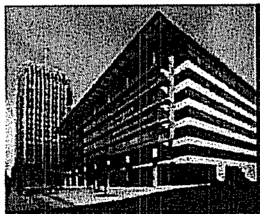






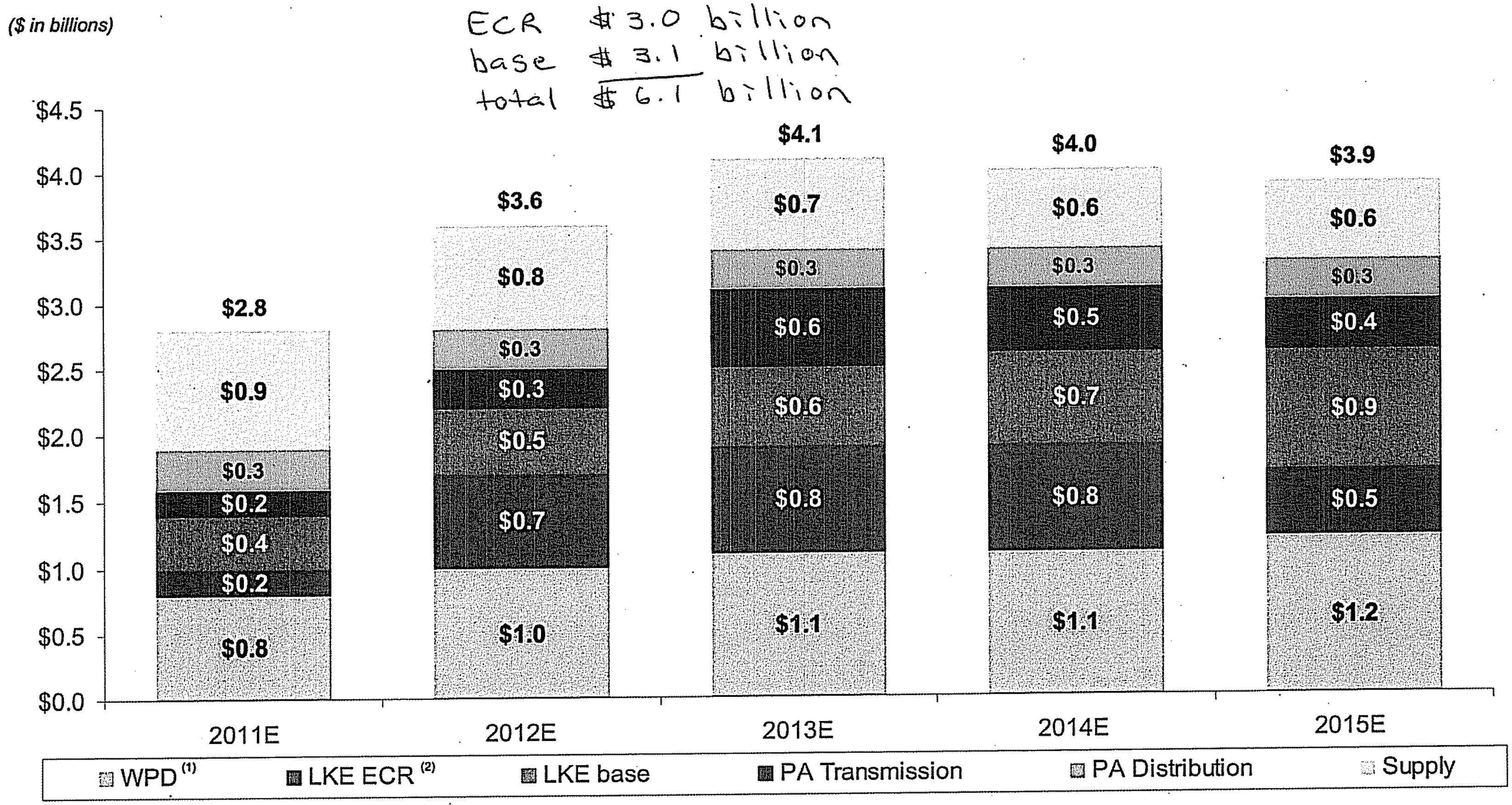
(1) Based on mid-point of forecasted earnings range.

Note: See appendix for reconciliation of earnings from ongoing operations to reported earnings.

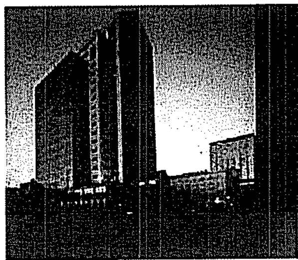


Capital Expenditures

Kentucky Cap. Ex. Growth
ECR $3.0 billion
base $3.1 billion
total $6.1 billion

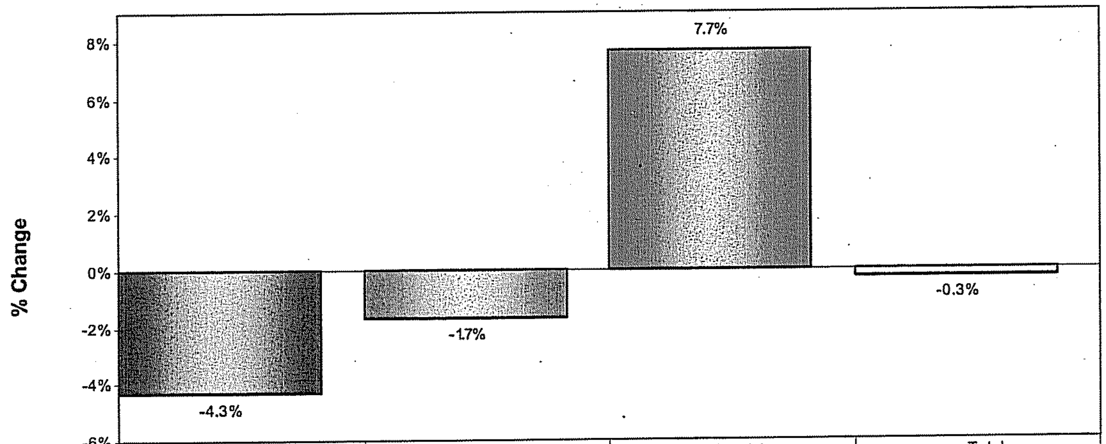


(1) *Includes capex for WPD Midlands. Figures based on assumed exchange rate of $1.60 / GBP.*
(2) *Expect approximately 85% to receive timely returns via ECR mechanism based on historical experience.*



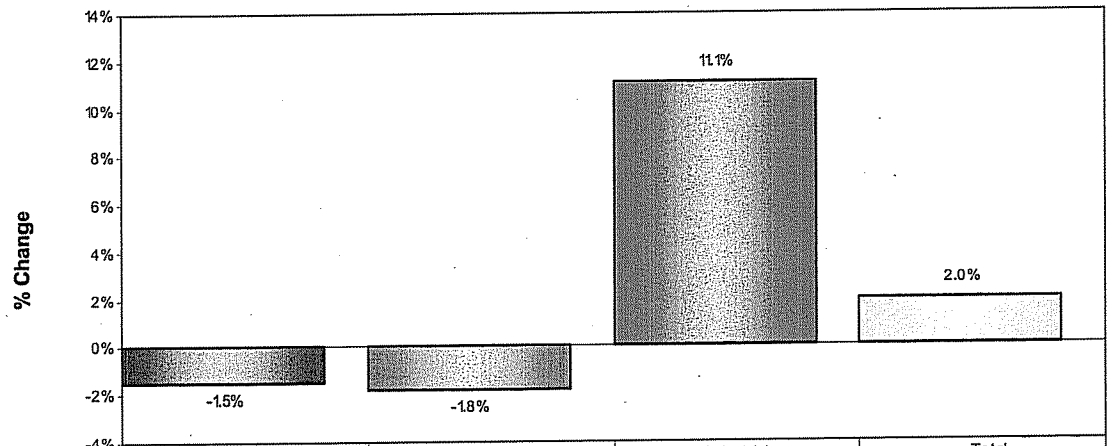
Kentucky Regulated Volume Variances

3-months Ended 3/31 2011 vs 2010



	Residential	Commercial	Industrial	Total
Weather-Normalized (charted)	-4.3%	-1.7%	7.7%	-0.3%
Actual	-10.2%	-3.8%	7.5%	-3.4%

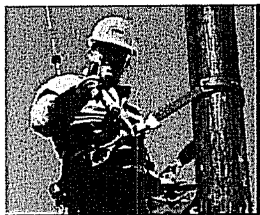
12-months Ended 3/31 2011 vs 2010



	Residential	Commercial	Industrial	Total
Weather-Normalized (charted)	-1.5%	-1.8%	11.1%	2.0%
Actual	4.2%	1.2%	11.5%	4.9%

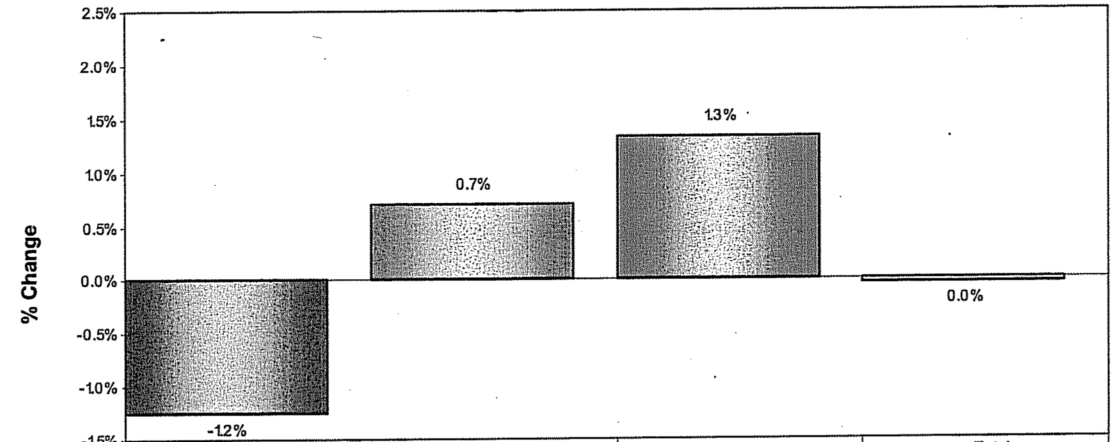
Note: Total includes Residential, Commercial and Industrial customer classes as well as "Other", which is not depicted on the charts above.

ppl



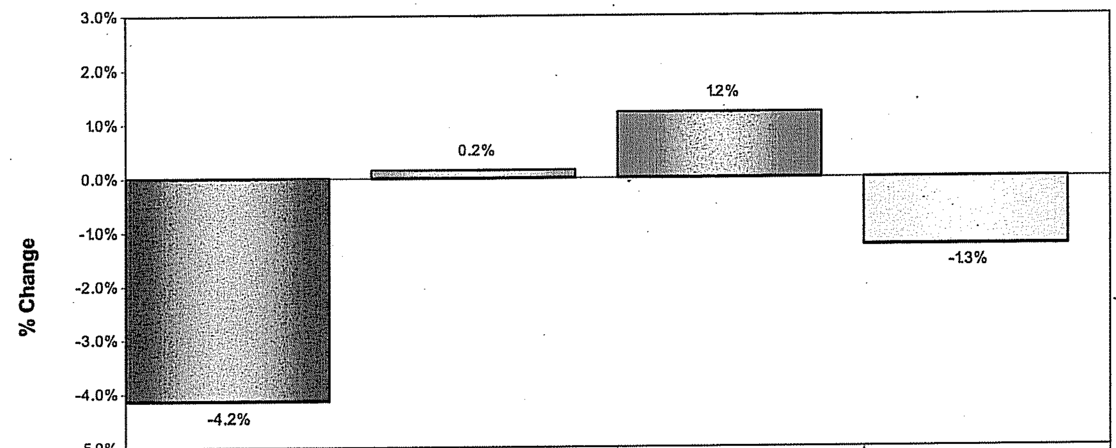
PA Regulated Volume Variances

3-months Ended 3/31 2011 vs 2010



	Residential	Commercial	Industrial	Total
Weather-Normalized (charted)	-1.2%	0.7%	1.3%	0.0%
Actual	1.9%	2.0%	1.3%	1.8%

12-months Ended 3/31 2011 vs 2010



	Residential	Commercial	Industrial	Total
Weather-Normalized (charted)	-4.2%	0.2%	1.2%	-1.3%
Actual	1.9%	2.6%	1.2%	2.0%

Note: Total includes Residential, Commercial and Industrial customer classes as well as "Other", which is not depicted on the charts above.

Enhancing Value Through Active Hedging

	2011[4]	2012
Baseload		
Expected Generation[1] (Million MWhs)	**50.7**	**54.7**
East	42.5	46.2
West	8.2	8.5
Current Hedges (%)	**99%**	**86%**
East	100%	84%
West	97%	94%
Average Hedged Price (Energy Only) ($/MWh)[2] [3]		
East	$57	$55-56
West	$54	$53-54
Current Coal Hedges (%)	**99%**	**96%**
East	99%	94%
West	100%	100%
Average Hedged Consumed Coal Price (Delivered $/Ton)		
East	$73-74	$76-80
West	$23-28	$23-29
Intermediate/Peaking		
Expected Generation[1] (Million MWhs)	7.1	6.2
Current Hedges (%)	58%	26%

Capacity revenues are expected to be $430 million, $385 million and $590 million for 2011, 2012 and 2013, respectively.

As of March 31, 2011

(1) Represents expected sales based on current business plan assumptions. Amounts do not reflect the impact of the Susquehanna turbine blade inspection/replacement outages.

(2) The 2011 average hedge energy prices are based on the fixed price swaps as of March 31, 2011; the prior collars have all been converted to fixed swaps.

(3) The 2012 ranges of average energy prices for existing hedges were estimated by determining the impact on the existing collars resulting from 2012 power prices at the 5th and 95th percentile confidence levels.

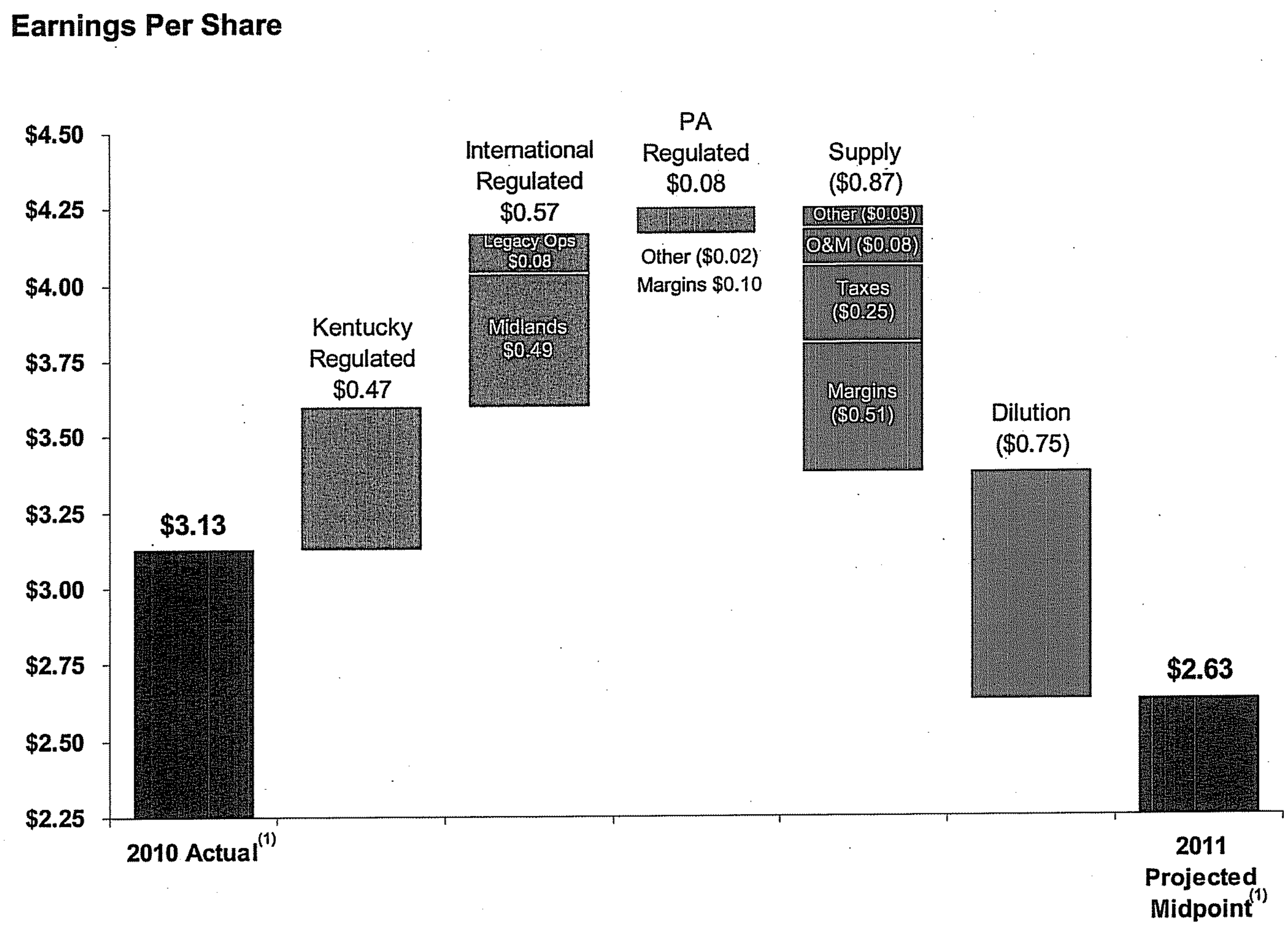
(4) Includes three months of actual results.

Market Prices

	2011	2012
ELECTRIC		
PJM		
On-Peak	$52	$54
Off-Peak	$37	$40
ATC(1)	$44	$46
Mid-Columbia		
On-Peak	$30	$39
Off-Peak	$21	$29
ATC(1)	$26	$35
GAS(2)		
NYMEX	$4.57	$5.06
TZ6NNY	$5.07	$5.83
PJM MARKET		
HEAT RATE(3)	10.2	10.6
CAPACITY PRICES *(Per MWD)*	$136.79	$123.63
EQA	88.3%	89.8%

(1) 24-hour average.
(2) NYMEX and TZ6NNY forward gas prices on 3/31/2011.
(3) Market Heat Rate = PJM on-peak power price divided by TZ6NNY gas price.

2010 to 2011 Earnings Walk

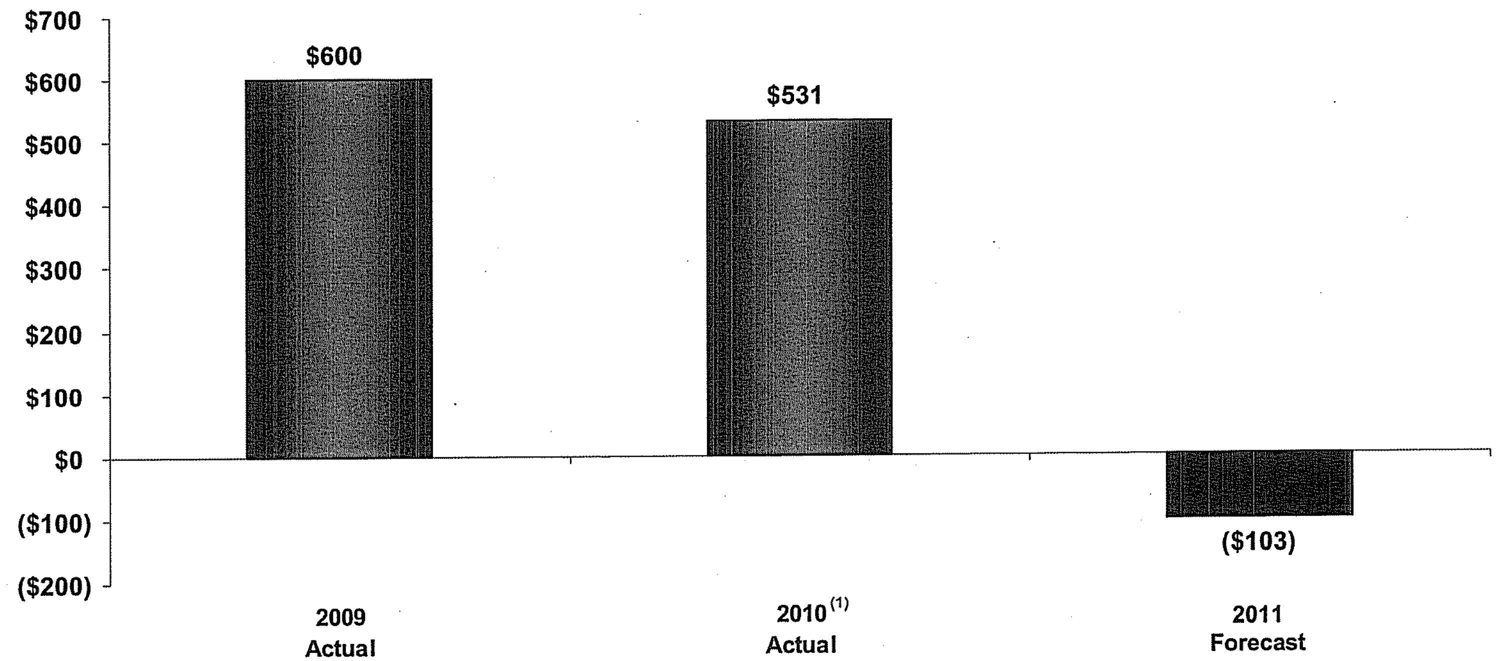


(1) Earnings from ongoing operations.

Note: See Appendix for the reconciliation of earnings from ongoing operations to reported earnings.

Free Cash Flow before Dividends

Millions of Dollars



(1) 2010 Free Cash Flow includes two months of the results of the Kentucky Regulated segment.

Note: See Appendix for reconciliation of free cash flow before dividends to cash from operations.

Shares Outstanding

Average Common Shares Outstanding (1)

(in millions)

As of:

March 31, 2011	485 (A)
December 31, 2011	557 (E)
December 31, 2012	582 (E)

(1) Projected average common shares outstanding include common stock issued for the acquisition of WPD Midlands and projected shares issued to satisfy DRIP and compensation-related stock requirements. These projections do not include common stock issued to fund future growth.

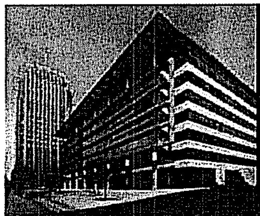
(A) Actual for quarter ended March 31, 2011.

(E) Estimate for average shares outstanding for the year indicated.

PPL Corporation Reconciliation of Cash from Operations to Free Cash Flow before Dividends

(Millions of Dollars)

	2009	2010	2011
Cash from Operations	$1,852	$2,034	$2,200
Increase (Decrease) in cash due to:			
Capital Expenditures	(1,265)	(1,644)	(2,837)
Sale of Assets	84	161	382
Other Investing Activities – Net	(71)	(20)	152
Free Cash Flow before Dividends	$ 600	$ 531	$ (103)

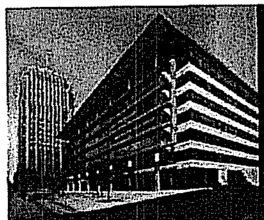


Reconciliation of PPL's Earnings from Ongoing Operations to Reported Earnings

(Per Share)

	Forecast		Actual	
	High 2011	Low 2011	2010	2009
Earnings from Ongoing Operations per share of common stock	$ 2.75	$ 2.50	$ 3.13	$ 1.95
Special Items:				
Energy-related economic activity	0.03	0.03	(0.27)	(0.59)
Sales of assets:				
Maine hydroelectric generation business			0.03	0.06
Long Island generation business				(0.09)
Latin American businesses				(0.07)
Interest in Wyman Unit 4				(0.01)
Impairments:				
Impacts from emission allowances			(0.02)	(0.05)
Other asset impairments				(0.01)
Central Networks acquisition-related costs:				
Bridge Facility costs	(0.02)	(0.02)		
Other acquisition-related costs	(0.02)	(0.02)		
Foreign currency-related economic hedges	(0.01)	(0.01)		
LKE acquisition-related costs:				
Monetization of certain full-requirement sales contracts			(0.29)	
Anticipated sale of certain non-core generation facilities			(0.14)	
Bridge Facility costs			(0.12)	
Discontinued cash flow hedges & ineffectiveness			(0.06)	
Reduction of credit facility			(0.01)	
Other acquisition-related costs			(0.05)	
Workforce reductions				(0.03)
Other:				
Montana hydroelectric litigation			(0.08)	(0.01)
Health Care Reform - tax impact			(0.02)	
Change in U.K. tax rate			0.04	
U.S. Tax Court ruling (U.K. Windfall Profits Tax)			0.03	
Change in tax accounting method related to repairs				(0.07)
Total Special Items	(0.02)	(0.02)	(0.96)	(0.87)
Reported Earnings per share of common stock	$ 2.73	$ 2.48	$ 2.17	$ 1.08

Note: Per share amounts are based on diluted shares outstanding.



Forward-Looking Information Statement

Statements contained in this presentation, including statements with respect to future earnings, cash flows, financing, regulation and corporate strategy are "forward-looking statements" within the meaning of the federal securities laws. Although PPL Corporation believes that the expectations and assumptions reflected in these forward-looking statements are reasonable, these statements are subject to a number of risks and uncertainties, and actual results may differ materially from the results discussed in the statements. The following are among the important factors that could cause actual results to differ materially from the forward-looking statements: market demand and prices for energy, capacity and fuel; weather conditions affecting customer energy usage and operating costs; competition in power markets; the effect of any business or industry restructuring; the profitability and liquidity of PPL Corporation and its subsidiaries; new accounting requirements or new interpretations or applications of existing requirements; operating performance of plants and other facilities; the length of scheduled and unscheduled outages at our plants, including the current outage at Unit 2 of our Susquehanna nuclear plant to inspect and repair turbine blades, and the timing and outcome of any similar outage for inspections at Unit 1 of the Susquehanna plant; environmental conditions and requirements and the related costs of compliance, including environmental capital expenditures and emission allowance and other expenses; system conditions and operating costs; development of new projects, markets and technologies; performance of new ventures; asset or business acquisitions and dispositions, and PPL Corporation's ability to realize the expected benefits from acquired businesses, including the 2010 acquisition of Louisville Gas and Electric Company and Kentucky Utilities Company and the 2011 acquisition of the Central Networks electricity distribution businesses in the U.K.; any impact of hurricanes or other severe weather on our business, including any impact on fuel prices; receipt of necessary government permits, approvals, rate relief and regulatory cost recovery; capital market conditions and decisions regarding capital structure; the impact of state, federal or foreign investigations applicable to PPL Corporation and its subsidiaries; the outcome of litigation against PPL Corporation and its subsidiaries; stock price performance; the market prices of equity securities and the impact on pension income and resultant cash funding requirements for defined benefit pension plans; the securities and credit ratings of PPL Corporation and its subsidiaries; political, regulatory or economic conditions in states, regions or countries where PPL Corporation or its subsidiaries conduct business, including any potential effects of threatened or actual terrorism or war or other hostilities; foreign exchange rates; new state, federal or foreign legislation, including new tax legislation; and the commitments and liabilities of PPL Corporation and its subsidiaries. Any such forward-looking statements should be considered in light of such important factors and in conjunction with PPL Corporation's Form 10-K and other reports on file with the Securities and Exchange Commission.

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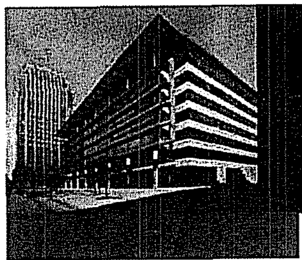

Definitions of Non-GAAP Financial Measures

"Earnings from ongoing operations" should not be considered as an alternative to reported earnings, or net income attributable to PPL, which is an indicator of operating performance determined in accordance with generally accepted accounting principles (GAAP). PPL believes that "earnings from ongoing operations," although a non-GAAP financial measure, is also useful and meaningful to investors because it provides management's view of PPL's fundamental earnings performance as another criterion in making investment decisions. PPL's management also uses "earnings from ongoing operations" in measuring certain corporate performance goals. Other companies may use different measures to present financial performance.

"Earnings from ongoing operations" is adjusted for the impact of special items. Special items include:

- *Energy-related economic activity (as discussed below).*
- *Foreign currency-related economic hedges.*
- *Gains and losses on sales of assets not in the ordinary course of business.*
- *Impairment charges (including impairments of securities in the company's nuclear decommissioning trust funds).*
- *Workforce reduction and other restructuring impacts.*
- *Acquisition-related costs and charges.*
- *Other charges or credits that are, in management's view, not reflective of the company's ongoing operations.*

Energy-related economic activity includes the changes in fair value of positions used economically to hedge a portion of the economic value of PPL's generation assets, full-requirement sales contracts and retail activities. This economic value is subject to changes in fair value due to market price volatility of the input and output commodities (e.g., fuel and power) prior to the delivery period that was hedged. Also included in energy-related economic activity is the ineffective portion of qualifying cash flow hedges, the monetization of certain full-requirement sales contracts and premium amortization associated with options. This economic activity is deferred, with the exception of the full-requirement sales contracts that were monetized, and included in earnings from ongoing operations over the delivery period of the item that was hedged or upon realization. Management believes that adjusting for such amounts provides a better matching of earnings from ongoing operations to the actual amounts settled for PPL's underlying hedged assets. Please refer to the Notes to the Consolidated Financial Statements and MD&A in PPL Corporation's periodic filings with the Securities and Exchange Commission for additional information on energy-related economic activity.

"Free cash flow before dividends" is derived by deducting capital expenditures and other investing activities-net, from cash flow from operations. Free cash flow before dividends should not be considered as an alternative to cash flow from operations, which is determined in accordance with GAAP. PPL believes that free cash flow before dividends, although a non-GAAP measure, is an important measure to both management and investors, as it is an indicator of the company's ability to sustain operations and growth without additional outside financing beyond the requirement to fund maturing debt obligations. Other companies may calculate free cash flow before dividends in a different manner.